UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

California Independent System Operator Corporation	))	**Docket No. ER06-___-000**

PREPARED DIRECT TESTIMONY
OF
KEITH CASEY

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Keith Casey. My business address is 110 Blue Ravine Road, Folsom, California 95630.

Q. By whom and in what capacity are you employed?

A. I am the Director of Market Monitoring for the California ISO ("CAISO").

Q. Please describe your professional and educational background.

A. I have over 8 years of experience with the CAISO in the Department of Market Monitoring ("DMM"). Prior to July 2005, the Department of Market Monitoring was titled the Department of Market Analysis ("DMA"). The department name was changed as a result of a corporate reorganization. From December 1997 through 2000, I worked as a staff economist for the DMA and was primarily responsible for developing a market monitoring system and conducting various technical analyses of market performance issues. During this period, I also served as a liaison to the CAISO Market Surveillance Committee and assisted them in developing their various analyses, reports, and recommendations. From 2001 through June 2005, I served as a Manager of Market Analysis and Mitigation for the DMA and was responsible for assessing the effects of market rules and design features on CAISO market performance, and for developing market redesign proposals to enhance market efficiency. From 2002 through June 2005, I was responsible for developing the market power mitigation provisions under the

Market Redesign and Technology Upgrade ("MRTU") initiative. In July 2005, I was named Director of Market Monitoring for the CAISO. In this capacity, I remain responsible for finalizing the market power mitigation proposal included in this filing.

I received a Ph.D. in Environmental and Resource Economics from the University of California, Davis in 1997. Prior to working at the CAISO, I conducted post-doctoral research and taught environmental economics at the University of California, Davis. A copy of my resume is provided as Appendix 1 to my testimony.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of the first part of my testimony is to: (1) describe the market power mitigation provisions being proposed under MRTU, (2) briefly explain the history of how these provisions were developed including the stakeholder input received and alternative provisions considered, and (3) explain why the final proposed provisions are reasonable and the best choice among the alternatives considered.

The purpose of the second part of my testimony is to: (1) describe the rules for an instrument available to Scheduling Coordinators ("SCs") under the MRTU Tariff that will effectuate contractual delivery of energy through the CAISO's settlement services ("Inter-SC Trades of Energy"); (2) explain how this instrument is consistent with the settlements resolving the "Seller's Choice" problem associated with certain bilateral energy contracts entered into by the State of California; and (3) explain why the option chosen by the CAISO for determining the weighting of Trading Hub prices as part of the Inter-SC Trade instrument is clearly reasonable and the most appropriate option among those considered by the CAISO and stakeholders as well.

II. EXECUTIVE SUMMARY

A. <u>Market Power Mitigation</u>

Q. Please summarize the most critical changes in the California energy markets in recent years that are relevant to the market power mitigation measures in the MRTU Tariff filing.

A. California's wholesale energy market has changed dramatically since the energy crisis in 2000-2001. Two critical changes are the high degree of forward energy contracting by load serving entities and the development of a Resource Adequacy ("RA") framework by the California Public Utilities Commission ("CPUC"). The high degree of forward energy contracting in the past few years significantly reduces the opportunities for the exercise of market power at a system level. The CPUC has also initiated a long-term procurement proceeding designed to ensure that load-serving entities ("LSEs") enter into additional long-term energy contracts that will supplement existing long-term energy contracts and replace existing contracts as they expire. The high level of forward energy contracting will be further supplemented by capacity contracting under the CPUC's RA framework. Collectively, these long-term contracts will provide a stable and significant source of revenue to suppliers that can contribute to fixed cost recovery. The market power mitigation ("MPM") provisions included in the MRTU Tariff filing were designed to reflect and complement these developments.

Q. What were the overarching goals and objectives in developing the market power mitigation provisions included in the MRTU Tariff filing?

A. The CAISO, in cooperation with market participants and other stakeholders, has developed the proposed MPM framework to achieve three fundamental objectives:

1) To provide strong and effective measures against the exercise of local market power;

2) To provide an explicit mechanism within the MRTU design for addressing revenue adequacy of Frequently Mitigated Units not under long-term contracts; and

3) To provide a defined transition plan for relaxing CAISO system market power mitigation measures so that system market power concerns can be more effectively addressed through greater demand response and additional long-term energy contracting.

I believe these objectives are critical for ensuring the California wholesale market design is a sustainable and stable design that can reliably and efficiently meet California's growing demand for electricity. The proposed market power mitigation provisions included in the CAISO's MRTU Tariff filing meet these fundamental objectives.

Q. How does the CAISO's MRTU Tariff filing address the first objective of market power mitigation?

A. Effective local market power mitigation is the cornerstone of the MPM proposal. In fact, the CAISO Management and Board of Governors conditioned their support for going forward with a market design based on Locational Marginal Pricing ("LMP") on having strong and effective measures for addressing local market power. While other financial risks that LSEs face can be more easily managed, the market effects of local market power are not as easily hedged and may be pervasive, propagating excess costs on LSEs and ultimately ratepayers. A stringent and effective mechanism for mitigating the exercise of local market power is critical to ensuring efficient market dispatch and pricing. The instant proposal contains such a mechanism that is based on the approved local market power mitigation ("LMPM") measures in effect in PJM and that has been conceptually approved by the Commission for use in the MRTU market design. Under the LMPM approach proposed in this filing, if a resource is dispatched out-of-merit to relieve congestion on a non-competitive transmission constraint, the bids associated with that out-of-merit dispatch are mitigated by substituting a Default Energy Bid. For the reasons discussed below, I believe these LMPM measures will be effective in mitigating local market power in the CAISO markets.

Q. How does the CAISO's MRTU tariff filing address the second objective of revenue adequacy for generating units needed for local reliability?

A. A stable and sustainable wholesale market design must also have sufficient mechanisms for ensuring that units critical for local reliability earn sufficient revenues on average over a reasonable period of time to cover their going forward fixed costs. The primary mechanisms for providing these revenues are the long-term contracts for capacity and energy from long-term procurement and the RA capacity contracts. The CAISO recognizes, however, that some critical units may not always receive revenues through such contracts and may have their cost recovery opportunities limited by a high frequency of mitigation for local market power. To the extent that certain generating units are not receiving revenues under such contracts and are frequently needed for local reliability, the instant proposal includes a bid adder mechanism, similar to an adder applied in PJM, to ensure such Frequently-Mitigated Units ("FMUs") that are critical for local reliability earn sufficient revenues to recover their going forward fixed costs. It is important to note that, as is the case in PJM, the bid adder proposed by the CAISO is not intended to compensate a unit for its entire fixed costs, only the unit's avoidable fixed costs on a prospective basis. The Commission conceptually approved this bid adder approach for FMUs under MRTU. This approach will address the revenue adequacy objective of MPM for the initial release of MRTU. As I discuss in my testimony, the CAISO is exploring alternative backstop mechanisms for revenue adequacy such as a capacity service tariff or some form of local capacity market, and these alternative mechanisms could replace the bid adder when implemented.

Q. How do the market power mitigation provisions in the CAISO's MRTU Tariff filing address the third objective related to system market power mitigation?

A. The third goal of the proposed market power mitigation framework is to facilitate a shift from administrative mechanisms to forward contracting and demand response as a means for managing the risk of price impacts resulting from the exercise of market power at the system level. Because market power at a system level will be much more effectively addressed through forward contracting, the instant proposal has less stringent system market power mitigation provisions than exist today. As noted above, this forward contracting will include existing forward contracts as supplemented by the additional forward contracting resulting from the CPUC's long-term procurement proceeding and RA requirements.

Forward contracting mitigates market power risks in two important ways. First, long-term power contracts at a fixed price minimize an LSE's exposure to high spot market prices. Second, because load is largely hedged through forward contracts, the spot market risk is shifted to the supply side of the market, which significantly reduces incentives for suppliers to attempt to exercise system market power.

Under the MPM proposal, system market power resulting from physical withholding will be mitigated by a must-offer obligation that will apply only to generator capacity that is bilaterally contracted to meet the CPUC's RA requirements or otherwise identified as RA Capacity (*e.g.*, a load serving entities own generation, generation capacity of non-CPUC jurisdictional load serving entities). Units not identified as RA Capacity are not obligated to offer into the CAISO markets. This approach is less stringent than the current Must-Offer obligation in the CAISO markets, which applies to all thermal resources, regardless of whether they have a bilateral contract to satisfy RA requirements.

With respect to the exercise of system market power through economic withholding, the instant proposal provides a more light-handed approach than the system market power mitigation measures that are in place under the current CAISO market design. The instant MPM proposal does not include the system bid conduct and market impact test (known as System Automated Mitigation Procedure or "System AMP") currently applied by the CAISO. The instant filing also provides for a transition of the damage control energy bid cap. A $500/MWh "hard" bid cap will apply to energy bids for day-one of MRTU implementation, with a two-year transition plan under which the energy bid cap will increase to $1,000/MWh in annual increments of $250/MWh. The MRTU market power mitigation proposal also includes $250/MWh bid caps for ancillary service bids and Residual Unit Commitment ("RUC") availability bids.

Q. Do these market power mitigation provisions reflect input from Commission staff and interested stakeholders?

A. Yes. The MPM provisions of the MRTU Tariff filing are the result of a three-year stakeholder process and reflect significant changes in response to concerns raised by stakeholders, the CAISO's Market Surveillance Committee ("MSC"), and the Commission staff and takes into account directives from past Commission orders on the CAISO's conceptual MRTU filings. I should note that market power mitigation is a very controversial subject, and reasonable people can disagree on how it should be approached. The stakeholder process leading up to the instant proposal had its share of controversies. In my testimony I describe some of the significant issues raised by stakeholders. In the end, I believe the final resolution of the various contentious issues reflected in the MRTU Tariff filing represents the best solutions among the various options considered, and I will explain in my testimony why I believe this to be the case.

Q. Are the MRTU market power mitigation provisions modeled on an approved package of market power mitigation measures?

A. Yes. The MPM provisions were modified to be consistent with the package of market power mitigation measures currently in effect in PJM. This was done, in part, in response to guidance from Commission staff that the CAISO's previous market power mitigation proposal combined unique elements of different FERC-approved ISO market power mitigation packages and ignored other elements of those packages, rather than adopting an approach to MPM based on an entire FERC-approved package. In light of that concern, the CAISO made several significant modifications to its prior MPM proposals to make it consistent with the PJM package of market power mitigation provisions. The CAISO's proposed MPM "package" now closely resembles the PJM approved "package" of MPM measures. For example, the Default Energy Bids used for local market power mitigation under the instant proposal are based on four options that are very similar to the options offered under PJM. Other modifications, including the elimination of System AMP, were made to the CAISO's prior conceptual MPM proposals for MRTU in order to make the overall proposal more consistent with the PJM package.

Q. Please summarize your conclusions about the proposed market power mitigation provisions.

A. In summary, I believe the MPM provisions in the CAISO's MRTU Tariff filing will provide effective protection against market power and are complementary to the overall California market design, which includes the long-term procurement framework, RA requirements developed by the CPUC and other Local Regulatory Authorities, and the RA provisions of the MRTU Tariff. By effectively addressing system market power through long-term energy contracting, the spot market can safely accommodate less stringent system market power mitigation, including higher energy bid caps, which will facilitate greater demand participation and encourage long-term contracting. Because local market power is not as easily remedied through long-term power contracts, it is imperative to have effective local market power mitigation but to complement that mitigation with an effective mechanism for ensuring units frequently subject to the mitigation earn sufficient revenues to cover their going forward fixed costs. The instant proposal provides for both of these. For these reasons, I believe the proposed MPM provisions are reasonable and should be approved by the Commission.

B. <u>Inter-Scheduling Coordinator Trades</u>

Q. What is the "Seller's Choice" problem?

A. During the electricity crisis of 2001, the State of California entered into several power purchase agreements with suppliers to ensure that adequate energy supplies would be available to meet the demand of California's end-use customers. Some, but by no means all, of these contracts could be interpreted to allow the sellers a degree of choice as to where energy will be delivered. An extreme application of this interpretation of a "Seller's Choice" contract would allow the seller to deliver energy at any location within the CAISO Control Area. Parties to such contracts used the CAISO's current Inter-SC Trade mechanism to effectuate contractual delivery by specifying one of the CAISO's existing congestion management zones in their Inter-SC Trade.

Q. Could these contracts have created issues under the MRTU market design?

A. Yes. Under a nodal LMP market design with a Day-Ahead Market, such as MRTU, these contracts could be interpreted, theoretically, as allowing a seller to effectuate contractual delivery at any of the several thousand nodes in the CAISO Control Area. Under such an interpretation of these contracts, sellers could, theoretically, select low priced nodes as the location for delivery and earn counter-flow revenues to the extent the LMP at the injection node was higher than the LMP at the delivery node. This, in turn, would increase the congestion costs charged to buyers—buyers would be responsible for paying the difference between the LMP at the delivery node specified in the Inter-SC Trade and the point where the energy is withdrawn (the Load Aggregation Point). Moreover, Congestion Revenue Rights ("CRRs") would not be adequate to hedge all possible congestion associated with a Seller's Choice option that allowed "delivery" at any node. CRRs, which are defined by points of injections and points of withdraws, must be simultaneously feasible with respect to the transmission network whereas Inter-SC Trades are not subject to congestion feasibility. If sellers were able to effectuate contractual delivery through Inter-SC Trades at infeasible delivery points, congestion charges associated with such deliveries cannot be hedged.

Q. Have these issues with the Seller's Choice Contracts been resolved?

A. Yes, assuming the Commission does not alter the proposed Inter-SC Trade design, which it approved conceptually in June of 2005 in connection with the settlement of Seller's Choice issues. The key element that resolved the Seller's Choice problem was the addition of a physical validation rule for Inter-SC Trades at specific nodes. This requirement allows sellers the flexibility to deliver at any location that is physically feasible and at which the seller has secured supply, while eliminating the ability of a seller to create counter-flow revenues by designating low cost nodes for delivery that is physically infeasible. The other element of the Inter-SC Trade design that is central to the settlements in the Seller's Choice docket is the commitment of the CAISO to create Existing Zone Generation Trading Hubs ("EZ Gen Hubs") for each of the current congestion management zones.

Q. Does the CAISO's design for Inter-SC Trades, as reflected in the MRTU Tariff have other beneficial features?

A. Yes. Inter-SC Trades will assist in settling bilateral energy contracts under the MRTU design in the following three respects: (1) contracting parties can use the Inter-SC Trade as the instrument for the contractual delivery of energy; (2) an Inter-SC Trade provides a counter payment mechanism to offset the double energy settlement that occurs from scheduling bilateral contracts in the CAISO's forward energy market; and (3) Inter-SC Trades will allocate congestion costs for contractual delivery between the two counter-parties.

Q. Did the CAISO receive input from stakeholders on the Inter-SC Trade design?

A. Yes. As described in my testimony, issues associated with the Inter-SC Trade design have been discussed at length with stakeholders since Spring of 2004. One extensively-discussed issue was the method for determining the weighting of Trading Hub prices as part of the Inter-SC Trade instrument. EZ Gen Hubs will be successor delivery points under Locational Marginal Pricing for the CAISO's current internal congestion zones. The hub prices represent the average price paid to generation within the zone and, as such, will be based on only Locational Marginal Prices at generation nodes. The hub prices will be weighted averages of the generation LMPs in the relevant zone. The weights will be determined annually based on the previous year's seasonal MWh output of the generation units and will be differentiated by peak and off-peak periods. The specification of seasons will be identical to the seasons used in the annual CRR Allocation, and the annual calculation of Existing Zone Generation Trading Hub weights will be performed in a timely manner to be coordinated with the annual CRR Allocation and CRR Auction processes. Hub prices will be produced for every hour of every day in both the Day-Ahead Market and the Hour-Ahead Scheduling Process/Real-Time Market.

As discussed in my testimony, the CAISO presented seven options for the weighting of Trading Hub prices to stakeholders. The CAISO made certain modifications to these options based on stakeholder input, and ultimately determined the most appropriate option based on the criteria of: (1) Market Efficiency, (2) Accuracy, (3) Simplicity, (4) Consistency, and (5) Balance Risk.

Q. Please summarize your conclusions about the proposed Inter-SC Trade provisions of the MRTU Tariff.

A. In summary, I believe that the CAISO's Inter-SC Trade mechanism is critical to implement the settlements resolving the "Seller's Choice" problem associated with certain bilateral energy contracts entered into by the State of California. The Inter-SC Trade mechanism will also help promote the objectives of the MRTU market design, by, among other things, facilitating the settlement of bilateral contracts under MRTU. Lastly, the CAISO has chosen a reasonable approach to determining the weighting of Trading Hub prices that is the most appropriate option among those considered by the CAISO and stakeholders based on the various criteria for evaluating those options.

III. MARKET POWER MITIGATION UNDER MRTU

A. The Three Tiers of Market Power Mitigation Under the MRTU Market Design

Q. Please describe the tiers of market power mitigation mechanisms under the MRTU market design.

A. The market power mitigation measures in the MRTU Tariff filing, coupled with other elements of the California market design, effectively address market power concerns through three tiers of protective measures.

Tier 1 relies on forward contracting by LSEs as a means of mitigating customers' exposure to market power and the incentives for suppliers to exercise market power. With adequate forward contracting for energy, LSEs will be sufficiently hedged against price volatility in the spot markets. Similarly, with sufficient generation under forward contract, generators will have lower exposure to price and revenue uncertainty resulting from price volatility in the spot markets. Moreover, with a large proportion of their generation capacity under fixed price contracts, suppliers will have very little incentive to exercise market power. To the extent suppliers are serving some of their bilateral obligation from the spot market, they will actually have an incentive to minimize spot market prices. In addition to the existing bilateral market for trading energy, which is driven in part by the CPUC long-term procurement requirements applicable to LSEs, the RA capacity framework currently being developed by the CPUC will provide additional energy contracting opportunities as parties may choose to bundle capacity and energy within the RA framework. The Tier 2 and Tier 3 elements are intended to address any residual market power issues that are not entirely addressed by this forward contracting.

Tier 2 of the market power mitigation measures under the MRTU market design will address physical withholding. As a replacement for the existing Must-Offer obligation, which currently applies to all thermal resources, physical withholding will be addressed through obligations on resources that meet the control area capacity requirements through RA contracts entered into to satisfy CPUC requirements or resources otherwise identified as RA Capacity, consistent with the MRTU Tariff. Such obligations could also apply to resources procured through one of the alternative backstop capacity mechanisms under consideration by the CAISO, such as a reliability capacity service tariff or some form of local capacity market. Resources identified to the CAISO as RA Capacity will be required to offer the associated capacity in the CAISO markets. With control area capacity requirements set at 15% above forecast peak load, offer obligations associated with complying capacity will substantially mitigate potential system market power that would result from physical withholding of the remaining non-RA resources.

Tier 3 of the market power mitigation measures under the MRTU market design includes specific measures to address economic withholding both at the system level and at the local level. The CAISO is proposing a framework for mitigating the potential effects of economic withholding at the system level that relies on the hedging of LSEs through forward contracting for energy. The MPM proposal does not include a bid conduct and market impact mitigation procedure for system market power (*i.e.*, System AMP). Instead, to supplement forward contracting as a mitigation measure for economic withholding, the MRTU Tariff includes damage control bid caps for energy, Ancillary Services, and RUC capacity.

Q. **Are there additional elements to Tier 3?**

A. Yes. Local market power mitigation is an additional and critical Tier 3 element. The LMPM mechanism is applied to market bids prior to running the Day-Ahead Market ("DAM") and the Hour-Ahead Scheduling Process ("HASP"). Bid mitigation in the HASP will carry over into the Real-Time Market ("RTM") as the "Day One" MRTU market design does not include an opportunity to re-bid between the HASP and the RTM. Under the proposed LMPM provisions, if a resource is dispatched out-of-merit to relieve congestion on a non-competitive transmission constraint, the bids associated with that out-of-merit dispatch are mitigated by substituting a Default Energy Bid.

The Default Energy Bids used for LMPM will be calculated by the CAISO or an alternative independent entity selected by the CAISO. Similar to the mitigated bids used in PJM, the value of the Default Energy Bids will be based on one of the following four options:

1. **Variable Cost Option -** variable costs plus ten percent (10%).
2. **LMP Option -** a weighted average of the lowest quartile of LMPs at the Generating Unit PNode during the preceding 90-days. To qualify for the LMP Option at least 50% of the MWh dispatched from a unit over the prior 90-day period must not have been mitigated.

3. **Negotiated Option –** a value negotiated with the CAISO or an alternative independent entity selected by the CAISO.

4. **Frequently Mitigated Unit Option –** only available for FMUs and is equal to the Variable Cost Option plus the Bid Adder.

Default Energy Bids will be calculated by the CAISO for the Peak Hours and Off-Peak Hours for both the DAM and RTM.

A critical element of the Tier 3 LMPM measures is the determination of which transmission constraints are competitive. The designation of transmission paths as "competitive" and "non-competitive" for purposes of applying the LMPM will be done on an annual basis. However, the CAISO may perform additional competitive constraint assessments during the year if changes in transmission infrastructure, generation resources, or load in the CAISO Control Area and adjacent Control Areas suggest material changes in market conditions or if market outcomes are observed that are inconsistent with competitive market outcomes.

A transmission constraint will be designated "competitive" if no three unaffiliated suppliers are jointly pivotal in relieving congestion on that constraint. The determination of whether or not the pivotal supplier criteria for an individual constraint are violated will be assessed using a Feasibility Index ("FI") methodology. The CAISO will perform a pivotal supplier test on all suppliers in the CAISO Control Area for frequently congested transmission paths using the FI methodology.

Q. Please briefly describe the Frequently-Mitigated Unit Option.

A. As I have already noted, units that are needed for local reliability, that are frequently mitigated and that are not receiving contract revenues will be eligible for a Bid Adder. Such units must select the Frequently Mitigated Unit Default Bid Option (Option 4) to receive the Bid Adder. Eligibility for a Bid Adder will be determined on a monthly basis. To receive a Bid Adder, a generating unit must:

(i) have a mitigation frequency that is greater than 80% in the previous 12 months;

(ii) have run for more than 200 hours in the previous 12 months; and

(iii) have some capacity not under an RA contract and not subject to any CAISO capacity service tariff.

The value of the Bid Adder for FMUs will be either: (i) a unit-specific value determined in consultation with the CAISO or an independent entity selected by the CAISO, or (ii) a default Bid Adder of $24/MWh. For generating units with only a portion of their capacity identified as meeting an LSE's RA Requirements, that unit's Bid Adder value will be reduced by the percent of the generating unit's capacity that is identified as meeting an LSE's RA Requirements. The reduced Bid Adder will be applied to that unit's entire Default Energy Bid curve.

B. Local Market Power Mitigation

1. Development of the LMPM Proposal

Q. Please describe the history behind the CAISO's local market power mitigation proposal that was filed with the Commission on May 13, 2005.

A. Of all the design elements contained in the MRTU Tariff filing, I believe the LMPM provisions were the most thoroughly reviewed and developed with stakeholders. During the MRTU development process, the CAISO and the MSC were particularly concerned that an LMP-based market design would provide a greater opportunity and incentive for suppliers to exercise local market power. This was such a critical issue that the CAISO Board conditioned its support for an LMP-based market design on the development of highly effective local market power mitigation provisions.

While the current proposed LMPM provisions reflect a number of significant changes based on input from stakeholders, Commission Staff, and the Commission itself, many of the basic mechanics of the LMPM are the same as those proposed in the CAISO's July 22, 2003 conceptual proposal for the redesign of the CAISO's markets ("July 22, 2003 Filing"). Specifically, the LMPM provisions in the MRTU Tariff incorporate the proposal from the July 22, 2003 Filing of a multi-pass approach where only transmission paths pre-designated as competitive are enforced in the first pass and then in the second pass all transmission constraints are enforced. Under this approach, units dispatched up in the second pass are subject to mitigation.

The July 22, 2003 Filing included two approaches to local market power bid mitigation, an approach similar to that used in PJM and an alternative approach similar to that used in the NYISO. Under the preferred "PJM-like" approach, a unit that is dispatched up to relieve congestion on a non-competitive path would have its bid curve mitigated to the higher of its highest accepted bid in a previous "competitive constraint" market pass or its Default Energy Bid.

Under the alternative, "NYISO-like" approach to local market power bid mitigation, a unit that is dispatched up to relieve congestion on a non-competitive path would be subject to a conduct and impact test for the accepted incremental portion of its bid. If the accepted incremental portion of its bid violated a conduct threshold, it would be mitigated to the higher of its highest accepted bid in the "competitive constraint" pass or its Default Energy Bid and tested, along with any other mitigated bids, and tested for market impact. In the July 22, 2003 Filing, the CAISO indicated its strong preference for the PJM-like approach but offered the NYISO-like approach in the event that the Commission insisted on a bid conduct and market impact test approach to LMPM.

On October 28, 2003, the Commission issued an order in which it approved in principle many of the elements of the July 22, 2003 Filing.[1] In the October 28, 2003 Order, the Commission deferred ruling on the CAISO's market power mitigation proposal until more details were available on the Resource Adequacy framework being developed by the CPUC. The Commission indicated that it could not assess the merits of the CAISO's proposal in isolation without knowing more about the mechanisms intended to provide suppliers with adequate opportunities to recover their going-forward fixed costs.

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[1] *California Independent System Operator Corp.*, 105 FERC ¶ 61,140 ("October 28, 2003 Order"), *reh'g denied*, 105 FERC ¶ 61,278 (2003).

Since the issuance of the Commission's October 28, 2003 Order, there have been numerous stakeholder meetings and Commission technical conferences to discuss market power mitigation and its consistency and compatibility with the CPUC resource adequacy framework. The extensive MRTU stakeholder activities that preceded this filing are summarized in Attachment E to the MRTU Tariff filing letter.

Q. What were the specific issues concerning LMPM raised by Commission Staff in their January 18, 2005 Commission Staff Guidance Letter?

A. On January 18, 2005, the Commission staff issued a guidance letter in which it identified various issues for the CAISO to address in its development of revised market power mitigation measures. The issues raised by Commission staff concerning the LMPM provisions included:

Frequently Mitigated Units and RMR – Commission staff raised the concern that, with stringent LMPM, frequently mitigated units may not be adequately compensated and incentives for upgrades and investment may not be present. Commission staff stated that the CAISO should explain market mechanisms it might implement for dealing with this and the time frame for such changes as well as any unique circumstances that will require the use of RMR contracts.

Default bid curves for LMPM – Commission staff stated that the CAISO should explain why it has limited its proposed PJM-style LMPM to variable cost plus 10%, and why the CAISO did not propose to offer generators the additional options available in PJM.

CAISO Role in Resource Adequacy – Commission staff expressed concern that compliance with and enforcement of the resource adequacy obligation (on both LSEs and suppliers) may not be administered in a way that ensures reliability and revenue adequacy and that it was unclear how resource adequacy would be applied to non-CPUC jurisdictional load serving entities.

Commission Staff also raised concerns that the CAISO market power mitigation proposal under development through the end of 2004 combined elements of different FERC-approved market power mitigation packages for different independent system operators.

Q. Did the CAISO LMPM Proposal that was filed with the Commission on May 13, 2005 address the concerns of Commission Staff, stakeholders, and the CAISO Market Surveillance Committee ("MSC")?

A. Yes. The external review process leading up to the CAISO's May 13, 2005 Filing served two purposes. First, it provided an opportunity to educate stakeholders on how the proposed local market power mitigation procedures would work. Prior to this process, numerous stakeholders had commented that they did not fully understand how the proposed LMPM provisions worked and interacted with the rest of the MRTU market design. The CAISO white papers, slide presentations, and face-to-face dialogue with market participants helped to clarify how the mechanics of the LMPM procedures worked. The second purpose of this review process was to seek comment on the merits of the LMPM proposal and based on those comments, make modifications to improve the proposal. Some significant changes to the original proposal included in the July 22, 2003 Filing proposal were made in response to stakeholder and MSC comments, input from Commission staff, and guidance orders from the Commission itself in previous orders.

Q. **How did the CAISO address Commission Staff concerns that prior market power mitigation proposals under consideration by the CAISO combined elements of different FERC-approved market power mitigation packages for different independent system operators?**

A. As previously discussed, the current proposal now contains the Default Energy Bid options offered by PJM as well as a mechanism for providing bid adders for Frequently Mitigated Units. Given these proposed changes to its LMPM proposal along with the other proposed changes including elimination of System AMP, the CAISO believes that its market power mitigation "package" now closely resembles the PJM approved "package." The CAISO has eliminated from the current proposal the alternative NYISO-like conduct and impact approach for local market power mitigation.

Q. **Are there additional reasons why the CAISO adopted PJM-style LMPM instead of a bid conduct and market impact test like that used by the NYISO?**

A. Yes.

The concern with the bid conduct and market impact approach to LMPM is that whatever thresholds are used in the conduct and impact tests essentially define an acceptable level of market power (*i.e.*, units having local market power will likely bid a penny below the thresholds in order to avoid being mitigated). In contrast, the PJM-like approach provides no such thresholds and therefore provides more effective local market power mitigation. Under the PJM-like approach, units dispatched up to relieve congestion on non-competitive transmission paths are automatically mitigated. It is for this reason that the CAISO is currently only proposing the PJM-like approach for LMPM.

Q. How did the Commission rule on the May 13, 2005 conceptual filing?

A. On July 1, 2005, the Commission issued an order approving many elements of the CAISO's proposed market power mitigation package, but modifying other elements.[2] The following is a summary of LMPM determinations from the July 1, 2005 Market Design Order:

- The Commission approved the CAISO's proposed PJM-style local market power mitigation measures for energy. The Commission also stated that it expected the CAISO to include in its MRTU Tariff filing the methodology that will be used to assess a path's competitiveness.
- The Commission approved the CAISO's proposal to compensate FMUs through the use of a bid-adder. With respect to the treatment of FMUs in the long-term, the Commission indicated that it would be more productive for the CAISO to focus its efforts on proposals that encourage market solutions that rely on forward contracting by LSEs, as opposed to CAISO-administered backstops. In the interim, the Commission directed the CAISO to continue its efforts with market participants to determine the appropriate level of the bid adder for FMUs.

Q. After the May 13, 2005 conceptual filing, did the CAISO continue to work on the details of various aspects of the market power mitigation mechanisms?

A. Yes. There were three sub-components of the market power mitigation framework that required further development after the CAISO made the May 13, 2005 conceptual filing: (1) the cost components of Default Energy Bids, (2) the specific value for the default Bid Adder for FMUs, and (3) the methodology for

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[2] *California Independent System Operator Corp.*, 112 FERC ¶ 61,013 (2005) ("July 1, 2005 Market Design Order").

performing the competitive path assessment. The CAISO held monthly open meetings with stakeholders from June through August, 2005 to address these market power mitigation issues prior to the CAISO's filing of proposed MRTU Tariff language.

2. Day-Ahead Local Market Power Mitigation

Q. Please describe the Day-Ahead provisions for mitigating local market power.

A. After the Market Close of the Day-Ahead Market (*i.e.*, the deadline for submitting bids), the CAISO will perform the Market Power Mitigation – Reliability Requirement Determination ("MPM-RRD") procedures in two processing runs that occur prior to the actual Integrated Forward Market ("IFM") Market-Clearing run. The MPM-RRD process performs the LMPM procedures for units that are not Reliability Must-Run ("RMR") units and identifies the RMR requirements for RMR units. The MPM-RRD process uses the same optimization used in the IFM but clears Energy and Ancillary Services bids to meet one hundred percent of the CAISO Demand Forecast and Export Bids (to the extent that the Export Bids are economic) and meet one hundred percent of Ancillary Services requirements. I will explain later in my testimony why the CAISO proposes to base the LMPM procedures on forecasted load rather than bid-in load and requests the Commission to modify its recent order indicating that the CAISO should use bid-in load for this purpose. This issue is also discussed in the Direct Testimony of Brian Rahman (Exhibit No. ISO-8.)

The first run of the MPM-RRD procedures is the Competitive Constraint Run ("CCR"), during which only limits on transmission lines pre-designated as "competitive" are enforced. The only RMR units considered in the CCR are Condition 1 RMR units that have provided market bids for the DAM. The dispatch outcomes from the CCR are the benchmark for determining which market bids must be dispatched in order to relieve congestion on non-competitive constraints.

The second run of the MPM-RRD procedures is the All Constraints Run ("ACR"), during which all transmission constraints are enforced. All RMR units, Condition 1 and Condition 2, are considered in the ACR. For a Condition 1 RMR unit that is dispatched in the CCR, the bid used in the ACR for the entire portion of the unit's bid above the CCR dispatch level and below the Maximum Net Dependable Capacity specified in the RMR contract will be set to the lower of the RMR Proxy Bid, or the market bid, but not lower than the unit's highest bid price that cleared the CCR. The RMR Proxy Bid is an estimate of the actual RMR variable costs as specified in the RMR contract. Since actual RMR variable costs typically have cost components (*e.g.*, fuel costs) that are not known at the time of dispatch, a proxy for these costs is used to determine dispatch.

Condition 2 RMR Units and Condition 1 RMR Units that are not bid or bid but are not dispatched in the CCR are considered in the ACR based on their RMR Proxy Bid. All non-RMR units are considered in the ACR based on their market bids. In the ACR, some units will be dispatched downward and others dispatched upward relative to their CCR dispatch level in order to relieve congestion on the additional (non-competitive) constraints that are not considered in the CCR. Because the uncompetitive transmission constraints are only enforced in the ACR, any incremental dispatch (compared to the CCR dispatch levels) is necessary to relieve congestion on an uncompetitive constraint.

Q. Please provide more specifics on this process.

A. More specifically, the CAISO compares the resource dispatch levels derived from CCR and ACR to determine RMR dispatch and bid mitigation for non-RMR units as follows:

- **RMR Dispatch Determination**: If the dispatch level produced through the ACR for an RMR unit in the pre-IFM or in the pre-HASP is greater than the dispatch level produced through the CCR, the Schedule produced as a result of the IFM, and the Dispatch Instructions issued in the RTM, will be flagged as RMR Dispatches. If a Condition 1 RMR unit is dispatched in the CCR and receives a greater dispatch in the ACR, the entire portion of the unit's bid above the CCR dispatch level and below the Maximum Net Dependable Capacity specified in the RMR Contract, will be set to the lower of the RMR proxy bid or the market bid, but not lower than the unit's highest bid price that cleared the CCR for purposes of being considered in the IFM. For Condition 1 RMR units, the market bid at and below the CCR dispatch level will be retained in the IFM. If the dispatch level produced through the ACR for a Condition 1 RMR unit is not greater than the dispatch level produced through CCR, the generating unit's original, unmitigated bid will be retained in its entirety in the IFM.

- **Non-RMR Units**. If the dispatch level produced through ACR is greater than the dispatch level produced through CCR, then the resource is subject to LMPM, in which case only the portion of the unit's bid curve that is above the CCR dispatch level will be mitigated to the lower of the Default Energy Bid or the market bid, but no lower than the unit's highest bid price that cleared the CCR. The Commission approved this approach in its July 1, 2005 Market Design Order.[3]

[3] 112 FERC ¶ 61,013 at PP 118, 122.

While the Day-Ahead MPM-RRD procedures are based on forecasted load, the resulting mitigated bids are used in the IFM Market Clearing run, which will clear supply bids against internal demand and export bids. Any bids that are not dispatched in the actual IFM can be re-bid for the HASP/Real-Time Market – even if they were mitigated in the Day-Ahead MPM-RRD process. As a consequence, the MPM-RRD process is performed again for the HASP/Real-Time Market.

Q. Please discuss the guidance the Commission has provided on the use of forecasted load or bid-in load for the Day-Ahead LMPM procedures.

A. In its May 13, 2005 Filing, the CAISO proposed to base the Day-Ahead MPM-RRD on forecasted load as opposed to bid-in load. In its July 1, 2005 Market Design Order, the Commission approved the CAISO's revised market optimization process, which included this approach.[4] However, in response to a rehearing request, the Commission reversed course and directed the CASIO to base the Day-Ahead LMPM procedures on bid-in load. [5] The CAISO requested rehearing of this issue.

Q. Please explain why the CAISO is proposing to keep the original design under which Day-Ahead MPM-RRD is based on forecasted load rather than bid-in load.

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4 112 FERC ¶ 61,013 at P 162.

5 *California Independent System Operator Corp.*, 112 FERC ¶ 61,310 at P 69 (2005) ("September 19, 2005 Order").

A. In the instant filing, the CAISO is proposing to keep the Day-Ahead MPM-RRD based on forecasted load but will consider basing the procedures on bid-in load in a subsequent release of MRTU. The CAISO cannot incorporate this change into MRTU Release 1 without substantially delaying MRTU implementation. As explained in the testimony of Brian Rahman (Exhibit No. ISO-8), it will be challenging for the CAISO to meet the proposed implementation date of November 2007 for the current design of MRTU Release 1. The CAISO's evaluation of this issue shows that MRTU Release 1 would likely be delayed by as much as 10-14 months if the CAISO is required to base the DA MPM-RRD on bid-in load.

Q. Are there additional reasons why the Commission should approve the use of forecasted load in Day-Ahead MPM-RRD notwithstanding the Commission's findings in the September 19, 2005 Order?

A. Yes. The Commission's findings in the September 19, 2005 Order appear to be based on the erroneous premise raised by the Independent Energy Producers Association ("IEP") and Williams that the CAISO's proposed approach for MRTU Release 1 contains a systemic bias toward over-mitigation and that significant over-mitigation will occur if the CAISO identifies the supply bids subject to mitigation during the pre-IFM runs based on CAISO forecasted load rather that bid-in load. That premise is incorrect. There is no systemic bias one way or the other. Because suppliers can re-bid the uncleared portion of their bid curves in the HASP, the impact on suppliers of using forecast load versus bid in load should be minimal during the interim period between MRTU Release 1 and MRTU Release 2.

The September 19, 2005 Order notes IEP's and Williams' claim that, under the CAISO's proposed market power mitigation measures, all bids dispatched from a given unit in Pass 2 of the IFM are deemed to be non-competitive if any bid dispatched from that unit is mitigated. September 19, 2005 Order at P 64. That is incorrect. As I explained, the portion of the bid curve below the accepted Pass 1 level is not mitigated under such circumstances. The September 19, 2005 Order also notes IEP's and Williams' claim that, as a result of the CAISO's pre-IFM runs, LSEs "will not only be afforded local market power mitigation for load that they may not even have bid into the day-ahead market, but for every remaining MW of the unit's operating range, regardless of the reason for which the unit might be subsequently dispatched." September 19, 2005 Order at P 65. This claim too is incorrect because all energy bids that are not accepted can be revised by the supplier for re-submission in subsequent markets.

Although the pre-IFM process applies mitigation based on forecasted load, the CAISO's IFM run applies mitigation based on scheduled and bid-in demand. Further, suppliers can re-bid the uncleared portion of their bid curves in the Hour-Ahead Scheduling Process. Whether or not the mitigated bids are used in IFM depends on the interplay between supply and demand bids in IFM. Depending on this interplay, the IFM may not use some of the bids that are mitigated in load forecast based pre-IFM, or it may use some unmitigated bids that would have been mitigated if forward market power mitigation were based on bid-in load.

While a more targeted approach for local market power mitigation would be to base the MPM procedures on bid-in load, such an approach would undermine the ability to accurately determine RMR dispatch levels. As discussed earlier in my testimony, the MPM-RRD procedures have two purposes: (1) determining local market power mitigation for non-RMR units and (2) determining RMR dispatch. Basing the MPM-RRD procedures on bid-in load would severely undermine the CAISO ability to accurately determine RMR dispatches. Specifically, if the MPM-RRD process was based on bid-in load and not all load was fully bid-in, it is possible that the MPM-RRD process would under-commit RMR resources to meet local reliability needs.

One potential solution would be to move RMR pre-dispatch identification out of the MPM-RRD process and into the RUC process, thereby allowing the MPM-RRD to be based on bid-in load. However, this option would require multiple changes to the existing market software as well as development of an additional pass in RUC whereby competitive transmission constraints would first be applied in the RUC, followed by all transmission constraints, in order to identify which RUC "dispatches" were required for local reliability and RMR. As discussed in Brian Rahman's testimony, implementation of this change would require changes in all parts of the software development cycle, including user interface displays, system set up input requirements, database schema, software optimization engine, and post-processing of "Final Pass" bids to the IFM/RT market processes, and an additional pass in the RUC market. This change would require additional time and resources to be allocated for integration, testing and documentation, thereby delaying MRTU implementation.

Q. Is there further support for the CAISO's proposal to use of forecasted load in Day-Ahead MPM-RRD.

A. The CAISO's conclusion that it is not imperative that MRTU Release 1 use bid-in load in the MPM-RRD passes is supported by Scott Harvey and Susan Pope of LECG, Inc., along with William Hogan of Harvard University in their *Comments on the California ISO MRTU LMP Market Design* ("February 2005 MRTU Report ").[6] In that regard, the February 2005 MRTU Report identified twelve potential problems with the proposed MRTU design "in rough order of priority." February 2005 MRTU Report at 1-4. Problem No. 10 identified by LECG was

> [t]he use of extreme decremental (DEC) bids for Pass 1 schedules in Pass 2 of the DAM, with the intent of "minimizing" incremental (INC) adjustments and the use of forecast load in the market power passes of the DAM (Passes 1 and 2) and bid load in the scheduling and pricing pass (Pass 3) of the DAM.

Id. at 3. LECG thought that this approach "could render the RMR dispatch and local market power mitigation process ineffective in some circumstances." February 2005 MRTU Report at 4. LECG also indicated that it might not fully promote least-cost procurement. *Id.* at 86. The report did not identify this issue as one that "ought to be addressed prior to the implementation date." *Id.* at 2. Rather, LECG concluded that "[w]hile it would be desirable in principle to

[6] The February 2005 MRTU Report was previously filed with the Commission as Attachment C to the CAISO's May 13, 2005 Filing.

address these features of the market design, it is uncertain whether these latter six features of the market [including the use of forecast load instead of bid in load in the pre-IFM runs] will, in practice, have much adverse impact in the near term." *Id* at 4.

Following issuance of the February 2005 MRTU Report, the CAISO re-visited the issue of using forecasted load in the pre-IFM runs rather than bid-in load. The CAISO acknowledged LECG's concern that this approach might not result in an optimal commitment of resources and that it might be possible that unmitigated bids would be used to relieve local constraints in the IFM. *See* CAISO White Paper entitled *Comprehensive Market Redesign Update,* at 16-17, Attachment A to the CAISO's May 13, 2005 Filing. However, the CAISO concluded that the impact would not be significant because, to the extent that bid-in load cleared the IFM at a level below the forecast, there would likely be fewer constraints than with the load forecast, and therefore less need for dispatching unmitigated bids to relieve local constraints. White Paper at 17. Accordingly, the CAISO concluded that revising the pre-IFM process to use bid-in load did not warrant the additional risk to the MRTU Release implementation schedule. *Id.* In the White Paper, the CAISO stated that this issue would be addressed in MRTU Release 2. The CAISO continues to believe that this issue should be addressed as part of MRTU Release 2.

3. <u>LMPM in the Hour-Ahead Scheduling Process and Real-Time</u>

Q. Please describe the HASP/Real-Time LMPM provisions.

A. Because there is no re-bidding opportunity between the Hour-Ahead Scheduling Process and the Real-Time Market, the LMPM procedures are applied only in the HASP and any mitigation that occurs in this procedure automatically carries over into the Real-Time Market.

After the market close of the HASP (*i.e.*, the deadline for submitting bids for the HASP), the CAISO conducts the same MPM-RRD procedures used in the DAM. However, the MPM-RRD during the HASP is conducted separately for each fifteen-minute interval of the Trading Hour to reflect forecasted changes in system conditions and consequently may produce up to four mitigated bids for the Trading Hour. The minimum bid price of the four mitigated bid curves at each bid quantity level is used to produce a single mitigated bid for the entire hour. For each 15-minute interval of the hour, the bids are mitigated only for the bid quantities that are above the minimum quantity cleared in the CCR.

Q. Please explain why the CAISO elected to determine a single mitigated bid to use for the entire hour based on the minimum bid price of the four mitigated bid curves.

A. The basic logic is that within a single hour, it is possible that a generating unit would only be mitigated in one 15-minute interval. If that were the case, and the generator submitted an extremely high market bid, that extremely high bid would be the bid curve for the remaining three 15-minute intervals. If the CAISO simply averaged the four curves to derive a single mitigated bid curve for the hour, the average curve would not provide sufficient mitigation in the interval that mitigation was warranted. Because of this concern, the CAISO chose to derive the single mitigated bid curve for the entire hour based on the minimum of the four 15-minute curves.

4. Determination of Default Energy Bids

Q. How will Default Energy Bids used in LMPM be determined?

A. The Default Energy Bids ("DEBs") used in local market power mitigation will be calculated by the CAISO or an alternative independent entity selected by the CAISO. Prior to the start of MRTU, the CAISO will make a determination on whether the CAISO or an alternative independent entity will administer the Default Energy Bids for all market participants.

Similar to the mitigated bids used in PJM, the Default Energy Bids will be based on one of the following four options: (1) the Variable Cost Option, (2) the LMP Option, (3) the Negotiated Option, and (4) the Frequently-Mitigated Unit Option.

The Variable Cost Option will be comprised of two components: Fuel Cost and Variable Operation and Maintenance Cost. The Fuel Cost portion will be calculated for each Bid Segment using the Heat Rate supplied by the resource owner on file in the Master File and applicable regional natural gas price indices as specified in the Business Practice Manual. The calculation of the DEB will use input costs including a proxy gas index calculated as the simple average of four published gas price indices (Platts Gas Daily, Btu Daily Gas Wire, NGI's Daily

Gas Price Index, the ICE index) for each region and will include proxy figures for intra-state gas transport costs based on the posted tariff rates of the gas carriers.

The default value for the Variable Operation and Maintenance Cost portion will be $2/MWh, except for generating units that utilize combustion turbines or reciprocating engine technology which will have a default Variable Operation and Maintenance Cost of $4/MWh. Resource owners also have the option of negotiating resource specific values with the CAISO (or an alternative independent entity selected by the CAISO) charged with calculating the Default Energy Bid.

Default Energy Bids will be calculated separately for the Peak Hours and Off-Peak Hours for both the DAM and the HASP/RTM (*i.e.*, each unit will have four Default Energy Bids). The Scheduling Coordinator for each generating unit owner or Participating Load must rank the options of calculating the Default Energy Bid starting with its preferred method. Each Scheduling Coordinator must provide the data necessary for determining the Variable Cost Option unless the Negotiated Rate Option precedes the Variable Cost option in the rank order, in which case the Scheduling Coordinator must have a Negotiated Rate established with the CAISO or Independent Entity charged with calculating the Default Energy Bid. If no rank order is specified for a generating unit or Participating Load, then the default rank order of: (1) Variable Cost Option, (2) Negotiated Rate Option, (3) LMP Option will be applied. As noted above, the Frequently Mitigated Unit Option is only available to a subset of units identified as being eligible for a Bid Adder. I will describe the Bid Adder and the FMU designation process later in this testimony.

Q. What issues did stakeholders raise with the Default Energy Bids?

A. The main issues raised by stakeholders about the formulation of the Default Energy Bid Options were the following:

- Lack of an option based on a unit's bid history;
- Use of a competitiveness screen for eligibility for the LMP Option;
- Use of the average of lowest quartile of LMP for the LMP Option; and
- The proposed value for the Variable Operation and Maintenance Cost component.

Q. Please discuss the potential option based on a unit's bid history and why the CAISO decided not to include this option among the options for Default Energy Bids.

A. Under an option based on a unit's bid history, DEBs would be calculated as a rolling weighted average of accepted bids from the unit during competitive periods. The CAISO currently has an option based on a unit's bid history in its methodology for calculating reference prices. The CAISO's current market power mitigation was modeled after the NYISO and includes bid-based reference levels and bid conduct and market impact tests. In moving to MRTU, the CAISO decided the PJM package of market power mitigation was preferable to the NYISO approach for reasons discussed earlier in my testimony. As the CAISO decided to opt for the PJM approach to LMPM, we adopted the same DEB options as PJM, which does not include an option based on a unit's bid history. However, the LMP Option is somewhat similar to an option based on a unit's bid history since the LMPs ultimately reflect the marginal market bids accepted.

Moreover, one of the primary concerns with an option based on a unit's bid history, as well as an LMP Option, is the potential for suppliers to manipulate their bids so as to increase their DEB. This concern was one of the main reasons the CAISO originally proposed only a Variable Cost Option for DEBs. However, in response to the January 18, 2005 Commission Staff Guidance Letter, the CAISO added the LMP Option and Negotiated Option to be consistent with PJM but as discussed further below, the CAISO added a competitive screen for the LMP Option to mitigate concerns over potential DEB manipulation. The same competitive screen was approved by the Commission for determining eligibility for bid-based reference prices under the CAISO's current market power mitigation procedures.

Q. What is the competitiveness screen that is used to determine eligibility for the Default Energy Bid LMP Option?

A. Under the CAISO's proposed competitive screen for the Default Energy Bid LMP Option, a unit must have at least 50% of the MWh dispatched over the prior 90 days not mitigated for local market power. This provision was approved in concept by the Commission in its July 1, 2005 Market Design Order.[7]

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7 112 FERC ¶ 61,013 at PP 118, 122.

Q. Please explain the purpose of the competitiveness screen and why you think it is necessary

A. As noted above, the competitiveness screen is a feature of the CAISO's current zonal market design that I think is equally necessary under our proposed LMP design. The CAISO's current LMPM procedures utilize bid-based reference prices that are based on a 90-day rolling average of accepted bids during "competitive periods." Under the CAISO's current zonal system, circumstances have arisen where generators in generation pockets are decremented in sequence so seldom, and out-of-sequence so often, that they have an incentive to attempt to influence their reference price by submitting excessively low decremental bids in the hope that such bids will be dispatched in sequence and thus included in their reference price calculation. This practice also only works when the generator has persistent opportunities to exercise local market power. In all other circumstances, the generator that bids too high is disciplined by the risk that profits foregone through having inflated bids unaccepted will offset any positive effect this bidding strategy has in raising the unit's reference price.

A similar issue could arise with the LMP-based Default Energy Bid ("LMP-DEB") under MRTU. As there is only market power mitigation in the incremental direction under MRTU, it is conceivable that a generator in a load pocket might bid high in hours where it does not have local market power in order to drive up the LMP at its location, which in turn will be used for determining its LMP-DEB. Of course, if the generator bids too high, it runs the risk that its bid will not be dispatched.

Q. Are there additional aspects of the LMP-based Default Energy Bid that were discussed in the stakeholder process?

A. Yes. Two other aspects of the LMP-DEB are important here, namely the proposal to limit the average under the LMP-DEB to the lowest quartile of LMPs when the unit was online and the decision to include all LMPs in that subset, which would include LMPs in hours the unit was mitigated as well as hours the unit was not mitigated. Both of these aspects of the LMP-DEB further serve to mitigate the ability of a generator to strategically bid so as to increase its LMP-DEB.

The lowest quartile proposal, which is valid for additional reasons discussed below, serves to lessen the ability of a generator to increase its LMP-DEB because the limited hours where the generator successfully raised the LMPs would likely not be included in the lowest quartile.

The inclusion of all LMPs in hours where a unit is running, rather than only hours that the unit is running and not mitigated for local market power, also dilutes the ability of a unit to strategically increase the LMP-DEB since the pool of LMPs being averaged will include a number of LMPs when the unit was mitigated, which when averaged will tend to offset any LMPs the generator managed to strategically increase in hours that it was not mitigated.

These three aspects of the Default Energy Bid LMP Option (the competitive screen, the "lowest quartile" approach, and inclusion of all LMPs when the unit is running) work together to mitigate the ability of a generator to strategically increase its LMP-DEB by bidding high in unmitigated hours.

Q. Why is the LMP Option designed in this manner?

A. The overall purpose of the LMPM provisions is to mitigate the bids of market participants so as to produce LMPs that approximate a competitive outcome. Under competitive circumstances generators will bid their marginal cost and will receive at least that and potentially more when prices clear above their marginal cost. Therefore, the LMP Option for DEBs needs to be designed in a manner that best captures an estimate of the variable cost of the unit. Because the subset of LMPs used for the LMP Option is limited only to those when the unit was operating, the resultant LMPs are those set both when the unit was marginal and when it was infra-marginal. Consequently, an average of all of these LMPs would overstate the unit's variable operating costs. Under competitive circumstances these infra-marginal LMP rents are not included in the generator's bids, nor should they be included in the mitigated bid. The very best LMP indicator of a unit's bidding behavior would be to limit the LMPs averaged to only those where the unit was marginal. Unfortunately this subset might be too small to be a reliable measure, hence the CAISO's decision to limit the subset to the lower quartile.

In addition, the Variable Cost Option, which is by far the most commonly used method to mitigate bids in PJM, explicitly targets the variable cost of the generator as an indicator of what the generating unit would bid under competitive circumstances. As this measure essentially tries to reproduce competitive bidding behavior the LMP-Option should have exactly the same aim. Including significant infra-marginal rents in the LMP Option by basing it on all LMPs when the unit is running would significantly undermine the accuracy of the LMP-Option. If such an approach were offered, every generator would likely opt for the LMP Option, simply because it would include infra-marginal rents. The CAISO's lowest quartile approach strikes a fair balance between the need for an option other than the variable cost option and maintaining the integrity of the mitigation.

Q. Does this lowest quartile approach have any precedent either at the CAISO or elsewhere?

A. Yes it does. It is already part of the CAISO's current tariff[8] where the lowest quartile of Market Clearing Prices ("MCPs") is used to determine the MCP-based reference level under the current AMP. A similar provision is extant in the NYISO tariff for use in determining its MCP-based reference levels.[9]

Q. Was this lowest quartile approach for calculating the LMP DEB Option proposed in the CAISO May 13, 2005 Conceptual Filing?

A. No. This provision was added after further consideration of the implementation details of the LMP Option. It was not proposed originally because such a provision was not part of the PJM Tariff. However, in talking with Joseph E. Bowring, head of PJM's Market Monitoring Unit, we learned that the LMP

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[8] *See* CAISO Tariff, MMIP at 3.1.1.1 (a) 4.

[9] *See* NYISO Tariff, Attachment H, Section 3.1.4 (2), http://www.nyiso.com/public/webdocs/documents/tariffs/market_services/att_h.pdf.

Option, although included in the PJM Tariff, has never been implemented because neither the market monitor nor generator owners could come up with an appropriate methodology for implementing it. Given this, we sought to develop our own methodology, which adopted the lowest quartile approach used in our current mitigation procedures and those of the NYISO.

Q. What is the CAISO's proposal concerning the O&M adder for the Default Energy Bid Variable Cost Option?

A. The CAISO's proposal is that the default level of the O&M adder for all generating units under the Variable Cost Option will be $2, except for combustion turbines and reciprocating engines, which will have a default O&M adder of $4, regardless of their fuel type. Market participants who believe that the applicable default value is not appropriate can provide documentation to the CAISO, or the independent entity selected by the CAISO to administer the Default Energy Bids, to justify why their O&M adder should be different.

Q. Why did the CAISO decide not to use the $6/MWh O&M adder that the Commission had previously decided should be used to determine the marginal cost of generators during the 2000-2001 energy crisis?

A. In 2001, the Commission issued a number of orders addressing a number of issues related to the California energy crisis. Of relevance to the discussion of O&M costs are the Commission's April 26, 2001 and June 19, 2001 orders establishing west-wide price mitigation, based on Market Clearing Prices in the CAISO Real-

Time market.[10] The nature of the mitigation was twofold. In reserve deficiency hours (Stage 1, meaning less than 7% reserves), the Commission required that the CAISO generate proxy bids based on the marginal cost of each unit and clear the market using these bids. All sellers in the CAISO's single-price auctions would receive the MCP and this price would be a ceiling for bilateral sales elsewhere in California and the rest of the WECC. During non-Stage 1 periods, the highest MCP set in the last Stage 1 would be a benchmark for all hours subject to a 15% reduction. Thus, if the highest hourly MCP was $140 for the most recent Stage 1 emergency, then for all subsequent hours, 85% of this figure ($119) would act as a price cap across the WECC.

In generating the proxy bids the Commission initially required the use of a $2/MWh O&M adder in its April 26, 2001 Order. However in the June 19, 2001 Order, the Commission increased this amount to $6 on the grounds that $2 was not sufficient for all generators, while $6 was sufficiently generous that all generating units would be able to recover their O&M costs at this rate.[11] The Commission recognized that previous Commission decisions as well as industry studies had found $2 to be reasonable, however such a low rate would not allow the marginal units to recover their costs.[12] The Commission also stated that "The California market primarily consists of older oil and gas-fired steam plants."[13] The Commission rejected the proposal to allow generators to include actual O&M

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10 *San Diego Gas & Electric Company v. Sellers of Energy and Ancillary Services*, 95 FERC ¶ 61,115 ("April 26, 2001 Order"), *order on reh'g*, 95 FERC ¶ 61,418 ("June 19, 2001 Order").

11 95 FERC ¶ 61,418 at 62,562-63.

12 *Id.*

13 *Id.* at 62,563.

costs and instead set the O&M rate at the marginal level. Exactly why the Commission decided against the option of allowing generators to submit their O&M costs directly is not made clear in the order. Given the scale of the energy crisis, with billions of dollars at stake, the difference between $2 and $6 was not contested at that time but should not be perpetuated.

There are a number of reasons why the CAISO believes that this $6 O&M charge should not be used for the DEB Variable Cost Option. First, the circumstances in which the original decision was made have long since ceased to exist. The June 19, 2001 Order put in place a mitigation system that itself is no longer operational, despite the longevity of one of its constituent parts. Far from having a mitigation system based on variable cost bidding during Stage 1 emergencies, the CAISO's MRTU Tariff will include a PJM style mitigation approach for LMPM and a bid cap for system market power mitigation. The CAISO's LMPM system under MRTU is far removed from the original mitigation system that implemented the $6 O&M adder and it is appropriate that it should be revisited.

The CAISO is revisiting much smaller issues than the $6 O&M charge. The gas transport costs used in calculating DEBs will most likely be less than $0.40/MWh. It would make no sense to leave the $6 O&M charge untouched while going into such detail about far lesser charges.

In the June 19, 2001 Order, the Commission referenced a document that gave the long-term O&M costs of a steam unit to be $6.[14] The Commission

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[14] 95 FERC ¶ 61,418 at 62,563 n.71.

further reasoned that these units would be on the margin in California. The document referenced in the June 19, 2001 Order is Table 3 of "Trends in Power Plant Operating Costs" by J. Alan Beamon and Thomas J. Leckey found at http://www.eia.doe.gov/oiaf/issues/power_plant.html. The CAISO contacted one of the authors at the Energy Information Administration ("EIA"), and he indicated that the document is dated and is not being updated any time soon. The CAISO believes that better data is now available. There have also been substantial generation additions of new Combined Cycle Gas Turbines ("CCGTs") to the California generating mix since 2001. While it is still true that during the summer the older gas-fired units are on the margin, for much of the rest of the year this is not true. The CAISO does not believe that the O&M characteristics of a minority of units should be used to determine the O&M values for all units during all hours of the year.

While the methodology the Commission used to establish the O&M rate for its Stage 1 based mitigation measures may have been appropriate for the circumstances, namely the tail end of the energy crisis, constrained by the need for quick action, the CAISO does not believe that this methodology is appropriate now. Setting the O&M rate for all units for all hours of the year based on the O&M of the marginal unit on the peak day of the year is a blunt and imprecise methodology in today's more rational markets. Using such a methodology will result in Default Energy Bids that resemble the actual variable O&M costs of only the very oldest steam units. Using a $6 O&M adder would be as if the variable cost for the system marginal unit on the peak day were imposed year-round for all units for all days as an approximation of variable cost. Under the MRTU design effort, there is ample time for units to provide unit-specific variable O&M values prior to the start of MRTU.

Q. Does the CAISO have additional support for its proposal to use an O&M adder of either $2 or $4 for the Default Energy Bid Variable Cost Option?

A. Yes. The CAISO has made an effort to find empirical evidence of O&M costs of generators using different generation technologies and particularly those located in California. In terms of publicly available documentation, the EIA's report entitled, *Assumptions to the Annual Energy Outlook 2005*, contains what we found to be the most accessible documentation in its "Table 38. Cost and Performance Characteristics of New Central Station Electricity Generating Technologies."[15] A snapshot of this page is reproduced in Table 1 below. This information is indicative of "new" generating technologies, not the installed generation units in California; however, it does give an indication of the nature of the O&M costs.

[15] *See* pages 67-to of this report, available at: http://www.eia.doe.gov/oiaf/aeo/assumption/pdf/0554(2005).pdf.

Table 1: Cost and Performance Characteristics of New Central Station Electricity Generating Technologies

Table 38. Cost and Performance Characteristics of New Central Station Electricity Generating Technologies

Technology	Online Year[1]	Size (mW)	Leadtimes (Years)	Base Overnight Costs in 2004 ($2003/kW)	Contingency Factors: Project Contingency Factor	Contingency Factors: Technological Optimism Factor[2]	Total Overnight Cost in 2004[3] (2003 $/kW)	Variable O&M[5] ($2003 mills/kWh)	Fixed O&M[5] ($2003/kW)	Heatrate in 2004 (Btu/kWhr)	Heatrate nth-of-a-kind (Btu/kWr)
Scrubbed Coal New	2008	600	4	1,134	1.07	1.00	1,213	4.06	24.36	8,844	8,600
Integrated Coal-Gasification Combined Cycle (IGCC)	2008	550	4	1,310	1.07	1.00	1,402	2.58	34.21	8,309	7,200
IGCC with Carbon Sequestration	2010	380	4	1,820	1.07	1.03	2,006	3.93	40.26	9,713	7,920
Conv Gas/Oil Comb Cycle	2007	250	3	540	1.05	1.00	567	1.83	11.04	7,196	6,800
Adv Gas/Oil Comb Cycle (CC)	2007	400	3	517	1.08	1.00	558	1.77	10.35	6,752	6,333
ADV CC with Carbon Sequestration	2010	400	3	992	1.08	1.04	1,114	2.60	17.60	8,613	7,493
Conv Combustion Turbine[5]	2006	160	2	376	1.05	1.00	395	3.16	10.72	10,817	10,450
Adv Combustion Turbine	2006	230	2	356	1.05	1.00	374	2.80	9.31	9,183	8,550
Fuel Cells	2007	10	3	3,679	1.05	1.10	4,250	42.40	5.00	7,930	6,960
Advanced Nuclear	2013	1000	6	1,694	1.10	1.05	1,957	0.44	60.06	10,400	10,400
Distributed Generation -Base	2007	2	3	769	1.05	1.00	807	6.30	14.18	9,950	8,900
Distributed Generation -Peak	2006	1	2	924	1.05	1.00	970	6.30	14.18	11,200	9,880
Biomass	2008	80	4	1,612	1.07	1.02	1,757	2.96	47.18	8,911	8,911
MSW - Landfill Gas	2007	30	3	1,402	1.07	1.00	1,500	0.01	101.07	13,648	13,648
Geothermal[6,7]	2008	50	4	2,960	1.05	1.00	3,108	0.00	104.98	45,335	36,468
Conventional Hydropower[6]	2008	500	4	1,319	1.10	1.00	1,451	4.60	12.35	10,338	10,338
Wind	2007	50	3	1,060	1.07	1.00	1,134	0.00	26.81	10,280	10,280
Solar Thermal[7]	2007	100	3	2,515	1.07	1.10	2,960	0.00	50.23	10,280	10,280
Photovoltaic[7]	2006	5	2	3,868	1.05	1.10	4,467	0.00	10.34	10,280	10,280

[1]Online year represents the first year that a new unit could be completed, given an order date of 2004.

[2]The technological optimism factor is applied to the first four units of a new, unproven design, it reflects the demonstrated tendency to underestimate actual costs for a first-of-a-kind unit.

[3]Overnight capital cost including contingency factors, excluding regional multipliers and learning effects. Interest charges are also excluded. These represent costs of new projects initiated in 2004.

[4]O&M = Operations and maintenance.

[5]Combustion turbine units can be built by the model prior to 2006 if necessary to meet a given region's reserve margin.

[6]Because geothermal and hydro cost and performance characteristics are specific for each site, the table entries represent the cost of the least expensive plant that could be built in the Northwest Power Pool region, where most of the proposed sites are located.

[7]Capital costs for geothermal and solar technologies are shown before the 10 percent investment tax credit is applied.

Sources: The values shown in this table are developed by the Energy Information Administration, Office of Integrated Analysis and Forecasting, from analysis of reports and discussions with various sources from industry, government, and the Department of Energy Fuel Offices and National Laboratories. They are not based on any specific technology model, but rather, are meant to represent the cost and performance of typical plants under normal operating conditions for each plant type. Key sources reviewed are listed in the 'Notes and Sources' section at the end of the chapter.

The CAISO currently has access to data supplied by a consulting firm Global Energy Decisions, Inc., which provides the variable O&M costs of a number of units in California. These data are summarized in Table 2 below.[16]

[16] The data shown in Table 1 represents about 87% of the metered generation since November 1, 2004 (start of Phase 1B). Categories with less than five units have been obscured for confidentiality reasons.

These data provide an indication of the approximate values of variable O&M costs for California generating stations.

Table 2: Empirical O&M Costs by Technology and Fuel Type

Gen Type	Fuel Type	#Units	Variable O&M			CAISO Proposal
			Avg.	Min	Max	
Combined Cycle	Gas	16	1.89	1.39	2.00	2.00
Gas Turbine	Gas	53	3.37	1.00	4.53	4.00
	Other	2	[redacted]	[redacted]	[redacted]	4.00
	Oil	3	[redacted]	[redacted]	[redacted]	4.00
Reciprocating Engine	Biogas	2	[redacted]	[redacted]	[redacted]	4.00
	Gas	2	[redacted]	[redacted]	[redacted]	4.00
Steam Turbine	Biomass	5	1.57	1.22	2.00	2.00
	Coal	2	[redacted]	[redacted]	[redacted]	2.00
	Gas	47	1.69	0.20	2.00	2.00
	Geothermal	15	1.00	1.00	1.00	2.00
	Nuclear	4	[redacted]	[redacted]	[redacted]	2.00

Data from both the EIA source and from Global Energy Decisions indicate that, for the California resource profile, there is a natural break between CCGTs and peakers, of about $2 and $4 respectively. According to the Global Energy Decisions' data, steam units appear to fall around $2 as well.

Q. What did stakeholders think of this proposal?

A. Stakeholders from LSEs agreed with the CAISO that the level of the O&M adder should be revisited, while members of the generator community appeared to be uniformly opposed to revisiting the O&M adder. For the reasons discussed above, however, I believe the CAISO proposal is more appropriate than retaining a $6 O&M adder.

5. Designation of Transmission Paths as Competitive or Non-Competitive

Q. How do non-competitive transmission constraints contribute to the potential exercise of market power?

A. Transmission constraints increase the potential for exercising market power by raising the level and decreasing the elasticity of effective demand curves facing generators. There are several distinct types of market power opportunities that transmission constraints can present. The most familiar is high concentration of supply within load pockets. In that case, by withholding capacity, local generation can induce congestion on connecting paths and prevent additional supply from entering the market, creating an uncompetitive situation for the residual demand in that location. Another example involves the interaction of generation controlled by a single supplier in different parts of the network; in certain situations, market power can be exercised by pricing a generator at one location below marginal cost in order to deliberately create congestion that raises prices for other generators at other locations.[17]

The focus of competitive path analysis is the identification of transmission constraints that result in the first type of uncompetitive conditions: high concentration in the supply-deficit areas. This is arguably the most prevalent and well-known set of market power problems caused by transmission. But because it is not the only way in which transmission constraints offer opportunities for strategic behavior, competitive path analysis may not necessarily be viewed as

[17] J. Cardell, C.C. Hitt, and W.W. Hogan, "Market Power and Strategic Interaction in Electricity Networks," *Resource and Energy Economics*, *Vol. 19, (Issues 1-2)*, March 1997, (pp. 109-137).

being sufficient for identifying all potential transmission-induced uncompetitive situations.

Q. Please describe the process by which transmission paths are designated as competitive or non-competitive.

A. The cornerstone of the LMPM provisions is the pre-designation of transmission paths as "competitive" or "non-competitive." The CAISO will complete the first assessment of competitiveness of transmission constraints prior to implementation of MRTU in November 2007. Constraint designations resulting from the first assessment will be applied in the LMPM mechanism on day one of MRTU and will not be changed until a subsequent assessment has been performed. Subsequent annual assessments will be made to be effective on January 1 of the following year, starting on January 1, 2009, assuming a November 2007 implementation date. Thus, the designations from the first assessment will cover the 14-month period from November 2007 through December 2008, unless a need arises to do an updated ad-hoc assessment within that period. The CAISO may elect to perform additional competitive constraint assessments during the year if changes in transmission infrastructure, generation resources, or load, in the CAISO Control Area and adjacent control areas suggest material changes in market conditions or if market outcomes are observed that are inconsistent with competitive market outcomes.

A transmission path or constraint will be deemed competitive if no three unaffiliated suppliers are jointly pivotal in relieving congestion on that constraint.

As mentioned earlier in my testimony, the determination of whether or not the pivotal supplier criteria for an individual constraint are violated will be assessed using a Feasibility Index ("FI") methodology. Assessment of competitiveness will be performed assuming various system conditions including but not limited to season, load, planned transmission and resource outages. If an individual constraint fails the pivotal supplier criteria under any of these system conditions, the constraint will be deemed uncompetitive for the entire year under all system conditions until a subsequent assessment deems the constraint competitive. In general, a constraint may be an individual transmission line or a collection of lines that creates a distinct transmission constraint. For purposes of the competitive assessment, the set of constraints that will be included in the network model are those modeled along with transmission limits to be enforced in the Full Network Model ("FNM") used in clearing the CAISO markets.

The assessments will be based on seasonal peak and off-peak supply and demand base cases, which reflect a relevant seasonal base case network (without contingencies), but which also reflect transmission ratings that already incorporate operational limits (based on a combination of thermal, voltage, and dynamic stability limits with N-1 contingency). For the first year, following the practice of other ISOs, the CAISO proposes that the Competitive Path Assessment results designate a path as either competitive or non-competitive with no seasonal distinction. For subsequent years, the CAISO proposes to study the advantages and disadvantages of a forward looking seasonal designation (based on actual experience under the LMP paradigm), where for each season the path in question would have to pass the competitiveness screen(s) only for the cases studied for that season.

Generation owners will be considered as potential pivotal entities for purposes of the competitive assessments. The portfolio of each supplier will be based on ownership information available to the CAISO, taking into account any material transfer of operational control that is of sufficient length that the transfer could have persistent impact on the relative shares of supply within the CAISO Control Area. Information on these transfers of control will be provided to the CAISO by the supplier based on its triennial filing with the Commission for market-based rate authority. The CAISO may also take into account partial unit ownership. However, to the extent that a single entity (perhaps one of the owners or the Scheduling Coordinator of the unit on behalf of all owners) may be the entity that decides on the bid price and quantity for the whole unit, the whole unit would be incorporated in the portfolio of that entity. The same consideration would apply to delegation of operational control to another entity based on long term contracts filed with the Commission and reflected in the triennial market based rate filing. The CAISO does not propose to treat the imports as pivotal suppliers, but will model import participation in conducting the Competitive Path Assessment.

Q. Please provide further details on the initial and subsequent assessments of competitive constraints.

A. The first assessment of competitive constraints will be determined prior to MRTU implementation. This assessment will reflect an assumption that all interfaces to neighboring control areas and all inter-zonal interfaces for zones that existed prior to the effective date of MRTU are competitive. The set of candidate constraints that will be evaluated for competitiveness in the initial assessment will be limited to intra-zonal constraints within current CAISO congestion management zones (NP15, SP15, ZP26), that were managed for congestion in real-time in greater than 500 hours in the 12-month period from April 1, 2006 through March 31, 2007. Because the Competitive Path Assessment requires extensive analysis and vetting with stakeholder before being finalized, the candidate paths will need to be identified well in advance of MRTU implementation. Moreover, sufficient lead-time will be necessary to implement the designations into the market software.

For the second competitive path assessment, the 12-month period of historical data will include several months of operation before MRTU and several months after MRTU implementation. The congestion frequency threshold of 500 hours for designation of competitive constraint candidates for the second annual Competitive Path Assessment will be based on the combination of pre-MRTU real-time intra-zonal congestion hours, and MRTU congestion in IFM and real-time markets for the 12 months of historical data. Subsequent annual assessments will again consider all pre-existing interfaces to neighboring control areas and all inter-zonal interfaces to be competitive. These interfaces will not be included in the set of candidate constraints for assessment.

The CAISO will perform a pivotal supplier test on all suppliers in the CAISO Control Area for each path to be assessed using the FI methodology. The FI methodology requires the CAISO to conduct power flow studies under various system scenarios that solve the network model having removed all internal resources of a supplier and modifying the candidate constraints of the network model such that the flow limits of the set of candidate constraints can be exceeded with a penalty imposed for excess flow. The resulting solution to the network model produces constraint flows that can be used to calculate the FI. The FI is calculated for each constraint as the proportion of the constraint limit that is exceeded to solve the FNM without the specified supplier's supply.

FI values less than zero indicate the supplier is pivotal in relieving congestion on that candidate constraint. The process is repeated by removing the supply portfolio of two and three suppliers for paths with non-negative FI. If any three suppliers are jointly pivotal in relieving congestion on a candidate path, as indicated by an FI value less than zero, the candidate path will be deemed uncompetitive. Otherwise, the candidate path will be deemed competitive.

Q. How does the CAISO's proposal compare to competitive path assessments by other ISOs?

A. Pivotal supplier analysis is the main criterion used by other ISOs (such as PJM and MISO) that have carried out competitive path assessment studies. Depending on the method adopted, a different number of "jointly pivotal suppliers" is used for competitiveness path assessment.

For example, PJM uses a "no-three-jointly-pivotal-suppliers" test; however, the pool of suppliers does not include all suppliers and if this criterion is not met for a given candidate path, the path may still be declared competitive if it passes a "no-two-jointly-pivotal-suppliers" test along with additional tests including a market concentration assessment (using the Herfindahl-Hirschman Index or "HHI") and a market-share test.

MISO uses a "no-two-jointly-pivotal-suppliers" test; however, although all suppliers are included in the pool, the maneuverability of the pivotal suppliers is assumed to be higher than the competitive fringe. The pivotal suppliers are assumed to be able not only to increase or decrease output to create congestion, but can also commit and de-commit their resources to do so, whereas the competitive fringe can only increase or decrease output to relieve congestion (they can change output only within the maximum and minimum operating limits of the units that happen to have been economically committed to be on line in the base case).

The PJM and MISO approaches require quantification of a "demand" for congestion relief as well as effectiveness of individual suppliers in creating or relieving congestion on a path in question. Determination of effectiveness requires the use of the so-called "shift factors" which measure the impact of a MW increase or decrease in production at a specific location (node) on the power flow on the specific path in question in the direction of interest. The shift factors (and thus the supplier effectiveness) depend on the choice of the sink (or slack bus or buses) used to measure the shift factors. The choice of such reference (slack bus) is arbitrary and as a consequence, the computed flows across transmission paths are also arbitrary. The arbitrary nature of the shift factor approach could lead to inaccurate assessments of competitiveness of transmission paths. Given this concern, the CAISO has designed an alternative method to conduct competitive path assessment based on pivotal supplier analysis without having to rely on shift factors, and even without having to quantify a "demand" for congestion relief. This new method is the Feasibility Index ("FI") methodology discussed earlier in my testimony.

Q. Did the CAISO consider alternatives to the Feasibility Index methodology?

A. Yes. The FI screen is a physical withholding test. It labels a supplier (or set of suppliers) as pivotal, and the path (or set of paths) as non-competitive, if congestion on the path (or set of paths) cannot be relieved at any price without the portfolio of the supplier(s) in question. One of the options considered was to supplement the pivotal assessment with a price impact assessment. The CAISO considered supplementing the pivotal analysis with a "Price Movement" screen. A Price Movement screen would consider price impacts and label the supplier(s) pivotal, and the path(s) non-competitive, even if the suppliers in question are not indispensable (*i.e.*, pivotal) for congestion management on the path(s) in question, if they can raise prices substantially by economic withholding. The CAISO is not proposing a Price Movement screen in conjunction with the FI approach ("no-three-jointly-pivotal-suppliers"). Adopting a Price Movement screen would be extremely complicated and difficult to implement. However, if a satisfactory methodology is worked out to implement a Price Movement screen in future annual assessments, then such a screen would likely be used based on the price impact of any two suppliers in tandem with "no-two-jointly-pivotal-suppliers".

Q. What were the stakeholder issues with the competitive path determination?

A. The CAISO's overall proposal is consistent with the stakeholder views on those design elements that had almost unanimous agreement within the stakeholder work group developed to review methodology options for the competitive path assessment. The proposal is intended to balance the objectives of simplicity, transparency, consistency, market efficiency, and market performance risk.

However, a number of stakeholders expressed concern that the CAISO's proposed competitive path assessment methodology was overly conservative in that the rebuttable presumption is that all paths (except current existing Inter-Zonal Branch Groups) are considered "non-competitive" unless they are shown by the study to be otherwise. A number of suppliers suggested the rebuttable presumption should be reversed (*i.e.*, all paths are considered "competitive" unless found to be otherwise).

I believe it would be very risky to simply assume all transmission paths are competitive unless shown to be otherwise. It is important to note that the outcome of a false positive (designating a path as "competitive" when in fact it is "non-competitive") is far more harmful than a false negative (designating a path as "non-competitive" when in fact it is "competitive"). If adequate competition does exist, bid prices are expected by definition to be not too far off the competitive levels, which can be approximated through Default Energy Bids. So, incorrectly designating a competitive path as non-competitive should not have a significant impact on final prices. However, if adequate competition does not exist and the path is declared as competitive (*i.e.*, false positive), the pivotal supplier will be in a position to raise prices with no local market power mitigation in place. This would clearly have a much greater price distortion impact.

Q. Please discuss the concerns of the CAISO Market Surveillance Committee about designating additional transmission paths as competitive.

A. The MSC has recommended that the CAISO not attempt to designate any path beyond the current Inter-Zonal Branch Groups as competitive for day one of MRTU implementation and wait until there is a full year of LMP operation before assessing whether additional paths should be designated as competitive. The MSC argues that it is very difficult to determine a priori how the market will behave under LMP and that some actual experience would provide better information for assessing path competitiveness. I appreciate the MSC's comments in this regard. In fact, their recommendation was the CAISO's original position on this issue. However, several market participants expressed concerns that such an approach is too conservative and would result in excessive mitigation. In response to these concerns, the CAISO agreed to perform a competitive path assessment prior to the start of MRTU, but that the assessment will be based on a fairly stringent criterion of "no three pivotal suppliers." I believe this is a reasonable compromise. As the MSC noted in its September 30, 2005 Opinion, provided as Attachment O to the MRTU Tariff filing letter, "We acknowledge that the three-pivotal-supplier approach is unlikely to be too lenient (*i.e.* it is unlikely to falsely designate transmission paths as competitive if they truly are not)."[18]

Q. Were there additional stakeholder concerns?

A. Some stakeholders also suggested that the competitive path assessment should be done on a seasonal basis with seasonal designations as opposed to a single designation for the entire year. While such an approach might be appropriate after the CAISO gains some significant operational experience under LMP, I believe that the CAISO should take a cautious approach for first year of LMP operation and provide a single designation for the entire first year. After some experience with LMP and the study methodology, a seasonal designation approach can be considered. I note that, to my knowledge, no other ISO is currently performing a forward temporal (seasonal) designation.

6. <u>LECG Concerns with PJM-Style LMPM</u>

Q. Please identify the concerns expressed by LECG in the February 2005 MRTU Report with respect to the proposed PJM-like local market power mitigation procedures.

A. First, I should note that the CAISO is submitting testimony prepared by Scott Harvey of LECG (Exhibit No. ISO-3) explaining generally how the CAISO has addressed the issues raised in the February 2005 MRTU Report. The following is

[18] *See* "Opinion on Aspects of the California CAISO's Market Redesign and Technology Upgrade (MRTU) Conceptual Filing", September 30, 2005.

my discussion of how the CAISO proposes to address the concerns raised in the February 2005 MRTU Report related to the market power mitigation provisions of MRTU.

The February 2005 MRTU Report raised several concerns with the proposed PJM-Like mitigation.

1. Constraints binding in the All Constraint Run of the MPM-RRD may be different than those binding in the actual IFM market clearing run or even if the same constraints were binding, the relative shadow prices will be different. As a consequence, generation possessing local market power may go unmitigated in the MPM-RRD or more likely, will be mitigated to a lower dispatch level than is actually needed in the IFM market clearing run and therefore will be able to exercise local market power in the IFM market clearing run.

2. Treating the Competitive Constraint Run unit commitment, which is based on a consideration of only competitive constraints, as fixed in the ACR could cause the ACR commitment to be quite different than the overall least cost unit commitment, which may result in units possessing local market power being unmitigated and potentially able to exercise market power in the actual IFM market clearing run.

3. The use of extreme negative decremental penalty bids in the ACR but not in the actual IFM market clearing may result in inaccurate mitigation in the IFM market clearing.

4. The structure of the ACR will not necessarily preclude the exercise of local market power by non-RMR units that are the least cost method of managing congestion but have high cost alternatives.

Before addressing these specific concerns, it is important to note that the MPM-RRD procedures that LECG reviewed formerly had a provision where bid mitigation was applied to only the incremental portion of the bid curve between the CCR and ACR dispatch level. As discussed previously in my testimony, the instant proposal now calls for mitigating the entire bid curve above the CCR dispatch level. This change was made largely in response to the concerns raised by LECG.

Q. Please discuss the first concern raised by LECG.

A. The first concern noted by LECG is largely addressed by the modification to mitigate the entire bid curve above the CCR dispatch level as opposed to only the incremental portion of the curve defined by the difference between the CCR and ACR dispatch levels. This modification results in better assurances that, to the extent additional output is needed in the IFM market clearing beyond what was dispatched in the ACR, such additional dispatch will be based on a mitigate bid curve. It is not possible to have a situation where a unit is not committed in the ACR but, due to a difference in the bids used in the actual IFM market clearing (*i.e.*, absence of extreme decremental bids), that unit is committed and dispatched in the IFM market clearing run and potentially able to exercise local market power. This will not occur due to the rule limiting the pool of resources considered in the IFM market clearing run to only those units that were committed in the ACR.

Q. Please discuss the second concern raised by LECG.

A. LECG's second concern was based on a misunderstanding of the MPM-RRD procedures. As noted above, the constraint on the pool of units considered for commitment is between the ACR and the IFM market clearing not between the CCR and ACR.

Q. Please discuss the third concern raised by LECG.

A. LECG's third concern on the use of extreme negative decremental penalty bids in the ACR is a legitimate concern. The CAISO proposes to address this concern in Release 2 of MRTU. For Release 1 of MRTU, this concern should be largely addressed by the modification to apply the mitigation to a unit's entire bid curve above the CCR dispatch level. It should be noted that eliminating the extreme decremental bids from the ACR would not eliminate the need for mitigating the entire bid curve because the proposed correction to this provision is to replace the extreme decremental bids with the LMP value from the CCR. While this correction will serve the same purpose as the extreme decremental bids, which is to prevent RMR units that are introduced to the ACR from being dispatched for anything other than local requirement, and to resolve what would be considered "intra-zonal congestion" under the current market design, the fact that a different set of bids will still be used in the IFM market clearing (*i.e.*, the LMP value used for the CCR dispatch level will be replaced by the actual market bids for those dispatch levels for use in the IFM market clearing) will still result in the potential for the IFM market clearing to produce a different dispatch. Therefore it will still be necessary to maintain the provision of mitigating the unit's entire bid curve above the CCR dispatch level.

Q. **Please discuss the fourth concern raised by LECG.**

A. LECG's fourth concern is best explained through a simple example. In this example, assume there is a load pocket with:

- 300 MW of Load

- a 400 MW steam unit with a DEB of $50/MWh
- 200 MW of gas turbines with a DEB of $150/MWh.

If the steam unit submitted an offer price of $200/MWh and the gas turbines were bid in at their DEB value of $150/MWh, the ACR of MPM-RRD procedures would dispatch the gas turbines for 200 MWh and the steam unit would be dispatched for 100 MWh and under the *prior* bid mitigation rule, only the first 100 MWh of the steam unit's bid curve would be mitigated to its DEB of $50/MWh. In the actual IFM market clearing, the gas turbines would be dispatched to 200 MWh, the steam unit would be dispatched to 100 MWh, and the prices would be set by the gas turbines at $150/MWh, even though the entire 300 MWh of load could have been met by the steam unit at a cost of $50/MWh. This scenario is corrected by the modification to extend the bid mitigation to the unit's entire bid curve above the CCR dispatch level. By mitigating the steam unit's bid curve to $50/MWh for the entire output range, the IFM market clearing would dispatch the steam unit to 300 MWh and the price would be set at $50/MWh.

Though the extension of the bid mitigation should largely address this issue, there is a residual case that is not addressed. This can be seen through a slight modification to the previous example. Now assume there is a load pocket with the following characteristics:

- 495 MW of load
- Two 300 MW steam units with DEBs of $50/MWh
- 200 MW of gas turbines with DEBs of $150/MWh

If the steam units submitted an offer price of $200/MWh and the gas turbines bid in at their DEB of $150/MWh, the ACR of the MPM-RRD would dispatch the gas turbines to 200 MWh and would dispatch one of the steam units to 295 MWh. Under the revised bid mitigation rule, the steam unit dispatched in the ACR would be mitigated to $50/MWh for its entire 300 MW. For simplicity, this example assumes that the steam unit was not dispatched in the CCR of the MPM-RRD and therefore the mitigation would apply to its entire output range. In the IFM market clearing, the steam unit would be dispatched to 300 MWh, the gas turbines would be dispatched to 195 MWh, and the price will be set by the gas turbines at $150/MWh, even though the entire load could have been met by both steam units at a price of $50/MWh. In this case, one of the steam units was economically withheld from the market forcing the LMP to go to the next highest cost alternative (*i.e.*, the gas turbines).

While such a situation is possible in theory, the CAISO discussed this issue with its Market Surveillance Committee and concluded that such situations are unlikely to be common. Such a situation generally could occur only in a load pocket where the load within the pocket could be served without the entire output of a low-cost base-load unit and the owner of that unit has a large enough portfolio of other generation in the pocket that the benefits the other dispatched units receive from the price effect of withholding the base-load unit exceeds the lost profits of not running the base-load unit. Nonetheless, the CAISO will conduct a study in 2006 to determine the potential for such situations. If this study finds that this is a more significant possibility than originally thought, the CAISO has some options to address it.

One option is a contractual fix, which would be to make sure the units in such locations have either an RMR contract or a local RA contract that is bundled with a fixed price offer obligation. Another option is to reconsider the NYISO-like local market power mitigation. Under the NYISO-like approach to local market power mitigation, this situation would be addressed by subjecting all units to a bid conduct test, which would mitigate any generator's ability to economically withhold an entire unit. However, the problem would have to be severe before considering the NYISO-like option because, as discussed earlier in my testimony, a significant downside of the NYISO-like approach is that the bid conduct and market impact thresholds themselves provide all generating units that have local market power an opportunity to exercise that market power up the level of the thresholds. This could be a case where the "disease is worse than the cure" because the issue identified by LECG is expected to apply to only a limited set of units.

7. Mitigating the Entire Bid Curve Above the CCR Dispatch Level

Q. Did stakeholders raise concerns about mitigating the entire bid curve above the CCR dispatch level?

A. Yes. The determination of which bids are mitigated is based on the MPM-RRD procedures, which are performed prior to the actual market clearing run of the market. The determination of which bids are subject to mitigation is done by comparing a non-RMR unit's dispatch under the All Constraint Run of the MPM-RRD to the Competitive Constraint Run CCR. Non-RMR units that have a higher dispatch level in the ACR will have mitigation applied to the *entire* portion of their bid curve above the CCR dispatch level. The Commission approved this approach in its July 1, 2005 Market Design Order.[19]

Some market participants argued that the mitigation should only apply to the portion of the unit's curve that is between the CCR and ACR dispatch levels, since that was the amount of additional dispatch determined to be needed from the ACR. In various stakeholder meetings, the CAISO explained the reasons why it is important to apply the mitigation to the entire bid curve above the CCR dispatch level. While the MPM-RRD procedures provide a technically sound and intuitive approach for determining mitigation, the dispatch from this process will not exactly match the dispatch determined from the actual market clearing run. Two aspects of the MPM-RRD procedures are likely to create some differences between the ACR dispatch levels and the final market clearing levels: (1) the use of penalty bids in the ACR and (2) basing the MPM-RRD on forecasted load. I will describe each of these in turn.

Large negative penalty bids are applied to accepted bids from the CCR for use in the ACR. The purpose of these large negative penalty bids is to ensure that any incremental dispatch from RMR units in the ACR is for local reliability reasons only (*i.e.*, to relieve congestion on the "non-competitive" paths, comparable to resolving intra-zonal congestion in the current zonal market design)

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[19] 112 FERC ¶ 61,013 at PP 118, 122.

rather than simply because they were cheaper to meet system needs. As explained earlier in my testimony, the only RMR units considered in the CCR are Condition 1 RMR units that offered market bids for the Day-Ahead Market. All RMR units (with one exception) are considered in the ACR based on their RMR Proxy Bids. The exception is for Condition 1 RMR Units that are partially dispatched in the CCR; these units are considered in the ACR based on the higher of their highest accepted market bid in the CCR or the lower of their market bids or RMR Proxy Bid. In this way, RMR Condition 1 Units are treated like non-RMR units to the extent their bids are competitive in the CCR. With the introduction of cost-based RMR Proxy Bids for RMR units in the ACR, there is a risk that these units could be dispatched up in the ACR simply because they are cheaper than some of the accepted bids from the CCR. Such a result is not consistent with the intended purpose of RMR units, which is to address local reliability concerns and to resolve intra-zonal congestion, or the equivalent, as modeled in the ACR. The use of large negative penalty bids on accepted CCR dispatch levels avoids this problem by making it very uneconomical to substitute RMR dispatch based on RMR Proxy Bids in the ACR for CCR dispatch from the CCR. Such a substitution would only occur if it were essential for solving the additional transmission constraints imposed in the ACR (*i.e.*, for solving local reliability needs or addressing the equivalent of intra-zonal congestion in the current zonal market design).

While this approach works fine for purposes of determining RMR dispatch and LMPM for non-RMR units, the bids that are ultimately passed on to the actual market clearing run will not include the large negative penalty bids used in the ACR. Consequently, the actual market clearing run may produce a different dispatch. In this case, the likely result would be that some resources that had penalty bids applied to them in the ACR run will be dispatched down further in the actual market clearing run and their decremented quantities would be replaced with dispatch of bids that were not subject to the penalty bids, which may include units that had their bids subject to mitigation through the LMPM procedures.

The second source of potential dispatch variation between the ACR and the actual market clearing run is the fact that the ACR run is based on forecasted load whereas the market clearing run is based on bid-in load. The rationale for this approach is described earlier in my testimony. This difference could result in the need to dispatch a mitigated unit in the market clearing run to a level higher than the ACR level. For instance, if all the units committed in the ACR are not committed in the market clearing run due to there being less load being cleared, then there may be a need to dispatch some mitigated units that are committed in the market clearing run to levels higher than the ACR dispatch.

For these reasons, the CAISO believes it is important to impose the mitigation on the entire bid curve above the CCR dispatch level as opposed to just that portion between the CCR and ACR levels. This approach is supported by the practice in other ISOs. It is my understanding that ISO-NE, NYISO, and PJM all have LMPM procedures that impose the mitigation on the entire bid curve.
Finally, this issue only arises in the context of the Day-Ahead Market. To the extent a unit is mitigated beyond what is needed to clear the IFM market clearing

run, the unit owner is free to re-bid the unselected portion of its unit in the subsequent HASP/RTM.

Q. Would basing the MPM-RRD on bid-in load eliminate the need to mitigate the entire bid curve?

A. No. Eliminating the extreme decremental bids from the ACR and basing the MPM-RRD on bid-in load (as opposed to forecasted load) would not eliminate the need for mitigating the entire bid curve because the proposed correction to the extreme decremental bids is to replace them with the LMP value from the CCR. While this correction will serve the same purpose as the extreme decremental bids, which is to prevent RMR units that are introduced to the ACR from being dispatched for anything other than local requirement, and to resolve what would be considered "intra-zonal congestion" under the current market design, the fact that a different set of bids will still be used in the IFM market clearing (*i.e.*, the LMP value used for the CCR dispatch level will be replaced by the actual market bids for those dispatch levels for use in the IFM market clearing) will still result in the potential for the IFM market clearing to produce a different dispatch. Therefore it will still be necessary to maintain the provision of mitigating the unit's entire bid curve above the CCR dispatch level even if the MPM-RRD was based on bid-in load and did not utilize extreme decremental bids.

C. Frequently-Mitigated Units and Bid Adders

Q. **Why is a Bid Adder for Frequently-Mitigated Units an appropriate component of the MRTU approach to local market power mitigation?**

A. Effective local market power mitigation must also be coupled with adequate mechanisms to ensure that those generating units critical for local reliability are earning sufficient revenues on average, and over a reasonable period of time, to cover their going forward fixed costs.

Q. **Please define "going forward fixed costs"?**

A. The term "going forward fixed costs" of a unit is a term which is interchangeable with the "avoidable fixed costs" of a unit and which refers to the unique operation and maintenance costs that could be avoided if a unit owner elected to deactivate or "mothball" the unit. The specific fixed costs pertain namely to fixed O&M and overhaul costs.

Q. **What is the primary mechanism for ensuring revenue adequacy for those generating units critical for local reliability?**

A. As discussed earlier in my testimony, a stable and sustainable wholesale market requires revenue adequacy for suppliers such that the pool of resources available to meet demand are in place where they are needed. Generation owners are likely to receive much of their cost recovery revenues through bilateral contracting, and bilateral contracting should be the primary mechanism for attracting new generation investment. CPUC-jurisdictional LSEs will be subject to regulatory requirements for forward bilateral contracting stemming from two different

CPUC proceedings: (1) the long-term procurement proceeding and (2) the Resource Adequacy proceeding. The implementation of local capacity requirements for LSEs is critical for addressing RA for units in constrained areas that are frequently subject to local market power mitigation. Although the CPUC deferred local requirement for LSEs in 2006, they have indicated that such requirements would be imposed in 2007. MRTU is not scheduled for implementation until the end of that year. Since roughly 75% of the CAISO load is comprised of CPUC jurisdictional entities, the CPUC contracting requirements will largely address revenue adequacy. Moreover, the CAISO's MRTU Tariff filing includes RA provisions applicable to all Scheduling Coordinators representing LSEs.

Q. Please explain what additional measures the CAISO proposes to address revenue adequacy for units needed for local reliability.

A. While the CAISO expects revenue adequacy issues will be largely addressed through bilateral contracting, the CAISO proposal specifically addresses potential revenue adequacy issues for those generating units critical for local reliability through a market bid adder, similar to an adder applied in PJM. This Bid Adder will provide additional revenues to contribute to going forward fixed cost recovery for any unit that is providing a necessary local capacity service and is mitigated with high frequency. By covering the avoided fixed costs, the bid adder provides sufficient revenues to make the unit economically viable to remain in operation until it is either no longer needed for reliability or is provided with a bilateral contract (*e.g.*, a Resource Adequacy contract). The CAISO's proposed Bid Adder mechanism was approved by the Commission in the July 1, 2005 Market Design Order.

Q. Is the Bid Adder for Frequently-Mitigated Units intended to address total fixed cost recovery?

A. No. It is important to note that, as is the case in PJM, the Bid Adder proposed by the CAISO is not intended to compensate a unit for its entire fixed costs, only the avoidable fixed costs. To the extent market conditions warrant it, total fixed cost recovery should be addressed through long-term bilateral contracts. Total fixed cost recovery, which includes recovery of capital costs, is never guaranteed. For instance, if there is a glut of existing generation, long-term bilateral contracts may reflect little to no capital cost recovery. However, if new investment is needed to meet demand over the contracting forward horizon (*i.e.*, three or more years out), then contracts should provide for capital cost recovery in order to provide for new generation investment.

1. <u>Eligibility for the Bid Adder</u>

Q. How is eligibility for the Bid Adder determined?

A. Eligibility for a Bid Adder will be determined on a monthly basis. To receive a Bid Adder, a generating unit must meet the following criteria:

(i) have a Mitigation Frequency that is greater than 80% in the previous 12 months;

(ii) have more than 200 run hours in the previous 12 months; and

(iii) must have some capacity not under an RA contract and not subject to any CAISO capacity service tariff.

Q. Please discuss the 80% mitigation criterion.

A. The 80% mitigation threshold for designation of a unit as Frequently-Mitigated, and for Bid Adder eligibility, is an established threshold approved by the Commission and implemented in the PJM revenue adequacy mechanism for Frequently-Mitigated Units. Units that are not mitigated in over 20% of their run hours should have sufficient opportunity to recover going forward fixed costs through infra-marginal rents occurring at their location during their unmitigated run hours. However, similar to PJM, such units have the option of seeking a consultative Default Energy Bid (*i.e.*, the Negotiated Option) that could include a contribution to going forward fixed costs if they can demonstrate that they cannot adequately recover sufficient revenues from the market and the CAISO determines they are critical to meeting local reliability needs.

Q. Please discuss the run hours criterion.

A. Run hours are those hours during which a Generating Unit has positive metered output. In order to provide sufficient time to assess eligibility and implement the Bid Adders for the next operating month, the 12-month assessment will actually end two weeks prior to the beginning of the next operating month.

During the first 12 months of MRTU operation, the Mitigation Frequency will be based on a rolling 12-month combination of: (1) RMR dispatches and incremental bids dispatched out of economic merit order to manage local congestion from the period prior to MRTU implementation, which will serve as a proxy to being subject to Local Market Power Mitigation under MRTU, and (2) a unit's Local Market Power Mitigation frequency after the effective date of MRTU. Generating units that received RMR dispatch orders and/or incremental bids dispatched out of economic merit order to manage local congestion in an hour during the pre-MRTU period will have that hour counted as a mitigated hour in their Mitigation Frequency. After the first 12 months of MRTU operation, the Mitigation Frequency will be based entirely on a unit being mitigated under the MRTU Local Market Power Mitigation procedures.

For new generating units, with less than 12-months of operation, determination of eligibility for the Bid Adder will be based on data beginning with the first date the generating unit participated in the CAISO Markets through the end of the evaluation period (*i.e.*, two weeks prior to the start of the next operating month). The 200 run hour criteria will be pro-rated for the proportion of a 12-month period that the new Generating Unit submitted effective bids in the CAISO markets.

Q. Did the CAISO modify the minimum run hours requirement from an earlier version of this proposal?

A. Yes. The proposal regarding minimum run hours has been increased from 100 run hours in a 12-month period to 200 run hours in a 12-month period based on an assessment of the cost recovery implications for units with 100 run hours. Using the Annual Fixed O&M figure reported by the California Energy Commission for a typical new combustion turbine, application of 100 run hours to this unit results in a capacity factor of just over 1% and a resulting Bid Adder of $200/MWh above the unit's variable costs. This report calculates fixed O&M costs of $20/kW-Yr for a new 100 MW combustion turbine, which equates to an annual fixed O&M cost of $2 million. If the unit only ran 100 hours per year, it would need a $200/MWh bid adder to fully recover its annual fixed O&M costs. It is unlikely that a unit requiring $200/MWh plus variable costs will be dispatched with the same frequency that the $200/MWh Bid Adder was based on. In fact, such a unit will likely be dispatched at a considerably lower frequency as there will likely be alternative less costly resources that can meet the same reliability needs. Consequently, such a high Bid Adder is likely to be counter-productive to providing revenue adequacy because, as the unit is dispatched less often, it will earn less revenues. Absent some run hour limitation on Bid Adders, this type of situation could deteriorate into a revenue "death spiral" as each year the unit will run less and qualify for an even higher Bid Adder, which in turn causes the unit to run even less frequently in the next period.

More fundamentally, it is important to note that the primary reason units with run hours less than 200 hours are not covering their fixed costs is because of their infrequent operation and not because of their frequent mitigation. The purpose for establishing a threshold for minimum run hours is to provide revenue adequacy for units that are unable to recover their avoidable fixed costs due to frequent mitigation. To the extent that infrequently run units are critical for meeting local reliability needs, their revenue requirements should be addressed through a local RA contract or through an alternative backstop capacity construct administered by the CAISO such as a capacity service tariff

Q. Please discuss the third criterion to be eligible for the Bid Adder.

A. The CAISO had originally proposed that units with any portion of their capacity under an RA contract would be ineligible for a Bid Adder. Comments received on this issue indicated that many stakeholders felt it unlikely that a unit would be able to recover all of their fixed costs from an RA contract if the contract covered only a portion of the unit's capacity. The CAISO has revised its proposal regarding the treatment of partially-contracted RA units and made the following modifications:

- Units with some portion of their capacity under an RA contract will not be prohibited from receiving a Bid Adder.
- If a partial-RA unit meets the eligibility criteria to select the FMU Default Energy Bid option, the Bid Adder (default or negotiated) will be pro-rated to reflect the proportion of that unit's capacity that is not contracted. For example, an FMU with 75% of its capacity under an RA contract would receive a $6/MWh Bid Adder as the default (*i.e.*, 25% of $24/MWh).

The pro-rated Bid Adder for partial-RA units will be applied to the entire cost-based Default Energy Bid.

Q. Are there additional requirements for a unit to receive the Bid Adder?

A. Yes. The bid adder is only available if the unit meets the three criteria that I just listed and if the resource owner selects the FMU Option (Option 4) for Default Energy Bids. This option preserves the avoidable cost compensation property of the bid adder while removing any "double payment" of avoidable cost. Payments under the FMU Option are the equivalent of the Variable Cost Option payment plus an adder to address revenue deficiencies for those units that meet the criteria described above. The overpayment of avoidable costs could occur if resources were allowed to receive the Bid Adder along with a Negotiated or LMP-based Default Energy Bid since the Negotiated Option could have incorporated avoidable costs in their negotiated value and the LMP Option could provide revenues above variable cost plus 10%. This approach also reduces portfolio incentives that may exist from having a Bid Adder set the LMP on which the DEB of one or more of a unit owner's resources are based. The issue of over-payment in this circumstance would introduce further inefficiencies into the market. For this reason, the Variable Cost Option is the correct basis for applying a Bid Adder that is intended as a short-term fix to a revenue deficiency issue.

2. Value of the Bid Adder

Q. How will the Bid Adder be calculated?

A. The MRTU Tariff includes two options for the Bid Adder value. The first option is a negotiated value that is negotiated between the Scheduling Coordinator for the FMU and either an Independent Entity selected by the CAISO or the CAISO itself. Under this option, Scheduling Coordinators will present cost data reflecting their unit specific avoidable costs to the CAISO or an Independent Entity and negotiate a unit-specific Bid Adder value that adheres to the intent of the Bid Adder, namely compensation for avoidable fixed cost.

The second option is a default value of $24/MWh. This figure was calculated using the same formula used by PJM to calculate PJM's default Bid Adder value, where the per MWh dollar value is calculated as the ratio of Annual Avoidable Fixed Cost to Annual Expected Energy Production. Based on data from characteristic in-service Combustion Turbines within its control area, PJM applied this formula and calculated a $40/MWh Bid Adder. The CAISO had proposed, through the stakeholder process, that owners of Combustion Turbines ("CTs") voluntarily submit to the CAISO avoidable cost data on each of their CTs and that this information would be used as the basis for calculating a default Bid Adder value. Only one unit owner responded to this request with avoidable cost data. A larger sample of cost data is required in order to use this source of data as a basis for calculating the default Bid Adder value for all potential FMUs. In the absence of a larger sample of cost data from existing Combustion Turbine owners, the CAISO has based its proposed Default Bid Adder value on the same formula used by PJM applied to Fixed O&M cost figures for a new Combustion Turbine in California, as reported in Appendix D of the California Energy Commission 2003 Final Staff Report titled "Comparative Cost of California Central Station Electricity Generation Technologies." This document reports fixed O&M costs of $20/kW-Yr for a new 100 MW CT that has a capacity factor of 9.4%. Using these figures, the Annual Fixed O&M Cost is $2,000,000 and the Annual Expected Energy Production is 82,344 MWh. This results in a default Bid Adder value of approximately $24/MWh.

3. Additional Issues Related to Revenue Adequacy

Q. Did the CAISO and other parties have concerns about the Bid Adder mechanism?

A. Yes. Initially, the CAISO was very reluctant to adopt the Bid Adder mechanism due to the clear distorting effect Bid Adders would have on optimal dispatches and LMPs. The CAISO Market Surveillance Committee, the Department of Market Monitoring, and a number of stakeholders expressed concern that introducing a Bid Adder could be very detrimental to market efficiency, would be unlikely to serve their intended purpose, and potentially could be very costly to load. In the end, the CAISO agreed to adopt the Bid Adder to be consistent with the PJM "package" of mitigation as was suggested by Commission Staff in their Guidance Letter. Moreover, the potential market inefficiencies associated with Bid Adders will be minimized if all or most units needed for local reliability have an RA contract for their entire capacity.

Q. Is the CAISO exploring alternative, long-term solutions to the revenue adequacy issue?

A. Yes. In the long run, I believe a better backstop mechanism for addressing revenue adequacy for Frequently-Mitigated Units that do not receive sufficient revenues through long-term contracts is for the CAISO to provide an upfront capacity payment to such units. To date, the only mechanism for such payment has been an RMR contract. The Commission has clearly indicated its preference to avoid reliance on RMR contracts and for more administratively simpler and market oriented mechanisms for addressing revenue adequacy. In the future, the CAISO may develop alternative backstop mechanisms for revenue adequacy such as some type of capacity service tariff rate or a local capacity market, which could replace the Bid Adder when implemented.

Recently, IEP filed a complaint in Docket No. EL05-147 in which it argued that the current Must-Offer provisions are not just and reasonable and proposed an alternative reliability capacity service tariff. In its Answer to IEP's filing, the CAISO agreed that it was appropriate to develop, as a replacement for the Must-Offer obligation, an appropriate backstop mechanism for the CPUC Resource Adequacy requirements that commence in 2006. The CAISO has been engaged in settlement discussions with IEP and others to see if agreement can be reached on these issues. To the extent that such a backstop mechanism for Resource Adequacy in 2006 is developed, the CAISO may consider using a similar mechanism as its backstop revenue adequacy mechanism under MRTU for FMU, as opposed to a Bid Adder.

D. <u>System-Wide Market Power Mitigation</u>

Q. What was the CAISO's original proposal for system-wide market power mitigation?

A. System-wide market power mitigation is addressed under the MRTU Tariff through "damage control" bid caps. In its May 13, 2005 Filing, the CAISO proposed a stepped transition for raising the energy bid caps under MRTU. Specifically, the CAISO proposed to start MRTU with the $250 soft bid cap on energy bids that was in effect through the end of 2005 and to implement a three-year transition plan for raising the bid cap to $1,000/MWh in increments of $250 each year subject to an assessment that the energy markets were sufficiently competitive to warrant raising the cap. The CAISO also proposed to lower the Ancillary Service bid caps and RUC availability bid caps from $250/MW to $100/MW in decrements of $50/MW over the same three-year period to be more in line with the ancillary service bid caps in other ISOs.

Q. How did the Commission act on that proposal?

A. In its July 1, 2005 Market Design Order, the Commission rejected the CAISO proposal on bid caps and directed the CAISO to start MRTU with a $500/MWh hard energy bid cap and to automatically increase it to $1,000/MWh in increments of $250 over a two-year period unless the CAISO makes a filing with the Commission showing that its markets are non-competitive and the Commission supports this assessment.[20] The Commission also rejected the CAISO proposal to lower the bid caps for Ancillary Services and RUC availability bids noting that unlike other ISOs, the CAISO lacks a capacity market and that the CAISO will not initially have the $1,000/MWh energy bid cap in effect in other ISOs.[21] This directive was consistent with the Commission's October 28, 2003 and June 2004 orders that indicated that the bid caps for ancillary services and RUC availability

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[20] 112 FERC ¶ 61,013 at P 104.

[21] *Id.* at PP 109-111.

bids should be $250/MW.[22] The Commission noted that as California and the CAISO progress towards implementation of the CPUC's RA requirements and possible capacity markets, the CAISO should reassess the level of the Ancillary Service and RUC availability bid caps. Furthermore, the Commission stated the CAISO should propose revised bid caps for these markets should structural or market issues arise in California that warrant the lowering of the caps.

The bid caps for the energy, Ancillary Services, and RUC markets in the MRTU Tariff are exactly as directed by the Commission in its July 1, 2005 Market Design Order.

[22] *California Independent System Operator Corp.*, 105 FERC ¶ 61,140 at P 123 (2003) ("October 28, 2003 Order"); *California Independent System Operator Corp.*, 107 FERC ¶ 61,274 at PP 65-68 (2004) (June 17, 2004 Order").

IV. INTER-SCHEDULING COORDINATOR TRADES

Q. Please explain your involvement in the development of the Inter-SC Trade Rules.

A. I became involved in designing the rules for Inter-SC Trades of Energy under MRTU in the Summer of 2004 to address the "Seller's Choice" problem associated with certain bilateral energy contracts entered into by the State of California. Many of these contracts, which were entered into during the California energy crisis, extend beyond the planned 2007 implementation date of MRTU and have delivery provisions that, prior to recent settlements, could have been construed to give the seller the choice of delivering power at any node within the CAISO existing zones. If the contracts were implemented in such a manner under an LMP-based market, they would potentially have a significant and detrimental financial impact to the State of California and ultimately California ratepayers. The potential financial impact to ratepayers of not addressing the potential incompatibility of the Seller's Choice delivery provisions with an LMP-based market design was so great that CAISO management and the CAISO Board of Governors publicly indicated they would not go forward with MRTU unless this issue was satisfactorily resolved. Given the significance of this issue, CAISO management tasked me with leading a stakeholder effort to try to resolve this issue by early 2005. CAISO management wanted to determine if this issue could be resolved as soon as possible so that if not, the CAISO could consider other market design options.

Q. Has the Seller's Choice Problem been resolved?

A. Yes, assuming the Commission does not alter the proposed Inter-SC Trade design, which it approved conceptually in connection with the settlement of Seller's Choice issues.

The Commission recognized the significance of the Seller's Choice issues when it initiated a Section 206 proceeding on June 17, 2004 in Docket No. EL04-108 specifically to address incompatibility of an LMP market design with seller's choice contracts.[23] Following numerous settlement conferences and public stakeholder meetings, the CAISO developed the Inter-SC Trade design that is reflected in the MRTU Tariff and parties to Seller's Choice contracts entered into settlement agreements resolving the Seller's Choice problem under MRTU provided the Commission accepts the CAISO's Inter-SC Trade design. The key element that resolved the Seller's Choice problem was the addition of a physical validation rule for Inter-SC Trades at specific nodes. This requirement allows sellers the flexibility to deliver at any location that is physically feasible and at which the sellers have secured supply, while eliminating the ability of a seller to create counter-flow revenues by designating low cost nodes for delivery that is physically infeasible. The other element of the Inter-SC Trade design that is central to the settlements in the Seller's Choice docket is the commitment of the CAISO to create Existing Zone Generation Trading Hubs ("EZ Gen Hubs") for each of the pre-existing congestion management zones (NP15, SP15, ZP26). Inter-SC Trades submitted for delivery at an EZ Gen Hub or any other aggregated

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[23] June 17, 2004 Order, 107 FERC ¶ 61,274 at PP 165-66.

pricing node will not be subject to the physical validation rule. The EZ Gen Hub prices will be calculated based on an average price of generation pricing nodes within each zone. The proposed design for Inter-SC Trades and EZ Gen Hubs was presented for Commission approval on March 15, 2005.

Q. Did the Commission approve the March 15, 2005 filing?

A. Yes. On June 10, 2005, the Commission issued an order approving in principle the CAISO's conceptual proposal to establish settlement services for bilateral energy transactions at generation nodes within the CAISO control area and at aggregated pricing points.[24] The Commission also approved the physical validation procedure under which Scheduling Coordinators trading at individual generation nodes must demonstrate that they have a physical resource schedule at the same generation node at a level not less than the amount of the trade. Finally, the Commission approved the proposed creation of EZ Gen Hubs as successor delivery points under Locational Marginal Pricing for the CAISO's existing internal congestion zones. The Inter-SC Trade proposal and creation of EZ Gen Hubs, the Commission noted, is a reasonable means to resolve the issues arising under seller's choice contracts and the transition of these contracts to Locational Marginal Pricing.

In addition, the settlements entered into by parties to the Seller's Choice contract were also approved by the Commission on June 10, 2005.[25] The Tariff

[24] *California Independent System Operator Corp.*, 111 FERC ¶ 61,384 (2005) (June 10, 2005 Order").

[25] 111 FERC ¶ 61,385 (2005) and 111 FERC ¶ 61,386 (2005).

language provided in this instant filing provides a more detailed description of the Inter-SC Trade rules and EZ Gen Hubs, all of which is consistent with the conceptual design that was approved by the Commission on June 10, 2005.

Q. What would be the implications if the Commission decided to modify the Inter-SC Trade design proposal?

A. It is important for the Commission to understand that the settlement agreements are intricately linked and conditioned on the Inter-SC Trade design the Commission conceptually approved on June 10, 2005. Any modification to that design would place the settlements at risk and would certainly be a tremendous setback that could jeopardize the entire MRTU project.

Q. Could you please provide a more detailed description of the "Seller's Choice" problem?

A. During the electricity crisis of 2001, the State of California, through the California Energy Resource Scheduler of the California Department of Water Resources ("CERS") entered into several power purchase agreements with generating companies and marketers to ensure that adequate energy supplies would be available to meet the demand of California's end-use customers following the credit crises of the state's investor-owned utilities. Some, but by no means all, of these contracts allow the sellers a degree of flexibility as to the location for delivery of the energy. Without characterizing or referring to any specific CERS contract, an extreme application of this interpretation of a Seller's Choice contract would allow the seller to deliver energy at any location within the CAISO Control Area. Under the zonal market design in effect when these contracts were entered into, delivery options were limited to the three active zones within the CAISO Control Area (NP15, SP15 and ZP26), so options even under the most flexible form of seller's choice contract were quite limited. Parties to such contracts used the CAISO's current Inter-SC Trade mechanism to effectuate contractual delivery by specifying NP15, SP15 or ZP26 in their Inter-SC Trade.

Under a nodal LMP market design with a Day-Ahead Market, such as MRTU, the same contract could be interpreted, theoretically, as allowing a seller to effectuate contractual delivery at any of the several thousand nodes in the CAISO Control Area. Under such an interpretation of these contracts, sellers could, theoretically, select low priced nodes as the location for delivery and earn counter-flow revenues to the extent the LMP at the injection node was higher than the LMP at the delivery node. This, in turn, would increase the congestion costs charged to buyers — buyers would be responsible for paying the difference between the LMP at the delivery node specified in the Inter-SC Trade and the point where the energy is withdrawn (the Load Aggregation Point). Moreover, CRRs would not be adequate to hedge all possible congestion associated with a Seller's Choice option that allowed "delivery" at any node. CRRs, which are defined by points of injections and points of withdraws, must be simultaneously feasible with respect to the transmission network whereas Inter-SC Trades are not subject to congestion feasibility. If sellers are able to effectuate contractual delivery through Inter-SC Trades at infeasible delivery points, congestion charges associated with such deliveries cannot be hedged.

Q. How does the Inter-SC Trade mechanism relate to the Seller's Choice Problem?

A. To answer this question, let me explain the use of Inter-SC Trades in the CAISO's current zonal market design. In the current zonal market design, Inter-SC Trades serve two functions. First, consistent with the CAISO's balanced schedule requirement, Inter-SC Trades allow Scheduling Coordinators to balance their portfolios of forward energy schedules through bilateral trades with other Scheduling Coordinators. As a result, Scheduling Coordinators are able to submit to the CAISO a balanced schedule of load and generation. Second, Inter-SC Trades are used to effectuate contractual delivery of bilateral energy requirements.

The introduction of a forward energy market under MRTU eliminates the balanced schedule requirement. Elimination of a balanced schedule requirement eliminates the need for Inter-SC Trades as an essential or required element of the market design. Scheduling Coordinators will be able to come into the forward market with unbalanced portfolios and bid to purchase and sell energy. Although not needed to run the forward energy markets, the CAISO recognized the value that the Inter-SC Trade mechanism provides to SCs to effectuate contractual delivery and to provide a settlement service for bilateral energy contracts and therefore proposed to provide an Inter-SC Trade service under MRTU. The Inter-SC Trade service under MRTU will be optional in the sense that the counter-parties to a bilateral contract could elect to settle their bilateral contract without using the CAISO Inter-SC Trade settlement service. As early as July 2003, the CAISO proposed to include an Inter-SC Trade mechanism as part of MRTU. At that time, however, the CAISO also recognized that the Inter-SC Trade mechanisms would need to be designed to adequately address the Seller's Choice problem.

Q. **In what ways will Inter-SC Trades assist in settling bilateral energy contracts under the MRTU design?**

A. Inter-SC Trades assist in settling bilateral energy contracts in three respects. First, contracting parties can use the Inter-SC Trade as the instrument for the contractual delivery of energy. Second, an Inter-SC Trade provides a counter payment mechanism to offset the double energy settlement that occurs from scheduling bilateral contracts in the CAISO's forward energy market. Under MRTU, all energy schedules in the forward energy market are settled at the relevant LMPs. The double settlement arises because a buyer is charged twice for its energy purchase, once under the bilateral contract and again when the demand associated with that contract is scheduled in the forward energy market. Similarly, a seller is paid twice, once under the bilateral contract and again when the power supporting that contract is scheduled in the forward energy market. The Inter-SC Trade provides a third (counter-settlement) to the forward energy market settlement. The third respect in which Inter-SC Trades assist in settling bilateral energy contracts occurs because Inter-SC Trades allocate congestion costs for contractual delivery between the two counter-parties. The CAISO market prices at the location of the Inter-SC Trade, and at points where the counter-parties schedule load and generation, determine the allocation of congestion costs. Some specific numeric examples of how Inter-SC Trades facilitate the settlement of bilateral contracts are provided in the CAISO's March 15, 2005 transmittal letter in Docket No. ER02-1656.

Q. Please describe the MRTU Inter-SC Trade design.

A. Under MRTU, the CAISO will offer Inter-SC Trade settlement services for bilateral energy transactions at generation nodes within the CAISO Control Area and at aggregated pricing points (Trading Hubs and Load Aggregation Points). Similar to the current Inter-SC Trade settlement services, the CAISO will not offer Inter-SC Trades under MRTU at Intertie Scheduling Points. Only Inter-SC Trades at individual generation nodes will be subject to a physical validation procedure.

Inter-SC Trade settlement services will be provided in both the Day-Ahead Market and the Hour-Ahead Scheduling Process. Inter-SC Trades submitted for the Day-Ahead Market will be settled at Day-Ahead Market prices, and trades submitted in the Hour-Ahead Scheduling Process will be settled at Real-Time Market prices based on a simple average of the Real-Time Dispatch Interval Prices. Should the CAISO implement a full-settlement Hour-Ahead market sometime after MRTU Release 1, Inter-SC Trades provided in the Hour-Ahead market will be settled at Hour-Ahead market prices.

It is also important to note that Inter-SC Trades do not settle or affect the bilateral contract price, but rather the counter-parties to the Inter-SC Trade will need to settle the bilateral contract price on their own.

Q. What will the Scheduling Coordinators trading at individual generation nodes be required to demonstrate during the physical validation procedure?

A. Scheduling Coordinators trading at individual generation nodes will need to demonstrate that their trade is supported by a "transmission feasible" generator resource schedule at the same location. Such trades will be referred to in this testimony as Physical Trades or "PTs." A "transmission feasible" generator resource schedule is a generator's final schedule after the CAISO forward energy market clears (*i.e.*, after congestion management and the clearing of supply and demand bids).

Q. Please describe in detail the physical validation procedures for Scheduling Coordinators trading at individual generation nodes.

A. The physical validation procedure includes the following three stages: (1) PT Submittal Screening, (2) PT Pre-Market Validation, and (3) PT Post Market Confirmation. PT Submittal Screening involves validating that a PT does not exceed the physical capabilities of the identified generator resource. PTs that violate this screen will be automatically kicked back to the Scheduling Coordinator. PTs that pass the Submittal Screening will receive, through the CAISO Inter-SC scheduling interface, immediate and frequent feedback on the status of their trade. At a minimum, this information will indicate whether the trade is “valid” or “invalid”, which the SCs can use to make modifications and communications with other trading SCs to complete and correct invalidated trades.

The second stage, PT Pre-Market Validation, takes place at the close of the Final Trading Period, which for Day-Ahead Inter-SC Trades occurs after the close of the Day-Ahead energy market but before the posting of the results of the Day-Ahead Market.

In its June 10, 2005 Order, the Commission noted that the MRTU Tariff filing would include additional detail on the duration of the Final Trading Period.[26] The Day-Ahead Final Trading Period will end at a time at least 30 minutes after the close of the Day-Ahead Market, but prior to the posting of LMPs from the Day-Ahead Market. The HASP Final Trading Period will end at a time at least 10 minutes after the close of the HASP but prior to the posting of Locational Marginal Prices from the HASP.

During this Final Trading Period, market participants can submit new PTs and make adjustments to existing PTs. At the period’s close, the CAISO will perform a final Pre-Market Validation. Any individual PTs that are invalid due to inconsistencies between the trading counter-parties on the quantity and location of the trade will be rejected and returned to the trading Scheduling Coordinators as invalid. The CAISO will not perform any settlement on these rejected PTs. Remaining PTs that are individually valid will be concatenated (*i.e.*, an SC with a buy position at a particular generation node may use that trade as its source in a

[26] 111 FERC ¶ 62,384 at P 29.

second PT at the same location in which it has a selling position; such trading is often referred to as "daisy-chain transactions"). If, within a particular trading chain, an SC has insufficient source trades to support all of its selling trades, the PTs of that SC and its trading counter-parties will be adjusted down pro-rata until the remaining PTs are valid. Further, if there are additional downstream transactions with the SC's trading counter parties (*i.e.*, the trading counter parties were using the trade as a source for another trade), those downstream transactions will be also adjusted pro-rata until they become valid. The CAISO will not perform any settlement with PT quantities that are curtailed during Pre-Market Validation.

The third stage, PT Post-Market Confirmation, confirms that the physical delivery obligation of PTs has been satisfied. The CAISO will adjust Inter-SC Trades after the forward market clears if the generation unit supporting the trade has a final market schedule that is below the quantity of Inter-SC Trades at that location. The megawatt quantities of the Inter-SC Trades that are adjusted down during this post-market validation process will be converted to trades (not physically validated) at the relevant Existing Zone Generation Trading Hubs ("EZ Generation Hub"). I will provide more details on EZ Gen Hubs later in my testimony.

Q. What is the rationale for settling the curtailed quantities in the PT Post-Market Confirmation at the EZ Generation Hub?

A. Settling the curtailed portion of these Inter-SC Trades at the Existing Zone Generation Trading Hub is appropriate because it represents the best proxy price for the "market cost" of serving the contract. For example, if Generator A and its counter-party had made an initial Inter-SC Trade at generation node A, where Generator A is located, for 100 MW, but Generator A's final market schedule was 80 MW, then the 80 MW schedule is serving the contract and this quantity of the Inter-SC Trade is appropriately settled at the LMP for generation node A. The only remaining question is how the remaining 20 MW of the bilateral contract is to be served. Assuming the buyer's 100 MW of load associated with the contract cleared the forward market, the 20 MW not being served by Generator A is essentially being served by "market energy" (*i.e.*, other supply resources that cleared the forward market). The CAISO reasoned, and most stakeholders agreed, that the best representation of "market energy" in this case is the EZ Gen Hub price for the zone that contains Generator A.

Q. How do the physical validation procedures fix the seller's choice problem?

A. Requiring physical validation of Inter-SC Trades at generation nodes limits the volume of power sales settled at any node to the physical capabilities of the grid at that node and in so doing increases the likelihood that load will obtain sufficient CRRs to hedge the congestion costs associated with the delivery of this bilateral energy. By prohibiting a seller from settling an Inter-SC Trade at a node for a volume of power that exceeds either the generator's capability (*i.e.*, P-max) or the ability of the transmission grid to receive power at that node, the physical validation requirement effectively eliminates the seller's opportunity to impose on the buyer a transaction that is impossible to hedge.

Q. Will Inter-SC Trades at aggregated pricing points be subject to any validation procedures?

A. Yes. Inter-SC Trades at aggregated pricing points (Trading Hubs and Load Aggregation Points) will be subject to a simpler Pre-Market Validation than is applied to PTs. The Pre-Market Validation of these trades will involve confirmation that both parties to the trade agree on the quantity and location of the trade. Similar to PTs, trades at aggregated pricing points can be submitted and adjusted during the Final Trading Period. However, they will not be subject to a Submittal Screening or a Post-Market Confirmation. SCs will receive immediate and continuous feedback on the status of their trades at aggregated pricing points through the CAISO Inter-SC Trade scheduling interface.

Q. Why is the CAISO not providing Inter-SC Trades at Intertie Scheduling Points?

A. The CAISO is not providing Inter-SC Trades at Intertie Scheduling Points under the MRTU Tariff because bilateral deliveries at such points can be easily settled without the use of Inter-SC Trades. It is important to note that the current market design also does not provide a mechanism for Inter-SC Trades at Intertie Scheduling Points.

A simple example will clarify why Inter-SC Trades at Intertie Scheduling Points are unnecessary. If a seller to a bilateral contract chooses to serve that contract through an import to the CAISO Control Area, both the buyer and seller will need to agree on the point of delivery. If the parties agree that the point of delivery is the intertie, then the buyer will schedule the energy at the Intertie Scheduling Point and incur any congestion costs from that point to where the power is withdrawn in the CAISO Control Area (*e.g.*, a LAP). Alternatively, if the parties agree that the delivery point is a point within the CAISO Control Area (*e.g.*, a LAP), the seller will schedule the import at the Intertie Scheduling Point and both parties will do an Inter-SC Trade at the LAP. In this case the seller will incur any congestion costs between the Intertie Scheduling Point and the LAP. Unlike a generator node, which can only be scheduled by the Scheduling Coordinator for that generator, any Scheduling Coordinator can schedule at an Intertie Scheduling Point. This difference makes it unnecessary to provide Inter-SC Trades at Intertie Scheduling Points.

This particular issue was discussed extensively with market participants and there was strong agreement, particularly among importing entities, that Inter-SC Trades at Intertie Scheduling Points were not necessary.

Q. Have stakeholders been involved in the development of the MRTU Inter-SC Trade design proposal?

A. Yes. This issue has been discussed extensively with stakeholders since the Spring of 2004 when the CAISO initiated an effort to explore options for an Inter-SC

Trade mechanism that would address the Seller's Choice contract issue under LMP-based markets. The CAISO released a white paper describing concerns associated with the settlement of seller's choice contracts under LMP and offered several options for Inter-SC Trade settlement rules to address those concerns.[27] The CAISO also requested and received comments from market participants about the different options proposed in the white paper.[28] In addition, the CAISO provided illustrative numerical examples of the potential effect of Inter-SC Trade settlement rules on pre-existing bilateral energy contracts once LMP is implemented.[29]

As mentioned earlier, in the June 17, 2004 Order, the Commission instituted a Section 206 proceeding for the purpose of investigating the feasibility of both upholding seller's choice contracts without modification and implementing the CAISO's proposed redesign, and directed that this assessment include an examination of the degree to which these types of contracts present market inefficiencies and are not operationally and economically compatible with the CAISO's proposed redesign, as well as the options for resolving the issues

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[27] *See* California ISO White Paper, "Market Design 2002 Scheduling Rules: Alternatives for Mitigating the Impact of Nodal Pricing on Pre-existing Bilateral Energy Contracts", March 9, 2004, available at http://www.caiso.com/docs/2004/03/09/2004030909273623396.pdf

[28] *See, e.g.*, stakeholder comments from Calpine, Northern California Power Association, Southern California Edison, Powerex, Pacific Gas & Electric, The Independent Energy Producers Association, SVP, Strategic Energy, California Municipal Utilities Association, and the California Public Utilities Association at http://www.caiso.com/docs/2004/03/09/2004030909140522185.html

[29] *See* California ISO Discussion Document, "Impact of Nodal Pricing on Pre-Existing Bilateral Energy Contracts (Illustrative Examples)", June 1, 2004, available at http://www.caiso.com/docs/2004/03/09/2004030909140522185.html

surrounding the Sellers' Choice contracts.[30] Settlement discussions commenced in July 2004.

The CAISO actively participated in the Section 206 proceeding, providing technical support to parties by explaining detailed aspects of the proposed LMP market design and how it relates to the settlement of bilateral energy contracts. The CAISO has also further developed aspects of the MRTU conceptual design that have important implications for Seller's Choice contracts as well as other pre-existing bilateral energy contracts. Specifically, the CAISO led an extensive stakeholder process to further define and clarify the role and definitions of Trading Hubs under MRTU.[31]

The CAISO's proposal on Inter-SC Trades that the Commission accepted on June 10, 2005 was the product of a significant stakeholder process in which several modifications to the CAISO's originally proposed Inter-SC Trade design were made in response to stakeholder feedback. The CAISO provided a white paper describing its proposal to market participants on November 19, 2004.[32] It then hosted an all-day stakeholder meeting on December 9, 2004 to review the proposal,[33] and requested and received numerous written comments on the proposal on December 22, 2004. The CAISO subsequently hosted a second stakeholder meeting on January 11, 2005 in which several significant

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[30] *See* June 17, 2004 Order at PP. 165-166.

[31] *See* CAISO papers regarding development of Trading Hubs under MRTU and stakeholder comments regarding CAISO Trading Hub proposals at http://www.caiso.com/docs/2004/08/17/2004081714581426212.html

[32] *See* "CAISO Proposed Market Rules for Inter-SC Trade Functionality under MRTU," November 19, 2004, available at http://www.caiso.com/docs/2004/03/09/2004030909140522185.html

[33] Meeting agenda and presentation available at http://www.caiso.com/docs/2004/03/09/2004030909140522185.html

modifications were made to the proposal in response to stakeholder feedback,[34] and issued a revised white paper on January 14, 2005.[35] The CAISO Board approved the proposal on January 27, 2005 and authorized the conceptual filing that was submitted on March 15, 2005.

Q. Please expand on the EZ Gen Hubs.

A. The EZ Gen Hubs will be successor delivery points under Locational Marginal Pricing for today's existing internal congestion zones (NP15, SP15, and ZP26). The hub prices represent the average price paid to generation within the zone and as such, will be based on only Locational Marginal Prices at generation nodes. The hub prices will be weighted averages of the generation LMPs in the relevant zone. The weights will be determined annually based on the previous year's seasonal MWh output of the generation units and will be differentiated by peak and off-peak periods. The specification of seasons will be identical to the seasons used in the annual CRR Allocation, and the annual calculation of Existing Zone Generation Trading Hub weights will be performed in a timely manner to be coordinated with the annual CRR Allocation and CRR Auction processes. Hub prices will be produced for every hour of every day in both the DAM and the HASP/Real-Time Market.

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[34] Meeting agenda and presentation available at http://www.caiso.com/docs/2004/03/09/2004030909140522185.html

[35] *See* http://www.caiso.com/docs/2004/03/09/2004030909140522185.html

Q. Please detail the process by which the CAISO arrived at its current proposal for EZ Gen Hubs.

A. Active stakeholder involvement with Trading Hub design began on August 5, 2004 when the CAISO issued a white paper describing the Trading Hubs that it had proposed in the "Amended Comprehensive Market Design Proposal", which was filed with the Commission on July 22, 2003. A total of three stakeholder meetings were held in the second half of 2004, during which proposals to have "EZ Load Hubs" were abandoned, and agreement was reached that three Existing Zone Generation Trading Hubs would be more suitable as successor delivery points under MRTU. The precise weighting factors used to calculate the EZ Gen Hubs were deferred for further stakeholder input and study, however analysis was presented on some of the weighting options as far back as October 26, 2004.[36]

In the June 10, 2005 Order, the Commission approved the CAISO's conceptual proposal that the EZ Gen Hub prices would represent successor delivery points to today's existing zones and would be calculated to represent the average price paid to generation in the zone. The CAISO then initiated a new round of stakeholder meetings to try and gain consensus on the outstanding issues, principally the exact mechanics of determining the average price paid to generation in the zone. This commenced at the July 13-14, 2005 stakeholder meetings. During these meetings, certain market participants offered to setup a working group to develop a proposal for calculating the EZ Gen Hubs. Starting with a conference call on July 26,' this group worked in parallel with CAISO to

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[36] A complete listing of all the meeting documents and comments on the various options presented can be found at http://www.caiso.com/docs/2004/08/17/2004081714581426212.html.

try and reach consensus initially within the working group and later among all stakeholders.

At a stakeholder meeting on August 16-18, 2005, the working group presented a proposal that had gained support among many of those participating with the group. The proposal was to base EZ Generation Hub prices on a simple average of generation nodes within each zone with no weighting of prices. Certain other participants in the working group also suggested a second set of hubs based only on 500kV and 230kV buses. Unfortunately while this proposal attained some traction among the working group, there were strong objections from other market participants. A further attempt to gain consensus among a broader group of market participants was attempted at the October 5-6, 2005 stakeholder meeting, however this did not materialize.

The CAISO originally planned to file tariff language that did not explicitly detail the mechanism of determining the weighting of the Trading Hub prices – an approach which is similar to the approach taken in tariffs for other ISOs such as PJM and MISO. However, some market participants indicated that they would prefer that a more detailed definition of the EZ Gen Trading Hubs be in the tariff, and the CAISO eventually agreed to include additional detail in the MRTU Tariff in response to these stakeholder requests. In order to facilitate this, the CAISO set up another conference call on October 20 2005. During this call, the CAISO presented a number of different options concerning the weighting of the Trading Hub prices, as well as the CAISO's preferred solution and solicited feedback from market participants.[37] The CAISO provided its proposed resolution on the EZ Gen Hub formula to stakeholders at the MRTU Tariff page turn meetings on October 24-28, 2005.

Q. What were the different options that were presented to stakeholders?

A. The ISO presented six possible options to stakeholders, however Option 1 was comprised of two sub-options that were slightly different, so numerically there were seven in all. All of these options were based on variations of the three features, namely which nodes were included, whether a simple or a weighted average was calculated, and finally, if a weighted average were chosen then what sort of weight was used and how did it change.

- Option 1A would include all generation nodes and would calculate a weighted average price based on the relative metered output of the generators within the zone for the prior year. The drawback of this option is that, during peak periods, it may underestimate hub prices since peakers will be underrepresented and during off-peak hours this option may overestimate hub prices as peaker generation will be partially included in the hub price even though they are not running.

- Option 1B would include all generation nodes and would calculate a weighted average price as in Option 1A, but would use two sets of weights for the entire year, one for peak and one for off peak periods based on the metered generation output of all generating resources within the hub. This option would address the drawback stated under Option 1A and would be consistent with peak and off-peak CRR release during the annual CRR allocation and auction. This was the option supported by the CAISO.

- Option 2 would use a simple average of all generation LMPs. There would be no differential weighting of the LMPs in this option. The prices would simply be summed and averaged by the number of observations regardless of the P-max or output of the various units. The disadvantage of this option is that a generator with a 10 MW schedule receives the same weighting as a generator

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[37] The CAISO white paper and stakeholder comments on this proposal can be found at http://www.caiso.com/docs/2002/08/23/200208231358035858.html

with a 600 MW schedule and this might result in prices that are a poor representation of the average price paid to generation in the zone.

- Option 3, like Option 2, would be a simple average of generation nodes with no weighting, however only a small subset of generation nodes would be used, and they would be carefully chosen and the formulation statistically verified to conform to the average price paid to generation in the zone. A concern with this option is that the lack of experience with LMPs in California makes it difficult to identify which nodes should be included in developing the hub formulation.

- Option 4 would use the P-max of all generation at each location as the LMP weight to compute the hub price. For this option, weights would be fixed for a year and would be changed once a year based on capacity additions and retirements. This approach would produce a better representation of the average price paid to generation in the zone than Options 2 and 3 above or Option 6 below, but would likely bias the results up as peakers that run for short periods would receive the same weighting as a similarly sized base load unit despite the vast difference in their output.

- Option 5 would be a dynamic weighted average output of all generation LMPs. Under this option, the EZ Gen Hub price would be an output weighted average price of all generation LMPs, but the weighting would vary by hour depending on market outcomes. The benefit of this approach is that it would accurately capture the true average price paid to generation. However, dynamic weights might affect CRRs revenue adequacy (since the feasible CRRs to or from a hub are based on a fixed set of weights). Moreover, it would have to be decided if the same or separate weights would apply in the Day-Ahead and HASP/RTM for hub price computation. If a single weight for the same hour is to be used there is a question whether it should be based on the Day-Ahead schedule, Real-Time incremental generation, or metered generation. The dynamic weighting of the nodes may also be problematic if the CAISO market design were, at some point, to include virtual bidding at Trading Hubs, since the weighting factors applied to these virtual bids would be needed prior to running the market. Additionally, this option is not completely consistent with the desired stability of Trading Hubs over time.

- Option 6 would use a simple average of the prices within the existing zones from a subset of all 500 kV nodes and those 230 kV nodes that would not be sensitive to price changes resulting from the outage of nearby generation or transmission. The proponents of this option argued that the selection of these nodes, rather than generation nodes, load nodes or LAPs, provides a middle-ground for balancing price risks between buyers and sellers.

Q. What constraints did market participants face in agreeing to a weighting for the hub price?

A. Broadly speaking there were two main constraints that the CAISO and market participants had to bear in mind when examining the Trading Hub price formulation. First, the Commission's June 10, 2005 Order approved the principle that the hub prices would reflect "the average price paid to generation in the zone," however the exact nature of this "average" price was left unspecified.

There was a widely held view among the CAISO experts working on the MRTU market design that the most accurate version of the average price paid to generation in the zone would be the hourly output weighted price whereby the product of the output at each generation node and the price at that node would be summed for all generation nodes and then divided through by the sum of all generation output at these respective nodes. This was considered the most accurate representation of the average price paid to generation in the zone. Whichever version of the weighting was chosen, the hub prices it produced could not vary significantly from this version to ensure conformity with the basic EZ Gen Hub definition. This average is essentially the same as Option 5 that was presented to stakeholders.

Secondly, whichever weighting and node formulation was used had to be sufficiently simple and robust to allow for contracting in the future. The formulation still had to be desirable to those participants who regularly trade energy, rather than just those with Seller's Choice contracts. Most participants tended to value hub price stability and simplicity more than a precise adherence to the average price paid to generation in the zone (*i.e.*, Option 5).

Q. What specific criteria did the CAISO use to choose between the various options?

A. The CAISO identified five criteria that it believed were relevant to determining the hub price formulation. These were

1. Market Efficiency – which is enhanced by using a simple static set of weights. Additionally each hub should have a sufficient number of nodes such that it is largely unaffected by outages and derates.
2. Accuracy – the hub price must be accurate with respect to the primary definition of EZ Gen Hubs representing the average price paid to generators within the zone.
3. Simplicity – the hub price formulation must be simple, as this will allow trading parties at a hub to easily verify the hub prices.
4. Consistency – the hub price must be consistent with other elements of MRTU design, such as CRR revenue adequacy and the potential for later implementation of virtual bidding, and
5. Balance risk – the formulation should balance the risks between buyers and sellers and not unduly burden or reward one set of market participants.

Q. Why did the CAISO choose Option 1B over the other options?

A. Between Option 1A and 1B, Option 1B was clearly the better option as it would better represent the average price paid to generation in the zone, so Option 1A was eliminated. Conceptually Option 2, the simple average of generation nodes, was problematic as the same weight was given to units with vastly different capacities and outputs. Option 3 was considered better than Option 2 because it would be designed to conform to the average price paid to generation in the zone, however the lack of experience with LMPs in California introduced both uncertainty and difficulty into the choice of generation nodes. Option 4 would produce a better representation of the average price paid to generation in the zone and was certainly a candidate formulation. Option 5, the dynamic weighting was clearly the most accurate representation of the average price paid to generation in the zone, however it had a number of drawbacks, namely the fact that it might affect CRR revenue adequacy, and also might create problems for virtual bidding after MRTU Release 1, which is an important feature for a number of interested parties. Concerning Option 6, there was some uncertainty regarding how closely it would represent the average price paid to generation within the zone, and additionally the lack of experience with LMPs in California would make the selection of nodes difficult. This left a choice between Option 1B and Option 4. Between the two, the CAISO felt that Option 1B was a better representation of the average price paid to generation in the zone, especially with the differential peak and off-peak weighting. Consequently this was the recommendation that the CAISO presented to stakeholders.

Q. Did the CAISO change its proposal in any way as a result of stakeholder feedback?

A. Yes, at the suggestion of a market participant, the CAISO modified the peak and off-peak weighting to include seasonal weighting. To prevent any detrimental effects on CRR revenue adequacy it was decided to make the Trading Hub seasons exactly the same as the CRR seasons in all circumstances.

Q. Did the CAISO receive any input from the Market Surveillance Committee regarding the hub price formulation?

A. Yes. The CAISO asked the MSC to provide an opinion and they did. At the CAISO Board meeting on October 19, 2005, the MSC provided an opinion on a number of MRTU issues including Trading Hub formation[38]. In this opinion the MSC urged that the definition be clear regarding geographic region covered, specific nodes included, and the method used to compute the Trading Hub price itself. The CAISO's current proposal satisfies all of these requirements. The MSC then went on to recommend what is essentially a variation of Option 5, namely the dynamically weighted price formulation, except that weights would be real-time weights, meaning that the weight for each nodal price would be the quantity injected at that node divided by the total quantity of hourly injections at all of the nodes included in the hub price. The MSC noted that such a formulation would require release of the hourly weights and nodal prices. The CAISO strongly considered the MSC's recommendation but felt that the dynamic weighting approach to calculating the EZ Gen Hubs would be problematic for the reasons noted above under Option 5. Ultimately, the CAISO concluded that Option 1B struck the best balance among competing objectives.

Q. How did stakeholders respond to the CAISO's recommendation?

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[38] This document is available at http://www.caiso.com/docs/09003a6080/37/89/09003a6080378960.pdf

A. In all, five parties presented written feedback and a number of other parties voiced their opinions verbally. Of the written comments, two utilities – Southern California Edison ("SCE") and Pacific Gas & Electric ("PG&E") – supported the CAISO proposal, although SCE had some suggestions regarding seasonal weighting. Two stakeholders continued to prefer the simple average of nodes, similar to the industry proposal mentioned earlier, and believed that the CAISO's proposal was needlessly complicated, however their criticism was simply based on unnecessary complexity rather than a more fundamental criticism. The final commenting party included Option 1B in a list of acceptable formulations. Verbally, two additional parties indicated that, although Option 1B was not their preferred option, it was sufficiently close to gain their acquiescence.

Q. Do you believe that Option 1B is an acceptable hub price formulation?

A. Yes. Prior to the CAISO recommendation, there was no consensus on the Trading Hub price formulation. As I discussed, there was some consensus among a small industry working group, all of whom supported Option 2, while a subset supported Option 6 as an additional hub to Option 2. Other industry participants supported Option 5, the dynamic weighting. The CAISO recommendation of Option 1B was a compromise position based on a trade off between competing objectives in choosing the formulation. This option meets the primary definition of the EZ Gen Hub in that it closely represents the average price paid to generation in the zone, and additionally, the weighting was simple enough to be congruent with other aspects of the LMP design, such as the CRR annual allocation and the introduction of virtual bidding at a later stage.

Q. Is the CAISO's weighted average pricing methodology consistent with the Seller's Choice settlements?

A. Yes. The hub price formulation establishes prices that are calculated using only generation pricing nodes. These prices are, in my opinion, as close to the average price paid to generators in the zone as it is functionally possible to be within the LMP and CRR framework.

Q. Will the CAISO create any additional aggregated pricing points beyond those discussed in your testimony?

A. The CAISO is open to developing additional Trading Hubs that meet the needs of the CAISO's market participants, but raises the caveat that, were the CAISO to develop a large number of Trading Hubs, such hubs might rob one another of the liquidity that is necessary to the success of Trading Hubs in general. Should a proposal for any Trading Hub aggregation gather significant participant support, the CAISO would be amenable to considering the proposal.

Q. Thank you. That concludes my questions.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

California Independent System Operator Corporation	))	**Docket No. ER06-___-000**

I, Keith Casey, declare under penalty of perjury, that the foregoing questions and answers labeled as my testimony were prepared by me, with the assistance of others working under my direction and supervision; and that the facts contained in my answers are true and correct to the best of my knowledge, information and belief.

Executed on: Feb 7, 2006
Date

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1989 - 1992 University of Maine Orono, ME

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- Nauman Scholarship, 1990-91

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2005 - Current California Independent System Operator Folsom, CA

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Manager Market Analysis & Mitigation, Department of Market Monitoring

- Assessed the effects of market rules and design features on market performance.
- Recommended market design changes to improve market efficiency and reduce potential for anti-competitive behavior.

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Publications & Working Papers

Awad, M., S. Broad, K. Casey, J. Chen, A. Geevarghese, J. Miller, A. Perez, A. Sheffrin, M. Zhang, E. Toolson, G. Drayton, F. Rahimi, B. Hobbs, and F. Wolak. 2006. "The California ISO Transmission Economic Assessment Methodology (TEAM): Principles and Application to Path 26", accepted for *IEEE Power Engineering Society General Meeting, 2006.*

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