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February 3, 2003

The Honorable Magalie Roman Salas
Secretary
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, D.C. 20426

Re: ***San Diego Gas & Electric Co., et al.***
Docket Nos. EL00-95-045, *et al.*

Dear Secretary Salas:

Enclosed for filing are one original and fourteen copies of the Reply Comments of the California Independent System Operator Corporation on Proposed Findings of California Refund Liability, submitted in the above-captioned proceeding. Two courtesy copies of this filing are being provided to Presiding Judge Bruce L. Birchman.

Also enclosed are two extra copies of the filing to be time/date stamped and returned to us by the messenger. Thank you for your assistance. Please contact the undersigned if you have any questions regarding this filing.

Sincerely,

J. Phillip Jordan
Bradley R. Miliauskas

Counsel for the California
Independent System Operator
Corporation

Enclosures

cc: The Honorable Bruce L. Birchman
Service List

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

San Diego Gas & Electric Company,	)	
	)	
Complainant,	)	
	)	
v.	)	**Docket No. EL00-95-045**
	)	
Sellers of Energy and Ancillary Service Into Markets Operated by the California Independent System Operator Corporation and the California Power Exchange,	)	
	)	
Respondents.	)	
	)	
	)	
Investigation of Practices of the California Independent System Operator and the California Power Exchange	)	**Docket No. EL00-98-042**

REPLY COMMENTS OF THE CALIFORNIA INDEPENDENT SYSTEM OPERATOR CORPORATION ON PROPOSED FINDINGS ON CALIFORNIA REFUND LIABILITY

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Dated: February 3, 2003

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UNITED STATES OF AMERICA
BEFORE THE
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San Diego Gas & Electric Company, **Complainant,** **v.** **Sellers of Energy and Ancillary Service Into Markets Operated by the California Independent System Operator Corporation and the California Power Exchange,** **Respondents.**	)	**Docket No. EL00-95-045**
Investigation of Practices of the California Independent System Operator and the California Power Exchange	)	**Docket No. EL00-98-042**

REPLY COMMENTS OF THE CALIFORNIA INDEPENDENT SYSTEM OPERATOR CORPORATION ON PROPOSED FINDINGS ON CALIFORNIA REFUND LIABILITY

Pursuant to the Commission's "Order on Clarification and Rehearing," 97 FERC ¶ 61,275, issued on December 19, 2001 ("December 19 Rehearing Order"), and "Notice Regarding Comment Dates," issued on December 13, 2002, the ISO provides the following reply comments in response to the initial comments submitted by a number of parties addressing the Presiding Judge's "Proposed Findings on California Refund Liability," 101 FERC ¶ 63,026, issued on December 12, 2002 ("Proposed Findings").[1]

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[1] Capitalized terms not otherwise defined herein are defied in the Master Definitions Supplement, ISO Tariff Appendix A, as filed on August 15, 1997, and subsequently revised. Additionally, citations herein to filings by parties are citations to those parties' initial comments (due January 13, 2002), except where otherwise noted.

I. COMMENTS

A. The Presiding Judge Was Correct in Finding That Incremental Heat Rates Should Be Universally Used in the MMCP Formula (Phase 1 – Issues I.B.1 and I.C)

1. Overview: The Presiding Judge Has Correctly Implemented the Commission's Balanced and Principled Approach to the Heat Rate Issue for the Refund Period

The Commission developed a framework for dealing with the Refund Period that includes four basic principles:

Principle 1: The mitigated market clearing price ("MMCP") for each interval will be a single price measured by the marginal cost of the last unit dispatched in that interval through the ISO's Real Time Market;

Principle 2: The measure of marginal cost will be limited to estimated incremental gas costs, determined by using incremental heat rates and a gas cost proxy, plus a $6/MWh proxy "adder" for O&M costs;

Principle 3: Any emission costs associated with spot market sales subject to mitigation are to be recovered separately, by netting these off refund obligations;

Principle 4: Each seller may seek for its whole portfolio over the whole Refund Period a cost of service alternative to recovery based upon the MMCP, so that no seller will receive less than full embedded costs and a reasonable return on investment.

The question of average versus incremental heat rates is a part of the measurement of marginal cost; however, the issue must be considered, as the Presiding Judge did, in the context of the Commission's whole framework of calculating MMCPs. The Proposed Findings agreed with the Commission that the marginal cost of the last unit dispatched is to be determined using incremental heat rates (Principle 2). Proposed Findings ¶ 67. Various sellers, primarily the California Generators ("Generators") and the Competitive Supplier Group ("CSG"), contend that the Commission intended (or should have intended) that average heat rates be used. The fallacy of sellers' contention is quickly established. The first step is to recognize, as did the Proposed Findings, that the Commission's approach to the MMCP for the Refund Period is on the issue of the appropriate heat rate exactly the same as its approach to the proxy clearing price for the prospective period. The identical nature of the two approaches was made clear by the Commission in *San Diego Gas & Electric Co., et al.*, 96 FERC ¶ 61,120 (2001) ("July 25 Order"), when it accepted the Chief Judge's recommendation to use the same approach to calculating the MMCP for the Refund Period as the Commission had established for calculating the proxy clearing price for the prospective period.[2] July 25 Order at 61,516.

The second step is to recognize that it is beyond dispute that the marginal cost of the last unit dispatched, for the purpose of calculating the proxy clearing price prospectively, is to be based on incremental heat rates. The Commission in the very first relevant order explicitly stated that incremental heat rates were to be used. *San Diego Gas & Electric Co., et al.*, 95 FERC ¶ 61,115, 61,539 (2001) ("April 26 Order").

[2] Except for minor changes having nothing to do with the question of whether incremental or average heat rates should be use in calculating the MMCP.

The Commission has subsequently approved ISO compliance filings and reports in which the ISO has been explicit that it is using incremental heat rates to calculate the proxy clearing price. *See* Proposed Findings ¶¶ 41-43. And finally, the Commission clarified in *San Diego Gas & Electric Co., et al.*, 99 FERC ¶ 61,159 (2002) ("May 15 Clarification Order"), that incremental heat rates are to be used. May 15 Clarification Order at 61,646. Since the proxy clearing price is to be calculated using incremental heat rates, and the Commission intended the MMCP to be calculated the same way as the proxy clearing price, it follows that the Commission intended the MMCP also to be calculated using incremental heat rates.

Those two steps are sufficient to show the error in the sellers' arguments. But in considering those arguments, it is important also to recognize *why* the Commission would have intended incremental heat rates to be used. When the Commission, in April 2001, first decided to cap prices using incremental heat rates to calculate the marginal cost of the last unit dispatched in an interval, it made clear that its approach was intended to represent neither cost minimization for consumers *nor full cost reimbursement for sellers*. April 26 Order at 61,362. Rather, as the Commission has indicated on various occasions, its entire mitigation effort is intended to emulate the results of a competitive market. *See id.* at 61,354; *San Diego Gas & Electric Co., et al.*, 97 FERC ¶ 61,293, 62,364 (2001) ("December 19 Compliance Order"); *San Diego Gas & Electric Co., et al*, 95 FERC ¶ 61,418, 62,547 (2001) ("June 19 Order"). The Commission is well aware that the use of a single market clearing price allows infra-marginal sellers to earn more than their production costs, but it also requires customers to pay in excess of the actual cost of production to meet demand. When the

Commission later, for the prospective period, allowed generators to recover start-up and (under limited circumstances) minimum load fuel costs, it did not include either of those costs in the proxy market clearing price (*id.*; June 19 Order at 62,563); including either in the proxy clearing price would have been a windfall to units that were on line, and would have increased the amount in excess of actual costs of production that consumers would have to pay.[3] Its approach to emissions costs for the Refund Period was the same: recovery outside the market clearing price. June 19 Order at 62,562. Including minimum load fuel costs in the MMCP, by using average instead of incremental heat rates, would have the very effects that the Commission has avoided elsewhere: huge windfalls to all units that already were on line, and huge wealth transfers from consumers to sellers.

The Commission's approach to the Refund Period is balanced between sellers and consumers and is consistent with the reasonable expectations of all market participants. The approval of the Chief Judge's recommendation[4] to apply the methodology of the June 19 Order (with changes not relevant here) to the Refund Period was in effect a decision by the Commission that the *equitable* outcome for the Refund Period is that outcome which an effectively competitive market would have produced: customers expected to pay prices and sellers expected to receive revenues based upon such a market.

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[3] For the Refund Period, the Commission has not allowed recovery of either start-up costs or minimum load fuel costs. The difference in treatment between the prospective and refund periods is readily explained by the existence of the must-offer requirement prospectively but not for the Refund Period. *See San Diego Gas & Electric Co., et al.*, 99 FERC ¶ 61,160, at 61,657 (2002) ("May 15 Rehearing Order"). The inability to recover start-up or minimum load fuel costs for the Refund Period cannot cause any generator harm, as any generator may seek cost-of-service rates for its entire portfolio over the entire Refund Period. July 25 Order at 61,518; Exh. ISO-19 (Hildebrandt) at 22:11-23:15.

The sellers have been pleased to accept the benefits of the Commission's four principles set out above, including especially a single mitigated market clearing price, but have protested loudly against calculating the MMCP in a way that meets the reasonable expectations of customers. None of their arguments have addressed the equity of meeting customers' reasonable expectations for the Refund Period: a competitive market that would have resulted in prices set by the marginal cost of fuel and variable O&M. None of their arguments acknowledge the balance inherent in the Commission's approach. The sellers fail even to acknowledge the unlimited earnings allowed infra-marginal units by a single market clearing price. They express not the slightest embarrassment that inclusion of minimum load fuel costs in the MMCP would result in a massive transfer of wealth from customers to generators that have *not* incurred those costs in the ISO's markets. Exh. ISO-19 (Hildebrandt) at 32:1-9. On the issue of the use of average versus incremental heat rates for the Refund Period the sellers are simply asking for more money.

To obscure the crassness of their position, the sellers have attempted to draw the Commission into a detailed debate on small issues. It is important to recognize at the outset that the sellers have framed each issue in cost-of-service terms, even though the Commission has been explicit that its approach to the MMCP is intended to replicate a competitive market,[5] not to incorporate cost-of-service principles. In the subsections

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[4] *See San Diego Gas & Electric Co., et al.*, 96 FERC ¶ 63,007, at 65,039-41 (2001) ("July 12 Report") (report and recommendation of Chief Judge for the most part endorsing methodology contained in the June 19 Order).

[5] In the July 12 Report, a refund methodology was recommended that would "recreate the competitive market." July 12 Report at 65,040. That methodology was accepted by the Commission in the July 25 Order at 61,516. Subsequently the Commission confirmed that it was adopting the rationale of the Report, not just its methodology. December 19 Rehearing Order at 62,178 ("refunds would be determined by the difference between prices charged and a *competitive market base-line*. . . ." (emphasis supplied)).

below we will address each of their arguments individually, but the most crucial points are that the sellers have refused to acknowledge the Commission's overall framework, have offered no coherent policy or legal discussion as to why meeting the reasonable expectations of sellers and customers is not an equitable result, and have offered no defense of the unfairness to customers that would be inherent in compensating minimum load fuel costs through the MMCP.

2. The Proposed Findings Implement the Commission's Decision to Calculate a Proxy of a Market Price, Not the Sellers' Wish to Calculate a Proxy for Rate Case Recovery of Costs

a. Sellers Wrongly Suggest That the Marginal Unit Must Recover All Variable Costs in Each 10-Minute Interval

The Generators make much of the fact that in some intervals the "variable" costs of the "last unit dispatched" will include minimum load fuel costs because the unit was not previously operating. Generators at 13. CSG does the same. CSG at 6.[6] The response is that properly functioning markets offer no assurance of full recovery of variable costs – whether they include minimum load fuel costs or not – in any given time interval. Exh. ISO-19 (Hildebrandt) at 22:1-11. It certainly is not correct, as the Generators and CSG assert, that a unit would not run as the result of failing to recover full variable costs for a single 10-minute interval, *id.* at 25:15-26:6, but rather it would seek to recover its full variable costs over an operating cycle or longer. In the short run, each generator has to formulate a bid that balances the desire to recover all variable costs in each interval against the risk of not being dispatched in a market that could prove to be very profitable. *See id.* If, as the Generators strongly suggest, bids were

[6] The Modesto Irrigation District ("MID") makes the same point more dramatically by charging that it would be "nonsensical to focus on the last megawatt dispatched." MID at 8. As MID never explains why

constrained by the requirement that a generator feel certain that total fuel cost would be recovered in each 10-minute interval, the generator would only produce in intervals when the market clearing price exceeds not only marginal cost, but also average cost (*i.e.*, a profitable price). *Id.* There is no evidence in the record to suggest that generators are so risk averse as to decline to operate when they forecast an expected net profit over an operating cycle, but losses in certain (even many) 10-minute intervals. *Id.*

Of course, a unit that incurred minimum load fuel costs solely to generate in the real time market at the request of the ISO might well have stayed on line for many subsequent intervals and, if it were infra-marginal for those intervals, it could have earned enough not only to recover minimum load fuel costs for those intervals, but also for the first interval as well. While it is conceivable that in some cases a unit would be the "last unit dispatched" for a whole operating cycle, in which case it would not recover its full variable costs (*i.e.*, total fuel costs) for that cycle if the MMCP is calculated using incremental heat rates, the Generators have leaped from the possibility of this occurrence to the conclusion that the MMCP for the entire Refund Period should be calculated based upon this occurrence. Generators at 14-18. The leap is too far to be supported by economics, equity, or the record in this proceeding.

The Generators' argument is based on an entirely hypothetical "10-minute world," in which the historical unit commitment decisions are not treated as fixed, and each unit must instead be recommitted or re-dispatched in each 10-minute interval during the Refund Period and must recover its full operating costs in every interval solely on the

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it would be nonsensical we assume that our response to the Generators and CSG in the text above also addresses MID's point.

basis of the MMCP calculated for that interval. However, the Commission decided in the July 25 Order that unit commitment and dispatch decisions are to be treated as fixed for the purposes of calculating the refund. July 25 Order at 61,517. As a result, it is entirely inappropriate to calculate the MMCP, as sellers would, as if each generator was able (or required) to make a unit commitment decision for each 10-minute interval during a historical period. *See* CSG Comments at 12.

The Generators have conveniently ignored the Commission's explicit focus on creating an equitable result for both suppliers and customers by basing the MMCP on the marginal cost. December 19 Rehearing Order at 62,212. The Generators' attempt to slide away from the Commission's focus on an equitable result from meeting expectations of a competitive market by playing a game of words is well-illustrated by their assertion that the "key consideration" in the MMCP Formula for the Refund Period is that the "marginal generating unit should be able to recover their marginal fuel costs in the interval when marginal." Generators at 24. They then proceed to argue that minimum load fuel costs are "marginal." The Generators have it wrong. The question the Commission has faced and answered is whether it is appropriate to include minimum load fuel costs in the market clearing price (MMCP), not whether by some dictionary definition those costs are "marginal" to a particular generator. April 26 Order at 61,354.

b. <u>Record Evidence Supports the Use of Incremental Heat Rates</u>

The evidence cited by the Generators and by CSG related to marginal units running only in response to the ISO does not take even the first small step down the road of making the case for using average heat rates to calculate the MMCP.

Generators at 16-17; CSG at 11-12. That evidence strongly suggests the opposite conclusion: that for the vast bulk of generators the increment to the MMCP resulting from using average heat rates to allow recovery of the minimum load fuel costs would be a windfall unrelated to the costs that they incurred. The Generators cite evidence suggesting that "in a large percentage of the intervals during the Refund Period, marginal generating units were running only in response to ISO real-time energy dispatches and had no other scheduled energy (and thus had no other way to recover their minimum load fuel costs for such intervals)." Generators at 17. Such evidence, even if true, provides no hint as to the size of the payments that would be made to units that did *not* incur minimum load fuel costs in an interval if such costs were included in the MMCP. The Generators cite with approval the testimony of Dr. Berry that shows, using incremental heat rates, only 11 units out of 119 studied would fail to recover their costs over the entire Refund Period. Exh. CAL-26 (Berry) at 15:21-18:9. For those eleven units the evidence does not address whether any unrecovered costs that may have existed for a specific unit were material for the portfolio of any generator. *Id.* This evidence suggests the payments to units that did not incur minimum load fuel costs might be large; however, the Generators have been explicit that the magnitude of those unfair payments is of no moment to them. Generators at 18 ("precision . . . is not required.").

Similarly, the evidence offered by the Generators[7] that generators: use average heat rates for unit commitment decisions; bid in the California market based on expected recovery of total fuel costs; and, for those owning short cycle gas fired combustion turbines, might not start absent recovery of minimum load fuel costs, sheds no light on the central question of whether unrecovered minimum load fuel costs should be allowed to set the market clearing price,[8] and especially not on the magnitude of the need for such a recovery or the magnitude of the windfall in providing recovery for units that did not incur minimum load fuel costs.

c. <u>Sellers Have Misused the Commission's Language</u>

Both the Generators and CSG have engaged in aggressive, none too subtle, language shopping, stringing together a few words taken out of context from various orders to attempt to show that when the Commission said that incremental heat rates were the best measure of marginal costs it really meant that average heat rates were the best measure.

"Recovery of total fuel costs" for each and every 10-minute interval is a cost of service concept that the Generators and CSG have introduced to this proceeding under the cover of the Commission's stated intention not to "punish" unfairly the marginal generators that operated during the Refund Period. Generators at 12-13; CSG at 6. The sentence in which the Commission rejected "unfair punishment" had nothing at all to do with collection of total fuel costs, no less in each 10-minute interval. July 25 Order at 61,517. In that sentence the Commission was addressing a specific issue: should the MMCP be based upon a hypothetical least cost dispatch. The Commission responded that it would not base the MMCP on the marginal costs of a unit that was more efficient than the units that actually ran. *Id.* The Generators and CSG have snatched out of context the phrase "unfairly punishes the very generators that helped keep the lights on in California," pasted it in large letters on their banners, and waved

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7 Generators at 16-17.

8 CSG makes essentially the same argument with respect to unit commitment. CSG at 12.

those banners madly to obscure the fact that the Commission never even hinted that using incremental heat rates to determine marginal costs of the last unit dispatched would unfairly punish generators.

CSG misuses the very same passage of the July 25 Order from which it shopped the "unfairly punishes" language to assert that "the Commission specifically rejected the 'marginal bidding requirement' concept." CSG at 7-8. CSG argues that in this passage the Commission rejected for the Refund Period basing the MMCP on marginal cost in order to allow full fuel cost recovery by generators, thereby requiring the use of average heat rates. The marginal bidding requirement was "rejected," however, in answering the very same question as to which the Commission wished to avoid "unfair punishment": Should the MMCP for the Refund Period be based upon a hypothetical dispatch that would be derived from assumed marginal bidding? The passage cannot reasonably be read to be a rejection of the concept of basing the MMCP on incremental heat rates.

Moving beyond language shopping to writing fiction, CSG applies a "critical cost recovery principle" to the language of the April 26 Order. CSG at 9. After correctly citing that order for the proposition that marginal cost is to be approximated "by using gas costs and emission credit information, which are effectively a unit's running costs," April 26 Order at 61,363, CSG asserts that "the marginal (or average variable) costs of [a] generating unit reflect competitive prices only when the unit's full running costs are recovered." CSG at 9. But the April 26 Order is explicit that there is no such cost recovery principle. April 26 Order at 61,632 ("Since marginal cost pricing best approximates competitive pricing, there is no need to include fixed or *other* costs in the bids." (emphasis supplied)).

The Generators assert that minimum load fuel costs are somehow special. Generators at 13-17. The Generators seek to distinguish minimum load fuel costs, which exist in every interval, from start-up costs, which occur once in an operating cycle. Generators at 13. The Generators do not tell us why the distinction suggests that minimum load fuel costs should affect the MMCP for the Refund Period. The fact that minimum load fuel costs occur in each 10-minute operating period is irrelevant to the question of whether those costs should be recovered through the MMCP.

While the Generators provide no credible empirical evidence that the MMCPs resulting from the use of incremental heat rates are insufficient to cover the actual minimum load costs over unit operating cycles, analysis performed by the California Parties shows that, in practice, the MMCPs resulting from incremental heat rates cover the full unit operating costs of units over virtually every operating cycle, and provide net operating revenues consistent with competitive market outcomes. Exh. CAL-26 (Berry) at 16:22-18:24.

As a result, the assertion by the Generators that "the only reasonable outcome is for the marginal generating unit to receive an MMCP that includes its minimum load fuel costs for that interval," Generators at 17, can only be read as a wish, not a conclusion. The evidence they cite simply cannot support such a conclusion. The reasonable solution to the possibility of unrecovered minimum load fuel costs in the Refund Period is the one adopted by the Commission: a cost of service filing in cases in which the impact of any unrecovered costs is material for a generator's portfolio over the whole Refund Period. *See, e.g.*, July 25 Order at 61,518.

d. Generators' Attempted Retreat to the Concept of "Mixed" Heat Rates is Unavailing

The Generators do not improve their argument by advocating that the Commission use "mixed heat rates," which they define as calculating the MMCP from average heat rates in intervals when the marginal unit is on line only in response to an ISO order. Generators at 12-13. The explicit premise of this proposal is that in some intervals average heat rates are a better choice for use in the MMCP than incremental heat rates. Generators at 13. The premise is false. The arguments favoring the use of incremental over average heat rates in the MMCP apply to *each 10-minute interval.* With "mixed heat rates," in each interval in which average heat rates are used to set the MMCP there will still be: (1) the same large potential for subsidizing generators that have not incurred unrecovered minimum load fuel costs; (2) the same risk that a unit will recover all (or more than all) of its minimum load fuel costs in a later interval; and (3) the same risk that even for a unit that unambiguously operates at the margin on ISO orders for a whole operating cycle, the unrecovered minimum load fuel costs will not be material for the unit, will be recovered in a later (or earlier) operating cycle, or will not be material for the generator's whole portfolio.

The Generators assert that "in a large percentage of intervals" units qualifying for average heat rates were at the margin. Generators at 17. They fail to recognize that as a result, the "mixed heat rate" approach would produce all of the inequitable effects of average heat rates "in a large percentage of intervals." *Id.* "Mixed heat rates" is not an idea that has not been adequately considered by the Presiding Judge, as the Generators argue. Generators at 12-13. It is merely a new way to label the use of average heat rates. The only small shred of substance behind the label is that "mixed heat rates" allow the *possibility* that in some intervals the MMCP could be calculated using incremental heat rates. The Commission has already correctly decided that incremental heat rates are the appropriate method to create a market proxy for all intervals that is equitable as between sellers and customers; the Commission should not now adopt an approach that allows only the possibility of using incremental heat rates in some intervals.

e. <u>Generators Misstate the Goal of the MMCP Formula</u>

The Generators' errors are explained in part by their confusion as to the goal of the MMCP formula. They assert that the Formula "is intended to capture marginal costs of each generator *in every interval*." Generators at 18 (emphasis in original).[9] To the contrary, the Formula is intended to be a reasonable proxy for the price that would be produced by a competitive, efficiently run market, not a perfect cost recovery mechanism.[10] The Commission noted in the April 26 Order that it wanted to address "the need for mitigation in as market-oriented a manner as possible." April 26 Order at 61,354. As to the Refund Period, the Commission has said the same: that it wanted to use a "competitive market base-line." December 19 Rehearing Order at 62,178. In seeking to make the MMCP into a cost recovery mechanism when cost recovery is needed at most by only a few generators part of the time, the Generators would completely undermine the Commission's intent to use the MMCP as a reasonable proxy for a competitive market price.

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9 CSG makes the same argument. CSG at 6-10.

10 The Generators incorrectly attempt to characterize the evidence in the record as to the availability of alternate sources for recovery of minimum load fuel costs as an attempt to prove that no marginal units have unrecovered minimum load fuel costs. That evidence, however, supports the proposition, not contradicted by the California Generators, that most units in the real time market do not need to recover minimum load fuel costs in order to provide incremental energy.

f. <u>There is No Tension Between the Prospective and Refund MMCPs</u>

CSG alleges that there is an inconsistency between the Commission's decision to allow recovery of start-up costs and its denial of recovery of minimum load fuel costs. CSG at 10-11. However, the Commission has granted recovery *both* of start-up costs (under limited circumstances) and of minimum load fuel costs for the *prospective period,* but neither for the Refund Period. There is no tension: Within each period the two costs are treated the same way. The Commission articulated a clear and sensible rationale for not allowing specific recovery of either cost in the Refund Period: the "must-offer" requirement did not exist. May 15 Rehearing Order at 61,658.

3. The Presiding Judge Was Correct in Finding that Heat Rates and Proxy Prices Should Emulate Behavior in a Competitive Market

The Commission made clear that it wanted a mitigation price that was as market-based as possible. April 26 Order at 61,354. One test of whether a proxy emulates the market in a reasonable fashion is to observe whether the movement of the proxy price in response to changes in supply and demand tracks either the expected movement of market prices or the historical movement of market prices. Proposed Findings ¶ 68. The Generators turn this test on its head by arguing that the failure of a market proxy price using average heat rates to behave in the expected fashion is perfectly acceptable because "the MMCP Formula is a cost-based calculation." Generators at 20.[11] The

[11] MID also seems to have some problems with the reference to the graphs in the Proposed Findings (MID at 8); however, we are at a loss to say what those problems are. MID appears to assert that the laws of supply and demand are constrained by the laws of physics. As a general proposition we are inclined to agree, but we do not know how the assertion relates to the use of the graphs in the Proposed Findings (or to any other part of the Proposed Findings). Yet another criticism seems to be that the graphs "fail to recognize" "that average heat rates reflect how operations actually occur." *Id.* To the contrary, the graphs demonstrate with clarity that the use of incremental heat rates better reflects the actual operation of the market in California. The Commission has been clear that the MMCP is a market

Commission, however, has been more than clear that the Formula is a market proxy which might not result in full cost recovery in every interval or, for some sellers, over the entire Refund Period. May 15 Rehearing Order at 61,658 (denying recovery of start-up costs and directing sellers who do not recover costs to seek cost of service treatment for their whole portfolio over the whole Refund Period); July 25 Order at 61,518 (cost of service alternative).

The Generators, in an attempt to divert attention from the fundamental error of their position, go on for several pages attempting to attack the graphs of price movement cited by the Presiding Judge. Generators at 20-24.[12] The Generators completely missed the point that the graphs are illustrative of a proposition that as a matter of arithmetic must be true: an MMCP based on average heat rates will force prices up as demand ebbs if the average heat rates are above incremental heat rates. An MMCP calculated with average heat rates sets the market clearing price at a level driven by the average cost of fuel. The Generators have asserted that for most units "average heat rates exceed incremental heat rates over their entire range of output levels." Generators at 14. If the average cost exceeds the incremental cost it is clear as a matter of arithmetic that a reduction in production (demand) will raise the average cost and, with an MMCP based upon average heat rates, raise the MMCP. The graphs merely illustrated with actual historical price data this inescapable arithmetic result.

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proxy. December 19 Rehearing Order at 62,178; June 19 Order at 62,547. Finally, MID complains that there is a failure to address the differences "between the Real-Time market and the Hour-Ahead and Day-Ahead markets." *Id.* As MID does not give its view on what distinctions it refers to and how those distinctions bear on the Proposed Findings, we cannot agree or disagree.

[12] As an oblique concession to the relevance of price patterns as a test of a proxy price the Generators assert that if the graphical evidence of price movements is sliced and diced differently it *might* follow a pattern that would be consistent with a competitive market. Generators at 21. The Generators cannot have it both ways. They open their critique of the Presiding Judge's finding with the argument that

Even if the specific placement of the lines in the graph might change under this or that finding by the Commission (which is all the Generators' argument boils down to), the finding of the Presiding Judge that the basic shapes of the curves shows the error of using average heat rates would remain correct and inescapably so.

4. The Commission's Treatment of Minimum Load Fuel Costs in the Prospective Mitigation Period Is Strong Evidence That Incremental Heat Rates Should Be Used in the Refund Period

The Generators are concerned about the implications of the Commission's treatment of minimum load fuel costs and start-up costs in the prospective period for the answer to the question of whether incremental or average heat rates should be used in the Refund Period. Generators at 23-25. The Commission denied recovery of start-up costs for the Refund Period based upon the absence of the "must-offer" requirement. May 15 Rehearing Order at 61,658. The reasoning the Commission used is equally applicable to minimum load fuel costs: the costs were incurred voluntarily as a part of seeking market compensation. *Id.*

In attempting to side-step the implications for the Refund Period of the recovery methodology for the prospective period the Generators have twisted the Commission's reasoning. The Generators argue that the use of incremental heat rates in the prospective period hinges on the fact that units will be presumed to operate at or near maximum output while for the Refund Period the actual output of the operating units is taken as a given. The Commission ultimately granted recovery of minimum load fuel costs based upon the cost causation of the "must-offer" requirement. December 19 Order at 62,363. That grant of recovery was premised on operation at minimum load

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the responsiveness of the MMCP to changes in supply and demand is irrelevant and close by saying that with enough changes they can make an MMCP based on average heat rates look like a market price.

pursuant to an ISO request and a failure to be dispatched. There was no suggestion that the actual output during the refund period – whatever the level – would justify any recovery of minimum load fuel costs, no less recovery through the MMCP.

The Generators and CSG each attempt to criticize the Presiding Judge's finding that the absence of a must-offer requirement in the Refund Period supports the use of incremental heat rates. Proposed Findings ¶ 65. The Generators assert that the Proposed Finding that minimum load fuel costs will be *incurred* by ISO dispatch of a unit not on line is sufficient to demonstrate the right to *recover* such costs. Generators at 24. The Generators have confused the physical reality of the possibility of unrecovered minimum load fuel costs with the Commission's decision that cost-causation justifying recovery is inextricably linked to the existence of the must-offer requirement. The Commission found that prior to the must-offer requirement units incurred such costs "based on the assumption that they would be compensated by the market." May 15 Rehearing Order at 61,658. CSG suggests that the absence of the "must-offer" requirement in the Refund Period *supports* the inclusion of minimum load fuel costs in the MMCP. CSG at 8. The reasoning of CSG is unfathomable. CSG seems to be arguing that the *absence* of cost causation in the Refund Period supports inclusion of minimum load fuel costs in the MMCP. That position is untenable.

The Generators' last argument on this score is that if the Commission uses incremental heat rates for the Refund Period it should limit the effect of that decision in other contexts. Generators at 25. This argument would have some appeal if the Commission had decided to use incremental heat rates for reasons specific to the Refund Period. But nothing in the reasoning of the Commission is specific to the

Refund Period. The presumption should be precisely the reverse of that advocated by the Generators: any party seeking in another context to allow minimum load fuel costs to set the market price (by using average fuel costs) should bear the burden of showing why the policy justifications offered by the Commission should be ignored in that other context.

5. The Presiding Judge Did Not Misinterpret the "Williams Language" or Recommend Confiscation

CSG cites the June 19 Order for the proposition that the Commission in discussing heat rates was of the view that the ISO was using average heat rates. The Commission noted in that order that the ISO was collecting heat rates "for eleven different operating points with the first and last operating points representing the unit's *minimum* and maximum operating level . . . ." June 19 Order at 62,563 (emphasis supplied). The Commission then concluded, in language much debated in this proceeding, that the "ISO's heat rate curve reflects the minimum fuel load requirements requested by Williams." *Id.* ("Williams language"). The heat rate for the minimum operating level in the data collected by the ISO does reflect the additional fuel cost for operating at minimum load. If the marginal unit were operating at its minimum load the use of incremental heat rates to calculate the MMCP would fully compensate it for minimum load fuel costs as the incremental heat rate would be the minimum load heat rate.

In the December 19 Compliance Order, the Commission authorized recovery of those prospective minimum load fuel costs under conditions requiring that the costs be the result of compliance with the must-offer obligation and the absence of dispatch by the ISO. December 19 Compliance Order at 62,363. This grant to generators of the right to recover minimum load fuel costs in the prospective period is instructive as it sweeps away any fog clinging to the Williams language. Had the Commission intended the Williams language to represent a broad order to use average heat rates to calculate the MMCP, as sellers argue, it would have been completely unnecessary and contradictory to include the provision in the December 19 Compliance Order allowing and restricting direct invoice recovery of minimum load fuel costs. Both the June 19 Order and the December 19 Compliance Order address the prospective period. The Commission would not have compensated the same costs twice, once by increasing the market clearing price and a second time through direct invoice. Nor would it have allowed inconsistent recovery, one for all generators and a second confined to a subset of generators. The Proposed Findings reach the same conclusion as to the Commission's intent. Proposed Findings ¶¶ 59-68.[13]

6. There is No Constitutional Issue

Finally, CSG invokes the hallowed constitutional ground plowed by the Supreme Court in *FPC v. Hope Natural Gas Co.*, 320 U.S. 591 (1944), to argue that use of incremental heat rates is confiscatory.[14] There is a quick and sufficient response: The

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[13] MID believes that the Proposed Findings (at ¶ 67) misuse the December 19 Rehearing Order as that order does not "say that incremental heat rates are to be used in computing the MMCP." MID at 8. MID has missed the point. The Proposed Findings cite as support for the conclusion that the Commission intended the use of incremental heat rates the acceptance by the Commission after the June 19 Order of an ISO Compliance Filing in which incremental heat rates were used to calculate marginal cost. The fact that the words "incremental heat rates are to be used in computing MMCP" do not appear in a specific order does not change the fact that subsequent to the order the Commission accepted calculations based upon incremental heat rates.

[14] At page 9 of its comments, MID makes a legal argument that cannot be viewed as serious. It cites *Kentucky Utils. Co.*, 22 FERC ¶ 63,011, at 65,029 (1983), for the proposition that "actual average heat rate curves better reflect what certain 'units experience in the real world.'" First, that discussion took place in the context of a cost of service case in which the estimate of margin from off-system sales was at issue. That context is hardly of use here. Even more striking is that the Initial Decision cited does not say that average heat rates are better than incremental heat rates. It says that accurate average heat rates would have been better than inaccurate average heat rates that were used by the expert being criticized (". . . has failed to adjust these idealized input/output curves to reflect the actual average heat rates which

Commission has offered cost-based rates for an entire portfolio as a backstop to its market based proxy price, June 19 Order at 62,564, so that no seller can be worse off under the Commission's mitigation plan than under traditional

B. The Proposed Findings Correctly Determined Eligibility To Set the MMCP (Phase 1 – Issue I.D.1)

In ¶ 94, the Proposed Findings concluded that eligibility to set the MMCP is limited to those units that bid into the ISO's markets and were eligible to set the MCP, *i.e.*, the BEEP stack. CSG and the Arizona Electric Power Cooperative ("AEPCO") contend that all units providing Imbalance Energy should be eligible. CSG rests its argument on assertions that the BEEP stack was not the primary source of Imbalance Energy during the Refund Period and that neither the Commission's orders nor the ISO Tariff direct that eligible units be so limited. CSG at 18-21. CSG is correct on the first count, but wrong on the other. AEPCO acknowledges that the Proposed Findings applied the methodology adopted by the Commission, but argues that the Commission should revise its methodology to include all units providing energy in real time because the BEEP stack was not the primary source of Imbalance Energy during the Refund Period. AEPCO at 8-10. AEPCO is correct in its factual statements, but errs in its conclusion.[15] CSG's and AEPCO's arguments are addressed in subsections 1-3, below.

CSG also contends that the BEEP stack is an unreliable indicator of the results of a competitive market because "bids CDWR was unwilling to support were not

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these units experience in the real world." *Id.*). This reading is confirmed by the fact that on the next page the same expert is taken to task for his calculation of "incremental production cost." *Id.* at 65,030.

[15] CSG and the Generators also contend that the BEEP stack was unreliable because the ISO excluded eligible units. CSG at 21-25; Generators at 1-11. Most of their complaints, concerning the

dispatched even if those bids would have been accepted under the automatic BEEP stack software." CSG at 22. None of the evidence cited by CSG suggests that any bids were taken out of sequence because of CDWR's decisions. Rather, at the point CDWR decided it could no longer offer credit support, no more bids were taken. *See* Exh. GEN-1 (Tranen) at 27:13-28:9 and deposition testimony cited therein. This is how a competitive market works when buyers have limited resources: buyers stop purchasing when the price gets too high.

1. The Commission's Orders Support the Proposed Findings

CSG contends that the Commission's decision that the MMCP be established by the last unit dispatched in the real time market does not really refer to the ISO's Real Time Market, as defined in the ISO Tariff, but rather to all units dispatched to provide Imbalance Energy. CSG at 19. In the July 25 Order, the Commission explicitly adopted as a methodology for determining the MMCPs during the Refund Period the methodology previously established for determining the proxy market clearing price prospectively during periods of resource deficiency. July 25 Order at 61,516-17. The methodology for determining the proxy market clearing price during periods of resource deficiency requires the ISO to determine the marginal unit *from among those gas-fired units with bids in the ISO's real time market, i.e., the "BEEP stack."*[16] *See, e.g.*, December 19 Compliance Order at 62,368. That aspect of the "forward-looking" methodology was not modified for purposes of determining mitigated prices during the

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exclusion of certain out-of-sequence ("OOS") dispatches from the BEEP stack, are addressed in section I.C, below.

[16] The Proposed Findings discussed in this section concern whether a unit, to be considered, must have had a bid in the real time market, *i.e.*, in the BEEP stack. Note, however, that the Commission was clear that for the Refund Period, a unit must not only have had a bid in the BEEP stack, but also must have been *dispatched in the real time market* in order to be eligible to set the mitigated price. This point becomes important in subsequent sections of the present filing, *e.g.*, in sections I.C and I.D.

Refund Period, and the universe of units eligible to set the mitigated price during the Refund Period is thus limited to gas-fired units that had bids in the BEEP stack. *See also* July 12 Report at 65,040; July 25 Order at 61,517.[17]

CSG argues that because the Commission did not capitalize "real-time market," the Commission must have been referring to something other than the Real Time Market as defined in the ISO Tariff. CSG at 19. But the Commission does not generally adopt the convention of capitalizing terms from the ISO Tariff. In the July 25 Order, the Commission used such terms as "generator," "market participant," "dispatch," "ancillary services," and "scheduling coordinator," each of which is defined in the ISO Tariff, without capitalization. There is no reason to believe that the Commission defined these terms differently from the manner in which the ISO Tariff defines them.

CSG also ascribes importance to the failure of the Commission to refer explicitly to the BEEP stack (CSG at 18),which is a ranking of bids in the ISO's Real Time Market, primarily in merit order. *See* Exh. ISO-1 (Hildebrandt) at 5:12-6:8, 7:21-8:17. But there was no need for the Commission to be redundant: when it referred to the "last unit dispatched" in the real time market, the reference could only be to the last unit dispatched from the BEEP stack, for that *is* the Real Time Market.

2. CSG's Proposed Definition of "real-time market" Is Inconsistent With the ISO Tariff

CSG contends that the ISO's definition of Real Time Market is broader than the BEEP stack. CSG at 21. However, CSG completely ignores the reference in the ISO definition to a "competitive market." The only competitive market for Imbalance Energy

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[17] Since the "forward-looking methodology applies to the Refund Period, CSG lacks any support for its assertion, CSG at 19 n.11, that the Commission's ruling in the December 19 Compliance Order at

is the ISO's Real Time Market, which consists of the Energy bids associated with Ancillary Services and Supplemental Energy, which together make up the BEEP stack. There is no room for a broader meaning.

3. Use of the BEEP Stack Is Consistent With the Results of a Competitive Market

An analysis prepared by Dr. Hildebrandt demonstrates that the methodology specified by the Commission and the Proposed Findings, including use only of units in the BEEP stack in calculating MMCPs, produces prices that reflect the principles of supply and demand in a competitive market: prices rise when demand is high, and fall when demand is low. Exh. ISO-19 (Hildebrandt) at 10:11-14:21. Dr. Hildebrandt's analysis shows that the methodologies advocated by Generators and CSG, including calculation of MMCPs using more units than those in the BEEP stack, do not reflect these fundamental principles. *Id.* Thus, in order to best emulate a competitive market, the Commission should, among other steps,[18] continue to calculate MMCPs using only units in the BEEP stack.

C. The Presiding Judge Correctly Found That Non-Congestion OOS Should Be Eligible To Set the MMCP if Dispatched Through the BEEP Stack (Phase 1 – Issues I.D.2.a, I.D.2.b, I.D.2.c, and I.D.2.d)

The Presiding Judge correctly found that units providing non-congestion OOS should be eligible to set the MMCP if they are dispatched through the BEEP stack. *See* Proposed Findings ¶¶ 115, 120.

Although CSG implies that dispatchers arbitrarily and incorrectly excluded from the BEEP stack dispatches that were contemporaneously identified as non-congestion

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62,368, quoted in ¶ 111 of the Proposed Findings, is irrelevant because it applies to prospective mitigation.

[18] These steps include the use of incremental heat rates.

OOS, CSG at 22, the evidence does not support such an inference. CSG first asserts that "placement of a unit in the BEEP stack was dependent on the discretion of individual ISO operators who 'had the option' to 'make a call' as to whether the unit belonged in the stack," CSG at 22, citing Dr. Hildebrandt's cross-examination, Tr. at 1356:7-1359:14; 1395:17-24. Although transcripts are not always crystal clear, a review of the cited passages, in context, shows that Dr. Hildebrandt was referring to the decision whether an OOS call was for congestion or non-congestion purposes. As the Commission is aware, the distinction between congestion and reliability concerns is not always a bright line. The ISO operator, who best knows the circumstances that prompted the dispatch, is best able to make that determination. The only way the Commission could evaluate that decision would be to second-guess the people who were on the scene. The ISO does not believe such an exercise would serve to better determine just and reasonable rates.

CSG next contends that ISO operators "on literally thousands of occasions" violated ISO Operating Procedures that provide that non-congestion OOS calls were eligible to set the MCP.[19] CSG at 22, citing Dr. Hildebrandt's cross-examination (Tr. at 1352:21-1353:1; 1356:7-11; 1371:18-1373:11) for the proposition that the requirements of ISO Procedure M-403 were not consistently followed. The transcript passages cited merely establish that non-congestion OOS dispatches were eligible under the procedure to set the market clearing price.

CSG's next assertion and citation do address circumstances in which non-congestion OOS was not included in the BEEP stack. CSG at 22, citing Dr. Hildebrandt, Tr. at 1362:24-1363:10; 1370:3-1371:13; Exh. GEN-19 (Tranen) at 12:21-

15:8. A review of these passages, however, shows that the testimony was not concerned with the distinction between congestion OOS and non-congestion OOS, but rather with non-congestion OOS that was mistakenly logged as out-of-market ("OOM"). These circumstances are discussed below, in connection with mislogging.

Finally, CSG asserts that "reliability" is a meaningless criterion, because Dr. Hildebrandt could not define it and stated "reliability is not a very good definition." CSG at 22, citing Tr. at 1373:8-11. Dr Hildebrandt, of course, is an economist, not an ISO operator. As Dr. Hildebrandt made clear, the implementation of operating criteria are not within his expertise. Tr. at 1372:14-15; 1373:9-11. As the Commission is aware, however, reliability is not in fact a vague concept to operators. The WECC and NERC have extensive operating reliability criteria with which operators must comply. The Commission has approved "reliability" as a criterion for authorizing many ISO actions. Dr. Hildebrandt's inability to define reliability is certainly no indictment of the decisions of ISO operators.

A separate issue is the mislogging of OOS non-congestion calls as OOM calls, which was a subject of the Commission's May 15 Rehearing Order. If an ISO operator dispatches a unit for reliability purposes that is not in strict merit order, but fails to determine that the unit had a bid in the BEEP stack, the dispatch under certain circumstances could mistakenly be logged as OOM. The Proposed Findings examined the results of an ISO audit, known as "Project X," as well as the testimony of Mr. Tranen, both of which document mislogged OOM dispatches, in the context of the determination of the MMCP. The Proposed Findings, in ¶ 134, concluded that the

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19 CSG, in what is most likely a typographical error, mistakenly refers to the MMCP.

mislogging was not shown to be "material and prejudicial" to Dr. Hildebrandt's determination of the universe of units eligible to set the MMCP.

The Commission should adopt the conclusions of the Proposed Findings. The ISO will address Project X in greater detail in connection with Phase 2 issues. The ISO would make two observations, however, that are particular to Phase 1. First, in the May 15 Rehearing Order, the Commission addressed the filing made by the Generators four business days before the Commission's order, in which they alleged that the ISO had mis-logged numerous OOS non-congestion transactions as OOM transactions during the Refund Period. The Commission stated that if the Presiding Judge found information that any "out-of-sequence non-congestion transactions [that] were not logged according to the ISO's Tariff provisions, the ISO must recalculate each clearing price during the refund period where an out-of-sequence non-congestion transaction was 'mis-logged' and use these corrected clearing prices in the refund hearing." May 15 Rehearing Order at 61,654.

The first important point to note is that the Commission limited the consequence of any mislogging that might be found to the correction of the historical MCP ("each clearing price during the refund period"), not the recalculation of the MMCP. Second, even if the Commission had intended that the MMCP be recalculated to correct mislogging, the Proposed Findings, at ¶ 134, specifically found a lack of evidence that mislogging was either prejudicial or material to Dr. Hildebrandt's calculations of the MMCP. The Generators' contention that there was "no 'materiality' component" to the Commission's orders is illogical. The Commission directed that the clearing price be recalculated if the Presiding Judge found that mislogging existed; but no recalculation is necessary if the mislogging, as the Proposed Findings concluded, was immaterial to the calculation of the MMCP.[20]

Indeed, there was no evidence presented during Phase I that supported any corrections to the universe of units eligible to set the MMCP, or even identifying which transactions would have been affected. There was no indication whether the mislogged transactions were out-of-state, which in certain cases would make them ineligible to set the MCP. There is also no indication whether the transactions were sales to CDWR that would be excluded from the universe. *See* Proposed Findings ¶¶ 133-34.

The issue of which units were to be included in the universe of units allowed to set the MMCP was litigated in the first hearing, and the record on that issue was closed even before the Commission issued its May 15 Rehearing Order. Proposed Findings ¶ 430. Based on that record, the Presiding Judge articulated preliminary findings at a discovery conference held on May 20, 2001. Specifically, the Presiding Judge, in discussing the ramifications of the May 15 Rehearing Order as to mislogging, stated that "there's a potential relationship between mischaracterization and a basket of dollars. But you guys [the Generators] went after that in the [Phase 1] hearing, and you missed." Tr. at 3283:7-10. While noting that there was some evidence suggesting mischaracterization of transactions, the Presiding Judge made clear that "One can't take that a step further based on what the generators have provided to determine, assuming it was relevant to determine in the MMCP phase, what the significance of that mischaracterization was in relationship to the MMCP." Tr. at 3242:6-13. The Proposed

[20] The Generators' characterization of the Proposed Findings might be read to imply that the Proposed Findings used "material" in a quantitative sense. In actuality, as noted here, the Proposed Findings referred to the materiality of the mislogging to Dr. Hildebrandt's calculations. "Material" in this context can only mean relevant.

Findings are consistent with those preliminary conclusions. The Commission should adopt them.

D. The Proposed Findings Correctly Determined That OOS Congestion Is an Energy Type That Is Not Eligible To Set the MMCP (Phase 1 – Issue I.D.2.e)

"OOS congestion" refers to a situation in which units with bids in the ISO's real time market were dispatched *outside of the BEEP system* to address local congestion, and were paid on an "as-bid" basis. The Proposed Findings, at ¶¶ 135-37, concluded that these units dispatched out-of-sequence to address local congestion were ineligible to set the MMCP. Proposed Findings ¶ 135. CSG did not specifically contest this Proposed Finding, but units dispatched out-of-sequence to address congestion would be within the general universe of units dispatched in real-time, other than through the BEEP stack, that CSG wants to be eligible to set the MMCP. The ISO believes the Proposed Findings, and the record citations there, adequately explain why OOS congestion dispatches do not make a unit eligible to set the MMCP. *See also* Tr. at 1335:10-17; 1345:14-16; 1347:23-1348:7; 1353:9-1360:18.[21]

E. The Proposed Findings Correctly Determined That OOM Energy Should Not Be Eligible To Set the MMCP (Phase 1 – Issue I.D.2.f)

The Proposed Findings, at ¶ 138, concluded that units called out-of-market are not eligible to set the MMCP. CSG did not specifically contest this Proposed Finding,

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[21] The ISO does note that the key portion of the July 25 Order is the sentence in which the Commission stated that "we will require that the ISO determine the last unit dispatched (the marginal unit) by selecting from the actual units dispatched in real time the maximum heat rate of any unit dispatched each hour *in the real-time imbalance market* for the [Refund Period]." July 25 Order at 61,517 (emphasis added). The Commission in that sentence described two different groups of units – those "dispatched in real time" and those "dispatched each hour in the real-time imbalance market." The latter group is a sub-set of the former: while units are dispatched in many ways and for many reasons in real time, only *certain* of those units are dispatched "in the real-time imbalance market." It was the maximum heat rate of any unit in that latter, smaller group of units that the Commission intended the ISO to use to calculate the

but OOM calls would be within the universe of units would like to see eligible to get the MMCP. The ISO believes the Proposed Findings, at ¶¶ 138-51 as well as the record evidence there cited, fully justify exclusion of units called OOM. After all, a unit dispatched through an OOM call is, by definition, not a unit with a bid in the real time market. The owner of the unit has chosen not to participate in that market. *See* n.21, *supra* (discussion of distinction, in July 25 Order, between "units dispatched in real time" and units "dispatched in the real-time imbalance market").

F. The Proposed Findings Correctly Determined That Residual Energy Is Not Eligible To Set the MMCP (Phase 1 – Issue I.D.2.g)

The Proposed Findings also correctly concluded, in ¶ 152, that units providing residual imbalance energy are not eligible to set the MMCP. CSG and AEPCO contest this finding. CSG at 28; AEPCO at 10-11. The Proposed Findings, at ¶¶ 151-58, clearly explain why residual energy should not make a unit eligible, and that explanation is fully supported by the record cited there. In short sum, a unit that provides residual energy during an interval either was not bid into the competitive market for that interval or was bid but not chosen. The unit *is not dispatched* by the ISO during the interval. Accordingly, it cannot be the "last unit dispatched" in the real-time energy market during an interval in which it provides residual energy and, as a result, it should not be eligible to set the MMCP in any such interval. *See* Exh. ISO-1 (Hildebrandt) at 46:17-22.

G. The Proposed Findings Correctly Determined That Regulation Energy Is Not Eligible To Set the MMCP (Phase 1 – Issue I.D.2.h)

In ¶ 158, the Proposed Findings concluded that units providing Regulation service should not be eligible to set the MMCP. CSG contests this finding, arguing that

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mitigated price. The units that the ISO dispatches "in the real-time imbalance market" are limited to those

Regulation provides a form of Imbalance Energy, and units providing regulation should therefore be eligible to set the MMCP. CSG at 28-29. As with other types of energy CSG contends should make a unit eligible to set the MMCP, the Proposed Findings (at ¶¶ 158-65) and the record cited there fully justify excluding units providing regulation energy. Stated succinctly, energy from regulation service is not dispatched "in the real-time imbalance market," but is dispatched completely *outside* that market, and receives whatever price is determined by those units that *are* dispatched in that market. Under the July 25 Order, units providing energy from regulation service during an interval should not be eligible to set the mitigated price. *See* n. 21, *supra* (discussing July 25 Order). *See also* Exh. ISO-1 (Hildebrandt) at 47:1-5.

H. The Proposed Findings Correctly Determined That "Other Imbalance Energy" Is Not Eligible To Set the MMCP (Phase 1 – Issue I.D.2.i)

In ¶ 166, the Proposed Findings concluded that units providing imbalance energy other than the types of imbalance energy discussed above should be excluded from the universe of units eligible to set the MMCP. CSG also contests this finding, arguing that units providing any form of imbalance energy should be eligible to set the MMCP. CSG at 29-30. At issue here are Reliability Must Run ("RMR") units, units providing uninstructed imbalance energy, and units generating above their final hour-ahead schedules. Once again, the Proposed Findings at ¶¶ 166-80, and the record cited, fully justify excluding units providing these forms of energy. Units that generate uninstructed energy are not dispatched by the ISO; nor are units with forward schedules. RMR units are dispatched but not in the real time market; rather, they are dispatched outside the market to meet local reliability concerns. *See* n. 21, *supra* (discussing July 25 Order).

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units that are dispatched through the ISO's BEEP system. *See* Exh. ISO-1 (Hildebrandt) at 5:12-6:8.

I. The Proposed Findings Correctly Determined That It Was Proper for the ISO To Consider Only Gas-Fired Units With Incremental Dispatch Instructions in Establishing the Universe of Units Eligible To Set the MMCP (Phase 1 – Issue I.D.3)

The issue in this situation is whether gas-fired units (if any) that received decremental dispatch instructions during an interval should be considered eligible to set the market clearing price when there are units in the same interval with incremental dispatch instructions. The ISO has considered only gas-fired units with incremental dispatch instructions in these circumstances. *See* Exh. ISO-1 (Hildebrandt) at 33:15-20; ISO-16 (Hildebrandt) at 4:13-5:2. The Proposed Findings endorsed this methodology, at ¶ 181. CSG, however, contends that the unit with the highest marginal operating cost of all units dispatched, whether according to incremental or decremental bids, should be eligible to set the MMCP. CSG at 30-33.

There are three reasons that only gas-fired units with incremental dispatch instructions should be eligible to set the market clearing price. First, considering only units with incremental dispatch instructions is called for by the language of the directly controlling Commission orders, which speak in terms of the "last unit dispatched to meet load." *See, e.g.*, December 19 Rehearing Order at 62,178, 62,192. Only units dispatched to provide incremental energy are dispatched "to meet load" as that phrase is commonly understood. *See* Exh. ISO-19 (Hildebrandt) at 43:7-13; 46:20-47:6. CSG posits that "a unit that was decremented from 150 MW to 140 MW still supplied 140 MW to the real-time market – *i.e.*, it was dispatched to meet a load of 140 MW." CSG at 32-33. CSG is mistaken. The decremental bid, and the associated dispatch, were for 10 MW, not 140 MW, and that 10 MW was *not* serving load. The 140 MW may or may not have been dispatched in the ISO's real-time market; if it was dispatched, however, the dispatch was pursuant to an incremental bid, not the decremental bid that CSG contends should set the MMCP.

Second, under the ISO Tariff, the ISO sets separate MCPs for incremental energy and decremental energy. Exh. ISO-1 (Hildebrandt) at 8:19-9:1. In intervals in which there are incremental dispatch instructions, only bids of units that receive such instructions are considered in determining the market clearing price for incremental energy. If the refund calculation is to emulate the operation of the ISO's real-time energy market under competitive circumstances, the ISO's methodology for determining the marginal unit during the Refund Period should be consistent with the Tariff. Exh. ISO-19 (Hildebrandt) at 45:10-14. Moreover, unless the decremental energy bid is negative, it determines the price a generator will *pay* to avoid the operating costs of generating. The refund proceeding concerns the prices that generators *receive* for producing energy. Decremental bids are thus irrelevant to the establishment of the MCP (except, as discussed below, when the decremental MCP must serve as a proxy for the incremental MCP).

Finally, the ISO has been determining the proxy prices during periods of reserve deficiency in manners approved by the Proposed Findings since its first compliance filing pursuant to the April 26 Order, with no indication from the Commission that it disapproved of this approach. Exh. ISO-19 (Hildebrandt) at 50:22-51:6. Since the Commission in the July 25 Order and the December 19 Rehearing Order did not suggest there should be any difference between the "forward-looking" mitigation methodology and refund methodology in this area, the ISO's unchallenged use of this method for the forward-looking mitigation indicates the same methodology is acceptable for the Refund Period.

J. The Proposed Findings Correctly Determined That, for Intervals in Which the ISO Issued Only Decremental Dispatch Instructions, It Was Proper for the ISO To Determine the MMCP From the Decremented Unit With the Lowest Marginal Operating Cost (Phase 1 – Issue I.D.4)

When there are only decremental dispatch instructions, it is necessary to determine a proxy for the MCP for incremental energy (to determine payment for uninstructed imbalance energy or energy from out-of-market purchases). Under its Tariff, the ISO uses the decremental MCP as that proxy. Exh. ISO-19 (Hildebrandt) at 47:17-48:4. Because decremental bids are selected in descending order of bid price, the MCP is set by the lowest bid, *i.e.*, the bid of the last unit dispatched. *See* Exh. ISO-1 (Hildebrandt) at 34:16-35:3; ISO-16 (Hildenbrandt) at 5:10-20. The Proposed Findings, at ¶ 188, applied the same approach to the determination of the MMCP – determining the marginal unit as the unit with the lowest marginal operating cost that received a decremental dispatch order.

AEPCO argues that the MMCP should reflect the highest marginal cost among units providing Instructed Imbalance energy, AEPCO at 11, which would include residual energy (specifically identified by AEPCO) and energy dispatched out-of-market. But AEPCO provides no way to square its suggestion with the Commission's admonition that to be eligible to set the MMCP for an interval a unit must be dispatched by the ISO in the real time market for that interval. As noted earlier (*see* sections I.E and I.F), units providing residual energy in an interval were not dispatched by the ISO in that interval, and those dispatched out-of-market are not in the real time market.

CSG contends that the MMCP should be established by the highest marginal cost among decremental units. CSG at 33-35. The methodology in the Proposed Findings, however, is most consistent with the relevant language of the Commission orders. The ISO's methodology does determine the "last unit dispatched" in these intervals: when only decremental dispatches are issued, the "last unit dispatched" is the unit with the lowest decremental bid, and determining the unit with the lowest marginal costs among those decremented units mimics that approach. Exh. ISO-19 (Hildebrandt) at 50:4-20. CSG's methodology would chose the *first* unit dispatched. If the methodology for determining the MMCP is to emulate the manner in which the ISO's real-time market would operate in a competitive environment, then it should use the rules established in the ISO Tariff.

Finally, as in the case when there are incremental bids, the ISO has consistently followed the methodology approved by the Proposed Findings in determining proxy prices during periods of reserve deficiency since its first compliance filing pursuant to the April 26 Order, without any challenge by the Commission; since the Commission in the July 25 Order and the December 19 Rehearing Order did not suggest any distinction between the forward-looking mitigation and mitigation during the Refund Period in this area, the same approach should be taken for the Refund Period. *Id.* at 50:15-51:6.

K. The Proposed Findings Correctly Determined That, in Intervals When There Are No Units Dispatched Through the BEEP Stack, the MMCP Should Be Determined by the Unit That Had the Lowest Marginal Cost Among Those Units That Had a Bid for Incremental Energy Submitted in the BEEP Stack (Phase 1 – Issue I.D.5)

The July 25 Order and the December 19 Rehearing Order require the ISO to base the mitigated price on the marginal costs of the last gas-fired unit dispatched in the real time market in an interval. In intervals in which no gas-fired unit was dispatched, a mitigated price still must be calculated. The Proposed Findings, at ¶ 194, concluded that, in this circumstance, the MMCP should be determined by the unit that had the lowest marginal cost among those units submitting incremental energy bids for the interval. CSG disagrees (*see* CSG at 35-36); while it is unclear from their comments what they propose instead, the Proposed Findings, at ¶ 198, indicate they contended previously that the MMCP should be based on the unit with the highest marginal operating costs of any unit dispatched in that hour.[22]

The Proposed Findings are consistent with the Commission's direction to determine the marginal unit by finding the cost of the unit that just meets demand. Since the Commission looked to the ISO to determine the marginal unit, it is reasonable to use the ISO's normal rules, under its Tariff, for doing that. As Dr. Hildebrandt explained:

> Under the ISO's Tariff, the ISO accepts bids for incremental Imbalance Energy in economic merit order (in ascending order of price). Thus, for purposes of determining the marginal gas unit for those intervals in which no gas-fired unit was dispatched in the ISO's Real Time Market, the lowest incremental heat rate of gas units with bids into the ISO's Real Time Market represents the best indication of the marginal gas unit that could be dispatched to meet demand, since this unit could have been called on first by the ISO's BEEP system had there been a need for incremental Imbalance Energy. This approach reflects how the ISO's BEEP software is designed to calculate the incremental MCP for Real Time Energy in the event that no units are dispatched through BEEP during any interval. This approach is also consistent with the standard economic principles that (1) marginal costs are the costs of producing one unit more (or less) and (2) under competitive market conditions, market clearing prices in uniform price auctions should equal the marginal costs of the last increment of supply needed to meet demand.

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22 AEPCO presents the same arguments here that it raised regarding issue I.D.4. *See* AEPCO at 12. The reason AEPCO is incorrect is discussed in section I.J, *supra*.

Exh. ISO-1 (Hildebrandt) at 38:21-39:14. *See also* Exh. ISO-16 (Hildebrandt) at 6:17-7:10. The marginal cost of producing one more megawatt of energy would be the marginal cost of the unit in the incremental BEEP stack that has the lowest marginal price. The Proposed Findings implement this principle. CSG would apparently have the Commission just abandon its focus on recreating a competitive market and cast about for the highest cost unit operating in the interval. There is no rationale for doing that – other than reducing the amount of refunds.

L. AEPCO Is Incorrect in Stating That the Commission Has Described a Need to Expand the Universe of Units Eligible To Set the MMCP (Phase 1 – Issue I.D.8)

The ISO has provided its comments on this issue in its Initial Comments. The ISO must, however, contest AEPCO's comment that "the Commission in [the May 15 Rehearing Order] recognized the need to expand the universe of eligible units." AEPCO at 12. The Commission recognized no such general need. Rather, the sole "expansion" was the Commission's clarification that units outside the ISO Control Area could, under specific limited circumstances, set the MMCP.

M. The Proposed Findings Correctly Accepted the ISO's Use of Midpoint Prices To Calculate Gas Prices (Phase 1 – Issue I.E.1)

The Proposed Findings at ¶ 241 found the ISO's use of the "midpoint" of daily spot gas prices as shown by indexes to be consistent with the Commission's intent. CSG repeats in its comments the two arguments thoroughly considered and rejected in the Proposed Findings, namely that: (1)(a) the Commission did not specifically tell the ISO to use the midpoint and (b) the "marginal" unit (according to CSG) experiences higher-than-average gas prices, making the "common high price" a better proxy than the midpoint; and that (2) if a midpoint is used, the ISO was wrong to take the midpoint of the "common range" instead of the midpoint of the "absolute range."

The first argument fails on two counts. First, the ISO simply followed the Commission's direction.[23] Although the Commission did not expressly use the term "midpoint," it did adopt the Chief Judge's specific recommendation to use the "midpoint." *See* Proposed Findings ¶¶ 244-46 (discussing the recommendation and the Commission's acceptance of it in the July 25 Order). Second, there is no reason to believe that the "marginal unit" dispatched must pay higher than average spot gas prices. A marginal unit is not necessarily chronologically the last unit to access the spot market for gas, as under the mitigation plan it is the "last" unit only in the sense that it is the highest cost unit dispatched under economic principles.[24]

The error in CSG's second argument is easily stated. The use of the "common range" is nothing more than a basic statistical technique to eliminate the "outliers" that appear in the absolute range, thereby correcting for the stray (and, based upon current events, rogue) report of an extraordinarily high spot price. Such high-side outliers can skew the average considerably in ways that are not indicative of the experience of most market participants, often moving the midpoint of the absolute range higher than that of

[23] AEPCO, which also disagrees with the use of the midpoint, at least acknowledges the correctness of the Proposed Finding that the ISO was following the Commission's instruction. AEPCO at 13.

[24] AEPCO recognizes that the "last unit dispatched" under the mitigation plan has nothing to do with the chronology but is just the one with the highest heat rate (and thus highest marginal cost before considering gas prices). But then AEPCO engages in the *non sequitur* that because the marginal unit's heat rate was highest it "logically" would have bought its gas last. AEPCO at 13. There is just no connection between a unit's heat rate and when it buys its spot gas.

the common range.[25] As a consequence, CSG, in a bald reach for more money, is advocating that the Commission adopt a less representative gas price.

N. The Proposed Findings Correctly Adopted Simple Averaging of Intervals MMCPs To Obtain Hourly MMCPs (Phase 1 – Issue I.E.2)

AEPCO does not actually challenge the Proposed Finding, at ¶¶ 248-52, that simple averaging of the ten-minute interval MMCPs to obtain an hourly MMCPs is appropriate, but uses that portion of its comments to make another oblique criticism of the Proposed Finding that the universe of units eligible to set the MMCP does not include units providing residual energy. AEPCO at 13. AEPCO makes no new argument about residual energy, so the ISO just refers the Commission to its reply in section I.F of this filing.

O. The Proposed Findings Correctly Addressed Section 202(c) Issues (Phase 1 – Section 202(c) Issues)

The ISO agrees with various parties' characterization that the period when the Department of Energy ("DOE") orders were in effect was a time of constant emergency, with the ISO struggling daily to locate enough power to keep the ISO controlled grid reliable. Both before and after the DOE orders, ISO personnel were constantly encouraging anyone with available power to sell it to the ISO, and held daily conference calls urging parties that could to bid into its markets to do so. Tr. at 2328:8-15.

As a last resort, the ISO sought an order under Section 202(c) of the Federal Power Act, that, under certain circumstances, would require each of several identified

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25 One of the indexes uses a volume-weighted average price for the same reason the others use the common range instead of the absolute range – to filter out the effect of the outlier price reports. (If there is a report of one transaction at a price far above the prices reported for the great bulk of transactions, using a weighted average reduces the impact of that outlier price.) Although CSG challenges the ISO's use of this index's volume-weighted price as well, the ISO's use of it is the only reasonable approach unless one wants stray, potentially suspect reports of exceedingly high prices to skew the average.

sellers to respond to an ISO demand that it provide energy. *See* Proposed Findings ¶ 289; Exh. No. ISO-11; Tr. at 2289:11-12. *See also* Exh. JE-3, Vol. I, Tab ISO Request 12/20/00, unnumbered third page (ISO tells DOE of its "*commitment to use the emergency power sparingly.*") The DOE orders clearly explain the regime they put in place:

- The ISO had no authority under the Section 202(c) orders unless it certified to the DOE that it was unable to acquire adequate supplies *through its markets.*
- This authority only lasted 24 hours after a certification was submitted to the DOE.
- The ISO could require only entities listed on Attachment A of the order, to provide energy.
- Attachment A entities were not required to make deliveries to the ISO until, initially, 12 hours (later 8 hours) after a certification was made to the DOE.
- Attachment A entities were only required to sell to the ISO excess energy or services as requested by the ISO.
- The ISO was originally directed by the order of December 14, 2000 to inform entities of the amounts and types of services needed by 9 PM prior to the certification day. The order of December 20, 2000 and subsequent orders directed the ISO only to seek information on the availability of energy or services.
- The terms of the sales were to be agreed between the parties and failing that, to be prescribed by the Secretary of Energy.

See, *e.g.*, Exh. ISO-11; ISO-12; ISO-22.

Prior to the DOE orders, the ISO could *require* only generators with Participating Generator Agreements ("PGAs") to provide it energy in an emergency; the DOE orders were clearly intended to be used as a last resort enabling the ISO to require *additional* entities to provide energy in an emergency. Staff witness Patterson outlined the program put in place by the DOE orders, enumerating three key criteria: (1) a seller listed on Attachment A; (2) a transaction a certification day; and (3) a transaction entered into outside the ISO's formal markets for energy and capacity.[26] Some parties refer to Staff's criteria as "post-hoc" or "retroactive."[27] To the contrary, Staff's criteria simply state the key elements of the DOE orders themselves. They are the Secretary of Energy's criteria, and they were well known to all parties both because the ISO faxed the Orders to all entities on Appendix A and because the orders were publicly available as soon as issued.

The Presiding Judge reviewed an enormous amount of evidence on the 202(c) issue, including nearly two weeks of testimony. After all of that, the Presiding Judge clearly understood the framework of the DOE orders and concurred with the description of the key elements as presented by Staff. *See, e.g.*, Proposed Findings ¶¶ 254-69, 308, 309 (Attachment A entities), 314 and 319 (certification days), 321 (non-market transactions).[28]

In addition, the Presiding Judge, after thoroughly reviewing the evidence, decided (as the ISO had contended) that some sales to the ISO by Attachment A entities on certification days could have been made for reasons other than the ISO's authority under the DOE orders, *e.g.*, a seller could have simply thought the high prices it could charge outweighed any credit-worthiness or other issues that might have made

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26 A fourth Staff criterion dealt with the special circumstances of one day, January 9, 2001.

27 *See* SMUD at 6; Burbank at 28; Glendale at 8, 12; Pasadena at 28; Coral Power at 10; MID at 15, 20.

28 Pasadena, Burbank, and Glendale claim that even if sales did not comply with the terms of the DOE orders, the sales should still be shielded from mitigation under the doctrine of equitable estoppel. Pasadena at 31-32; Burbank at 45; Glendale at 25. The major deficiency in this argument is that it is really seeking to estop the Commission from mitigating these parties' sales – nothing the ISO did or did not do can be used to estop the Commission. Putting that aside, the argument does not come close to meeting the legal test for equitable estoppel. Finally, the Commission never suggested that mitigation could be avoided by "estoppel," as opposed to proof that a transaction *in fact* was made pursuant to the DOE orders.

it leery of selling. *See, e.g.*, Proposed Findings ¶¶ 309-310, 313, 340; Exh. ISO-21 (O'Neill) at 12:14-21; 14:12-16:9. To separate the sales for other reasons from the true sales pursuant to the ISO's invocation of the DOE order, the Presiding Judge imposed a requirement that, to escape mitigation, there be some contemporaneous evidence that a sale was made pursuant to the DOE order. *See, e.g.*, Proposed Findings ¶ 320.[29]

The ISO's difference with the Proposed Findings, set forth in our Initial Comments, is one of nuance with respect to certain OOM sales.[30] Other parties, however, are attempting to dramatically expand the universe of transactions that may be exempt from the Commission's price mitigation. In considering their arguments, it is important to remember that, while many of the comments make it sound like parties will suffer if their sales are not found to have been made pursuant to the DOE orders, all that actually will happen is that those parties will receive a *just and reasonable rate* for their sales, pursuant to the Commission's price-mitigation methodology.

The parties' major arguments are dealt with below.

1. Non-Certification Days

Several parties contend that even transactions occurring on non-certification days were made pursuant to the DOE orders. Burbank at 32-34; Glendale at 12-14, Pasadena at 34-35; MID at 13. Some parties even argue that sales were made pursuant to the order even before the ISO made the first certification. Coral Power at 5-

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29 Certain parties challenge the premise that the burden of proof is borne by an entity seeking characterization of its transactions as pursuant to the DOE orders. Burbank at 30-31; Glendale at 10-11; MID at 9-12. These parties' argument is far off-base. While the burden of showing unjust and unreasonable rates was originally on the Section 206 complainants, the Commission has long since found that conditions caused unjust and unreasonable rates during the refund period and that spot-market sales for that period should be mitigated. But the Commission created an *exception* from mitigation for sales that meet certain criteria, *e.g.*, sales made pursuant to the DOE orders. *See* July 25 Order at 61,516. The burden is thus borne by the party seeking an exemption, as the proponent of the claim (*i.e.*, a claim that a sale meets a certain criteria). The Proposed Findings at ¶ 273 are correct.

12.[31] The terms of the DOE orders were available to all to see, and they are clear that for the order to be in effect on a given day, the ISO must submit a certification *for that day* to the DOE. Proposed Findings ¶¶ 314-319; Exhibit ISO-11 at 1. As the Proposed Findings noted, certification was "central" to the orders. Proposed Findings ¶ 315. Arguments that the DOE orders themselves were all the certification needed to make the orders effective (Coral Power at 8; MID at 20) or that non-certification days should be covered by the DOE order because the ISO requested power from sellers on all days (Glendale at 13; Burbank at 33) are refuted by the terms of the orders themselves.

Some parties argue that sales made to the ISO on non-certification days should be exempt from mitigation because the parties felt they were required to sell on those days. Burbank at 25-26, 32-33; Glendale at 5; Coral Power at 5-8; MID at 16.[32] Some parties point to letters from Terry Winter, CEO of the ISO, to the Secretary of Energy stating that the DOE orders had helped the California power situation. Burbank at 36-37; Glendale at 17; MID at 18; Pasadena at 37. These arguments simply highlight the moral persuasiveness of the DOE orders, which brought home the critical situation in California and made more concrete the notion that not only was the reliability of the ISO's grid threatened but any domino effect could affect connected systems as well.

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[30] See ISO at 27, 30.

[31] Although the first order was issued on December 14, the ISO did not filed its first signed certification until December 19, 2000 for the operating day of December 20, 2000. Exh. ISO-21 (O'Neill) at 8:17-19; Exh. JE-3, Vol. I, Tab ISO Certification 12/20/00.

[32] SWC-MWD's argument that sales by Attachment A entities on certification days should all be considered DOE sales because of the context of the transactions, SWC-MWD at 10-13, casts aside the process set out in the DOE orders and the intended use of the orders as a last resort. Proposed Findings ¶ 289; Exh. ISO-11; Tr. at 2289:11-12. *See also* Exh. JE-3, Vol. I, Tab ISO Request 12/20/00, unnumbered third page (ISO tells DOE of its "*commitment to use the emergency power sparingly.*"). Burbank and Glendale argue that they worried about violating their fiduciary duty by selling into the market and would have not made such sales unless convinced it was done under the DOE orders. Burbank at 24; Glendale at 6. These arguments are hollow as the reliability of those systems is tied to the reliability of the ISO Control Area. Exh. ISO-21 at 19:10-19. Moreover, it simply doesn't matter that a

Exh. ISO-21 (O'Neill) at 19:12-19; Tr. at 2276:11-17; Tr. at 2449:12-2450:5. The moral persuasion or greater concern for reliability caused by the DOE 202(c) orders do not change the terms of the legal rights and obligations thereunder. Nowhere do any of the entities claiming 202(c) sales on non-certification dates explain how the language of the order does not mean what it clearly states.

2. Market Bids

Parties also challenge the Proposed Findings' determination at ¶ 321, that bids into the ISO's formal markets – the ISO's Day-Ahead and Hour-Ahead markets for Ancillary Services, as well as its Real Time Market for Energy – could not result in transactions pursuant to the DOE orders. Burbank at 26; Glendale at 6-7, 14-18; MID at 25-28; Southern Cities at 3-9.

The ISO's markets represented the mechanism on which the ISO was relying in order to *avoid* the need to use the authority granted to it under the DOE orders. Tr. at 2353:16-19. Terry Winter, in his December 20, 2000 letter requesting an extension of the DOE authority, specifically stated that the ISO had "endeavored to obtain needed supplies, to the maximum extent possible, through *existing market mechanisms.*" Exh. No. JE-3 at Tab ISO Request 12/2-0/00 at unnumbered page 3 (emphasis added). Indeed, the ISO relied on data as to the amount of energy and capacity already scheduled with it or already bid into its day-ahead markets, or forecast to be bid into its markets, in determining whether or not to file a certification as required by the DOE orders. *See, e.g.*, Exh. ISO-13. *See also* Proposed Findings ¶ 347; Tr. at 2200:1-8; 2261:13-21, 2288:1-12, 2935:17-19.

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party might have "thought" it was selling pursuant to the orders – there are *objective requirements* that must be met before a transaction can be found to have been pursuant to the orders.

In addition, the timing of the process established by the DOE orders simply excludes the possibility that bids into the Day-Ahead Market for Ancillary Services could have been made pursuant to the orders. As the Proposed Findings found,

> [S]ales to the ISO through bids into its Day-Ahead Market cannot be considered as DOE transactions since the ISO would not yet have asked for information on available excess energy at the time the Day-Ahead Market closed and would not have contacted an Attachment A entity to request that excess energy.

Proposed Findings ¶ 346.

Moreover, bids into the ISO's formal markets simply did not meet the terms of the DOE orders. The DOE orders required Attachment A entities to "make arrangements to generate, deliver, interchange, and transmit electric energy when, as, and in such amounts as may be requested by the [ISO]." Exh. ISO-11 at 1. Additionally, the DOE orders stated that the "terms of any arrangement made between the entities subject to this order and the [ISO] pursuant to [these orders] are to be as agreed by the parties." Exh. ISO-11 at 2. *See also*, Exh. S-1 (Patterson) at 17, Exh. S-33 at 37. These phrases clearly contemplate a bilateral process through which the ISO would specifically request energy from an Attachment A entity, rather than the automated process by which bids are submitted and awarded in the ISO's markets.[33] *See* Proposed Findings ¶ 322; Exh. S-1 (Patterson) at 17:4-14; Exh. ISO-21 (O'Neill) at

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[33] BPA argues that the ISO was required to request energy from resources prior to the certification day, and that that was the "request" with which sellers had to comply. BPA at 4. BPA fails to note, however, that the provision on which it relies, from paragraph E of the December 14 order, was eliminated by the December 20th order, Exh. ISO-22 at 1-2, and replaced by a requirement for the ISO to call for information on excess energy that would be available the next day. Since the operative provision of the orders, requiring sellers to respond to ISO "requests," stayed the same before and after that change, it is clear that the "request" referred to in the operative provision could not be the day-before ISO request for energy that was dropped entirely from the orders as of December 20.

5:14-16. *See also* Tr. at 2338:20-2339:7.[34] In practice, the ISO limited its use of its DOE authority to OOM transactions and suppliers have provided no evidence in the record to contradict this fact; no one has provided evidence that the ISO actually used the authority available to it under the DOE orders to require that an entity submit a bid into its markets. Moreover, when the DOE requested information during the DOE order period on what supplies were being made available to the ISO pursuant to the DOE orders, it requested information on OOM transactions and not market transactions. Tr. at 2332:13-19; 2353:22-2354:3. This shows the limited type of transactions that DOE itself considered to be made pursuant to the orders.

3. Requests from the ISO

Certain parties challenge the Proposed Finding's determination, in ¶ 309, that only a sale made in response to a specific request by the ISO qualifies as being made pursuant to the DOE orders. Burbank at 32, 33-41; Glendale at 19-20; Pasadena at 33-35; Southern Cities at 7-9.

Their arguments, however phrased, amount to arguing that the ISO's constant, general entreaties that suppliers make all possible energy available to the ISO should suffice as the "request" contemplated by the orders. The ISO was in constant telephone contact with suppliers and held daily conference calls, both before and after the first DOE order and on non-certification days as well as certification days, to urge sellers to sell into the ISO markets or otherwise make energy available. Tr. at 2328:8-15. But the

[34] Certain parties argue that they were "voluntarily complying" with the DOE orders, *see, e.g.*, MID at 20-24; Pasadena at 27, by not waiting for a specific request and by simply bidding into the ISO's markets when they could (as opposed to selling directly to the ISO under agreed terms). These parties essentially argue that they were "voluntarily" complying with an order when it was not in effect, and/or complying with an order by ignoring its clear terms. Pasadena attempts to characterize the terms of the DOE orders as enforcement provisions, arguing that all sales to the ISO of power were made under the

regime put in place by the DOE orders required specific steps before a transaction would be made pursuant to those orders: an ISO certification for the following day, an ISO request for information on available power for that day, and a specific ISO request to Appendix A entities for some of that power on agreed-to terms. *See, e.g.*, Exh. ISO-12 (January 11, 2001 DOE order). The ISO's continuous pleas for all available energy, made day in and day out during late 2000 and early 2001, may have been made more effective by the Secretary of Energy's recognition of the crisis, which recognition was embodied in the orders, but the mere existence of the orders did not turn all sales to the ISO during a nearly two-month period into sales "pursuant to" the DOE orders. *See, e.g.*, Proposed Findings ¶¶ 254-269, 308-309, 313-314, 319, 321.

4. Entities With Participating Generator Agreements

Certain parties argue that their transactions were made subject to the DOE orders even though they had Participating Generator Agreements ("PGAs") with the ISO. Pasadena at 28-29; SWC-MWD at 7, 18-24. These arguments are without merit because the ISO had sufficient authority under the PGA to require the generators to provide energy to prevent an imminent or threatened emergency. See Proposed Findings ¶ 312; SWC-MWD at 19 (quoting the PGA provision).

With regard to Pasadena, while that entity voluntarily chose to make energy and/or capacity available to the ISO, without the ISO actually ordering Pasadena do so, it is nevertheless apparent that in the event that the ISO did require energy from Pasadena's Participating Generators, it could have obtained that energy without the need to invoke the authority provided by the DOE orders. Doing so would also have

DOE orders while they were in effect. Pasadena at 30. These arguments simply do not change the structure put in place by the DOE Section 202(c) orders.

been consistent with the ISO's commitment to use the DOE order only when necessary. *See* Proposed Findings ¶¶ 289, 387; Exh. No. ISO-11; Tr. at 2289:11-12. *See also* Exh. JE-3, Vol. I, Tab ISO Request 12/20/00, unnumbered third page.

SWC-MWD's argument is different as there is evidence that the ISO did invoke its PGA agreement in that case. SWC-MWD's argument that the ISO could not have been relying on the PGA on a certain five DOE certification days because the ISO did not declare system emergencies during those days ignores the fact that the ISO was attempting to ward off "threatened" system emergencies by making calls under the PGA – just as the terms of the PGA allow.[35] Moreover, as the Proposed Findings note, DWR – the actual seller in the transactions for which SWC-MWD seeks exemption from mitigation, has *not* claimed the transaction were made pursuant to the DOE orders, and SWC-MWD's own witness acknowledged that the sales would have been made even absent the DOE order. Proposed Findings ¶ 413. Finally, Staff noted that the transactions SWC-MWD asserts were pursuant to the orders were priced "as bid or Option A/B," the pricing options contained in the PGA. Tr. at 3024:21-3025:5; Proposed Findings ¶¶ 412-14; Exh. SWC-4 at Schedule 4.

As the Proposed Findings noted, the only reason a few parties with PGAs wound up on Attachment A is that the ISO, in its haste to provide DOE with a list, relied on its client relations department to come up with one. Proposed Findings ¶ 312 (citing ISO witness O'Neill). The parties that are relying on the chaotic genesis of Attachment A to

[35] SWC-MWD's argument that there was no threatened emergency is completely belied by the fact that the ISO had certified to DOE a need for authority under the DOE order for those days. The ISO only did that when, in effect, an emergency was threatened based on forecast shortfalls in available energy. The certification shows the threatened emergency that authorized the ISO to invoke the PGA.

try to get the Commission to ignore their obligations under the PGA, and bootstrap their OOM sales into an exemption from mitigation, should be soundly rebuffed.

P. The Proposed Findings Correctly Determined That No Showing Had Been Made That Mislogging of Transactions Had Affected the MCP (Phase 2 – Issue I.A.1.b)

This issue concerns the mislogging of OOS non-congestion calls as OOM dispatches, which was a subject of the Commission's May 15 Rehearing Order. The Proposed Findings, after reviewing all the evidence regarding such mislogging, concluded:

> [T]he California Generators have failed to demonstrate that mis-logging of OOS non-congestion transactions resulted in the ISO establishing incorrect *historical MCPs.* The California Generators have not shown or given the Commission good reason to believe that claimed mislogged OOS non-congestion transactions were, in fact, the last units dispatched in their interval, and, thus, should have set the *historical MCP.*

Proposed Findings ¶ 423 (emphasis in original).

CSG and Generators contend that the Commission intended that the ISO be required to recalculate clearing prices if the Presiding Judge simply found evidence of mislogging, regardless of its impact. CSG at 42-43; Generators at 1-3. Staff urges the Commission to direct the ISO, at the time it makes its compliance filing in this proceeding, to examine the mislogging issue and correct any errors that the ISO identified in its internal "Project X" audit. Staff at 7-10. The Proposed Findings, however, rightly proceeded on the basis that the Commission was only concerned with mislogging that would have affected the MCP, and concluded that no showing had been made of such an effect.

A review of the entire universe of dispatches that the ISO, as the result of its internal audit, resettled at the bid price would be extremely costly for the ISO, would take personnel away from other important tasks (such as running the normal settlements and billing process), and would delay the final compliance resolution of the necessary refunds. The cost would eventually be borne by Market Participants. There is no reason to undertake such an endeavor in the absence of evidence that it would make a material difference in the calculation of refunds.

CSG and the Generators also complain that the Proposed Findings put the burden on the Generators and CSG to come forward with evidence of mislogging that would affect the MCP. CSG at 42; Generators at 3-5. The Commission directed the Presiding Judge to evaluate the issue of mislogging *for the purpose of determining whether the MCPs should be revised.* It directed revision of MCPs *only if* the Presiding Judge found sufficient evidence; it did not direct revision of the MCP's *unless* the ISO produced evidence that there was no material mislogging. May 15 Rehearing Order at 61,654. It only makes good sense for the Presiding Judge to require some affirmative showing of mislogging material to the calculation of the MCPs. For the Commission to have directed otherwise would have required the ISO to go through the process of re-examining all transactions that the ISO resettled, based on its internal audit, without any prior showing of material mislogging. Because the Proposed Findings concluded that there was no persuasive evidence of mislogging that affected the MCPs, they are wholly consistent with the Commission's May 15 Rehearing Order.

The Generators go on to argue that the Proposed Findings' conclusion that the evidence was insufficient is not supported by the record. Generators first criticize the Proposed Findings' statement that the price paid for a transaction logged as OOM[36] is

[36] The ISO must assume that when Mr. Tranen, as well as the Generators on brief and in comments, refer to the price paid for a transaction logged as OOM being other than the MCP, they refer

not sufficient to demonstrate that it should have been logged as OOS. The Generators contend that Mr. Tranen used the price only as an indication of potential mislogging, signaling the need for further analysis. Generators at 5-6. The evidence, however, indicates that Mr. Tranen used the price as a confirmation of his initial analysis, asserting that the payment of a price higher than the MCP demonstrated the accuracy of his conclusion of mislogging. *See* Exh. GEN-89 (Tranen) at 35:9-17; *compare* Exh. GEN-36 (Tranen) at 18:16-19:12.

As the Proposed Findings concluded, such an inference cannot be made. Generators that provide OOM dispatches can elect payment under one of two methods, the MCP or a cost-based payment. Mr. Tranen did not distinguish the Generators' selection of a cost-based payment from his allegedly mislogged OOM dispatches. In addition, during the Refund Period the ISO engaged in numerous spot negotiations for real-time energy outside of its centralized markets, which would also be logged as OOM dispatches with a price other than the MCP. Mr. Tranen did not screen for those spot transactions either. Proposed Findings ¶¶ 441-42.

Generators defend Mr. Tranen's price comparison process on the basis that the ISO used a price screen for "GG Exceptions" in its internal audit and that 85% of Mr. Tranen's claimed mislogged transactions matched the audit, confirming that those 85% are "indisputably non-congestion OOS transactions that the ISO had categorized improperly as OOM." Generators at 6. This defense has two flaws. First, the ISO did not perform a price screen in the audit for GG Exceptions. A GG Exception is defined as an instance in which a unit that was dispatched to provide OOM energy during an

to the ultimate price paid. *See* Proposed Findings ¶ 438. Otherwise, the argument would make no sense because the whole dispute is about dispatches that were logged as OOM and paid the MCP, but should interval had an unaccepted bid in the BEEP Stack during that interval; the criteria that the ISO used to determine GG exceptions are identical to the definition. *See* Exh. ISO-37 (Gerber) at 34:2-7. More importantly, GG Exceptions did not distinguish between congestion and non-congestion OOS transactions. *Id.* *See also* Exh. GEN-62. Generators' "indisputable" conclusion simply does not follow its premise.

Second, the Generators criticize the Proposed Findings' focus on Mr. Tranen's failure to verify his list of mis-logged transactions based on ISO records with the Generators' own records, noting the ISO demonstrated the existence of mislogging using only its own records. Generators at 6-7. The Proposed Findings made this finding, however, in connection with (indeed, in the same paragraph as the discussion of) Mr. Tranen's failure to establish a one-to-one correspondence between an OOM dispatch and a bid of the same unit in the BEEP stack, discussed below. Proposed Findings ¶ 461. A review of Generators' records might have filled this gap in the analysis.

The Generators' next contention is that in comparing the 36,288 intervals during the Project X period with Mr. Tranen's 66,873 claimed misloggings, the Proposed Findings did not take into account the fact that more than one transaction can be mis-logged in an interval. Generators at 7. Generators misread the Proposed Findings. The Proposed Findings did not use the number of intervals as an independent basis for faulting Mr. Tranen's analysis. Rather, the Proposed Findings simply concluded that the number of intervals demonstrates that the "list of transactions in Ex. GEN-61 must be further filtered" in order to determine the intervals in which the MCP would have been

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have been logged as OOS and paid as-bid.

affected. Proposed Findings ¶ 461. The finding is merely prefatory to the following finding regarding the inadequacy of Mr. Tranen's filtering process.

The Generators' fourth criticism concerns the Proposed Findings' conclusion that Mr. Tranen had failed to show a nexus between the bids in the BEEP stack and the claimed OOS non-congestion dispatches. Generators at 7-8. The Generators assert that the Proposed Findings' conclusion is relevant only with regard to whether the unit could set the MCP. *Id.* at 7. The Generators are wrong. As the Proposed Findings went on to note, Mr. Tranen concluded that the transaction was mis-logged if there were sufficient bids in the BEEP stack to accommodate the transaction in addition to all energy dispatched through the BEEP stack. Proposed Findings ¶ 461. As the Proposed Findings also noted (in a point unchallenged by the Generators), Mr. Tranen did not determine whether the particular unit involved actually had a bid in the BEEP stack. *Id.* Under these circumstances, Mr. Tranen apparently would classify as mis-logged a unit that was dispatched OOM for the Trading Day, and did not subsequently submit any bids into the ISO markets, if other units had submitted bids sufficient to accommodate the OOM dispatch. He would also classify as mis-logged a unit that was dispatched OOM for the Trading Day at 10 MW, and subsequently bid 100 MW into the market at $100, when the MCP turned out to be $120 and there remained bids in the BEEP Stack. In neither case would the OOM dispatch have properly been classified as OOS.

Of course, any errors in this methodology could have been discovered if Mr. Tranen had later compared the actual bid of the unit in question with the MCP in order to determine whether if could actually have affected the MCP. In any event, the

Generators have not failed to refute the Proposed Findings' conclusion that Mr. Tranen never explained the manner in which he determined which transactions would have changed the MCP. *Id.* The Generators' comments are revealing. Although they cite Mr. Tranen's testimony to establish that he identified the transactions that would have been eligible to set the MCP, Generators at 7, a review of the testimony, Exhibit GEN-36, reveals only that Mr. Tranen identified certain transactions as eligible to set the MCP. Nowhere in the cited testimony does Mr. Tranen explain how he did so or why his identification is correct. The Generators then point to an Exhibit in which Mr. Tranen "listed . . . the specific BEEP stack bids that would have set the higher clearing price" and identified those bids as the mis-logged bids that were higher than the MCP, but lower than the soft cap. Generators at 7-8 (citing Exh. GEN-63). The exhibit itself does not identify mis-logged bids, but only specifies a "corrected MCP." *See* Exh. GEN-63. The only citation that the Generators offer to establish that those "corrected MCPs" reflect mis-logged bids that were higher than the original MCP, but lower than the soft cap, is *their own initial brief*, which in turn only cites Exhibit GEN-36, discussed above. Generators then assert that Mr. Tranen selected the intervals that would involve revised MCPs by relying upon the ISO's own description of the manner in which the BEEP system determines MCP. Generators at 7-8. For this assertion about Mr. Tranen's methodology, Generators cite only the ISO's testimony. Finally, the Generators cite Staff testimony about the relationship between instances of mislogging and the MCP and MMCP. *Id.* at 8. That testimony, however, offers nothing regarding Mr. Tranen's identification or methodology, but only explains how mislogging could affect the MCP. *See* Exh. S-95 (Patterson) at 13:15-14:6. Indeed, in its comments, Staff indicated that it agreed with the Presiding Judge's finding that the Generators had failed to show the extent of any mislogging and any specific effect on historical MCPs or the MMCPs. Staff at 9.

The Generators' dismissal of the Proposed Findings regarding Mr. Tranen's failure to check his findings against Generator records and to provide his work papers, Generators at 8, is thus unconvincing. It is not surprising that the Presiding Judge would require such information in the absence of any other evidence supporting Mr. Tranen's identification of intervals when the MCP should be revised and of the revised MCPs themselves. Yet Generators go on to assert that there must be no problem with Mr. Tranen's findings because they provided his workpapers to the other parties, and no one criticized them on the record. This is certainly a novel approach to establishing facts before the Presiding Judge. The Generators are clearly grasping for straws. The Commission should adopt the Proposed Findings in this regard.

Finally, although the Proposed Findings did not address the issue of the sequencing of OOM dispatches and bids (*i.e.*, whether out-of-sequence bids submitted during the period that units are responding to multi-hour OOM dispatches should be able to set the market clearing price), the Generators do so anyway. A bid submitted for the same energy that is the subject of an ongoing OOM dispatch does not change the OOM dispatch to an OOS dispatch. Exh. ISO-37 (Gerber) at 34:20-35:8. While the energy from the OOM dispatch may appear to be OOS, it is in fact not; it remains an OOM dispatch and should not be eligible to set the MCP (unless, and to the extent that, the dispatch includes energy in excess of that included in the OOM dispatch). Otherwise, a generator that is dispatched OOM would thereafter have the ability freely to skew the market. As the ISO argued before the Presiding Judge, Mr. Tranen's failure to take sequencing into account in this analysis further undermines its validity. ISO Initial Brief at 13 (submitted Oct. 4, 2002).

The Generators contend that the Commission "already has rejected the notion that the ISO could be allowed to categorize a dispatch as OOM when a bid in the BEEP Stack is submitted after the ISO gave an OOM dispatch order." (citing *California Independent System Operator Corp.*, 90 FERC ¶ 61,006 at 61,010-12, *reh'g denied* 91 FERC ¶ 61,026 (2000)). The Generators' interpretation of that order is flawed. In that decision, the Commission addressed and rejected a specific ISO proposal to "direct the redispatch of generating units to manage intrazonal congestion, not only when there are insufficient bids, but also when it determines that the bids that are submitted will not be the result of a competitive market." *Id.* at 61,011. In doing so, the Commission stated:

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

Id. (emphasis original).

The Generators take this sentence to mean that the ISO could not characterize a transaction as OOM if a generator had a valid bid in the BEEP Stack, even if the ISO had dispatched the unit as OOM prior to the Scheduling Coordinator ("SC") for that unit submitting the bid or bids into the BEEP stack. The order was not, however, making a broad pronouncement of this sort; instead, the order was only drawing a distinction between the ISO's authority to require a generator to operate for physical reasons, such as transmission constraints, and its lack of authority to dispatch a generator for purely economic reasons. *Id.* at 61,011.

The Generators' citation of *Dynegy Power Marketing, Inc.*, 98 FERC ¶ 61,074 (2002) to support Mr. Tranen's description of the ISO's legal authority to issue OOM dispatches is even more off-point. *Dynegy* concerned the ISO's ability to make significant changes to its market through procedures instead of tariff filings, and *nothing* more. Its relationship to the asserted legal principle is less than tenuous.

The Generators also point out that the ISO's internal audit did not focus on the timing of a unit's bid, but instead, looked only to whether a particular unit had a bid in the BEEP stack. Generators at 11. This proves nothing more than the fact that the Project X list of "GG transactions" is not equivalent to a list of mis-logged transactions for purposes of this proceeding. As an initial matter, the purpose of the internal audit was to correct settlements; no effort was made to address the MCPs. *See* Tr. at 3382:22-3383:16. Moreover, the criteria were used only to establish an "exception" – an exception did not guarantee a revised payment, but rather identifies a transaction that needed to be examined further. As the document on which Generators rely to establish the Exception GG criteria reveals, after the exception was noted, it was referred to a team leader to *determine* appropriate corrective action. *See* Exh. GEN-62. There is simply no direct correlation between the criteria for Exception GG and criteria for determining the MCP.

Q. The Proposed Findings Correctly Mitigated Certain Out-of-Market Spot Transactions (Phase 2 – Issue I.A.2.a)

In summarizing the scope of the transactions subject to refund, the Commission stated that "transactions subject to refund . . . include sales by all sellers into the spot markets operated by the ISO and the PX," and that "the refund requirements apply to ISO OOM purchases . . . ." December 19 Rehearing Order at 62,178. Sempra Energy Trading Corp. ("SET"), Public Utility District No. 2 of Grant County ("Grant"), Burbank, and the Los Angeles Department of Water and Power ("LADWP") argue that the Commission also intended to exclude from mitigation – or should have excluded from mitigation – spot transactions that did not occur in the centralized ISO/PX market, and for which a negotiated price was paid. On August 14, 2002, after reviewing motions and after oral argument, the Presiding Judge found that these transactions were subject to mitigation under the Commission's orders and struck testimony arguing that the Commission had intended to exclude these transactions from mitigation. Proposed Findings ¶¶ 19, 466-68. Certain parties contend that the exclusion of testimony was in error and again raise their arguments that these transactions were not OOM. The arguments of these parties fail, however, as it is clear that OOM transactions include all transactions that the ISO made outside of its formal markets, and that the Commission intended them to be mitigated if they were entered into the day before or the day of the transaction and were less than 24 hours in duration. The arguments raised by these parties amount to a prohibited collateral attack on prior Commission orders.

1. Definition of Out-of-Market Transactions

In its July 25 Order explaining why OOM transactions would be subject to mitigation, the Commission quoted from an order previously issued in the refund proceeding, stating:

> [W]hen OOM calls are made, suppliers realize that the ISO is in a must-buy situation. . . . To the extent the ISO made spot market OOM purchases (*i.e.*, 24 hours or less and that were entered into the day of or

> day prior to delivery), such purchases are no different than purchases through its markets.

July 25 Order at 61,515-16, quoting *San Diego Gas & Electric Co., et al.*, 93 FERC ¶ 61,121, 61,349 (2000). The Commission confirmed in the December 19 Rehearing Order that OOM transactions would be mitigated. *See* December 19 Rehearing Order at 62,195.

SET argues that the Presiding Judge broadened the scope of what is considered to be an OOM purchase beyond what the Commission had intended. SET at 4. Grant, Burbank, and LADWP advance similar arguments. Grant at 13-15; Burbank at 21-23; LADWP at 8-15. More specifically, SET argues that the term "OOM sales" includes only sales compensated under Section 11.2.4.2 of the ISO Tariff on an hourly ex post price basis or on the basis of a pre-determined formula, and not sales that are compensated based on a negotiated price. SET also contends that it entered into spot transactions with the ISO pursuant to Section 2.3.5.1.5 of the Tariff, and that this somehow distinguishes its transactions from "OOM" transactions. SET at 5-6. As the ISO stated in its testimony the fact that the ISO compensated suppliers pursuant to its authority to enter into contracts under Section 2.3.5.1.5 of the ISO Tariff demonstrates nothing more than that the ISO enters into different types of OOM transactions, with the different types being settled pursuant to different provisions of the ISO Tariff. Exh. ISO-37 (Gerber) at 90:6-14. As ISO witness Gerber stated, "Neither section of the Tariff [2.3.5.1.5 or 11.2.4.2] cited by these witnesses mentions the term 'OOM' or 'Out-of-Market' explicitly . . . ." *Id.* SET's argument thus attempt to create conditions for a transaction to be considered an OOM transaction that simply do not exist, either in the Tariff or in practice. The Commission's orders do not create any distinction between

OOM sales the payment for which is negotiated under Section 2.3.5.1.5 of the ISO Tariff and OOM sales the payment for which is pre-determined under Section 11.2.4.2 of the Tariff. In fact, *the Commission's orders explicitly recognize that some OOM sales are the result of negotiation*. The December 19 Rehearing Order, for example, in the process of discussing how to identify OOM sales made pursuant to DOE orders, notes, "Although the ISO *negotiated* directly with parties to obtain both types of OOM sale . . . ." December 19 Rehearing Order at 62,196-97. The Commission similarly states, "APPA provides no justification to extend the scope of our investigation or the mitigation to bilateral transactions other than those in spot markets." *Id.* at 62,222.

SET also argues that what it calls the "bilateral" spot market transactions are not OOM transactions because they occurred in some cases prior to the close of the ISO's formal markets. SET at 6-7. This statement is based on the flawed premise that only OOM purchases made after the close of the formal markets were made in order to address reliability issues resulting from market insufficiencies. As the ISO explained in its testimony, the ISO's formal markets do not close until 45 minutes prior to real-time operations. Exh. ISO-37 (Gerber) at 88:21-26. During the Refund Period, it was common knowledge that bids into the ISO's formal markets were often grossly insufficient to meet load and that the ISO would need to procure energy outside of those markets. *Id.* at 88:26-89.3. As Mr. Gerber testified:

> The ISO knew full well, prior to the close of the markets, that it would need to seek alternative sources of supply, often in large quantities. Therefore, the ISO did not wait until less than one hour prior to real-time to ensure that the necessary supplies would be available to keep the lights on in California. To do so would have been imprudent in the extreme. Moreover, this method of transacting was preferred by many suppliers, because they then had the opportunity to negotiate up-front sales to the

> ISO spanning several hours or longer, rather than transacting on an hour-by-hour basis.

Id. at 89:3-11. SET's timing argument does not justify an exception to the Commission's finding that OOM transactions made within 24 *hours* or less of the need for the energy in question (rather than *45 minutes* or less, as SET would have the Commission's finding read) were made in a must-buy setting that should be mitigated. *See* July 25 Order at 61,515.

Grant cites ISO Operating Procedure S-318 to argue that the so-called "bilateral" spot transactions in question are not OOM transactions. Grant at 13-14. Burbank makes a similar argument, citing a Commission decision in another proceeding as alleged support for the proposition that OOM transactions can *only* occur between the ISO and Participating Generators and then citing the same Operating Procedure as does Grant for the proposition that OOM trades can *only* occur between Scheduling Coordinators and the ISO. Burbank at 21-23. SET makes a similar argument, citing an operating protocol requiring OOM instructions to be settled in a certain manner. SET at 6.

Grant, Burbank, and SET attempt to cobble together a definitional argument using excerpts of the various ISO operating protocols because neither the terms "OOM" or "out-of-market" appear anywhere in the ISO Tariff. Exh. ISO-37 (Gerber) at 90:20-91:1. With regard to Operating Procedure S-318 relied on by Grant and SET, ISO witness Gerber testified:

> The definition of OOM in S-318 . . . was included therein for purposes of distinguishing types of transactions discussed in that Operating Procedure only, and was not meant to be applicable outside of that Operating Procedure. Moreover, prior to, and during the refund period, ISO personnel, as well as many suppliers, used the term OOM broadly to

> mean any energy that the ISO procured outside of the competitive market process . . . .

Id. at 91:1-8.

Regarding Burbank's citation of the Commission's treatment of OOM in a different proceeding, the ISO has pointed out that the case cited by Burbank is limited to pricing issues relevant to the ISO's authority to dispatch Participating Generators even when those generators have not bid into the ISO markets. *Id.* at 91:19-22. The ISO agrees that non-Participating Generators are not obligated to respond to dispatch instructions, but this in no way suggests that the ISO cannot enter into voluntary OOM transactions with non-PGA generators. *Id.* at 91:20-92:4.

The Commission's orders in this proceeding shed further light on the use of the term OOM. The Commission has addressed the issue of refund liability in direct response to arguments raised by non-PGA sellers, never suggesting that it felt such arguments were somehow unnecessary because transactions by non-PGA sellers might be exempt, per se, from mitigation. *See, e.g.*, December 19 Rehearing Order at 62,196-97 (Commission response to PS Colorado's concern regarding OOM sales pursuant to DOE orders, and describing the transactions as "negotiated").

In fact, in its December 19 Rehearing Order, the Commission noted that several parties without Participating Generator Agreements, in their requests for rehearing of the July 25 Order's finding that OOM transactions should be subject to mitigation, argued "that these sales should not be subject to refund because OOM sales do not involve sales into either the ISO's or PX's markets; rather, *they are bilateral transactions* that arise out of a separate authorization under the ISO's tariff for the purpose of assuring grid reliability." December 19 Rehearing Order at 62,194 (emphasis added).

Again, the Commission did not attempt to narrow the definition of an OOM transaction but rather – in *denying* the request for rehearing – gave a broad description of OOM, one that clearly encompassed transactions the ISO entered into with sellers that did not have PGAs. *See id.* at 62,195.[37]

SET's attempt at a technical distinction – that OOM instructions may only be settled in a certain manner – also takes a specific operating protocol out of context. The protocol only addresses OOM transactions that are made by the ISO's *instruction*. SET at 6. This protocol simply does not address OOM transactions entered into as a result of bilateral negotiations. The key point is that nothing in the protocol in any way limits the universe of OOM transactions to transactions entered into as a result of the ISO's instruction. Exh. ISO-45 (Gerber) at 6:7-23. As noted above, the Commission's orders in this proceeding recognize that OOM transactions may be negotiated.

2. Mitigation of OOM Sales by Government Entities

Grant, Burbank, LADWP and Redding argue that, even if the so-called "bilateral" out-of-market sales described above are properly subject to mitigation, the Presiding Judge erred in not excluding the OOM sales of governmental entities. Grant at 6-11; Burbank at 10-21; LADWP at 9-13; Redding at 22-23.

The Commission's orders have established a framework in which spot transactions are subject to mitigation unless specifically exempted, as in the case of transactions made pursuant to the DOE orders. While the Commission never explicitly stated that OOM transactions with governmental entities were to be mitigated, several

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[37] It should also be noted that there is no reference to S-318 or the definition contained therein in the refund orders.

factors indicate that this is the intended effect of the July 25 and the December 19 Rehearing Orders.

Both the July 25 Order and the December 19 Rehearing Order discuss transactions in the formal spot markets and the Commission's authority over governmental entities selling into the ISO market. July 25 Order at 61,511-13; December 19 Rehearing Order at 62,180-87. Both orders then separately address spot sales made outside of the formal markets. July 25 Order at 61,515-16; December 19 Rehearing Order at 62,194-96. The necessary conclusion from these discussions is that sales by governmental entities into the formal spot markets were to be mitigated, and that OOM transactions were no different than those conducted in the ISO's formal markets and therefore had to be mitigated. See July 25 Order at 61,515. The Commission gave no indication whatsoever that, having made no distinction between sales by non-governmental entities and sale by governmental entities into the formal spot markets, and having concluded that OOM sales were indistinguishable from sales into the formal spot markets and thus had to be mitigated, it was nonetheless *sub silentio* carving out an exemption from mitigation for OOM transactions involving governmental entities. The Proposed Findings thus correctly applied the Commission's orders in mitigating the out-of-market spot transactions of government entities.

R. The Proposed Findings Correctly Determined That EPME's December 2000 Transactions With the ISO Were Spot Market Transactions (Phase 2 – Issue I.A.2.b)

El Paso Merchant Energy ("EPME") argues that it had an output contract with the ISO over a 10-day period in December of 2000 and because of this arrangement, certain of its transactions with the ISO were misclassified by the Proposed Findings as spot transactions. Rather than an output contract, EPME simply had an agreement with the ISO to conduct business. *See* Exh. ISO-37 (McQuay) at 74:6-10.

The arrangement that EPME claims was an output contract is missing key elements of such a contract. Moreover, the course of dealing between EPME and the ISO did not indicate the existence of an output contract. Historically, if parties left open the essential terms of a supposed contract, such as quantity, price, and the duration, without providing for any mechanism to determine those terms, the agreement was likely to be found to be so indefinite as to be unenforceable. *See* Arthur L. Corbin, Corbin on Contracts at § 95 (One Volume Ed. 1952). Section 2-204(3) of the Uniform Commercial Code is more liberal in this respect, but still provides that a contract can fail for indefiniteness if the parties did not intend to contract and there is no "reasonably certain basis for giving an appropriate remedy."

EPME claims that the element of a price term is met because the ISO understood that EPME would mark up the price at which EPME bought the power from Avista. EPME at 6. But while EPME may have been marking up the price at which it re-sold to the ISO, the key point is that there was no agreed price formula in place between EPME and the ISO. Exh. ISO-37 at 54:15-18 (Gerber); 74:6-13 (McQuay). EPME made these sales in the its usual course of business as an energy trader, buying power at a cheaper price and reselling it to a buyer willing to – or in this case bound by its responsibility to ensure reliability, needing to – purchase the power at a higher price. *Id.* at 54:12-15 (Gerber). The price of the power EPME sold to the ISO was not understood in advance, but was negotiated on a transaction-by-transaction basis. *Id.* at 54:15-18 (Gerber); 74:11-13 (McQuay). Prices and quantities were determined during and by the same spot market that the Commission has found resulted in unjust and unreasonable prices due to the ISO's must-buy position.

In addition to the lack of a price term, there was no understanding that the ISO would purchase all of the power that could be obtained by EPME, that is, no quantity was specified. *Id.* at 74:11-13 (McQuay). Telephone conversations between operators for the ISO and EPME arranging the sales indicate that the quantity of power purchased was open to discussion. *See* Exh. CAL-101. For example, on page 7 of Exh. CAL-101, a representative of EPME (Greg), asks whether the ISO "wanted to roll another hour." Similarly, on pages 13, 14, and 15 of the same exhibit, Greg from EPME again inquires of the ISO operator whether the ISO wants to continue to purchase energy from EPME. *Id.* at 13-14. Clearly, if the ISO and EPME had entered into a contract for all of the power EPME could obtain, there would have been no need, or reason, for EPME to inquire of the ISO whether it wanted to continue to transact with EPME. If an output contract had existed, the ISO would have been contractually required to purchase whatever energy EPME was offering. This on-going negotiation from hour-to-hour demonstrates the lack of any term setting the duration for the alleged output contract.

Rather than lacking only a single material term, the "output contract" for which EPME contends lacked *all* of its material terms. There was no price term, no quantity term and no specified duration. There is no basis whatsoever for characterizing these transactions as anything other than spot transactions subject to mitigation.

S. "Third-Party Financial Intermediaries" and "Sleeve" Transactions: Mitigation Should Be Applied to the True Seller, Not the Intermediary or Sleeving Party; Even So, Some Alleged Sleeves Were Not Sleeves at All (Phase 2 – Issues I.A.2.d and I.A.2.e)

Testimony regarding third party intermediary and sleeve transactions was struck from the record and submitted as an offer of proof. Proposed Findings ¶¶ 19, 466-68. In comments, parties renew their arguments based on those offers of proof. SMUD, LADWP, TransAlta, and EPME argue that this testimony should be considered and renew their arguments that transactions in which they sold the ISO power should not be mitigated as they were merely acting as financial intermediaries in sleeve transactions. SMUD at 12-20; LADWP at 16-32; TransAlta at 6; EPME at 13-17.

1. True Intermediary or Sleeve Transactions

A true intermediary or sleeve transaction is one in which the ISO negotiated the elements of a purchase with a seller but had to procure an "intermediary" who would pay the seller and then accept the credit risk associated with the ISO market. The intermediary appears in the ISO settlements system as the seller into the markets, but the ISO believes that the equitable result is for the Commission to apply price mitigation to the supplier who sold to the sleeving party, rather than having mitigation applied only to the intermediary, who did not stand to profit from the transaction, but merely provided a creditworthy buyer. Exh. ISO-37 (Gerber) at 50:9-21. Thus, for example, the ISO agrees with the position of the California Parties with respect to certain transactions involving Powerex. *See* California Parties at 33-35.

2. Certain Claimed Sleeves Were Not Sleeves and Are Indistinguishable From All Other Sales to the ISO

Many of the sales referenced by SMUD, LADWP, TransAlta, and EPME were not sleeve transactions, and thus there is no reason to treat those sales differently from any others; the prices received by SMUD, LADWP, TransAlta, and EPME should simply be mitigated, without trying to reach the suppliers to those parties.

T. The Proposed Findings Correctly Allowed the ISO To Treat Energy Exchange Transactions in Accordance With the ISO Tariff (Phase 2 – Issue I.A.2.g(ii))

The California Parties contend that the Proposed Findings erred by adopting the ISO's methodology for accounting for Energy Exchange Transactions. California Parties at 42. The California Parties continue to argue that the accounting method approved by the Proposed Findings was not allowed by the ISO Tariff during the Refund Period, and that the ISO's treatment of energy exchange transactions would require a Section 205 filing. *Id.* at 42-43. The BPA exchange agreement in Docket No. ER01-2886-000, which was accepted by the Commission by letter order, is consistent with the mechanism in Section 2.3.5.1.9 of the ISO Tariff – not a change that would require a Section 205 filing.[38]

The key issue in this proceeding is not the consistency of the BPA transaction with the ISO Tariff, but rather it is whether the ISO is permitted to account for energy

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[38] The ISO Tariff does not mention energy exchange transactions specifically. Nevertheless, Section 2.3.5.1.5 of the ISO Tariff grants the ISO broad authority to enter into contracts with suppliers when necessary to secure the reliability of the ISO Controlled Grid. The Tariff further provides that the ISO will charge Scheduling Coordinators for the costs of those contracts *pro rata* based on each Scheduling Coordinator's negative deviations. ISO Tariff, Section 2.3.5.1.9.

Staff argues that clarification is needed as to whether the Commission intended the BPA methodology to apply only to transactions after January 17, 2001, or whether it was also to apply to transactions that occurred prior to that date. Staff at 26-29. Although the ISO agrees that the Commission should clarify this issue, it is the ISO's belief that energy exchange transactions before that exchanges in its settlements rerun in a manner consistent with its pre-mitigation treatment of those transactions. To do otherwise would create chaos as there would be a complete mismatch between the pre- and post-mitigation results. The differences in parties' positions before and after the mitigation rerun would result not only from mitigation of certain transactions, but also from application of a different accounting treatment for energy exchange transactions – and it would be impossible to tell what proportion of the differences resulted from mitigation and what from the different accounting treatment. The Proposed Findings correctly concluded that the ISO has authority to treat exchange transactions consistently in the pre-mitigation data base and in the settlement rerun.

U. The Presiding Judge Was Correct in Excluding Testimony Regarding "Foregone Opportunities" (Phase 2 – Issue I.A.2.h)

In the course of the August 14, 2002 pre-hearing conference in these proceedings, TransAlta agreed to withdraw testimony regarding so-called "foregone opportunities" and instead submitted that testimony as an offer of proof. Tr. at 3764:5-9.

TransAlta raises the issue again in its comments on the Proposed Findings and argues that its transactions with the ISO should not be mitigated because it forwent opportunities to sell energy into the Northwest market so that it could sell power to the ISO instead. TransAlta at 3. In making this argument, TransAlta implies criteria for mitigation in this proceeding that do not exist. TransAlta states that it "was not bidding into the market as a last resort to resell to the CAISO energy that otherwise would go unsold." *Id.* at 3-4. The Commission's orders in this proceeding have found that conditions existed during the Refund Period that made sales into the ISO markets, or

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date can be accounted for in the same way as the BPA transaction, under the authority that already

OOM sales, unjust and unreasonable. It is irrelevant that TransAlta, or other suppliers, could have sold the energy that went to the ISO in other markets. That TransAlta sold energy to the ISO under the conditions found to have existed by the Commission is all that is required to mitigate the price of the sale.

V. If the Commission Determines That It Should Adopt an Hourly MMCP for Imports, That MMCP Should Be Applied On an Interval Basis (Phase 2 – Issue I.A.2.i)

The Proposed Findings concluded that the MMCP for imports should be determined on an hourly basis. The ISO explained in its Initial Comments why this would lead to inequitable results. CSG, in its comments, seeks "clarification" that the MMPC will be applied on an hourly basis. For the same reasons set forth in its Initial Comments, the ISO believes that if the Commission should adopt an hourly MMCP for imports – which the ISO considers unwise – that MMCP should be applied on an interval basis.

To do otherwise would unjustly favor exporters over other sellers of real-time energy, whose sales are mitigated on an interval basis. Favoring importers would simply allow them to retain more money, for no reason. For example, suppose an hourly MMCP of $100. Further suppose an MCP of $80 for four intervals and an MCP of $120 for two intervals. Because the ISO settles imports on an interval basis, an exporter that successfully bid into all intervals would receive an unmitigated payment of (4 x 80) + (2 x 120) = $560. The exporter would have received $40 above the MMCP (2 x 20), and if the MMCP is applied on an interval basis, the exporter will owe $40. The average MCP, however, was $83.33. Thus, if the MMCP is applied on an hourly basis, the exporter will owe nothing. The Commission should avoid this inequity.

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existed in the ISO Tariff, and is noted above.

W. The Proposed Findings Correctly Determined That the Commission Has Ordered the Use of the MMCP to Mitigate Capacity Charges for Ancillary Services and Other Non-Energy Charges (Phase 2 – Issue I.A.2.j)

The California Parties argue that the Proposed Findings erred by mitigating Ancillary Services using the MMCP, rather than capping the Ancillary Services markets at the Imbalance Energy clearing price when that price was at a lower level than the MMCP. California Parties at 47-49. However, a review of the documents relied on by the California Parties makes clear – as the Proposed Findings found – that the Commission has specifically directed the parties to compute the mitigated price for the purpose of refunds in only one way for both Energy and the capacity charges for Ancillary Services. Proposed Findings ¶ 554, *citing* the July 25 Order. *See also* December 19 Rehearing Order at 62,216, discussed below; Exh. GEN-83 (Tranen) at 16:13-17:2; Tr. at 5414 (Patterson) ("ancillary services for capacity . . . are to be mitigated using the mitigated market clearing prices that were computed in Phase I, or the methodology in Phase I.").

The California Parties argue that the proper cap for the price of capacity charges for Ancillary Services is the Imbalance Energy clearing price as that price would sometimes match the MMCP, but sometimes be lower. California Parties at 47-48. The California Parties point to, and quote from, the Commission's December 19 Rehearing Order for support. The cited order only serves to reiterate, however, that the ISO is to use the "mitigated Imbalance Energy price," *i.e.*, the MMCP, to cap the Ancillary Services markets and that prices for Ancillary Services below the MMCP are unaffected, simply being determined by the Ancillary Services clearing price. December 19 Rehearing Order at 62,216.

The crux of the argument seems to be that if a price for capacity in the Ancillary Services markets was below the MMCP, the price of Ancillary Services should not be *brought up* to meet the MMCP, arguing that prices can be lower than the cap. California Parties at 48. Neither the Commission nor the Presiding Judge have ordered a lower price to be brought up to meet the MMCP. The Commission's December 19 Rehearing Order is clear that the MMCP should act as the *cap* of that market and if prices historically cleared beneath that cap in an hour, then the ISO would pay the historical *Ancillary Services* clearing price. December 19 Rehearing Order at 62,216. In the December 19 Rehearing Order, the Commission clearly stated, quoting from an order previously issued in the refund proceeding: "'If the Ancillary Services market clear below the average hourly mitigated Imbalance Energy price for that hour, then the ISO will pay the Ancillary Services clearing price for that market.'" December 19 Rehearing Order at 62,216, quoting *San Diego Gas & Electric Co., et al.*, 95 FERC ¶ 61,275, 61,971-72 (2001). The Commission again stated in its December 19 Rehearing Order, "To the extent Ancillary Service markets clear below the hourly Imbalance Energy Clearing price, no further adjustment is necessary." December 19 Rehearing Order at 62,216. The Commission was thus very specific as to how Ancillary Services are to be mitigated: they are to be capped by the MMCP and clear at the historical *Ancillary Services* clearing price if clearing below the MMCP (not the *imbalance energy* clearing price derived after application of the MMCP as a cap as desired by the California Parities).

The California Parties also argue that the Presiding Judge "missed" their argument, "confusing computation with appropriate application of mitigation." California

Parties at 49. They go on to explain that they do not intend to change the manner in which the MMCP is calculated, but argue that "in some hours the energy imbalance clearing price is lower than the energy MMCP, and in those hours the ancillary service prices . . . should be *capped* at the energy imbalance clearing price." However, the December 19 Rehearing Order expressly **forbade** this sort of treatment for capacity charges for Ancillary Services. The Commission expressly stated: "[T]he Ancillary Services markets should *not* be capped at a level lower than the Imbalance Energy Market." December 19 Rehearing Order at 62,216 (emphasis added). In direct opposition to the Commission's orders, the California Parties argue for a lower cap on the Ancillary Services market than in the Energy markets in some hours. For example, in an hour where the historical Energy clearing price was lower than the MMCP (which is the cap on the Imbalance Energy market), the California Parties would have the lower historical Energy clearing price apply to the Ancillary Services market (which would be a lower cap than would have applied to the Energy market itself).

The Commission has established a scheme in which prices for Energy as well as Ancillary Services are to be capped using only the MMCP, and in which it is clear that Ancillary Services *may not be capped at a level lower than Energy*. As explained above, nothing in the Commission's orders or the Proposed Findings prohibits a price for Ancillary Services lower than the MMCP; however, the Commission expressly directs that if the clearing price were under the MMCP, the ISO would simply pay the historical *Ancillary Services clearing price*, not the energy imbalance clearing price. For these reasons, the Commission should affirm the Proposed Findings regarding the mitigation of capacity charges for Ancillary Services.

X. The Presiding Judge Correctly Determined That It Is Improper to Mitigate, Adjust, and/or Offset Neutrality Adjustment Charges Against Refund Amounts by Applying the MMCP to Them, and Correctly Determined That Issues Raised in the Neutrality Proceeding Should Be Excluded From the Refund Proceeding (Phase 2 – Issue I.A.2.k(i))

Salt River Project ("SRP"), the Southern Cities, and Staff each request clarification from the Commission related to this issue. Additionally, CSG alleges that the Presiding Judge erroneously excluded from consideration refunds owed by the ISO to certain Scheduling Coordinators resulting from improper assessment of neutrality charges. The ISO will address the comments of each of these parties in turn.

SRP notes that the Proposed Findings concluded, with respect to the issue of how neutrality charges should be mitigated, adjusted, and/or offset against refund amounts, that "it is not necessary and would be improper to mitigate, adjust, and/or offset neutrality adjustment charges against refund amounts by applying the MMCP to them." Proposed Findings ¶ 565. In response, SRP requests that the Commission "clarify this finding and ensure that all energy charges, including those captured in neutrality, are properly mitigated in accordance with the Commission's orders." SRP at 33-34. SRP states that the wording of the Proposed Findings "makes it unclear whether this is indeed the case," but that "[i]f the energy charges that are captured in the neutrality charge types are mitigated before being included in neutrality, SRP's concerns are satisfied." SRP at 34.

The neutrality charges themselves are not mitigated, *per se*, but decrease by virtue of the fact that the underlying transactions *are* mitigated. Because the ISO is required to maintain cash neutrality during every settlement period, charges and credits flow through to ISO Scheduling Coordinators through the neutrality adjustment charge.

Exh. ISO-24 (Gerber) at 11:8-12. This load-based charge accounts for, among other things, mismatches between amounts charged and amounts credited for specific services. The neutrality adjustment charge is allocated to Scheduling Coordinators based on their pro-rata share of system load. *Id.* at 11:12-15. When the prices and volumes that create the neutrality charge are mitigated the charge itself will be mitigated. For example if mitigation reduced the differences between the prices for Instructed Energy and Uninstructed Energy, and a substantial amount of real-time load was met by Uninstructed Energy the result would be a reduction in the neutrality charges and credits to Scheduling Coordinators. *Id.* As a consequence, buyers such as SRP would in such a case receive the benefit of price mitigation both directly and through neutrality charges.

The Southern Cities also make a request for clarification. As explained below, their request for clarification is ambiguously phrased. The Southern Cities assert that "the Commission should clarify that the ISO must include as part of its settlement re-runs at the compliance stage recalculation of neutrality charges to flow through the effects of price mitigation for transactions previously included, in whole or in part, in the neutrality charges." Southern Cities at 9. We assume that the Southern Cities are requesting the Commission to clarify that the ISO should indirectly adjust the neutrality charges as a result of mitigation of the charges underlying the neutrality charges. We support such a clarification. If, however, the request is one for a direct mitigation of neutrality charges it should be denied as the Southern Cities would be asking not for a clarification but for a reversal of the clear and correct finding in the Proposed Findings that "it is not necessary and would be improper to mitigate, adjust, and/or offset neutrality adjustment charges against refund amounts by applying the MMCP to them." Proposed Findings ¶ 565.

Staff requests clarification that the finding in the Proposed Findings that neutrality charges should not be mitigated, adjusted and/or offset should not be interpreted to mean "that there should be no changes to neutrality charges, no matter what happens to the other Charge Types." Staff at 29. The ISO believes that the Proposed Findings were not intended to be interpreted in the manner described by Staff or should not be so interpreted.

Additionally, Staff states that it finds "the statement in Finding ¶ 565 that it is not necessary to offset neutrality charges against refund amounts most puzzling," because "[i]f a buyer were to owe money under the neutrality charge, but be due a refund for its purchases, the final accounting could appear to offset one against the other." Staff at 30. Staff asserts that the Proposed Findings "should not be interpreted to rule out a final accounting of amounts owed and owing under all charge types." Staff at 30. The ISO does believe it was not the intention of the Proposed Findings to rule out a final accounting of amounts owed and owing under all charge types. What the Proposed Findings explained was that "it is not necessary and would be improper to mitigate, adjust, and/or offset neutrality adjustment charges against refund amounts *by applying the MMCP to them*." Proposed Findings ¶ 565 (emphasis added). As described above, the Proposed Findings correctly found that the MMCP should not be applied directly to neutrality adjustment charges.

CSG argues that, at oral argument on August 14, 2002, the Presiding Judge erroneously "excluded from consideration refunds which the ISO owes to certain SCs, resulting from the ISO's assessment of charges in excess of its filed tariff rate for neutrality charges through February 26, 2001." CSG at 66-69. As explained below, however, the Presiding Judge's decision at the oral argument was entirely proper.

The assessment of neutrality charges to which CSG alludes relates to an issue raised in the ongoing complaint proceeding before the Commission in Docket Nos. EL00-111 and EL01-84 (the "neutrality proceeding"). On July 31, 2002, a number of parties, including the ISO, jointly filed an "Offer of Settlement and Settlement Agreement" ("Settlement Agreement") to resolve all issues in the neutrality proceeding. Exh. ISO-45 (Gerber) at 10:8-14. *Inter alia*, the Settlement Agreement provides that the parties to the Settlement Agreement would agree, as a matter of compromise, to request that the Commission exercise its discretion to decline to order the ISO to pay refunds of amounts collected in excess of any "cap" in the ISO Tariff on neutrality charges, during the period June 1, 2000 through February 26, 2001. Exh. ISO-45 (Gerber) 15:2-7. The Commission has not yet acted on the Settlement Agreement.

The concern of the Presiding Judge in the present proceeding was that the issue of the treatment of neutrality charges was not one that he was empowered to address or should address. *See* Order Adopting Joint Narrative Stipulation of Issues and Concerns With Regard to Whether Certain Issues Are Beyond the Scope, Docket Nos. EL00-95-045 and EL00-98-042 (July 31, 2002), at ¶¶ 3, 3.a. The Presiding Judge convened the parties for the August 14, 2002 oral argument in part to address this issue. At the oral argument, the Presiding Judge stated, after hearing argument from some of the parties, including the argument from an attorney for the ISO and from Mr. Acker, the attorney for CSG:

> [If] we're dealing with something that doesn't have an immediate and a direct relationship to the prices that we're supposed to be mitigating, then it's not clear to me that this is the venue that the Commission intended for addressing that subject, because we're here in a very limited way, as everybody understands it. I'm not going to repeat the 1, 2, and 3 that Mr. Acker went through and that I've cited in orders from time to time and the other language that says don't stray from the reservation.

Tr. at 3777:8-17. The Presiding Judge then excluded matters concerning neutrality charges in excess of any cap on such charges, for the reason that those matters are not "directly involved with the mitigated market clearing pricing methodology, which in turn triggers a refund liability." Tr. at 3778:18-3780:1.

This determination by the Presiding Judge was correct and entirely accords with the testimony provided by Mr. Gerber that "the refund and neutrality proceedings have different purposes." *See* Exh. ISO-45 (Gerber) at 15:12-18. Mr. Gerber also stated:

> As explained on page 16 of the ["Explanatory Statement in Support of Offer of Settlement" ("Explanatory Statement") that was included in the filing containing the Settlement Agreement], amounts shown on Scheduling Coordinators' settlement statements that changed as a result of applying the terms of the Settlement Agreement would remain subject to further changes as a result of other proceedings pending before the Commission and/or the court(s). The Explanatory Statement specifically mentions the refund proceeding as an example of a proceeding that may require such further changes to Scheduling Coordinators' settlement statements. The Explanatory Statement goes on to state that the Settlement Agreement would not in any way interfere with the outcome of the refund proceeding, because the settlement statements would reflect further changes resulting from the refund proceeding.

Exh. ISO-45 (Gerber) at 15:21-16:9. Mr. Gerber went on to explain that the issues raised in the neutrality proceeding should not be addressed in the refund proceeding, in relevant part because the neutrality proceeding concerns issues that are separate from those under consideration in the refund proceeding, the Commission has before it now a Settlement Agreement that would resolve all Neutrality Adjustment issues, and there is no possibility that the approval of the Settlement Agreement would cause interference with the outcome of the refund proceeding. Exh. ISO-45 (Gerber) at 17:4-18:19. Thus, it was entirely proper for the Presiding Judge not to consider any Neutrality Adjustment charge issues in the Proposed Findings.

Additionally, CSG argues that "[i]f the Commission declines to address the neutrality charge refunds in this proceeding, the Commission must, at a minimum, confirm that affected parties are not foreclosed from securing the repayment of these excess charges directly from the ISO." CSG at 69. As described above, the Commission has not yet acted on the Settlement Agreement. If accepted, the Settlement Agreement will resolve all issues in the neutrality proceeding, including the issue of the payment of refunds of amounts collected in excess of any cap on neutrality charges. This CSG request for Commission confirmation is premature.

Y. The Proposed Findings Were Correct in Their Determinations Concerning the Refund Amounts Owed and Owing and Their Determinations Concerning How Refunds and Amounts Owed and Owing Should Be Calculated (Phase 2 – Issues III and III.A)

A number of parties provide calculations of amounts they assert are owed to them and argue that the Commission should adopt these calculated amounts. *See* Burbank at 54-56; Glendale at 27-28; MID at 32-33; NCPA at 8-11; SMUD at 39-42; Turlock at 14-16. These parties argue that the Commission should reject the determinations in the Proposed Findings, which explained, with regard to the overarching issue of what refund amounts are owed by each supplier, and what amounts are currently owed to each supplier by the ISO, PX, the investor owned utilities, and the State of California (Phase 2 – Issue III, which encompasses Phase 2 – Issues III.A through III.F):

> I find the parties' illustrative calculations claimed to be owed to them by the ISO and/or the PX provide little confidence of their accuracy, their utility is dubious, and, in any event, the Commission's orders make it clear that the ISO's settlement rerun data and the PX's refund calculations are to be the templates for determining who owes what to whom .
>
> . . . .
>
> In those instances where the parties have not agreed to the settlement calculations of the ISO and/or PX and propose different obligations, their underlying methodology is either unstated or unclear and is not useful in determining final obligations. Little or no probative value can be accorded the parties' illustrative calculations in these circumstances.

Proposed Findings ¶¶ 765, 766.

The Proposed Findings went on to discuss how refunds and amounts owed and owing should be computed (Phase 2 – Issue III.A), explaining:

> The Commission's July 25 Order requires findings of "the amount currently owed to each supplier (with separate quantities due from each entity) by the ISO, the investor owned utilities, and the State of California." 96 FERC at 61,520. *Once the Commission determines the mitigated prices, the ISO and the PX can figure out what the ISO's SCs and PX market participants owe or are owed.*

Proposed Findings ¶ 771 (emphasis added).

These determinations in the Proposed Findings are correct. The Commission has directed that the ISO – not any of the other parties – make the final calculations of the amounts owed and owing, after the Commission has determined the final mitigated prices. Thus, the calculations of the parties that have calculated amounts owed and owing should not be adopted. As Mr. Epstein stated in his Prepared Rebuttal Testimony, the ISO's calculations of amounts owed and owing were only "snapshots" of amounts owed and owing at a particular point in time. These amounts have and will continue to change as time passes. Exh. ISO-37 (Epstein) at 104:8-12. Similarly, the amounts calculated by the other parties will necessarily change over time.

Moreover, the Proposed Findings were correct in stating that little or no probative value should be accorded the parties' calculations of amounts owed and owing, where those calculations differ from the ISO's calculations of amounts owed and owing. In his testimony, Mr. Epstein explained the various reasons that the Commission should not adopt the calculations of such parties. *See* Exh. ISO-37 (Epstein) at 110:1-119:4.

Additionally, Mr. Gerber, in response to parties that disagreed with the refund amounts calculated by the ISO and that asserted that the ISO's methodology for calculated refunds was flawed, explained:

> The ISO has implemented the methodology for calculating refunds based on mitigated amounts that the Commission required in this proceeding. The Commission did *not* give the ISO discretion to consider alternative methods of calculating refunds. Thus, the ISO is not permitted (or inclined) to adopt any alternative refund calculation methods, in the absence of Commission direction that such methods are permissible.

Exh. ISO-37 (Gerber) at 121:11-17.

Further, Mr. Epstein, in response to parties that calculated post-mitigation amounts owed and owing, stated that the ISO has not at this point calculated post-mitigation amounts. Exh. ISO-37 (Epstein) at 124:21-22. Mr. Epstein explained, "I take no position at this time as to what the post-mitigation amounts should be. It is my understanding that there is a consensus that the MMCPs and refund amounts will change after the Commission rules." Exh. ISO-37 (Epstein) at 125:4-7.

There is no need for the ISO to reiterate here any of its detailed arguments in response to parties' erroneous calculations of amounts owed and owing. As explained above, the ISO calculated the amounts owed and owing as required by its own settlements process and by the Commission. Moreover, the relevant calculations for determining the amounts owed and owing are the calculations that the ISO will make after the Commission has determined the final MMCPs.[39]

Z. The Proposed Findings Correctly Determined That the ISO and PX Refund Obligations Should Be Kept Discrete (Phase 2 – Issue III.B)

With regard to how refunds should be applied as offsets against amounts owed and owing, the Proposed Findings stated: " The record establishes that the ISO and PX markets and tariffs are discrete and should continue to be discrete particularly as concerns the calculation of refunds and, as discussed under D. below, of interest." Proposed Findings ¶ 789. AEPCO states that it disagrees with this finding , arguing that "a seller could be forced to pay net refunds to one market (*e.g.*, the PX), while it is still owed net accounts receivable in the other market (*e.g.*, the ISO). AEPCO at 15-16.

AEPCO does not consider the complications that would result from a commingling of the ISO and PX refund obligations. As Mr. Epstein explained , combination of ISO and PX obligations may not be workable. The ISO and PX are two separate legal entities and the PX has filed for bankruptcy. If the obligations of the ISO and PX were commingled, the ISO would not be able to identify the amounts legally owed from and to its Market Participants as each has specific legal claims in the PX bankruptcy. *See* Exh. ISO-45 (Epstein) at 31:21-32:12.

[39] CSG argues that the ISO's refund calculations "are illustrative and should not be presumed to be valid." CSG at 65. The ISO agrees that its refund calculations are illustrative, because, as explained above, they constitute a "snapshot" of the refunds owed at a particular point in time, and because the final refund amounts can be calculated only after the Commission determines the final MMCPs. However, because the ISO followed the methodology directed by the Commission in making its illustrative calculations, these calculations are as valid as any illustrative calculations can be.

AA. The Proposed Findings Correctly Rejected SRP's Proposals Concerning the Cash Positions of the Parties (Phase 2 – Issue III.C)

SRP argues both that "refund amounts for each party must be calculated separately by market and by month in order to avoid improper cost shifting," and that the ISO markets should "be recalculated in the same manner as they were originally calculated, that is, separately and by month, and within each separate market, each monthly billing statement must be settled separately *with no inter-period netting of sales and purchases.*" SRP at 7-11(emphasis supplied). This argument seems akin to one made by SRP on brief, which the Proposed Findings explained was "contrary to the December 19 Rehearing Order, 'that offsets to supplier refund liability should include amounts owed to suppliers by the PX as well as by the ISO . . . [W]e will expect suppliers to pay net refunds, or offset amounts that they owe to the PX from amounts that the PX owes them.'"

Proposed Findings ¶ 797, quoting December 19 Rehearing Order at 62,254. The ISO believes that the Proposed Findings are correct on this point. Further, it would be entirely illogical, as well as inequitable to use cash positions as they stood during the Refund Period in determining amounts owed and owing. To do so would entirely ignore amounts paid by Market Participants since the end of the Refund Period (some of which amounts were for transactions that occurred during the Refund Period). For example, assume that at the conclusion of the Refund Period, a specific Market Participant owed the ISO markets $5 million for transactions that took place during the Refund Period. Subsequently, that Market Participant paid those amounts to the ISO, and the ISO, in turn, paid suppliers. It would clearly be inequitable to calculate amounts owed by and owing to that participant, after taking into account refunds, based on that participant still owing this $5 million. There is nothing in the Commission's orders that suggests that this should be the result.

BB. The Generators' Proposal Concerning the Treatment of Interest on Adjusted Transactions Is Unworkable and Should Be Rejected by the Commission (Phase 2 – Issue III.D)

The Generators assert that "[w]hat is not entirely clear from the Proposed Findings is how the Presiding Judge intends interest on refunds to be applied in instances where the ISO adjusted a payment for a transaction after the date the initial payment was made or should have been made." Generators at 26. The Generators go on to request clarification from the Commission that interest on [payments in excess of the MMCP] resulting from transactions that were later adjusted ("adjusted transactions") should accrue . . . only on the date or dates that payment of such excess payments took place or should have taken place," and state that the approach for calculating interest described in FERC Staff's testimony "supports this clarification." Generators at 26-27. They also assert that "[w]hile it may be easier for the ISO to simply aggregate all payments and deem them paid or due on the initial payment date, the results would be unfair to sellers . . . ." *Id.* at 27. Additionally, they deny that the Proposed Findings imply that all interest should be calculated from the transaction date or the date initial payments were due. *Id.* at 27-28 (citing Proposed Findings ¶¶ 770-72).

The Generators' approach is unworkable and should therefore be rejected. The ISO's existing billing, settlement, and invoicing process *is completely inconsistent with* the implementation of the Generators' proposal.

The ISO settlement system does not settle on a transaction matching basis, but rather aggregates monthly activity for all market services in a single invoice. Exh. ISO-

24 (Gerber) at 37:23-38:5. As a consequence, it has no method for determining interest on a transactional basis. Further, some Scheduling Coordinators, in certain months, will change from debtor to creditor and vice versa when the MMCP is applied. Exh. ISO-24 (Gerber) at 38:12-19. As such, even determining an interest amount due on a monthly basis is nearly impossible without some other decomposition of the ISO settlement and invoicing data. Thus, the Generators' proposal is infeasible. The only way it could be implemented is if the ISO's billing, settlement, and invoicing process were to be augmented by the amounts of interest owed and owing as determined by an off-line process and the individual Scheduling Coordinator interest amounts were to be provided to the ISO for the purposes of including on an invoice.

Moreover, the Generators are incorrect in asserting that their proposal is consistent with – much less supported by – the Proposed Findings and Staff's testimony. The idea of making a radical alteration to the ISO processes as described above for the purpose of assessing interest on adjusted transactions is so outlandish that neither the Proposed Findings nor Staff's testimony discussed it. Moreover, the Proposed Findings indicated, in the context of the bilateral obligation issue (described below in section I.CC), that "considering the complexities involved [in bilateralization], it is reasonable to resettle the markets using the information and funds available to the ISO . . . ." Proposed Findings ¶ 769. Carrying the logic of the Proposed Findings one step further, if it is *infeasible* for the ISO to implement a proposal that requires it to fundamentally change its current procedures, the *only* reasonable course is to resettle the markets in accordance with the ISO current information and procedures.

CC. If the Commission Determines That Bilateral Obligations Between Individual Buyers and Sellers That Look Through the ISO Markets Should Be Established, the Commission Should Completely Substitute Those Bilateral Obligations for Obligations Vis-à-vis the ISO Markets (Phase 2 – Issue III.E)

With regard to the issue of whether bilateral obligations that look through the ISO and PX markets should be determined, and, if so, how they should be determined, the California Parties and CSG argue that bilateral obligations should be determined and propose methodologies for doing so. California Parties at 88-91; CSG at 60-64. On this issue, the California Parties and CSG disagree with the Proposed Findings, which found that "'it seems most reasonable to resettle the markets using the information and funds available to the ISO and the PX,'" rather than to determine refund obligations on a bilateral basis. Proposed Findings ¶ 788 (quoting Staff Reply Brief at 52 (submitted Oct. 25, 2002).

The ISO takes no position on whether bilateral obligations between individual suppliers and sellers that look through the ISO markets should be established. However, as Mr. Gerber explained in his Prepared Direct Testimony, the ISO's systems cannot match specific sellers of energy or other services in its markets to specific purchasers of those services from its markets. Exh. ISO-24 (Gerber) at 38:12-13. If nonetheless the Commission were to determine that such bilateral obligations should be established, then fairness would require that those bilateral obligations should completely substitute for obligations vis-à-vis the ISO markets. The ISO settlement and invoicing process cannot accurately express obligations for some parties in terms of the ISO marketplace when the obligations of other parties have been calculated on a bilateral basis. *See* Exh. ISO-24 (Gerber) at 21:9-22:3, 38:12-14.

DD. With Regard to the Determinations of Refund Amounts and Amounts Owed and Owing, the ISO Stands on the Arguments It Has Presented Herein Concerning Issues Falling Under Phase 2 Issue III (Phase 2 – Issue III.F)

As to this issue, the ISO stands on the arguments presented above with regard to the other issues encompassed under Phase 2 Issue III.

EE. The Proposed Findings Correctly Determined That APX Should Be Liable for Refunds in This Proceeding, But APX Should Be Allowed to Pass Through the Cost of any Such Refunds to its Market Participants (Phase 2 – Issue IV.B.1)

A number of parties, most notably the Automated Power Exchange ("APX") itself, make a variety of arguments that APX should not be held liable for refunds in the present proceeding, and that calculations for refunds should instead look through APX to its participants. APX, *passim*; Enron at 2; SMUD at 29-32.[40] APX also argues that the ISO has testified that "it would be inequitable to impose refund liability on the intermediary because that entity did not earn the profit from the sale and only acted as a middleman." APX at 28-29 (italics removed). APX and these other parties disagree with the determination in the Proposed Findings that APX should be held liable for refunds. Proposed Findings ¶¶ 824-58.

In the July 25 Order, the Commission made clear that refunds and amounts owed and owing, with respect to the ISO markets, are to be determined by rerunning

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[40] APX argues that holding APX primarily liable for refunds is inconsistent with Commission precedent; that imposing refund liability on APX's participants is consistent with the Federal Power Act; that equity warrants that the Commission look through APX and impose the refund obligation on the actual sellers of power; that holding APX liable for refunds in this proceeding would result in APX being forced to pay out amounts far in excess of what it earned for services rendered during the Refund Period and is thus improper; and that the holding in the Proposed Findings on refund allocations for Scheduling Coordinator transactions in the ISO market is misplaced. Enron argues that, as a matter of policy, APX is not the appropriate party to hold liable for transactions that PX submitted on behalf of other entities to the PX day-ahead and day-of markets. SMUD argues that APX acted as a neutral middleman on behalf of actual buyers and sellers in the ISO and PX spot markets, and that subjecting APX to refund liability for

the ISO's settlements and billing system. July 25 Order at 61,519. That system accounts for obligations through Scheduling Coordinators. Exh. ISO-24 (Gerber) at 5:21-6:9, 6 n.1. APX participated in the ISO markets as a Scheduling Coordinator during the Refund Period, and it is APX with which the ISO had privity of contract, not the entities that APX represented in its role as a Scheduling Coordinator. Exh. ISO-37 (Gerber) at 122:22-123:3. As the transacting party in the ISO market, APX is responsible for refund amounts allocated to it. Of course, the ISO would agree that *ultimate* liability for the APX refund amounts should be on the Market Participants that bid through APX as their Scheduling Coordinator.

APX notes that the ISO has testified, in the context of "sleeve" transactions, that "it would be inequitable to impose refund liability on the intermediary because that entity did not earn the profit from the sale and only acted a middleman" (APX at 28-29 (italics removed)), that assertion is inapposite. The two issues – "sleeve" and responsibility of APX as Scheduling Coordinator – are unrelated to one another, but the ISO does see that the equities could be similar. The problem is that APX signed a Scheduling Coordinator Agreement, thus agreeing to be the transacting party in the ISO market that is responsible for amounts allocated to APX. If the Commission could find a way to look through APX to impose liability on the "true sellers," that might be the equitable result, just as the ISO has suggested in the context of "sleeves." But for purposes of the ISO's settlements system, APX as the Scheduling Coordinator is the party obligated for refunds.

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amounts it did not collect, or providing APX with refunds for payments it did not make, is contrary to the purpose of the instant proceeding.

FF. The Generators' Proposal That CERS Be Treated as the Scheduling Coordinator for the Net Short Load of the IOUs in the ISO's Settlement Rerun Should Be Rejected (Phase 2 – Issue IV.C.1)

The Generators propose that CERS be treated as the Scheduling Coordinator for the net short load of the investor-owned utilities ("IOUs") in the ISO's settlement rerun. Generators at 30-31. They argue that the ISO's settlement process has resulted in parties other than the three IOUs being improperly charged for a portion of the CERS transaction amounts, because under the ISO's settlement process those amounts are charged to buyers in proportion to their net negative deviation.

The Generators' proposal should be rejected. It would be completely impracticable for the ISO to fundamentally change its settlement process to give CERS the special treatment that the Generators request. The ISO's settlement process is conducted on a pooled basis, as required by its Tariff, and no effort is made to distinctly match buyers and sellers of real-time energy. Exh. ISO-24 (Gerber) at 6:4-9; 21:9-22:6. For the purpose of settling imbalance energy, CERS transactions were properly treated just like the transactions of other Scheduling Coordinator providing imbalance energy. Thus, to distinctly match the CERS sales of imbalance energy to a subset of all buyers (i.e., the buyers other than the IOUs) would violate the ISO's settlement principles. Further, there could be instances when the amount of energy provided by CERS exceeded that required to meet the IOU net short and in fact provided for the net short of the Generators to the extent that they had net negative deviations in these instances. As such, it would be improper to allocate the costs of CERS imbalance energy only to the IOUs' net short load. Apart from these concerns, to retroactively change the Scheduling Coordinator for any parties during the refund period for purposes of rerunning the ISO settlement would be extraordinarily time-consuming and burdensome for the ISO Settlements Department.

Moreover, in arguing that CERS must be made the Scheduling Coordinator for the IOUs' net short load in the settlement rerun in order to "avoid the improper subsidization" of the IOUs by other parties (Generators at 31), the Generators completely ignore the existence of an invoicing process that ensures that any refunds will be returned to the party that paid the ISO market. This invoicing process is currently the subject of a separate proceeding at the Commission, in Docket Nos. ER01-889, *et al.* Because this process will ensure that all parties, including CERS, will receive refunds of all the amounts they paid the ISO market, the Generators' concerns about the IOUs' being subsidized are groundless.

II. CONCLUSION

For the reasons set forth above, the ISO respectfully requests that the Commission rule on the Proposed Findings consistent with the ISO's positions as set forth herein.

Respectfully submitted,

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Dated: February 3, 2003

CERTIFICATE OF SERVICE

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

Dated at Washington, DC this 3rd day of February, 2003.

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