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 BRIEF OF THE
CALIFORNIA INDEPENDENT SYSTEM OPERATOR CORPORATION

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REPLY BRIEF OF THE CALIFORNIA INDEPENDENT SYSTEM OPERATOR CORPORATION ON MITIGATED PRICES ("PHASE I")

INTRODUCTION

The Commission's orders[1] establish a refund methodology under which each individual seller may ultimately choose between one of two mutually exclusive approaches for determining its refund obligation. The proceeding before the Presiding Judge involves only the first of these two approaches: the calculation of Mitigated Market Clearing Prices ("MMCPs" or "mitigated prices") that approximate prices that would have resulted in the ISO's real time market under competitive market conditions, and the application of those mitigated prices in order to determine "who owes what to whom" under this first approach. The second alternative provided to each seller by the Commission -- to opt for cost-based rates for the seller's portfolio of resources over the entire refund period --- is available to sellers only after refunds due under the first, "market based" approach have been calculated through the current Proceedings. The Commission has explicitly stated that the issue of cost recovery for sellers – individually or collectively – is not relevant in the current proceedings.

The sellers have turned the Commission's overall refund methodology – first, a market-based approach, and second, if necessary, an individualized cost-based approach -- on its head. They have proposed a methodology for calculating MMCPs based entirely on a cost-based principle: that the MMCPs should guarantee full recovery of operating costs to every generating unit during every 10-mintute interval of the refund period. They do not anchor this cost-based approach in the specific provisions of the Commission's various orders; at most, they attempt to show that it might be consistent with a strained reading of a couple of carefully selected passages, if one isolates them from the Commission's many other descriptions of its market-based approach. Rather, they attempt to justify their cost-based methodology for calculating the MMCPs by constructing a completely hypothetical, economically unrealistic, and technically infeasible world. In this world, the historical unit commitment decisions, which the Commission intended to be treated as fixed, are ignored, and we must assume that each unit would have been turned on or off in each 10-minute interval of the refund period, depending on whether it would have recovered its total operating costs during each 10-minute period solely on the basis of the mitigated price calculated for that interval. Moreover, the sellers would not apply the results of this cost-based approach on a seller-by-seller basis, as the Commission intended the alternative, cost-based part of its methodology to be applied; instead, sellers would set the MMCP for all sellers in an interval based on the maximum result of their cost-based approach for each generating unit. Thus, the sellers' methodology is designed to provide them the best of each of the two mutually exclusive options for calculating refunds provided by the Commission,

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[1] We will refer to the orders by their dates, as in our initial brief. In addition we carry over from the initial brief the short form references to certain entities, *e.g*., "ISO."

and is supported simply on the contention that the mitigated price must be set so high as to completely eliminate the possibility that any generator will seek cost-based rates

That the sellers have turned the Commission's approach to calculating the MMCPs on its head is shown by the "upside down" MMCPs produced under their approach; their MMCPs defy the laws of supply and demand, by rising during off-peak periods when demand is lowest and falling during peak periods when demand is highest. Most importantly, perhaps, the "heads, I win; tails, you loose" approach proposed by the sellers would undermine the Commission's most fundamental l objective of providing a more just and reasonable outcome for buyers in California's wholesale spot markets during the refund period.

The points made in this Introduction are elaborated upon in section I.B.1, below, which discusses the issue of whether incremental heat rates, or average heat rates, should be used in calculating the mitigated prices. That is the issue on which most of the refunds turn.

I. HOW ARE THE MITIGATED MARKET CLEARING PRICES DETERMINED FOR EACH 10-MINUTE INTERVAL DURING THE REFUND PERIOD?

A. What is the applicable formula for determining the MMCPs for each interval?

The parties agree.

B. What is the appropriate heat rate data set for each unit eligible to set the MMCP that should be referenced for insertion in the MMCP Formula?

1. Should average and/or incremental heat rate curves be used in the determination of the MMCP?

(a) The Commission's Goal in This Proceeding Is Competitive Pricing, Not Cost Recovery

The California Generators ("GEN") and the Competitive Supplier Group ("CSG") (together, referred to as "sellers") claim that the use of average heat rates, which ensures recovery of minimum load fuel costs for the marginal unit in each interval, is a "competitive outcome" and is consistent with Commission orders. GEN Brief at 5; CSG Brief at 7. They contend that the use of incremental heat rates, which will not always ensure the recovery of minimum load fuel costs by the marginal unit, is inconsistent with a competitive market and Commission orders. *See, e.g.*, GEN Brief at 4, 19-21; CSG Brief at 7, 9. These claims are based on a fundamental misinterpretation of the Commission's overall refund methodology.

The Commission's overall refund methodology affords each seller two options for determining its refund obligation: (i) the price-mitigation approach, which mitigates prices paid to each unit based on a single MMCP for each interval, or (ii) the opportunity for the individual seller to receive cost-based rates for its entire portfolio over the entire refund period. As demonstrated in the initial briefs of the ISO, the California Parties ("CAL"), and Staff, the Commission has adopted an approach to price mitigation that emulates pricing in a competitive real time energy market. In the December 19 Order, the Commission explicitly noted that its "mitigation plan is intended to replicate the price that would be paid in a competitive market, in which sellers have the incentive to bid their marginal costs." 97 FERC at 62,212. For the first of the two options, therefore, the Commission has adopted a price mitigation approach in which the MMCP is calculated in a way that emulates the pricing observed in a competitive market, in which the marginal unit would recover its marginal costs; it has not adopted an approach designed to ensure total cost recovery by marginal units. To suggest otherwise, as do sellers, is inconsistent with the numerous descriptions of the price mitigation methodology in the Commission orders. In fact, the Commission explicitly addressed the irrelevance of all costs other than marginal costs in establishing the mitigated price, in the December 19 Order:

> No purpose would be served by allowing the presentation of actual costs in the hearing, because they would not be relevant to the determination of the mitigated price in each hour of the refund period pursuant to the refund methodology, nor to refunds owed or amounts past due.

97 FERC at 62,253 – 62,254.

While the Commission has provided generators with a reasonable opportunity to recover their total costs in this proceeding, which implements the mitigated pricing approach, it has recognized the possibility that the mitigated prices, plus all other sources of revenue (which are not being mitigated), may not cover a specific generator's (or specific other seller's) costs. If that turns out to be the case, an individual generator may file for cost-of-service rates covering all of its units in the WSCC for the duration of the Commission's mitigation plan. *See* June 19 Order, 95 FERC at 62,564.

While the California Generators allege that the California Parties have sought to transform the current proceeding into the "a morass much like a rate case," GEN Brief at 14, it is in fact the sellers who have introduced the issue of cost recovery into these proceedings. The only reason for providing analysis of generators' other sources of revenue is to rebut arguments introduced by sellers, by demonstrating that the Commission's use of marginal cost bidding to emulate competitive pricing in the real time market is not "unfair" to generators, and will not result in numerous filings for cost-based rates.

(b) The Sellers' Hypothetical 10-Minute World

The California Generators, at the outset of their brief, acknowledge that the Commission intended the *historical dispatch* of units to be treated as *fixed*, and the mitigated prices to be calculated based on the marginal costs of these units. As the California Generators state, "We thus are not to engage in any hypothetical redispatch. July 25 Order at 61,517. We are, instead, to create new prices using the marginal costs of units that actually ran . . . ."[2] GEN Brief at 13. This is precisely what the ISO has done. As the CSG Brief itself acknowledges, the ISO has indeed used a "definition of marginal costs – based on incremental heat rates – to calculate MMCPs, which assumes that all of the units supplying energy in the real-time market are indeed already operating." CSG Brief at 10, citing Ex. ENR-1 at 8:1-7. This is, indeed, precisely what the Commission required. The ISO calculated MMCPs for the refund period by applying the same approach used to calculate proxy prices under the June 19 Order on a prospective basis, using the same unit commitment decisions and dispatch data that were used historically to calculate the marginal clearing prices during the refund period.

The California Generators, however, support their use of average heat rates by proceeding to argue that the July 25 Order requires (or at least allows) marginal costs to be calculated based --- quite literally --- 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 and must recover its full operating costs every interval solely on the basis of the MMCP calculated for that interval. *Id.* at 8-9. This hypothetical 10-minute world is built on (i) unsupportable inferences about the Commission's intent with respect to cost recovery, (ii) false arguments about the economics of unit commitment decisions, and (ii) technically infeasible assumptions about actual unit operating characteristics.

Within the construct of this hypothetical 10-minute world, the California Generators explicitly argue that MMCPs must pass what we will refer to as a *unit commitment simulation test*, under which the MMCPs – considered in a vacuum -- must result in the same

[2] While the California Generators' brief includes the phrase "that actually ran to 'keep the lights on in California'," the passage referenced in the brief actually includes, in the very next sentence, the restrictive phrases "in real-time" and "in the real time imbalance market." 96 FERC at 61,517.

unit commitment decisions that existed historically for each 10-minute interval. The California Generators' own brief describes this explicitly in terms of a simulation exercise, in a which a hypothetical re-dispatch of units is performed: "We are, however, to keep one factor constant: the units that run under the reconstituted prices [MMCPs] must be the same units that actually ran during the refund period." GEN Brief at 19.[3] The specific language of the July 25 Order that they cite as requiring MMCPs to pass this unit commitment simulation test in fact describes an entirely *different* process: one in which unit commitment and dispatch decisions are indeed treated as fixed, *i.e.*, no *additional* units are assumed to have run, with mitigated prices being calculated based on the marginal cost of each unit that *in fact ran historically*. 96 FERC at 61,517.

Upon cross examination, the sellers' chief witness on marginal cost economics, Dr. Tabors, could not deny that if unit commitment decisions are indeed treated as fixed, the actual marginal costs of each unit should be based on incremental heat rates. Tr. 1808: 24-1809:4. Dr. Tabors's attempt to finesse his way out of his own longstanding definition of marginal costs relied upon his construction of a theoretical world in which each unit's marginal costs during each 10-minute interval include the opportunity cost of not generating by simply turning a unit off or on during each interval. Tr. 1812:9 - 1813:9. Yet, the Commission explicitly directed that opportunity costs are not to be included in the calculation of the mitigated price, either on a prospective basis or for the refund period. *See* December 19 Order, 97 FERC at 62,211- 62,214; Tr. 1813: 10-23.

The California Generators do not really attempt to base their unit commitment simulation test, or Dr. Tabors's definition of marginal costs as including the opportunity costs

3 Elsewhere, California Generators again describe their assumption that the Commission's methodology requires that mitigated price level pass a unit commitment simulation test: "The incremental heat rate approach fails this test because, over extended periods, it does not produce prices that would have attracted

of not shutting down a unit in each interval, in the Commission's orders. Instead, they turn to flawed arguments constructed on incorrect "statements of fact" concerning the economics of unit commitment decisions, combined with infeasible assumptions about the operating characteristics of the generating units identified as the marginal unit under their cost-based methodology. For example, the California Generators acknowledge that "a generator would look to recover its minimum load fuel costs over its entire operating cycle" (rather than during each 10-minute interval), but argue that this "cuts in favor of average heat raters, not incremental heat rates," based on a single hypothetical example of a CT that could "start very quickly, in as short as 10 minutes." They then jump to the conclusion that the MMCP should be calculated in a hypothetical world in which every unit has a 10-minute operating cycle.[4] GEN Brief at 17.

Contrary to this hypothetical world, which California Generators would construct solely for purposes of calculating the MMCPs, unit commitment decisions are not made for each 10-minute interval, but are based on the operating cycles of units, which typically range from a period of at least several hours for a CT to several days or weeks for steam units. Tr. 1264: 8-17 (Rothleder); 2056: 6 – 2057: 3 (Sammon). Moreover, the California Generators' hypothetical world is simply inconsistent with the technical operating constraints of units, which, due to start-up and shut down times, minimum operating levels, and minimum

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the same level of supply that actually came forward to keep the lights on in California during the refund period." GEN Brief at 19.

[4] Simply because a unit may be able to start in 10 minutes, it does not follow that it has a 10-minute operating cycle (which includes at a minimum the unit's start-up plus minimum operating time). The California Generators' brief attempts to extend this flawed example to steam units (which represent the bulk of gas-fired capacity in the ISO system) by simply stating that "the same is true of steam units, albeit in a somewhat longer time horizon." GEN Brief at 17. In addition, as noted elsewhere in this brief, typical operating cycles are much longer than the minimum operating times --- ranging from several hours for CTs to several days or weeks for steam units – since it is typically economic for units to stay on-line for longer periods, given the marginal (incremental) costs of a unit (excluding minimum load costs) once it is started up and committed to operate.

operating cycles, simply cannot be instantly committed or “un-committed” to operate during each 10-minute interval. Tr. 1271:19-25 (Rothleder).

The CSG argument is built on the same self-contradictory logic as the California Generators’ argument. On the one hand, the CSG acknowledges that “the Commission did not intend to recreate a hypothetical dispatch or use mathematical models,” to calculate the MMCPs, CSG Brief at 41, and that MMCPs should not be based on “hypothetical assumed estimates developed for litigation purposes.” *Id.* at 8. The CSG also acknowledges that *system dispatch decisions,* which treat unit commitment decisions as fixed, are based on incremental heat rates and incremental fuel costs. CSG at 8-9, citing Tr. 1839: 11-13 and Ex. S-26 at 12:13 – 13:15. However, the CSG then seeks to justify the use of average heat rates based on a methodology that does not treat unit commitment decisions as fixed, and is instead designed to calculate MMCPs that would perfectly recreate historical unit commitment decisions during each 10-mintue interval. CSG Brief at 8 –9. Thus, the CSG’s argument for use of average heat rates also relies upon the fiction of a hypothetical and technically infeasible 10-minute world in which “average heat rates are used by operators to decide whether to generate in real-time (*i.e.*, whether to keep generating or shut down),” during each 10-minute interval. CSG Brief at 8. The flawed economics underlying the CSG’s argument is evidenced in the CSG’s own brief, which cites testimony of its own witnesses and FERC staff indicating the unit commitment decisions are in fact made considering the total operating costs of a unit, not during any individual 10-mintue interval, but over its entire operating cycle. CSG Brief at 8-9, citing Tr. 1838:22 – 1839:13 and 2056:18-2057:12.

The California Generators contend that we are free to construct this hypothetical world because – they say -- the Commission’s orders give the Presiding Judge discretion to decide whether incremental or average heat rates should be used. As noted in their brief, “If we use average heat rates in the MMCP formula, we can be sure that the marginal unit will recover the fuel costs it incurs to operate during the interval in which it is marginal – *including* minimum load fuel costs." GEN brief at 13. They go on to suggest that the Presiding Judge should approve the use of average heat rates in order to avoid the potential that some suppliers will exercise the option provided them under the Commission's orders to opt for the alternative, cost-based formula based on an individual supplier's actual total costs and total revenues. *Id. a*t 14. They suggest this, although (i) they have presented absolutely no evidence to support the possibility that even one supplier may opt for this alternative cost-based formula, *see* Exh. ISO-19 at 26:17 – 29:27, and (ii) the Commission has expressly indicated that it is fully prepared for this possibility and that consideration of this possibility is simply not relevant to the issue of how to calculate MMCPs. *See* December 19 Order, 97 FERC at 62,193.

The ultimate evidence that the sellers, by constructing their hypothetical 10-minute world, have turned the Commission's overall refund methodology on its head is a simple comparison of the MMCPs produced by their approach to the basic pattern of prices that would result under competitive market conditions in any electricity market. As shown by Dr. Hildebrandt, the MMCPs resulting from the sellers' approach defy the basic laws of supply and demand, by increasing during off-peak hours (when demand is lower) and decreasing during peak hours (when demand is higher). Exh. ISO-19 at 10:11 – 13:15. This highly counterintuitive trend is precisely the opposite of the trend that was actually observed in all of California's wholesale electricity markets in the two years prior to the refund period, when prices rose significantly during peak hours and fell during off-peak hours. *Id.* at 13:1–15. Moreover, as shown in the rebuttal testimony of Dr. Stern, while the MMCPs calculated by the ISO would reduce the average historical market clearing prices in the ISO real time imbalance market over the refund period by about 12 to 21%, the MMCPs submitted by the sellers' witnesses actually exceed the historical prices by 85% to 130%. CAL-19 at 3:5-8.

This clear visual evidence that the sellers' methodology is inconsistent with the Commission's objective of establishing MMCPs that serve as a proxy for prices that would have resulted under competitive market conditions was unchallenged during cross examination.[5]

(c) The ISO's Approach, Not the Sellers', Is Consistent with the Language of the Commission's Orders

The ISO agrees with California Generators' statement that "[t]he Commission orders necessarily are the touchstone for resolving the heat rate question." GEN Brief at 7. Beyond that statement, however, agreement ceases. The California Generators have taken three discrete passages from the Commission's orders out of context and imposed a strained interpretation upon them, in order to build the most tenuous support for their average heat rate approach. The CSG has done the same with two of those same three passages. In doing so, the sellers studiously ignored the underlying theme of the Commission's orders – approximation of prices that would have resulted in a competitive market -- which requires the use of incremental heat rates. (*See* discussion in next sub-section.) They also ignored the many other Commission statements that provide context for the three statements upon which they rely; these other Commission statements also compel a straightforward interpretation of those three statements that supports the use of incremental heat rates. We will address in turn the three statements relied upon by the California Generators (and, in two instances, by the CSG as well).

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[5] In cross examination, the only discussion of this aspect of Dr. Hildebrandt's testimony occurred when the CSG entered in evidence Exhibit SEL-16, which was represented as showing the hourly MMCPs submitted in Dr. Cicchetti's revised testimony after being averaged for each operating hour in the same manner as the prices submitted with Dr. Hildebrandt's rebuttal testimony, Exhibit ISO-19 at 10:11 – 13:15. Dr. Hildebrandt explained that he did not feel that they could accurately reflect the MMCPs that would be derived from the methodology described in Dr. Cicchetti's testimony. Tr.1563:7 – 24. Specifically, while Dr. Cicchetti's testimony appears to indicate that he adopted the same basic methodology as the sellers' other witnesses, his mitigated prices bear no resemblance to the mitigated prices provided by these witnesses, and instead "appear to be the ISO's calculations with some adder on them." Tr. 1563:22 – 23.

(1) ***<u>The phrase "last unit dispatched" in the July 25 Order</u>***

California Generators first point to the italicized language in the following passage from the July 25 Order:

> The end result of using an assumed economic dispatch (prices lower than the actual marginal costs of the last generator dispatched) unfairly punishes the very generators that helped keep the lights on in California. Therefore, 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 period October 2, 2000 through May 28, 2001.

96 FERC at 61,517 (emphasis added by California Generators). The California Generators attempt to derive three points from this passage. First, they contend that the Commission's use of the phrase "last unit dispatched" indicates the Commission intended the focus to be on the costs of an entire generating unit, not on the costs of the last increment of production from a unit. GEN Brief at 8. The CSG makes the same contention. CSG Brief at 8. Second, the California Generators contend that the same phrase shows the Commission intended that "marginal costs" be interpreted "to encompass whatever costs were marginal for a particular unit at the time a decision was made – including decisions regarding whether to start up or shut down." GEN Brief at 8-9 (emphasis in original). Finally, the California Generators contend that the passage shows that the Commission intended that the last generator dispatched would recover its total average operating costs in the interval in which it was dispatched, *i.e.*, one should not look to the complete refund period or even an entire operating cycle to determine whether those costs would be recovered. *Id*. at 9.

California Generators can make their first contention, that the passage shows a Commission focus on an entire unit rather than an increment of production, only by ignoring both the context of that passage and the rest of the July 25 Order, as well as the Commission's other orders. In the passage, the Commission was addressing and rejecting the suggestion by the ISO and others that the "must offer" requirement from the forward-looking mitigation plan be re-created for the refund period. In the paragraph preceding the passage relied upon by California Generators, the Commission described the "must offer" requirement: "that each generator offer all available and uncommitted capacity in real-time." 96 FERC at 61,517 (emphasis added). The Commission's description of the "must offer" requirement shows that the Commission was, in fact, always focusing on *increments* of supply rather than entire units when considering a real time interval. The "must offer" requirement was not that a generator offer all of its capacity (*i.e.*, the entire unit) in a real time interval, but rather that it offer any capacity that was *available* (*i.e.*, not unavailable due to an outage, either total or partial) and *uncommitted* (*i.e.*, not already scheduled to generate energy to meet a previous commitment such as a bilateral contract). This context informs the interpretation of the Commission's meaning when it subsequently said that it would not apply the "must offer" requirement to the refund period, but would instead require the ISO to "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." It is clear in context that the Commission was directing the ISO to determine the marginal unit by looking to the heat rate associated with the last increment of capacity that the ISO actually dispatched in an interval, rather than – as would be the case under the "must offer" requirement – also considering other increments of capacity that were available and uncommitted but which generators, for whatever reason, had not bid into the market and which the ISO therefore had not dispatched. [6]

[6] The California Generators contend that Mr. Rothleder conceded on cross-examination that the Commission, in the passage relied on by the California Generators, intended the term "unit" to mean an entire generating unit. GEN Brief at 8 (citing Tr. 1248:24 – 1249:4). At the place in the transcript cited by California Generators, Mr. Rothleder was discussing an entirely different Commission statement, namely, the passage in the *June 19 Order* in which the Commission stated: " because the ISO will have the approximate heat rate curve for each unit, the ISO would be required to calculate the proxy market clearing price based upon the approximate point on the heat rate curve at which the last unit is dispatched." Tr. 1247:19 – 1248:5; (quoting Exh. ISO-5 at 14:16-20); 95 FERC at 62,563. Mr. Rothleder was simply acknowledging the questioner's suggestion that the second use of the word "unit" in that other passage

Passages in the Commission's other orders also show that the passage relied upon by the California Generators cannot be read as they would read it. These other passages show very clearly that the Commission intended its mitigation plan to focus on the marginal costs that a generating unit incurred in producing the last increment of supply, which are determined by using incremental heat rates, and not the total costs of the entire generating unit that happened to provide that last increment of supply (which would be determined by using average heat rates). We will not repeat all of those passages here, but refer the Presiding Judge to our initial brief at pages 6-13.

The California Generators' second proposition based on this passage is that the Commission intended "marginal costs" to be interpreted "to encompass whatever costs were marginal for a particular unit at the time a decision was made – *including* decisions regarding whether to start up or shut down." GEN Brief at 8-9 (emphasis in original). The California Generators' proposition is, in essence, that the Commission intended the phrase "marginal costs" in this passage to mean *either* the costs of the last unit of production of a unit that was already running at the time the ISO dispatched it in real time, *or* the costs of starting up a unit and ramping it through minimum load to the level of the ISO's real time dispatch if that unit was not already running.

It is understandable that the California Generators would attempt to squeeze support for this meaning of "marginal costs" out of this passage, because stretching the concept of

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probably referred to a generating unit. That "concession," as the California Generators characterize it, establishes nothing of use to their position. The Commission was simply telling the ISO to calculate the proxy price based on the "approximate point" on the heat rate curve at which the last generating unit was dispatched. That direction is perfectly consistent with the use of incremental heat rates. In fact, only three sentences before the sentence in the June 19 Order about which Mr. Rothleder was questioned, and discussing the same general subject matter, the Commission had noted that "the ISO will be able to approximate the actual *incremental* cost curve of each generating unit and thereby develop *representative proxy prices for each unit throughout the unit's operating range*." 95 FERC at 62,563. When the sentence about which Mr. Rothelder was questioned is read in the context of that earlier sentence, it is clear that when the Commission directed the ISO to calculate a proxy price "based upon the approximate point on the "marginal costs" to mean, at least in some instances, all of a unit's variable costs of operation lies at the very heart of their case. But there is nothing in this passage that supports such a meaning of the term "marginal costs," when one considers both the context of the passage within the July 25 Order and the context of the July 25 Order within the series of Commission orders on the mitigation of prices in the California market. With respect to the context of the passage within the July 25 Order, we have already shown, above, that the Commission was dealing in this passage with some parties' suggestion that the must-offer requirement should be adapted to the refund period, and that in discussing that requirement in the paragraph before this passage the Commission made clear that it was focusing on additional increments of production from a unit in the real time market, rather than on total production from the unit. With respect to the context of the July 25 Order within the series of mitigation orders, we refer the Presiding Judge back to the relevant discussion in our initial brief. There, at pages 7-8, we showed that the Commission in the April 26 Order *equated* the calculation of "marginal costs" to the use of incremental heat rates, and at pages 8-11 we showed that throughout the remaining orders, including the July 25 Order, the Commission never hinted at any other meaning of or manner of calculating "marginal costs." The passage from the July 25 Order quoted by the California Generators' does not suggest any different meaning, either.

The California Generators' last contention based on this quoted passage has been addressed in the introduction to this section. The ISO agrees that the Commission intended the marginal unit to recover its marginal costs in the interval in which it was marginal. That is not the issue; the issue is what the Commission meant by "marginal costs." California Generators and the ISO disagree on what those "marginal costs" costs are. As noted in the

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heat rate curve at which the last unit is dispatched," it was telling the ISO to use the various generating units' *incremental* heat rate curves in order to calculate that price.

introduction, the ISO's methodology treats the historical dispatch of units as fixed, and calculates the marginal costs of these units given the reality that these units were in fact committed to be in operation. The California Generators, however, turn the historical dispatch approach described by the Commission on its head, and argue that the Commission's methodology requires (or allows) "marginal costs" to be calculated based on an entirely hypothetical "10-minute world," in which each unit must be re-committed or re-dispatched and recover full costs during every 10-minute interval solely on the basis of the MMCP calculated for that 10-minute interval. GEN Brief at 8-9.

(2) ***<u>The "Williams" language in the June 19 Order</u>***

The California Generators next point to the Commission's statement in the June 19 Order that "[t]he ISO's heat rate curve reflects the minimum fuel load requirements requested by Williams." GEN Brief at 9, quoting from 95 FERC at 62,563. The CSG relies upon this same statement. CSG Brief at 4. We have already addressed this language in our initial brief, at pages 11-13, and refer the Presiding Judge to the discussion there. We address here only one misleading statement by the California Generators.

The California Generators state: "Not surprisingly, the Commission declined to accept the ISO's May filings [Items by Reference B and C, the May 11 and May 18 filings] and required the ISO to submit a new compliance filing that reflected the changes wrought in the June 19 Order." GEN Brief at 11, citing 95 FERC at 62,571. The inference the California Generators clearly wish the Presiding Judge to draw is that the Commission directed the ISO to change from using incremental heat rates, which the ISO had been using (pursuant to the crystalline direction in the April 26 Order), to using average heat rates. Such an inference would be incorrect. The Commission simply ordered the ISO to "submit tariff changes to comply with this order." 95 FERC at 62,571. On July 10, the ISO did so. In its December 19 Order on Compliance Filings, the Commission described the changes to its

May 11 compliance filing that the ISO had made in that July 10 filing. *See* 97 FERC at 62,361. None of those changes involved the heat rate curve that the ISO was using. *See id.* In addressing both the May 11 and July 10 filings in the December 19 Order on Compliance Filings, the Commission addressed every issue that had been raised by intervenors. *See* 97 FERC at 62,362 – 62,371. None of those issues involved the fact that the ISO was using incremental heat rates to calculate the proxy prices, *i.e.*, apparently no intervenor raised that issue even though the ISO, following the June 19 Order, had shown (in the July 11 filing) its intention to continue using incremental heat rates. The Commission approved the ISO's May 11 and July 10 compliance filings in the December 19 Order on Compliance Filings except as indicated in the discussion in that Order; nowhere in the discussion did the Commission indicate any disapproval of the ISO's use of incremental heat rates. *Id.* at 62,371.

The California Generators have referred to the Commission's acceptance of the ISO's use of incremental heat rates in the December 19 Order on Compliance Filings as a "tacit" acceptance, as if to suggest that the "tacit" nature of Commission action would undercut its import. GEN Brief at 11-12. They even suggest that the Commission may have been unaware that the incremental heat rates being used by the ISO did not include minimum load fuel costs. *Id.* at 11. Both of these suggestions are pure smoke.

First, the Commission did more than tacitly accept the ISO's filings. The Commission in the December 19 Order on Compliance Filings stated that the mitigated reserve deficiency proxy price established in the June 19 Order "is the marginal cost of the last unit dispatched to serve the last increment of load." 97 FERC at 62,361 and n.7. As noted in our initial brief, at pages 7-8, the Commission in the April 26 Order had equated "marginal cost" with the use of incremental heat rates and had referred to "marginal cost" in the June 19 Order without indicating any view that calculation of marginal cost suddenly required use of some other heat rates. The reference in the December 19 Order on Compliance Filings to the proxy price being the "marginal cost" of the last unit dispatched shows that the Commission was expressly – not tacitly -- reaffirming that point from the June 19 Order.

The suggestion that the Commission at the time of the June 19 Order may not have understood that the ISO's heat rates omitted minimum load fuel costs cannot withstand a modicum of scrutiny. The Commission in the April 26 Order had *directed* the ISO to use "operational heat rates that do not include start-up and minimum load fuel costs." 95 FERC at 61,359. Are we to believe that the Commission forgot its own direction less than two months later? Surely we are not supposed to believe that the ISO's decision to allow generators to submit average heat rates and thereafter calculate the incremental heat rate curves itself (instead of requiring the generators to submit incremental heat rates)[7] somehow confused the Commission. That possibility is belied by the June 19 Order itself, in which the Commission recounted that the ISO (pursuant to the April 26 Order) was collecting average heat rates at eleven operating points and that by doing so "the ISO will be able to approximate the actual *incremental* cost curve of each generating unit and thereby develop representative proxy prices for each unit throughout the unit's operating range." 95 FERC at 62,563 (emphasis added). The Commission clearly knew exactly what the ISO was doing.

(2.a) Prospective Price Mitigation and the Refund Period

Nor is there any doubt that the Commission intended the same incremental heat rates to be used for the refund period as the ISO was using for the forward-looking mitigation. The Chief Judge's recommendation leading up to the July 25 Order was as follows:

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[7] *See* Exh. ISO-5 at 13:20 – 14:4 (explaining April 26 Order's requirement that generators provide incremental heat rates); 21:10-24 (explaining that ISO collected average heat rates from generators and then calculated incremental heat rates); 22:13 – 23:8 (explaining how ISO collected heat rate information

> To re-create the outcome of a competitive market, the Chief Judge recommends that the methodology set forth in the June 19th Order be used [with modifications not relevant here]. . . . The June 19th Order established a mitigated price based upon the marginal cost of the last unit dispatched to meet load in the CAISO's real-time market.

96 FERC at 65,040. In the very next sentence, the Chief Judge's recommendation then proceeds to directly describe his proposed methodology for calculating the MMCPs to be used in the refund calculation, further clarifying that the Chief Judge intended the "marginal cost of the last unit dispatched to meet load in the CAISO's real-time market" to be calculated for the refund period in the same manner as under the June 19 Order. *Id.*

In the July 25 Order, the Commission then stated:

> We find the approach suggested by the Chief Judge [the modifications not here relevant] to be a workable addition to the June 19 Order methodology consistent with the determination of the actual running costs of the marginal unit. We will adopt the method proposed by the Chief Judge . . . .

96 FERC at 61,518. (The Commission had defined "running costs" in the April 26 Order as the equivalent of marginal costs. 95 FERC at 61,363.)

Finally, in the December 19 Order, the Commission was explicit that the marginal cost approach to approximating competitive prices for the refund period was the same as the approach used for the forward-looking mitigation plan:

> The refund methodology adopted most of the criteria of the June 19 price mitigation plan, modified as to be appropriate for a past, rather than a future, period. Under the methodology, refunds would be determined by the difference between prices charged and a competitive market base-line calculated for each hour of the refund period. Hourly mitigated prices would be developed using the marginal costs of the last unit dispatched to meet load in the ISO's real-time market . . . .

97 FERC at 62,178. Later in the December 19 Order, the Commission discussed both the June 19 Order and the July 25 Orders as having adopted a "marginal cost based approach," and explicitly said it was using the same reasoning in rejecting requests for rehearing of both

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from generators); 25:19 – 26:5 (explaining why ISO collected average heat rates instead of incremental orders that were aimed at allowing recovery of additional costs. 97 FERC at 62,214. *See generally* 97 FERC at 62,211 – 62,215 (discussing rehearing requests directed at both orders).

(3) Reference to "the unit's heat rate curve" in the December 19 Order on Compliance Filings

In the December 19 Order on Compliance Filings, the Commission directed the ISO to develop a mechanism to compensate generators under the forward-looking mitigation plan for their minimum load fuel costs when the ISO ordered them to be operating at minimum load in order to be available under the "must offer" requirement for dispatch at higher levels in real time, but then did not in fact dispatch them in real time. To determine the level of compensation, the Commission directed the ISO "to multiply the minimum point on the unit's heat rate curve by [a fuel index]." 97 FERC at 62,363. In this case, in order to determine the minimum load fuel costs, the heat rate curve from which the minimum point was taken would have to be the average heat rate curve, in order to obtain the fuel consumption necessary to produce the unit's full output at minimum load. The California Generators leap from this fact to the conclusion that "[t]he Commission thus plainly assumed that there was one set of heat rate curves in this case and that it *included* minimum load fuel costs." GEN Brief at 12 (emphasis in original). About the best that can be said for the California Generators' argument is that it is a *non sequitur*. How does a reference that, in this context, means "average" heat rate curves necessarily imply that the Commission "assumes" that *only* average heat rate curves are relevant throughout this docket? One cannot logically reach that conclusion. The Commission in the April 26 Order referred to "operational heat rates that do not include start-up and minimum load fuel costs." 95 FERC at 61,359. In the June 19 Order it described the ISO's collection of average heat rates from

heat rates from generators, then calculated incremental heat rate curves itself).

which it would determine the "incremental cost curve" of each unit. The record is clear that the Commission knows that different curves – average or incremental – are appropriately used for different purposes.

(d) The ISO's Approach, Not the Sellers', Is Consistent with the Commission's Intent To Emulate Pricing in a Competitive Market

At the outset of their argument, the California Generators acknowledge that Commission intended to emulate the *prices* that would result from a competitive market, *i.e.*, "prices that would have occurred if suppliers all bid their marginal costs." GEN Brief at 13. But they immediately slide into discussing the need to ensure that the "marginal unit will recover the fuel costs it incurs to operate during the interval in which it is marginal – *including* minimum load fuel costs." *Id.* The not so subtle shift is from acknowledging that the focus of the Commission's inquiry is on ensuring that bids of all units are based on those units' *marginal costs* in order to approximate competitive *prices*, to suggesting that the inquiry is how to ensure that the *marginal unit* (the "last unit dispatched") recovers all of its fuel *costs* for the interval. The attempt is to suggest that the Commission has equated *bidding based on marginal costs* to *recovery by the marginal unit of all fuel costs*. The Commission has never suggested any such thing, and in fact has made clear its recognition that bidding based on marginal costs does *not* ensure that the marginal unit will recover all fuel costs.[8] *See* April 26 Order, 95 FERC at 61,362; December 19 Order, 97 FERC at 62,214- 62.215.

[8] The Modesto Irrigation District ("MID"), in a separate brief, does not even try to make the "shift" engaged in by the California Generators. Rather, MID baldly contends not only that the marginal unit should recover all its fuel costs from the mitigated price payment, but also that the marginal unit could be *any* unit that was running in an interval (even if it was running solely to fulfill an hour-ahead schedule) and not necessarily a unit that was dispatched in the real time imbalance market. The latter contention, that any unit that happened to be running could be the marginal unit, simply cannot be squared with the Commission's direction in the July 25 Order (consistent with all other orders) to choose the marginal unit from the units "dispatched . . . in the real time imbalance market." 96 FERC at 61,517. The first contention, that the marginal unit should recover all fuel costs from the mitigated price payment, is no different from California Generators' argument.

The California Generators then suggest that average heat rates are to be preferred to incremental heat rates because the tight supply situation in California during the refund period would lead one to believe, intuitively, that the marginal unit would recover at least its full operating costs. GEN Brief at 13. We agree that in tight supply situations one would expect units to recover their operating costs -- and even earn a healthy contribution toward offsetting their fixed costs, as well as more than a bit of profit -- than would be the case in situations of sufficient or excess supply. But the relevant question is *how* one would expect them to earn those amounts (*i.e.*, in what markets and in what hours). Remember that the ISO's purchasing activities in real time, whether through its real time market or through out-of-market or out-of-sequence calls, are the very last means of obtaining supply to meet demand. Exh. ISO-1 at 4:10 – 6:8; 9:19 – 10:10. The ISO must dispatch the unused capacity from units only when load-serving entities' own generation, plus their bilateral contracts, plus their purchases in forward markets, *all* have failed to balance demand with supply. When supply is tight in general, as it frequently was in California during the refund period, one would expect generators to have *myriad* opportunities to earn their start-up costs, minimum load fuel costs, and even some fixed costs, and make some profit, through forward markets and bilateral contracts well before real time.

As the Commission itself has noted, sellers were not basing their decisions during the refund period on the prices that will result from the mitigation methodology, which is being imposed retroactively, and therefore it is possible that not all sellers will recover all costs under this mitigation methodology. The Commission pointed this out in the December 19 Order in explaining why it was adhering to its marginal cost-based approach and not allowing *any other costs* to be recovered by the marginal unit, but was permitting any seller to show, after the refund proceeding concluded, that it would not recover all of its costs over the entire refund period under the mitigation methodology. 97 FERC at 62,214. The Commission clearly foresaw that the marginal unit might have to look to other sources of revenue in addition to its mitigated payment under the Commission's methodology. After all, when it was operating during the refund period, that unit may not have been marginal and it may have decided to operate only because it was expecting to receive the higher prices that now are being mitigated. Imposing a mitigation methodology retroactively *always* creates that risk for individual sellers, as the Commission pointed out. The reason the California Parties have pointed out the other sources of revenue for the unit that happens to be marginal in a given interval (*e.g.*, payments it receives under the mitigation methodology when it is infra-marginal; payments it received from bilateral contracts, prices of which are *not* being mitigated; payments from ancillary services) is not to make this into a rate case, as California Generators suggest. Rather, the purpose is to show that just because the retroactive marginal cost mitigation methodology may, in some cases, prevent the marginal unit in a given interval from recovering all of its fuel costs (which should happen *only* if that unit was *only* running during an interval because of having been called by the ISO), does not mean that over the entire refund period that unit will not recover all of its costs. In addition, if the owner of a group of units will not recover the costs of *all* those units over the refund period, the Commission has allowed that seller to obtain separate relief after this proceeding.

California Generators next argue that, at the very least, the Commission should use average heat rates for intervals in which the marginal unit was running only as a result of ISO dispatch instructions, because in that situation it is only through using average heat rates that the marginal unit would be assured of recovering all of its fuel costs. GEN Brief at 15. This entire line of argument by the California Generators is based on a false premise: that the marginal unit must always recover its total fuel costs in the interval in which it is marginal. There is no support whatsoever in the Commission's orders for that premise. The purpose of the Commission's mitigation methodology is to approximate the prices in a competitive auction market. It is crystal clear from the Commission's orders that its view of pricing in a competitive auction market is the accepted view in economic circles: that the market will clear at the marginal cost of the last unit necessary to clear the market. *See* April 26 Order, 95 FERC at 61,354, 61,362 & nn. 44-45; December 19 Order, 97 FERC at 62,212. In some intervals, when a unit that turns out to be marginal was running only for the ISO, retroactive imposition of this mitigation method may not provide that unit full recovery of its fuel costs. But, as noted above, the Commission has expressly acknowledged that "market participants were not basing their buying and selling decisions with specific knowledge of the mitigated Market Clearing Prices during the refund period, and . . . they may not have an opportunity to recover their costs (once refunds are ordered) because the refund methodology is being imposed retrospectively." December 19 Order, 97 FERC at 62,214.

If a unit operated only for the ISO in an interval in which it is found to be marginal under the mitigation methodology, so that it does not recover minimum load fuel costs in that interval, one place it might well recover those costs is in other intervals in which it was infra-marginal. California Generators contend the Commission intended revenues in those infra-marginal intervals to be applied to the unit's fixed costs, but not its variable costs (such as minimum load fuel costs). GEN Brief at 16, *citing* April 26 Order, 95 FERC at 61,363. But the very citation relied upon by the California Generators disproves their contention.

They cite to the April 26 Order, which is the very order in which the Commission explicitly stated that the mitigated prices should be calculated using heat rates that do not include minimum load fuel costs. That was the Order, of course, in which the Commission clearly stated that it was adopting marginal cost pricing for the mitigation methodology *and* made clear that the ISO should calculate marginal costs using heat rates that did not include minimum load fuel costs. Therefore, there is no basis for the contention of the California Generators that in that Order the Commission intended to suggest that revenues earned during infra-marginal intervals should *only* go toward recovery of fixed costs. Moreover, the Order itself establishes that the Commission intended no such thing. On the page *before* the page cited by California Generators, the Commission recounted various proposals of various parties for mitigation methods that differed from the marginal cost pricing method the Commission settled upon. One of those methods would have used *variable* cost-based bid caps. *See* 95 FERC at 61,362, text at n.41. In discussing why it was rejecting these other mitigation methods, the Commission stated: "Since marginal cost pricing best approximates competitive pricing, there is no need to include *fixed or other costs* in the bids." 95 FERC at 61,362 (emphasis added). Thus, in that passage, the Commission clearly stated that prices based on marginal costs would omit not only fixed costs, but also *other costs*. In context, the Commission had to be addressing, in part, variable costs other than marginal costs -- such as minimum load fuel costs.[9] When the Commission on the next page, in the passage cited by California Generators, mentioned only "some amount for fixed costs" as being earned by infra-marginal units, the Commission was simply using short-hand for the earlier phrase, "fixed or other costs."[10]

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[9] The California Generators spend ink on the issue of whether minimum load fuel costs are fixed costs, as they say was suggested by one witness for California Parties under cross-examination, or variable costs, as they say one of the California Parties had contended in an earlier proceeding. *See* GEN Brief at 16 (*citing Pacific Gas & Electric Co*., 81 FERC ¶ 61,122 (1997). This is a red herring; even if one agrees with California Generators that minimum load fuel costs are variable costs, it is clear from the April 26 Order that the Commission intended them to be earned, in part, in infra-marginal intervals.

[10] We should also note that in the very passage relied upon by California Generators, the Commission *reiterated* its view that marginal cost pricing (which uses incremental heat rates, *i.e.*, heat rates that do not include minimum load fuel costs) produces competitive-market pricing:

> Generators will receive the market clearing price determined by the proxy bid, since that price best replicates the results that would be produced in a competitive market. In a competitive market, the marginal value of each unit sold is the same, so each seller should be entitled to receive the same price.

April 26 Order, 95 FERC at 61,363.

(e) The Generators Support Their Arguments By Citing Irrelevant and Misleading Statistics

Both the California Generators and CSG seek to support their arguments by citing statistics that are irrelevant as well as misleading.[11] For example, the California Generators seek to support the use of average heat rates or the "mixed heat rate approach" that Mr. Tranen postulates the Commission may have intended for the ISO to use, by citing Mr. Tranen's testimony that during 48% of the intervals the marginal unit (as identified from Mr. Tranen's expanded universe of units) was "operating solely in response to an ISO dispatch instruction." GEN Brief at 15. As a first point, the California Generators' argument that this statistic somehow justifies the use of average heat rates represents an attempt to "bootstrap": their argument using statistics continues to rely on the logic that – in a hypothetical world in which units could be turned off and turned on during each 10-minute interval – the average heat rate represents the incremental heat rate for every unit. Again, this hypothetical 10-minute world, upon which the sellers' argument rests, is inconsistent with the Commission's explicit direction to calculate marginal costs with unit commitment decisions taken as fixed, as well as being inconsistent with the reality of unit commitment economics and the technical operating constraints of thermal generator units. Testimony shows that the bulk of units operating in response to OOM or OOS calls under Mr. Tranen's approach would be gas-fired steam units which were requested the day ahead of real time, s*ee* Tr. 1404:25 – 1405:2 ; 1410:12 – 1411:18 (Hildebrandt), and were requested to be in operation at minimum load levels. *See* Tr. 1526:19-21 (Hildebrandt). Thus, Mr. Tranen's repeatedly cited statistic continues to ignore the fact that virtually all gas-fired generating units have operating cycles of at least several hours or days, and that these were committed to operate (and thus had the

[11] A discussion of the irrelevant and misleading statistics in the CSG Brief, which are repeatedly cited in support of other aspects of the CSG's methodology, is provided below, in section I.D. 1(b) of this brief.

opportunity to earn revenues) for an entire operating cycle, as a result of either a previous bilateral energy schedule, or a BEEP dispatch and/or OOM or OOS call issued by the ISO. Thus, even if the Commission's directive to treat the historical dispatch of units as fixed is ignored, the simple statistic provided by Mr. Tranen in no way supports his conclusion that the Commission should deviate from the definition of marginal costs used throughout its Orders (as well as throughout utility economics and system operations), and instead calculate the marginal cost of these units based on average rather than incremental heat rates.

In addition, a review of Mr. Tranen's testimony indicates that his definition of operating "solely in response to an ISO dispatch" simply means that a unit did not submit an Hour Ahead Energy schedule to the ISO for that hour (*i.e.*, "had no other scheduled energy"). GEN-1 at 15:20-21. Mr. Tranen provides no support for his assumed fact that the marginal units identified under his approach during these intervals are indeed operating "solely in response to an ISO instruction," rather than due to the fact that the unit was in fact on-line and was committed during a previous interval. As noted in the testimony of Dr. Hildebrandt, the actual metered generation of units frequently deviates from their scheduled operating levels. Exh. ISO-1 at 15:19-21; ISO-19 at 34:5-9. For example, a unit without any Hour Ahead Energy Schedule submitted to the ISO may simply continue to operate that hour. As Mr. Tranen himself acknowledged in cross examination, the ability to de-commit units that are scheduled to operate in order to meet bi-lateral obligations in one hour (or may be needed in a future hour) is limited by the technical operating constraints of the unit, including minimum run times, minimum start-up times, and minimum down times. Tr. 1991:15 – 1992:3.

(f) The Generator's Approach Is Inconsistent with the Commission's Overall Methodology, in that It Seeks To Justify Use of Average Heat Rates as Necessary To Eliminate the Possibility that Any Supplier Will Opt for the Alternative Cost-Based Approach Provided by the Commission

California Generators contend that the studies prepared by Dr. Berry, a witness for the California Parties, support their view that the Commission intended average heat rates to be used. Their argument starts from the proposition that Dr. Berry's studies show that using incremental heat rates would result in some number of units not recovering their minimum load fuel costs over two-week periods or over the entire refund period, if one assumes that the units received all of their revenue from the mitigated spot energy markets and ancillary services markets. GEN Brief at 17-19. They then conclude that the incremental heat rate approach is to be rejected because the Commission required that the mitigation methodology result in the same units running under rationale decision-making as actually operated during the refund period, and the incremental heat rate approach, viewed over extended periods (two weeks or the entire refund period) "would not have attracted the same level of supply" as actually existed. *Id.* at 19.

There are several flaws in California Generators' argument. First, as fully reviewed in the brief of the California Parties, Dr. Berry's analysis suggests that "it is doubtful that any of the sellers would have failed to recover their costs if the ISO's MMCPs for each interval of the Refund Period were applied to the full output of each gas-fired unit represented in the ISO's data. CAL Brief at 14. Moreover, the California Generators presented no evidence to support their contention that they would not be able to recover their costs.

Second, and of equal importance, the Commission never said, or even hinted, that the price mitigation methodology must meet the test the California Generators set forth, *i.e.*, that the MMCPs result, under a hypothetical model of rational economic decision-making, in precisely the same units running as actually ran during any two-week or longer period. Their citation for this proposition is the passage in which the Commission rejected the suggestion of some parties (including the ISO) that the Commission adopt the "must offer" requirement for the refund period. *See* GEN Brief at 19, *citing* July 25 Order, 96 FERC at 61,517. The passage does not support their proposition; all the Commission said there was that the mitigated price would be based on the marginal costs of the units that actually ran, rather than on a universe that included units that were available but did not run. The Commission in the December 19 Order clearly stated that some units might *not* recover all their costs under the refund methodology:

> [W]e will not allow any additional cost items to be included in the refund formula. To hold otherwise would be inconsistent with our marginal cost based approach. We recognize, however, that market participants were not basing their buying and selling decisions with specific knowledge of the mitigated Market Clearing Prices during the refund period, and that they may not have an opportunity to recover their costs (once refunds are ordered) because the refund methodology is being imposed retroactively.

97 FERC at 62,214. Obviously, if a generator had known at the time that it would not recover its costs, it would not have run. The Commission was unmoved by that possibility; it said that any seller finding itself in that situation (*i.e.*, not recovering its total costs under the refund methodology) could simply apply for relief after the refund proceeding ended. *Id.*

(g) Substitution of Average Heat Rates for Incremental Heat Rates Is Not the "Better Course" for California

The California Generators argue that the "better course is to fully compensate the marginal unit for its operating costs, including minimum load fuel costs, when it is marginal." GEN Brief at 21. They suggest that this produces a "sustainable set of MMCPs… that more closely approximate a competitive outcome." *Id.* They, of course, fail to acknowledge that substitution of average heat rates for incremental heat rates would have consequences for California.

As demonstrated by Dr. Hildebrandt (and not challenged by any party), the mitigated prices resulting from use of average heat rates are substantially higher than the mitigated prices developed using the ISO's methodology. Moreover, as discussed previously, the pattern of these prices is inconsistent with patterns of prices observed in the initial two years of the ISO's market. *See generally* Exh. ISO-19 at 10:11 – 14:22. The ultimate result of applying these prices would be a substantial reduction in the amount of money generators would be required to refund to California buyers. California Generators' suggestion that using average heat rates is the "better course" leaves the impression that there are no significant consequences associated with what may appear, at first glance, to be a minor revision to the methodology incorporated in the Commission's orders and implemented by the ISO. Using average heat rates instead of incremental heat rates would, in fact, lead to a major wealth transfer from buyers to sellers.

2. Which heat rate source data should be used and are the data accurate?

The parties agree, except with respect to the Pasadena Gas Turbines ("GTs"). On the Pasadena GTs, the ISO adopts the proposed finding of the California Parties and the accompanying argument, at pages 21-22 of their initial brief.

3. If incremental heat rate curves are used, should they be adjusted to be monotonically non-decreasing?

The ISO's position is that it is unnecessary to adjust the curves for the refund period, unlike the forward-looking period where adjustment is necessary for the ISO's dispatch algorithm. ISO Brief at 18-19. Staff and California Parties object to the adjustment. The California Parties contend that the adjustment is "improper" and "artificially increases the level of the heat rates," CAL Brief at 22-23, while Staff considers it an unnecessary complication. Staff Brief at 16-18. The California Generators and CSG propose that the adjustment be made, *See* GEN Brief at 21-22; CSG Brief at 13. Their positions, however, appear to be results-driven (*i.e.*, adjusting the curves to make them non-decreasing can result in higher mitigated prices), rather than based on reasoned argument.

C. At what operating point on the heat rate curve should a unit's heat rate be taken for insertion into the MMCP Formula?

Neither the California Generators nor the CSG have identified any way in which the ISO's use of the Acknowledged Operating Target ("AOT") is inconsistent with the

Commission's orders. The California Generators state that "[t]he Commission directed the ISO to determine the heat rate for the marginal unit based on the actual operating levels of all units dispatched by the ISO each interval." GEN Brief at 22. The CSG states that the ISO "ignored the Commission's instructions and created the AOT instead of using the actual dispatch data." CSG Brief at 14. The California Generators and the CSG rely entirely on the same sentence in the July 25 Order for their contention that the Commission directed the ISO to use actual operating levels: the sentence in which the Commission required "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." 96 FERC at 61,517. There is, however, nothing about the use of AOT that is inconsistent with "selecting . . . the maximum heat rate of any unit dispatched . . . ."

As explained in our initial brief, at pages 20-22, the ISO used the AOT for two related reasons. First, the AOT was the concept it had used to effectuate the Commission's directive in the June 19 Order that it determine "the approximate point on the heat rate curve at which the last unit *is dispatched*," 95 FERC at 62,563 (emphasis added), and the Commission had not directed that this aspect of the forward-looking methodology be changed. And second, using actual operating levels instead of AOT would mean considering the amount of a unit's uninstructed energy in determining the heat rate – which would be completely inconsistent with the Commission's concept that what counts is the level at which the ISO dispatched a unit. Nothing cited or argued by the California Generators or the CSG undercuts those justifications for the use of AOT.

To their credit, the California Generators acknowledge Dr. Hildebrandt's point that using actual operating levels in conjunction with average heat rates would reward units for failing to run at the levels at which the ISO dispatched them. GEN Brief at 23. They attempt to downplay this problem by noting that Dr. Hildebrandt provided only one example, from the data, of this occurring. *Id*. But they miss the bigger point: Why use actual operating levels instead of the AOT used by the ISO for the forward-looking mitigation methodology, when there is no indication the Commission intended actual operating levels be used and when the use of actual operating levels can lead to the abhorrent result identified by Dr. Hildebrandt, *i.e*., identifying as the marginal unit one that failed to follow the ISO's dispatch instructions?

Faced with the absence of any support in the Commission's orders for the use of metered generation levels rather than the levels at which units were dispatched to operate, both the California Generators and the CSG resort to misrepresentations of and false statements about Dr. Hildebrandt's testimony, in an effort to promote their approach over the ISO's methodology.

For example, after claiming (without support, as shown above) that the July 25 Order requires the use of "actual operating levels," the California Generators contend that on cross examination Dr. Hildebrandt "explained" that "the AOT methodology . . . produces an 'approximation' of the operating levels of the units at issue," GEN brief at 22, and conclude that "[t]he ISO provided no solid justification for engaging in approximations when actual operating data is readily available." *Id.* at 23. A review of the transcript cited in support of this statement (1548:11-13) shows that Dr. Hildebrandt clearly explained that the AOT is designed to approximate the "dispatch level" rather than the "operating level" of each unit:

> Q. Dr. Hildebrandt, the acknowledged operating target does not reflect the actual generation from any marginal unit that you selected; isn't that correct?
> A. It represents the approximate dispatch level. The unit may generate above or significantly below that level.[12]

[12] In this instance, the CSG's brief more accurately summarized the above exchange, noting that Dr. Hildebrandt explained that the AOT "is intended to represent the approximate dispatch level" of each unit. CSG Brief at 14.

The fact that the AOT is designed to approximate the level at which a unit was dispatched in the ISO's real time market – rather than the operating level of a unit – was made in greater detail by Dr. Hildebrandt elsewhere in his cross examination (Tr. 1545:2 – 10) and in his redirected testimony (Tr. 1594:7 – 1596:11).

Both the California Generators and CSG also mischaracterize Dr. Hildebrandt's testimony with respect to whether the AOT ever results in "dispatch levels" that are outside of the actual operating limits of any units. The California Generators state that cross examination of Dr. Hildebrandt established that "[I]n certain cases, the approximation [AOT] produced an output level above or below the maximum or minimum operating levels of a unit." GEN Brief at 22. The CSG goes further, contending that "[d]uring cross-examination, Dr. Hildebrandt also admitted that the AOT *often* produced results that were not physically possible for the generating unit that was being studied." CSG Brief at 14 (emphasis added). The CSG provided *no* citation to the record to support the statement in its brief. A review of the record citation provided by the California Generators (1551:2-8) shows that it does not support a contention that the AOT was *ever* outside the minimum or maximum operating levels of units. Elsewhere in the record, in response to a series of questions concerning the theoretical possibility that the AOT could fall outside of a unit's minimum and maximum operating levels, Dr. Hildebrandt explained that he did not examine *whether or not* this ever actually occurred, but that the ISO's methodology includes a constraint that would "bound" the AOT used in actually determining a unit's heat rates to be within the unit's minimum and maximum operating levels, *if* this theoretical situation had occurred. Tr. 1549:3 - 1551:9. In the end, the most telling indication of whether the AOT is ever outside the operating range of a unit is the fact that none of the sellers' own witnesses provided any example of this theoretical situation actually occurring.

The CSG claims that the ISO's use of AOT resulted in "an approximate dispatch level that often underestimated the actual dispatch of the unit," providing no direct citation, but implying by the sentence structure that the claim is somehow supported by cross examination of Dr. Hildebrandt. CSG Brief at 15. Again, however, a review of the transcript citation, Tr. 1548:1-19, shows that it provides no support.[13] Moreover, analysis by the CSG's own witness, Mr. Adamson, indicates that the AOT tends to *overestimate* – rather than underestimate – the level at which a unit actually operated. *See* CSG Brief at 16 (AOT more than 5% above actual operating level in 51% of cases).

Finally, in an apparent effort to undermine Dr. Hildebrandt's overall credibility, the CSG claims that "Dr. Hildebrandt acknowledged that the AOT is an *ad hoc* concept that the ISO created -- no earlier than June 20, 2001 -- exclusively for purposes of this litigation." *Id.* Again, however, a review of the transcript cited in support of this statement (1544:13-1545:10) shows that CSG has wrongly paraphrased the testimony. The California Generators cited this same portion of Dr. Hildebrandt's cross examination, but paraphrased it more accurately in stating that Dr. Hildebrandt explained that the "AOT was originally developed in the context of the *prospective mitigation plan*." GEN Brief at 22 (emphasis added). As Dr. Hildebrandt explained, the AOT "was developed by the ISO shortly after the June 19 Order," when, "[a]bout June 20 we received -- we were directed by the Commission to recalculate for the refund period proxy prices that would result using the methodology outlined in the June 19 order." Tr. 1594:10-14. He also testified that the AOT "was developed to emulate how the proxy price bids would be calculated under the June 19 order for the approximate level at which the unit is dispatched." Tr. 1595:22-24. Moreover, the "origin" and rationale of the

[13] At the cited point in the record, Dr. Hildebrandt noted only that a unit "may generate above or significantly below that level [*i.e.*, the approximate dispatch level determined by the AOT]." Tr. 1548:11-13.

AOT has been clearly and consistently explained in detail on several occasions by Dr. Hildebrandt during his deposition and cross examination (Tr. 1544:13 –1547:25), and in redirected testimony (Tr. 1594:7-1596:11). Rather than impeaching Dr. Hildebrandt's credibility, the sellers' contortions of the record concerning this issue provides a revealing case study of their questionable tactics.

D. What units are eligible to set the MMCP for each 10-minute interval in the refund period?

The question of which dispatches or transactions may result in a unit being eligible to set the mitigated price actually involves two distinct issues. The first issue is which *principles* or *decisional rules* are to be applied in determining the dispatches or transactions that qualify a unit. The second, entirely distinct issue, is which specific *data* or *set of dispatches or transactions records* should be used in applying these principles or decisional rules. By muddling and misrepresenting the ISO's position with respect to these two distinct issues, the California Generators have sought to create the illusion of Dr. Hildebrandt's having taken inconsistent or shifting positions. *See* GEN Brief at 24-29. The ISO's position has been consistent.

With respect to the *principles or decisional rules* to be used in identifying the dispatches that qualify units to set the mitigated price, the ISO's position has consistently been that the July 25 Order calls for the marginal unit to be determined from units that were dispatched on the basis of bids that were eligible to set the actual market clearing price in the ISO's Real Time Market. Exh. ISO-1 at 42:1 – 45:2; Tr. 1350:10 – 1351:7 (Hildebrandt). The Real Time Market is defined in the ISO Tariff as "the competitive generation market controlled and co-ordinated by the ISO for arranging real time Imbalance Energy." ISO Tariff Original Sheet 341, *quoted in* Exh.GEN-1 at 31:6-9. Section 2.5.23.1 of the ISO Tariff defines the "marginal Generating Unit" or "marginal bid" to be used in setting the market clearing price for incremental energy in the Real Time Market as "the highest bid that is accepted by the ISO's BEEP software." *See* Tr. 1392:18 – 1393:16 (Hildebrandt). It is reasonable to assume that this definition (*i.e.*, the units whose bids were used by the BEEP system to calculate the actual price of energy in the Real Time Market) is what the Commission, in the July 25 Order, intended to be used as a "bright line test" for determining the "last unit dispatched (the marginal unit) . . . in the real-time imbalance market." *See* Tr. 1393:7-10; 1394:10-15; 1405: 7-18 (Hildebrandt).[14]

The sellers' own witness, Dr. Tabors, acknowledged that in the July 25 Order, "the Commission restricts the possible size of the universe [of eligible units]," explaining that:

> It does so in two ways. First, the Commission states that the last unit dispatched must be selected from "'actual units dispatched in real time". This could limit the universe to only those units the CA ISO was incrementing or decrementing. Second, the Commission says to choose the unit with the "'maximum heat rate" in the "real-time imbalance market". This later statement could limit the size of the universe, but for the fact that the operation of the market during much of the refund period had a massive imbalance condition caused by under-scheduling that left the "imbalance market" providing major portions of the energy delivered to the CA ISO's control area.

Exh. PWX-1 at 13: 9-22.

Thus, after acknowledging that the July 25 Order, on its face, would appear to limit the transactions defining units eligible to set the mitigated price to those transactions occurring in the Real Time Market, Dr. Tabors explained why he would not read the Order that way. His sole reason was that the "imbalance market" (a term apparently defined by Dr. Tabors to include all sources of imbalance energy procured by the ISO or CERS) provided

[14] In response to cross examination about ISO operating procedures describing a category of out-of-sequence dispatches that are eligible to set the market clearing price in the Real Time Market, Dr. Hildebrandt noted that Section 2.5.23.1 of the ISO's Tariff provides a "very clear definition" of the "marginal Generating Unit" to be used in setting the market clearing price. Tr. 1392:18 – 1393:16. That section of the ISO Tariff defines the "marginal bid" for incremental energy as the resource "with the highest bid that is accepted by the ISO's BEEP software," while the "marginal bid" for decremental energy is defined as the resource "with the lowest bid that is accepted by the ISO's BEEP software." Dr. Hildebrandt noted that "this is precisely the definition of the marginal unit in the real-time market that I followed, that I believe FERC intended when they used the words 'marginal unit dispatched in the ISO's real-time market.'" Tr. 1393:7-10.

"major portions of the energy delivered to the CA ISO's control area." *Id.* Thus, the sellers' basic argument for expanding the universe of transactions that may make units eligible to set the mitigated price is, simply, that the amount of energy dispatched through the Real Time Market (*i.e.*, the BEEP system) represented a relatively small portion of total imbalance energy procured by the ISO during the refund period. But the Commission was well aware that there were, at times, few transactions in the ISO's Real Time Market during the refund period. In the June 19 Order, the Commission stated, "In fact, in certain hours, the ISO data show no purchases whatsoever in its imbalance energy market." June 19 Order, 95 FERC at 62,546. Nevertheless, with full awareness of the relative "thinness" of that Real Time Market, the Commission in the July 25 Order directed – as Dr. Tabors said, on the face of the Order – that the mitigated price be based on units dispatched in that market.

There is no basis for sellers' assumption that the Commission intended the universe of eligible units to be expanded beyond those in the Real Time Market, simply because the ISO happened to be relying on units that were not bid into the Real Time Market in real time. The Commission designed the mitigated price to serve as a "proxy price." It is *calculated* based on the marginal cost of the gas-fired units that were dispatched historically in the ISO's Real Time Market, and is then *applied* in mitigating the price of *other* transactions, not only in real time (OOS and OOM) but also prior to real time (the PX markets, Ancillary Services markets). There is simply no support in the Commission's orders for equating the universe of transactions that make units eligible to set the mitigated price, with the universe of transactions to which the mitigated price is to be applied. *See* Tr. 1405:19 - 1406:10.

With respect to the issue of the *set of dispatches or transaction records* which should be used in identifying the units to be eligible (under the correct principles or decisional rules) to set the mitigated price, Dr. Hildebrandt has consistently expressed the opinion that, on balance, the historical record of units dispatched through the BEEP system (*i.e.*, the set of records upon which the market clearing prices for energy were actually calculated in the Real Time Market) is the most appropriate set of data to be used.[15] Tr. 1334:22 – 1335:17; 1357:11 – 1358:19; 1359:6-14; 1378:1-15. At the same time, he has acknowledged that in this proceeding, the Presiding Judge or the Commission might modify or further define the specific data that should be used to perform any re-calculations of the mitigated prices. Tr. 1534:17 – 1535:1. Dr. Hildebrandt's overall conclusion that the historical record of the dispatches made through the BEEP system should be used is supported by several considerations. First, as noted above, the Commission explicitly noted its awareness that at times there were few dispatches through that system during the refund period, but nevertheless directed that the mitigated price be based on units that had been thus dispatched. The Commission also noted that it had chosen a simplified approach to calculating the mitigated prices that could be readily implemented and that would reasonably approximate the prices resulting from a competitive market, and that it did not require a perfect re-simulation of the market.[16] 97 FERC at 62,202 -- 62,203; Tr. 1428:12 – 25.

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[15] The California Generators cynically, and gratuitously, portray as "positional hopscotch" Dr. Hildebrandt's straightforward efforts to clarify and provide a clear record of what transactions are included in the different data files being utilized and referenced by the different parties in this proceeding. One of key purposes of live testimony during an administrative hearing is to obtain precisely this type of clarification on precisely this type of issue. In the course of cross examination, Dr. Hildebrandt explained that the OOS.CSV file referenced extensively by the sellers' witnesses in fact contains only a sub-set of the out-of-sequence calls: that sub-set consists only of OOS bids which *were not* dispatched through the BEEP system and were therefore not used in setting the actual market clearing price. Tr. 1353:13 – 1354:18. Similarly, Dr. Hildebrandt clarified that all out-of-sequence bids that *were* dispatched through the BEEP system are automatically included in the "BEEP Output" file that was used, in its entirety, in the ISO's analysis, but that there is no "flag" or other marker in the "BEEP Output" file that can be used to identify these bids. Tr. 1358:2-19. Although Dr. Hildebrandt's use of the term "in merit order" in his prepared testimony to differentiate bids that were dispatched *through* the BEEP system from those dispatched *outside* of the BEEP system (which were the only transactions in any data file specifically labeled as being made "out-of-sequence") may have created some initial confusion, *see* Exh. ISO-1 at 5:12-19; Tr. 1353:9 – 1354:18; 1355:19 – 1356:6, his efforts to clarify the data underlying his analysis, as well as the data relied upon by the sellers' witnesses, in no way represents a change on the methodological principles underlying his testimony.

[16]Relevant to this point about perfectly re-creating the pricing in a competitive market, one should note there are several potential modifications to the ISO's calculations that are reasonable and readily implemented based on the record in these proceedings, and that would tend to *decrease* the mitigated prices calculated by the ISO. These include "screening out" units that did not actually respond to dispatch

Moreover, while California Generators argue that the ISO data logging practices cannot be relied upon for purposes of identifying eligible units because those practices were inconsistent, the scheme for categorizing OOS dispatches proposed by Mr. Tranen relies upon the sort of (often ambiguous) descriptive remarks recorded through those same logging practices. *See* Tr. 2033:18 – 2034:2 (Tranen). The California Generators, in effect, ask the Commission to deal with any possible inconsistencies in the logging practices by *assuming* that virtually all OOS calls that did not show up in the BEEP output file, and thus were not used by the ISO in calculating the historical market clearing price or by Dr. Hildebrandt in calculating the mitigated price, would in fact be eligible to be used for both purposes under "correct" logging practices.[17]

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instructions, as recommended by Dr. Stern and Mr. Sammon, *see* Exh. ISO-19 at 39:6-15, and use of incremental heat rates without the ISO's adjustment to make them monotonically non-decreasing, as also recommended by Dr. Stern and Mr. Sammon. *See* Exh. ISO-20 at 8:1-17.

[17] In response to questions about how new information concerning the ISO data might affect his opinions, Dr. Hildebrandt first noted that potential changes in the data used in the ISO's analysis have been identified by both the sellers and the California Parties, and explained:

> You're asking does a change in the input change your outputs. The answer is yes. If you want my opinion in this case, do I think we want to try to identify all the potential changes and rerun BEEP based on those? I don't think that's what's called for here.

Tr. at 1430:9-14. Dr. Hildebrandt supported this view, in part, by reference to specific language in the December 19 Order. There, in the context of rejecting arguments by both sellers and the California Parties that the approach outlined in the July 25 Order should be modified to include additional factors that might affect the mitigated prices, the Commission explained that it had "selected a remedy with theoretical underpinnings that, at the same time, could be reasonably implemented," and that "[w]e believe our refund methodology ensures just and reasonable rates as required by the FPA; we are under no obligation to make, or recreate, a perfect market based on a hypothetical dispatch of resources." 97 FERC at 62,202 – 62,203; *See* Tr. 1428:12 – 25.

Upon being asked to review summary findings of studies not previously available to him (Exh. GEN –31 & 32) and then to comment on how these might affect his opinion or analysis, Dr. Hildebrandt explained that, without knowing the magnitude of the impact that these changes may have on the mitigated prices, he would continue to rely on the methodology and data he had used to date:

> I think they [the Commission] expected us to do a calculation based on the best calculation we can based on the data available that was a methodology that could be reasonably implemented. If we're told to include, to go back -- if, in the course of these proceedings, evidence is shown that these [dispatches or transactions] should be included and these [dispatches or transactions] should maybe not be included, we would clearly rerun the calculation based on what's determined in this proceeding. And I don't know how else to answer your question, but if you're asking my best judgment to respond to the spirit of the Commission's order, I would stand by the analysis we've done.

The California Generators have also not supported any specific "corrections" (*i.e.*, additions) to the BEEP dispatch data.[18] Contrary to what is implied by citations to Dr. Hildebrandt's cross examination in the California Generators' brief, *see* GEN Brief at 25-26, Dr. Hildebrandt did not confirm on cross examination the validity of the criteria used by Mr. Tranen to "correct" the BEEP stack. In fact, Dr. Hildebrandt showed that Mr. Tranen's "corrections" were based on false assumptions. For one thing, contrary to Mr. Tranen's assumption that a unit was improperly called out-of-market if a bid from that unit exists in the "BEEP Stack" file (BEEP_STACK.CSV) provided by the ISO (GEN-19 at 13:11-13), Dr. Hildebrandt explained that a unit can first receive an OOM call and then subsequently bid into the BEEP stack. *See* Tr. 1410:15 – 1414:11, especially 1414:7-11. Similarly, since

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Tr. 1430:23 – 1431:9. The California Generators' untrustworthy use of citations and quotations extends as far as attributing to the witness words used only by counsel in posing a question, while ignoring the actual answer provided. The California Generators' brief states, at page 33: "The old adage fits (as at trial): garbage in, garbage out. Tr. (Hildebrandt) at 1377:12-15)." However, the cited transcript reads as follows:

> Q . So you must know the old sort of adage about computers, garbage in/garbage out, it matters what the reliability is of your source data?
>
> A . The source data can affect the outcome, sure.

Omitted from the California Generators' brief is the more detailed response Dr. Hildebrandt provided immediately thereafter, to the more relevant question of whether, in his opinion, the adage "garbage in/garbage out" applies in this situation:

> [W]ith the amount of data involved in this case, you can go through it forever counting chads, taking this [bid]or that [bid] -- and I think the Commission adopted an approach. I think they used language that could be readily implemented and they're not under an obligation to do a detailed resimulation of the market. I think they wanted an objective, clear process for calculating it. I'm following the process we've been doing actually since June of 2000 [2001] at the request of Judge Wagner, and we've been telling the Judge in filings at FERC how we've been doing the analysis. We've been told to modify certain aspects of it, but not this aspect.
>
> That's what I mean by the right answer. I think the right answer in this case is an approximation of a competitive market output that yields just and reasonable prices over the refund period.
>
> Q. That's an awfully long way of saying that you're going to follow the way you've always been doing it even if it gives an incorrect answer because you're relying on incorrect data?
>
> A. I don't believe the answer is necessarily incorrect. I'm being very up front about the set of dispatches. I'm using the same set of dispatches that the price -- the historical price was actually determined on. When you resimulate the market, that's, in effect, the universe of units that I believe the Commission intended for us to use.

Tr. 1377:22 – 1379:2.

OOM transactions may be settled in several different ways, including a cost-based option described in the ISO Tariff, one cannot conclude that an OOM transaction should have been logged as an OOS transaction simply based on the price of the transaction reflected in data files, as proposed by Mr. Tranen. *See* Tr. 1392:1-6; 1414:12 – 1415:19.[19]

What is equally important, the impact of calculating mitigated prices based on "corrected" BEEP dispatch data is relatively minor. The testimony of the California Generators' own witness indicates that the incremental impact of re-running the ISO's analysis with Mr. Tranen's "corrected" BEEP stack data would be relatively insignificant. As explained in Mr. Tranen's rebuttal testimony, Mr. Tranen successfully recreated the ISO's methodology and re-ran the MMCP calculations using his "corrected" BEEP stack data. Results of this analysis indicted that the average MMCP over the refund period would increase from about \$180 to \$184. (GEN-19 at 15:11-15).[20]

While including Mr. Tranen's "corrected" BEEP stack data in the ISO's analysis may result in a small incremental increase in the MMCP, testimony of the California Parties' indicates that this increase would be approximately offset by the incremental impact of just one of the other refinements to the data used in the ISO's analysis that have been suggested in these proceedings. As summarized in the testimony of witnesses for the California Parties, Staff and the ISO, it is appropriate to exclude units that did not actually respond to dispatch instructions (based on metered data) from being eligible to set the MMCP. *See* ISO Initial Brief at 43 - 45. Data provided in Exh.CAL-2 shows that if this single refinement is added

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[18] The "corrected BEEP stack" used in Mr. Tranen's analysis, *see* EXH. GEN-19 at 16:4-15, has not been entered into the record. Tr. 1959: 3-11.

[19] The only acknowledgment of the limitations of the approach employed by Mr. Tranen is the use of the phrase that "OOM transactions *generally* are paid the ex-post clearing price" in the California Generators brief. GEN Brief at 25 (emphasis added).

[20] Elsewhere in his testimony, Mr. Tranen characterized a \$2 decrease in the MMCP as "small," suggesting that Mr. Tranen would be likely to consider a \$4 increase in the MMCP to be relatively small as well. *See* Exh. GEN-19 at 10:9-11.

to the ISO's methodology, the MMCP would be reduced by $3.47 [21] --- virtually the same $4 level by which the MMCP would increase if Mr. Tranen's "corrected" BEEP stack was incorporated in its entirety into the MMCP calculation. Thus, if this one other modification was made to the data in the ISO's analysis, it would approximately offset the maximum impact of incorporating Mr. Tranen's "corrected" BEEP stack into the analysis.

Finally, in addition to these points pertaining specifically to the BEEP dispatch data used in the ISO's analysis, the conclusion that the "bottom line" results of the specific *combination* of methodology and data used in the ISO's MMCP calculations already fall clearly within the "zone of reasonableness" has been established in the course of these proceedings. As shown in the rebuttal testimony of Dr. Stern, the MMCPs calculated by the ISO would reduce the average historical market clearing prices in the ISO real time imbalance market over the refund period by about 12 to 21% (in contrast to the MMCPs submitted by the sellers' witnesses, which actually exceed the historical prices by 85% to 130%). CAL-19 at 3:5-8. Analysis presented by the California Parties shows that the MMCPs submitted by the ISO in this proceeding would provide significant revenues to generators that are consistent with those that would be received by generators (and paid by buyers) under competitive market prices**.** *See* CAL-26 at 15:2 - 18:24; *see generally* CAL Brief at 14-18. Although sellers have argued that the ISO's MMCPs would not provide sufficient "cost-recovery" to many sellers, they have provided *no evidence* to this effect. In addition, the Commission provided a "safety net" of cost-based rates in the event that the MMCP derived from the simplified "proxy price" formula outlined in its orders result in insufficient revenues for any individual generators or other sellers. Thus, on balance, absent

[21] Based on the difference between the simple average of the hourly prices from the ISO's initial MMCP calculation, Exhibit ISO-3, presented in Column 0 of Exhibit CAL-2 ($176.15), less the hourly prices presented in Column 5 of Exhibit CAL-2 ($172.68), which represent results of the ISO's initial analysis

specific direction to the contrary from the Commission, the ISO believes it is most reasonable to maintain consistency in both the methodology and the data utilized in the previous calculations of the mitigated prices (with the exception of the modifications specified in the Heat Rate Stipulation, Exh. J-1) that have been described and submitted to the Chief Judge and Commission in these proceedings. Tr. 1398:3-14.[22]

1. Is eligibility to set the MMCP contingent upon a unit having had a bid in the BEEP Stack?

(a) The California Generators Rely on Mischaracterizations of the ISO Tariff and Deposition Transcripts To Support Allowing Units Without Bids in the Real Time Market To Set the MMCP

The portion of the California Generators' brief in which they contend that a unit should be able to set the mitigated price even without having had a bid in the BEEP stack is, frankly, shocking. Their basic argument is wrong,: that it would be "unreasonable to restrict the universe of eligible units to a subset of the units that the ISO relied on to meet real-time demand." GEN Brief at 32. It is wrong because it flies in the face of the Commission's orders, in which the Commission consistently restricted the eligible units to those in the "real time imbalance market" What is shocking, however, is that in arguing that their position is supported by the ISO Tariff and by the deposition of Jim Detmers, the ISO officer responsible for operations, the California Generators have engaged in a series of mis-characterizations and misleading citations to the record.

First, under "*Finding 6(a)*," the California Generators attempt to parse the ISO Tariff to show that the Real Time Market includes "*any* source of energy 'able to respond to the

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modified to exclude units that did not respond to dispatch instructions, as described in Dr. Stern's initial written testimony, Exhibit CAL-1.

[22] Dr. Hildebrandt noted that the ISO has described its methodology, including the reliance on the specific set of dispatch records made through the BEEP software, to the Chief Judge and the Commission on various occasions dating back to June 2001, and that while the Chief Judge and the Commission have directed the ISO to modify other aspects of its methodology, neither has indicated that any changes should be made to this aspect of the proxy price calculation. Tr. 1398:3-14.

ISO's request for more or less energy.'" GEN Brief at 30-31. They ignore the fact that the Tariff's definition of Real Time Market includes the concept that it is "the *competitive market* controlled and coordinated by the ISO for *arranging* real-time Imbalance Energy." ISO Tariff Original Sheet No. 341, quoted in GEN Brief at 30. They attempt to equate a type of energy – imbalance energy – with the *market* for obtaining *some* of that energy. In quoting from the Detmers deposition, Exh. GEN-10 at 25, they fail to reveal that immediately prior to the quoted passage, when first asked to define "the real time energy market," Mr. Detmers had responded, "The real time – the competitive real time energy market was designed to be the imbalance energy market that we referred to as BEEP." *Id.* (Detmers Dep. at 130:9-13). That exchange shows, of course, that upon hearing the phrase "real time energy market," Mr. Detmers immediately thinks of the competitive market dispatched through BEEP – thus *supporting* the ISO's position that the Commission, which is familiar with the ISO Tariff, must have intended that market when it used the same phrase. *See* ISO Initial Brief at 26. It was only when the questioner, not satisfied with that answer, asked Mr. Detmers to define the market "more broadly," that Mr. Detmers switched to the less-precise, vernacular description that California Generators have quoted.

Under "*Finding 6(d),*" the California Generators contend that the BEEP stack was "tainted" during the "latter part of the refund period" due to CERS (which was providing the creditworthiness back-up required by the Commission) having set a limit on what the ISO could pay. GEN Brief at 32-33. They cite Mr. Detmers's deposition for the proposition that this occurred as early as January 17, 2001. But even a cursory reading of the deposition shows that what Mr. Detmers was referring to at the cited point was not CERS's BEEP-related activity, but rather its out-of-market purchases; that's the ISO "job" Mr. Detmers is referring to as having been taken over by CERS, in the quotation used by California Generators. Exh. GEN-10 at 49-51 (Detmers Dep. At 242:22 – 244:24). In the portion of the deposition where Mr. Detmers discussed CERS's having "capped" the price that could be paid through the BEEP stack, it is very clear that this did not occur before mid-April 2001 – virtually the end of the refund period – not as early as January 17. Exh. GEN-10 at 63-64 (Detmers Dep. At 265:23 – 266:10). Finally, the California Generators assert that Mr. Detmers acknowledged that "on some days" as much as 500 MW went undispatched through BEEP due to CERS's cap of the price. Review of the deposition transcript, however, shows that he said only that 500 MWs might have been in excess of CERS's "target" price "during that entire period" of mid-April through June 20, 2001. Exh. GEN-10 at 63-64 (Detmers Dep. at 267:6-18).

(b) The CSG Relies on Irrelevant and Misleading Statistics to Support Allowing Units Without Bids in the Real Time Market to Set the MMCP

The CSG's Brief repeatedly cites a set of irrelevant and misleading statistics provided in Dr. Cicchetti's testimony in an attempt to support virtually every key aspect of their methodology, including the use of average heat rates and providing essentially no limit on universe of units that should be eligible to set the MMCP. CSG Brief at 21, 37, 38, 40. However, all the statistics cited in the CSG Brief represent a circular argument that starts from (and ends with) the CSG's position that any unit "that supplied energy" to the ISO system should be allowed to set the MMCP. *See* CSG Brief at p.39. As summarized in the CSG's Brief, Dr. Cicchetti's testimony indicates that during 57% of the intervals "the ISO's methodology selected a unit with a heat rate that was lower than the heat rate of a unit that was actually running dispatched in accordance with the final hour ahead schedule." CSG Brief at 21. Thus, the statistics quoted in the CSG's brief indicate nothing more than the fact that at least one unit with a final hour-ahead schedule (but not necessarily providing *any* form of imbalance energy) had a higher heat rate (calculated based on average heat rates at metered generation levels) than the marginal unit identified by the ISO's analysis.

In arguing that any unit operating should be allowed to set the MMCP, Dr. Cicchetti represents an "outlier" in these proceedings, in that everyone else appears to agree that the universe of units should be limited to some subset of units providing imbalance energy. In addition, as noted in footnote 4 of this brief, while Dr. Cicchetti agrees with all other key aspects of the methodology proposed by the California Generators, the MMCPs actually submitted by Dr. Cicchetti bear no resemblance to the MMCPs submitted by the California Generators' witnesses, and instead appear to be the "the ISO's prices with some 'adder' on them." Tr. 1563:22 – 23 (Hildebrandt).

2. Are the following energy types eligible to set the MMCP?

(a) BEEP Supplemental?

The parties agree.

(b) BEEP Spin, Non-spin and Replacement A/S?

The parties agree.

(c) OOS Non-congestion Imbalance Energy Supplemental

We stand on our Initial Brief and the discussion in sections I.D and I.D.1, above.

(d) OOS Non-congestion Imbalance Energy Spin, Non-Spin and Replacement A/S

We stand on our Initial Brief and the discussion in sections I.D. and I.D.1, above.

(e) OOS Congestion?

The parties agree.

(f) OOM?

We stand on our Initial Brief and the discussion in sections I.D. and I.D.1, above.

(g) We stand on our Initial Brief and the discussion in sections I.D and I.D.1, above.Residual Energy?

We stand on our Initial Brief and the discussion in sections I.D. and I.D.1, above.

(h) Regulation?

We stand on our Initial Brief and the discussion in sections I.D. and I.D.1, above.

(i) Other Imbalance Energy?

We stand on our Initial Brief and the discussion in sections I.D. and I.D.1, above.

3. If eligibility of a unit is contingent upon having had a bid in the BEEP Stack, what approach to eligibility should be taken during intervals in which there were incremental dispatch instructions from the BEEP Stack

We stand on our Initial Brief.

4. If eligibility of a unit is contingent upon having had a bid in the BEEP Stack, what approach to eligibility should be taken during intervals in which there were decremental dispatch instructions, but not incremental dispatch instructions, from the BEEP Stack

We stand on our Initial Brief.

5. What approach to determining the unit that sets the MMCP should be taken during intervals in which no eligible unit was dispatched for imbalance energy?

We stand on our Initial Brief.

6. Should units running on fuels other than natural gas be eligible to set the MMCP?

The parties agree.

7. Should units that did not show positive or negative responses to BEEP Stack dispatch instructions be eligible to set the MMCP?

We stand on our Initial Brief.

8. Should units outside the ISO control area be eligible to set the MMCP?

We stand on our Initial Brief.

E. Additional Issues related to the MMCP Calculation.

1. What is the proper use of gas price indices for the calculation of the MMCP for each interval?

Only the CSG has challenged the ISO's interpretation of the Commission orders regarding gas price indices. The CSG argues that use of the common high index more closely reflects the costs the units dispatched by the ISO actually paid and is consistent with Commission orders. CSG references bald claims in the testimony of CSG's own witnesses, to the effect that the index used by the ISO does not "reflect the true marginal cost of natural gas during the critical period" and that "'spot electricity generators would typically pay the highest prices recorded for gas sold on any given day.'" CSG Brief at 43-44, citing testimony by Dr. Cicchetti and Dr. Jones. However, CSG provides no quantitative support for these claims, *i.e.*, no evidence concerning the costs of specific generators. The statements referenced regarding costs incurred by Generators are only the opinion of the witnesses for CSG and are not consistent with the opinion of other witnesses. *See* Exh. ISO-20 (Rothleder) at 15:19 – 16:13; Exh. CAL-22 (Harris) at 14:1-10; 17:2 – 18:8; 19:18 – 20:2. Despite the impression that may be left by the CSG's brief, CSG's witnesses provided no quantitative evidence to support their claims regarding the specific costs incurred by participants in the ISO's real time imbalance market.

With regard to Commission direction, only CSG reads the July 25 Order to suggest that the Commission was not accepting the Chief Judge's recommendation regarding the use of the midpoint indices. *See* Staff Brief at 36-39; GEN Brief at 47; CAL Brief at 46-48; ISO Brief at 46 –47. The ISO believes the Commission implicitly accepted the Chief Judge's recommendation. *See* ISO Initial Brief at 46 – 47.

2. To the extent hourly MMCPs are calculated based upon 10-minute interval MMCPs, should the interval MMCPs be averaged on a weighted or simple average basis?

We stand on our Initial Brief.

3. Is there a separate formula for calculating MMCPs for ancillary services and, if so, what is it?

This issue is deferred until "Phase II."

CONCLUSION

For the reasons stated above, we request that the Presiding Judge adopt the proposed findings in our Initial Brief and not any inconsistent proposed findings in the initial briefs of the other parties or Staff.

Respectfully submitted,

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