THE UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

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

PREPARED REBUTTAL TESTIMONY OF
DR. ERIC HILDEBRANDT ON BEHALF OF
THE CALIFORNIA INDEPENDENT SYSTEM
OPERATOR CORPORATION

Q. PLEASE STATE YOUR NAME.

A. Dr. Eric Hildebrandt.

Q. ARE YOU THE SAME ERIC HILDEBRANDT WHO PREVIOUSLY FILED TESTIMONY IN THIS PROCEEDING ON BEHALF OF THE CALIFORNIA INDEPENDENT SYSTEM OPERATOR CORPORATION (“ISO”)?

A. Yes.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. I will respond to statements and arguments made by witnesses who have filed initial and supplemental responsive testimony concerning Issue 1 in these proceedings on behalf of other parties.

Q. HOW IS YOUR TESTIMONY ORGANIZED?

A. Section I provides a summary of the methodological differences between my previous testimony and the testimony of the seller's witnesses, along with a comparison of the mitigated prices that result from these different methodologies. Section II addresses – point by point -- the methodological differences that lead to these different results, and the sellers' witnesses' rationale for the different methodologies they propose. Section III addresses a variety of issues raised by the initial and supplemental testimony of the sellers' witnesses which have either been resolved through the December 19 Order, or are the subject of requests for clarification. I address these issues while recognizing that further clarification or rulings on these issues may make this discussion unnecessary.

SECTION I. OVERVIEW

Q. WHAT PROPOSED CHANGES IN THE ISO'S METHODOLOGY FOR DETERMINING THE MITIGATED PRICE WILL YOU ADDRESS IN THIS REBUTTAL TESTIMONY?

A. The sellers' witnesses contend that a number of significant modifications should be made in the methodology used by the ISO for calculating the mitigated price. The California Parties generally support the ISO's methodology but do propose some specific changes dealing with the universe of units, the selection of the "last unit dispatched", and the calculation of heat rates. In Section II of this testimony, I address the following key issues:

1) Most of the sellers' witnesses argue for the use of average heat rates, or what some call "operational" heat rates, rather than the incremental heat rates used by the ISO to calculate mitigated prices. Ex. No. ENR-1 (Issue 1 Prepared Responsive Testimony of Seabron Adamson) at 11:18 – 14:22; Ex. No. GEN-1 (Prepared Direct and Answering Testimony of Jeffrey Tranen) at 5:17; Ex. No. PWX-1 (Prepared Responsive Testimony on Issue 1 of Richard D. Tabors) at 6:23 - 7:1; Ex. No. SEL-1 (Issue 1 Prepared Responsive Testimony of Charles J. Cicchetti) at 19:4-5, 19:19 – 27:17. Several of the witnesses filing supplemental responsive testimony reiterate this position. Ex. No. GEN-19 (Prepared Supplemental Direct and Answering Testimony of

Jeffrey Tranen) at 18:5-8; Ex. No. PWX-47 (Prepared Supplemental Responsive Testimony Judith B. Cardell) at 2:6-7; Ex. No. SEL-11 (Prepared Supplemental Testimony of Charles J. Cicchetti) at 5:8. The different heat rates used in the sellers' methodology accounts for most of the increase in the mitigated prices calculated by sellers as compared to the mitigated prices calculated by the ISO.

2) Several of the sellers' witnesses argue that the heat rate for specific units should be calculated using a unit's metered generation level (including uninstructed deviations from scheduled generation levels), rather than the level at which the unit was actually scheduled or dispatched to operate in the ISO's Real Time Market for Energy. Ex. No. GEN-1 (Tranen) at 45:5-22; Ex. No. PWX-1 (Tabors) at 18:9-15.

3) Most of the sellers' witnesses argue that the transactions making individual generating units eligible to set the mitigated price during any interval ("universe of units") should include gas-fired units that were not dispatched in the ISO's Real Time Market for Energy, but received instructions from the ISO through Out-of-Market ("OOM") and Out-of-Sequence ("OOS") requests. Ex. No. ENR-1 (Adamson) at 4:1-3; Ex. No. GEN-1 (Tranen) at 19:20-20:7; Ex. No. GEN-19 (Tranen) 11:15-18; Ex. No. PWX-1 (Tabors) 6:2-10; Ex. No. SEL-1 (Cicchetti) at 15:13-17:2.

4) Many of the sellers' witnesses argue that the mitigated price should be eligible to be set based on the highest cost generation decremented by

the ISO (i.e., to *reduce* generation below the Hour Ahead schedule submitted by each unit's Scheduling Coordinator), such that the mitigated price would be based on the highest cost generation incremented or decremented by the ISO. Ex. No. GEN-19 (Tranen) 6:16-17:12; Ex. No. PWX-46 (Prepared Supplemental Responsive Testimony of Dr. Richard D. Tabors) at 3:10-17; Ex. No. SEL-11 (Cicchetti) at 8:4-10.

5) Several of the sellers' witnesses contend that the ISO's methodology for determining the mitigated price during intervals when no units eligible to set the mitigated price were dispatched by the ISO in the Real Time Market (based on the lowest cost bid for Real Time Energy available, but not dispatched) is inconsistent with the Commissions orders. Ex. No. GEN-19 (Tranen) 8:13-16. One of these witnesses proposed an alternative approach that calculates mitigated price for these time periods based on mitigated prices from other time periods. Ex. No. GEN-19 (Tranen) 8:2-12.

6) Some witnesses for the sellers also argue that the "universe of units" used in determining the marginal unit for an interval should include units that were not actually dispatched by the ISO during that interval, but generated energy as a by-product of an expired dispatch instruction, or what is referred to as "residual energy" in the ISO's settlement process. Ex. No. GEN-1 (Tranen) at 37:4-15; Ex. No. SEL-11 (Cicchetti) at 9:1-8.

7) Some sellers' witnesses would also allow the mitigated price to be set by units scheduled to provide energy through the PX market that were not dispatched at all by the ISO. Ex. No. ENR-1 (Adamson) at 29:6 – 30:7; Ex. No. PWX-1 (Tabors) at 14:22 – 15:2.

8) Several of the suppliers' witnesses argue that non-gas fired resources should be allowed to set the mitigated price. Ex. No. ENR-1 (Adamson) at 31:22-23; Ex. No. PWX-1 (Tabors) at 7:19 – 18:6. Meanwhile, a witness for the California Parties identifies specific units included in the ISO's analysis that are not capable of operating on natural gas, and contend that these units should therefore be excluded from setting the mitigated price. Ex. No. CAL-1 (Stern) at 9:19-21, 10:20-23; Ex. No. CAL-7 (Strack) at 12:1-6. At least one witness for the suppliers also argues that resources outside of California should be eligible to get the mitigated price. Ex. No. AEP-12 (Prepared Direct Testimony of Walter Bray) at 4:1 – 5:15.

9) Witnesses for the California Parties identify several dual fuel units included in the ISO's analysis that burned fuels other than natural gas during some hours during the refund period, and contend that these units should be excluded from eligibility to set the mitigated price during hours when were not burning natural gas. Ex. No. CAL-1 (Stern) at 9:22 – 10:17.

10) One of the sellers' witnesses proposes a different approach for the averaging of 10-minute interval prices in the determination of hourly prices. Ex. No. GEN-1 (Tranen) at 50:6-8.

Section II of my testimony responds to each of these arguments in turn.

Q. ARE THERE ANY OTHER MAJOR POINTS OF DISAGREEMENT BETWEEN YOUR TESTIMONY AND THE RESPONSIVE TESTIMONY OF THE SELLERS ?

A. The sellers' witnesses also recommend a number of other modifications in the ISO's methodology that have either been definitively addressed in the December 19 Order, or are the subject of pending requests for clarification or rehearing before the Commission. These issues include the following:

11) At least two witnesses argue that in calculating refunds, the mitigated price should not be applied as a cap, but should be applied as a new transaction price, thereby increasing payments for transactions that cleared below the mitigated price. Ex. No. GEN-1 (Tranen) at 50:20-54:11; Ex. No. SEL-1 (Cicchetti) at 4:17 – 5:2.

12) One witness argues that the mitigated price should not be applied to transactions in the ISO's Ancillary Service capacity markets. Ex. No. SEL-1 (Cicchetti) at 70:8 – 71:15.

13) The testimony of one witness continues to contend that emissions costs should be included in the mitigated price calculations (Ex. No.

ENR-1 (Adamson) at 48-55), despite the clarification of this issue provided in the December 19 Order.

14) The testimony of one witness also continues to contend that start-up-costs should be included in the mitigated price calculations, Ex. No. ENR-1 (Adamson) at 39-48, despite the clarification of this issue provided in the December 19 Order.

15) One witness suggests that CERS sought to manage OOM and OOS purchases in a way that would drive down prices in the ISO's Real Time Market, and that the mitigated price should be adjusted somehow to account for this. Ex. No. ENR-1 (Adamson) at 24:23 – 27:5.

Section III of my testimony responds to each of these arguments in turn. I address these issues while recognizing that further clarification or rulings on these issues by the Presiding Judge or the Commission may make this discussion unnecessary.

Q. PLEASE SUMMARIZE YOUR FUNDAMENTAL DISAGREEMENT WITH SELLERS' WITNESSES.

A. The sellers' witnesses and I seem to be in agreement with respect to the ultimate goal of the July 25 Order: "to determine just and reasonable price levels that are, on average, reasonably good proxies for competitive market prices." Ex. No. ENR-1 (Adamson) at 5:6-9; Ex. No. SEL-1 (Cicchetti) at 8:19-20; Ex. No. PWX-1 (Tabors) at 3:5-7. Beyond that, however, I disagree with the sellers' witnesses about a number of key issues. Most importantly, perhaps, I disagree with these witnesses as to the approach that yields overall results that are most consistent with the ultimate goal of just and reasonable price levels that are, on average, reasonably good proxies for competitive market prices over the refund period as a whole.

As summarized in my initial testimony, the ISO's methodology is based on the specific methodology outlined in the July 25 Order (as clarified and modified by the December 19 Order), along with preceding Orders and filings under this docket that are incorporated by reference or by implication in the July 25 Order and December 19 Order. The ISO followed this approach since it is most reasonable to assume that the Commission believed that the ISO would rely primarily on the specific provisions of the July 25 Order (as modified by the December 19 Order), including the much more detailed provisions of the April 26 and June 19 Orders incorporated by reference into the July 25 Order, and with the manner in which these preceding Orders have already been implemented by the ISO. This overall approach is also most consistent with the economic principles and practical considerations upon which the Commission based these Orders and approved (or modified) how the aforementioned Orders have been implemented by the ISO. Accordingly, the approach followed by the ISO better realizes the goals of the Commission with respect to this proceeding: just and reasonable price levels that are, on average, reasonably good proxies for competitive market outcomes over the entire refund period.

The deviations from the ISO's methodology that are advocated by sellers' witnesses are not supportable under the specific provisions of the Commission's Orders, do not correctly apply economic principles underlying these orders, and undermine the Commission's overall objective of reducing the unjust and unreasonable prices faced by buyers of wholesale energy during the refund period.

Q. OVERALL, HOW DO RESULTS PRODUCED BY THE METHODOLOGY PRESENTED IN YOUR TESTIMONY COMPARE TO THE RESULTS PRODUCED BY THE METHODOLOGIES OFFERED ON BEHALF OF THE SELLERS?

A. The flaws in the methodologies proposed by the sellers' witnesses can be illustrated by comparing the mitigated prices resulting from these methodologies to basic price trends that would be expected given the laws of supply and demand in any electricity system or market. Figure 1 compares the average hourly mitigated prices for the refund period resulting from the sellers' witnesses' methodologies, to the mitigated prices calculated by the ISO. Figure 2 shows the average hourly prices actually observed in California's wholesale market over the same months for the two years preceding the refund period.

As shown in Figure 1, mitigated prices calculated by sellers' witnesses are highest during off-peak hours and drop during peak hours. This is precisely the opposite of the trend that would be expected in virtually any electricity system or market given the basic laws of supply and demand. While the anomalous price trends resulting from the methodology proposed by the sellers' witnesses can be traced to specific methodological deviations from the Commission's refund methodology, such results clearly don't meet the Commission's overall objective of establishing mitigated price levels reflective of competitive market conditions. Moreover, sellers' witnesses go on to argue that the mitigated prices resulting from their methodologies should be substituted as the new prices for all transactions occurring in the ISO and PX markets during the refund period, rather than being applied as an upper limit on historical transaction prices. In making such arguments, the sellers' witnesses seek to further magnify the degree to which the bottom line resulting from their overall methodology deviates from the fundamental goal of the July 25 Order: to determine just and reasonable price levels that are, on average, reasonably good proxies for competitive market prices.

In contrast to mitigated prices resulting from the sellers' proposed methodologies, the mitigated prices calculated by the ISO are true to the Commission's orders and are consistent with fundamental laws of supply and demand in electricity markets. As shown in Figures 1, prices calculated by the ISO rise during peak hours when demand is high and fall during off-peak hours when demand is low. As shown in Figure 2, this is in fact the basic trend that was observed in California's wholesale energy markets for the same time period as the refund period in the preceding two years, when the ISO and PX energy markets were reasonably competitive during most hours.

FIGURE 1. AVERAGE HOURLY MITIGATED PRICES DURING REFUND PERIOD

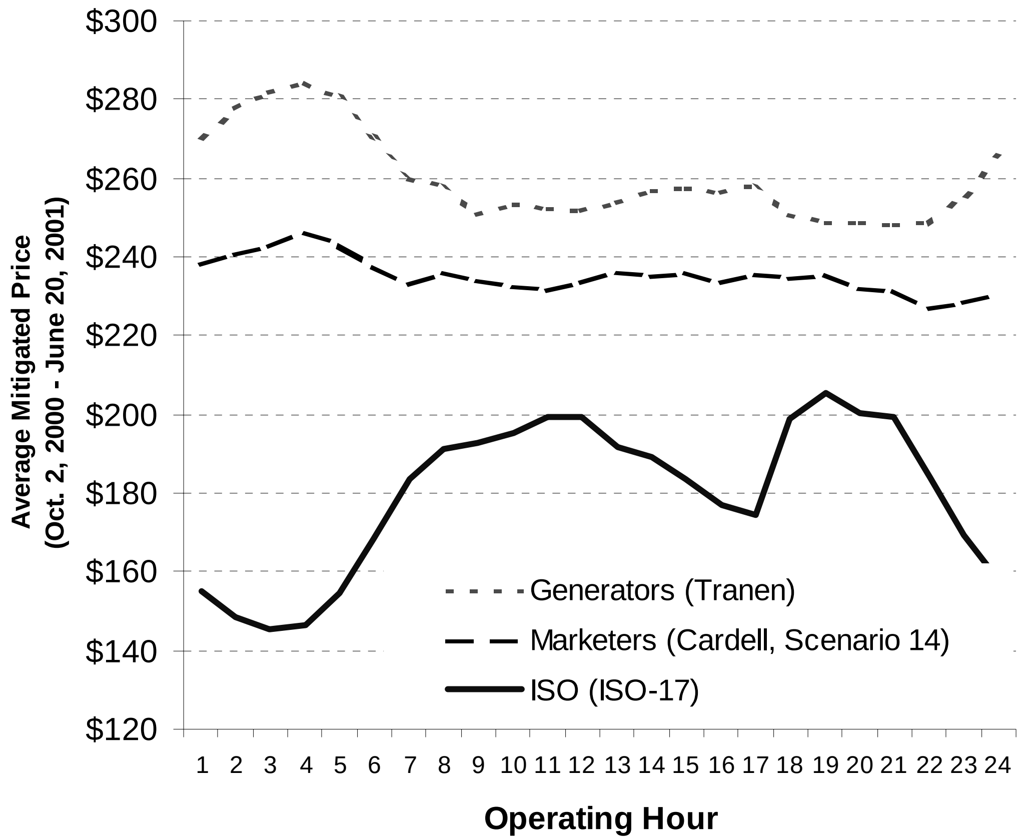
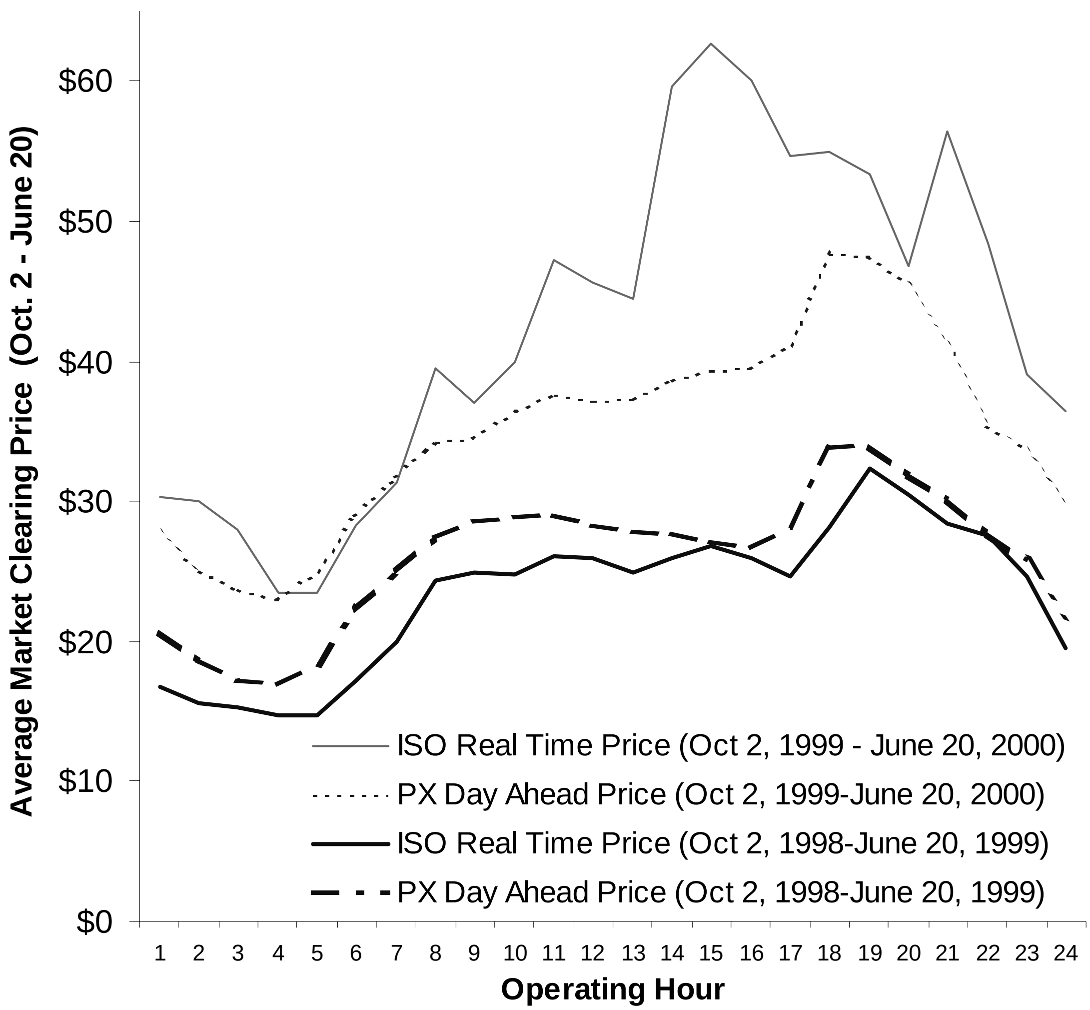


FIGURE 2. AVERAGE ACTUAL HOURLY PRICES IN CALIFORNIA WHOLESALE MARKET DURING PRECEEDING PERIODS



Prices in Figure 2 are based on a simple (unweighted) average of market clearing prices for NP15 and SP15 congestion zones.

SECTION II. RESPONSE TO TESTIMONY OF WITNESSES FOR SELLERS

<u>ISSUE 1: AVERAGE VS. INCREMENTAL HEAT RATES</u>

Q. ALL THE SELLERS' WITNESSES ARGUE FOR THE USE OF AVERAGE, OR WHAT SOME CALL "OPERATIONAL" HEAT RATES, RATHER THAN THE INCREMENTAL HEAT RATES USED BY THE ISO. ARE THEY CORRECT TO DO SO?

A. Absolutely not. The seller's witnesses attempt to justify the use of average heat rates on several grounds. First, they contend that the language of the July 25 Order requires the use of average heat rates. Ex. No. SEL-1 (Cicchetti) at 19:19 – 20:2; Ex. No. GEN-1 (Tranen) at 10:13-11:18. Second, they argue that the use of average heat rates is necessary to ensure that no generator ever receives payment for less than its assumed fuel costs and other variable operating costs for each 10-minute interval. Ex. No. PWX-1 (Tabors) at 10:14-11:4; Ex. No. GEN-1 (Tranen) at 17:10-11. Finally, they argue that use of average heat rates is more consistent with economic principles and the overall goal of replicating the outcome of a competitive market. Ex. No. ENR-1 (Adamson) at 11:15 – 12:3; Ex. No. SEL-1 (Cicchetti) at 27:9-17. However, each of these arguments is inconsistent with specific language in the July 25 Order and December 19 Orders, fundamental economic principles, and the Commission's goal of making market outcomes over the refund period more just and reasonable and reflective of competitive market outcomes.

Q. WHY DO YOU BELIEVE SELLERS ARE INCORRECT IN ARGUING THAT THE JULY 25 ORDER REQUIRES THE USE OF AVERAGE RATHER THAN INCREMENTAL HEAT RATES?

A. There are numerous specific references throughout the July 25 and related Orders that make it clear that the heat rates to be used should reflect *marginal* (i.e., incremental) costs of the last or marginal unit dispatched in the ISO's real-time market. For example, the July Order states that:

> Generators actually dispatched in the market during these periods have specific *marginal* costs that are reasonably recovered under our methodology. 96 FERC ¶61,120 at 61,517 (emphasis added).

The June 19 Order, the methodology of which is, to a large extent, incorporated in the July 25 Order, also includes statements specifying the use of heat rates which reflect marginal costs:

> Therefore, using the *marginal cost* of the least efficient generating unit dispatched best replicates prices in a competitive market. 95 FERC ¶61,418 at 62,560 (emphasis added).
>
> The Commission's mitigation plan is based on the payment of the *marginal cost* of the last generator dispatched to serve the last increment of load. *Id.* at 62,560 (emphasis added).

Since suppliers did not seek clarification or rehearing on the issue of how heat rates are used in calculating marginal costs under the July 25 Order, the December 19 Order did not explicitly address this issue. However, the December 19 Order consistently describes the mitigated price as being based on the marginal costs of the last unit dispatched to meet load in the ISO's Real Time Market. In the December 19 Order, the Commission clarified that under the July 25 Order:

> Hourly mitigated prices [for use in calculating refunds] would be developed using the *marginal costs of the last unit dispatched to meet load in the ISO's real-time market*. 97 FERC ¶61,275 at 62,178 (emphasis added).

In response to a request for rehearing by generators of the method of determining the marginal costs of units dispatched in real time, the Commission, in the December 19 Order, modified the July 25 Order to require use of unit marginal costs based on separate gas cost indices for northern and southern California rather than based only on heat rates, on the grounds that this modification "will lead to the best approximation of the *marginal costs of the last unit dispatched*." *Id.* at 62,203 (emphasis added). However, the commission went on to state that:

> "[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*." *Id.* at 61,214 (emphasis added).

Q. WHY DO YOU BELIEVE THE COMMISSION'S SPECIFICATION OF MARGINAL COSTS IN THE JULY 25 REFUND FORMULA REQUIRES THE USE OF INCREMENTAL RATHER THAN AVERAGE HEAT RATES?

A. In the context of electric utility operations and sound principles of economics, "marginal cost" must be understood to reference incremental heat rates. In fact, Dr. Cicchetti, on behalf of the marketers, provides a mathematical equation for calculating the Marginal Running Cost of a generating unit that is precisely the formula used by the ISO in its calculation of mitigated prices using incremental heat rates and marginal gas costs. As Dr. Cicchetti illustrates, the Marginal Running Costs of a generating unit, or the change in total running costs (Δ TRC) divided by the corresponding change in output (Δ Q), are equal to P_t, or the price per unit of input to run a plant (e.g. $/MMBTU of gas), multiplied by the incremental heat rate (IHR) associated with increasing output from a unit:

$$P_t, \times \text{ IHR} = \frac{\Delta \text{ TRC}}{\Delta \text{ Q}} = \text{Marginal Running Cost}$$

Dr. Cicchetti's formula is based, correctly, on the common understanding in the electric utility industry that the "marginal cost" of increasing output from a generating unit is a function of the incremental heat rate of the unit, or the *change* in total fuel consumption, divided by the corresponding *change* in unit output. Ex. No. SEL-1 (Cicchetti) at 22:8.

Additionally, it is important to note that incremental heat rates have consistently been used by the ISO in every step of this proceeding: in compliance filings submitted in response to the Commission's April 26 and June 19 Orders, and in analyses performed and submitted by the ISO in response to the June 20th direction of the Chief Judge which, in turn, provided the basis for his recommendation to the Commission and for the July 25 Order.[1] While the Chief Judge and Commission have required other modifications to the refund methodology in various stages of these proceedings, the Chief Judge's recommendation and subsequent Commission Orders do not provide any indication that this aspect of the refund methodology should deviate from the marginal cost approach specified in the April 26 and June 19 Orders.

[1] Analysis of Payments in Excess of Competitive Market Levels in California's Wholesale Energy Market, May 2000-2001, and Appendix A: Description of Methodology, submitted for public record at conclusion of FERC Settlement Conference, July 9, 2001.

Q. SELLERS CITE THE FACT THAT THE JULY 25 ORDER REFERS TO "THE MAXIMUM HEAT RATE OF ANY UNIT DISPATCHED EACH HOUR IN THE REAL-TIME IMBALANCE MARKET" AND THE REFERENCE TO "ACTUAL HEAT RATES" IN THE CHIEF JUDGE'S RECOMMENDATION AS EVIDENCE THAT INCREMENTAL HEAT RATES SHOULD NOT BE USED. WHAT IS YOUR RESPONSE TO THAT CONTENTION?

A. The sellers' witnesses cite both of these phrases out of context. Ex. No. PWX-1 (Tabors) at 9:12-15; Ex. No. GEN-1 at (Tranen) at 10:13-20, 15:12-15. A review of the *complete* discussion from which these citations are taken supports – rather than contradicts – the use of the methodology used by the ISO in calculating the mitigated price. Both of these citations are from discussions specifically referring to the difference between two methodologies that had been presented by the ISO and discussed in the settlement conference: (1) the "assumed economic dispatch" advocated by the ISO in filings prior to the July 25 Order as the <u>best</u> approach for approximating competitive market prices, and (2) the methodology based on "historical dispatch," or the marginal cost of the last unit *actually* dispatched in the ISO's Real Time Market, an analysis of which was also submitted by the ISO in response to a request from the Chief Judge. Both of these discussions simply indicate that the latter approach ("historical dispatch") should be used by the ISO instead of the "assumed economic dispatch" approach. The Commission's rationale for the discussion from which these references were drawn by the suppliers' witnesses was further clarified in the December 19 Order, which states that in the July 25 Order the Commission "concluded that the end result of using assumed economic dispatch would be to unfairly lower prices below the marginal costs of the last generator dispatched." 97 FERC ¶61,275 at 62,202.

Q. PLEASE DISCUSS SELLERS' WITNESSES SECOND ARGUMENT FOR NOT USING INCREMENTAL HEAT RATES -- THAT THE USE OF AVERAGE HEAT RATES IS REQUIRED UNDER THE COMMISSION'S JULY 25 ORDER TO ENSURE THAT NO GENERATOR EVER RECEIVES PAYMENT FOR LESS THAN THE ASSUMED OPERATING COSTS FOR EACH 10-MINUTE INTERVAL.

A. This argument, which is made by at least two of the sellers' witnesses, is not supported either by the Commission's Orders of July 25 and December 19 or by economic principles. Ex. No. PWX-1 (Tabors) at 10:14 – 11:11; Ex. No. GEN-1 (Tranen) at 17:10-14. While embracing a methodology that combines use of "historical dispatch" data with the principle that competitive prices should reflect marginal costs, the Commission made clear that it was proposing a methodology that was consistent with the operation of a competitive market and that offered a fair opportunity – but not the certainty – of reasonable cost recovery over the entire refund period. In the July 25 Order, sellers were reminded of what always has been the reality, namely that:

> [A]s noted in the June 19 Order, the FPA and our authorization of market-based rates, sellers are not guaranteed to recover all costs, but are provided the opportunity to do so. 96 FERC ¶61,120 at 61,518.

There is nothing "unfair" about a methodology that may, during certain discrete intervals, fall short of providing full cost recovery while permitting supra-competitive returns during other intervals. That is precisely what occurs in competitive markets, and particularly in wholesale electricity markets. Moreover, the Commission provided the sellers with a safety net not typically available in competitive markets: the freedom to elect cost-based rates if they believe that the mitigation methodology based on marginal cost of the last unit dispatched in the ISO's Real Time Market is insufficient to cover their costs over the entire refund period as a whole. As the Commission stated in the July 25 Order:

> If sellers in California … do not believe that these prices sufficiently cover their costs, they can file for cost-of-service rates covering *all of their generating units in the WSCC for the duration of the mitigation period and including the refund period*. 96 FERC ¶61,120 at 61,518 (emphasis added).

The Chief Judge's recommendation – adopted in relevant part under the July 25 Order --- further clarifies that the mitigated price methodology being recommended to calculate refunds may not cover every seller's costs.

> It is important to note that a single methodology be adopted for calculating potential refunds in this proceeding. However, such a methodology may not be appropriate for all sellers . . . in an after-

> the-fact refund calculation. In any event, sellers not using this methodology should bear the burden of demonstrating that their costs exceeded the results of the methodology recommended herein over the entire refund period. 96 FERC ¶63,007 at 65,039.

Finally, in response to a range of issues related to cost recovery that were raised by sellers in response to the July 25 Order, the December 19 Order contains repeated, unambiguous clarifications that the Commission recognizes that the methodology specified for calculation of refunds may not cover every seller's costs, but that any attempt to justify costs in excess of the mitigated price must be based on a comparison of the total costs and revenues of a supplier's entire resource portfolio in the Western region over the entire refund period after application of the refund methodology to affected transactions. See, e.g., 97 FERC ¶61,275 at 62,193 – 62,194.

Q. IS THE USE OF AVERAGE HEAT RATES AS PROPOSED BY SELLERS CONSISTENT WITH EITHER COST-BASED OR MARKET-BASED RATE PRINCIPLES OR RESULTS?

A. No. The July 25 Order as modified by the December 19 Order allows sellers to choose between a methodology designed to provide them a fair opportunity to realize profits by approximating marginal cost pricing under competitive market conditions, and more traditional cost-based rate-making under which sellers are guaranteed to recover costs and earn a just and reasonable profit. However, the sellers' witnesses attempt to justify deviations from the methodology specified in the Commission's Orders on the grounds that these deviations are necessary to ensure that every generator earns no less than the revenues it would receive under traditional cost-based ratemaking during each 10-minute interval. If adopted, the various modifications proposed by the suppliers' witnesses would constitute a third methodology that, in effect, incorporates selective elements of traditional cost-based ratemaking into a methodology that was designed by the Commission to approximate marginal cost pricing under competitive market conditions. The net result of this hybrid approach would be to inflate the mitigated price well above a level that approximates marginal cost pricing under competitive market conditions.

Q. PLEASE COMMENT ON THE CONTENTION, MADE TO SUPPORT THE USE OF AVERAGE HEAT RATES, THAT ECONOMIC PRINCIPLES REQUIRE THAT THE MITIGATED PRICE MUST BE SET AT THE HIGHEST TOTAL OPERATING COST OF ANY UNIT CONTRIBUTING TO MEET TOTAL DEMAND FOR EACH 10-MINUTE INTERVAL?

A. Again, this contention by several of the sellers' witnesses is supported neither by the Commission's orders nor by economic principles. Ex. No. PWX-1 (Tabors) at 11:3-4; Ex. No. GEN-1 (Tranen) at 17:10-12. As I have already discussed, the July 25 Order explicitly recognizes that the "historical dispatch" methodology is designed to allow only recovery of the *marginal* costs of the last generator dispatched in the ISO's real time market, and allows generators to apply for cost-based rates if they believe that prices yielded by this methodology are insufficient to cover their costs over the refund period as a whole. Moreover, economic principles do not require that energy prices in a competitive market equal or exceed average variable costs (or running costs) of every unit for each 10-minute interval, as argued by the sellers' witnesses.

The sellers' witnesses' theoretical economic argument to this effect is flawed in at least three major respects. First, it ignores the fact that much of the capacity available in the Real Time Market represents excess capacity of generating units that are on-line as a result of being committed to run in order to deliver energy to fulfill a bilateral obligation, sale in the Day Ahead market, or Reliability Must-Run (RMR) contract obligation.

Second, the sellers' arguments ignore the operating constraints of most thermal generating units, in terms of start-up times, minimum run times and operating levels, and minimum down times. Due to operational constraints, most gas units simply cannot choose to be shut down or operate during each individual 10-minute interval. As noted by one of the suppliers' own witnesses:

> Thermal generation owners whose plants were not very flexible might agree to run at a loss for some off-peak hours, possibly down to incremental costs. This would allow these units to avoid the costs of shutting down and starting again in a few hours, if they can do so at all. Ex. No. ENR-1 (Adamson) at 14:8-10.

Rational unit operators will continue to operate in intervals in which they are not recovering their costs if they expect that the additional revenues received in subsequent intervals (in the Real Time, Day Ahead and bilateral markets) will exceed their operating costs for all intervals combined, with some opportunity to contribute to fixed cost recovery.

Finally, the sellers' argument ignores revenues (and related minimum operating requirements) from other sources, including the Ancillary Service markets, RMR contracts, and bilateral contracts. Dr. Cicchetti, Dr. Tabors, and Mr. Tranen simply make no mention of any other sources of revenue. Mr. Adamson mentions these sources of revenue, but dismisses them as being irrelevant or insufficient to cover costs under mitigated prices calculated based on the marginal cost-based approach outlined in the Commission's orders.

Q. DID ANY OF THE SELLRS' WITNESSES PROVIDE DIRECT EVIDENCE DEMONSTRATING THAT THE MITIGATED PRICE CALCULATED BY THE ISO WOULD BE INSUFFICIENT TO COVER ANY UNIT'S COSTS OF PRODUCTION?

A. The initial responsive testimony of several witnesses for the sellers included statements indicating that the mitigated prices that had been submitted by the ISO would be insufficient to cover the costs of some suppliers. Ex. No. PWX-1 (Tabors) at 10:4-6; Ex. No. GEN-1 (Tranen) at 17:13-16. However, none of the witnesses for sellers has provided information to support the contention that, under the manner in which the ISO is implementing the refund methodology, any supplier would be denied recovery of its costs over the refund period.

For example, in his testimony on calculation of mitigated prices to be used in calculating refunds, Dr. Tabors notes that one of the key objectives of the Commission's July 25 Order was that "no unit that helped 'keep the lights on in California' should be unfairly denied the opportunity to recover its costs." Ex. No. PWX-1 (Tabors) at 5:7-8. I agree. However, Dr. Tabors fails to provide any evidence that suggests that a seller would, under the mitigated prices that have been calculated by the ISO, fail to recover its costs over any relevant time period. Instead, Dr. Tabors simply states that:

> Simple arithmetic shows that MMCPS calculated in this way [with incremental heat rates] will cause the marginal unit to under-recover its costs. If the incremental heat rate of a unit is always below its average heat rate, then *for that specific time interval in which the unit is marginal*, it would earn in revenues less than its *average cost* of delivering energy." Ex. No. PWX-1 (Tabors) at 10:15-18 underline added).

Dr. Tabors argues hypotheticals, not realities. Dr. Tabors himself notes that his hypothetical establishes no more than that the use of incremental heat rates may cause the marginal unit to earn less than its *average cost* of delivering energy *for that specific time interval in which the unit is marginal*. However, even this possibility is speculative, as Dr. Tabors ignores revenues (and related minimum operating requirements) from other sources, including the Ancillary Service markets, RMR contracts, and bilateral contracts. More importantly, Dr. Tabors does not and cannot opine that his criticisms lead to the conclusion that any generator is likely to fail to recover its operating costs and to earn a just and reasonable return over the entire refund period, particularly when all sources of actual revenues and costs are compared over the entire refund period, as required under the July 25 Order.

Similarly, Mr. Tranen argues that the ISO's methodology "generally under-compensates the marginal unit for its actual fuel costs during any interval when it sets the market clearing price." Ex. No. GEN-1 (Tranen) at 5:1-9, 17:13-14. However, Mr. Tranen neglects to demonstrate that this may actually be the case for any unit over any time period. Nor does he explain why failure of the particular marginal unit to recover operating costs in a specific interval necessarily means that unit would not recover more than its costs over a longer period of time that would be relevant, in light of the operating characteristics and patterns of most generating units in electricity markets, and the requirement of the July 25 Order that costs and revenues be compared over the entire refund period.

In any event, following submission of the sellers' witnesses initial testimony in these proceedings, the December 19 Order clarified that the issue of cost recovery was not relevant in the portion of these proceedings dealing with the calculation of the mitigated price:

> The July 25 Order established an evidentiary hearing limited to the collection of data needed to apply the refund methodology. During the hearing, parties do not have an opportunity to submit additional evidence. However, as explained further below, the Commission will provide an opportunity after the conclusion of the refund hearing for marketers to submit cost evidence on the impact of the refund methodology on their overall revenues over the refund period. 97 FERC ¶61,275 at 62,193 (footnote omitted).

In sum, it is telling that these witnesses seek to support their proposed modifications to the ISO's method for calculating the mitigated price on the grounds that these modifications are necessary to provide adequate compensation for all suppliers during the refund period, yet no empirical evidence has been submitted to this effect. The theoretical debate on cost recovery introduced by the sellers' witnesses in support of their methodology for calculating the mitigated price must not be allowed to obscure the simple fact that no seller has yet provided evidence of its inability to recover its costs and to earn a fair return over the entire refund period, and, more importantly, that if any seller believes that to be the case, the Commission has offered an alternative "safety net" – cost-based rates.

Q. DO YOU AGREE WITH THE "MIXED HEAT RATE" APPROACH DESCRIBED BY MR. TRANEN IN HIS SUPPLEMENTAL TESTIMONY (EX. NO. GEN-19 (TRANEN) AT 17:3 – 19:4)?

A. No. In his Supplemental Testimony, Mr. Tranen opines that "[i]t is at least conceivable . . . that the Commission intends to use average heat rates when a unit is being dispatched only according to an ISO dispatch instruction, and incremental heat rates when a generator is already running the unit for other reasons, and then modifies that operating level to comply with an ISO dispatch instruction." Ex. No. GEN-19 (Tranen) at 18:8-12. However, Mr. Tranen's rationale for this mixed heat rate approach continues to be that using incremental heat rates when units are on solely in response to an ISO dispatch instruction "would deny recovery of minimum load fuel costs in numerous intervals." Id. at 18:17-18.

Like the average heat rate approach preferred by sellers, Mr. Tranen's mixed heat rate approach is flawed in several respects. First, as I have discussed previously in this testimony, the July 25 and December 19 Orders clearly indicate that the issue of cost recovery is not relevant to calculating the mitigated price, and that the mitigated price methodology specified in these orders is not designed to ensure that every generator recovers its full costs in every interval of the refund period. Under the July 25 Order, generators are provided an alternative "safety net" to ensure cost recovery over the refund period as a whole: the option of cost-based rates.

Second, the economic logic underlying the mixed heat rate approach proposed by Mr. Tranen is flawed in that it would frequently allow the mitigated price to be set based on the no-load costs of units called to operate at or near minimum load. This directly contradicts economic principles of marginal cost pricing, as well as the approach adopted by the Commission in its order issued on December 19, 2001 addressing the ISO's compliance filings ("Compliance Order") for paying minimum load costs on a going-forward basis. Mr. Tranen correctly notes that the Compliance Order contains provisions to ensure that under some conditions generators are compensated for minimum load fuel costs on a prospective basis, but fails to mention the most relevant aspect of these provisions: *that the overall proxy market clearing price is not set by these minimum load costs*.

Finally, analysis presented in Mr. Tranan's own testimony demonstrates that, in practice, the mixed heat rate approach would result in essentially the same level and "inverted" pattern of mitigated prices as the "average heat rate" approach preferred by sellers. Since the mixed heat rate approach continues to allow the mitigated price to be set based on the extremely high average heat rates of units operating at low load levels, this approach continues to result in mitigated prices that defy basic laws of supply and demand by being higher during off-peak hours than during peak hours. Thus, similar to the "average heat rate" approach preferred by sellers, Mr. Tranen's mixed heat rate approach would provide unreasonable windfalls to sellers on the grounds that such a mechanism is necessary to ensure recovery of the minimum load costs for every generator during each 10-minute interval directly through the mitigated price applied to mitigate all market transactions covered under the July 25 refund methodology.

Q. WHAT ARE YOUR VIEWS ON THE PROPOSALS BY SOME OF THE SELLERS' WITNESSES TO SET THE MITIGATED PRICE BASED ON THE MAXIMUM SHORT-RUN MARGINAL COSTS AND AVERAGE VARIABLE COSTS?

A. Both Mr. Adamson and Dr. Cicchetti proposed approaches that would appear to have the effect of setting the mitigated price based on the maximum of the incremental or average costs of each unit. Mr. Adamson has proposed that the mitigated price be "set equal to system short-run marginal costs, as long as these are above average variable costs." Ex. No. ENR-1 (Adamson) at 6:5-6. Dr. Cicchetti draws on alleged economic theory to make a similar proposal:

> Economic theory requires price to equal or exceed average variable (or running cost). Therefore, incremental heat rates should not be used to determine the MMCP unless the incremental heat rate exceeds the

> corresponding average heat rate for a specific level of unit output. This economic proposition requires that start-up and other variable production costs should be included in the conceptually correct determination of the MMCP. Ex. No. SEL-1 (Cicchetti) at 26:14-19

Both proposals are seriously flawed. First, as with the mixed heat rate approach proposed by Mr. Tranen, these proposals are designed to ensure full cost recovery for every unit for every interval of the refund period. The fact that cost recovery is not relevant in determining the appropriate mitigated price is ignored. Second, the claim that these proposals are supported by economic theory is totally unfounded. There is no economic principle that suggests that price needs to equal or exceed average variable cost, even when there is only one market or source of revenue for suppliers. More importantly, as noted above, the participants in the ISO Real Time Market for energy have various other sources of revenues (e.g., bilateral contracts, RMR contracts).

<u>ISSUE 2: DISPATCH VS. OPERATING LEVEL</u>

Q. SELLERS ARGUE THAT THE HEAT RATE OF A UNIT SHOULD BE SELECTED BASED ON ITS METERED GENERATION LEVEL, RATHER THAN ON THE LEVEL AT WHICH THE UNIT WAS DISPATCHED TO PROVIDE ENERGY IN THE ISO'S REAL TIME MARKET. DO YOU AGREE?

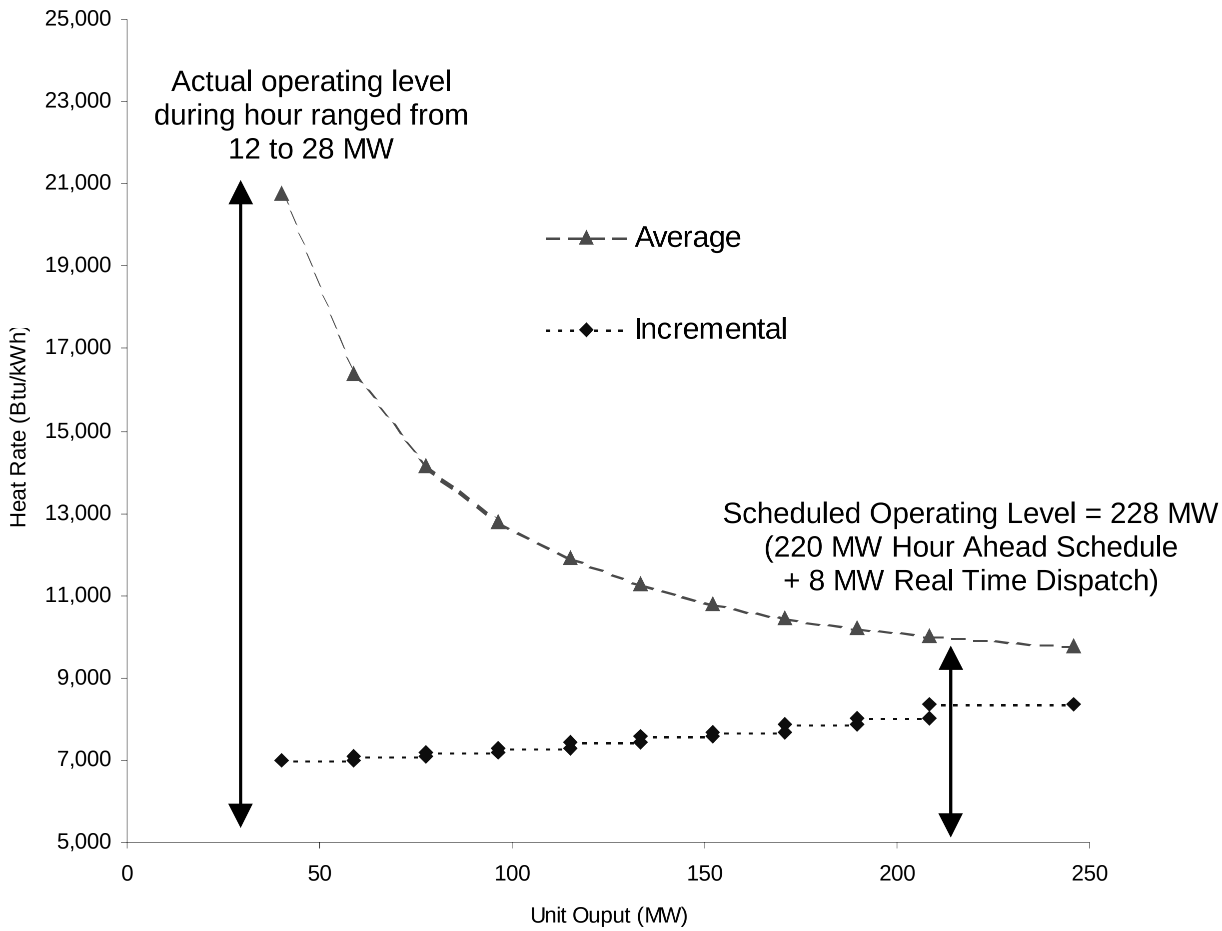
A. No. At least three of the sellers' witnesses propose using metered generation levels to identify a unit's operating point for purposes of selecting the appropriate heat rate for that unit during specific intervals, as opposed to using the generation level at which the unit was dispatched. Ex. No. GEN-1 (Tranen) at 4:15-5:2; Ex. No. PWX-5 (Prepared Responsive Testimony of Judith Cardell) at 12:8-11; Ex. No. ENR-1 (Adamson) at 20:11 – 21:21. There are, however, many instances during the refund period where the actual operating level of a unit did not reflect the unit's dispatch instruction, or its total scheduled operating level. To the extent the actual operating point does not reflect the dispatch instruction, the generator is undertaking an uninstructed deviation. Mr. Tranen admits on page 41 of his testimony that uninstructed deviations should be excluded from setting the price (Ex. No. GEN-1 (Tranen) at 41:12-15), yet the methodology proposed by Mr. Tranen and other witnesses for the sellers to select heat rates based on metered generation levels does just that. This position confuses the concept of "dispatch" and "metered operations" and is therefore inconsistent with the Commission Orders, which consistently instruct the ISO to select the marginal unit based on the "last unit *dispatched*."

Use of metered generation levels without any screening or other limitations would be particularly inappropriate if it were combined with the use of average heat rates, which tend to be extremely high for steam units operating at low load levels (see unit heat rates graphs in Ex. No. ISO-8). Ironically, when average heat rates are used in conjunction with metered generation levels, any steam unit that is dispatched but grossly under-generates or even goes off-line can easily become the "marginal" unit upon which the mitigated price is set.

Q. **CAN YOU PROVIDE AN EXAMPLE OF HOW USE OF METERED GENERATION LEVELS RAISES THE MITIGATED PRICE ?**

A. Yes. One illustrative example is Coolwater Unit 3 (CWATER_7_UNIT 3) on operating date January 18, 2001 operating hour 9. During intervals 2 through 6 of this hour, both Mr. Tranen and Dr. Cardell identify Coolwater Unit 3 as the marginal unit upon which the mitigated price would be set based on their methodologies. During these intervals, the Coolwater Unit's Final Hour Ahead Schedule was 220 MW; after submittal of the Final Hour Ahead Schedule, the unit was then dispatched to provide an additional 8 MW of incremental energy by the ISO. This represents a total scheduled operating level (or "Acknowledged Operating Target") of 228 MW. However, the actual operating level of this resource for these intervals ranged from only 12 to 28 MW, representing a negative uninstructed deviation of over 200 MW. Yet, the results presented on behalf of the generators show this resource setting the mitigated price at its average heat rate of 20,746 Btu/kWh based on its actual operating level (Figure 3). This example illustrates the perverse impact that would result if the heat rate were calculated at the actual operating point as opposed to the scheduled dispatch of the unit. As illustrated in this example, generators would be rewarded for not delivering energy in response to a dispatch notice if the methodology proposed by the sellers' witnesses were to be adopted. The result is also inconsistent with Mr. Tranen's own testimony in which he explicitly states that Uninstructed Energy should be excluded. Ex. No. GEN-1 (Tranen) 41:11-15. As illustrated by this example, uninstructed deviations in fact have a major impact on results under his methodology.

Figure 1: Average and Incremental Heat Rate For CWATER_7_UNIT 3



Q. DOES THE ISO'S METHODOLOGY INCORPORATE UNINSTRUCTED DEVIATIONS?

A. No. The ISO's approach is based on scheduled operating levels. However, it is likely that the net effect of this is to overestimate the mitigated price. For example, one of the sellers' own witnesses provided analysis indicating that the Acknowledged Operating Target (AOT) used in the ISO's methodology tends to ***overestimate*** the actual operating level of the marginal unit. Ex. No. ENR-1 (Adamson) at 20:12 – 21:21.[2] Since the monotonic incremental heat rates used in the ISO's analysis typically increase at higher levels of unit output (and never decrease), use of an AOT that is higher than actual metered generation can only tend to *overestimate* the actual incremental heat rate of the unit. Thus, Mr. Adamson's finding serves to indicate that the ISO's approach of relying on scheduled operating levels tends to overestimate the actual marginal cost of the marginal unit dispatched in the real time market.

[2] As noted by Mr. Adamson, of the 20 units most frequently identified as marginal units in the ISO's analysis (accounting for 76% of all intervals during the refund period), actual generation levels were more than 5% below the AOT used in the ISO's analysis for 51% of the intervals, but were more than 5% above the AOT in only 19% of the intervals. In addition, in 5% of the intervals,

Q. WOULD YOU RECOMMEND CONSIDERATION OF THE USE OF ANY OTHER ALTERNATIVES RATHER THAN THE ACKNOWLEDGED OPERATING TARGET USED IN YOUR METHODOLOGY OR THE METERED GENERATION LEVELS USED BY THE SELLERS' WITNESSES?

A. It may be appropriate to consider metered generation levels and uninstructed deviations from schedules in cases where metered generation indicates that units operated at levels significantly below scheduled or dispatched levels. Specifically, it may be appropriate to utilize metered generation levels to "screen out" units that did not deliver energy pursuant to dispatches (i.e., making them ineligible to set the mitigated price for that interval). This adds some additional complexity to the analysis, but provides a more reasonable indication of the marginal gas-fired unit dispatched to meet demand in the Real Time Market that actually helped to "keep the lights on".

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the marginal units were found to have no metered generation at all. Ex. No. ENR-1 (Adamson) at

<u>ISSUE 3: OUT-OF-MARKET AND OUT-OF-SEQUENCE PURCHASES</u>

Q. SELLERS ALSO ARGUE THAT THE "UNIVERSE OF UNITS" THAT SHOULD BE USED IN THE CALCULATION OF THE MARGINAL UNIT SHOULD INCLUDE UNITS CALLED BY THE ISO TO PROVIDE ENERGY THROUGH OUT-OF-MARKET AND OUT-OF-SEQUENCE REQUESTS. DO YOU AGREE?

A. No. Most of the sellers' witnesses have proposed expanding the "universe of units" that may set the mitigated price to include units providing energy through out-of-market ("OOM") and out-of-sequence ("OOS") requests. Ex. No. ENR-1 (Adamson) at 24:3-8, 24:14 – 27:15; Ex. No. GEN-1 (Tranen) at 30:1-21 (OOS) and 35:6 - 36:23 (OOM); Ex. No. SEL-1 (Cicchetti) at 15:24-17:12, 43:11-18, 44:14 – 45:7 (OOM), and 43:22 – 44:101-13 (OOS). Mr. Tranen reiterated this argument in his supplemental testimony. Ex. No. GEN-19 (Tranen) at 4:1-11. As discussed in my initial testimony, these arguments erroneously suggest that OOM and OOS requests are equivalent to dispatches in the ISO's Real Time Market, and should set overall market clearing prices in the ISO's Real Time Market. Moreover, this argument ignores the fact that in many cases, gas-fired units that received OOS and OOM calls by the ISO were steam units that were called by the ISO to start up or continue generating at minimum operating levels for the entire operating day in the

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20:12 – 21:21, 23:13-18.

event they were needed to provide additional energy. This trend, combined with the use of average heat rates by the sellers' witnesses, dramatically skews the maximum average heat rate of the pool of units from which the marginal unit is selected under the sellers' methodologies.

Q. ONE OF THE SELLERS' WITNESSES ARGUES THAT THE ISO IMPROPERLY EXCLUDED A NUMBER OF UNITS THAT WERE DISPATCHED THROUGH THE BEEP STACK FROM ITS CALCULATIONS OF THE MITGATED PRICE. DO YOU AGREE?

A. No. In supplemental testimony, Mr. Tranen has suggested that "the ISO improperly excluded a number of units that were dispatched through the BEEP Stack from its MMCP calculations." Ex. No. GEN-19 (Tranen) at 12:14-16. This alleqation appears to simply be a continuation of Mr. Tranen's argument for categorizing OOS transactions as "dispatches in the real time energy market" on the grounds that these OOS transactions represent bids that were submitted into the ISO's Real Time Market, and would therefore have *appeared as bids in the BEEP stack*. Assuming this is indeed the logic underlying this portion of Mr. Tranen's supplemental testimony, this argument ignores the difference between bids that are dispatched (in merit order) *through* the BEEP system, and bids that may *appear in the BEEP stack*, but are called *out of their merit order* by ISO dispatchers for a variety of reasons related to operational reliability.

Mr. Tranen's supplemental testimony goes on to argue that the "ever-evolving production of source data has demonstrated a clear need to modify the ISO's BEEP Stack analysis." Ex. No. GEN-19 (Tranen) at 12:12-18. However, the data on units dispatched through BEEP used in the ISO's analysis ("acknowledged energy dispatches") have not changed since the start of these proceedings. The changes in source data which Mr. Tranen refers to in his testimony appear to be limited to data on OOM and OOS calls, which have never been used in the ISO's mitigated price calculations, and were only used in the calculations of Mr. Tranen and other witnesses for the sellers.

ISSUE 4: DECREMENTAL DISPATCHES

Q. AT LEAST ONE WITNESS FOR THE SELLERS CONTENDS THAT UNITS RECEIVING DECREMENTAL DISPATCHES OR DECREMENTAL OOS OR OOM REQUESTS FROM THE ISO SHOULD BE TREATED THE SAME AS UNITS RECEIVING INCREMENTAL INSTRUCTIONS IN DETERMING THE MARGINAL UNIT, I.E., THAT THE MARGINAL UNIT SHOULD BE BASED ON THE MAXIMUM COST OF ANY UNIT PROVIDING EITHER INCREMENTAL OR DECREMENTAL ENERGY IN REAL TIME DURING ANY INTEVAL. DO YOU AGREE?

A. No. Mr. Tranen's testimony explicitly states that he followed this approach. Ex. No. GEN-19 (Tranen) at 6:16-7:14. The testimonies of Dr.

Tabors, Dr. Cardell and Dr. Chicchetti do not explicitly address the issue of decremental dispatches, but provide criticisms of the ISO's methodology that suggest they propose to treat decremental dispatches in the same manner as Mr. Tranen. Ex. No. PWX-1 (Tabors) at 6:20-23; Ex. No. PWX-5 (Cardell) at 6:16-18; Ex. No. SEL-11 (Cicchetti) at 9:1-12.

Any methodology that takes the maximum cost of units that decrement (or decrease) their generation during any interval as a result of an ISO dispatch is clearly contrary to numerous references by the Chief Judge and subsequent Orders of the Commission that the mitigated price should be based on the marginal cost of the "last unit dispatched to meet load in the ISO's real time market." See, e.g., 97 FERC ¶61,275 at 62,178, 62,192.. In addition, the approach proposed by sellers is inconsistent with how the prices are actually determined in the ISO's Real Time Market and the economic principles underlying these pricing procedures.

Gas-fired units that are decremented by the ISO in real time are not being dispatched to provide any real time energy that helps to "meet load." On the contrary, gas-fired units responding to decremental dispatches represent resources *not needed to meet load* which are *decreasing* the amount of energy generated (i.e., to a level below the unit's Hour Ahead schedule submitted to the ISO by its Scheduling Coordinator). Thus, during every interval in which any gas-fired unit was dispatched in the

Real Time Market to provide energy to meet load (i.e., incremental energy), the ISO's methodology bases the mitigated price on the gas-fired unit with the highest marginal cost that was dispatched for incremental energy. The generator's methodology, which allows the mitigated price to be set by units that are decremented and provide no energy to help meet load during intervals when gas-fired units were dispatched to provide energy to meet load, is inconsistent with references in the July 25 and December 19 Orders requiring that the mitigated price be based on the last unit dispatched "*to meet load*." During these intervals, including decremental dispaches in the pool of dispatches made "to meet load" which may set the mitigated price is contrary to the language of the Commission's Orders, as well as being contrary to the economic principles used in determining marginal costs and how market clearing prices are actually set in the ISO's Real Time Market.

The second major flaw in the methodology proposed by the sellers' witnesses is evident during intervals when no gas-fired unit was dispatched in the Real Time Market to help meet load (i.e., no gas-fired units were dispatched for incremental energy). The July 25 and December 19 Orders are silent on how to calculate the mitigated prices during these intervals. However, pre-existing procedures for determining market clearing prices in the ISO's Real Time Market provide a clear and consistent guide for how the mitigated price should be set under these conditions. The ISO's approach, which mirrors how the price for incremental energy is actually set in the Real Time Market when no incremental dispatches are made, is to set the mitigated price based on the lowest cost gas-fired unit decremented in the Real Time Market. Under these conditions, the mitigated price calculated by the ISO is set based on the *lowest* cost unit decremented, since units being decremented are dispatched in *descending* – rather than ascending – order of bid price. Thus, when units are being decremented in real time by the ISO, the "last unit dispatched" is the unit with the lowest – rather than highest – bid price. The sellers' methodology, which allows the highest cost unit decremented to set the mitigated price, is inconsistent with repeated references to the "last unit dispatched" in the July 25 and December 29 Order, as well as with the economic principles governing how market clearing prices are actually set in the ISO's Real Time Market.

Q. MR. TRANEN CONTENDS THAT THE ISO'S RATIONALE FOR EXCLUDING DECREMENTAL DISPATCHES IN CALCULATING THE MITGATED PRICE (WHENEVER ONE OR MORE UNITS WERE DISPATCHED FOR INCREMENTAL ENERGY) IS BASED ON A FLAWED ASSUMPTION THAT HEAT RATES FOR UNITS BID INTO THE BEEP STACK LINE UP IN MONOTONICALLY NON-DECREASING FASHION, WITH HEAT RATES FOR INCREMENTAL BIDS ALWAYS BEING HIGHER THAN HEAT RATES FOR DECREMENTAL UNITS. IS THIS CORRECT?

A. No. The ISO's methodology does not make or rely on any assumption about whether the heat rates for incremental and decremental bids in the BEEP stack are monotonically non-decreasing. Whenever a gas-fired unit was dispatched for incremental energy, the ISO's methodology does not exclude decremental dispatches from the mitigated price calculation for the reason suggested by Mr. Tranen (i.e., based "on the fiction that the heat rates for BEEP stack units line up neatly in monotonically non-decreasing fashion, with heat rates for incremental bids always being higher than the heat rates for decremental bids." Ex. No. GEN-19 (Tranen) at 6:18-21. As I previously noted, the ISO's methodology is based on the fact that decremental dispatches do not result in the production of additional energy to meet load in the Real Time Market; thus, decremental dispatches are not relevant in determining the "last unit dispatched to meet load" during any interval when a gas-fired unit was actually dispatched to provide additional (incremental) energy to met load in the Real Time Market. Thus, whenever a gas-fired unit was dispatched for incremental energy in the Real Time Market, the ISO's methodology bases the mitigated price on the highest cost unit dispatched for incremental energy. During these intervals, the ISO's methodology does not consider (or make any assumption about) any decremental dispatches.

Q. SEVERAL OF THE SUPPLIERS' WITNESSES CONTEND THAT THE ISO'S METHODOLOGY ERRS BY NOT TAKING THE HIGHEST COST UNIT DISPATCHED FOR DECREMENTAL ENERGY DURING INTERVALS WHEN NO GAS-FIRED UNITS WERE DISPTACHED FOR INCREMENTAL ENERGY. EX. NO. GEN-19 (Tranen) at 7:16-21; EX. NO. SEL-11 (CHICCHETTI) at 9:4-12. HOW DO YOU RESPOND TO THIS?

A. During intervals when no gas-fired units were dispatched to provide incremental energy in the Real Time Market (i.e., no gas-fired unit was dispatched to provide energy to "meet load"), the ISO's mitigated price methodology replicates how the ISO's price for incremental energy is actually set when no resources are incremented. In such situations, the ISO's incremental price for energy is based on the "last unit dispatched" to decrement generation. Accordingly, the ISO's methodology for calculating the mitigated price identifies the "last unit dispatched" during these intervals based on the lowest (rather than highest) cost unit decremented by the ISO in real time, reflecting the fact that decremental bids are dispatched in descending (rather than ascending) order of price.

Q. HOW DO THE SUPPLIERS' WITNESSES DEFEND THEIR USE OF THE HIGHEST COST UNIT THAT WAS DECREMENTED IN DETERMINING THE MITIGATED PRICE?

A. In describing his approach for determining units that may set the mitigated price, Mr. Tranen states that "I determined the 'universe' of units eligible to be chosen as the marginal unit (because they were dispatched to provide real time energy)." Ex. No. GEN-19 (Tranen) 5:12-13. However, this statement does not accurately describe his actual methodology, which includes units that were *not* "dispatched to provide real time energy", but in fact simply *decreased* generation in real time after having a decremental bid accepted by the ISO as a result of a surplus of generation. In this situation, the unit would not have provided any real time energy (unless it continued to operate above its modified operating target, creating an uninstructed deviation). This aspect of the suppliers' methodology allows the mitigated price to be set by the highest cost generation that was *not* needed to meet demand and was therefore decremented by the ISO.

Dr. Tarbors and Dr. Cardell support their treatment of decremental energy dispatches by citing to a single sentence of the July 25 Order, appearing in the context of a discussion in which the Commission provided its rationale for using "historical" rather than "assumed economic dispatch" to identify the marginal unit needed to meet demand. This sentence references the "maximum heat rate of any unit dispatched each hour in the real time imbalance market." Ex. No. PWX-1 (Tabors) at 13:19-22. The suppliers' witnesses' reliance on this single passage ignores repeated, consistent references in the Chief Judge's Report and Recommendation and Commission Orders that indicate the marginal unit should be the "last unit dispatched to meet load in the ISO's real time market". 96 FERC ¶63,007 at 65,040 (Chief Judge's Repot and Recommendation on July 12, 2001); 96 FERC ¶61,120 at 61,517 (July 25, 2001 Order); 97 FERC ¶61,275 at 62,178 (December 19 Order). The December 19 Order, for example, summarizes the Commission's April 26, June 19 and July 25 Orders as being designed to mitigated prices "at a price not higher than the least efficient generating unit *needed to meet load*, for the period October 2, 2000 through September 30." 97 FERC ¶61,275 at 62,172 (emphasis added). The December 19 Order goes on to clarify that under the July 25 Order's refund methodology, hourly mitigate prices would be developed using the marginal costs of the *last unit dispatched to meet load in the ISO's real-time market*. *Id.* at 62,178 (emphasis added). Similarly, other references in the December 19 Order consistently refer to "the actual marginal costs of the *last generator dispatched.*" *Id.* at 62,202 (emphasis added).

I believe a more reasonable interpretation of these various passages is that the single passage cited by the sellers' witnesses simply addresses the most common situation in which one or more gas-fired units were actually dispatched to provide energy needed to meet load in the Real Time Market, and that the orders do not explicitly address intervals when no gas-fired units were dispatched to provide energy in the Real Time Market. Thus, the ISO's methodology relies first and foremost only on incremental dispatches (whenever a gas-fired unit was in fact dispatched for incremental energy) to identify the "last unit dispatched to meet load," and, alternatively, identifies the "last unit dispatched" based only on decremental dispatches during intervals when no gas-fired units were dispatched for incremental energy. Taking the lowest cost (rather than highest cost) unit dispatched for decremental energy during intervals when no gas-fired unit was dispatched for incremental energy is consistent with the "last unit dispatched" language of the Commission's orders, as well as with the basic economic principles used in determining how market clearing prices are actually set in the ISO's Real Time Market.

Finally, I believe it is important to note that the ISO's methodology, including the manner in which decremental dispatches are used in determining the marginal unit, was first described in filings submitted as part of the record upon which the Chief Judge's Report and Recommendation and the subsequent Commission orders were based. Nothing in these orders suggests that this aspect of the ISO's methodology and its longstanding procedures for calculating the market clearing price for incremental energy should be modified.

<u>ISSUE 5: INTERVALS WHEN NO GAS UNITS WERE DISPATCHED IN THE REAL TIME MARKET</u>

Q. SEVERAL OF THE SUPPLIERS' WITNESSES CONTEND THAT THE ISO'S METHODOLOGY FOR DETERMING THE PRICE DURING INTERVALS WHEN NO GAS-FIRED UNIT WAS DISPATCHED IS INCONSISTANT WITH THE COMMISSION'S ORDERS. HOW DO YOU RESPOND TO THESE CRITICISMS?

A. During intervals when no gas-fired unit had an incremental energy or decremental bid dispatched by the ISO, the ISO's methodology calculates the mitigated price based on the lowest cost gas-fired unit with an incremental energy bid submitted in the Real Time Market. Dr. Ciccetti characterizes this approach as "a form of market simulation that the Commission explicitly rejected," Ex. No. SEL-11 (Cicchetti) at 9:1-8, but does not propose a specific alternative. Mr. Tranen objects to the ISO's methodology on the grounds that it "conflicts with the December 19 Order's directive to select the marginal unit based on highest total cost." Yet, he proposes to calculate a mitigated price during intervals in which no units eligible to set the mitigated price had dispatch instructions based on an *average* of the mitigated prices for intervals immediately before and after intervals with no eligible dispatches, a proposal which, itself, finds no basis in the language of the Commission's Orders. Ex. No. GEN-19 (Tranen) 8:2-16.

Since the July 25 and December 19 Orders do not address this specific situation, the ISO's approach was designed to mirror how the price for incremental energy is actually determined in such situations in the ISO's Real Time Market. Unlike the approach proposed by Mr. Tranen, the ISO's approach also reflects supply conditions in each specific interval, and avoids the need to base mitigated prices in these intervals on mitigated prices during other time periods when supply/demand conditions may have been significantly different. At the same time, the ISO's approach is equally as "simple and consistent" as the approach proposed by Mr. Tranen.

ISSUE 6: UNINSTRUCTED AND RESIDUAL ENERGY

Q. SOME SELLERS ARGUE THAT THE "UNIVERSE OF UNITS" USED IN CALCULATING THE MARGINAL UNIT SHOULD INCLUDE UNITS THAT WERE NOT ACTUALLY CALLED BY THE ISO, BUT GENERATED ENERGY THROUGH AN UNINSTRUCTED DEVIATION OR GENERATED RESIDUAL ENERGY RESULTING FROM A DISPATCH DURING A PREVIOUS INTERVAL. DO YOU AGREE?

A. No. Mr. Tranen argued for the inclusion of units providing Uninstructed Imbalance Energy and Residual Energy. Ex. No. GEN-1 (Tranen) at 37:11 – 38:14. However, Mr. Tranen's proposal ignores the Commission's direction that in calculating the mitigated clearing price, that the units used in that calculation should be those that are actually "dispatched" in an ISO market. In addition, as noted in my initial testimony, units providing uninstructed or residual energy during any interval that are not actually dispatched by the ISO to provide real time energy that interval cannot set the market clearing price under the ISO's actual Real Time Market for Energy.

ISSUE 7: UNITS SCHEDULED IN PX ONLY

Q. SOME SELLERS ALSO ARGUE THAT THE UNITS SCHEDULED ONLY THROUGH THE PX SHOULD BE INCLUDED IN THE UNIVERSE OF UNITS USED TO IDENTIFY THE MARGINAL UNIT DISPATCHED IN THE ISO'S REAL TIME MARKET. DO YOU AGREE?

A. No. The sellers' witnesses who make this argument (Ex. No. ENR-1 (Adamson) at 29:5-7, 31:13-17, 32:13-17; Ex. No. PWX-1 (Tranen) at 14:8 - 15:8) have ignored the fact that units only scheduled through the PX do not directly affect the prices in the ISO's real time market. Why these units should be included in the "universe of units" eligible to set the mitigated price is not at all clear and is inconsistent with the Commission's instructions concerning calculation of the marginal price. Indeed, the language in the July 25 Order and the December 19 Order makes clear that the ISO should limit the universe to only units "dispatched" in the ISO's market.

ISSUE 8: NON-GAS FIRED RESOURCES AND IMPORTS

Q. HAS THE COMMISSION LIMITED THE GROUP OF RESOURCES ELIGIBLE TO SET THE MITIGATED PRICE DURING THE REFUND PERIOD TO THOSE RESOURCES CAPABLE OF BURNING NATURAL GAS?

A. Yes. Beginning with the April 26 Order, the marginal cost methodology developed by the Commission for mitigating prices prospectively has consistently limited the group of units eligible to serve as the marginal unit for purposes of setting the mitigated market price to gas-fired resources. In the July 25 Order, the Commission adopted this same marginal cost methodology for mitigating prices retrospectively with several modifications, but nowhere indicated that units other than those capable of burning natural gas should be eligible to set the mitigated price during the refund period. The December 19 Order contains an extensive discussion of the gas prices to be used in determining the marginal costs of generating units eligible to set the price, and indicates that the mitigated price shall be calculated based only on the specific marginal cost formula provided in the July 25 Order. Moreover, the December 19 Order clarified that the mitigated price used in determining refunds may *not* be set based on costs claimed by sellers of several specific types of non-gas resources, such as hydroelectric resources or resources derived from purchased power (such as pumped storage). As explained 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 . . . . [T]he Commission will provide an opportunity after the conclusion of the refund hearing for marketers and those reselling purchased power or selling hydroelectric power to submit evidence as to whether the refund methodology results in an overall revenue shortfall for their transactions in the ISO and PX spot markets during the refund period. 97 FERC ¶61,275 at 62,253 – 62,254 (emphasis added).

Since gas-fired units are the only resources for which the July 25 Order specifies a fuel price to be used in determining "assumed" marginal costs, the Commission's clarification that the "actual costs" of any resources "would not be relevant to the determination of the mitigated price in each hour of the refund period pursuant to the refund methodology" further reinforces the conclusion that the mitigated price is to be based only on gas-fired units.

Q. DID THE ISO INADVERTENTLY INCLUDE SOME RESOURCES THAT WERE NOT CAPABLE OF BURNING NATURAL GAS IN THE UNIVERSE OF RESOURCES ELIGIBLE TO SET THE MITIGATED PRICE?

A. Possibly. Mr. Strack, testifying on behalf of the California Parties, identified three resources that the ISO included in the calculation of the mitigated price. According to Mr. Strack, two of these resources do not have access to natural gas (Division GT 1 and North Island GT 1), while the third resource, Union Chemical/Tosco, runs primarily on petroleum coke. Ex. No. CAL-7 (Prepared Responsive Testimony of Jan J. Strack) at 11:16-12:7.

Q. DO YOU AGREE WITH DR. STERN THAT THESE RESOURCES SHOULD BE INELIGIBLE TO SET THE MITIGATED PRICE?

A. Yes, as outlined in the testimony of Dr. Stern, the Commission's Orders, as well as economic principles indicate that these resources should not be allowed to set the mitigated price. To the extent it is established (through the Presiding Judge's findings of fact or through stipulation) that any of these units did not burn gas, or operated primarily on fuels other than gas during the refund period, the unit or units should be excluded from any further calculations of mitigated prices that might be done for the refund period.

Q. WHAT ABOUT SELLERS WHO CLAIM THAT IMPORT TRANSACTIONS SHOULD BE ELIGIBLE TO SET THE MITIGATED PRICE? EX. NO. AEP-12 (BRAY) AT 4:1 – 5:15.

A. In response to requests for rehearing filed by several sellers, the December 19 Order clarifies that imports may not set the mitigated price during the refund period under the July 25 Order, on the grounds that any attempt to factor in heat rates for these resources would be "extremely speculative" and is not likely to significantly affect the mitigated price. 97 FERC ¶61,275 at 62,202. The December 19 Order also clarifies that gas-fired resources outside the ISO system may only be eligible to set the mitigated price on a *prospective* basis under the June 19 Order, and even then only if heat rate and gas source data is provided to the ISO. *Id*. at 62,203.

The Commission's decision to prohibit imports from setting the mitigated price on a retrospective basis, while allowing imports provided by gas-fired generation outside the ISO system to set the prospective mitigated price (subject to provision of required heat rates and gas source data to the ISO *before the fact*) is logical in light of the tremendous difficulty that would be involved in verifying *after the fact* that imports were provided by specific gas units outside the ISO system. While gas-fired units within the ISO system are directly metered and dispatched by the ISO, the ISO does not have the necessary information to trace imports to specific generating resources.[3] Any retrospective process for verifying the specific source of imports by sellers over the refund period would be, at best, an extremely burdensome endeavor that would be subject to gaming by sellers with portfolios of resources, from which it may be impossible to determine a specific generating unit and gas source used to meet any specific sale in

[3] Significantly, although the June 19 Order allows generating units outside the ISO system to set the mitigated price on a prospective basis subject to provision of the required heat rate and gas

the PX or ISO markets. Thus, as a practical matter, the Commission's decision to base the mitigated price used in the refund formula only on gas-fired units within the ISO system clearly reflects the fact that "the Commission selected a remedy with theoretical underpinnings that, at the same time, could be *reasonably implemented*." 97 FERC ¶61,275 at 62,202 (emphasis added).

<u>ISSUE 9: DUAL FUEL UNITS</u>

Q. PLEASE COMMENT ON DR. STERN'S RECOMMENDATION THAT RESOURCES CAPABLE OF BURNING NATURAL GAS AS WELL AS OTHER FUELS SHOULD BE INELIGIBLE TO SET THE MITIGATED PRICE FOR PERIODS WHEN THE RESOURCES WERE OPERATING USING FUELS OTHER THAN NATURAL GAS.

A. Dr. Stern has recommended that the ISO's calculations be "corrected to make ineligible to set the mitigated market-clearing price cap for a given hour any unit that was not running on natural gas in that hour." Ex. No. CAL-1 (Stern) at 10:20-21. In principle, I agree with the rationale provided by Dr. Stern for this recommendation. However, the ISO does not have the resources to definitively investigate and determine the actual fuel source being used during every interval by each dual fuel unit over the refund period. Thus, to the extent it is established (through the ALJ's

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source data, no sellers have taken steps to submit the data that would be necessary to make imports from gas-fired units eligible to set the mitigated price on a prospective basis.

findings of fact or through stipulation) that a unit was not burning gas, I believe the unit should be excluded from any further calculations of mitigated prices that might be done for the refund period. If the specific time periods when dual fuel units were burning gas cannot be determined, units that do not primarily burn gas could be excluded from setting the mitigated price. Also, heat rates for any dual fuel units eligible to set the mitigated price should represent the heat rate applicable to burning natural gas.

ISSUE 10: CALCULATION OF AN AVERAGE HOURLY MITIGATED PRICE

Q. DO YOU AGREE WITH THE PROPOSAL BY MR. TRANEN CONCERNING HOW TO CALCULATE AN AVERAGE HOURLY MITIGATED PRICE FOR USE IN DETERMINING REFUNDS IN THE PX AND ANCILLARY SERVICE MARKETS?

A. No. Mr. Tranen proposes to use a weighted average approach that is inconsistent with the July 25 Order, as well as basic mathematical logic. He has proposed an inappropriate weighted average of the six interval prices. Ex. No. GEN-1 (Tranen) at 50:6-11. First, it is important to note that – as described in my previous testimony -- the use of a simple average of the six 10-minute interval prices for transactions in hourly markets is most consistent with the specific language of the July 25 Order. Ex. No. ISO-1 (Hildebrandt) at 55:13 – 56:14.

Mr. Tranen's approach is flawed in that it calculates a weighted average based on one group of transaction quantities for each interval within an hour (i.e., gas-fired generation within the ISO system in excess of final hour head schedules), and then applies this weighted average to an entirely *different* set of transactions that are made on an hourly basis (i.e., for energy or capacity to be delivered in *equal* quantities for each of the six 10-minute intervals within the hour). This weighted average proposed by Mr. Tranen is entirely unnecessary and inappropriate because, for these hourly transactions, the true quantity weighted average of the six interval prices is equal to the *simple* average of these interval prices.

Q. CAN YOU GIVE AN EXAMPLE ILLUSTRATING THIS STATISTICAL PRINCIPLE?

A. Certainly. Figure 4 illustrates the fundamental difference between Mr. Tranen's approach and the approach used by the ISO based on specific language in the July 25 Order. This example assumes the following:

- A total of 150 MWh was transacted in the PX during the hour, or 25 MWh per 10-minute interval (as shown in column A of Figure 4).

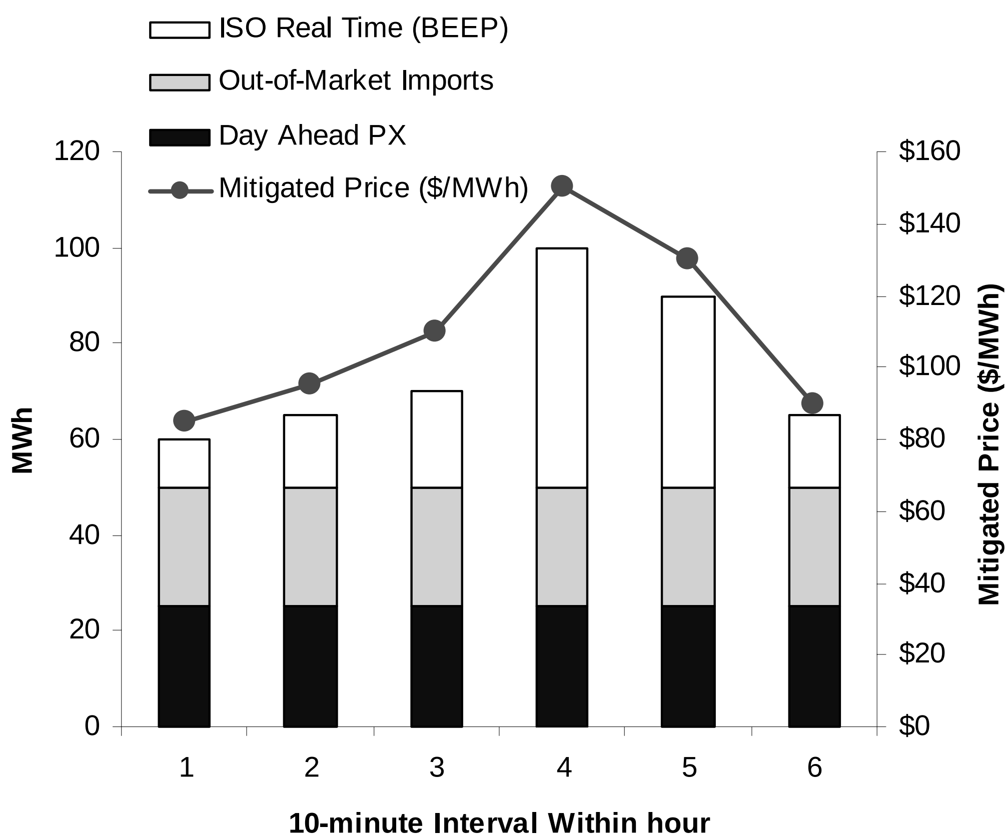
- A total of 150 MWh was purchased by the ISO Out-of-Market from suppliers outside the ISO system or 25 MWh per 10-minute interval (as shown in column B of Figure 4).
- A total of 150 MWh was purchased in the ISO's Real Time Market from gas-fired resources within the ISO system (delivered in the quantities for each 10-minute interval shown in column C of Figure 4).
- The mitigated prices for each 10-minute interval are shown in Column E of the table in Figure 4.

Under each of the different approaches used by the ISO and Mr. Tranen, the amount of gas-fired generation actually dispatched on a 10-minute basis (Column C) would be settled at the corresponding prices for each 10-minute interval. However, under Mr. Tranen's methodology, the hourly weighted average of these transactions would be applied to several entirely different sets of transactions that are all made on an hourly basis, which include: the PX Day Ahead market, Out-of-Market purchases of imports made on an hourly basis, and hourly capacity purchases made in the ISO's hourly Ancillary Service markets.

As shown in Figure 4, the hourly mitigated price based on Mr. Tranen's methodology would be $124, or the weighted average of the six 10-minute interval prices multiplied by the volume of energy purchased in the ISO's Real Time Market from gas-fired resources within the ISO system during each of these 10-minute intervals (see bottom row of column C).

However, as shown in Figure 4, the actual weighted average of the mitigated price of energy delivered as a result of energy transactions made on an hourly basis would be only $110 (see bottom row of columns A and B). This illustrates the basic mathematical fact that for transactions made for the delivery of energy or capacity on an <u>hourly</u> basis (i.e., for energy or capacity to be delivered in <u>equal</u> quantities for each of the six 10-minute intervals within the hour), the true weighted average of the six interval prices is equal to the simple average of the interval prices.

Figure 4. Example of Interval Prices and Quantities



	(A)	(B)	(C)	(D)	(E)
Interval	PX	OOM (Imports)	BEEP	Total (MWh)	MMCP
1	25	25	10	60	$85
2	25	25	15	65	$95
3	25	25	20	70	$110
4	25	25	50	100	$150
5	25	25	40	90	$130
6	25	25	15	65	$90
Total MWh	150	150	150	450	
Avg. $/MWh	$110	$110	$124	$115	

Q. IS MR. TRANEN'S APPROACH CONSISTENT WITH THE ISO'S TARIFF?

A. No. First, the transactions that make units "eligible to set the mitigated market clearing price" under Mr. Tranen's calculations are not at all like those actually used to set market clearing prices in the Real Time Market, as discussed in my previous testimony. Second, the quantities (or transaction volumes) used in Mr. Tranen's approach are not at all similar to those used in calculating the ISO's actual ex-post price. Again, the quantities used in the actual calculation are limited to the volumes actually dispatched through the Real Time Market (BEEP). Mr. Tranen uses many gas-fired units and volumes not dispatched through BEEP in his calculation (including uninstructed generation), while excluding all energy purchased through BEEP from imports and non-gas resources within the ISO system. Finally, Mr. Tranen's calculation is based on a single mitigated price that is only somewhat analogous to the actual market clearing price for incremental energy in the ISO's Real Time Market. In practice, however, the ISO's actual ex-post price is calculated by applying a separate decremental price -- which is always equal to or lower (and often significantly lower) than the incremental price -- to the volume of decremental dispatches made through the BEEP system.

In sum, although Mr. Tranen criticizes the simple average used in the ISO's calculation on the alleged grounds that it is inconsistent with the ISO

Tariff, in fact it is the weighted average approach that he recommends that is dramatically different from the formula specified in the ISO Tariff. Moreover, Mr Tranen's approach ignores basic mathematical logic which can be used to show that the hourly price referenced in the July 25 order should be based on the simple average of 10-minute interval prices, given that this hourly price is specifically to be used only in calculating refunds for transactions representing an equal quantity of energy or capacity to be delivered each 10-minute interval within each hour.

SECTION III. OTHER ISSUES.

ISSUE 11: USE OF MITIGATED PRICE AS A PRICE CAP IN DETERMINING REFUNDS

Q. DO YOU AGREE WITH THE CONTENTION THAT THE COMMISSION INTENDED FOR ANY TRANSACTION PRICES LOWER THAN THE MITIGATED PRICE TO BE "RE-SETTLED" AT THE HIGHER MITIGATED PRICE?

A. No. The argument made by the sellers' witnesses (Ex. No. SEL-11 (Cicchetti) at 7:8 – 12:7; Ex. No. GEN-1 (Tranen) at 50:12 – 54:11) that the mitigated price should be used as a *substitute* price rather than a *limit* on actual prices is inconsistent with specific language provided in Commission's Orders in this docket, economic principles, and the overall goal of the July 25 Order.

Q. WHAT SPECIFIC LANGUAGE REQUIRES THAT THE MITIGATED PRICE BE USED AS A CAP RATHER THAN AS A NEW MARKET CLEARING PRICE IN DETERMINING REFUNDS?

A. The July 25 Order and previous orders in these proceedings are not "silent" on this issue, as Dr. Cicchetti contends, and, in fact, these Orders provide numerous references to the mitigated price being used as a price cap. As noted in my initial testimony, the July 25 Order states that "the hourly mitigated price established in the hearing" would "establish the *maximum price* with refunds for transactions over this level." 96 FERC at 61,515 (emphasis added).

Dr. Cicchetti claims that it is reasonable for the Commission to have been silent on this issue because "its policy on refunds is so well settled and established." Ex. No. SEL-1 (Cicchetti) at 8: 13-18. However, the Commission has consistently used the terms "mitigated market clearing price" or "market clearing proxy price" to refer to prices used as a cap (or upper limit) on transaction prices, rather than as a new or substitute price to be applied for all transactions. For example, in its March 9 Order, [4] in which the Commission first specified a methodology for determining refunds in this docket, the Commission established what it called a "proxy market clearing price approach" designed to approximate the outcome of competitive market conditions. Under this approach, a "proxy market clearing price" was established based on the heat rate of a marginal gas unit and spot market gas prices, with all transactions *over this proxy market clearing price* being subject to refund. The July 25 Order grants requests for rehearing of the March 9 Order by extending "the application of price mitigation during all hours." 96 FERC ¶61,120 at 61,521.

[4] FERC Order Directing Sellers to Provide Refunds of Excess Amounts Charged for Certain Electric Energy Sales During January 2001, or, alternatively, to Provide Further Cost or other Justification for Such Charges in Docket Nos. EL00-95-000, *et al*. 94 FERC ¶61,245 (March 9, 2001 Order).

The April 26 and June 19 Orders continued to utilize the terms "mitigated" or "market clearing proxy price" or "proxy market clearing price" to mean a maximum price limit, not a floor as well where unmitigated bids resulted in a lower market clearing price. 95 FERC ¶61,115 at 61,358-61,360 (April 26, 2001 Order); 95 FERC ¶61,418 at 62,555-62,559 (June 19, 2001 Order). Nothing in the July 25 Order or in the recommendation of the Chief Judge suggests anything to the contrary, and it would be irrational to presume otherwise. The object of this entire exercise is to disgorge the fruits of unjust and unreasonable prices charged by suppliers, not to further reward sellers at times when they were provided competitive returns. As summarized in the December 19 Order:

> For the last year, the Commission has worked to correct the market dysfunction, and possible exercise of market power, that it believes are the cause of the *price increases*. As explained below, we have mitigated prices to ensure they are no higher than those that would result in a competitive market, *i.e., at a price no higher than the cost of the least efficient generating unit needed to meet load*, for the period October 2, 2000 through September 30, 2002, when we predict conditions to be adequate to revert to pricing based on market prices without regulatory price intervention. 97 FERC ¶61,275 at 62,172 (emphasis added).

Q. PLEASE DEVELOP YOUR LAST POINT FURTHER. WHY WOULD THE USE OF THE MITIGATED PRICE AS A SUBSTITUTE FOR MARKET CLEARING PRICES BE INCONSISTENT WITH ECONOMIC PRINCIPLES?

A. The application of the mitigated price as a cap simply reflects the fact that the impacts of market power or other market dysfunctions are asymmetrical: prices spike when markets are not competitive, but do not drop below competitive levels when markets are workably competitive. The fact that actual market prices were sometimes *lower* than the mitigated price calculated pursuant to the July 25 Order may simply reflect the fact that the formula for calculating incremental costs may sometimes *overestimate* the actual incremental costs of suppliers. As discussed in the testimony of Dr. Berry, data indicate that units frequently bid lower than even the marginal cost calculations based on the formula specified in the July 25 Order. Ex. No. CAL-6 (Prepared Responsive Testimony of Carolyn Berry) at 8:18-24. This indicates that these suppliers' true marginal costs are in many cases lower than the marginal costs used in the ISO's analysis.

Q. WHY IS THE USE OF THE MITIGATED PRICE AS A NEW MARKET CLEARING PRICE INCONSISTENT WITH THE COMMISSION'S OVERALL OBJECTIVE OF JUST AND REASONABLE PRICES?

A. The various Orders in this docket leading up to the July 25 Order consistently emphasize that prices *charged by suppliers* were unjust and unreasonable – not that prices *paid to suppliers* were ever unjust and unreasonable. In cases when historical transaction prices were lower than the mitigated price calculated pursuant to the July 25 Order, applying the mitigated price as a new transaction price would be tantamount to finding that historical prices were "unjust and reasonably" low and would result in additional payments from buyers to sellers during many time periods, if not for the entire refund period as a whole.

ISSUE 12: ANCILLARY SERVICE PRICES

Q. ONE OF THE SELLERS' WITNESSES ARGUES THAT THE MITIGATED PRICE CALCULATED PURSUANT TO THE JULY 25 ORDER SHOULD NOT BE APPLIED TO TRANSACTIONS IN THE ISO'S ANCILLARY SERVICE CAPACITY MARKETS. DO YOU AGREE?

A. No. The Chief Judge recommended that in order to "re-create the outcome of a competitive market . . . the methodology set forth in the [Commission's June 19, 2001 Order should] be used with [certain modifications] in order to calculate any potential refunds that may be due to customers in the CAISO's and Cal PX's spot energy *and ancillary service markets.*" 96 FERC ¶63,007 at 65,039-65,040. The July 25 Order incorporated the Chief Judge's recommendation, except where otherwise noted, but the July 25 Order left intact the Chief Judge's recommendation with respect to Ancillary Services. There is simply no basis for Dr. Cicchetti's claim that the Commission intended to exclude the ISO's Ancillary Service markets from refund liability. Ex. No. SEL-1 (Cicchetti) at 70:5-18.

Furthermore, the December 19 Order clarified that:

> The arguments of Duke and Dynegy regarding mitigated prices in other ISO markets are similar to those addressed in the section on the treatment of Ancillary Service. As we explain there, *it is appropriate to have separate market clearing prices for each Ancillary Service, capped by the Imbalance Energy mitigated reserve deficiency MCP*. 96 FERC ¶63,007 at 62,203 (emphasis added).

ISSUE 13: EMISSIONS COSTS

Q. AT LEAST ONE OF THE SELLERS' WITNESSES ARGUES THAT NOX EMISSIONS COSTS SHOULD BE INCLUDED IN THE MITIGATED PRICE. DO YOU AGREE?

A. No. Two of the sellers' witnesses ignored the direction provided by the July 25 Order and argued for inclusion of NOx emissions costs in the mitigated price calculation in their initial responsive testimony. Ex. No. ENR-1 (Adamson) at 50:1-9; Ex. No. SEL-1 (Cicchetti) at 56:9-15. In his supplemental responsive testimony, Dr. Cicchetti acknowledged that the Commission in its December 19 Order had determined that emissions costs should be excluded from the mitigated price calculations; the other witness, Dr. Adamson, did not file supplemental responsive testimony. Ex. No. SEL-11 (Cicchetti) at 3:3-8.

In the December 19 Order, the Commission clarified that emissions costs are not to be considered in calculating the mitigated price under the refund formula in the December 19 Order, reiterating that:

> The July 25 Order permitted generators to recover in full all of the demonstrable emissions costs incurred during the refund period.

> The order provided that sellers will submit their emissions costs during the refund hearing for subtraction from their respective refund liabilities. We also explained why it would not be appropriate to include these costs in the calculation of the mitigated Market Clearing Prices. 97 FERC ¶61,275 at 62,207.

ISSUE 14: START-UP COSTS

Q. AT LEAST ONE OF THE SELLERS' WITNESSES ARGUES THAT START-UP COSTS SHOULD BE INCLUDED IN THE MITIGATED PRICE. EX. NO. ENR-1 (ADAMSON) at 39-48. DO YOU AGREE?

A. No. In the December 19 Order, the Commission clarified that it "will not allow any additional cost items to be included in the refund formula," since "[t]o hold otherwise would be inconsistent with our marginal cost based approach." 97 FERC ¶61,275 at 62,214. The Order went on to specifically exclude start-up costs, explaining that:

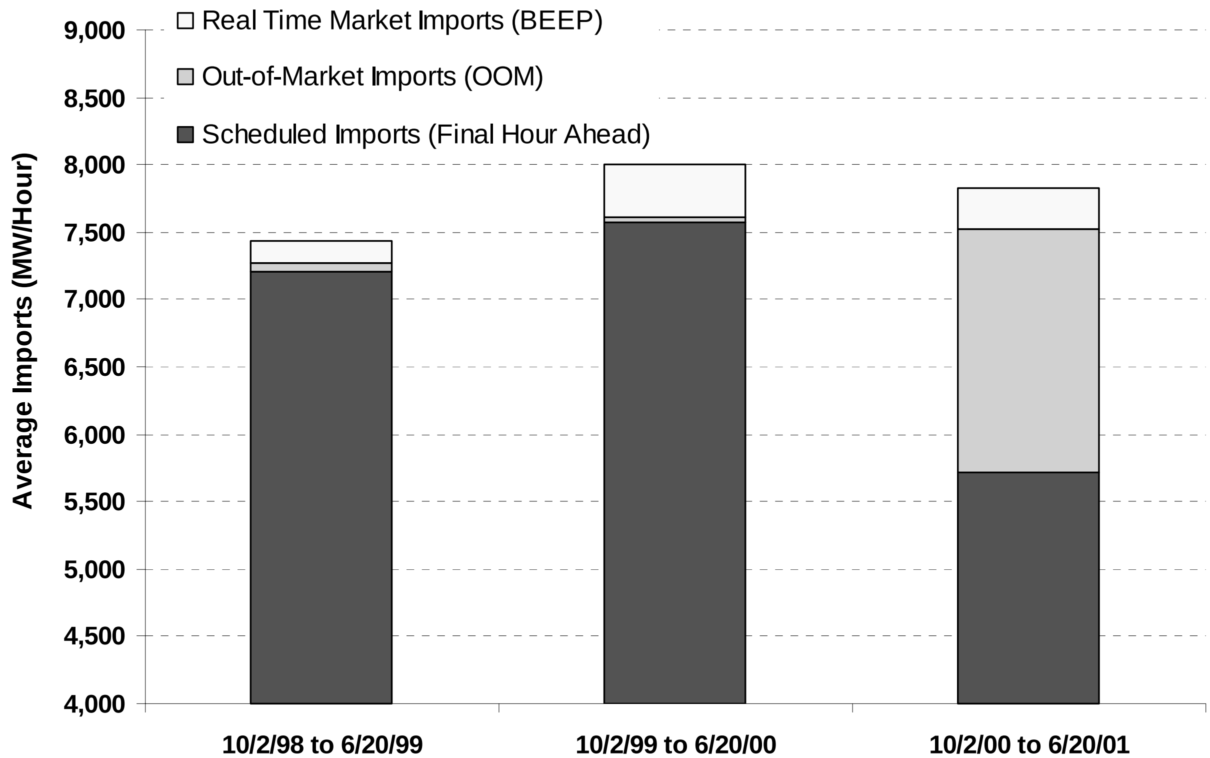
> [W]e will not permit start-up fuel costs to be recovered under the refund methodology. It will be impossible to reconstruct and demonstrate what gas costs were incurred strictly for start-up that are not otherwise recoverable. For example, a unit may have incurred start-up costs in order to be available to provide spinning reserves (which is a capacity Ancillary Service). In this instance, it would be inappropriate to seek double recovery of those costs. Moreover, these start-up costs were allowed to be recovered in the June 19 Order because of the impact of the must-offer requirement, and that requirement was not in place during the refund period. *Id.* at 62,215.

<u>ISSUE 15: IMPACT OF OUT-OF-MARKET PURCHASES OF IMPORTS BY CERS ON REAL TIME MARKET CLEARING PRICES</u>

Q. ONE OF THE SELLERS' WITNESSES ALLEGES THAT THE ISO AND CDWR SOUGHT TO LOWER THE MARKET CLEARING PRICE BY PURCHASING ADDITIONAL OUT-OF-MARKET OR OUT-OF-SEQUENCE ENERGY. DO YOU AGREE?

A. No. Mr. Adamson contends that "the way in which BEEP quantities and prices appear to have been actually managed was based on determining the quantity of OOM or OOS required," and that "[t]his would change the effective volume of energy taken out of the BEEP stack." Ex. No. ENR-1 (Adamson) at 26:1-4. However, Mr. Adamson does not present any evidence of this, nor do the quantities of imports into the ISO system indicate any such "overpurchasing" of imports. Figure 5 shows average hourly imports over the refund period compared to the same time period in previous years since the ISO has been in operation. As shown in Figure 5, overall imports actually dropped during the refund period compared to the same months of the previous year, despite the fact the out-of-market purchases of imports increased dramatically in the refund period. Figure 5 illustrates how during the refund period out-of-market purchases of imports simply replaced imports that were sold through the PX Day Ahead market during prior years. Thus, while the amount of generation from resources within the ISO Control Area ultimately depends on the difference between system loads and imports, it seems unreasonable to conclude that out-of-market purchase of imports by the ISO and CERS during the refund period "biased" the quantity and price of energy purchased from resources within the control area downwards, as Mr. Adamson contends.

Figure 5. Average Hourly Imports by Source



	Scheduled Imports (Final Hour Ahead)	Out-of-Market Imports (OOM)	Real Time Market Imports (BEEP)	Total Imports
10/2/98 to 6/20/99	7,208	62	165	7,435
10/2/99 to 6/20/00	7,577	30	396	8,003
10/2/00 to 6/20/01	5,715	1,810	303	7,828

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.