California ISO
Your Link to Power

California Independent
System Operator Corporation

December 20, 2006

Hon. Magalie Roman Salas, Secretary
Federal Energy Regulatory Commission
888 First Street, NE
Washington, DC 20426

**RE: California Independent System Operator Corporation
Docket No. ER06-615-____**

Dear Secretary Salas:

Pursuant to the order issued by the Federal Energy Regulatory Commission ("Commission") in the above-captioned dockets on September 21, 2006 ("September 21 Order"), 116 FERC ¶ 61,274 (2006), the California Independent System Operator Corporation ("CAISO") hereby submits an original and five copies of a filing in compliance with the September 21 Order. Specifically, this filing consists of three items from the September 21 Order for which the CAISO requested and was granted a 30-day extension of time within which to comply.[1] The CAISO also is tendering two copies of this filing to be time and date stamped and returned to our courier.

I. BACKGROUND

The CAISO's market redesign efforts can be traced back to a series of Commission orders, commencing in the year 2000, directing the CAISO first to overhaul its approach to managing transmission congestion and then to engage in a more comprehensive redesign of its market structure, including the creation of a Day-Ahead Energy market to replace the defunct markets of the California Power Exchange.[2] Based on those directives, the CAISO developed a series of conceptual proposals that were filed for Commission review. Since 2002, the Commission has issued a series of orders on conceptual market design filings made by the CAISO in what became known as the Market Redesign and Technology Upgrade ("MRTU") market design.

After a lengthy stakeholder process, and with the directives of the Commission in mind, the CAISO filed its MRTU Tariff on February 9, 2006 ("February 9 Tariff Filing"). After reviewing comments on and protests of the MRTU Tariff filing by numerous stakeholders, on September 21, 2006, the Commission accepted for filing the

[1] *See Notice of Extension of Time*, Docket No. ER06-615 (November 27, 2006).
[2] Capitalized terms not otherwise defined herein have the meaning set forth in the Master Definitions Supplement, Appendix A to the MRTU Tariff.

MRTU Tariff to become effective November 1, 2007, subject to a number of modifications, as detailed in the September 21 Order.

In addition to tariff changes, the Commission also directed the CAISO to take various other actions, including providing additional details concerning several of its proposals, filing with the Commission status reports on specific issues, and making certain information available to Market Participants. The Commission provided several timeframes for the CAISO to comply with these various requirements. On November 20, 2006, the CAISO filed with the Commission a compliance filing that included most of the items that the Commission ordered the CAISO to address within 60 days of the September 21 Order ("November 20 Compliance Filing"). On that same date, the CAISO also filed a motion for extension of time to comply with several of the 60-day compliance items. As explained in greater detail in its motion for extension of time, the CAISO requested these extensions in order to allow for time to discuss with its stakeholders how to best resolve these issues, and incorporate stakeholder feedback into its compliance proposals. Because the CAISO required additional time to address these issues with its stakeholders, these items were not included in the November 20 Compliance Filing.

On December 19, 2005, the CAISO Board of Governors voted to extend the MRTU implementation date from November 1, 2007 to January 31, 2008, in order to afford the CAISO sufficient time to complete necessary modifications to the MRTU market design.

The instant filing represents the second filing made by the CAISO in compliance with the September 21 Order, consisting of the items regarding which the Commission granted the CAISO a 30-day extension of time within which to comply.

II. CONTENTS OF FILING

This filing comprises:

This Transmittal Letter,

Attachment A	MRTU Tariff Sheets Blacklined Against MRTU Tariff Sheets Filed on February 9, 2006 and on November 20, 2006
Attachment B	MRTU Tariff Sheets Clean
Attachment C	DMM Whitepaper on Negotiated Price Option for Default Energy Bids

Attachment D	DMM Whitepaper on Frequently Mitigated Unit Option for Default Energy Bids

III. COMMUNICATIONS

Correspondence and other communications regarding this filing should be directed to:

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IV. DESCRIPTION OF MODIFICATIONS TO THE MRTU TARIFF IN COMPLIANCE WITH SEPTEMBER 21 ORDER

On November 27, 2006, the Commission granted the CAISO a 30-day extension to comply with three directives from the September 21 Order: (1) explaining how the CAISO will handle sales of Interruptible Imports in the Day-Ahead Market;[3] 2) clarifying procedures in MRTU Tariff Section 39.7.1.3 concerning the Negotiated Rate Option for Default Energy Bids;[4] and 3) considering the appropriateness of the 80 percent threshold for Frequently Mitigated Units and reporting back to the Commission the CAISO's findings.[5] This filing addresses these three items.

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3 *See* September 21 Order at P 389.

4 *See id.* at P 1057.

5 *See id.* at P 1063.

A. Treatment of Sales of Interruptible Imports in the Day-Ahead Market

In the September 21 Order, the Commission directed the CAISO to explain how it will handle sales of Interruptible Imports in the Day-Ahead Market.[6] This question arises because Scheduling Coordinators are responsible for an Operating Reserve Obligation equal to 100% of Interruptible Imports. Unless the Interruptible Import is a Self-Schedule, however, the CAISO will not know how much additional Operating Reserves to procure to cover the Interruptible Import prior to the simultaneous optimization of the Energy and Ancillary Services markets.

On November 20 the CAISO posted draft tariff language regarding the sales of Interruptible Imports, proposing the following:

- Interruptible Imports will be supported under MRTU.
- Interruptible Imports must be submitted as Self-Schedules and may only be submitted in the Day-Ahead Market.
- The CAISO will adjust Ancillary Service requirements based on the quantity of Interruptible Imports submitted as Self-Schedules to meet WECC Minimum Operating Reliability Criteria.
- An Operating Reserve Obligation equal to 100% of the quantity of the Interruptible Imports will be allocated to the Scheduling Coordinator submitting the Interruptible Import.
- No additional Interruptible Imports, beyond what was scheduled in the Day-Ahead Market, will be accommodated in the Hour Ahead Scheduling Process ("HASP") or Real Time Market ("RTM").

To accomplish these objectives, the CAISO proposed changes to MRTU Tariff Sections 30.5.2.4, 34.16.2, and the definition of "Interruptible Imports." The CAISO presented its proposed tariff language revisions at a November 29 stakeholder meeting. Stakeholders were given from November 21 through December 5 to review the draft tariff language and submit comments to the CAISO. Comments were submitted by Pacific Gas and Electric Company ("PG&E") and Southern California Edison Company ("SCE"), neither of whom objected to the proposal, although SCE requested that the CAISO clarify how Interruptible Imports will be handled in the HASP. On December 8, a conference call was held to discuss any remaining concerns. Based on a concern raised by Powerex during the call, the CAISO also clarified language in Section 11.10.3.2. On December 12, the CAISO posted revised tariff language for final stakeholder review and comment. No additional comments were received.

In light of the comments made by stakeholders, and after further reflection, the CAISO made revisions to the proposed tariff language in order to permit Interruptible Imports to be submitted as Self-Schedules in the Day-Ahead timeframe. The Scheduling Coordinator submitting the Self-Schedule will be responsible for 100% of the Operating

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6 September 21 Order at P 389.

Reserves Obligation based on the MWh quantity reflected in the Self-Schedule. With respect to the treatment of Interruptible Imports in the HASP and RTM, the MRTU Tariff will not permit any incremental increase in the HASP or RTM over and above the quantity reflected in the Day-Ahead Schedule.

B. Clarifying Procedures Concerning the Negotiated Rate Option for Default Energy Bids

In the September 21 Order, the Commission directed the CAISO to clarify the procedures a Market Participant must follow and the type of information it must provide to take advantage of the Negotiated Rate Option for Default Energy Bids.[7] The CAISO was also directed to file procedures for dispute resolution in the event that the market participant and the CAISO cannot agree on a negotiated price.[8]

On November 20, 2006, the CAISO commenced a stakeholder process aimed at developing procedures for exercising the Negotiated Rate Option for Default Energy Bids, and resolving related disputes. On that date, the CAISO circulated to stakeholders a whitepaper from the CAISO's Department of Market Monitoring ("DMM") regarding the Negotiated Rate Option for Default Energy Bids ("Negotiated Rate Option Whitepaper")[9] as well as draft tariff language on this issue, proposing changes to MRTU Tariff Section 39.7.1.3. The CAISO held a conference call on December 8 to discuss this proposal. Based on comments received from stakeholders during this process, the CAISO made several modifications to its proposed tariff language. On December 12, the CAISO posted revised tariff language for final stakeholder review and comment.

The CAISO proposes to amend the MRTU Tariff in order to implement the following process with respect to the Negotiated Rate Option for Default Energy Bids:

1. Scheduling Coordinators must first submit to the CAISO a proposed Default Energy Bid and supporting information and documentation for the Negotiated Rate Option, as will be prescribed in a BPM.[10]

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7 September 21 Order at P 1059.

8 *Id.* In the September 21 Order, the Commission also directed the CAISO to modify the MRTU Tariff to require that an agreed-upon negotiated price for Default Energy Bids be filed at FERC. In its Request for Clarification and Rehearing of the September 21 Order, the CAISO requested that the Commission clarify that this directive will be satisfied by a monthly informational filing, and that Commission review and approval of the negotiated Default Energy Bids will not be required prior to those Bids taking effect.

9 This whitepaper is included with this filing as Attachment C.

10 The CAISO anticipates that the details regarding supporting information and documentation that will be included in a BPM will be largely consistent with those described in the Negotiated Rate Option Whitepaper.

2. After receipt of a request to establish a Default Energy Bid under the Negotiated Rate Option, the CAISO's Market Monitoring Unit or an alternative Independent Entity selected by the CAISO will review the information and provide a written response within ten (10) Business Days.

3. The CAISO will assess Default Energy Bid levels or formulas proposed by Scheduling Coordinators on the basis of criteria that will be set forth in a BPM.[11]

4. Default Energy Bids will become effective as follows:

   - Any Default Energy Bid proposed in writing by a Scheduling Coordinator to the CAISO shall become effective within three (3) Business Days after acceptance by the CAISO or the Independent Entity.
   - Any Default Energy Bid that is agreed to by the CAISO or the Independent Entity and the Scheduling Coordinator as a result of good faith negotiations shall become effective within three (3) Business Days after the date of the agreement.

5. Default Energy Bids will remain in effect unless modified by the Commission or by mutual agreement of the CAISO and the Scheduling Coordinator, or the Default Energy Bid expires, is terminated, or is modified pursuant to any agreed upon term or condition or pertinent Commission Order.

6. Pending any agreement on the Default Energy Bid, the Default Energy Bid shall be based on one of the options set forth in MRTU Tariff Section 39.7.1 (*i.e.*, cost-based Default Energy Bid, LMP-Based Default Energy Bid), at the option of the Scheduling Coordinator.

7. If the Scheduling Coordinator does not elect to use one of the options set forth in MRTU Tariff Section 39.7.1 pending an agreement on the Default Energy Bid, or if there is insufficient information to calculate a Default Energy Bid using any of these options, the CAISO will calculate a temporary Default Energy Bid based on one or more of several criteria, as explained in greater detail below.

8. If a Scheduling Coordinator and the CAISO cannot reach mutual agreement on a Default Energy Bid to be used under the Negotiated Rate Option within 60 days, the Scheduling Coordinator may file with the Commission pursuant to Section 205 of the Federal Power Act for approval of a rate to be used under the Negotiated Rate Option.

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11 As set forth in the Negotiated Rate Option Whitepaper, these criteria will likely include such things as: (1) operating cost data, opportunity costs and other appropriate inputs from the Scheduling Coordinator; (2) the CAISO's estimated costs of the applicable Electric Facility; and (3) an appropriate average of competitive Bids of one or more similar Electric Facilities.

This proposal reflects a variety of changes made by the CAISO to the initial draft tariff language in order to address concerns and suggestions provided by Western Power Trading Forum ("WPTF") and Williams. First, the CAISO modified the proposed tariff language to eliminate the unilateral right of either the CAISO or the Scheduling Coordinator to terminate the Default Energy Bid. Specifically, the CAISO modified Section 39.7.1.3.1 to clarify that one of the three conditions under which a Default Energy Bid may no longer remain in effect is if it "is terminated or is modified pursuant to any terms specified in the agreement or FERC order through which the Default Energy Bid was established." The intent of this provision is to recognize that an agreement reached under the Negotiated Rate Option may include terms specifying conditions under which the Default Energy Bid applies, including a date upon which the Default Energy Bid will terminate, or termination or modification of the Default Energy Bid in response to a change in system or market conditions. Without the ability to establish such provisions under mutual agreement, it may often be difficult for the CAISO to reach agreement under the Negotiated Rate Option, particularly when system or market conditions – of an unknown duration or magnitude – may otherwise warrant a sudden increase in a unit's Default Energy Bid on an expedited basis. Since such provisions would be subject to mutual agreement as part of the terms of the Default Energy Bid established under the Negotiated Rate Option, this tariff provision, as proposed, does not permit the CAISO unilateral authority to modify or terminate the use of a Default Energy Bid established under the Negotiated Rate Option.

In addition, the CAISO revised Sections 39.7.1.3.and 39.7.1.5 to address concerns expressed by WPTF and Williams with respect to the conditions under which the CAISO has authority to establish a temporary Default Energy Bid. The revised language clarifies that the CAISO may establish a temporary Default Energy Bid based on the criteria set forth in Section 39.7.1.5 under two specific scenarios. As described in Section 39.7.1.3.1, the first scenario involves a situation when the CAISO and a Scheduling Coordinator fail to agree upon the Default Energy Bid. Under this scenario, the Scheduling Coordinator first has the option of electing to establish a temporary Default Energy Bid using any of the other options set forth in Section 39.7 for which data are available. However, in the event the Scheduling Coordinator does not exercise this option, or if sufficient data do not exist to calculate a Default Energy Bid on the basis of any of the options selected by the Scheduling Coordinator, the CAISO may establish a temporary Default Energy Bid as specified in Section 39.7.1.5.

The intent of this provision is to ensure that that CAISO or an alternative Independent Entity selected by the CAISO can expeditiously establish an appropriate Default Energy Bid pending any agreement or determination by the Commission under such circumstances. The CAISO also notes that because this provision only applies in cases where a Scheduling Coordinator opts not to use a Default Energy Bid, this provision would most likely be invoked only in cases when a Scheduling Coordinator feels that any of these other options would result in an unreasonably low Default Energy Bid, such as when system or market conditions may warrant a sudden increase in a unit's Default Energy Bid on an expedited basis. In such cases, this provision would provide the CAISO with the flexibility to implement a temporary Default Energy Bid that reflects such conditions, even though a valid Default Energy Bid may exist under any of the other options.

The second scenario under which the CAISO may establish a temporary Default Energy Bid as specified in Section 39.7.1.5 is when sufficient data do not exist to calculate a Default Energy Bid on the basis of any of the available options. The proposed tariff language further specifies that any temporary Default Energy Bids established by the CAISO shall be based on one or more of the following: (1) operating cost data, opportunity cost, and other appropriate input from the Market Participant; (2) the CAISO's estimated operating costs of the Electric Facility, taking the best information available to the CAISO; (3) an appropriate average of competitive Bids of one or more similar Electric Facilities; or (4) any of the other options for determining a Default Energy Bid for which data are available.

Finally, the CAISO wishes to respond to the contention made by WPTF in this stakeholder process that the CAISO's Negotiated Rate Option proposal represents a change from previously-approved tariff provisions, in that it proposes to give the CAISO discretion to directly conduct negotiations with Scheduling Coordinators under the Negotiated Rate Option. WPTF is incorrect. The CAISO's February 9 Tariff Filing specifically indicated that the Negotiated Rate Option would be "derived through consultation between the Scheduling Coordinator for a Generating Unit and the CAISO or an alternative Independent Entity selected by the CAISO."[12] Moreover, in the September 21 Order, the Commission specifically rejected WPTF's argument that Commission should *require* the CAISO to use an independent third party to determine Default Energy Bids under the Negotiated Rate Option, or to sufficiently justify why it should be afforded this authority,[13] and concluded that the CAISO or an independent party selected by the CAISO has the authority to negotiate specific values to be used under the Negotiated Rate Option.[14]

C. Appropriateness of the 80 Percent Frequency Threshold for Frequently Mitigated Units

The Local Market Power Mitigation ("LMPM") provisions of the MRTU Tariff filing include an option that would allow Frequently Mitigated Units ("FMUs") to be eligible for a $24/MWh Bid Adder to their cost-based Default Energy Bids. To be eligible for this Bid Adder, units would need to meet three conditions:

1. Units cannot be fully contracted as Resource Adequacy ("RA") Resources or Reliability Must Run ("RMR") Generation resources;
2. Units must have at least 200 run hours in the preceding 12-month period; and

12 MRTU Tariff Section 39.7.1.3.

13 September 21 Order at P 1054.

14 *Id.* at P 1058.

3. Units must be mitigated in at least 80% of their run hours.

In the September 21 Order, the Commission directed the CAISO to consider whether the 80 percent mitigation frequency threshold is appropriate, and whether units mitigated less than 80 percent of the time should also receive a bid adder, and to report its conclusions.[15] The September 21 Order expressed two specific concerns about the CAISO's proposal that only units that are mitigated at least 80 percent of the time should be eligible for a Bid Adder under the FMU option.

1. ***Revenue Adequacy.*** In the September 21 Order, the Commission indicated that it expects that "many of the resources currently under RMR contracts with the CAISO represent those units which will likely be frequently mitigated," and "to the extent that the use of RMR units is phased out in the future, the FMU option will become a market mechanism by which these units will receive a contribution to their fixed forward costs."[16]

2. ***Perverse Bidding Incentives***. The September 21 Order also states that "one concern with a single arbitrary cut-off threshold such as 80 percent is that it may create a perverse incentive for units mitigated slightly less than the threshold to bid in a manner that increases their mitigation just above the threshold. One method that can avoid this problem is ... a sliding scale for units that are mitigated less frequently and establish corresponding graduated bid adders for each level of mitigation."[17]

On November 20, the CAISO circulated to stakeholders a whitepaper prepared by the DMM regarding the FMU Bid Adder ("FMU Bid Adder Whitepaper").[18] In that whitepaper, the DMM noted that it continues to believe that Bid Adders do not represent the most efficient manner in which to address revenue adequacy problems caused by relatively low run hours and/or frequent Bid price mitigation, since Bid Adders inevitably create the risk of market distortions and inefficiencies by making Bid prices of some units less reflective of actual marginal costs. In addition, DMM believes that as Local Capacity Area Resource Adequacy requirements are phased in, sufficient resources should be available under RA Resource contracts to meet the bulk of local reliability needs, without significant reliance on FMUs. Moreover, the DMM stated that it has supported the application of a Bid Adder for FMUs without capacity contracts under the expectation that the application and markets impacts of such Bid Adders would be relatively limited.

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15 September 21 Order at P 1063.

16 September 21 Order at P 1063.

17 *Id.*

18 This whitepaper is included with this filing as Attachment D.

Several stakeholders submitted comments on this issue:

PG&E and SCE oppose the use of FMU Bid Adders at all, and thus oppose any expansion of their use as would be presented in lowering the percentage of use trigger currently contemplated in the MRTU Tariff.

WPTF objects to a FMU Bid Adder that is not based on in providing sufficient revenues for continued operation of the FMUs.

Williams expressed the view that the apparent need for an FMU Bid Adder demonstrates a failure of the RMR and RA mechanisms. As such, Williams feels that the appropriate step to take would be to correct those mechanisms. Williams does not believe that recovery of fixed costs by an FMU would be sufficient to ensure its continued operation. Williams recommends that if the FMU Bid Adder is retained, that the level of that adder be determined by dividing the fixed costs of a new entry unit by the annual amount of Energy needed to address the constraint.

In light of the diversity of comments and further discussion with stakeholders on the December 8 conference call, and on careful reflection, the CAISO has determined that no changes to the FMU tariff language in the MRTU Tariff are warranted at this time. As previously noted, the CAISO believes that Bid Adders do not represent the most efficient manner in which to address revenue adequacy problems, and that as Local Capacity Area RA requirements are phased in, sufficient resources should be available under RA contracts to meet the bulk of local reliability needs, without significant reliance on FMUs

In response to the Commission's second concern – that a single arbitrary cut-off threshold such as 80 percent may create a perverse incentive for units to bid in a manner that increases their mitigation just above the threshold – the CAISO believes that using the type of sliding scale suggested in the September 21 Order may be equally or even more likely to create perverse incentives for units to bid in a manner that makes them eligible for a FMU Bid Adder. For example, if units mitigated in only 60 percent of run hours become eligible for a FMU Bid Adder, the number of units that seek to become eligible for such an adder may increase as a result.

Finally, the CAISO would like to address the criticism made by WPTF of the FMU Bid Adder Whitepaper that the CAISO did not perform any additional quantitative analysis to identify specific units that might be eligible for the FMU Bid Adder and the frequency with which these units would be mitigated. In response, CAISO staff explained that such analysis could not be done in any meaningful way at this time, because such analysis would require making a series of assumptions about market conditions and behavior under MRTU. First, such analysis would require making assumptions about the specific units that will not be under RMR or RA contracts (which are ineligible for the FMU Bid Adder) upon MRTU implementation. In addition, the frequency with which units are mitigated under MRTU will depend on the actual Bids submitted for these units, relative to Bids and Default Energy Bids for all other resources in the CAISO system. Since neither market Bids nor Default Energy Bids are based on a unit's actual marginal costs, the results of any such analysis undertaken at this time would be highly sensitive to a virtually unlimited set of assumptions that might be made about various resources' Bids and Default Energy Bids.

Although such additional analysis of the FMU option is not feasible prior to MRTU, the CAISO will be closely monitoring and analyzing the Mitigation Frequency as MRTU is implemented. Should such analysis indicate that modifications to the FMU Bid Adder – like any market power mitigation other provisions – are necessary, the CAISO will determine the appropriate changes through a stakeholder process and make a filing with the Commission. Thus, the CAISO commits to monitor the Mitigation Frequency once MRTU goes live, and will consider modifications to the FMU Bid Adder once there is a sufficient amount of data to determine whether such modifications are necessary in practice.

V. REQUEST FOR WAIVER OF ORDER NO. 614 REQUIREMENTS

Although the clean MRTU Tariff sheets provided in Attachment B to this filing letter do contain header and footer information, the CAISO requests waiver of the requirements of Order No. 614[19] to the extent this information does not fully comport with these requirements. As the CAISO explained in the February 9 Tariff Filing and the November 20 Compliance Filing, this waiver is justified because the portions of the S & R Tariff that serve as the basis of the MRTU Tariff are likely to be amended in the normal course of business between the filing date and the proposed January 31, 2008 MRTU implementation date. Moreover, in light of the recent change in the MRTU implementation date, the CAISO will need to make a filing to correct the effective date of the MRTU tariff sheets filed previously. Therefore, prior to the MRTU implementation date, the CAISO will submit tariff sheets containing the MRTU Tariff provisions approved by the Commission that fully comply with Order No. 614.

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19 *Designation of Electric Rate Schedule Sheets*, FERC Stats. & Regs., Regs. Preambles ¶ 31,096 (2000).

VI. CONCLUSION

For the reasons set forth above, the CAISO respectfully requests that the Commission accept its proposed modifications to the MRTU Tariff, in compliance with the Commission's September 21 Order.

Respectfully submitted,

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ATTACHMENT A

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11.10.3.2 Hourly Net Obligation for Spinning Reserves.

Each Scheduling Coordinator's hourly net obligation for Spinning Reserves is determined as follows: the Scheduling Coordinator's total Ancillary Services Obligation for Operating Reserve for the hour multiplied by the ratio of the CAISO's total Ancillary Services Obligation for Spinning Reserves in the hour to the CAISO's total Operating Reserve obligations in the hour, (and if negative, multiplied by NOROCAF), reduced by the accepted Self-Provided Ancillary Services for Spinning Reserves, plus or minus any Spinning Reserve Obligations for the hour acquired or sold through Inter-SC Trades of Ancillary Services. The Scheduling Coordinator's total Operating Reserve Obligation for the hour is the sum of 5% of its Real-Time Demand (except the Demand covered by firm purchases from outside the CAISO Control Area) met by Generation from hydroelectric resources plus 7% of its Demand (except the Demand covered by firm purchases from outside the CAISO Control Area) met by Generation from non-hydroelectric resources, plus 100% of any Interruptible Imports, which must be submitted as a Self-Schedule in the Day-Ahead Market, and on-demand obligations which it schedules.

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30.5.2.4 Supply Bids for System Resources.

In addition to the common elements listed in Section 30.5.2.1, Supply Bids for System Resources shall also contain: the relevant Ramp Rate; Start-Up Bid; and Minimum Load Bid. Start-Up Bids and Minimum Load Bids for System Resources, except for Dynamic or Non-Dynamic System Resources must be zero. Dynamic or Non-Dynamic Resource-Specific System Resources may submit non-zero Start-Up and Minimum Loads Bids. Dynamic and Non-Dynamic Resource Specific System Resources must register resource specific information in the Master-File in a similar manner as Generating Units and are eligible to participate in the Day-Ahead Market on an equivalent basis as Generating Units and are not obligated to participate in RUC or the RTM if the resource did not receive a Day Ahead Schedule unless the resource is a Resource Adequacy Resource. If the Resource Specific System Resource is a Resource Adequacy Resource, the resource is obligated to make itself available to the CAISO market as prescribed by Section 40.6. Dynamic Resource-Specific System Resources are also eligible to participate in the HASP and RTM on an equivalent basis as Generating Units. Non-Dynamic Resource-Specific System Resources will be treated like other System Resources in the HASP and RTM. The quantity (in MWh) of Energy categorized as Interruptible Imports (non-firm imports) can only be submitted through Self-Schedules in the Day-Ahead Market and cannot be incrementally increased in the HASP or RTM.~~must also be included in the Bid.~~ Bids submitted to the Day-Ahead Market for ELS Resources will be applicable for two days after they have been submitted and cannot be changed the day-after they have been submitted.

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34.16.2 Dispatch of Self-Provided Ancillary Services.

Where a Scheduling Coordinator has chosen to self-provide the whole of the additional Operating Reserve required to cover any Interruptible Imports which it has submitted through Self-~~s~~Schedules~~d~~ in the Day-Ahead Market and has identified specific Generating Units, Participating Loads, System Units or System Resources as the providers of the additional Operating Reserve concerned, the CAISO shall Dispatch only the designated Generating Units, Participating Loads, System Units or System Resources in the event of the CAISO being notified that the On Demand Obligation is being curtailed. For all other Ancillary Services which are being self-provided the Energy Bid shall be used to determine the Dispatch, subject to the limitation on the Dispatch of Spinning Reserve and Non-Spinning Reserve set forth in Section 34.10.

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39.7.1.3 Negotiated Rate Option.

~~The Negotiated Option is a Default Energy Bid that is derived through consultation between the Scheduling Coordinator for a Generating Unit and the CAISO or an alternative independent entity selected by the CAISO to determine an amount for its Default Energy Bid.~~

39.7.1.3.1 Submission Process

Scheduling Coordinators that elect the Negotiated Rate Option for the Default Energy Bid shall submit a proposed Default Energy Bid along with supporting information and documentation as described in a BPM. Within ten (10) Business Days of receipt, the CAISO or an Independent Entity selected by the CAISO will provide a written response. If the CAISO or Independent Entity accepts the proposed Default Energy Bid, it will become effective within three (3) Business Days from the date of acceptance by the CAISO and remain in effect until: (1) the Default Energy Bid is modified by FERC; (2) the Default Energy Bid is modified by mutual agreement of the CAISO and the Scheduling Coordinator; or (3) the Default Energy Bid expires, is terminated or is modified pursuant to any agreed upon term or condition or pertinent FERC order.

If the CAISO or Independent Entity selected by the CAISO does not accept the proposed Default Energy Bid, the CAISO or Independent Entity selected by the CAISO and the Scheduling Coordinator shall enter a period of good faith negotiations that terminates 60-days following the date of submission of a proposed Default Energy Bid by a Scheduling Coordinator. If at any time during this period, the CAISO or Independent Entity selected by the CAISO and the Scheduling Coordinator agree upon the Default Energy Bid, it will be become effective within three (3) Business Days of the date of agreement and remain in effect until: (1) the Default Energy Bid is modified by FERC; (2) the Default Energy Bid is modified by mutual agreement of the CAISO and the Scheduling Coordinator; or (3) the Default Energy Bid expires, is terminated or is modified pursuant to any agreed upon term or condition or pertinent FERC order.

If by the end of the 60-day period the CAISO or Independent Entity selected by the CAISO and the Scheduling Coordinator fail to agree on the Default Energy Bid to be used under the Negotiated Rate Option, the Scheduling Coordinator has the right to file a proposed Default Energy Bid with FERC pursuant to Section 205 of the Federal Power Act.

During the 60-day period following the submission of a proposed negotiated Default Energy Bid by a Scheduling Coordinator, and pending FERC's acceptance in cases where the CAISO or Independent Entity selected by the CAISO fail to agree on the Default Energy Bid for use under the Negotiated Rate Option and the Scheduling Coordinator filed a proposed Default Energy Bid with FERC pursuant to Section 205 of the Federal Power Act, the Scheduling Coordinator has the option of electing to use any of the other options available pursuant to Section 39.7. If the Scheduling Coordinator does not elect to use any of the other options available pursuant to Section 39.7, or if sufficient data do not exist to calculate a Default Energy Bid using any of these options, the CAISO may establish a temporary Default Energy Bid as specified in Section 39.7.1.5.

39.7.1.3.2 Informational Filings With FERC

The CAISO shall make an informational filing with FERC of any Default Energy Bids negotiated pursuant to this section ~~of the CAISO Tariff~~, or any temporary Default Energy Bids established pursuant to Section 39.7.1.5, no later than seven (7) days after the end of the month in which the Default Energy Bids were established.

* * *

39.7.1.5 Temporary Default Energy Bid

If the Scheduling Coordinator does not elect to use any of the other options available pursuant to Section 39.7, or if sufficient data do not exist to calculate a Default Energy Bid using any of the available options, the CAISO may establish a temporary Default Energy Bid based on one or more of the following: (1) operating cost data, opportunity cost, and other appropriate input from the Market Participant; (2) the CAISO's estimated operating costs of the Electric Facility, taking the best information available to the CAISO; (3) an appropriate average of competitive Bids of one or more similar Electric Facilities; or (4) any of the other options for determining a Default Energy Bid for which data are available.

* * *

Appendix A

Interruptible Imports	Non-firm Energy sold by a Generator or resource located outside the CAISO Controlled Grid which by contract can be interrupted or reduced at the discretion of the seller. Interruptible Imports must be submitted through Self-Schedules in the Day-Ahead Market.

* * *

ATTACHMENT B

HASP, and Real-Time Markets, minus, (ii) the Spinning Reserve capacity associated with payments rescinded pursuant to any of the provisions of Section 8.10.8 of the CAISO Tariff. The amount (MW) of awarded Spinning Reserve capacity includes the amounts (MW) associated with any Regulation Up Reserve capacity used as Spinning Reserve under Section 8.2.3.5 of this Tariff.

11.10.3.2 Hourly Net Obligation for Spinning Reserves.

Each Scheduling Coordinator's hourly net obligation for Spinning Reserves is determined as follows: the Scheduling Coordinator's total Ancillary Services Obligation for Operating Reserve for the hour multiplied by the ratio of the CAISO's total Ancillary Services Obligation for Spinning Reserves in the hour to the CAISO's total Operating Reserve obligations in the hour, (and if negative, multiplied by NOROCAF), reduced by the accepted Self-Provided Ancillary Services for Spinning Reserves, plus or minus any Spinning Reserve Obligations for the hour acquired or sold through Inter-SC Trades of Ancillary Services. The Scheduling Coordinator's total Operating Reserve Obligation for the hour is the sum of 5% of its Real-Time Demand (except the Demand covered by firm purchases from outside the CAISO Control Area) met by Generation from hydroelectric resources plus 7% of its Demand (except the Demand covered by firm purchases from outside the CAISO Control Area) met by Generation from non-hydroelectric resources, plus 100% of any Interruptible Imports, which must be submitted as a Self-Schedule in the Day-Ahead Market, and on-demand obligations which it schedules.

11.10.3.3 Spinning Reserve Neutrality Adjustment

For each Settlement Period, the difference between the Spinning Reserve Net Requirement at the hourly Spinning Reserve user rate determined in Section 11.10.3.1 and the total revenue collected from all Scheduling Coordinators in the Spinning Reserve Charge pursuant to Section 11.10.3 shall be allocated to all Scheduling Coordinators in proportion to their Spinning Reserve Obligation quantity. The Spinning Reserve Net Requirement is the Real-Time Spin Requirement net of the sum of Effective Qualified Spin Self-Provision over all Resources.

and Minimum Load Bids for System Resources, except for Dynamic or Non-Dynamic System Resources must be zero. Dynamic or Non-Dynamic Resource-Specific System Resources may submit non-zero Start-Up and Minimum Loads Bids. Dynamic and Non-Dynamic Resource Specific System Resources must register resource specific information in the Master-File in a similar manner as Generating Units and are eligible to participate in the Day-Ahead Market on an equivalent basis as Generating Units and are not obligated to participate in RUC or the RTM if the resource did not receive a Day Ahead Schedule unless the resource is a Resource Adequacy Resource. If the Resource Specific System Resource is a Resource Adequacy Resource, the resource is obligated to make itself available to the CAISO market as prescribed by Section 40.6. Dynamic Resource-Specific System Resources are also eligible to participate in the HASP and RTM on an equivalent basis as Generating Units. Non-Dynamic Resource-Specific System Resources will be treated like other System Resources in the HASP and RTM. The quantity (in MWh) of Energy categorized as Interruptible Imports (non-firm imports) can only be submitted through Self-Schedules in the Day-Ahead Market and cannot be incrementally increased in the HASP or RTM. Bids submitted to the Day-Ahead Market for ELS Resources will be applicable for two days after they have been submitted and cannot be changed the day-after they have been submitted.

30.5.2.4.1 Intertie Block Bids.

Intertie Block Bids must contain the same energy Bid price for all hours of the period for which the Intertie Block Bid is submitted. Intertie Block Bids may only be submitted in the DAM.

30.5.2.5 Supply Bids for Metered Subsystems.

Consistent with the bidding rules specified in this Section 30.5, Scheduling Coordinators that represent MSS Operators may submit Bids for Energy and Ancillary Services, including Self-Schedules and Submissions to Self-Provide an Ancillary Service, to the DAM. All Bids to supply Energy by MSS Operators must identify each Generating Unit on an individual unit basis. The CAISO will not accept aggregated Generation Bids without complying with the requirements of Section 4.9.12 of the CAISO Tariff. All Scheduling Coordinators that represent MSS Operators must submit Demand Bids at the relevant MSS LAP. Scheduling Coordinators that represent MSS Operators must comply with Section 4.9 of the CAISO Tariff. Scheduling Coordinators that represent MSS Operators that have opted out of RUC participation pursuant to Section 31.5 must Self-Schedule one hundred (100) percent of the Demand Forecast for the MSS. For an MSS that elects Load following, the MSS Operator shall also self-schedule the entire Trading Hour. The HASP shall perform the hourly pre-dispatch for each Trading Hour once prior to the Operating Hour. The hourly pre-dispatch shall not subsequently be revised by the SCED and the resulting HASP Intertie Schedules are financially binding and are settled pursuant to section 11.4.

(h) Daily Energy use limitation to the extent that energy limitation is expressed in a resource's Bid.

34.16 Ancillary Services in the Real-Time Market.

34.16.1 Requirement to Submit Energy Bids For Awarded or Self-Provided Ancillary Services Capacity.

Scheduling Coordinators for resources that have been awarded or self-provide Regulation Up, Spinning Reserve, or Non-Spinning Reserve capacity must submit an Energy Bid for at least all the awarded or self-provided Ancillary Services capacity.

34.16.2 Dispatch of Self-Provided Ancillary Services.

Where a Scheduling Coordinator has chosen to self-provide the whole of the additional Operating Reserve required to cover any Interruptible Imports which it has submitted through Self-Schedules in the Day-Ahead Market and has identified specific Generating Units, Participating Loads, System Units or System Resources as the providers of the additional Operating Reserve concerned, the CAISO shall Dispatch only the designated Generating Units, Participating Loads, System Units or System Resources in the event of the CAISO being notified that the On Demand Obligation is being curtailed. For all other Ancillary Services which are being self-provided the Energy Bid shall be used to determine the Dispatch, subject to the limitation on the Dispatch of Spinning Reserve and Non-Spinning Reserve set forth in Section 34.10.

34.16.3 Ancillary Services Requirements for RTM Dispatch.

The following requirements apply to the Dispatch of Ancillary Services in the RTM:

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.

39.7.1.1 Variable Cost Option.

The Variable Cost option will calculate the Default Energy Bid as Variable Costs plus ten percent (10%). Variable Cost 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 default value for the Variable Operation and Maintenance Cost portion will be $2/MWh. Generating Units that are of the Combustion Turbine or Reciprocating Engine technology will be eligible for a default Variable Operation and Maintenance Cost of $4/MWh. Resource specific values may be negotiated with the Independent Entity charged with calculating the Default Energy Bid.

39.7.1.2 LMP Option.

The CAISO will calculate the LMP Option for the Default Energy Bid as a weighted average of the lowest quartile of LMPs at the Generating Unit PNode in periods when the unit was Dispatched during the preceding ninety (90) days. The weighted average will be calculated based on the quantities Dispatched within each segment of the Default Energy Bid curve.

39.7.1.3 Negotiated Rate Option.

39.7.1.3.1 Submission Process

Scheduling Coordinators that elect the Negotiated Rate Option for the Default Energy Bid shall submit a proposed Default Energy Bid along with supporting information and documentation as described in a BPM. Within ten (10) Business Days of receipt, the CAISO or an Independent Entity selected by the CAISO will provide a written response. If the CAISO or Independent Entity accepts the proposed Default Energy Bid, it will become effective within three (3) Business Days from the date of acceptance by the CAISO and remain in effect until: (1) the Default Energy Bid is modified by FERC; (2) the Default Energy

Bid is modified by mutual agreement of the CAISO and the Scheduling Coordinator; or (3) the Default Energy Bid expires, is terminated or is modified pursuant to any agreed upon term or condition or pertinent FERC order.

If the CAISO or Independent Entity selected by the CAISO does not accept the proposed Default Energy Bid, the CAISO or Independent Entity selected by the CAISO and the Scheduling Coordinator shall enter a period of good faith negotiations that terminates 60-days following the date of submission of a proposed Default Energy Bid by a Scheduling Coordinator. If at any time during this period, the CAISO or Independent Entity selected by the CAISO and the Scheduling Coordinator agree upon the Default Energy Bid, it will be become effective within three (3) Business Days of the date of agreement and remain in effect until: (1) the Default Energy Bid is modified by FERC; (2) the Default Energy Bid is modified by mutual agreement of the CAISO and the Scheduling Coordinator; or (3) the Default Energy Bid expires, is terminated or is modified pursuant to any agreed upon term or condition or pertinent FERC order.

If by the end of the 60-day period the CAISO or Independent Entity selected by the CAISO and the Scheduling Coordinator fail to agree on the Default Energy Bid to be used under the Negotiated Rate Option, the Scheduling Coordinator has the right to file a proposed Default Energy Bid with FERC pursuant to Section 205 of the Federal Power Act.

During the 60-day period following the submission of a proposed negotiated Default Energy Bid by a Scheduling Coordinator, and pending FERC's acceptance in cases where the CAISO or Independent Entity selected by the CAISO fail to agree on the Default Energy Bid for use under the Negotiated Rate Option and the Scheduling Coordinator filed a proposed Default Energy Bid with FERC pursuant to Section 205 of the Federal Power Act, the Scheduling Coordinator has the option of electing to use any of the other options available pursuant to Section 39.7. If the Scheduling Coordinator does not elect to use any of the other options available pursuant to Section 39.7, or if sufficient data do not exist to calculate a Default Energy Bid using any of these options, the CAISO may establish a temporary Default Energy Bid as specified in Section 39.7.1.5.

39.7.1.3.2 Informational Filings With FERC

The CAISO shall make an informational filing with FERC of any Default Energy Bids negotiated pursuant to this section, or any temporary Default Energy Bids established pursuant to Section 39.7.1.5, no later than seven (7) days after the end of the month in which the Default Energy Bids were established.

39.7.1.4 Frequently Mitigated Unit Option.

A Frequently Mitigated Unit that is eligible for a Bid Adder may select a fourth Default Energy Bid option, which is equal to the Variable Cost Option plus the Bid Adder as described in Section 39.7.

39.7.1.5 Temporary Default Energy Bid

If the Scheduling Coordinator does not elect to use any of the other options available pursuant to Section 39.7, or if sufficient data do not exist to calculate a Default Energy Bid using any of the available options, the CAISO may establish a temporary Default Energy Bid based on one or more of the following: (1) operating cost data, opportunity cost, and other appropriate input from the Market Participant; (2) the CAISO's estimated operating costs of the Electric Facility, taking the best information available to the CAISO; (3) an appropriate average of competitive Bids of one or more similar Electric Facilities; or (4) any of the other options for determining a Default Energy Bid for which data are available.

	calculated from the due date of the bill to the date of payment, except as provided in Section 11.29.13.1. When payments are made by mail, bills shall be considered as having been paid on the date of receipt.
Interim Black Start Agreement	An agreement entered into between the CAISO and a Participating Generator (other than a Reliability Must-Run Agreement) for the provision by the Participating Generator of Black Start capability and Black Start Energy on an interim basis until the introduction by the CAISO of its Black Start auction (or until terminated earlier by either party in accordance with its terms).
Intermediary Control Area	Any Control Area between a Host Control Area and the CAISO Control Area. An Intermediary Control Area may, or may not, be directly interconnected with the CAISO Control Area.
Interruptible Imports	Non-firm Energy sold by a Generator or resource located outside the CAISO Controlled Grid which by contract can be interrupted or reduced at the discretion of the seller. Interruptible Imports must be submitted through Self-Schedules in the Day-Ahead Market.
Intertie Block Bid	A Bid from a System Resource in the DAM that offers the same quantity of Energy, RUC Availability, or Ancillary Services across multiple, contiguous hours of the Trading Day.
IOU	An investor owned electric utility.
LAP Price	The marginal price for a particular LAP, calculated as a weighted average of the nodal LMPs at the associated PNodes pursuant to Section 27.2.2.
Large Generating Facility	A Generating Facility having a Generating Facility Capacity of more than 20 MW.
Line Loss Correction Factor	The line loss correction factor as set forth in the Technical Specifications.
LMP Option	A method of calculating Default Energy Bids based on Locational Marginal Prices.
Load	An end-use device of an End-Use Customer that consumes power. Load should not be confused with Demand, which is the measure of power that a Load receives or requires.
Load Aggregation Point (LAP)	A set of Pricing Nodes as specified in Section 27.2 that are used for the submission of Bids and Settlement of Demand.

ATTACHMENT C

MRTU Market Power Mitigation

Negotiated Price Option for Default Energy Bids (DEB)

Department of Market Monitoring (DMM)

November 20, 2006

Background

The FERC's September 21 MRTU Order requires the CAISO to modify the tariff section addressing the Negotiated Option for the Default Energy Bid (DEB) in two respects:

(1) Require the Negotiated DEB to be filed with FERC (P. 1057); and

(2) Provide procedures for dispute resolution in the event the Market Participant and the CAISO cannot agree on a negotiated bid price and clarify the procedures a Market Participant must follow to exercise this option and the type of information they must provide (P. 1059). [1]

In its Request for Clarification and Rehearing of the Commission's September 21 MRTU Order, the CAISO requested that the Commission clarify that its directive that the CAISO file negotiated DEBs with the Commission will be satisfied by a monthly informational filing, and that Commission review and approval of the negotiated Default Energy Bids will not be required prior to those Bids taking effect. If the Commission declines to provide this clarification, then the CAISO requested rehearing of the Commission's decisions to require the CAISO to file with it the negotiated Default Energy Bids.

This white paper provides a discussion of these two related issues, along with a straw proposal for consideration and further discussion by stakeholders. Due to the compressed time frame for stakeholder consideration, we have also provided draft tariff language. Detail in the straw proposal that is not included in the draft tariff language would be included in a BPM. It should also be noted that the straw proposal assumes that the Commission will grant the CAISO request for clarification that the requirement to file negotiated DEBs with the Commission will be satisfied by a monthly informational filing, and that Commission review and approval of the negotiated Default Energy Bids will not be required prior to those Bids taking effect.

Discussion

As discussed in the CAISO's Request for Clarification and Rehearing of the Commission's September 21 MRTU Order, DEBs are used in *ex ante* bid mitigation and can affect overall market outcomes in a variety of irreversible ways. For example, in addition to affecting market prices paid/charged to other participants, bids used in *ex ante* mitigation affect which other supply/demand bids are accepted. Even if a bid is not dispatched, the price of the bid can ultimately have a significant impact on which other bids were dispatched and the resulting market prices.

In light of this, DMM believes that the process for development and use of Negotiated DEBs in *ex ante* mitigation must provide several key elements:

- A clear process that Market Participants must follow to exercise this option and the type of information they must provide;

- A process for resolution of any disputes regarding a Negotiated DEB; and
- Clarity about the rate that should be used in *ex ante* bid mitigation pending consideration of a request for a Negotiated DEB and resolution of any related disputes.

Since some situations may warrant establishing or modifying a bid under the Negotiated Option on an expedited basis, DMM believes that the CAISO, or an alternative independent entity selected by the CAISO, should have the authority to quickly approve a bid to be used under the Negotiated Option. For example, this expedited option may be necessary in the event of a sudden increase in operating costs or other conditions that may warrant immediate use of a special DEB level to avoid potential disruptions of supply critical for system local reliability.

Another scenario that may warrant establishing or modifying a bid under the Negotiated Option on an expedited basis is if one of the other DEB options in 39.7.1 (i.e., the LMP-Based DEB) produces a very unreasonably high DEB. Under this scenario, the CAISO would have the authority to make a Section 205 filing requesting authorization to apply appropriate mitigation measures, as specified in 39.1. However, in order to avoid such a filing, the CAISO may seek to work with a Market Participant to establish an appropriate DEB under the Negotiated Option. Under this scenario, an SC may agree to submit a proposed DEB under the Negotiated Option in order to avoid a Section 205 filing.

In the event that an agreement cannot be quickly reached between a Participant and the CAISO, DMM believes that the CAISO must have the ability to establish a temporary DEB pending any such agreement or resolution, if necessary, by FERC. The current CAISO Tariff (which is based on similar language in the New York ISO Tariff) provides the CAISO with the authority and criteria that can be adapted for use under the MRTU Tariff for setting temporary DEBs in such cases. Specifically, Section 3.1.1.1(a)5 of the current CAISO Tariff Appendix P – Attachment A provides that:

> If sufficient data do not exist to calculate a reference level on the basis of [other option in the tariff]…. or an attempt to determine a reference level in consultation with a Market Participant has not been successful, the ISO shall determine a reference level on the basis of:
>
> 1. The ISO's estimated costs of an Electric Facility, taking into account available operating costs data [sic], opportunity cost, and appropriate input from the Market Participant, and the best information available to the ISO; or
>
> 2. An appropriate average of competitive bids of one or more similar Electric Facilities.

DMM does not believe that the type of ADR Procedures provided in the CAISO Tariff (Section 13, which is the same in both the current and MRTU Tariffs) is appropriate for disputes involving negotiated rates to be used in *ex ante* bid mitigation. The process dictated by Section 13 is designed for after-the-fact settlement and contractual disputes in which time is not as critical. For example, the process provides a potentially extended process that can involve selection and use of outside mediators and arbiters. While this process may be appropriate for use in *ex post* disputes involving historical data, settlement calculations or contractual issues, it does not seem appropriate for resolving disagreements about rates to be used in *ex ante* bid mitigation.

DMM believes that a tariff requirement to enter into good faith negotiations prior to filing with the FERC is more appropriate and more likely to result in expeditious resolution of any dispute. If an agreed upon DEB cannot be negotiated, the Scheduling Coordinator would have the right to file a proposed DEB at FERC pursuant to Section 205 of the Federal Power Act. At FERC, parties could also avail themselves of the ADR and settlement judge procedures.

In order to provide a straw proposal for consideration and further discussion, DMM is suggesting the following process be reflected in Section 39.7.1.3 (Negotiated Option) with details included in a BPM.

DMM Straw Proposal

Process for the Negotiated Option for Establishing a Default Energy Bid

In order to establish a Default Energy Bid for a Generating Unit based on the Negotiated Option, the Scheduling Coordinator for the Generating Unit must provide the CAISO's Market Monitoring Unit or an alternative independent entity selected by the CAISO with the following information:

1. The proposed Default Energy Bid for the Generating Unit to be used under the Negotiated Option.
2. The market and time periods for which the proposed bid would be applicable (DAM and RTM; peak and off-peak hours; start and end dates).
3. A descriptive explanation and justification of the basis or need for the proposed bid, including numerical calculations and supporting documentation.
4. The rank order of the three options for determining the Generating Unit's Default Energy Bid to be used if the proposed bid is accepted under the Negotiated Option.
5. If applicable, any formulas, methodology or criteria proposed for modifying the bid to be used under the Negotiated Option in response to potential changes in costs, operational or market conditions, or other relevant factors.
6. If applicable, the Scheduling Coordinator may propose two alternative bids: (a) a preferred bid reflecting the Scheduling Coordinator's preferred bid under the Negotiated Option, and (b) a temporary bid that could be utilized on an expedited basis pending more detailed review, discussion and negotiation concerning the preferred bid for the Generating Unit.

After receipt of a request to establish a bid under the Negotiated Option, the CAISO's Market Monitoring Unit or an alternative independent entity selected by the CAISO will review the information and provide a written response within ten (10) business days.

The CAISO will assess bid levels or formulas proposed by Scheduling Coordinators on the basis of one or more of the following:

- Operating cost data, opportunity cost, and other appropriate input from the Market Participant
- The CAISO's estimated costs of the Electric Facility, taking into account the best data available to the CAISO
- An appropriate average of competitive bids of one or more similar Electric Facilities

Additional information may be requested from the Scheduling Coordinator as necessary to assess the reasonableness of the proposed bid and other potential bid levels. To expedite this process, the Scheduling Coordinator shall make representatives available to explain and discuss the rationale and supporting documentation for the proposed bid with the CAISO and any alternative independent entity selected by the CAISO.
All information provided by a Scheduling Coordinator shall be subject to confidentiality provisions of the CAISO Tariff.

Any DEB proposed in writing by a Scheduling Coordinator to the CAISO shall become effective within three (3) business days after acceptance by the CAISO.

Any DEB proposed in writing by the CAISO to a Scheduling Coordinator shall become effective within three (3) business days after acceptance by the Scheduling Coordinator is received by the CAISO.

Any DEB agreed upon by the CAISO and a Scheduling Coordinator under the Negotiated Option shall be filed at FERC within the first seven (7) days of the next calendar month. The DEB shall remain in effect unless:

1. The DEB is modified by FERC;
2. The DEB is modified by mutual agreement of the CAISO and a Scheduling Coordinator; or
3. The CAISO or Scheduling Coordinator provides written notification that the DEB is no longer acceptable for use under the Negotiated Option.

Pending any agreement between the Scheduling Coordinator and the CAISO with respect to a DEB to be used under the Negotiated Option, the Generating Unit's Default Energy Bid shall be based on either:

1. The other DEB options provided in 39.7.1 (i.e., Cost-Based DEB, LMP-Based DEB); or
2. A temporary DEB established by the CAISO.

The second of these options – a temporary DEB established by the CAISO – would be applicable only in the event that the CAISO determines that market or operational conditions warrant establishing a temporary DEB (or modifying a DEB) pending any agreement or resolution of a DEB proposed by the SC under the Negotiated Option. For example, this option may be necessary in the event of a sudden increase in operating costs or other conditions that may warrant immediate use of a special DEB level to avoid potential disruptions of supply critical for system local reliability. The CAISO may also need to establish a DEB under this option in the event that sufficient data are not available to calculate a DEB under any of the other options for establishing a DEB under the CAISO tariff.

Any modified DEB established by the CAISO would be based on the same criteria the CAISO would use to assess bid levels or formulas proposed by Scheduling Coordinators:

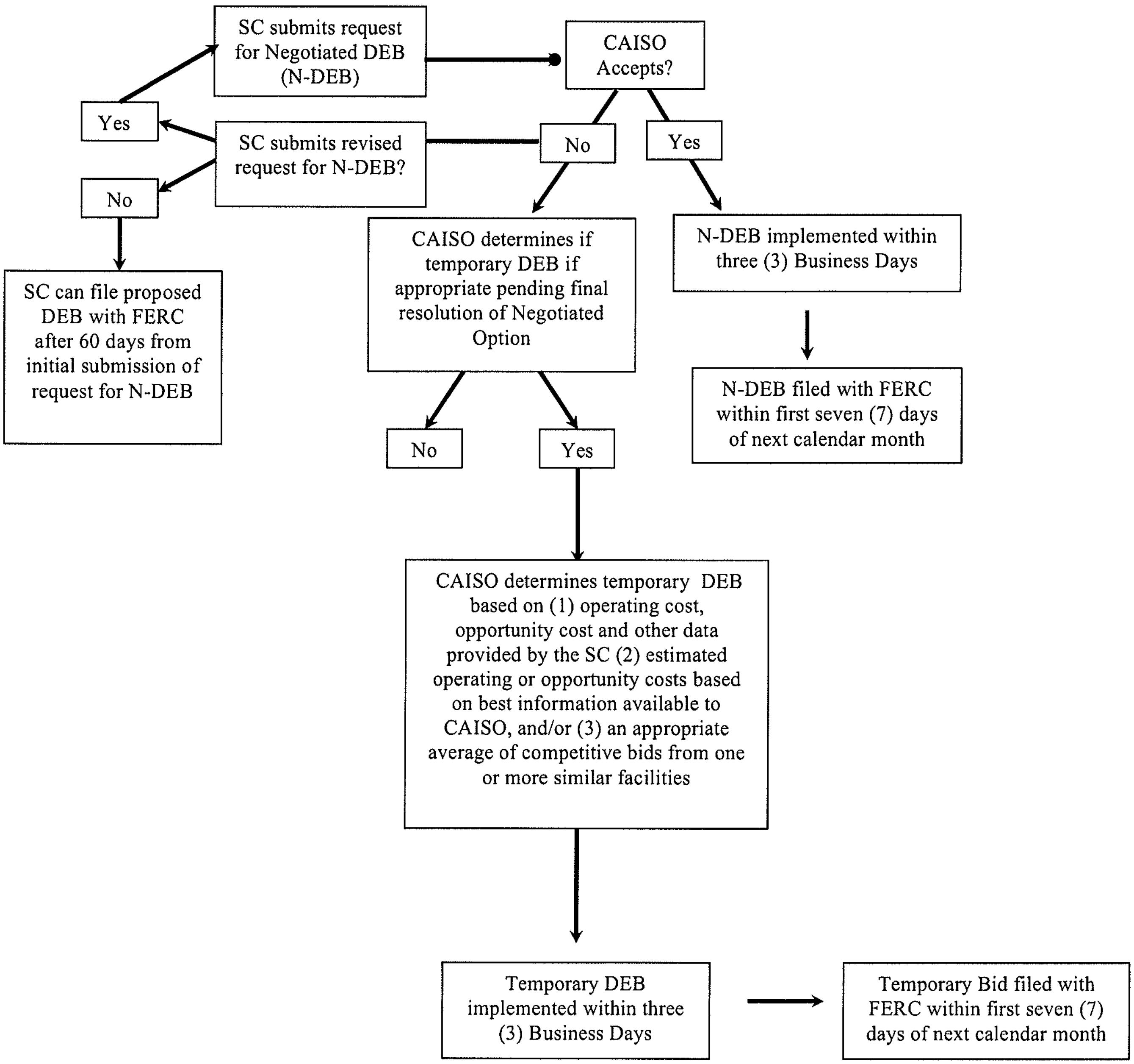
1. Operating cost data, opportunity cost, and other appropriate input from the Market Participant
2. The CAISO's estimated costs of the Electric Facility, taking into account the best data available to the CAISO
3. An appropriate average of competitive bids of one or more similar Electric Facilities

Dispute Resolution

If a Scheduling Coordinator and the CAISO cannot reach mutual agreement on a bid to be used under the Negotiated Option, the Scheduling Coordinator may file at FERC pursuant to Section 205 of the Federal Power Act for approval of a rate to be used under the Negotiated Option after 60 days from the commencement of initial negotiations on the proposed DEB.

Figure 1 provides a decision tree depicting this process, starting from the point at which a Participant submits a request for approval of DEB under the Negotiated Option through the point at which a DEB is either agreed upon or filed at FERC due to an inability to reach agreement.

Figure 1. Decision Tree on Negotiated DEB Option (N-DEB)



ATTACHMENT D

MRTU Market Power Mitigation

Frequently Mitigated Unit Option for Default Energy Bids (DEB)

CAISO Department of Market Monitoring (DMM)

November 20, 2006

Background

The local market power mitigation (LMPM) provisions incorporated in the CAISO's February 9, 2006, MRTU filing include an option that would allow Frequently Mitigated Units (FMUs) to be eligible for a $24/MWh adder to their cost-based Default Energy Bids (DEBs). To be eligible for this $24/MWh adder, units would need to meet three conditions:

- Units cannot be fully contracted as Resource Adequacy (RA) or Reliability Must Run (RMR) resources;
- Units must have at least 200 run hours in the preceding 12 month period; and
- Units must be mitigated in at least 80% of their run hours.

The FERC's September 21 MRTU Order accepted the CAISO's proposed $24/MWh bid adder for FMUs, but required the CAISO to:

(1) Remove the minimum 200 run-hour requirement for being eligible for the FMU bid adder (Order at Page 291, ¶1062); and

(2) Consider "whether the 80 percent mitigation frequency appropriately captures FMUs, and whether units that are mitigated less than 80 percent of the time should also receive a bid adder." (Order at Page 291, ¶1063).

This white paper provides a discussion of this second issue – i.e., whether units that are mitigated less than 80 percent of the time should also receive a bid adder.

Discussion

A discussion of the rationale for the CAISO's initial proposal for FMU and previous stakeholder comments is provided in an August 10, 2005, FMU whitepaper, which is posted on the CAISO website.[1] As noted in this whitepaper and subsequent MRTU filings, the main rationale for the 80 percent run hour mitigation frequency requirement is that this approach was incorporated in the overall package of LMPM measures in the PJM market, upon which the CAISO's LMPM plan is largely based. In response to stakeholder comments that the 80% mitigation threshold is too high, the CAISO has pointed out that:

> The 80% mitigation threshold for designation as Frequently Mitigated, and for Bid Adder eligibility, is an established threshold approved by FERC 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 fixed costs through

[1] http://www.caiso.com/docs/2005/08/10/2005081016580613580.pdf

infra-marginal rents occurring at their location during their unmitigated run hours. However, such units have the option of seeking a negotiated Default Energy Bid 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.[2]

However, in its September 21 Order, the Commission expressed two basic concerns about the CAISO's proposal that only units that are mitigated at least 80 percent of the time should be eligible for a bid adder under the FMU option.

- ***Revenue Adequacy.*** The Commission's September 21 Order indicates that FERC expects that "many of the resources currently under RMR contracts with the CAISO represent those units which will likely be frequently mitigated," and "to the extent that the use of RMR units is phased out in the future, the FMU option will become a market mechanism by which these units will receive a contribution to their fixed forward costs." (Order at ¶ 1063, p. 291)

- ***Perverse Bidding Incentives***. The Commission's Order also indicates "one concern a single arbitrary cut-off threshold such as 80 percent is that it may create a perverse incentive for units mitigated slightly less than the threshold to bid in a manner that increases their mitigation just above the threshold. One method that can avoid this problem is ... a sliding scale for units that are mitigated less frequently and establish corresponding graduated bid adders for each level of mitigation." (Order at ¶ 1063, p. 291)

In fact, since the CAISO's initial LMPM proposal was developed, PJM's market rules governing FMUs have been modified to include the type of sliding scale described in FERC's September 21 Order, under which units with mitigated run hours less than 80 percent are also eligible for a lower bid adder.[3] Specifically, PJM's revised market rules provide for three levels of bid adders to the cost-based DEB for FMUs:

1. For units that are subject to bid price mitigated 60 to 70% of their run hours, the DEB may be equal to incremental cost plus <u>either</u> 10% <u>or</u> $20/MWh.
2. For units that are subject to bid price mitigated 70 to 80% of their run hours, the DEB may be equal to incremental cost plus <u>either</u> 15% <u>or</u> $30/MWh.[4]
3. For units that are subject to bid price mitigated 80% or more of their run hours, the DEB may be equal to incremental cost plus <u>either</u> 10% <u>or</u> $40/MWh.[5]

The modifications in PJM's FMU rules were made as part of a Settlement Agreement reached in November 2005 to resolve a variety of issues relating to PJM's market power mitigation rules that had been set for hearing. Since these modifications were made as part of a Settlement Agreement, no explanatory information is available on the rationale for the specific thresholds incorporated in the Settlement Agreement.

[2] FMU Whitepaper, August 10, 2005, p. 6.
[3] See November 16, 2005, Settlement Agreement (EL-03-236-006, EL04-121-000), pp.7-8; Explanatory Statement p. 6; and Revised Tariff Sections 6.4.2 (a) (iii).
[4] Under this option, the 15% adder to incremental may not exceed $40/MWh.
[5] Alternatively, as with the CAISO's proposal, units that are subject to bid price mitigated 80% of more of their run hours may seek a negotiated DEB reflecting their unit specific going forward costs.

Table 1 shows how the basic framework established under the PJM Settlement Agreement might be applied in the context of the to CAISO's market power mitigation plan to determine bid adders for units with less than 80% of run hours mitigated. Specifically, potential bid adders shown in Table 1 for units with less than 80% of run hours mitigated are calculated by multiplying the bid adder for each category of unit in the PJM market by the ratio of the bid adders for units with at least 80% of run hours mitigated in the CAISO and PJM markets ($24/MWh or $40/MWh, respectively). For example, for a unit with 60 to 70% of run hours mitigated, this would result in a bid adder of $12/MWh ($20 x $24 / $40 = $12/MWh).[6]

Table 1. Potential FMU Bid Adders for CAISO Market

Mitigated Run Hours	PJM Bid Adders	CAISO Equivalent of PJM*
60-70%	Incremental cost plus <u>either</u> 10% <u>or</u> $20/MWh.	Incremental cost plus 10% <u>and</u> $12/MWh *
70-80%	Incremental cost plus <u>either</u> 15% <u>or</u> $30/MWh.	Incremental cost plus 10% <u>and</u> $18/MWh *
≥ 80%	Incremental cost plus <u>either</u> 10% <u>or</u> $40/MWh	Incremental cost plus 10% <u>and</u> $24/MWh

* Note: Potential adders for units with less than 80% of run hours mitigated based on bid adders for units mitigated less than 80% of run hours in PJM market multiplied by ratio of bid adder for units with ≥ 80% of run hours approved for the CAISO and PJM markets ($24/MWh and $40/MWh, respectively).

[6] When comparing bid adders for PJM with the potential bid adders for the CAISO in Table 1, it is also necessary to consider that the bid adders under the CAISO's FMU option are applied in addition to the 10% adder to fuel and variable costs, while FMUs receiving bid adders in PJM do not appear to also receive a 10% adder to fuel and variable costs. The additional 10% adder that FMUs receive under the CAISO MRTU plan could typically range from $6 to $10/MWh (depending on the heat rate and gas price upon which the unit's cost-based DEB is based).

DMM Comments

As an initial matter, DMM believes that bid adders do not represent the most efficient way for addressing revenue adequacy problems caused by relatively low run hours and/or frequent bid price mitigation. Bid adders inevitably create the risk of market distortions and inefficiencies by making bid prices of some units less reflective of actual marginal costs. Consequently, DMM continues to believe that revenue adequacy issues should be addressed primarily through capacity contracts or other types of contracts that provide contribution to fixed costs in the form of fixed revenue payments, rather than through bid adders.

As Local Area Resource Adequacy (LARA) requirements are phased in, DMM believes that sufficient resources should be under RA contracts to meet the bulk of local reliability needs, without significant reliance on FMUs.[7] Thus, DMM disagrees with FERC's assessment that "to the extent that the use of RMR units is phased out in the future, the FMU option will become a market mechanism by which these units will receive a contribution to their fixed forward costs." (Order at ¶ 1063, p. 291)

At the same time, DMM recognizes that some provision may need to be made for units that are not under capacity contracts in the context of an overall package of market power mitigation measures. DMM has supported the application of a bid adder for frequently mitigated units without capacity contracts under the expectation that the application and markets impacts of such bid adders would be relatively limited. In this context, DMM believes the level of bid adders outlined in Column 3 of Table 1 might be reasonable as part of the overall package of market power mitigation measures under MRTU. The limited magnitude of such bid adders should avoid significant market distortions and inefficiencies, particularly given the limited frequency during which units not under RA or RMR contracts should be needed for local reliability.

[7] DMM notes that even with sufficient resources under RA contracts to meet local reliability needs, non-RA or non-RMR units may still be selected to meet local reliability requirements during the Day Ahead scheduling process and be subject to bid price mitigation. This would occur whenever the initial (unmitigated) bid price of non-RA or non-RMR units that could be used to meet a local requirement was lower than the bid prices of RA or RMR units that are available to meet the same local requirement.

Certificate of Service

I hereby certify that I have this day served a copy of this document upon all parties listed on the official service list compiled by the Secretary in the above-captioned proceeding, in accordance with the requirements of Rule 2010 of the Commission's Rules of Practice and Procedure (18 C.F.R. § 385.2010).

Dated this 20th day of December, 2006 at Folsom in the State of California.

Charity Wilson (HWK)

Charity Wilson