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February 23, 2007

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

Re: California Independent System Operator Corporation
Docket No. ER07-___
Load Scheduling Amendment to the ISO Tariff

Dear Secretary Salas:

Pursuant to Section 205 of the Federal Power Act ("FPA"), 16 U.S.C. § 824d, and Section 35.13 of the regulations of the Federal Energy Regulatory Commission ("Commission"), 18 C.F.R. § 35.13, the California Independent System Operator Corporation ("CAISO") respectfully submits for filing an original and five copies of an amendment (the "Load Scheduling Amendment") to the ISO's Tariff. The Load Scheduling Amendment revises the ISO Tariff by modifying the scheduling and forecast submission requirements in several respects, including reducing the minimum scheduling requirement during off-peak hours to 75 percent of each Scheduling Coordinator's Demand forecast and establishing specific exemptions to account for small or infrequent scheduling deviations below the scheduling requirements. The CAISO requests that the Load Scheduling Amendment be made effective as of the earlier of the second Trading Day after issuance of the Commission's order on this filing or April 26, 2007.[1]

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[1] Under the ISO Tariff, a Trading Day is the twenty-four hour period beginning at the start of hour ending 0100 and ending at end of the hour ending 2400 daily, except where there is a change to or from daylight savings time. However, if the second Trading Day after issuance of the Commission's order falls on a weekend, the CAISO requests that the effective date be the Tuesday following issuance of the order. Similarly, April 26, 2007 is two Trading Days after elapse of the 60-day review period under Federal Power Act section 205. The purpose underlying the requested effective dates is to allow Load Serving Entities to take the new

Two extra copies of this filing are also enclosed. Please stamp these copies with the date and time filed and return them to the messenger.

I. THE PROPOSED AMENDMENTS

In October 2006, the CAISO Board of Governors approved pursuing the revised scheduling requirements established by the Load Scheduling Amendment.[2] In January 25, 2007, the CAISO Board of Governors authorized CAISO management to prepare and file the Tariff language proposed in the instant filing. The Load Scheduling Amendment is, among other things, designed to refine the 95 percent scheduling and Demand forecast reporting requirements adopted as part of ISO Tariff Amendment No. 72.[3] Based on experience implementing Amendment No. 72, the CAISO and stakeholders have identified a number of valid concerns with the existing requirements. The CAISO has proposed the tariff modifications contained in this filing in order to address and alleviate these concerns in a manner that balances the need to ensure reliability, the costs and burdens borne by Scheduling Coordinators, and the feasibility and complexity of the administration and enforcement of scheduling and Demand forecast reporting requirements by the CAISO and Commission Staff during an interim period until superseded by measures adopted for the Market Redesign and Technology Upgrade ("MRTU") project.[4]

A. Background

On September 22, 2005, the CAISO filed Amendment No. 72 to the ISO Tariff, which proposed to add a requirement that Scheduling Coordinators submit Day-Ahead Schedules that reflect at least 95 percent of their forecasted demand for each hour of the Trading Day.[5] The CAISO explained this requirement was reasonable in light of increased occurrences of underscheduling during the summer of 2005. The CAISO explained that when at least 95 percent of forecasted demand is scheduled in the Day-Ahead timeframe, the task of ensuring that sufficient generating units are on-line and available in the right locations is manageable. However, when Day-Ahead Schedules are significantly less than forecasted load, the CAISO finds itself in the position of having to

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scheduling requirements into account in a manner consistent with the usual bilateral trading timeframes in the west.

2 A copy of the Board memorandum regarding "Generator Outage Reporting," dated October 12, 2006, is attached hereto as Attachment A.

3 *California Independent System Operator Corporation,* Docket No. ER05-1502-000.

4 *See California Independent System Operator Corporation,* "Order Conditionally Accepting the California Independent System Operator's Electric Tariff Filing to Reflect Market Redesign and Technology Upgrade," 116 FERC ¶ 61,274 at P 452 (2006) (requiring the CAISO to propose mechanisms to address, as of the effective date of MRTU, the potential incentives to underschedule prior to the implementation of convergence bidding).

5 Amendment No. 72 also proposed certain requirements relating to resource identification and demand reporting.

commit as much as 4,000 to 4,500 MW of generation capacity in order to ensure reliability. This generation commitment effort, the CAISO stated, negatively affects the ability of its operators to react and respond to other grid reliability issues. The CAISO also noted that underscheduling renders it more difficult to anticipate or detect Real-Time transmission congestion, which can unacceptably increase the number of instances and quantity of resources that must be redispatched in Real-Time to address the reliability needs.

In addition to creating reliability and operational burdens, the CAISO explained that underscheduling can lead to increased costs to Market Participants. The failure of Day-Ahead schedules to reflect accurately forecasted load places the CAISO in the position of having to estimate the amount of load that will appear on the system in the hour-ahead timeframe and in Real-Time, and to procure sufficient resources to reliably serve those forecast loads. The CAISO stated that it must procure sufficient capacity available to cover all potential loads, but that without accurate forecast data, there is a risk of over-procuring resources, which results in significant and unnecessary cost impacts to Market Participants.

In Amendment No. 72, the CAISO also proposed to require that Scheduling Coordinators submit to the CAISO preliminary data for the preceding week regarding their forecasted and scheduled Demand and an estimate of the Scheduling Coordinator's actual Demand. In addition, the ISO proposed to require Scheduling Coordinators to provide, no later than 60 days after the submission of preliminary data, actual Demand data for the applicable period.

On November 21, 2005, the Commission accepted almost all of the proposed modifications contained in Amendment No. 72, including the 95 percent scheduling requirement and the requirement that Scheduling Coordinators submit data for the preceding week regarding their forecasted, scheduled, and actual Demand.[6] Consistent with the CAISO's proposal, the Commission stated that the scheduling requirements in Amendment No. 72 would expire upon implementation of MRTU. The Commission also granted the CAISO's request for waiver of the 60-day prior notice requirement and allowed Amendment No. 72 to go into effect as of September 23, 2005.

B. Need for Tariff Amendment

Since the implementation of Amendment No. 72, the CAISO has closely monitored the impacts of the 95 percent scheduling and Demand forecast

6 *California Independent System Operator Corporation,* "Order Accepting for Filing, Subject to Modifications, Tariff Amendment No. 72," 113 FERC ¶ 61,187 (2005) (rejecting the CAISO's proposal to require Scheduling Coordinators to submit updated actual demand data within a 60-day window).

submission requirements. The CAISO has also engaged in ongoing discussions with Market Participants and Commission Staff concerning these requirements.

Based on these activities, the CAISO has identified the following primary concerns with the 95 percent scheduling and Demand forecast submission requirements:

- Numerous Market Participants have indicated that the bulk of bilateral market supply is only available in standard multi-hour blocks (e.g., 16 peak hours or 8 off-peak hours), so that complying with the 95 percent scheduling requirement often requires them to over-procure energy and then over-schedule significant amounts of load, particularly during off-peak hours.

- The over-scheduling of load in the off-peak hours due to block-hour purchases to comply with the 95 percent scheduling requirement may create additional costs to Market Participants in cases when the price of procuring this energy in the bilateral market exceeds the Real-Time Energy price received by the Market Participant for over-scheduled load (which is settled as positive Uninstructed Energy). Some Market Participant have indicated that limiting the 95 percent scheduling requirement only to peak hours may greatly reduce this problem.

- CAISO Grid Operations staff has expressed concern that any over-scheduling during off-peak hours due to the 95 percent scheduling requirement may negatively affect system reliability by exacerbating over-generation conditions. This impact was particularly evident during the spring of 2006, when over-scheduling that was attributed to the Amendment 72 requirements – combined with other sources of unscheduled energy and uninstructed generation – resulted in significant over-generation conditions during many hours. Nevertheless, Grid Operations has also indicated that it is important to retain the 95 percent scheduling requirement during peak hours for reliability reasons.

- Numerous Market Participants have expressed concern that, under current ISO Tariff provisions, even infrequent and inadvertent violations of the 95 percent scheduling requirement that have no impact on reliability are nonetheless subject to investigation and potential sanction by the Commission, and the Tariff provides no discretion to the CAISO to excuse such minor violations.

- Some Market Participants have expressed concerns that infrequent and inadvertent violations of Demand forecasting submission requirements may occur, but they are automatically subject to a $500 penalty under current ISO Tariff provisions

Based on these concerns, the CAISO concluded that certain refinements to the scheduling and forecast submission requirements may be justified, and commenced a stakeholder process to explore such potential refinements. The CAISO began this process with an announcement of general modifications to the scheduling and forecast requirements under consideration in the first week of December 2006. On December 11, 2006, the CAISO issued a whitepaper prepared by its Department of Market Monitoring addressing concerns relating these requirements along with a "straw" proposal for various modifications to these requirements.[7] On December 18, 2006, the CAISO received stakeholder comments on this proposal, and held a conference call with stakeholders to discuss these comments on December 20, 2006. Based on stakeholder comments, the CAISO issued an addendum to its whitepaper on December 22, 2006,[8] and received further stakeholder input on this addendum on January 5, 2007, which were incorporated into materials provided to the CAISO Board of Governors for consideration. As noted above, on January 25, 2007, the CAISO Board of Governors authorized CAISO management to proceed to prepare and file Tariff language consistent with the policies and objectives supporting the Load Scheduling Amendment.

On February 6, 2007, the CAISO published proposed Tariff language for the Load Scheduling Amendment. The CAISO solicited stakeholder comments on the proposed Tariff language, which were received by February 12, 2007. Changes in response to stakeholder comments were made to the proposed Tariff language and discussed with stakeholders on a February 14, 2007 conference call.

C. Proposed Tariff Modifications

The CAISO continues to believe that the 95 percent scheduling and Demand forecast submission requirements significantly enhance reliability, and nothing in its own internal investigation or discussion with Market Participants suggests that these requirements should be discarded. Nevertheless, based on the stakeholder process, the CAISO believes that certain refinements to the 95 percent scheduling and Demand forecast submission requirement can and should be made that reflect an appropriate balance between the following factors:

- The potential reliability and operational impacts of changes to the Day-Ahead scheduling requirements.
- The difficulty and costs to participants of complying with Day-Ahead scheduling requirements during different time periods and conditions.

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7 This whitepaper is included with this filing as Attachment D.
8 This addendum is included with this filing as Attachment E.

- The potential additional difficulty of compliance for relatively small Load Serving Entities ("LSEs") with the principle that all participants should be subject to the same rules and requirements. [9]

- The feasibility and complexity of the administration and enforcement of scheduling requirements by the CAISO and Commission Staff.[10]

Based on these considerations, the CAISO proposes the following modifications to the scheduling and forecast submission requirements as currently contained in its Tariff.

1. Reduction to Minimum Scheduling Requirement for Off-Peak Hours

First, the CAISO proposes to reduce the minimum scheduling requirement during off-peak hours[11] to 75% of each Scheduling Coordinator's Demand forecast. This modification is intended to address concerns that application of the 95% scheduling requirement during off-peak hours may – under some load and system conditions – provide little reliability or operational benefits, and may actually exacerbate problems associated with over-scheduling and over-generation. The CAISO believes that a 75 percent scheduling requirement for off-peak hours will provide sufficient protection against excessive under-scheduling during off-peak hours, while still allowing Scheduling Coordinators to meet this scheduling requirement through standard 8-hour blocks of off-peak energy without over-scheduling of load or relying on any load-shaping resources or hourly bilateral purchases. Analysis of actual CAISO load data used to develop the 75 percent level for off-peak hours is included in the December 22, 2006 addendum to the CAISO's whitepaper developed for the stakeholder process.[12]

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[9] For example, SCs serving relatively small amounts of load may find it difficult or more costly to procure the small "odd lots" of energy in bilateral markets that may be necessary to "shape" their hourly supply schedules to meet 95% of forecasted load each hour. However, if scheduling requirements are less stringent for smaller LSEs, it may be argued that this allows smaller LSEs to "lean" on the CAISO's real-time energy market and causes larger LSEs to bear a greater share of the cost associated with enhancing system reliability through greater day-ahead scheduling.

[10] For example, because assessing the compliance with hourly scheduling requirements of each Scheduling Coordinator is highly data-intensive and involves an extremely large volume of scheduling "events," automated mechanisms and highly objective criteria are needed in order for the evaluation of compliance to be practical.

[11] As described below, for purposes of this tariff amendment, "off-peak" hours consist of hours 1 through 6 and hours 23 and 24, seven days a week.

[12] *See* Attachment E to this filing at pages 2-4.

The 75 percent level was developed during the stakeholder process as an alternative to several other options that were examined for providing some protection against excessive under-scheduling during off-peak hours and days, by allowing the CAISO the flexibility to require a minimum level of scheduling during off-peak hours in response to projected system conditions. However, most stakeholders and CAISO Grid Operations staff preferred a constant 75 percent off-peak scheduling requirement to these other options due to the potential operational uncertainty and added complexity inherent in the other options.

Also, due to concerns expressed by Grid Operations staff that a 75 percent scheduling requirement may provide insufficient protection against excessive under-scheduling on Sundays during peak daytime hours, the 95 percent scheduling requirement would continue to apply to hours 7 through 22 on all days of the week, including holidays, rather than only during the standard WECC definition of peak hours (Monday through Saturday, Hour Ending 7 through 22, excluding holidays).

These changes are reflected in ISO Tariff Section 4.5.4.2.1.1.

2. Safe Harbor for Exempt Scheduling Deviations from the 95/75 Percent Scheduling Requirements

The CAISO is also proposing to establish a safe harbor for Exempt Scheduling Deviations from the forward scheduling requirements. The modifications associated with this proposal are designed to address concerns that certain deviations below the 95 percent scheduling requirement may be inadvertent and have no impact on reliability, yet under current ISO Tariff provisions, are nevertheless subject to potential investigation and sanction by FERC. The CAISO proposes the threshold for such Exempt Scheduling Deviations be the lower of (a) 3 MWh or (b) 5% of the SC's Demand forecast. All deviations up to the Exempt Scheduling Deviation level, regardless of the number of occurrences, will be considered compliant with the hourly scheduling requirement.

Analysis by DMM based on the historical peak load of each Scheduling Coordinator in each Utility Distribution Company ("UDC") area indicates that, at an aggregate level, this threshold equates to an effective scheduling requirement of about 94.7% of the aggregate Demand forecast by SCs.[13] The specific formula proposed reflects an appropriate balance between the potential additional

[13] In other words, if all Scheduling Coordinators scheduled below 95% of their forecast but at the applicable threshold for *de minimis* deviations, total day-ahead scheduling by all Scheduling Coordinators would equal 94.7% of the aggregated forecast of all Scheduling Coordinators.

difficulty of compliance for relatively small LSEs and the need for reliability as well as the principal that all participants should be subject to the same rules and requirements. Attachment A to the Board Memo provides an illustrative calculation of this threshold for various levels of forecasted load (see Columns AF).

Stakeholders urged adoption of an exemption for *de minimis* deviations applicable to all hours. While numerous stakeholders – particularly small LSEs – advocated larger deviation allowances (5 to 25 MWh), a smaller threshold is being proposed for several reasons: (1) because this exemption would be applicable during all hours for all Scheduling Coordinators and would be applied to the quantity of load served by each Scheduling Coordinator within each separate UDC area, a larger threshold could have significant cumulative effects on overall scheduling; (2) the CAISO is concerned that a higher threshold level could create an incentive for LSEs to circumvent the intent of this threshold by creating multiple Scheduling Coordinator identification codes and dividing up their load under different identification codes;[14] and (3) higher thresholds would represent a very large percentage (or all) of load served by smaller LSEs within each UDC area, which would lead to a result inconsistent with the principal that Market Participants should generally be subject to the same rules and requirements.

Changes reflecting Exempt Scheduling Deviations are found at ISO Tariff Section 4.5.4.2.1.2 and in the Master Definitions Supplement (Appendix A).

3. Monthly Allowance for Minor Scheduling Deviations

In order to further balance the need for operational reliability with the exposure of Market Participants to sanctions for failure to comply with scheduling requirements, the CAISO is also proposing to provide each Scheduling Coordinator an allowance of up to six Minor Scheduling Deviations from the scheduling requirements per calendar month. This modification is designed to address deviations which are larger than the *de minimis* threshold described above, but that are unlikely to affect reliability if occurring infrequently and not simultaneously by all Scheduling Coordinators in all UDC areas. In other words, the potential occurrence of a Minor Scheduling Deviation is triggered only when the threshold for an Exempt Scheduling Deviation has been exceeded. As such, a deviation within the Exempt Scheduling Deviation threshold will not reduce the number of permitted Minor Scheduling Deviations.

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[14] Currently, the CAISO allows Scheduling Coordinators to request multiple SC identification codes for scheduling different loads and resources in order to facilitate accounting or other business purposes of the Scheduling Coordinator.

The proposed threshold for Minor Scheduling Deviations is the greater of (a) 25 MWh or (b) 2% of the Scheduling Coordinator's forecast Demand. Within each calendar month, each Scheduling Coordinator's first six deviations below each of the scheduling requirements that are less than the Minor Scheduling Deviation level will be considered compliant with the scheduling requirement. Specifically, each Scheduling Coordinator will be permitted a total of twelve (12) one-hour instances each calendar month in which its schedule drops below the applicable scheduling requirement – six for the 75% of forecast Demand requirement during off-peak hours and six for the 95% of forecast Demand requirement during peak hours.

As with the Exempt Scheduling Deviation threshold, the specific formula proposed by the CAISO for this Minor Scheduling Deviation allowance reflects the most appropriate balance between the potential additional difficulty of compliance for relatively small LSEs and the need to ensure reliability as well as the principle that all Market Participants should be subject to the same rules and requirements. As shown in Table 1 of Attachment A to the Board Memo, the threshold for Minor Scheduling Deviations equals 25 MWh for all Scheduling Coordinators with Demand forecast up to 1,250 MWh within any UDC area. All Scheduling Coordinators except the state's three major Investor Owned Utilities ("IOUs") fall in this category. For the three IOUs, the threshold for minor deviations equals 2% of forecasted Demand.

Due to concern about the potential cumulative impact of deviations of this magnitude, this exemption applies to only the first six hourly deviations within each calendar month for each Scheduling Coordinator within each UDC area. Thus, the exemption is designed to cover infrequent deviations that may occur due to exceptional circumstances, rather than lowering the target that Scheduling Coordinators should strive to meet during peak periods. It should also be noted that the Commission retains discretion with respect to enforcement activities relating to any deviations not covered by this exemption, and may consider any mitigating circumstances that lead to such deviations in determining whether or not to impose sanctions or other penalties.

The provisions allowing Minor Scheduling Deviations are set forth in ISO Tariff Section 4.5.4.2.1.3 and the Master Definitions Supplement (Appendix A).

4. Exemption from the $500 Penalty for First Violation of Demand Forecast Submission Requirement each Calendar Month

In order to address concerns that although infrequent violations of Demand forecasting submission requirements may be inadvertent in nature, they are nonetheless subject to a $500 penalty under current ISO Tariff provisions, the CAISO is proposing to provide each Scheduling Coordinator one exemption from this $500 penalty per calendar month. This exemption would apply to a Scheduling Coordinator's first deviation from the Demand forecasting submission requirements in a particular calendar month. This exemption is limited to the forecasting submission requirements in ISO Tariff Section 31.1.4.1, which are specifically incorporated into the Scheduling provisions of ISO Tariff Section 4.5.4.2.1.

Although compliance with the Demand forecast submission requirements has improved dramatically and virtually no violations have occurred since October 2006, periodic violations may continue to occur. The CAISO does not have discretion under its Tariff to waive or reduce penalties for identified violations, regardless of their nature. Rather, the CAISO may only submit a filing with the Commission recommending that the Commission waive or reduce a penalty based on mitigating circumstances. The CAISO believes that this limited exemption will reduce the exposure of Market Participants to penalties for inadvertent and infrequent violations of the Demand forecast submission requirement while at the same time ensuring continued compliance with these requirements.

The exemption is reflected in ISO Tariff Section 31.1.4.1.

5. Clarification Concerning the Applicability of the Scheduling Requirement to Revised Schedules or Unchanged Preferred Schedules

The CAISO proposes to modify Tariff Section 4.5.4.2.1.1 to clarify which Day-Ahead Schedules apply for determining compliance with the 95/75 percent Scheduling requirement. Section 4.5.4.2.1.1 now makes clear that the Day-Ahead Schedule shall be either a Revised Schedule pursuant to Section 30.3.4 if submitted by the Scheduling Coordinator, or, if the Scheduling Coordinator does not submit a Revised Schedule, a Preferred Day-Ahead Schedule pursuant to Section 30.3.1.

The Amendment No. 72 filing included Tariff language requiring that each Scheduling Coordinator "shall submit to the CAISO" Day-Ahead Schedules that equal at least 95 percent of the Scheduling Coordinator's forecasted demand for each hour, without specifying which Schedule this requirement applied. Under the ISO Tariff, Scheduling Coordinators may first submit Initial Preferred Schedules by 10:00 a.m. (Section 30.3.1), and then may submit Revised Schedules by 12:00 p.m. (Section 30.3.4). Thus, some ambiguity may exist as to whether Amendment No. 72 scheduling requirements apply to Preferred or Revised Schedules, or both.

In practice, initial Preferred Schedules submitted by Scheduling Coordinators by 10:00 a.m. the day before the Trading Day are not financially or physically binding or required, in that only Revised Schedules submitted by 12 noon are used by the CAISO in the final congestion management and settlement process. In other words, Scheduling Coordinators may adjust their Preferred Schedule submitted by 10 a.m. in any way they choose through the Revised Schedules submitted by 12 noon. However, the CAISO's Scheduling Infrastructure ("SI") records Revised Schedules through one of two means. First, the Scheduling Coordinator may submit a Revised Schedule. Second, a Preferred Schedule will be deemed a Revised Schedule if no Revised Schedule is received from the Scheduling Coordinator. In making this conversion, the SI does not currently retain the data necessary to distinguish what was a Preferred Schedule and what was, in fact, a Revised Schedule. Accordingly, in order to make clear that a Scheduling Coordinator is not required to submit a true-up Revised Schedule, the ISO Tariff has been modified to indicate that compliance is based on a Revised Schedule or, if no Revised Schedule is received, an unchanged Preferred Schedule.

6. Exemption for Scheduling Coordinators Serving Less than 1 MWh of Load Within a UDC Area

The CAISO also proposes that LSEs whose peak metered Demand during the preceding twelve months was less than 1 MWh within a particular UDC area would be exempt from the 95/75 percent scheduling requirement and Demand forecast submission obligation. Based on the CAISO's analysis of LSEs' peak metered Demand during 2006, this exemption would apply to only three cases, representing a total combined peak Demand of less than 1 MWh. Therefore, the CAISO believes that this exemption appropriately balances the need to ensure reliability with a desire to avoid burdening those Scheduling Coordinators with particularly small Demands.

While some LSEs have argued that exemptions from day-ahead scheduling requirements should be provided for LSEs with Demand greater than 1 MWh, the CAISO believes that attempting to establish and administer such an exemption may create significant additional complexity. Additionally, the CAISO's analysis of all peak Demands over the past year shows that there is a notable break in the frequency between those peak Demands less than 1 MWh and those greater than 3 MWh. Thus, 1 MWh represents a natural break point, and there is no natural break between higher MWh peak Demands. Also, as with the Exempt Scheduling Deviation threshold, the CAISO is concerned that an exemption for larger Demands would lead to the potential circumvention the scheduling requirement by dividing up Demand amongst multiple Scheduling Coordinator identification codes, and that the higher the exemption, the greater the incentive for such behavior.

Given that the exemption for Scheduling Coordinators serving less than 1 MWh of Demand applies to the Scheduling requirement and Demand forecast submission obligation, the necessary modifications are reflected in ISO Tariff Sections 4.5.4.2.1.1 and 31.1.4.1.

7. Elimination of Unused Forecast Submittal Requirements

Section 19 of the ISO Tariff includes a variety of longer-term forecast submission requirements that appear to have been included in the ISO Tariff since its inception, but are now not wholly consistent with the Demand Forecast needs of the ISO or the requirements imposed on the CAISO through NERC Standard MOD-017-0. That standard focuses on monthly and annual peak forecasts. Accordingly, in order to reduce uncertainty concerning Market Participants' obligations under the ISO Tariff, the CAISO proposes to remove the Demand Forecast requirements from Section 19 and modify Section 4.5.3.7 to be consistent with NERC MOD-017-0. In doing so, the CAISO is eliminating the separate and redundant requirement that a Utility Distribution Company submit weekly forecasts. Instead, the obligation will apply to Scheduling Coordinators and request, on a monthly basis, forecasts of limited to monthly and annual peak information.

However, ISO Tariff Section 19 does include provisions setting forth general obligations imposed on Scheduling Coordinators that submit forecast data, such as the obligations "to the best of their ability" to submit accurate forecasts and to avoid duplicating the load claimed by another Scheduling Coordinator. The CAISO believes these good faith obligations should be preserved. Accordingly, the Load Scheduling Amendment retains these provisions in ISO Tariff Sections 19.1.2 and 19.1.3, but specifically incorporates reference to the substantive Demand forecasting provisions in ISO Tariff Sections 4.5.3.7, 31.1.4.1 and 40.3.

In addition, those provisions of ISO Tariff Section 19 that relate to the CAISO's responsibilities to publish forecasting information have been consolidated and revised to conform to CAISO practice and WECC requirements.

8. Miscellaneous Changes

The CAISO has also made a number of changes to conform to current conventions used in the ISO Tariff as follows:

- Clarify that the Scheduling requirements of ISO Tariff Section 4.5.4.2.1.1 apply to Demand served by the Scheduling Coordinator within both a UDC and a Metered Subsystem ("MSS") Service Area. For a definitional perspective, the CAISO treats UDC and MSS Service Areas as separate and distinct.

- Replace "forecast Demand" with just "Demand" in ISO Tariff Sections 4.5.4.2 and 30.4.1.2, relating to the Balanced Schedule requirement. The CAISO made this change to reflect that Balanced Schedules can, but need not, equal the "forecast" Demand of the Scheduling Coordinator. A requirement that the Balanced Schedule equate to forecast Demand is inherently inconsistent with the Load Scheduling Amendment.

- Eliminate "forecast" from ISO Tariff Sections 4.5.4.2 and 30.4.1.2 and the definition of Balanced Schedule to acknowledge that under the Load Scheduling Amendment a Scheduling Coordinator's Balanced Schedule need not "equal" forecasted Demand, but rather must equal Demand appropriately scheduled under the requirements of the ISO Tariff.

- Clarify in ISO Tariff Section 20.2 on confidentiality that the Demand Forecast data submitted pursuant to ISO Tariff Section 4.5.3.7 will also be accorded confidential treatment similar to the Demand Forecast information received pursuant to ISO Tariff Section 31.1.4.1.

II. COMMUNICATIONS

Communications regarding this filing should be addressed to the following individuals, whose names should be placed on the official service list established by the Secretary with respect to this submittal:

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III. EFFECTIVE DATE

The CAISO requests that the Load Scheduling Amendment be made effective as of the earlier of the second Trading Day after the Commission issues its order on this application or April 26, 2007. As noted above, under the ISO Tariff, a Trading Day is the twenty-four hour period beginning at the start of hour ending 0100 and ending at end of the hour ending 2400 daily, except where there is a change to or from daylight savings time. However, if the second Trading Day after issuance of the Commission's order falls on a weekend, the CAISO requests that the effective day be moved to the Tuesday following issuance of the order. April 26, 2007 is two days after the conclusion of the 60-day review period under Federal Power Act Section 205. The rationale underlying the requested effective dates is to allow Load Serving Entities to take the new scheduling requirements into account in a manner consistent with the usual bilateral trading timeframes in the West. Moreover, allowing these provisions to become effective at this time will help address reliability concerns relating to Overgeneration conditions, which are most prevalent during the spring months.

IV. SERVICE

The CAISO has served copies of this transmittal letter, and all attachments, on the California Public Utilities Commission, the California Energy Commission, the California Electricity Oversight Board, all parties with effective Scheduling Coordinator Service Agreements under the ISO Tariff. In addition, the CAISO is posting this transmittal letter and all attachments on the CAISO Home Page.

V. ATTACHMENTS

The following documents, in addition to this letter, support this filing:

Attachment A	Clean Tariff Sheets
Attachment B	Blacklined Tariff Sheets
Attachment C	Board Memo Concerning Load Scheduling Amendment
Attachment D	December 11, 2006 Whitepaper Addressing Potential Modifications to Amendment No. 72 Scheduling Requirements
Attachment E	December 22, 2006 Addendum to December 11, 2006 Whitepaper

Two extra copies of this filing are also enclosed. Please stamp these copies with the date and time filed and return them to the messenger. Please feel free to contact the undersigned if you have any questions concerning this matter.

Respectfully submitted,

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ATTACHMENT A

4.5.3.2 Submit Schedules. Submitting Schedules for Energy in the Day-Ahead Market and Hour-Ahead Market in relation to Market Participants for which it serves as Scheduling Coordinator, Scheduling Coordinators shall provide the ISO with intertie Interconnection schedules prepared in accordance with all NERC, WECC and ISO requirements;

4.5.3.3 Modifications in Demand and Supply. Coordinating and allocating modifications in scheduled Demand and exports and scheduled Generation and imports at the direction of the ISO in accordance with this ISO Tariff;

4.5.3.3A Trades between Scheduling Coordinators. Billing and settling an Inter-Scheduling Coordinator Energy or Ancillary Service Trade shall be done in accordance with the agreements between the parties to the trade. The parties to an Inter-Scheduling Coordinator Energy or Ancillary Service Trade shall notify the ISO, in accordance with the ISO Protocols, of the Zone in which the transaction is deemed to occur, which, for Inter-Scheduling Coordinator Energy Trades, shall be used for the purpose of identifying which Scheduling Coordinator will be responsible for payment of applicable Usage Charges;

4.5.3.4 Scheduling Deliveries. Including in its Schedules to be submitted to the ISO under this ISO Tariff, the Demand, Generation and Transmission Losses necessary to give effect to trades with other Scheduling Coordinators;

4.5.3.5 Tracking and Settling Trades. Tracking and settling all intermediate trades among the entities for which it serves as Scheduling Coordinator;

4.5.3.6 Ancillary Services. Providing Ancillary Services in accordance with Section 8;

4.5.3.7 Annual and Monthly Forecasts. Submitting to the ISO its forecasted monthly and annual peak Demand in the ISO Control Area and/or its forecasted monthly and annual Generation capacity, as applicable. The forecasts shall be submitted to the ISO electronically on a monthly basis by noon of the 18th working day of the month and shall cover a period of twelve (12) months on a rolling basis;

4.5.3.8 **ISO Protocols.** Complying with all ISO Protocols and ensuring compliance by each of the Market Participants which it represents with all applicable provisions of the ISO Protocols;

4.5.3.9 **Interruptible Imports.** Identifying any Interruptible Imports included in its Schedules;

4.5.3.10 Participating Intermittent Resources. Submitting Schedules consistent with the ISO Protocols; and

4.5.3.11 Compliance with Environmental Constraints, Operating Permits and Applicable Law. Submitting Ancillary Services bids, Adjustment Bids and Supplemental Energy bids so that any service provided in accordance with such bids does not violate environmental constraints, operating permits or applicable law. All submitted bids must reflect resource limitations and other constraints as such are required to be reported to the ISO Control Center.

4.5.4 Operations of a Scheduling Coordinator.

4.5.4.1 Maintain Twenty-four (24) Hour Scheduling Centers.

Each Scheduling Coordinator shall operate and maintain a twenty-four (24) hour, seven (7) days per week, scheduling center. Each Scheduling Coordinator shall designate a senior member of staff as its scheduling center manager who shall be responsible for operational communications with the ISO and who shall have sufficient authority to commit and bind the Scheduling Coordinator.

4.5.4.2 Submitting Balanced Schedules.

A Scheduling Coordinator shall submit to the ISO only Balanced Schedules in the Day-Ahead Market and the Hour-Ahead Market. A Schedule shall be treated as a Balanced Schedule when aggregate Generation, Inter-Scheduling Coordinator Energy Trades (whether purchases or sales), and imports or exports to or from external Control Areas adjusted for Transmission Losses as appropriate, equals aggregate Demand with respect to all entities for which the Scheduling Coordinator schedules in each Zone. If a Scheduling Coordinator submits a Schedule that is not a Balanced Schedule, the ISO shall reject that Schedule provided that Scheduling Coordinators shall have an opportunity to validate their Schedules prior to the deadline for submission to the ISO by requesting such validation prior to the applicable deadline. On an interim basis, the ISO may assist Scheduling Coordinators in matching Inter-Scheduling Coordinator Energy Trades.

4.5.4.2.1 Submission of Schedules Sufficient to Meet Forecasted Demand

4.5.4.2.1.1 Subject to Sections 4.5.4.2.1.2 and 4.5.4.2.1.3, each Scheduling Coordinator shall submit to the ISO a Day-Ahead Schedule (1) for each hour ending 7 through 22 of each Trading Day that includes at least ninety-five percent (95%) of that Scheduling Coordinator's Demand Forecast, pursuant to Section 31.1.4.1, for each hour, for each UDC or MSS Service Area, with respect to all entities for which the Scheduling Coordinator schedules in the applicable UDC or MSS Service Areas and (2) for each hour ending 1 through 6, 23 and 24 of each Trading Day that includes at least seventy-five percent (75%) of that Scheduling Coordinator's Demand Forecast for each hour, for each UDC or MSS Service Area, with respect to all entities for which the Scheduling Coordinator schedules in the applicable UDC or MSS Service Areas. For purposes of Section 4.5.4.2.1, the Day-Ahead Schedule shall be either a Revised Schedule pursuant to Section 30.3.4 if one is submitted by the Scheduling Coordinator, or, if the Scheduling Coordinator does not submit a revised Schedule, a Preferred Day-Ahead Schedule pursuant to Section 30.3.1.

The requirements of this section do not apply to (a) the portion of a Scheduling Coordinator's Demand associated with Station Power and (b) the Scheduling Coordinator's Demand within a UDC or MSS Service Area if the Scheduling Coordinator's maximum Demand within that UDC or MSS Service Area during the preceding twelve (12) months was less than one (1) megawatt, provided that this exemption shall not apply to any Scheduling Coordinator that did not submit Schedules for any metered Demand within a UDC or MSS Service Area over the preceding twelve (12) month period.

4.5.4.2.1.2 Exempt Scheduling Deviations by a Scheduling Coordinator in each UDC or MSS Service Area below the ninety-five percent (95%) and seventy-five percent (75%) scheduling levels specified in Section 4.5.4.2.1.1 shall not be deemed violations of Section 4.5.4.2.1.1.

4.5.4.2.1.3 In addition to the Exempt Scheduling Deviations permitted under Section 4.5.4.2.1.2, the first six (6) Minor Scheduling Deviations during each calendar month by each Scheduling Coordinator in each UDC or MSS Service Area below the ninety-five percent (95%) Day-Ahead scheduling requirement and the first six Minor Scheduling Deviations during each calendar month by each Scheduling

Coordinator in each UDC or MSS Service Area below the seventy-five percent (75%) Day-Ahead scheduling requirement, specified in Section 4.5.4.2.1.1, shall not be deemed a violation of Section 4.5.4.2.1.1.

4.5.4.3 Dynamic Scheduling.

Scheduling Coordinators may dynamically schedule imports of Energy, Supplemental Energy, and Ancillary Services (other than Regulation) for which associated Energy is delivered dynamically from System Resources located outside of the ISO Control Area, provided that (a) such dynamic scheduling is technically feasible and consistent with all applicable NERC and WECC criteria and policies, (b) all operating, technical, and business requirements for dynamic scheduling functionality, as posted in standards on the ISO Home Page, are satisfied, (c) the Scheduling Coordinator for the dynamically scheduled System Resource executes an agreement with the ISO for the operation of dynamic scheduling functionality, and (d) all affected host and intermediary Control Areas each execute with the ISO an Interconnected Control Area Operating Agreement ("ICAOA") or special operating agreement related to the operation of dynamic functionality. See the forms of agreement in Attachment A to Appendix X.

4.5.4.4 Termination of Service Agreement.

(a) A Scheduling Coordinator's Scheduling Coordinator Agreement may be terminated by the ISO on written notice to the Scheduling Coordinator:

(i) if the Scheduling Coordinator no longer meets the requirements for eligibility set out in Section 4.5 and fails to remedy the default within a period of seven (7) days after the ISO has given written notice of the default;

17 [Not Used]

18 [Not Used]

19 DEMAND FORECASTS.

19.1 Scheduling Coordinator and Load-Serving Entity Demand Forecast Responsibilities.

19.1.1 Applicability to Scheduling Coordinators and Load-Serving Entities.

This Section 19.1 shall apply to each Scheduling Coordinator that must submit a Demand Forecast pursuant to Sections 4.5.3.7, 31.1.4.1 or the provisions of Section 40, and each Load-Serving Entity on whose behalf such Demand Forecasts are submitted.

19.1.2 Avoiding Duplication.

Each Scheduling Coordinator submitting a Demand Forecast to the ISO, and each Load-Serving Entity on whose behalf such Demand Forecast is submitted, shall ensure, to the best of their ability, that any Demand Forecast submitted to the ISO is not duplicated in another Scheduling Coordinator's Demand Forecast.

19.1.3 Required Performance.

Each Scheduling Coordinator submitting a Demand Forecast to the ISO, and each Load-Serving Entity on whose behalf such Demand Forecast is submitted, shall take all necessary actions to provide a Demand Forecast that reflects reasonable forecast accuracy standards. Scheduling Coordinators may develop and submit Demand Forecasts earlier than the timeline specified in Section 31.1.4.1 as appropriate to implement WECC-compliant weekend and holiday Demand Forecasts and scheduling practices.

[NOT USED]

[NOT USED]

19.2 ISO Responsibilities.

19.2.1 ISO Advisory Control Area Demand Forecasts.

The ISO will develop and publish on the ISO website and supply to the Scheduling Coordinators advisory Demand Forecasts comprised of Hourly Demand Forecasts for each Congestion Zone for each Settlement Period of the relevant Trading Day. The ISO will publish this information in accordance with the timing requirements set forth in this ISO Tariff.

19.2.2 ISO Annual Reports of Demand and Resources.

On an annual basis in accordance with the requirements of the WECC, the ISO will publish on its website reports that provide estimates of resource availability, peak Demand levels, and reserve capacity during anticipated peak Demand conditions for the ISO Control Area for the summer and any other specified seasons.

20 CONFIDENTIALITY.

20.1 ISO.

The ISO shall maintain the confidentiality of all of the documents, data and information provided to it by any Market Participant that are treated as confidential or commercially sensitive under Section 20.2; provided, however, that the ISO need not keep confidential: (1) information that is explicitly subject to data exchange through WEnet pursuant to Section 6 of this ISO Tariff; (2) information that the ISO or the Market Participant providing the information is required to disclose pursuant to this ISO Tariff, or applicable regulatory requirements (provided that the ISO shall comply with any applicable limits on such disclosure); or (3) information that becomes available to the public on a non-confidential basis (other than as a result of the ISO's breach of this ISO Tariff).

20.2 Confidential Information.

The following information provided to the ISO by Scheduling Coordinators shall be treated by the ISO as confidential:

(a) individual bids for Supplemental Energy;

(b) individual Adjustment Bids for Congestion Management which are not designated by the Scheduling Coordinator as available;

(c) individual bids for Ancillary Services;

(d) transactions between Scheduling Coordinators;

(e) individual Generator Outage programs unless a Generator makes a change to its Generator Outage program which causes Congestion in the short term (i.e. one month or less), in which case, the ISO may publish the identity of that Generator.

(f) Demand Forecast and other hourly data provided by Scheduling Coordinators to the ISO pursuant to Sections 4.5.3.7 and 31.1.4.

The following information provided to the ISO by Scheduling Coordinators or Market Participants for purposes of the Interim Reliability Requirements Program shall be treated by the ISO as confidential:

(a) Annual and monthly Resource Adequacy Plans pursuant to Sections 40.2.1 and 40.2.2, respectively, and Supply Plans pursuant to Section 40.6; however, any Planning Reserve Margin information required by Section 40.4 and any Qualifying Capacity eligibility criteria information required by Section 40.5.1 contained in the Resource Adequacy Plans and/or Supply Plans shall not be treated as confidential.

(b) Demand Forecast and other hourly data provided pursuant to Section 40.3.

(c) Information on existing import contracts, and any trades or sales of allocated import capacity, provided pursuant to Section 40.5.2.2.

(d) Information reported by non-Participating Generators pursuant to Sections 40.6A.3 and 40.7.3.

(e) Information submitted through the dispute or discrepancy resolution process pursuant to Section 40.2.3.

20.3 Other Parties.

No Market Participant shall have the right hereunder to receive from the ISO or to review any documents, data or other information of another Market Participant to the extent such documents, data or information is to be treated as in accordance with Section 20.2; provided, however, a Market Participant may receive and review any composite documents, data, and other information that may be developed based upon such confidential documents, data, or information, if the composite document does not disclose such the Scheduling Coordinator adds a new Schedule or modifies an existing Schedule, that Schedule must be re-validated. Scheduling Coordinators must comply with the ISO Data Templates and Validation Rules document, which contains the validation criteria for Balanced Schedules.

30.4.1.1 Stage One Validation.

During stage one validation, each incoming Schedule will be validated to verify proper content, format and syntax. The ISO will check that the Scheduling Coordinator had not exceeded its Aggregate Credit Limit and verify that the Scheduling Coordinator is certified in accordance with the ISO Tariff. The ISO will further verify that the Scheduling Coordinator has inputted valid Generating Unit and Demand location identification. Scheduled Reliability Must-Run Generation will be verified against the contract reference numbers in the ISO's Scheduling Coordinator database. A technical validation will be performed verifying that a scheduled Generating Unit's output is not beyond it's declared capacity and/or operating limits. If there is an error found during stage one validation, the Scheduling Coordinator will be notified immediately through WEnet. The Scheduling Coordinator can then look at the notification messages to review the detailed list of errors, make changes, and resubmit the Schedule if it is still within the ISO's timing requirements. Additionally, if the ISO detects an invalid contract usage (of either Existing Contract rights or Firm Transmission Rights), the ISO will issue an error message in similar manner to the Scheduling Coordinator and allow the Scheduling Coordinator to view the message(s), to make changes, and to resubmit the contract usage template(s) if it is still within the ISO's timing requirements. The Scheduling Coordinator is also notified of successful validation via WEnet.

30.4.1.2 Stage Two Validation.

During stage two validation, Schedules will be checked to determine whether each Scheduling Coordinator's aggregate Generation and external imports (adjusted for Transmission Losses) and Inter-Scheduling Coordinator Energy Trades (whether purchases or sales) equals the Scheduling Coordinator's aggregate Demand, including external exports. The Scheduling Coordinator must take into account the applicable Generation Meter Multipliers (GMMs). The Scheduling Coordinator will be notified if the counterpart trade to any Inter-Scheduling Coordinator Ancillary Service Trade has not been submitted, or is infeasible (i.e., if both Scheduling Coordinators are selling or both are buying).

purpose of balancing the RMR Contract Energy not otherwise Scheduled to forecast Demand or through an Inter-Scheduling Coordinator Energy Trade. The price for the RMR Contract Energy Scheduled to the RMR Contract Energy Load Point shall be the price paid to Demand deviations from Final Hour-Ahead Schedules.

31.1.3.5 [Not Used]

31.1.4 Demand Information.

31.1.4.1 Daily Information. By 10:00 a.m. on the day preceding the Trading Day, each Scheduling Coordinator shall provide to the ISO a Demand Forecast specified by UDC or MSS Service Area for which it will schedule deliveries for each of the Settlement Periods of the following Trading Day; however, the requirements of this Section shall not apply to (a) the portion of a Scheduling Coordinator's Demand associated with Station Power and (b) the Scheduling Coordinator's Demand within a UDC or MSS Service Area if the Scheduling Coordinator's maximum Demand within that UDC or MSS Service Area during the preceding twelve (12) months was less than one (1) megawatt, provided that this exemption shall not apply to any Scheduling Coordinator that did not submit Schedules for any metered Demand within a UDC or MSS Service Area over the preceding twelve (12) month period. The ISO shall aggregate the Demand information by UDC or MSS Service Area and transmit the aggregate Demand information to each UDC or MSS serving such aggregate Demand. The first instance in each calendar month in which a Scheduling Coordinator fails to submit the information required pursuant to this Section shall not be deemed a violation of this Section.

31.1.4.2 Preliminary Weekly Information. Each Scheduling Coordinator shall provide to the ISO, no later than seven (7) days after the end of each week, which shall end at Sunday HE 24, data for the previous week (Monday through Sunday), in electronic format, comparing, for each hour of that week: (1) the Scheduling Coordinator's total Day-Ahead scheduled Demand by UDC Service Area, as submitted pursuant to Section 4.5.4.2, (2) the Scheduling Coordinator's total Day-Ahead Demand Forecast by UDC Service Area, as submitted pursuant to Section 31.1.4.1, and (3) an estimate of the Scheduling Coordinator's actual Demand by UDC Service Area. The requirements of this section do not apply to the portion of a Scheduling Coordinator's Demand associated with Station Power.

31.1.5 The Preferred Schedule of each Scheduling Coordinator for the following Trading Day shall be submitted at or prior to 10:00 a.m. on the day preceding the Trading Day together with any Adjustment Bids and Ancillary Services bids.

31.1.6 In submitting its Preferred Schedule, each Scheduling Coordinator shall notify the ISO of any Dispatchable Loads which are not scheduled but have submitted Adjustment Bids and are available for Dispatch at those same Adjustment Bids to assist in relieving Congestion.

	rating guidelines, less any reserved uses applicable to the path.
Backup ISO Control Center	The ISO Control Center located in Alhambra, California.
Balanced Schedule	A Schedule shall be deemed balanced when Generation, adjusted for Transmission Losses equals Demand with respect to all entities for which a Scheduling Coordinator schedules.
Balancing Account	An account set up to allow periodic balancing of financial transactions that, in the normal course of business, do not result in a zero balance of cash inflows and outflows.
Black Start	The procedure by which a Generating Unit self-starts without an external source of electricity thereby restoring power to the ISO Controlled Grid following system or local area blackouts.
Black Start Generator	A Participating Generator in its capacity as party to an Interim Black Start Agreement with the ISO for the provision of Black Start services, but shall exclude Participating Generators in their capacity as providers of Black Start services under their Reliability Must-Run Contracts.
Bulk Supply Point	A UDC metering point.
Business Day	Monday through Friday, excluding federal holidays and the day after Thanksgiving Day.
C.F.R.	Code of Federal Regulations.
Calendar Day	Any day including Saturday, Sunday or a federal holiday.
CDWR-SWP	The California Department of Water Resources, State Water Project.
CDWR-SWP Participating Generating Units	The Generating Units operated by the California Department of Water Resources, State Water Project, that are subject to a Participating Generator Agreement with the ISO.
Certificate of Compliance	A certificate issued by the ISO which states that the Metering Facilities referred to in the certificate satisfy the certification criteria for Metering Facilities contained in the ISO Tariff.
Check Meter	A redundant revenue quality meter which is identical to and of equal accuracy to the primary revenue quality meter connected at the same metering point which must be certified in accordance with the ISO Tariff.

Energy Export	For purposes of calculating the Grid Management Charge, Energy included in an interchange Schedule submitted to the ISO, or dispatched by the ISO, to serve a Load located outside the ISO's Control Area, whether the Energy is produced by a Generator in the ISO Control Area or a resource located outside the ISO's Control Area.
Entitlements	The right of a Participating TO obtained through contract or other means to use another entity's transmission facilities for the transmission of Energy.
Environmental Dispatch	Dispatch designed to meet the requirements of air quality and other environmental legislation and environmental agencies having authority or jurisdiction over the ISO.
Estimated Aggregate Liability	The sum of a Market Participant's or FTR Bidder's known and reasonably estimated potential liabilities for a specified time period arising from charges described in the ISO Tariff, as provided for in Section 12 of the ISO Tariff.
Exempt Scheduling Deviation	The difference between a Day-Ahead Schedule submitted by any Scheduling Coordinator, pursuant to Section 4.5.4.2.1.1, and its Demand Forecast, pursuant to Section 31.1.4.1, within any UDC or MSS Service Area that does not exceed the lesser of (a) three (3) MW or (b) five percent (5%) of that Scheduling Coordinator's Demand Forecast for the relevant UDC or MSS Service Area.
Export Percentage	Export Percentage will be calculated for each Participating Intermittent Resource as the ratio of the Participating Intermittent Resource's Pmax in the ISO Master File minus the MW subject to an exemption under EIRP 5.3.2 on a MW basis to the Participating Intermittent Resource's Pmax in the ISO Master File.
Exporting Participating Intermittent Resource	A Participating Intermittent Resource with Export Percentage greater than zero (0).
Ex Post GMM	GMM that is calculated utilizing the real-time Power Flow Model in accordance with Section 27.2.1.2.1.2.
Ex Post Price	The Hourly Ex Post Price, the Dispatch Interval Ex Post Price, the Resource-Specific Settlement Interval Ex Post Price, or the Zonal Settlement Interval Ex Post Price.

Ex Post Transmission Loss	Transmission Loss that is calculated based on Ex Post GMM.
Existing Contracts	The contracts which grant transmission service rights in existence on the ISO Operations Date (including any contracts entered into pursuant to such contracts) as may be amended in accordance with their terms or by agreement between the parties thereto from time to time.

under terms approved by a Local Regulatory Authority or FERC, as applicable, or the customer's Load can be curtailed concurrently with an outage of the Generating Unit.

Meter Data Exchange Format The format for submitting Meter Data to the ISO which will be published by the ISO on the ISO Home Page or available on request to the Meter and Data Acquisition Manager, ISO Client Service Department.

Meter Data Request Format The format for requesting Settlement Quality Meter Data from the ISO which will be published by the ISO on the ISO Home Page or available on request to the Meter and Data Acquisition Manager, ISO Client Service Department.

Metered Quantities For each Direct Access End-User, the actual metered amount of MWh and MW; for each Participating Generator the actual metered amounts of MWh, MW, MVAr and MVArh.

Metering Facilities Revenue quality meters, instrument transformers, secondary circuitry, secondary devices, meter data servers, related communication facilities and other related local equipment.

Minimum Load Costs The costs a Generating Unit incurs operating at minimum load.

Minor Scheduling Deviation The difference between a Day-Ahead Schedule submitted by any Scheduling Coordinator, pursuant to Section 4.5.4.2.1.1, and its Demand Forecast, pursuant to Section 31.1.4.1, within any UDC or MSS Service Area that is (a) greater than the lesser of (i) three (3) MW or (ii) five percent (5%) of that Scheduling Coordinator's Demand Forecast for the relevant UDC or MSS Service Area as set forth in Section 4.5.4.2.1.2, but (b) less than the greater of (i) twenty-five (25) MW or (ii) two percent (2%) of that Scheduling Coordinator's Demand Forecast for the relevant UDC or MSS Service Area.

Month-Ahead System Resource Adequacy Requirements The amount of Qualifying Capacity that a RA Entity must reflect in its monthly Resource Adequacy Plan submitted pursuant to Section 40.2.2 in compliance with Resource Adequacy Rules adopted by the CPUC or a Local Regulatory Authority, as applicable.

Month-Ahead System Resource Deficiency	The monthly deficiency in meeting the Month-Ahead System Resource Adequacy Requirements as determined by the CPUC and applicable Local Regulatory Authorities for each RA Entity subject to their jurisdiction.
Monthly Peak Load	The maximum hourly Demand on a Participating TO's transmission system for a calendar month, multiplied by the Operating Reserve Multiplier.
Monthly RCST Charge	The monthly charge determined in accordance with Appendix F, Schedule 6.
MRTU Tariff	The ISO Tariff that will implement the ISO's Market Redesign and Technology Upgrade ("MRTU").

ATTACHMENT B

* * *

4.5.3.7 **Annual and ~~Weekly~~ Monthly Forecasts.** Submitting to the ISO ~~the~~ its forecasted~~weekly~~ monthly and annual peak Demand in the ISO Control Area ~~on the ISO Controlled Grid~~ and/or its ~~the~~ forecasted monthly and annual Generation capacity, as applicable. The forecasts shall be submitted to the ISO electronically on a monthly basis by noon of the 18th working day of the month and shall cover a period of twelve (12) months on a rolling basis;

* * *

4.5.4.2 **Submitting Balanced Schedules.**

A Scheduling Coordinator shall submit to the ISO only Balanced Schedules in the Day-Ahead Market and the Hour-Ahead Market. A Schedule shall be treated as a Balanced Schedule when aggregate Generation, Inter-Scheduling Coordinator Energy Trades (whether purchases or sales), and imports or exports to or from external Control Areas adjusted for Transmission Losses as appropriate, equals aggregate ~~forecast~~ Demand with respect to all entities for which the Scheduling Coordinator schedules in each Zone. If a Scheduling Coordinator submits a Schedule that is not a Balanced Schedule, the ISO shall reject that Schedule provided that Scheduling Coordinators shall have an opportunity to validate their Schedules prior to the deadline for submission to the ISO by requesting such validation prior to the applicable deadline. On an interim basis, the ISO may assist Scheduling Coordinators in matching Inter-Scheduling Coordinator Energy Trades.

* * *

4.5.4.2.1 **Submission of Schedules Sufficient to Meet Forecasted Demand**

4.5.4.2.1.1 Subject to Sections 4.5.4.2.1.2 and 4.5.4.2.1.3, ~~E~~each Scheduling Coordinator shall submit to the ISO~~,~~ a Day-Ahead Schedule (1) for each hour ending 7 through 22 of each Trading Day~~, a Day-Ahead Schedule~~ that includes at least ninety-five percent (95%) of that Scheduling Coordinator's ~~forecast~~ Demand Forecast, pursuant to Section 31.1.4.1, for each hour, for each UDC or MSS Service Area, with respect to all entities for which the Scheduling

Coordinator schedules in the applicable UDC or MSS Service Areas and (2) for each hour ending 1 through 6, 23 and 24 of each Trading Day that includes at least seventy-five percent (75%) of that Scheduling Coordinator's Demand Forecast for each hour, for each UDC or MSS Service Area, with respect to all entities for which the Scheduling Coordinator schedules in the applicable UDC or MSS Service Areas. For purposes of Section 4.5.4.2.1, the Day-Ahead Schedule shall be either a Revised Schedule pursuant to Section 30.3.4 if one is submitted by the Scheduling Coordinator, or, if the Scheduling Coordinator does not submit a revised Schedule, a Preferred Day-Ahead Schedule pursuant to Section 30.3.1.

The requirements of this section do not apply to (a) the portion of a Scheduling Coordinator's Demand associated with Station Power and (b) the Scheduling Coordinator's Demand within a UDC or MSS Service Area if the Scheduling Coordinator's maximum Demand within that UDC or MSS Service Area during the preceding twelve (12) months was less than one (1) megawatt, provided that this exemption shall not apply to any Scheduling Coordinator that did not submit Schedules for any metered Demand within a UDC or MSS Service Area over the preceding twelve (12) month period.

4.5.4.2.1.2 Exempt Scheduling Deviations by a Scheduling Coordinator in each UDC or MSS Service Area below the ninety-five percent (95%) and seventy-five percent (75%) scheduling levels specified in Section 4.5.4.2.1.1 shall not be deemed violations of Section 4.5.4.2.1.1.

4.5.4.2.1.3 In addition to the Exempt Scheduling Deviations permitted under Section 4.5.4.2.1.2, the first six (6) Minor Scheduling Deviations during each calendar month by each Scheduling Coordinator in each UDC or MSS Service Area below the ninety-five percent (95%) Day-Ahead scheduling requirement and the first six Minor Scheduling Deviations during each calendar month by each Scheduling Coordinator in each UDC or MSS Service Area below the seventy-five percent (75%) Day-Ahead scheduling requirement, specified in Section 4.5.4.2.1.1, shall not be deemed a violation of Section 4.5.4.2.1.1.

* * *

19 DEMAND FORECASTS.

19.1 Scheduling Coordinator and Load-Serving Entity Demand Forecast Responsibilities.

19.1.1 ~~Data to be Submitted to the ISO by~~ Applicability to Scheduling Coordinators and Load-Serving Entities.

~~At the time specified in Section 19.1.3,~~ This Section 19.1 shall apply to each Scheduling Coordinator that must submit a Demand Forecast pursuant to Sections 4.5.3.7, 31.1.4.1 or the provisions of Section 40, and each Load-Serving Entity on whose behalf such Demand Forecasts are submitted ~~shall submit to the ISO its Weekly Peak Demand Forecast by Congestion Zone reflecting (1) the Weekly Peak Demand Forecasts of the UDCs that it proposes to Schedule and (2) any other non-UDC Demand that it proposes to Schedule. All Weekly Peak Demand Forecasts submitted shall include Demand Forecasts for the following 52 weeks~~.

~~**19.1.2 Format of Demand Forecasts.** Demand Forecasts must be submitted to the ISO electronically in the format set forth in Section 19.1.5.~~

~~**19.1.3 Timing of Submission of Demand Forecasts.** The Demand Forecasts described in this Section shall be submitted by Scheduling Coordinators to the ISO on a monthly basis by noon of the 18th working day of the month.~~

~~**19.1.4 Forecast Standards.**~~

19.1.2~~4.1~~ Avoiding Duplication.

Each Scheduling Coordinator~~s~~ submitting a Demand Forecast~~s~~ to the ISO, and each Load-Serving Entity on whose behalf such Demand Forecast is submitted, shall ensure, to the best of their ability, that any Demand ~~they are f~~Forecast~~ing~~ submitted to the ISO is not ~~included~~duplicated in another Scheduling Coordinator's Demand Forecasts. ~~To accomplish this, each Scheduling Coordinator's Demand Forecasts should only reflect those End-Use Customers who they actually have under contract and who have notified their UDC or previous Scheduling~~

~~Coordinator of their intention to change to another Scheduling Coordinator, and which are actually scheduled to convert.~~

19.1.3~~4.2~~ Required Performance.

Each ~~Scheduling Coordinators~~ Scheduling Coordinator submitting ~~its~~ a Demand ~~Forecasts~~ Forecast to the ISO, and each Load-Serving Entity on whose behalf such Demand Forecast is submitted, shall take all necessary actions to provide a Demand ~~Forecasts~~ Forecast that reflects reasonable forecast accuracy standards. Scheduling Coordinators may develop and submit Demand Forecasts earlier than the timeline specified in Section 31.1.4.1 as appropriate to implement WECC-compliant weekend and holiday Demand Forecasts and scheduling practices. ~~the best judgment of the submitting Scheduling Coordinator to help avoid potential System Reliability concerns and to enable the ISO to administer a meaningful market for Energy and Ancillary Services. From time to time the ISO may publish information on the accuracy of Scheduling Coordinator Demand Forecasts.~~

~~**19.1.4.3 Incomplete or Unsuitable Demand Forecasts.**~~

~~If the Demand Forecasts supplied by a Scheduling Coordinator to the ISO are, in the ISO's opinion, incomplete or otherwise unsuitable for use, or a particular Demand Forecast has not been supplied by a Scheduling Coordinator to the ISO as required under this Section, the ISO will substitute the last valid Demand Forecast received from the Scheduling Coordinator in replacement for any incomplete, unsuitable or not supplied Demand Forecasts.~~

~~**19.1.5 Scheduling Coordinator Demand Forecast Format.** This template is used to post 52 Weeks Demand Forecast.~~

~~**19.1.5.1** Scheduling Coordinator's ID code.~~

~~**19.1.5.2** Forecast Weekly Maximum Generation capacity for each of the next 52 weeks.~~

~~**19.1.5.3** Forecast Weekly Maximum Demand for each of the next 52 weeks.~~

~~**19.2 UDC Responsibilities.**~~

~~**19.2.1 Data to be Submitted to the ISO by UDCs.**~~

~~At the time specified in Section 19.2.3, each UDC shall submit to the ISO its Weekly Peak Demand Forecasts by Congestion Zone reflecting the Weekly Peak Demand Forecast for Load expected to be served by facilities under the control of the UDC. All Weekly Peak Demand Forecasts submitted shall include Demand Forecasts for the following 52 weeks.~~

~~19.2.2 Format of Demand Forecasts.~~

~~Demand Forecasts must be submitted to the ISO electronically in the format set forth in Section 19.2.5.~~

~~19.2.3 Timing of Submission of Demand Forecasts.~~

~~The Demand Forecasts described in this Section shall be submitted by UDC to the ISO on a monthly basis by noon of the twelfth working day of the month.~~

~~19.2.4 Forecast Standards.~~

~~19.2.4.1 Avoiding Duplication.~~

~~Each UDC submitting Demand Forecasts to the ISO and its Scheduling Coordinator shall ensure, to the best of its ability, that any Demand Forecasts that it is submitting to the ISO and its Scheduling Coordinator are not duplicated in another Scheduling Coordinator's Demand Forecasts.~~

~~19.2.4.2 Required Performance.~~

~~Each UDC submitting its Demand Forecasts to the ISO and its Scheduling Coordinator shall take all necessary actions to provide Demand Forecasts that reflect the best judgment of the submitting UDC to help avoid potential System Reliability concerns and to enable the ISO to administer a meaningful market for Energy and Ancillary Services. The ISO may publish information on the accuracy of UDC Demand Forecasts from time to time.~~

~~19.2.5 UDC Demand Forecast Format.~~ ~~This template is for use by the Scheduling Coordinators to forecast their direct-access loads for each UDC. The forecast must be for seven (7) future days including the current Day-Ahead Market.~~

~~19.2.5.1 Scheduling Coordinator's ID code.~~

~~19.2.5.2 Trading Day of current Day-Ahead Market (month/day/year).~~

~~19.2.5.3 UDC's ID code.~~

~~19.2.5.4 Hourly Demand Forecast for the 168 hours beginning with the first hour of the current Day-Ahead Market.~~

19.2~~3~~ ISO Responsibilities.

19.2~~3~~.1 ISO Advisory Control Area Demand Forecasts.

The ISO will develop and publish on the ISO ~~W~~website and supply to the Scheduling Coordinators advisory ~~Control Area~~ Demand Forecasts comprised of Hourly Demand Forecasts for each Congestion Zone for each Settlement Period of the relevant Trading Day. The ISO will publish this information in accordance with the timing requirements set forth in this ISO Tariff.

~~**19.3.2 ISO Demand Forecasts.**~~

~~The ISO shall publish monthly on the ISO Website on the following two (2) Demand Forecasts for the next 52 weeks.~~

~~**19.3.2.1 Consolidated Scheduling Coordinator Forecast.** This forecast will be developed by adding together the Weekly Peak Demand Forecasts of the individual Scheduling Coordinators.~~

~~**19.3.2.2 Independent ISO Forecast.** This forecast will be developed by the ISO.~~

~~The ISO may, at its discretion, publish on the ISO Website additional Demand Forecasts for two or more years following the next year.~~

19.2.2~~3.3~~ ~~System Adequacy~~ISO Annual Reports of Demand and Resources.

On an annual basis in accordance with the requirements of the WECC, ~~T~~the ISO will publish on its website reports that provide estimates of resource availability, peak Demand levels, and reserve capacity during anticipated peak Demand conditions for the ISO Control Area for the summer and any other specified seasons. ~~the following reports comparing the projected aggregate Generation capacity to the peak forecast Demands, as calculated in accordance with this Section.~~

~~**19.3.3.1** **Annual Reports.** On an annual basis and within eight weeks after receiving the annual or updated long-range planned Outage schedules from all Participating Generators, the ISO shall publish on the ISO Website a report comparing the aggregated weekly peak Generation capacity to the weekly peak forecast Demand for the next 52 weeks;~~

~~**19.3.3.2** **Quarterly Reports.** On a quarterly basis, the ISO shall publish on the ISO Website a report comparing the aggregated weekly peak Generation capacity to the weekly peak forecast Demand for the next 3 months; and~~

~~**19.3.3.3** **Monthly Reports.** On a monthly basis, the ISO shall publish on the ISO Website a report comparing the aggregated weekly peak Generation capacity to the weekly peak forecast Demand for the next month.~~

~~**19.3.3.4** The ISO shall, on the basis of the information supplied by Participating Generators under Section 4.6.6.1 and other information available to the ISO, prepare and publish on WEnet forecast aggregate available Generation capacity and forecast Demand on an annual, quarterly and monthly basis. In publishing these forecasts, the ISO shall identify any expected Congestion conditions caused by planned Outages of Participating Generators.~~

* * *

20.2 **Confidential Information.**

The following information provided to the ISO by Scheduling Coordinators shall be treated by the ISO as confidential:

(a) individual bids for Supplemental Energy;

(b) individual Adjustment Bids for Congestion Management which are not designated by the Scheduling Coordinator as available;

(c) individual bids for Ancillary Services;

(d) transactions between Scheduling Coordinators;

(e) individual Generator Outage programs unless a Generator makes a change to its Generator Outage program which causes Congestion in the short term (i.e. one month or less), in which case, the ISO may publish the identity of that Generator.

(f) Demand Forecast and other hourly data provided by Scheduling Coordinators to the ISO pursuant to Sections 4.5.3.7 and 31.1.4.

The following information provided to the ISO by Scheduling Coordinators or Market Participants for purposes of the Interim Reliability Requirements Program shall be treated by the ISO as confidential:

(a) Annual and monthly Resource Adequacy Plans pursuant to Sections 40.2.1 and 40.2.2, respectively, and Supply Plans pursuant to Section 40.6; however, any Planning Reserve Margin information required by Section 40.4 and any Qualifying Capacity eligibility criteria information required by Section 40.5.1 contained in the Resource Adequacy Plans and/or Supply Plans shall not be treated as confidential.

(b) Demand Forecast and other hourly data provided pursuant to Section 40.3.

(c) Information on existing import contracts, and any trades or sales of allocated import capacity, provided pursuant to Section 40.5.2.2.

(d) Information reported by non-Participating Generators pursuant to Sections 40.6A.3 and 40.7.3.

(e) Information submitted through the dispute or discrepancy resolution process pursuant to Section 40.2.3.

* * *

30.4.1.2 Stage Two Validation.

During stage two validation, Schedules will be checked to determine whether each Scheduling Coordinator's aggregate Generation and external imports (adjusted for Transmission Losses) and Inter-Scheduling Coordinator Energy Trades (whether purchases or sales) equals the Scheduling Coordinator's aggregate Demand ~~Forecast~~, including external exports. The Scheduling Coordinator must take into account the applicable Generation Meter Multipliers (GMMs). The Scheduling Coordinator will be notified if the counterpart trade to any Inter-Scheduling Coordinator Ancillary Service Trade has not been submitted, or is infeasible (i.e., if both Scheduling Coordinators are selling or both are buying). Mismatches in Inter-Scheduling Coordinator Ancillary Service Trades shall be adjusted to be equal to the amount specified by the selling Scheduling Coordinator. A Scheduling Coordinator can also check whether its Schedules will pass the ISO's stage two validation by manually initiating validation of its Preferred Schedules or Revised Schedules, at any time prior to the deadline for submission of Preferred Schedules or Revised Schedules (as the case may be). It is the Scheduling Coordinator's responsibility to perform such checks, if desired. The Scheduling Coordinator will be notified immediately through WEnet of any validation errors. For each error detected, an error message will be generated by the ISO in the Scheduling Coordinator's notification screen which will specify the nature of the error. If the ISO detects a mismatch in Inter-Scheduling Coordinator Trades, the ISO will notify both Scheduling Coordinators of the mismatch in Energy quantity and/or location. The Scheduling Coordinator can then look at the notification messages to review the detailed list of errors, make changes, and resubmit the Schedule if it is still within the ISO's timing requirements. The Scheduling Coordinator is also notified of successful validation via WEnet.

* * *

31.1.4.1 Daily Information. By 10:00 a.m. on the day preceding the Trading Day, each Scheduling Coordinator shall provide to the ISO a Demand Forecast specified by UDC <u>or MSS</u> Service Area for which it will schedule deliveries for each of the Settlement Periods of the following Trading Day<u>; however, the requirements of this Section shall not apply to (a) the portion of a Scheduling Coordinator's Demand associated with Station Power and (b) the Scheduling</u>

Coordinator's Demand within a UDC or MSS Service Area if the Scheduling Coordinator's maximum Demand within that UDC or MSS Service Area during the preceding twelve (12) months was less than one (1) megawatt, provided that this exemption shall not apply to any Scheduling Coordinator that did not submit Schedules for any metered Demand within a UDC or MSS Service Area over the preceding twelve (12) month period. The ISO shall aggregate the Demand information by UDC or MSS Service Area and transmit the aggregate Demand information to each UDC or MSS serving such aggregate Demand. The first instance in each calendar month in which a Scheduling Coordinator fails to submit the information required pursuant to this Section shall not be deemed a violation of this Section.

* * *

Balanced Schedule

A Schedule shall be deemed balanced when Generation, adjusted for Transmission Losses equals~~forecast~~ Demand with respect to all entities for which a Scheduling Coordinator schedules.

Exempt Scheduling Deviation

The difference between a Day-Ahead Schedule submitted by any Scheduling Coordinator, pursuant to Section 4.5.4.2.1.1, and its Demand Forecast, pursuant to Section 31.1.4.1, within any UDC or MSS Service Area that does not exceed the lesser of (a) three (3) MW or (b) five percent (5%) of that Scheduling Coordinator's Demand Forecast for the relevant UDC or MSS Service Area.

Minor Scheduling Deviation

The difference between a Day-Ahead Schedule submitted by any Scheduling Coordinator, pursuant to Section 4.5.4.2.1.1, and its Demand Forecast, pursuant to Section 31.1.4.1, within any UDC or MSS Service Area that is (a) greater than the lesser of (i) three (3) MW or (ii) five percent (5%) of that Scheduling Coordinator's Demand Forecast for the relevant UDC or MSS Service Area as set forth in Section 4.5.4.2.1.2, but (b) less than the greater of (i) twenty-five (25) MW or (ii) two percent (2%) of that Scheduling Coordinator's Demand Forecast for the relevant UDC or MSS Service Area.

ATTACHMENT C

California ISO
Your Link to Power

California Independent
System Operator Corporation

Memorandum

To: ISO Board of Governors

From: Eric Hildebrandt, Manager Market Analysis & Mitigation

Keith Casey, Director Market Monitoring

Date: January 18, 2007

Re: Decision Regarding Refinements to Load Scheduling Requirements

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This memorandum requires Board action.

EXECUTIVE SUMMARY

In October 2005, the CAISO filed Tariff Amendment 72, which required Scheduling Coordinators (SCs) to submit day-ahead schedules equal to at least 95% of their forecast demand for each hour of the next day. The 95% day-ahead scheduling requirement was designed to enhance reliability and reduce the need for the CAISO to take actions to protect against under-scheduling, such as requiring additional capacity to be on-line through Must-Offer Waiver denials. In its filing on Amendment 72, the CAISO committed to examining the impact of these scheduling requirements after implementation of Amendment 72 and making further modifications if appropriate.

During 2006, overall compliance with the 95% scheduling requirement improved dramatically and has been extremely high since spring 2006, particularly during peak hours. However, numerous SCs have expressed concerns about the impacts and difficulty of compliance with the 95% scheduling requirement, particularly during off-peak and weekend hours. In addition, Grid Operations staff has indicated that it is important to retain the 95% scheduling requirement during peak hours for reliability reasons, but have expressed concern that during some off-peak hours the 95% scheduling requirement may exacerbate operational problems due to over-scheduling and over-generation. In response to these concerns, the CAISO initiated a stakeholder process to identify and consider potential refinements to Amendment 72.[1]

Based on input from Grid Operations staff and this stakeholder process, management is recommending several key modifications to Amendment 72 scheduling requirements, which include:

- Reducing the minimum scheduling requirement during off-peak hours to 75% of each SC's load forecast.
- Establishing specific exemptions for small or infrequent scheduling deviations below the 95% on-peak/75% off-peak requirement for all SCs.

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[1] Discussions of Amendment 72 compliance and concerns with Amendment 72 was provided in DMM's October 10, 2006 and December 6, 2006 Market Monitoring Report memos to the CAISO Board (http://www.caiso.com/188d/188d792d5a4a10.pdf and http://www.caiso.com/188d/188d792d5a4a10.pdf). A more detailed analysis was provided in a December 11, 2006 DMM whitepaper on *Potential Modifications to Amendment 72 Day Ahead Scheduling Requirements* (http://www.caiso.com/18c9/18c9b9aa27f70.pdf).

BACKGROUND

The modifications being proposed are designed to address a number of concerns with scheduling requirements established under Amendment 72 that have been identified by stakeholders, CAISO staff, and FERC Office of Enforcement (OE) staff.

- Numerous participants have indicated that the bulk of bilateral market supply is only available in standard multi-hour blocks (e.g., 16 peak hours or 8 off-peak hours), so that complying with the 95% scheduling requirement often requires SCs to over-procure energy and then over-schedule significant amounts of load particularly during off-peak hours.

- The over-scheduling of load in the off-peak hours due to block-hour purchases to comply with the 95% scheduling requirement may create additional costs to participants in cases when the price of procuring this energy in the bilateral market exceeds the real-time energy price received by the SC for over-scheduled load (which is settled as positive uninstructed energy). Some participants have indicated that limiting the 95% scheduling requirement only to peak hours may greatly reduce this problem.

- CAISO Grid Operations staff has expressed concern that any over-scheduling during these off-peak hours due to Amendment 72 may negatively affect system reliability by exacerbating over-generation conditions. This impact was particularly evident this spring, when over-scheduling that was attributed to the Amendment 72 requirements – combined with other sources of unscheduled energy and uninstructed generation – created significant over-generation during many hours. However, Grid Operations has also indicated that it is important to retain the 95% scheduling requirement during peak hours for reliability reasons.

- Numerous participants have expressed concern that, under current CAISO Tariff provisions, even infrequent and minor violations of the 95% scheduling requirement may be inadvertent and have no impact on reliability, but are nonetheless subject to investigation and potential sanction by FERC.

To address these concerns, the CAISO has conducted a stakeholder process and developed a series of modifications to scheduling requirements established under Amendment 72. In developing these recommendations, the CAISO has sought to balance a variety of considerations, including:

- The potential reliability and operational impacts of changes to the day-ahead scheduling requirements based on input from CAISO Grid Operations staff.

- Input from different stakeholder groups on the difficulty and costs to participants of complying with day-ahead scheduling requirements during different time periods and conditions.

- A desire to balance the potential additional difficulty of compliance for relatively small Load Serving Entities (LSEs) with the principle that all participants should be subject to the same rules and requirements. For example, SCs serving relatively small amounts of load may find it difficult or more costly to procure the small "odd lots" of energy in bilateral markets that may be necessary to "shape" their hourly supply schedules to meet 95% of forecasted load each hour. However, if scheduling requirements are less stringent for smaller LSEs, it may be argued that this allows smaller LSE's to "lean" on the CAISO's real-time energy market and causes larger LSEs to bear a greater share of the cost associated with enhancing system reliability through greater day-ahead scheduling.

- The feasibility and complexity of the administration and enforcement of scheduling requirements by the CAISO and FERC OE staff. For example, since assessing hourly scheduling requirements of each SC within each UDC area is highly data-intensive and involves an extremely large volume of scheduling "events," automated mechanisms and highly objective criteria are needed in order for the evaluation of compliance to be feasible.

PROPOSED MODIFICATIONS

Based on the various considerations described above – combined with input received from Grid Operations staff and a stakeholder process – management recommends the following modifications to Amendment 72 scheduling requirements:

1. Reduce the minimum scheduling requirement during off-peak hours to 75% of each SC's load forecast.

This modification addresses concerns that application of the 95% scheduling requirement during off-peak hours may – under some load and system conditions – provide little reliability or operational benefits, and may actually exacerbate problems associated with over-scheduling and over-generation.

The specific scheduling requirement proposed for off-peak hours (75%) is designed to provide sufficient protection against excessive under-scheduling during off-peak hours, while still allowing SCs to meet this scheduling requirement through standard 8-hour blocks of off-peak energy without over-scheduling of load or relying on any load-shaping resources or hourly bilateral purchases. Analysis of actual CAISO load data used to develop the 75% level for off-peak hours is presented in an addendum to DMM's whitepaper developed for the stakeholder process.[2]

This specific option was developed during the stakeholder process as an alternative to several other options that were examined for providing some protection against excessive under-scheduling during off-peak hours and days, by allowing the CAISO flexibility to require a minimum level of scheduling during off-peak hours in response to projected system conditions. However, most participants and Grid Operations staff preferred a constant 75% off-peak scheduling requirement to these other options due to the potential operational uncertainty and added complexity of other options considered.

Due to concerns by Grid Operations staff that a 75% scheduling requirement may provide insufficient protection against excessive under-scheduling on Sundays during peak day time hours, the 95% peak requirement would apply to hours 7 through 22 all days of the week (including holidays), rather than only during the standard WECC definition of peak hours (Monday through Saturday, HE 7-22, excluding holidays).

2. Establish a threshold for de minimis deviations below 95% on-peak/75% off-peak scheduling requirement applicable to all hours.

This modification is designed to address concerns that, under current CAISO Tariff provisions, *de minimis* deviations below the 95% scheduling requirement may be inadvertent and have no impact on reliability, but may nonetheless be subject to potential investigation and sanction by FERC.

The proposed threshold for *de minimis* deviations is the minimum of (a) 3 MWh or (b) 5% of the SC's Load Forecast. All deviations below the 95% on-peak/75% off-peak scheduling requirement that are less than this *de minimis* deviation level are considered compliant with the hourly scheduling requirement. Analysis by DMM based on the historical peak load of

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[2] *Addendum: Potential Modifications to Amendment 72 Day Ahead Scheduling Requirements*, prepared by the Department of Market Monitoring, December 11, 2006, pp.3-4. *(http://www.caiso.com/18d4/18d489af50e80.pdf).*

each SC in each UDC area indicates that, at an aggregate level, this threshold equates to an effective scheduling requirement of about 94.7% of the aggregate load forecast by SCs.[3]

The specific formula proposed reflects a desire to balance the potential additional difficulty of compliance for relatively small LSEs with the principal that all participants should be subject to the same rules and requirements. Table 1, provided as Attachment A, provides an illustrative calculation of this threshold for various levels of forecasted load (see Columns A-F). As shown in Table 1, for an SC with a load forecast up to 60 MWh within any UDC area, the deviation threshold equals 5% of the SC's load forecast, so that the effective scheduling requirement is 90% (that is, 95% - 5% allowance = 90%). For an SC with a load forecast greater than 60 MWh within any UDC area, that allowance equals 3 MWh, so that the effective scheduling requirement begins to exceed 94% as load forecast increases to 300 MWh.

The specific concept of exemption for *de minimis* deviation applicable to all hours was suggested by stakeholders. While numerous stakeholders – particularly small LSEs – advocated larger deviation allowances (5 to 25 MWh), a smaller threshold is being proposed for several reasons:

- First, since this exemption would be applicable during all hours for all SCs and would be applied to the quantity of load served by each SC within each separate UDC area, a larger threshold could have significant cumulative effects on overall scheduling.
- Second, the CAISO is concerned that a higher threshold level could create an incentive for LSEs to circumvent the intent of this threshold by creating multiple SC identification codes and dividing up their load under different SC identification codes.[4]
- Finally, higher thresholds would represent a very large percentage (or all) of load served by smaller LSEs within each UDC area, which would be inconsistent with the principal that all participants should generally be subject to the same rules and requirements.

3. ***Provide each SC with an allowance for up to six (6) other minor deviations below 95% scheduling requirement per calendar month.***

This modification is designed to address deviations which are larger than the *de minimis* threshold described above, but are relatively infrequent and are unlikely to affect reliability if occurring infrequently (and not simultaneously by all SCs in all UDC areas). The proposed threshold for *minor* deviations is the <u>maximum</u> of (a) 25 MWh or (b) 2% of the SC's load forecast. Within each month, each SC's first six deviations below the scheduling requirement that are <u>less than</u> this *minor* deviation level are considered compliant with the hourly scheduling requirement. Specifically, each SC will be allowed a total of six one-hour instances each calendar month in which its schedule drops below the applicable scheduling requirement – 75% of forecast load during the off-peak, 95% during the peak.

Again, the specific formula proposed for minor deviations reflects a desire to balance the potential additional difficulty of compliance for relatively small LSEs with the principle that all participants should be subject to the same rules and requirements. Table 1, provided as Attachment A, shows a sample calculation of this threshold for various levels of load (see Columns G-J). As shown in Table 1, the threshold for minor deviations equals 25 MWh for all SCs with load forecast

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[3] In other words, if all SCs scheduled below 95% of their forecast but at the applicable threshold for *de minimis* deviations, total day-ahead scheduling by all SCs would equal 94.7% of the aggregated forecast of all SCs.

[4] Currently, the CAISO allows SCs to request multiple SC identification codes for scheduling different loads and resources in order to facilitate accounting or other business purposes of the SC.

up to 1,250 MWh within any UDC area. All SCs except the state's three major Investor Owned Utilities (IOUs) fall in this category. For these three largest LSEs, the threshold for minor deviations equals 2% of forecasted load.

Due to concern about the potential cumulative impact of deviations of this magnitude, this exemption applies to only the first six hourly deviations within each calendar month for each SC within each UDC area. Thus, the exemption is designed to cover infrequent deviations that may occur due to exceptional circumstances, rather than lowering the target that SCs strive to meet during peak periods. It should also be noted that FERC retains discretion with respect to enforcement activities relating to any deviations not covered by this exemption, and may consider any mitigating circumstances that lead to such deviations.

4. Establish an exemption from the current $500 penalty for failure to submit load forecast data for the first violation by each SC during each calendar month.

This modification is designed to address concerns that under current CAISO Tariff provisions, infrequent violations of load forecasting requirements may be inadvertent, but are nonetheless subject to a $500 penalty by the CAISO. While compliance with the load forecast submission requirements has improved dramatically and virtually no violations have occurred since October 2006, periodic violations may continue to occur. As discussed in DMM's October 10, 2006 *Market Monitoring Report*, DMM does not have the discretion under the CAISO Tariff to waive or reduce penalties for identified violations subject to this $500 penalty. Rather, DMM may only submit a filing at FERC recommending that the Commission waive or reduce a penalty based on mitigating circumstances. With this proposed modification, however, an exemption from the $500 penalty would be provided to each SC in each calendar month for the first violation of load forecast submission requirement.

5. Clarify that scheduling requirement applies to Revised Preferred Schedule submitted by SC (by 12:00 pm)

This revision would modify Tariff Section 2.2.7.2.1.1 to clarify that the 95% on-peak/75% off-peak scheduling requirement applies only to "Revised Preferred Schedules" (submitted by 12:00 pm), as defined in Tariff Section 30.3.4. The CAISO's initial Amendment 72 filing included Tariff language requiring that each SC "shall submit to the CAISO" day-ahead schedules that equal at least 95% of the SC's forecasted demand for each hour (2.2.7.2.1.1). In practice, under the CAISO Tariff, SCs may first submit Initial Preferred Schedules by 10:00 am (30.3.1) , and may submit Revised Preferred Schedules by 12:00 pm (30.3.4). Thus, some ambiguity may exist as to whether Amendment 72 scheduling requirements apply to Initial or Revised Preferred Schedules (or both). However, DMM has determined that the CAISO's Scheduling Infrastructure (SI) does not currently retain the data necessary to assess compliance with any scheduling requirement applicable to Initial Preferred Schedules (submitted by 10:00 am).[5] Virtually all participants appear to support this modification.

6. Specify that SCs serving less than 1 MWh within a UDC area exempted from 95% scheduling requirement.

The CAISO's MRTU Tariff provisions defining "Load Serving Entity" for purposes of administering Resource Adequacy (RA) provisions include an exemption for LSEs serving *de minimis* load, defined as load with actual metered peak demand during the preceding twelve months of less than 1 MWh. For the sake of consistency with this provision, this modification would specify that LSEs whose peak metered demand during the preceding twelve months was less than 1 MWh would be exempt from the 95% on-peak/75% off-peak scheduling requirements. Based on DMM's analysis of LSEs' peak

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[5] Specifically, if an SC submits adjustment bids following the Day Ahead Market's first congestion run, and their Initial Preferred Schedule is altered accordingly, then this "Revised Preferred" Schedule overwrites the Initial Preferred Schedule. If no adjustments are made to the Initial Preferred Schedule in response to the congestion management run, then the Initial Preferred Schedule is retained.

metered demand during 2006, this exemption would apply to only three cases, representing a total combined peak demand of less than 1 MWh.

While some LSEs have argued that exemptions from day-ahead scheduling requirements should be provided for LSEs with load levels higher than 1 MWh, the CAISO believes that attempting to establish and administer such an exemption may create significant additional complexity. Additionally, DMM's analysis of all peak loads over the past year shows that there is a notable break in the frequency of peak loads less than 1 MWh and those greater than 3 MWh. Thus, 1 MWh represents a natural break point. There is not such a natural break at higher MWh peak loads. Finally, it is worth again noting that there is the potential to circumvent the scheduling requirement by dividing up load amongst multiple SC identification codes, and that the higher the *de minimis* exemption, the greater the incentive for such behavior.

7. Eliminate Unused Tariff Forecast Submittal Requirements

Section 19 of the CAISO Tariff includes a variety of longer term forecast submission requirements that appear to have existed in the CAISO Tariff since its inception, but do not appear to have been implemented or utilized by the CAISO. In order to reduce uncertainty concerning participants' obligations to meet these other requirements, these other load forecast requirements will be eliminated.

IMPLEMENTATION ISSUES

The potential revisions to Amendment 72 noted above could be implemented without any modification to the CAISO's operational or market software systems, and would only require minimal adjustments to data analysis programs used by DMM to calculate and report potential non-compliance with day-ahead scheduling requirements on an *ex-post* basis.

Numerous stakeholder comments concern various requested changes to the CAISO's System Infrastructure (SI) interface to facilitate entering and verifying forecast data. DMM communicates these comments and requests to appropriate other departments within the CAISO, but notes that any changes to the SI system are difficult due to MRTU implementation efforts. Specific steps that have been taken to address potential forecast data entry problems include the following:

- The CAISO has worked closely with participants to explain the template used to enter and submit forecasts to the CAISO SI system, and proactively educate participants on potential problems or mistakes they may make.

- Although the SI system does not allow SCs to retrieve and view forecast data at any time after it is submitted, the CAISO has developed an automated routine that emails each SC a "snapshot" of forecast data they have entered into the SI system as of 9:00 am each day – one hour prior to the 10:00 am deadline for submission of final day-ahead forecasts.

- Reports showing any deviations below the 95% scheduling requirement based on scheduling and forecast data in the SI system are made available to SCs for review on a weekly basis. SCs may contact the CAISO with any questions or to resolve any discrepancies. Several days after these reports are made available to SCs for review, reports are forwarded to FERC.

- On a weekly basis, SCs also submit a weekly summary report of hourly forecasts and schedules based on each SCs own records, along with any notes or explanations the SC may provide. These reports are provided to FERC along with the reports developed by the CAISO based on scheduling and forecast data in the SI system.

- DMM works with FERC Office of Enforcement staff in an effort to ensure that prior to undertaking any enforcement action, FERC works with the CAISO and SCs to resolve any specific data discrepancies that FERC may observe.

In sum, DMM believes that the current data systems, compliance tracking and reporting processes provide a reasonable and sufficient mechanism for compliance with Amendment 72 requirements.

Finally, it should be noted that the modifications described in this memo would only apply to day-ahead scheduling requirements in effect until implementation of MRTU. Pursuant to FERC's September 21, 2006 Order on MRTU, a separate stakeholder process is being conducted later in 2007 to address potential provisions to address under-scheduling under MRTU prior to successful implementation of convergence bidding.[6]

STAKEHOLDER PROCESS AND FEEDBACK

The process for developing any changes to Amendment 72 was conducted on a relatively accelerated timeframe, so that any changes may be effective prior to the spring months when problems related to over-generation tend to be highest. However, the process included development and distribution of a comprehensive whitepaper and addendum on potential revisions to Amendment 72, two rounds of written stakeholder comments, and a two-hour conference call with stakeholders to discuss the straw proposal and stakeholder comments.

Many of the key issues raised by participants have been briefly mentioned and addressed in the preceding sections of this memorandum. A detailed listing of stakeholder comments and the CAISO's response to these comments is provided as Attachment B. As noted in Attachment B and throughout this stakeholder process, the range of potential modifications proposed, considered and ultimately adopted by the CAISO was limited to modifications that would not compromise the fundamental reliability goals of the 95% scheduling requirement based on assessment from Grid Operations staff.

CONCLUSION

CAISO Management requests authority to file necessary tariff language to implement the modifications described in this memorandum.

MOVED,

That the CAISO Board of Governors authorize CAISO Management to file a Tariff Amendment at FERC to modify Day Ahead Market scheduling and forecast submission requirements as described in this memorandum.

[6] The CAISO's filing on Amendment 72 indicated that the day-ahead scheduling requirement was viewed as a "stop gap" measure that the CAISO expects would be unnecessary and not be extended under MRTU once the Integrated Forward Market (IFM) and Residual Unit Commitment (RUC) processes were in place. However, FERC's September 21 Order on MRTU indicated that the FERC is concerned about the potential for day-ahead under-scheduling by LSEs in the absence of convergence bidding and/or any explicit day-ahead scheduling requirement. Consequently, the Order directs the CAISO to develop and file interim measures, no later than 180 days prior to the effective date of MRTU Release 1, to address the potential economic incentive for LSEs to under-schedule in the Day Ahead Market until the successful implementation of convergence bidding has been achieved. (September 21 Order at 452, p.132).

Attachment A

Table 1. Illustrative Example of Deviation Allowances and Net Scheduling Requirements by Load Forecast Level (Peak Hours 7-22)

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)
Load Forecast (MW)	95% Requirement (MW)	De Minimis Deviation Threshold (All-Hours)		Net Scheduling Requirement		Minor Deviation Threshold		Net Schedule Threshold for Minor Deviation	
		MW	%	MW	%	MW	%	MW	%
3	2.9	0.2	5.0%	2.70	90.0%	25	100%	0	0%
10	9.5	0.5	5.0%	9	90.0%	25	100%	0	0%
20	19	1.0	5.0%	18	90.0%	25	100%	0	0%
30	29	1.5	5.0%	27	90.0%	25	83%	4	12%
40	38	2.0	5.0%	36	90.0%	25	63%	13	33%
50	48	2.5	5.0%	45	90.0%	25	50%	23	45%
60	57	3.0	5.0%	54	90.0%	25	42%	32	53%
70	67	3.0	4.3%	64	90.7%	25	36%	42	59%
80	76	3.0	3.8%	73	91.3%	25	31%	51	64%
90	86	3.0	3.3%	83	91.7%	25	28%	61	67%
100	95	3.0	3.0%	92	92.0%	25	25%	70	70%
200	190	3.0	1.5%	187	93.5%	25	13%	165	83%
300	285	3.0	1.0%	282	94.0%	25	8%	260	87%
400	380	3.0	0.8%	377	94.3%	25	6%	355	89%
500	475	3.0	0.6%	472	94.4%	25	5%	450	90%
600	570	3.0	0.5%	567	94.5%	25	4%	545	91%
700	665	3.0	0.4%	662	94.6%	25	4%	640	91%
800	760	3.0	0.4%	757	94.6%	25	3%	735	92%
900	855	3.0	0.3%	852	94.7%	25	3%	830	92%
1,000	950	3.0	0.3%	947	94.7%	25	3%	925	93%
5,000	4,750	3.0	0.1%	4,747	94.9%	100	2%	4,650	93%
10,000	9,500	3.0	0.0%	9,497	95.0%	200	2%	9,300	93%
15,000	14,250	3.0	0.0%	14,247	95.0%	300	2%	13,950	93%
20,000	19,000	3.0	0.0%	18,997	95.0%	400	2%	18,600	93%
25,000	23,750	3.0	0.0%	23,747	95.0%	500	2%	23,250	93%

Description of Column Data and Formulas

A) Day Ahead Load Forecast of SC for UDC Area

B) 95% Day Ahead Scheduling Requirement (A × .95).

C) *De Minimis* Deviation Threshold in MW (Minimum of: 3 MW or (A × .05)). *This represents the de minimis level by which the SCs Day Ahead schedule may fall below the 95% requirement any hour without being deemed non-compliant.*

D) *De Minimis* Deviation Threshold as % of Forecast (C ÷ A).

E) Net Scheduling Requirement in MW (B – C). *If the SC's Day Ahead schedule in MW is equal to or greater than this value, the SC is in compliance with the 95% scheduling requirement.*

F) Net Scheduling Requirement as % of Forecast (E ÷ A). *If the SC's Day Ahead schedule as a percent of forecast is equal to or greater than this value, the SC is in compliance with the 95% scheduling requirement.*

G) Minor Deviation Threshold in MW (Maximum of: 25 MW or (A × .02)). *This represents the maximum level by which the SC's Day Ahead schedule may fall below the 95% requirement and still be deemed a minor deviation. The first six minor deviations by each SC within each UDC area during peak hours each calendar month are not deemed non-compliant.*

H) Minor Deviation Threshold as % of Forecast (G ÷ A). *This represents the maximum level (as a percent of the SC's forecast) by which the SC's Day Ahead schedule may fall below the 95% requirement and still be deemed a minor deviation. The first six minor deviations by each SC within each UDC area during peak hours each calendar month are not deemed non-compliant.*

I) Net Schedule Threshold for Minor Deviation in MW (B- G). *If the SC's Day Ahead schedule is lower than the Net Scheduling Requirement in Column E, but not lower than the Net Schedule Threshold for Minor Deviations in this Column (I), the schedule is deemed a minor deviation. The first six minor deviations by each SC within each UDC area during peak hours each calendar month are not deemed non-compliant.*

J) Net Schedule Threshold for Minor Deviation as % of Forecast (I ÷ A). *This represents the minimum level (as a percent of the SC's forecast) that the SC may schedule while still being deemed a minor deviation. The first six minor deviations by each SC within each UDC area during peak hours each calendar month are not deemed non-compliant.*

Attachment B
Stakeholder Process

Stakeholder Process to Date

Activity	Date	Number of Stakeholder Representatives
First white paper posted	December 11, 2006	N/A
Written comments due	December 18, 2006	15 received
Conference call	December 20, 2006	45 by conference call
Addendum to the White Paper posted	December 22, 2006	N/A
Written comments due	January 5, 2007	12 received
Memo from ISO Staff to Board of Governors	January 24-25, 2007	N/A

Stakeholder Process Going Forward

Activity	Date
Distribute draft tariff language	
Written comments due	
File ISO tariff amendment	

Entities that Participated in Stakeholder Conference Call

NAME	COMPANY
1. COOPER, BRAD - HOST	CALIFORNIA ISO
2. BOWEN, GRAHAM	CITY OF ANAHEIM
3. CASEY, KEITH	CALIFORNIA ISO
4. CHEN, BILL	CONSTELLATION
5. CLEATH, LARS	STRATEGIC ENERGY
6. COLETTI, JULIE	STRATEGIC ENERGY
7. COMNES, ALAN	NRG
8. CONSTANTINE, MICHAEL	CONSTELLATION
9. COOK, GREGG	CALIFORNIA ISO
10. CORR, THOMAS	SEMPRA
11. DECOTEAU, LISA	CONSTELLATION
12. DIETZ, DEBBIE	WESTERN AREA POWER
13. DORMAN, ELIZABETH	CPUC
14. EVANS, MIKE	CORAL POWER
15. GENSLER, KATHERINE	FERC
16. GODDARD, BILL	SEMPRA ENERGY SOLUTIONS
17. JYLKKA, CHRIS	EDISON MISSION
18. KAPLAN, KATIE	I E S
19. LAM, JEFF	POWEREX
20. LITTLE, ERIC	SOUTHERN CA EDISON
21. LLOYD, DEBRA	CITY OF PALO ALTO
22. LYNCH, MARY	CONSTELLATIONS ENERGY COMMODITIES GROUP
23. MARA, SUE	RTO ADVISORS
24. MARTIN, JULIE	B P ENERGY
25. MARTINEZ, JESUS	CITY OF RIVERSIDE
26. MCINTOSH, JIM	CALIFORNIA ISO
27. MCNAUL, MARGARET	THE SIX CITIES
28. MORRISON, ANDREA	STRATEGIC ENERGY
29. NELSON, TIFF	SAN DIEGO GAS & ELECTRIC
30. PAK, ALVIN	SEMPRA ENERGY
31. SANDERS, WILLIE	CITY OF PASADENA
32. SANDOVAL, EFRAIN	CITY OF VERNON

33. SCHNEIDER, SUSAN	PHOENIX CONSULTING
34. SHEA, KAREN	P U C
35. SHERIF, LINDA	CALPINE
36. SOLBERG, GLENN	CALIFORNIA DEPARTMENT OF WATER RESOURCES
37. STEPHENS, SUSAN	CITY OF ANAHEIM
38. THAI, ALBERTINA	PACIFIC GAS & ELECTRIC
39. THEAKER, BRIAN	WILLIAMS POWER COMPANY
40. ULMER, ANDREW	CA DEPT WATER RESOURCE
41. VUONG, TIM	CITY OF AZUSA
42. WEINSTEIN, ANDREW	STRATEGIC ENERGY
43. WHITHEAD, JEFF	CUSTOMIZE ENERGY
44. WILLIAMS, STEVE	SDG&E
45. WRIGHT, KATHLEEN	CDWR
46. ZORC, EILEEN	CITY OF VERNON

Issues Addressed to Develop Final Proposal Sent to Board

Stakeholder Comments on December 11, 2006 White Paper
(Discussed on December 20, 2006 Stakeholder Conference Call; Comments due on December 18, 2006)
(Documents available at: http://www.caiso.com/18c9/18c9b8e3224d0.html)

Stakeholder	Comment	ISO Response
City of Anaheim	1. States that SCs would require advance notice if the off-peak exemption is to be suspended for a Sunday or Holiday	Given concern from numerous stakeholders and Grid Operations staff, this option was not adopted.
	2. Recommends 16 exemptions per calendar month to coincide with a standard on-peak block (as opposed to 6 exemptions)	Noted.
	3. Strongly disagrees that the day-ahead scheduling requirement should apply to Revised Preferred schedules. Feels initial Preferred would be more appropriate	Basing compliance on Initial Preferred Schedules would provide an opportunity for SCs to circumvent the requirement by submitting initial schedules equal to 95% of forecasted load, and then revising those schedules downward after the first congestion management run. Additionally, the SI system does not retain the Initial Preferred Schedule if Revised Schedules are submitted
	4. Supports the exclusion of *de minimis* loads	Incorporated in Management recommendation.
	5. Supports the exclusion of penalties for one forecast non-submittal each calendar month	Incorporated in Management recommendation.
	6. Supports the second option of modification to the template for the weekly reports	Will be incorporated in modified template and instructions.
	7. Supports clarification of Tariff forecast submittal requirements	Incorporated in Management recommendation.
	8. Recommends modification to SI to allow DA forecast to be viewed and verified	Suggestions forwarded to CAISO IS staff. However, DMM feels existing SI template, 9 am email verification of load forecast, and opportunity to respond to all potential violations due to load forecast problems provides a sufficient and reasonable mechanism for compliance.

Stakeholder	Comment	ISO Response
	9. States that metered LSEs should not be required to submit data on metered or scheduled load	In many cases, data required in weekly reports have provided a valuable means for SCs and the CAISO to identify and reconcile data or scheduling problems in a timely and efficient manner. Thus, DMM believes the rationale for load schedule and estimated metered data submission requirements approved by FERC provided in initial Amendment 72 proceedings are still valid.
	10. Recommends modification to SI to eliminate need to sometimes re-submit forecasts submitted more than one day in advance due to the 7-day timeframe of SI template (e.g. if a forecast for Monday is submitted on Friday, and the SC submits a forecast for Sunday on Saturday, the forecast for Monday would need to be re-submitted along with the Sunday forecast).	Suggestions forwarded to CAISO IS staff. However, DMM feels existing SI template provides a sufficient and reasonable mechanism for compliance.
	11. States that violations in the instance of a forced outage after 7 AM on the NERC pre-scheduling day should be excluded	Such circumstances represent potentially mitigating circumstances that only FERC has authority to consider. Any mitigating circumstances are appropriately noted in the weekly report's "Notes" field, which is included with the information routinely provided to FERC along with forecast and scheduling data from the SI system.
California Department of Water Resources	1. Supports changing the requirement to on-peak only	Management recommendation reduces off-peak requirement to 75%.
	2. Does not Support limited thresholds for exempting non-compliance due to added complexity	DMM believes that proposed exemptions represent a minor additional complexity that is borne by the CAISO, rather than SCs. Since exemptions are designed to excuse relatively small, infrequent and inadvertent deviations, SCs should continue to schedule based on the 95%/75% requirements, rather than seeking to only schedule to lowest thresholds allowed by exemptions.
	3. Supports clarifying that the scheduling requirement applies to Revised Preferred DA Schedules	Incorporated in Management recommendation.
	4. Supports exemption of *de minimis* load, and supports exemption of SCs serving load that is "known and controllable" and "are able to balance generation and load and do not rely on the CAISO to procure additional supply."	Criteria for exempting SCs are not objectively verifiable enough *ex ante* to easily administer. Also, SCs that are "are able to balance generation and load and do not rely on the CAISO to procure additional supply" should not have any problem complying with the 95%/75% scheduling requirement. Finally, CAISO staff believes that submitting a forecast and schedule for load that "known and controllable" should represent a minimal administrative burden since this load is "known and controllable".

Stakeholder	Comment	ISO Response
	5. Supports the exclusion of penalties for one forecast non-submittal each calendar month, and states that application of any sanctions should be suspended until SI is revised to allow verification of data	Suggestions forwarded to CAISO IS staff. However, DMM feels existing SI template, 9 am email verification of load forecast, and opportunity to respond to all potential violations due to load forecast problems provides a sufficient and reasonable mechanism for compliance.
	6. Supports clarification of weekend scheduling issues	Will be incorporated in modified template and instructions.
	7. Supports clarification of Tariff forecast submittal requirements	Will be incorporated in modified template and instructions.
Southern California Edison	1. Strongly supports changing the scheduling requirement to cover only on-peak hours, but does not support the option to apply a scheduling requirement to Sunday dependant on the declaration of an RMO	Partially incorporated in Management recommendation, which reduces requirement during off-peak hours to 75% rather than eliminating requirement. The option to apply a scheduling requirement to Sunday dependant on the declaration of an RMO was not adopted, due to concern from Grid Operations and many SCs about the potential implementation problems and uncertainty this could create. However, in response to Grid Operations concerns about potential under scheduling problems on Sundays, Management recommendation maintains 95% scheduling requirement during Sunday peak hours 7-22.
	2. Supports 93% threshold, would prefer 30-day rolling period	Staff explained, to the SC's apparent satisfaction, that a rolling 30-day period was significantly more administratively burdensome and problematic for both CAISO and participants.
	3. Supports clarification that scheduling requirement applies to Revised Preferred Schedule	Incorporated in Management recommendation.
	4. Does not object to exemption of *de minimis* load	Incorporated in Management recommendation.
	5. Supports the exclusion of penalties for one forecast non-submittal each calendar month, would prefer 30-day rolling period	Staff explained, to the SC's satisfaction, that a rolling 30-day period was administratively burdensome
	6. Supports the second option to modify the template for weekly data submittals	Will be incorporated in modified template and instructions.
	7. Supports clarification of Tariff language	Incorporated in Management recommendation.
Arizona Public Services	1. Suggests a 3 MWh tolerance band	Suggestion partially incorporated in Management recommendation.
	2. Suggests changes to the SI template through which forecasts are submitted	Suggestions forwarded to CAISO IS staff. However, DMM feels existing SI template, 9 am email verification of load forecast, and opportunity to respond to all potential violations due to load forecast problems provides a sufficient and reasonable mechanism for compliance.

Stakeholder	Comment	ISO Response
Williams Power Company	1. Does not oppose scheduling requirement for on-peak hours only. Agrees that advance notice is required if the off-peak exemption is suspended	Partially incorporated in Management recommendation, which reduces off-peak requirement to 75% rather than eliminating requirement, and does not allow CAISO to modify 95%/75% requirements in response to system conditions.
	2. Does not support altering the 95% scheduling requirement	Incorporated in Management recommendation.
	3. Supports the clarification that the scheduling requirement applies to Revised Preferred Schedules. Requests explanation of potential market abuse this could enable.	Incorporated in Management recommendation. Staff clarified that use of the Revised Preferred Schedules leaves the least opportunities for circumvention of scheduling requirement.
	4. Supports the exclusion of *de minimis* load from scheduling requirements	Incorporated in Management recommendation.
	5. Does not support the exclusion of penalties for one forecast non-submittal per calendar month	Noted, but not incorporated in Management recommendation.
	6. Does not oppose clarification of weekend scheduling issues, supports second option	Will be incorporated in modified template and instructions.
Calpine	1. Recommends that the CAISO exempt on-site and/or over-the-fence metered load from the scheduling requirement regardless of metering arrangements.	Exemptions for specific types of LSEs, other than those serving a *de minimis* load, are outside the scope of this effort
Constellation	1. Suggests applying an 80-85% scheduling requirement only to super-peak hours	Grid Operations staff has expressed the need for maintaining a 95% scheduling requirement for all on-peak hours (HE 7 through HE 22)
	2. Suggests changing the requirement to schedule the greater of 95% of forecast or within 25 MWh	This suggestion was included in the Addendum to the Straw Proposal. Management recommendation includes a smaller deviation allowance (up to 3 MWh) for all hours, and an allowance for deviations of 25 MWh or more for up to 6 hours per month. However, CAISO feels 25 MWh level suggested for all hours could result in significant cumulative under scheduling when applied to all SCs within all UDC areas. Also, a 25 MWh level would allow smaller SCs to rely on real time market for a relatively large portion of total load, while larger LSEs would still be required to schedule about 95% of load.
	3. Suggests that compliance be evaluated over an aggregated period rather than on an hourly basis.	CAISO feels this approach is would undermine reliability goals of scheduling requirement by allowing significant cumulative under scheduling during peak hours.
	4. Suggests having a 5 MWh bandwidth around the 95% scheduling requirement	This suggestion, in modified form, was included in the Addendum to the Straw Proposal

Stakeholder	Comment	ISO Response
	5. Suggests having a dynamic scheduling requirement that reflects seasonal changes in critical hours.	Grid Operations staff has expressed the need for maintaining a 95% scheduling requirement for all on-peak hours (HE 7 through HE 22).
	6. Supports ending off-peak scheduling requirement	Partially incorporated in Management recommendation, which reduces off-peak requirement to 75% rather than eliminating requirement.
	7. States that SCs will require advance notice if the off-peak exemption is to be suspended for a Sunday or Holiday	Given concern from numerous stakeholders and Grid Operations staff, this option was not adopted.
	8. Recommends 10 excusable events per month	(This comment was revised in the SC's comments to the Addendum)
City of Riverside	1. Supports scheduling requirement for on-peak hours only, expresses concern over advance notice if the off-peak exemption is to be suspended for a Sunday or Holiday	Partially incorporated in Management recommendation, which reduces off-peak requirement to 75% rather than eliminating requirement, and does not allow CAISO to modify 95%/75% requirements in response to system conditions.
	2. Supports threshold for limited non-compliance, and suggests establishing a fixed minimum of 5 MW as well.	Comments appear to reflect misunderstanding of proposed level for deviations allowed up to six times per month, which is the <u>maximum</u> of 25 MWh or 2% of forecasted load. Thus, the fixed minimum is 25 MWh.
	3. Expresses concern that there are no liquid energy markets after the close of the DA market, thus the requirement should apply to Initial Preferred Schedules	Staff explained that basing compliance on Initial Preferred Schedules would provide an opportunity for SCs to circumvent the requirement by submitting initial schedules equal to 95% of forecasted load, and then revising those schedules downward after the first congestion management run. Additionally, the SI system does not retain the Initial Preferred Schedule is Revised Schedules are submitted. Finally, the CAISO notes that the 95% scheduling requirement was designed with the expectation that SCs would seek to procure sufficient energy to meet 95% of their next day forecast prior to 10 am.
	4. Supports the exemption of SCs serving a *de minimis* load	Incorporated in Management recommendation.
	5. Supports 1 excused forecast non-submittal per calendar month, suggests that DMM have a greater level of discretion for evaluating any additional non-submittals	Exemption incorporated in Management recommendation. However, under CAISO tariff, DMM does not have discretion to excuse violations of objectively identified violations for which there are specific penalties in CAISO tariff due to mitigating circumstances of other considerations.
	6. Supports option 2	Will be incorporated in modified template and instructions.
	7. Supports clarification of Tariff language	Incorporated in Management recommendation.

Stakeholder	Comment	ISO Response
	8. Suggests that DMM should have additional discretion to evaluate apparent non-compliance	DMM provides data from CAISO SI system identifying potential non-compliance with scheduling requirements to FERC, which retains all authority (and discretion) to sanction any non-compliance. DMM also provides weekly reports submitted by participants to FERC as an additional source of information that can be used to asses any apparent non-compliance.. In the event FERC Office of Enforcement takes any investigative or enforcement actions, significant due process is provided for evaluation of any potential non-compliance and mitigating circumstances. However, DMM does not have authority to make subjective determinations about compliance or the applicability of any mitigating circumstances identified in weekly reports.
Powerex	1. Supports the elimination of the 95% scheduling requirement during off-peak hours provided that the pre-dispatch market-clearing of interties bids be adopted for real time energy at the same time (to replace the current "as bid" settlement mechanism)	DMM does not believe that there is a logical or necessary connection between the elimination or reduction of the 95% scheduling requirement during off-peak hours, and the replacement of the current "as bid" settlement mechanism for pre-dispatched inter-tie bids with a single price market design for inter-tie bids, as suggested by Powerex..
	2. Supports the other potential modifications	Noted.
Western	1. Supports the exemption of SCs serving *de minimis* load, suggests that the exemption should apply to those SCs be 10 MWh instead of 1 MWh	The CAISO believes that a 10 MWh exemption for *de minimis* load could negatively impact reliability. Additionally, there is the concern that SCs could divide up their load into multiple SC_ids to avoid being subject to reporting and scheduling requirements.
	2. Requests that there be a function added to SI to enable SCs to check a box indicating that their schedule is 100% of their forecast	This request has been forwarded to appropriate CAISO staff. However, DMM does not recommend this change on the basis that it may encourage circumvention of the spirit of A72, which is that SCs should make a good faith effort to accurately forecast their load, rather than submitting a load forecast that equals their schedule. Meanwhile, for SCs that are truly scheduling 100% of their forecast, DMM believes that the current mechanism for submission of forecasts is reasonable and not unduly burdensome.
Alliance for Retail Energy Markets	1. Requests an expanded stakeholder process	In order to have changes in effect for summer 2007, this stakeholder process has been expedited.

Stakeholder	Comment	ISO Response
	2. Suggests that A72 requirements may be superfluous in light of CPUC RA requirements	CAISO Grid Operations believe that the 95% scheduling requirement remains an important safeguard for reliability during peak hours. The scope of this stakeholder process was to make selected modifications to address some of the concerns with Amendment 72, without sacrificing the fundamental reliability goals of Amendment 72.
	3. Describes market inefficiencies potentially attributable to A72.	The reduction of the scheduling requirement to 75% during off-peak hours should reduce potential market inefficiencies. To the extent some additional costs may be incurred due to the scheduling requirements, this represents a potential tradeoff between costs and reliability.
	4. Suggests that the CAISO do a cost-benefit analysis of the A72 scheduling requirements.	CAISO Grid Operations believe that the 95% scheduling requirement remains an important safeguard for reliability during peak hours. DMM does not believe the CAISO has data and resources to do a meaningful cost benefit analysis of A72 scheduling requirements.
	5. Details administrative burdens and technological difficulties of complying with A72 reporting requirements.	Concerns about technical difficulties have been shared with the appropriate CAISO Departments.
	6. Supports eliminating off-peak scheduling requirement, suggests that the requirement only apply to the 1 peak hour.	Partially incorporated in Management recommendation, which reduces off-peak requirement to 75% rather than eliminating requirement. Grid Operations believe that the 95% scheduling requirement remains an important safeguard for reliability during all peak hours.
	7. Supports a MWh threshold for limited non-compliance.	Incorporated in Management recommendation, which includes allowances for deviations based on both a MWh and percentage thresholds.
	8. Expresses concern over requirement to submit additional schedule information.	Additional schedule information is not required. In the event that an SC does not submit a Revised Schedule, the SC's Initial Preferred Schedule is automatically used to evaluate compliance with the scheduling requirement
	9. Supports the exemption of *de minimis* load, and recommends that the threshold for such be 25 or 50 MWh.	Management recommendation includes an all hours deviation allowance equal to the minimum of 3 MWh or 5% of the SCs forecast. However, CAISO feels 25 -50 MWh level suggested for all hours could result in significant cumulative under scheduling when applied to all SCs within all UDC areas. Also, 25 -50 MWh level would allow smaller SCs to rely on real time market for a relatively large portion of total load, while larger LSEs would still be required to schedule about 95% of load.
	10. Strongly supports the exemption from sanction one missed forecast submittal	Incorporated in Management recommendation.

Stakeholder	Comment	ISO Response
	11. Requests additional time to evaluate weekend scheduling issues	CAISO believes the weekend scheduling issue can be addressed by modifying the weekly reporting template and associated instructions. Since this would not require a tariff modification, further discussion and refinement of options to address this issue may be possible. However, other stakeholder comments reflect a strong preference for Option 2 identified in whitepaper. No other specific options have been proposed.
	12. Supports the clarification of tariff language regarding forecast submittal requirements	Incorporated in Management recommendation.
Strategic Energy	1. Supports the comments of AReM (above)	AReM comments are addressed above.
	2. Expresses concern about the unavailability (cost) of load-shaping products and thus the market inefficiency of the A72 scheduling requirements	CAISO Grid Operations believe that the 95% scheduling requirement remains an important safeguard for reliability during peak hours. The reduction of the scheduling requirement to 75% during off-peak hours should reduce potential market inefficiencies. To the extent some additional costs may be incurred due to the scheduling requirements, this represents a potential tradeoff between costs and reliability.
	3. Requests that the CAISO convey to FERC that it was not the intent of A72 that SCs be penalized for every hour of compliance with the 95% scheduling requirement. States that 25 MWh is one appropriate safe harbor that should be considered	Management recommendation incorporates two separate categories of allowances for deviations below the 95% scheduling requirement. An allowance for up to six deviations of 25 MWh or more is proposed. CAISO has conveyed to FERC that mitigating circumstances should be considered, and has established a mechanism for SCs to proactively identify mitigating circumstances (weekly summary report).
	4. Expresses concern over SI limitations	Suggestions forwarded to appropriate CAISO Departments. However, DMM feels existing SI template, 9 am email verification of load forecast, and opportunity to respond to all potential violations due to load forecast problems provides a sufficient and reasonable mechanism for compliance.
	5. Supports the clarification of the Tariff language regarding forecast submittal requirements	Incorporated in Management recommendation.

Stakeholder	Comment	ISO Response
Coral Power	1. Requests that there be a function added to SI to enable SCs to check a box indicating that their schedule is 100% of their forecast	This request has been forwarded to appropriate CAISO staff. However, DMM does not recommend this change on the basis that it may encourage circumvention of the spirit of A72, which is that SCs should make a good faith effort to accurately forecast their load, rather than submitting a load forecast that equals their schedule. Meanwhile, for SCs that are truly scheduling 100% of their forecast, DMM believes that the current mechanism for submission of forecasts is reasonable and not unduly burdensome.
	2. Expresses concern over SI limitations	Suggestions forwarded to appropriate CAISO Departments. However, DMM feels existing SI template, 9 am email verification of load forecast, and opportunity to respond to all potential violations due to load forecast problems provides a sufficient and reasonable mechanism for compliance.
	3. Does not object to having the scheduling requirement for peak hours only.	Partially incorporated in Management recommendation, which reduces off-peak requirement to 75% rather than eliminating requirement.
	4. Does not object to thresholds for limited non-compliance.	Incorporated in Management recommendation.
	5. Does not object to clarification that the scheduling requirement be evaluated relative to the Revised Preferred DA Schedule.	Incorporated in Management recommendation.
	6. Supports the exemption of SCs serving de minimis load, and suggests an all hours threshold	This suggestion was incorporated in the Addendum, and was incorporated in Management recommendation.
	7. Expresses concern over the daily penalty for forecast non-submittal	DMM has sent out letters of investigation in the cases when SCs have apparently missed a forecast. These letters clearly indicate that the penalty is \$500/day per SC – not \$500/hour per SC per UDC
Sempra Energy Solutions	1. Suggests that A72 may be obsolete in light of the CPUC's RA Program	CAISO Grid Operations believe that the 95% scheduling requirement remains an important safeguard for reliability during peak hours.
	2. Suggests that the scheduling requirement be restricted to on-peak hours Monday through Friday, during the months of May through September only	CAISO Grid Operations believe that the 95% scheduling requirement remains an important safeguard for reliability during peak hours of all months.
	3. Suggests that the scheduling requirement be by NP15 and SP 15 rather than by UDC service area	While supply schedules and bilateral agreements are based on a zonal level (NP15 and SP15) as noted by Sempra, load is scheduled and metered at specific load points within different UDC areas. Thus, the CAISO believes this modification would provide little, if any, advantages, while creating significant problems due to any change in current practices.

Stakeholder	Comment	ISO Response
	4. Supports a MWh scheduling threshold so as to avoid giving SCs with larger loads undue advantage	Management recommendation includes two categories of deviations allowances – both of which are based on a combination of a MWh value and percentage of the SCs load forecast. Both formulas are designed to balance the interests of smaller and larger LSEs in an equitable manner.
Pacific Gas and Electric	1. Supports the clarification that the scheduling requirement be applied to the Revised Preferred Schedule	Incorporated in Management recommendation.
	2. Supports limiting the scheduling requirement to on-peak hours and notes that, included in the off-peak periods should be NERC holidays	Partially incorporated in Management recommendation, which reduces requirement during off-peak hours to 75% rather than eliminating requirement. However, in response to Grid Operations concerns about potential under scheduling problems on Sundays, Management recommendation maintains 95% scheduling requirement during peak hours 7-22 on all days (including Sundays and NERC holidays).
	3. Recommends that the CAISO have the discretion to waive scheduling requirements during on-peak hours as circumstances require.	This suggestion was incorporated in the Addendum to the Straw Proposal. However, this was not adopted, due to concern from Grid Operations and many SCs about the potential implementation problems and uncertainty this could create.
	4. Supports option 2	Will be incorporated in modified template and instructions.
	5. Supports a percentage-based threshold for limited non-compliance, and opposes a MWh based threshold	Management recommendation includes two categories of deviations allowances – both of which are based on a combination of a MWh value and percentage of the SCs load forecast. Both formulas are designed to balance the interests of smaller and larger LSEs in an equitable manner.
	6. Supports the exemption of SCs serving *de minimis* load	Incorporated in Management recommendation.
	7. Supports the exemption of one forecast non-submittal per calendar month from penalty, and recommends that the CAISO have discretion to impose penalties even on that one non-submittal for "habitual offenders"	Exemption of one forecast non-submittal per calendar month incorporated in Management recommendation. FERC Orders indicated that FERC only allow ISOs to issue penalties based on specific formulas in ISO tariffs, and will not grant ISO Market Monitors authority to exercise discretion in modifying or imposing special penalties.
	8. Requests that the CAISO share any compliance analyses performed to SCs to enable them to verify the results	Compliance analysis is made available to SCs on a weekly basis prior to submission to FERC.
	9. Requests that "safe harbors" be clearly defined	Incorporated in Management recommendation, which includes specific thresholds for allowable deviations.

Stakeholder Comments on December 22, 2006 Addendum to White Paper
(Comments due on January 5, 2007)
(Documents available at: http://www.caiso.com/18c9/18c9b8e3224d0.html)

Stakeholder	Comment	ISO Response
City of Anaheim	1. Expresses concern that temporary reductions of the scheduling requirement would need to be made with sufficient advance notice to enable SCs to adjust their schedules accordingly	This option was not adopted due to concern from Grid Operations and many SCs about the potential implementation problems and uncertainty this option may create.
	2. Supports scheduling requirement for on-peak hours only; and recommends that the super-peak be considered as the period to which the requirement would apply. Expresses the preference that there be no off-peak scheduling requirement, but indicates that the proposal of 75% would be appropriate if an off-peak scheduling requirement is put in place	Partially incorporated in Management recommendation, which reduces off-peak requirement to 75% rather than eliminating requirement. CAISO Grid Operations believe that the 95% scheduling requirement remains an important safeguard for reliability during all peak hours.
	3. Suggested clarifications to the description of the proposed definition of a minor violation	Suggested clarifications acknowledged and accepted by CAISO as being consistent with the proposal.
	4. Reiterates concern over SI system limitations	See response to City of Anaheim comments on initial whitepaper.
California Public Utilities Commission	1. Supports, with cautions, CAISO authority to temporarily reduce the scheduling requirement	This option was not adopted due to concern from Grid Operations and many SCs about the potential implementation problems and uncertainty this option may create.
	2. Supports a reduction in the off-peak scheduling requirement to 75% of forecasted load	Incorporated in Management recommendation.
	3. Recommends that, in the interest of equity, a minor violation be defined as the minimum of either 3 MWh of 5% of an SC's load	Recommendation incorporated in Management recommendation. Proposed formula appears to balance the interests of smaller and larger LSEs in an equitable manner.
City of Vernon	1. Supports applying the scheduling requirement to on-peak hours only	Partially incorporated in Management recommendation, which reduces off-peak requirement to 75% rather than eliminating requirement.
	2. Supports a threshold for limited non-compliance with the scheduling requirement	Incorporated in Management recommendation. Specific formula for the threshold for a "minor violation" incorporates both a MWh and percentage, and is designed to balance the interests of smaller and larger LSEs in an equitable manner.

Stakeholder	Comment	ISO Response
	3. Requests that the SC have the opportunity to review and contest potential violations before submission to FERC	Compliance analysis by DMM based on schedule and forecast data from CAISO SI system is made available to SCs on a weekly basis prior to submission to FERC. Any inquiries from SCs are reviewed by DMM. DMM also provides weekly reports submitted by participants to FERC as an additional source of information that can be used to asses any apparent non-compliance. In the event FERC Office of Enforcement takes any investigative or enforcement actions, significant due process is provided for evaluation of any potential non-compliance and mitigating circumstances. However, DMM does not have authority to make subjective determinations about compliance or the applicability of any mitigating circumstances identified in weekly reports.
Constellation	1. Does not support the option to allow the CAISO to temporarily alter the scheduling requirement due to the burdens of resulting uncertainty	This option was not adopted due to concern from Grid Operations and many SCs about the potential implementation problems and uncertainty this option may create.
	2. Supports the application of the 95% scheduling requirement to peak hours only, and supports the 75% scheduling requirement for off-peak hours	Incorporated in Management recommendation.
	3. Supports a 25 MWh grace region below the 95% requirement, and adapts its support of the number of needed exempted potential violations from 10 to 6 (as per the CAISO's White Paper Straw Proposal)	Management recommendation includes an allowance for up to six deviations of 25 MWh or more below the 95% requirement (i.e. the maximum of 25 MWh or 2% of forecasted load).
California Department of Water Resources	1. Reiterated concern about SI limitations	See response to CDWR comments on initial whitepaper.
	2. Reiterates recommendation that SCs with known and controllable load be exempted from A72 requirements	See response to CDWR comments on initial whitepaper.
	3. Expresses concern that limiting consideration of proposals to those acceptable to CAISO Grid Operations personnel is not transparent, and may preclude some reasonable alternatives to A72 requirements	CAISO Grid Operations believe that the 95% scheduling requirement remains an important safeguard for reliability during peak hours. The scope of this stakeholder process was to make selected modifications to address some of the concerns with Amendment 72, without sacrificing the fundamental reliability goals of Amendment 72.
Joint Parties (City of Anaheim, Commerce	1. Expresses concern about SI limitations	See response to same or similar comments about SI limitations by individual Joint Party members.

Stakeholder	Comment	ISO Response
Anaheim, Commerce Energy, Coral Power, Sempra Energy Solutions, Strategic Energy)	2. Expresses concern about data quality	Data identifying potential non-compliance with scheduling requirements provided by DMM to FERC is based directly on data from the CAISO SI system, which is entered by each SC. Numerous data problems or discrepancies were encountered as DMM implemented its reporting program due to misunderstandings of these data systems and other miscellaneous issues by both DMM and participants. However, DMM believes that the automated reporting queries based on SI system data that are now in place are highly reliable. Reports generated by these automated reporting queries are made available to SCs on a weekly basis prior to submission to FERC. Any inquiries from SCs are reviewed by DMM. DMM also provides weekly reports submitted by participants to FERC as an additional source of information that can be used to asses any apparent non-compliance. In the event FERC Office of Enforcement takes any investigative or enforcement actions, DMM stands ready to assist in reviewing any data discrepancies identified by FERC or participants.
	3. Supports permitted deviations to be on a MWh basis rather than on a percentage basis	Management recommendation includes two categories of deviations allowances – both of which are based on a combination of a MWh value and percentage of the SCs load forecast. Both formulas are designed to balance the interests of smaller and larger LSEs in an equitable manner.
	4. Supports an exemption of SCs serving a *de minimis* load, and recommends that this threshold be 25 MWh	CAISO feels the 25 MWh level suggested for a de minimum load exemption from scheduling requirements could result in significant cumulative under scheduling when applied to all SCs within all UDC areas. Also, a 25 MWh level would allow smaller SCs to rely on real time market for a relatively large portion of total load, while larger LSEs would still be required to schedule about 95% of load.
	5. Requests an expanded stakeholder process	In order to have revised scheduling requirements in place by the Spring, this stakeholder process has been expedited. However, the CAISO feels the process produced extensive review and input from stakeholders, and that the final Management recommendation incorporates significant input from stakeholders.

Stakeholder	Comment	ISO Response
	6. Suggests that the scheduling requirement be by NP15 and SP15 rather than by UDC service area	While supply schedules and bilateral agreements are based on a zonal level (NP15 and SP15) as noted by Sempra, load is scheduled and metered at specific load points within different UDC areas. Thus, the CAISO believes this modification would provide little, if any, advantages, while creating significant problems due to any change in current practices.
	7. Supports CAISO discretion to suspend scheduling requirement, and suggests that each such instance be two weeks in duration	This option was not adopted due to concern from Grid Operations and many SCs about the potential implementation problems and uncertainty this option may create. For example, the suggestion that any suspension of the scheduling requirement be required to be at least two weeks in duration is clearly infeasible from the perspective of Grid Operations staff, who emphasized that the dynamic nature of system conditions would prevent suspension or modification of scheduling requirements with significant advance notice or for extended period of time.
	8. Supports limiting the scheduling requirement to Monday through Friday	In response to Grid Operations concerns about potential under scheduling problems on weekends, Management recommendation maintains 95% scheduling requirement during Saturday and Sunday peak hours 7-22.
	9. States that the CPUC RA requirements obviate the need for CAISO scheduling requirements	See response to same or similar comments by individual Joint Party members.
	10. Recommends the definition of a minor violation be 25 MWh to correspond to standard market products	Management recommendation includes an allowance for up to six deviations of 25 MWh or more below the 95% requirement (i.e. the maximum of 25 MWh or 2% of forecasted load). Thus, this allowance would be at least 25 MWh for all SCs.
	11. Recommend the immediate implementation of convergence bidding	This option is infeasible.
	12. Recommend the re-evaluation of the need for A72	See response to same or similar comments by individual Joint Party members.
Southern California Edison	1. Does not object to enabling the CAISO to temporarily reduce the DA scheduling requirement, but stipulates that advance notice would be required so that SCs may adjust their scheduled accordingly	This option was not adopted due to concern from Grid Operations and many SCs about the potential implementation problems and uncertainty this option may create.
	2. Supports a 95% scheduling requirement in the peak hours, and a 75% requirement in the off-peak	Incorporated in Management recommendation.
	3. Does not oppose exemptions for minor levels of non-compliance during all hours	Incorporated in Management recommendation.

Stakeholder	Comment	ISO Response
Alliance for Retail Energy Markets	1. Suggests that the CAISO adopt a protocol enabling temporary reductions in the DA scheduling requirement	This option was not adopted due to concern from Grid Operations and many SCs about the potential implementation problems and uncertainty this option may create.
	2. Strongly supports a reduced (75%) scheduling requirement in the off-peak hours	Incorporated in Management recommendation.
	3. Requests that the CAISO evaluate raising the threshold for minor non-compliance from 3 MWh to 25 MWh	Management recommendation includes an allowance for up to six deviations of 25 MWh or more below the 95% requirement (i.e. the maximum of 25 MWh or 2% of forecasted load). However, CAISO feels a 25 MWh deviation allowance for all hours could result in significant cumulative under scheduling when applied to all SCs within all UDC areas. Also, a 25 MWh level would allow smaller SCs to routinely rely on real time market for a relatively large portion of total load, while larger LSEs would still be required to schedule about 95% of load.
	4. Underscores CDWR's comment that penalties or sanctions for non-compliance be suspended until the SI workspace is modified	See response to CDWR comments.
	5. Underscores Coral Power's comment about the burden of penalties, and expresses uncertainty and concern about the timing of CAISO fines and FERC investigations	See response to Coral Power comments.
City of Riverside	1. Expresses support for the CAISO's ability to temporarily reduce the DA scheduling requirement, but notes that advance notice to SCs will be required	This option was not adopted due to concern from Grid Operations and many SCs about the potential implementation problems and uncertainty this option may create.
	2. Supports the reduction of the scheduling requirement to 75% of forecasted load during off-peak hours	Incorporated in Management recommendation.
	3. Supports a 3 MWh exemption below the 95% scheduling requirement for all hours	Management recommendation provides all hours deviation allowance of the minimum of 3 MWh or 5% of forecasted load. Proposed formula appears to balance the interests of smaller and larger LSEs in an equitable manner.

Stakeholder	Comment	ISO Response
	4. Repeat that all violations which DMM deems unintentional should not be sent to FERC	Along with its compliance reports based on SI data, DMM sends FERC all weekly summary reports submitted by SCs. These weekly summary reports provide a means for SCs to identify any mitigating circumstances for any potential deviations from scheduling requirements. In the event FERC Office of Enforcement takes any investigative or enforcement actions, significant due process is provided for evaluation of any potential non-compliance and mitigating circumstances. However, DMM does not have authority to make subjective determinations about compliance or the applicability of any mitigating circumstances identified in weekly reports.
Williams Power Company	1. Does not oppose relaxing the scheduling requirement for off-peak hours, but opposes the relaxing of the requirement in adjacent on-peak hours because of concerns about off-peak over-generation	Incorporated in Management recommendation.
	2. Recommends relaxing the scheduling requirement in the off-peak, but leaving the 95% requirement intact during peak hours, Sundays and holidays	Incorporated in Management recommendation.
	3. Opposes relaxing compliance around the edges of the 95% requirement	Noted.
Pacific Gas & Electric	1. Supports the ability to temporarily reduce the scheduling requirement, but expresses concern that advanced and explicit notice be given to SCs	Given this understandable concern, as well as the concern expressed by Grid Operations that advance notice would be difficult or impossible to give, this option seems infeasible
	2. Supports maintaining the 95% scheduling requirement during peak hours 7 days/week and eliminating the off-peak scheduling requirement entirely	Management recommendation retains 95% scheduling requirement during peak hours all 7 days of the week. However, in order to protect against potential under scheduling problems during off-peak hours, a 75% scheduling requirement for off-peak hours is recommended. The 75% level is based on analysis summarized in the Addendum on page 4.
	3. Does not object to allowing exemptions for minor levels of non-compliance during all hours	Incorporated in Management recommendation.
	4. Requests that the CAISO supply to SCs all analyses performed to assess compliance	See response to same comment by PG&E in response to initial whitepaper.
	5. Requests that the CAISO clearly define "safe harbors"	See response to same comment by PG&E in response to initial whitepaper.

ATTACHMENT D

Potential Modifications to Amendment 72
Day Ahead Scheduling Requirements

Department of Market Monitoring (DMM)

December 11, 2006

I. Introduction

In September 2005, the CAISO filed Tariff Amendment 72, which required Scheduling Coordinators (SCs) to submit day-ahead schedules equal to at least 95% of their forecast demand for each hour of the next day. Overall compliance with the 95% day-ahead scheduling requirement has been extremely high since spring 2006, particularly during peak hours. However, some participants and CAISO operations staff have expressed concerns about the impacts and difficulty of compliance with the 95% scheduling requirement, particularly during off-peak and weekend hours. In response to these concerns, the CAISO has initiated a stakeholder process to identify and consider potential refinements to Amendment 72.

This whitepaper provides a discussion of issues related to Amendment 72 scheduling requirements and presents a straw proposal for potential refinements to Amendment 72. The remainder of this paper is organized as follows:

- Section II provides a background discussion of the objectives of Amendment 72 and various issues relating to the impacts and compliance with the 95% scheduling requirement that have been identified by participants and CAISO staff.
- Section III presents quantitative analysis relating to these various issues, which is intended to provide a better framework for assessing potential modifications to address these issues.
- Section IV provides a straw proposal for several modifications to Amendment 72.
- Section V summarizes next steps in the process for considering potential changes to Amendment 72.

II. Background

The 95% day-ahead scheduling requirement established through Amendment 72 was designed to enhance reliability and reduce the need for the CAISO to take actions to protect against under scheduling, such as requiring additional capacity to be on-line through Must-Offer Waiver denials. The CAISO's Amendment 72 filings also indicated that the CAISO expected that the 95% scheduling would generally have a positive overall financial impact on participants, due to a reduction in costs relating to Must Offer Waiver denials and real time intra-zonal congestion management.[1]

In summary, Amendment 72 required the following:

1. Day-ahead schedules submitted by participants must equal at least 95% of the SC's forecast demand for each hour, for each UDC Service Area (CAISO Tariff 4.5.4.2.1.1).

2. SCs must submit demand forecasts (through their SI Workspace) for each hour of the following Trading Day, for each UDC Service Area (CAISO Tariff 31.1.4.1 (first).

3. SCs must submit reports to the CAISO that compare the SCs' forecasted, scheduled, and estimated actual Demand by UDC Service Area for each hour of the past week (CAISO Tariff 31.1.4.1 (second)).

The CAISO did not seek to include a penalty for failing to meet the 95% scheduling requirement in Amendment 72, and instead indicated that any failure to meet this requirement may be subject to enforcement by the Federal Regulatory Energy Commission (FERC) under FERC market rules, which include a general requirement that participants comply with all provisions of the CAISO Tariff. FERC approved Amendment 72 in November 2005.

Overall compliance with the 95% day-ahead scheduling requirement has been extremely high since spring 2006, particularly during peak hours.[2] However, some participants and CAISO operations staff have expressed concerns about the impacts and difficulty of compliance with the 95% scheduling requirement, particularly during off-peak and weekend hours. For example:

- Numerous participants have indicated that the bulk of bilateral market supply is only available in standard multi-hour blocks (e.g. 16 peak hours or 8 off-peak hours), so that complying with the 95% scheduling requirement during peak hours often requires SCs to over procure energy and then over schedule significant amounts of load during off-peak hours. In addition to creating a need to over schedule load in the off-peak hours in order to comply with the 95% requirement, this may create additional costs to participants in cases when the price of procuring this energy in the bilateral market exceeds the real time energy price received by the SC for over scheduled load (which is settled as positive uninstructed energy). Some participants

[1] e.g. See Amendment 72 Transmittal Letter, September 22, 2005, p. 1-5. *http://www.caiso.com/docs/2005/09/23/20050923085702339.pdf*

[2] A discussion of Amendment 72 compliance was provided in DMM's October 10, 2006 Market Monitoring Report memo to the CAISO Board (*http://www.caiso.com/188d/188d792d5a4a10.pdf*).

have indicated that limiting the 95% scheduling requirement only to peak hours may greatly reduce this problem.

- CAISO Grid Operations staff have expressed concern that any over scheduling during these off-peak hours due to Amendment 72 may negatively affect system reliability by exacerbating over generation conditions. This impact was particularly evident this spring, when over scheduling attributed to the Amendment 72 requirements – combined with other sources of unscheduled energy and uninstructed generation – created significant over generation during many hours. Nevertheless, Grid Operations has also indicated that it is important to retain the 95% scheduling requirement during peak hours for reliability reasons.

- Numerous participants have expressed concern that under current CAISO Tariff provisions even infrequent and minor violations of the 95% scheduling requirement (and related load forecasting requirements) may be subject to investigation and potential sanction by FERC.[3] Section III provides analysis of the frequency and magnitude of potential violations of the 95% scheduling requirement (and related load forecasting requirements) that may be subject to investigation and potential sanction by FERC.

- At least one participant has suggested that the 95% scheduling requirement should not apply to SCs serving some minimal level of load.[4] Specifically, Williams has proposed that SCs that represent a quantity of load less than 1 MW should be exempt from the A-72 requirements, consistent with an exemption from MRTU's Resource Adequacy ("RA") provisions provided for LSEs serving *de minimus* loads.[5]

- Some uncertainty has arisen concerning whether compliance with the 95% scheduling requirement should be based on Initial Preferred or Revised Preferred schedules submitted to the CAISO by participants, or Final Schedules determined by the CAISO after congestion management. This issue is discussed in more detail later under the heading ***Day Ahead Schedules Submitted by SCs***, below.

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[3] As discussed in DMM's October 10, 2006 Market Monitoring Report, under the CAISO Tariff, DMM has the authority to issue a penalty of $500 per day for failure to submit a day-ahead load forecast, but does not have the discretion to waive or reduce penalties for violations identified pursuant to this authority. Rather, as in the case of penalties for failure to meet outage generation reporting requirements, DMM may only submit a filing at FERC recommending that the Commission waive or reduce a penalty based on mitigating circumstances.

[4] In written comments in response to the CAISO's initial Amendment 72 filing, several participants argued that the reporting requirements established under Amendment 72 should not apply to participants with some minimum thresholds of under scheduling. However, these protests only applied to the reporting requirements established under Amendment 72, and proposed relatively high "materiality thresholds," such as the greater of 100 MW, 2 percent of the CAISO's peak load, or 10 percent of forecast load (see the CAISO's *Answer to Comments and Protests* on Amendment 72, p.6-7 *http://www.caiso.com/docs/2005/10/28/2005102814471071 08.pdf*

[5] Section 40.1 provides and exemption for LSEs serving *de minimis* load, and defines *de minimis* load as actual metered peak Demand during the preceding twelve (12) months of less than one (1) megawatt.

- Under commonly accepted scheduling practices, the day-ahead forecasts and schedules for Sundays and Mondays are often submitted on Fridays. However, in cases where significant changes occur that may warrant a forecast or supply schedule to be modified over the weekend, some issues have arisen in terms of how to report and assess compliance with the 95% scheduling requirement. These issues are discussed in more detail under the heading ***Weekend Forecasting and Scheduling Issue***, below.

Day-Ahead Schedules Submitted by SCs

The 95% scheduling requirement established under Amendment 72 was incorporated into the CAISO tariff in terms of the schedules that SCs submit to the CAISO:

> Each Scheduling Coordinator shall submit to the CAISO, for each hour of each Trading Day, a Day-Ahead Schedule that include at least ninety-five percent (95%) of that Scheduling Coordinator's forecast demand for each hour, for each UDC Service Area ….[emphasis added] (2.2.7.2.1.1)

Two types of schedules may be submitted by participants to the CAISO as part of the day-ahead scheduling process:

- **Preferred Schedules** (submitted by 10 am) are defined in 30.3.1 and are described in Appendix C (Sheet 717) as "initial preferred energy schedule". For sake of clarity, this paper refers to these schedules as "Preferred Schedules", consistent with term used in 30.3.1 of the CAISO Tariff.

- **Revised Schedules** (submitted by 12 noon) are defined in 30.3.4 and are described in Appendix C (Sheet 718) as "revised Preferred Schedules". For sake of clarity, this paper refers to these schedules as "Revised Schedules", consistent with term used in 30.3.4 of the CAISO Tariff.

Thus, a literal reading of current tariff language would suggest that the 95% scheduling requirement applies to both Preferred Schedules (submitted by 10 am) and Revised Schedules (submitted by 12 noon). In addition, since any under scheduling in either of these two steps may lead the CAISO to commit additional capacity through the Must Offer Waiver denial process, it would be logical that any day-ahead scheduling requirement be applicable to both Preferred Schedules and Revised Schedules submitted by participants.

In practice, however, DMM has determined that the CAISO's Scheduling Infrastructure (SI) does not currently retain the data necessary to assess compliance with any scheduling requirement applicable to Preferred Schedules (submitted by 10 am).[6]

At least two approaches could be taken to clarify the compliance obligations of SCs and potential enforcement authority of FERC:

1) Modify Section 2.2.7.2.1.1 so that the 95% scheduling requirement applies only to Revised Schedules (submitted by 12 noon) as defined in 30.3.4.

2) Clarify that any enforcement of the 95% scheduling requirement as applied to Preferred Schedules (submitted by 10 am) would be based on data reported by participants. Under this approach, additional tariff modification would be necessary to specifically require submission of these data to the CAISO and/or FERC.

These options are discussed further in Section IV.

Weekend Forecasting and Scheduling Issues

Under commonly accepted scheduling practices in the WECC, an entity may develop and submit forecasts and schedules two or three days ahead of a Trading Day (e.g. on Thursday and/or Friday for Trading Days falling on weekends and Mondays, and similar practices for certain holidays). This practice reflects or accommodates the fact that the bulk of trading and scheduling activity is done during the common non-holiday business work week of Monday through Friday. In the FERC proceeding on Amendment 72, such weekend or holiday scheduling was deemed to be compliant with the Amendment 72 requirements. However, changes to load forecasts or schedules that occur between the time these weekend or holiday schedules are submitted and the day-ahead timeframe may result in situations that may appear to not meet the Amendment 72 requirements.

In recognition of this weekend and holiday scheduling practice, the instructions for the weekly report required to be submitted by SCs under Amendment 72 indicate that if an SC submits two-day-ahead schedules for weekend or holidays that it did not update in the day-ahead timeframe, the SC should use the weekly report to indicate that any apparent deviations from the 95% scheduling requirement are due to weekend or holiday scheduling.[7] Specifically, the template indicates that:

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[6] When SCs submit their Preferred Day-Ahead Schedules into SI, the "Schedule Class" variable is set to "P". If, an SC subsequently provides the CAISO with adjustments to their schedule, those adjustments overwrite the Preferred Schedule data, and the "Schedule Class" variable is set to "R". When this occurs, data containing the Preferred Schedule initially submitted by SCs are not retained in the SI system, according to CAISO Market Operations staff.

[7] http://www1.caiso.com/177a/177ad2412e760.pdf ; http://www.caiso.com/14d8/14d8acf022820.xls

1) In the field for the day-ahead forecast (D_FC), "the SC should include the Demand Forecast data that it used to develop the two-day ahead Schedule."

2) If data in the field for the Demand scheduled on a Day Ahead basis (D_DA) are based on a two-day ahead forecast, the SC should "make an appropriate notation in the "Notes" field."

3) The "Notes" field should include "any explanations that are appropriate, such as explanations of large forecast errors and notations indicating that Demand Schedules and Forecasts were developed on a two day-ahead basis for weekends and holidays."

In the event that an SC follows the above instructions, but updates its day-ahead load forecast or Schedules prior to the final deadline for submittal of this information to the CAISO,[8] a discrepancy may occur between information in the SCs weekly report and the final day-ahead load forecast and schedule data appearing in the CAISO SI system. Market Participants have identified two specific scenarios under which this may occur:

- ***Increase in Load Forecast.*** One SC has indicated that it has revised its load forecast for Sunday and/or Monday upwards after developing resource schedules prior to the weekend that met or exceeded the 95% Day ahead scheduling requirement. Although the SC had the ability to update its forecast, the SC indicated it could not increase its day-ahead schedules due to a lack of bilateral market activity on weekends. As a result, the SC's day-ahead schedules fell below the 95% of its final day-ahead load forecast (as revised upwards over the weekend).

- ***Decrease in Supply Availability.*** Other SCs have indicated that they have revised their resource schedules downwards over the weekend due to a decrease in available supply, either through generating unit outages or downward forecasts of the availability of intermittent resources (e.g. wind, solar, etc.). Again, however, due to a lack of bilateral market trading and scheduling opportunities on weekends, the SCs were unable to schedule additional supply to compensate for the decrease in available supply resources. Since the CAISO requires each SC's portfolio of supply and demand to be balanced, the SCs needed to reduce their day-ahead load schedules by an equal amount. The result of this was that the SCs' day-ahead schedules fell below 95% of forecast.

The weekly report submitted by SCs under Amendment 72 was designed to provide a basis for identifying and explaining precisely this type of situation. For example, if a potential violation of the 95% scheduling requirement during any specific hour is identified based on day- ahead load forecast and schedule data in the CAISO SI system,

[8] 10 a.m. of the day preceding each Trading Day.

the SC's weekly report is designed to provide an initial source of information, or explanation, from the SC as to why this occurred.

This issue will still be applicable even if the 95% scheduling requirement is limited to peak hours, since Mondays are considered peak days.

One option to address these scenarios may be to specify that SCs should not update their day-ahead forecast or day-ahead schedule in SI for Sundays or Mondays if this increase would cause them to drop below the 95% scheduling requirement.

Another option is to modify the template for the weekly reports to include columns for the SC's forecasts and schedules as submitted to the CAISO at the time of the deadline for the day-ahead market, as well as separate (additional) columns for any alternative forecast and schedule that the SC used as the basis for seeking to comply with the 95% scheduling requirement

These options are discussed further in Section IV.

III. Analysis of Scheduling Data

This section presents quantitative analysis relating to the various issues identified in the preceding section, and is intended to provide a better framework for assessing potential modifications to address these issues.

Methodology

All analysis in this section defines a *potential violation* of the 95% scheduling requirement as any hour during which data in the CAISO SI system indicate that an SC submitted day-ahead schedules equaling less the 95% of the day-ahead forecast submitted by the SC for any UDC area. Thus, if two SCs submit schedules less than 95% of forecast in any UDC area during one hour, this is counted as two potential violations. Day-ahead schedules used in this analysis are the "revised preferred schedules" or Revised Schedules (submitted by 12 noon), as defined in CAISO tariff section 30.3.4.[9]

Analysis of the total or average MWh associated with *potential violations* is based on the difference between the amount of energy scheduled by the SC and 95% of the SC Day-Ahead forecast. For example, if an SC submitted a Day Ahead forecast of 100 MWh for a UDC area, but submitted a Revised Schedule in this UDC area equaling only 90 MWh, this would represent a 5 MWh potential violation of the 95% scheduling requirement.

In order facilitate use of this analysis to directly assess the potential impact of potential exemptions to the 95% scheduling requirement during different time periods, results are presented in terms of three time periods:

- Peak (Monday – Saturday, HE 7-22)
- Off-Peak (HE 1-6 and 23-24)
- Sunday Peak (Hours 7-22)

Potential Violations of 95% Scheduling Requirement

Overall compliance with the 95% scheduling requirement has improved significantly over the last year, as shown in Figures 1 and 2. Compliance began to improve significantly in the late spring as DMM and FERC increased communications to participants about compliance monitoring and potential enforcement actions. Another significant increase in compliance occurred over the months of August, September and

[9] As noted on page 3, these Revised Schedules are also described in CAISO Tariff Appendix C (Sheet 718) as "revised preferred schedules".

October. As shown in Figure 1, since August, potential violations of the 95% scheduling requirement represent only 1 to 2% of total scheduling hours for all SCs.

While the rate of overall compliance with the 95% scheduling requirement — as a percentage of total scheduling hours — has been very high, the total number of potential individual hourly violations remains significant. For example, while the overall rate of compliance was about 99% during September and October, about 500 potential hourly violations of the 95% scheduling requirement occurred during each of these months. Thus, even if the overall rate of compliance with the 95% scheduling requirement remains very high, the total number of potential hourly violations may remain significant, simply due to the large number of scheduling hours in which the 95% scheduling requirement applies.

About half of the potential violations of the 95% scheduling requirement have consistently occurred during peak hours, as summarized in Figures 2 through 4. These results suggest that even if the 95% scheduling requirement is applied only during peak hours, the number of potential violations may still be remain significant from the standpoint of administration, enforcement and potential penalties or sanctions.

The *magnitude* of potential violations of the 95% scheduling requirement has also been relatively small. As shown in Figure 5, virtually all potential violations involve schedules that are only about 10 to 50 MWh lower than the 95% requirement. As shown in Figure 6, most of these potential violations involve schedules that are over 90% of the SC's day ahead load forecast, and virtually no potential violations involve schedules that are under 80% of forecasted load.

As shown in Figure 7, the overall frequency of potential violations is relatively comparable across all hours of the day, further illustrating that that even if the an exemption were made for off-peak and weekend hours, potential violations may still remain significant from the standpoint of administration, enforcement and potential penalties or sanctions. However, the frequency of potential violations is slightly higher in the "shoulder" off-peak hours (HE 6 and 23), which represent the off-peak hours with the highest loads. Several SCs have indicated that due to the need to purchase off-peak energy in 8 hour blocks, they often seek to purchase just enough off-peak block energy to meet the 95% requirement for these hours in order to minimize their over scheduling in the other off peak hours when loads are lower. A similar trend exists during peak hours, with the frequency of potential violations being highest during the highest load peak hours of the day.

As shown in Figure 8, the *average magnitude* of potential violations of the 95% scheduling requirement is significantly lower during the highest peak load hours of the day, when any under scheduling would typically have a potential impact on reliability, day-ahead unit commitment and real time dispatches. During HE 12 through HE 20, the average magnitude of each violation ranges between 40 and 60 MWh.

Figure 9 shows that the portion of potential violations of the day-ahead forecasting and scheduling requirement established under Amendment 72 have been slightly higher on Sunday and Monday which represent the days during which the special weekend forecasting and scheduling issues discussed in Section II may create potential violations. However, as shown in Figure 9, these data do not indicate that these issues have led to significant difference in compliance for these days relative to other days of the week.

Finally, as shown in Figure 10, potential violations with the requirement to submit a day-ahead load forecast by 10 a.m. dropped dramatically in May 2006 as DMM began its program for enforcing potential penalties for failure to submit load forecasts. Potential violations continued to decline steadily over the course of the summer, as DMM and Client Services continued to work with participants to facilitate improved compliance. Since September, potential violations have been minimal.

Figure 1. Potential Violations of 95% Scheduling Requirement Number and Percentage of Total Scheduling Hours (By Week)

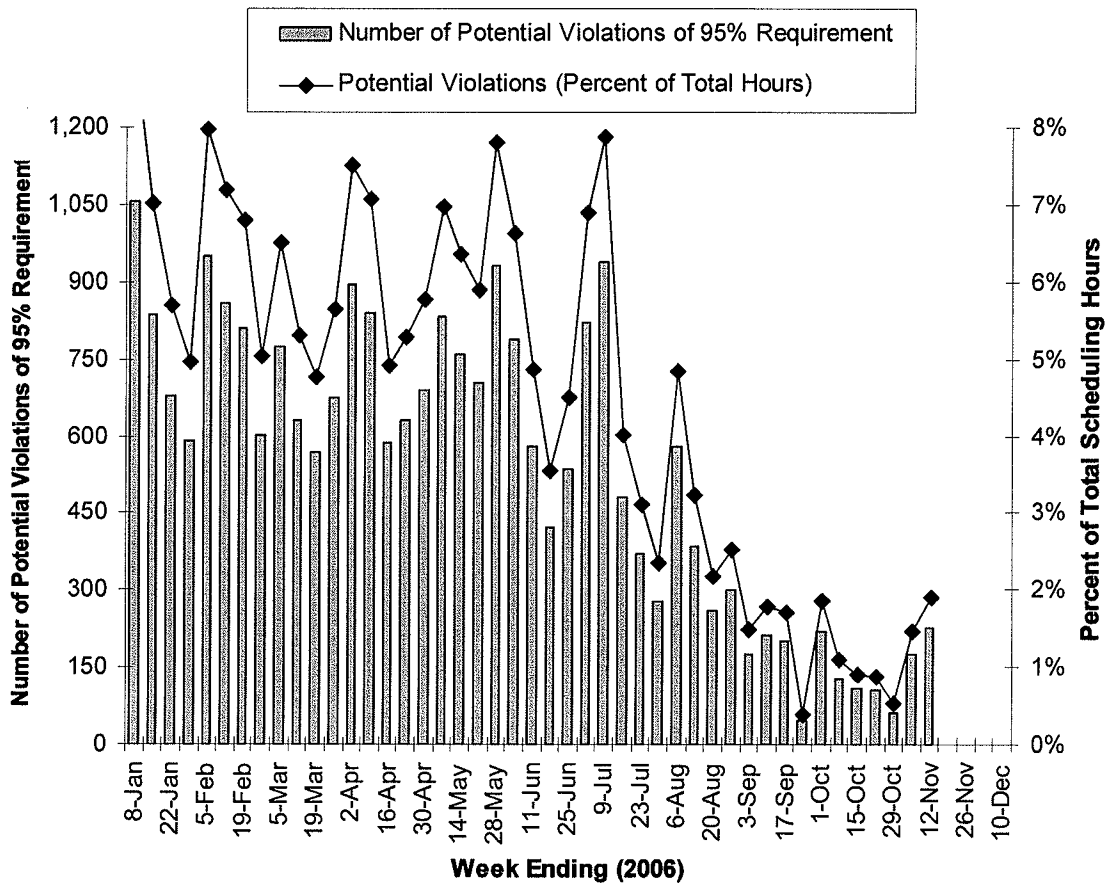


Figure 2. Potential Violations of 95% Scheduling Requirement By Month and Time Period (Peak vs. Off Peak)

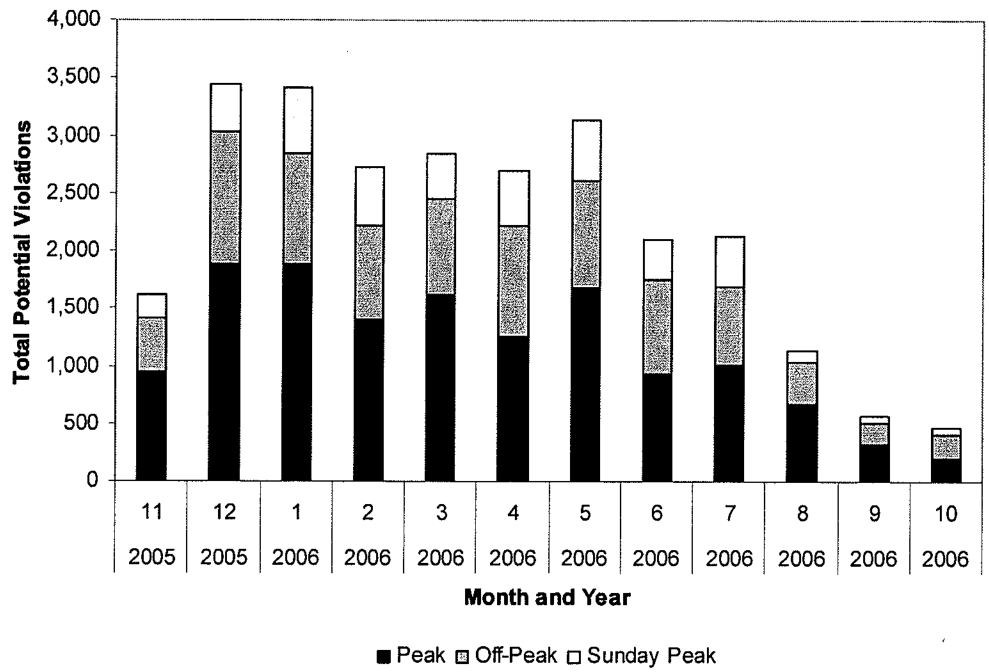


Figure 3. Potential Violations of 95% Scheduling Requirement Percentages Based on Total Potential Violations

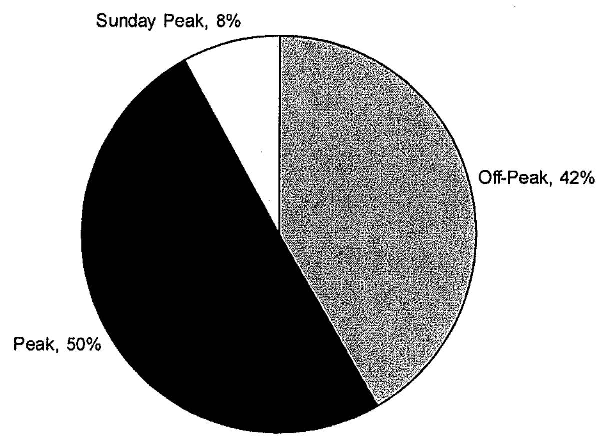


Figure 4. Potential Violations of 95% Scheduling Requirement Percentages Based on Total MW Less Than 95% of Forecast Scheduled by SC

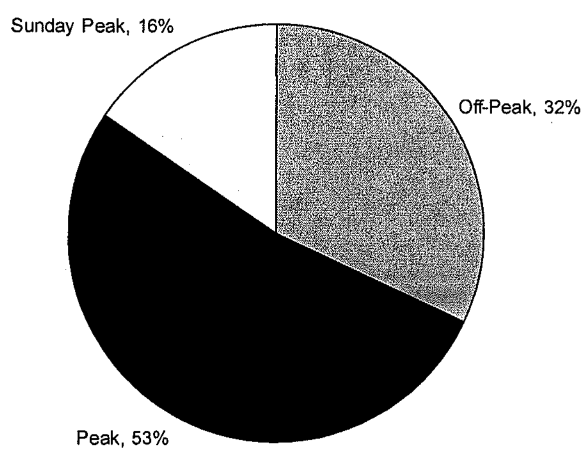


Figure 5. Potential Violations of 95% Scheduling Requirement Total MW Less Than 95% of Forecast Scheduled

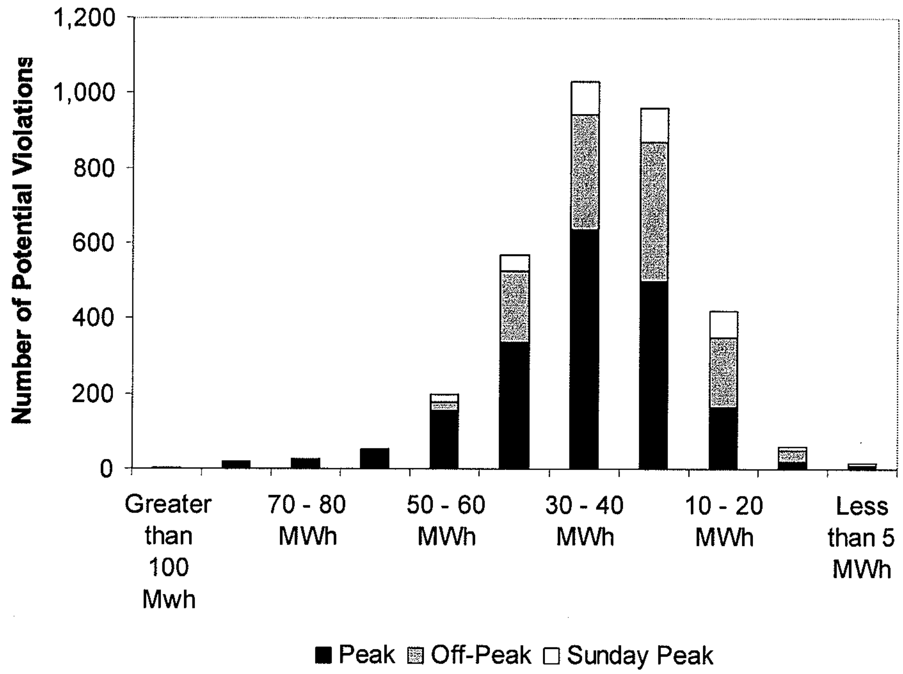


**Figure 6. Potential Violations of 95% Scheduling Requirement
Percent of Forecast
Scheduled**

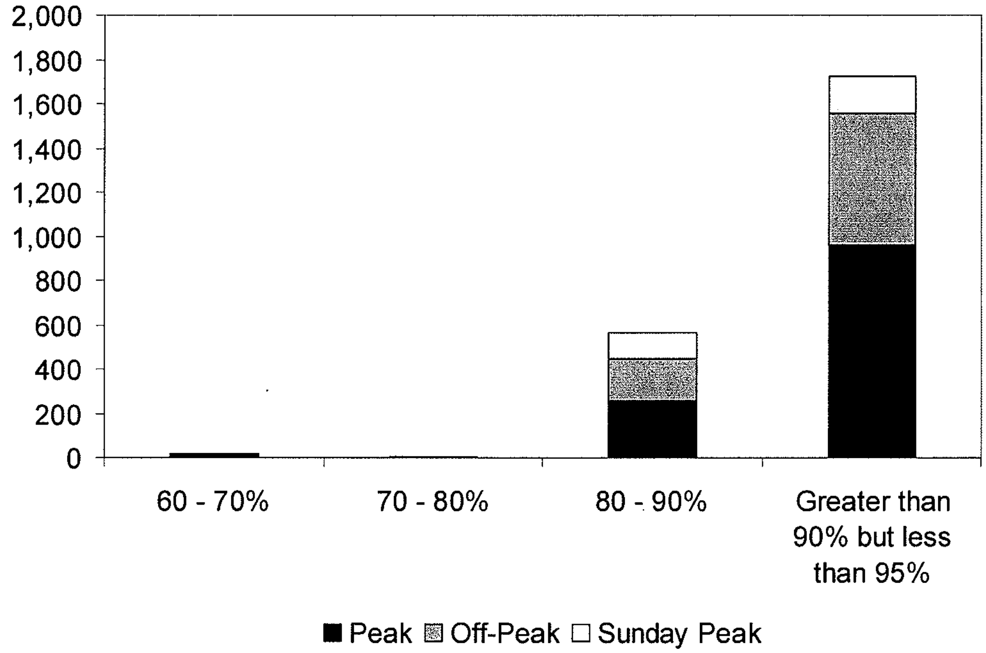


Figure 7. Potential Violations of 95% Scheduling Requirement

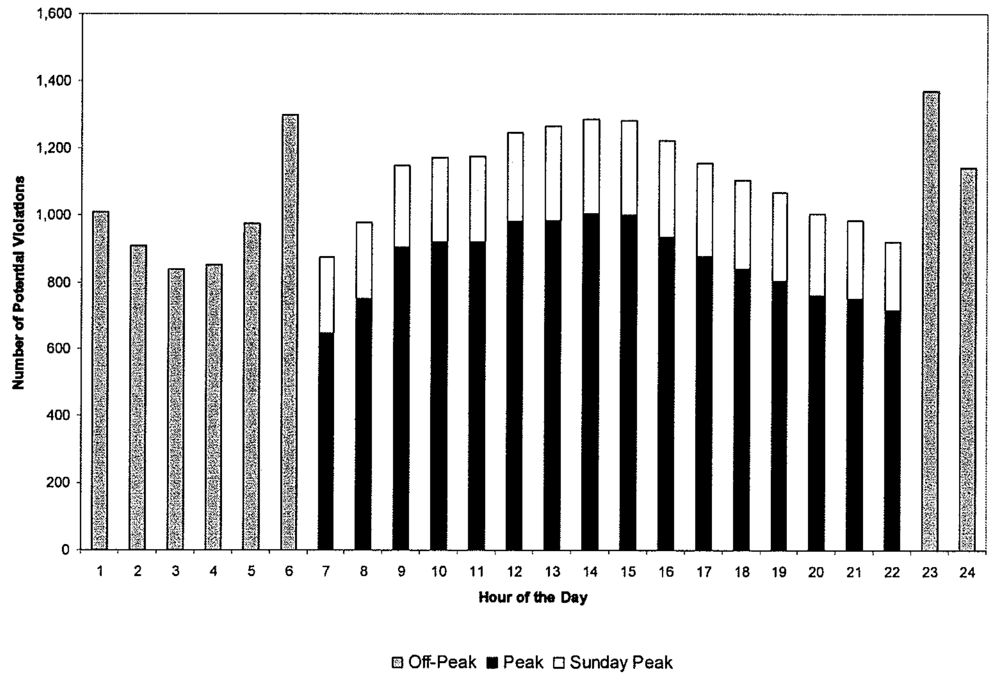


Figure 8. Potential Violations of 95% Scheduling Requirement
Average MW Less Forecast Scheduled

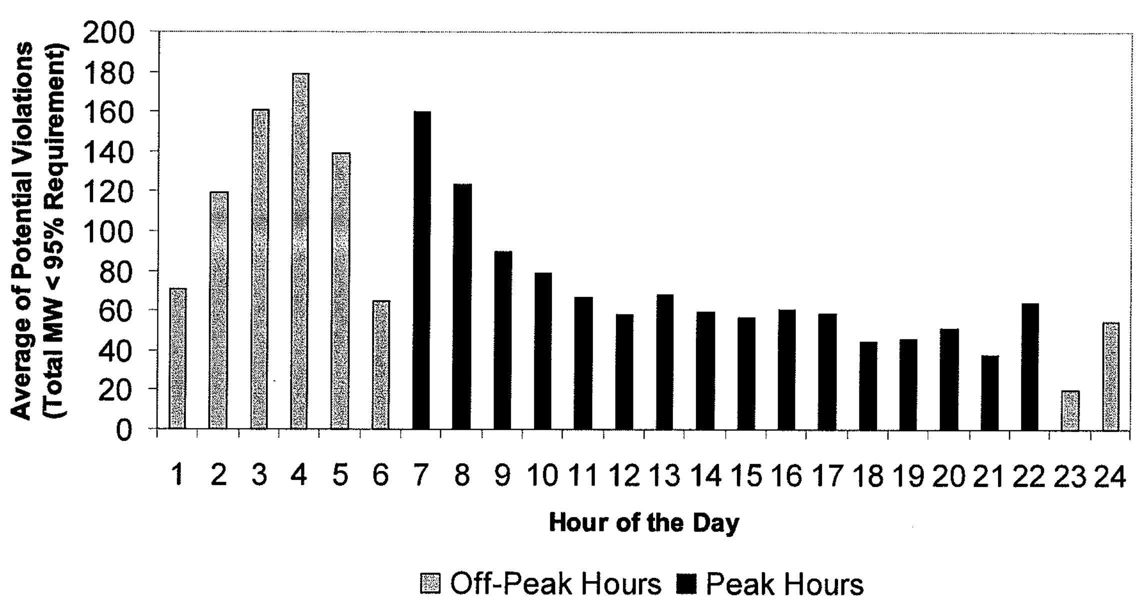


Figure 9. Potential Violations of Forecast and Scheduling Requirements By Day of Weeks

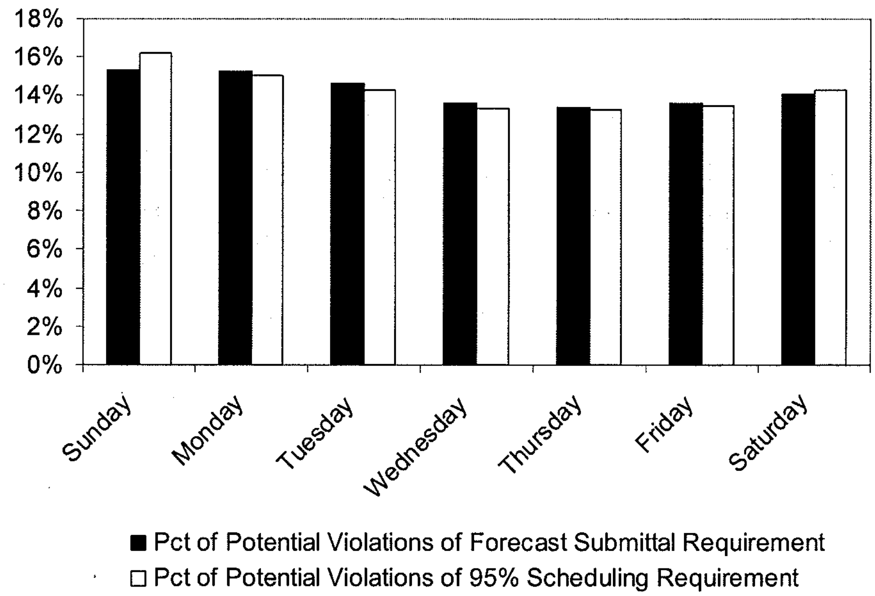
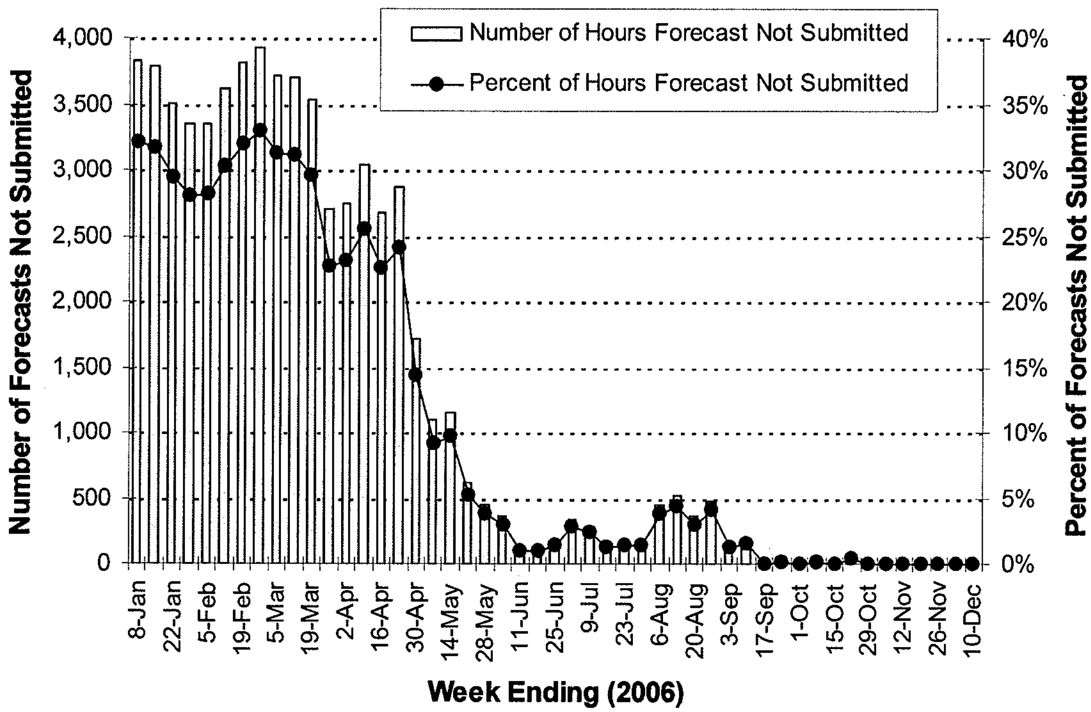


Figure 10. Potential Violations of Forecast Submission Requirement



IV. Potential Modifications

This section outlines a straw proposal for several potential modifications to the scheduling requirements established under Amendment 72. DMM notes that these potential changes are provided for discussion based on initial input provided from CAISO Grid Operations and participants. However, since the fundamental purpose of the scheduling requirements established under Amendment 72 is to enhance system operations and reliability, DMM believes that CAISO Grid Operations' assessment of the potential operational and reliability impacts of any modifications will be critical in determining any specific modifications that may be made.

Potential tariff changes that may address the major concerns with the 95% day ahead scheduling requirement — without undermining the basic operational and reliability goals of Amendment 72 — include the following.

1. Scheduling Requirements for Peak Hours Only

Modify the Tariff so that day-ahead schedules submitted by each SC are required to meet 95% of forecasted load only during peak hours.

The CAISO believes that for purposes of this requirement, peak hours should be defined using the standard definition of Monday through Saturday, Hours Ending 7 through 22. This provides the greatest consistency between scheduling requirements and the definition of peak hours commonly used in the bilateral market.

To address concerns that under scheduling on a Sunday with very high loads could create potential operational and reliability problems, such as occurred this summer, it has been suggested that the exemption for Sundays may be designed to be non-applicable on Sundays that the CAISO issues a "Restricted Maintenance Operations" (i.e., "No-Touch") alert prior to the day-ahead scheduling deadline. With this option, DMM notes that it may be necessary to notify SCs that the Sunday exemption will be suspended well in advance of the day-ahead scheduling deadline (Saturday, 10 a.m.). Since bilateral trading opportunities are limited on weekends, it may be necessary to actually notify SCs relatively early on the preceding Friday that the Sunday exemption will be suspended. DMM also notes that a clear deadline and method for notifying SCs that the Sunday exemption will be suspended should be specified in order to provide clear rules for assessing compliance.

2. Threshold for Limited Non-Compliance with 95% Scheduling Requirement Not Subject to Sanction

Establish a specific thresholdfor limited non-compliance with the 95% scheduling requirement by individual SCs that would not be subject to sanction by FERC.

DMM proposes a specific tariff provision indicating that any hour in which an SC scheduled less than 95% of their forecasted load with a UDC area would not be constitute a violation if (a) the SC scheduled at least 93% of their forecasted load, and (b) the number of hours within that UDC area during which the SC scheduled at least 93% but less than 95% of their forecasted load did not exceed six per calendar month.

In other words, the total number of violations for each SC within each UDC area each month would be the sum of (a) each hour in which the SC scheduled less than 93% of their forecasted load with the UDC area, plus (b) the number of hours in which the SC scheduled at least 93% but less than 95% of their forecasted load within the UDC area in excess of six hours. Thus, each SC would have these six exemptions for each UDC Area in which the SC schedules load.

A variation of this option would be to expand the 93% threshold described above to include an absolute value (in MWh) by which schedules might fall below the 95% requirement without constituting a violation. For example, the threshold could be based on the lower of (a) 93% of the SC's forecast or (b) 25 MWh less than 95% of the SC's forecast. DMM notes that under this approach, a relatively small threshold such as 25 MWh could reduce potential violations, and provide SC scheduling relatively small amounts of load a reasonable threshold in terms of actual MWhs, without having a significant impact on overall under scheduling.

Again, to address concerns that under scheduling during any peak hour of a very high load day could create potential operational and reliability problems, it has been suggested that these exemptions exclude any violations of the 95% scheduling requirement during days on which the CAISO issues a "Restricted Maintenance Operations" (i.e., "No-Touch") alert prior to the day-ahead scheduling deadline. Under this approach, all violations of the 95% scheduling requirement on "No-Touch" days would be referred to FERC as violations – even if the SC had fewer than six total violations for that calendar month. With this option, DMM again notes that it may be necessary to notify SCs that "Restricted Maintenance Operations" conditions exist well in advance of the day-ahead scheduling deadline (Saturday, 10 a.m.). This may require modification of current CAISO practices in order to issue "No-Touch" alerts earlier than is typically done. Again, DMM also notes that a clear deadline and method for notifying SCs that "Restricted Maintenance Operations" conditions have been declared should be specified in order to provide clear rules for assessing compliance.

Finally, DMM notes that, despite any specific thresholds included in the CAISO tariff, FERC will retain all authority to enforce the scheduling requirement and to exercise discretion not to enforce any sanctions due to mitigating circumstances and other factors they deem appropriate.

3. Clarify that day-ahead scheduling requirements apply to Revised Preferred schedules

Clarify that compliance with day-ahead scheduling requirements will be assessed based on Revised Schedules, as defined in 30.3.4 of the CAISO Tariff, submitted by each SC to the CAISO during the day-ahead scheduling process.

Revised Schedules (submitted by 12 noon) are defined in 30.3.4 of the CAISO Tariff and are also described in Appendix C (Sheet 718) as "revised Preferred Schedules."

As discussed in Section II, it may be logical to also apply the 95% scheduling requirement to Preferred Schedules (submitted by 10 am), as defined in 30.3.1 of the CAISO Tariff and described in Appendix C (Sheet 717) as "initial preferred energy schedule". However, DMM has determined that the CAISO's Scheduling Infrastructure (SI) does not currently retain the data necessary to assess compliance with any scheduling requirement applicable to Preferred Schedules (submitted by 10 am). Thus, absent any source of information to verify compliance with a 95% scheduling requirement applicable to Preferred Schedules, DMM recommends specifying that compliance with day-ahead scheduling requirements is assessed based on Revised Schedules, which are retained in the SI system.

4. Exclude SCs Serving a *de minimus* level of load from 95% scheduling and reporting requirements.

Specify that SCs representing a quantity of load less than 1 MW are exempted from the 95% scheduling requirement.

As discussed in Section II, this provision would be consistent with an exemption from MRTU's Resource Adequacy ("RA") provisions provided for LSEs serving *de minimus* loads.[10]

DMM believes that this provision could be easily implemented and would reduce unnecessary administrative burdens for a very small number of SCs, without creating potential "loopholes" or additional administrative problems associated with setting any higher threshold for levels of load that may be exempted from the 95% scheduling requirement.

[10] Section 40.1 provides and exemption for LSEs serving *de minimis* load, and defines *de minimis* load as actual metered peak Demand during the preceding twelve (12) months of less than one (1) megawatt.

5. Exclude Limited Non-Compliance with Load Forecasting and Reporting Requirements from Sanction

Establish a specific threshold for limited non-compliance with the requirement that SCs submit day ahead forecasts by 10 a.m. and weekly summary reports.

Potential violations with the requirement to submit a day-ahead load forecast by 10 a.m. dropped dramatically since May, and have been minimal since September, as discussed in Section II and illustrated in Figure 10. Meanwhile, compliance with weekly reporting requirements has been 100%. In addition, the penalty for failure to meet either of these informational requirements is only $500 per event (e.g. one missed daily forecast would potentially be penalized $500).

However, given that DMM does not have discretion to unilaterally waive penalties for inadvertent or unintentional violations of these requirements, DMM believes it would be administratively beneficial to establish a specific provision exempting limited non-compliance with these information-submission requirements from the $500 penalty.

DMM proposes a specific tariff provision indicating that the $500 penalty for either load forecasting or weekly reporting requirements not be assessed for the first violation in any calendar month.[11]

6. Clarify Weekend Scheduling Issues

Establish specific guidelines and/or a specific mechanism for SCs to comply with the 95% scheduling requirement while using WECC-compliant weekend and holiday scheduling practices.

As discussed in Section II, several SCs have expressed concern about weekend scheduling issues that arise when an SC may comply with the 95% scheduling requirement based on schedules and forecasts established on Friday for Sunday and Monday, but then updates its forecast or schedule over the weekend.

DMM believes that this appears to be a relatively limited scenario, and notes that this is precisely the type of situation that DMM believes FERC would be expected to exercise the wide degree of discretion it has in interpreting and enforcing CAISO market rules. In addition, DMM suggests several possible approaches for dealing with this issue:

- The first option would address these scenarios may be to specify that SCs may should not update their day-ahead forecast in SI for Sundays or Mondays if their forecast increases between the time the schedules are submitted and the respective day-ahead timeframe over the weekend, if this increase would cause them to drop below the

[11] Since only four weekly reports may be required each month, DMM believes that it would not be reasonable to provide a separate exemption for failing to comply with weekly reporting requirement once each month. Instead, DMM proposed to that the exemption be applied to the sum of any failures to comply with daily load forecasting requirements plus and any failures to comply with the weekly reporting requirement.

95% scheduling requirement. It is probably desirable, however, for SCs to reduce their day-ahead schedules in the day-ahead timeframe in the event that supply resources become, or are anticipated to be, unavailable, so that the CAISO has the opportunity to commit any replacement must-offer resources that may be needed. As this may cause the data in SI to indicate that the SC did not meet the 95% scheduling requirement, the second option may also have to be implemented even if this first option is selected.

- The second option would be to modify the template for the weekly reports to include columns for the SC's forecasts and schedules as submitted to the CAISO at the time of the deadline for the day-ahead market, as well as separate (additional) columns for any alternative forecast and schedule, submitted in advance of the day-ahead timeframe, that the SC used as the basis for seeking to comply with the 95% scheduling requirement

DMM believes these and other options should be discussed, along with and other options that may be identified by participants and CAISO Grid Operations staff.

7. Clarify Tariff Forecast Submittal Requirements

Clarify forecast submission requirements.

Several SCs have sought clarification of the relationship of various demand forecast submission requirements described in Section 19 of the CAISO Tariff to the requirement in Section 31.1.4.1, referenced by Amendment 72, to submit a daily demand forecast for the following day. As Section 19 appears to describe obsolete requirements, tariff revisions to improve the consistency of the demand forecast requirements should be discussed.

V. Further Steps

The process for developing any changes to Amendment 72 will be conducted on a relatively accelerated timeframe, so that any changes may be effective prior to the spring months when problems related to over generation tend to be highest. The specific steps in this process, which were outlined in a November 30, 2006 Market Notice, include the following tasks. Dates have been updated:

- Development and distribution of whitepaper outlining issues with Amendment 72 and a draft straw proposal for changes to Amendment 72 (December 11, 2006)
- Submission of initial stakeholder comments on straw proposal (Close of Business, December 18, 2006)
- Conference call with stakeholders to discuss straw proposal and stakeholder comments (10:00 AM to 12:00 PM, December 20, 2006)
- Submission of final stakeholder comments on straw proposal (January 5, 2007)
- Development of CAISO recommendation to CAISO Board (January 10, 2007)
- Discussion and potential approval of Tariff modifications at CAISO Board Meeting (January 24-25, 2007)

The stakeholder process described above will only address potential modifications to day-ahead scheduling requirements until implementation of MRTU. Pursuant to FERC's September 21, 2006 Order on MRTU, a separate stakeholder process is being conducted later in 2007 to address potential provisions to address under scheduling under MRTU prior to successful implementation of convergence bidding. [12]

[12] The CAISO's filing on Amendment 72 indicated that the day-ahead scheduling requirement was viewed as a "stop gap" measure that the CAISO expects would be unnecessary and not be extended under MRTU once the Integrated Forward Market (IFM) and Residual Unit Commitment (RUC) processes were in place. However, FERC's September 21 Order on MRTU indicated that the FERC is concerned about the potential for day-ahead under scheduling by LSEs in the absence of convergence bidding and/or any explicit day-ahead scheduling requirement. Consequently, the Order directs the CAISO to develop and file interim measures, no later than 180 days prior to the effective date of MRTU Release 1, to address any potential economic incentives for LSEs to under schedule in the Day Ahead Market until the successful implementation of convergence bidding has been achieved. (September 21 Order at 452, p.132).

ATTACHMENT E

Addendum:

Potential Modifications to Amendment 72 Day Ahead Scheduling Requirements

Department of Market Monitoring (DMM)

December 22, 2006

I. Introduction

This addendum describes several additional options for modifying the scheduling requirements established under Tariff Amendment 72. These modifications were identified in comments provided in response to the whitepaper developed by the Department of Market Monitoring (DMM) outlining a straw proposal for potential refinements to Amendment 72.[1] As noted in DMM's initial whitepaper, since the fundamental purpose of the scheduling requirements established under Amendment 72 is to enhance system operations and reliability, DMM believes that CAISO Grid Operations' assessment of the potential operational and reliability impacts of any modifications will be critical in determining any specific modifications that may be made. Consequently, the modifications described in this addendum are limited to several options that may be acceptable to CAISO Grid Operations - based on their initial review. However, due to the very limited time that CAISO Grid Operations and other CAISO staff have had to review these additional options, further review and consideration of these options by CAISO staff are necessary. Nonetheless, this description and discussion of these options is being provided at this time to allow for review and comment by stakeholders by the January 5, 2007 date established for comments on the straw proposal provided in the aforementioned whitepaper.

II. Other Potential Modifications

1. Ability to Temporarily Reduce Day Ahead Scheduling Requirement

This option would establish a tariff provision allowing the CAISO to temporarily reduce the day-ahead scheduling requirement if CAISO Grid Operations determines that over-generation has become a reliability problem.

Some participants have suggested eliminating the 95% scheduling requirement during off-peak seasons, as well as off-peak hours. This concept of eliminating the 95% scheduling requirement during the all hours (peak and off-peak) of off-peak seasons was

[1] *Potential Modifications to Amendment 72 Day-Ahead Scheduling Requirements*, Department of Market Monitoring (DMM), December 11, 2006, http://www.caiso.com/18c9/18c9b9aa27f70.pdf

previously discussed and rejected by CAISO Operations because, historically, under-scheduling has occasionally created reliability issues even in off-peak seasons. However, another option that has been suggested by Grid Operations is to include a tariff provision that would allow the CAISO to relax or waive the 95% scheduling requirement for limited time periods if Grid Operations deems over-generation to be a reliability problem.

Under this option, the CAISO would have the authority to issue a market notice specifying the 95% scheduling requirement was being reduced to a specific level (%) for a specific limited time period. Absent a further market notice extending any such reduction, the 95% scheduling requirement would resume to be effect at the end of the time period specified in the market notice. Grid Operations staff has noted that, in practice, the time period for which the scheduling requirement might be reduced may typically be relatively short (e.g. one day at a time) due to the difficulty of projecting system conditions over a longer time period.

DMM notes that, under this approach, any SC opting to reduce it's scheduling level in response to such notices would need to monitor notices issued by the CAISO, and would need to remain prepared to resume meeting the 95% scheduling requirement at the end of the limited time frame that may be specified in the market notice. Meanwhile, any SC believing this would create potential compliance problems would always have the option of continuing to schedule to the 95% requirement.

In the event that a separate lower scheduling requirement is established for off-peak days and hours (as outlined in the following section of this addendum), the tariff provision would also allow the CAISO to temporarily reduce any off-peak scheduling requirement.

2. Reduced Scheduling Requirements for Off-Peak Hours

This additional option would establish a lower minimum scheduling requirement for weekends and/or other off-peak hours (e.g. 75% of forecasted load).

The first potential modification outlined in the initial whitepaper was to modify the Tariff so that day-ahead schedules submitted by each SC are required to meet 95% of forecasted load only during peak hours (e.g. Monday through Saturday, Hours Ending 7 through 22).

To address concerns that under scheduling on a Sunday with very high loads could create potential operational and reliability problems, such as occurred during summer 2006, it has been suggested that the exemption for Sundays may be designed to be non-applicable on Sundays for which the CAISO issues a "Restricted Maintenance Operations" notice prior to the day-ahead scheduling deadline.

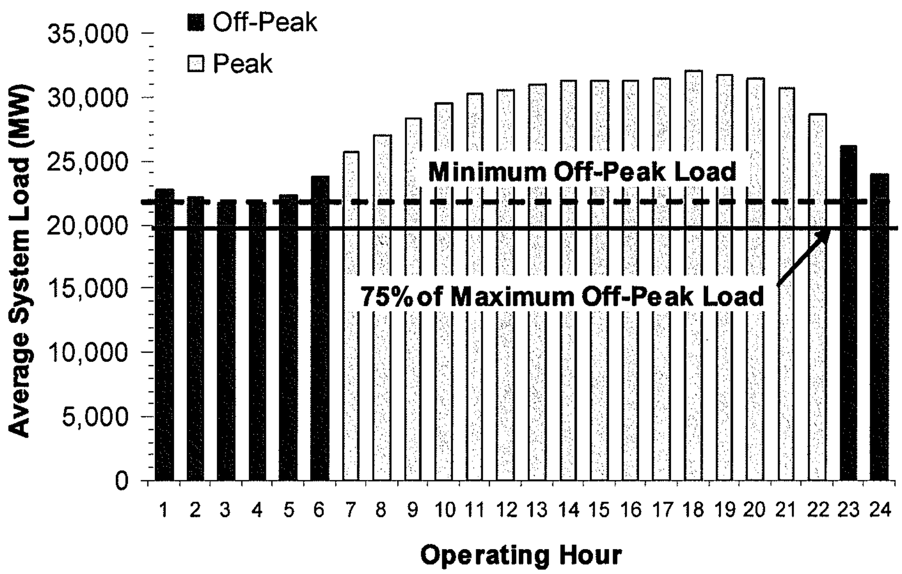
CAISO Operations staff has expressed concerns that they cannot issue "Restricted Maintenance Operations" notices sufficiency in advance of the time when Day Ahead schedules are developed, particularly on Sundays. In addition, virtually all stakeholders commenting opposed the concept of making the 95% scheduling requirement applicable for Sundays (or other off-peak hours) only when the CAISO issued a "Restricted Maintenance Operations" notice in advance of the Day Ahead market, due to the uncertainty and compliance issues this would create.

An alternative that has been suggested is to set a lower scheduling requirement for off-peak and/or weekend hours that would provide some degree of assurance against excessive under-scheduling on during off-peak and/or weekend hours. The specific level of a separate scheduling requirement for off-peak and/or weekend hours would be designed to reflect the minimum amount of load a typical SC serves during off-peak hours (which typically occurs at 2 or 3 a.m.). This level represents the "baseload" or minimum amount of energy each off-peak hour of each SCs' off-peak load that could be met without relying on any "load shaping" resources or products.

An example of this is provided in Figure 1, which shows the average system load for the CAISO system over a recent 12 month period. As shown in Figure 1, average system load is lowest in Hour Ending 4 (21,678 mw), which represents about 83% of the average system load during the highest off-peak hour (26,173 MW in Hour Ending 23). Thus, a typical SC with this load shape could meet at least 83% of its load for all off-peak hours by scheduling a constant amount of energy during each off-peak hour, as depicted by the dashed line in Figure 1. An off-peak scheduling requirement set in this way would allow SCs to meet the requirement through standard 8-hour blocks of energy without relying on any load-shaping resources or hourly bilateral purchases.

In recognition that of difference in the load shapes of different SCs, different seasons, and the "lumpiness" of the increments in which off-peak power may be available, the actual scheduling requirement for off-hours or weekends could be set at a somewhat lower levels, such as 75% of each SCs' Day Ahead load forecast, as depicted by the solid line in Figure 1.

Figure 1. Potential Off-Peak Scheduling Requirement Based on Average Hourly CAISO System Load



3. Additional exemption for minor levels of non-compliance during all hours.

This option would establish an additional exemption that would apply to all hours, under which any SC/UDCs which schedule no more than 3 MWh below the 95% requirement would be deemed in compliance with the 95% requirement.

An additional suggestion made in stakeholder comments was to also set some *de minimus* level (in MWh) by which any SC's schedule (by UDC area) might fall below the 95% requirement during all hours and not be deemed a violation. Suggestions for the specific level that would be considered *de minimus* ranged from 3-5 MWh.

Currently, there are about 70 combinations of LSEs and UDC areas to which such an exemption would apply each hour. Thus, the potential impact of a 3 MWh standard for *de minimus* violations could represent a 210 MWh reduction in required scheduling levels each hour. A 5 MWh threshold would equate to a maximum of 350 MWh.[2] Of course, these potential impact estimates represent a worst-case scenario in which all 70 combinations are simultaneously under-scheduled by the threshold amount. However, based on the potential cumulative effects of a 3-5 MWh allowance during all hours, the CAISO believes a 3 MWh threshold would accomplish the basic purpose of this threshold as well as a 5 MWh threshold, while limiting the potential cumulative impacts of such an allowance to a significantly lower level (210 MWh compared to 350 MWh).

Finally, it should noted that 3 MWh allowance would be applied in addition to the other allowances for limited violations of the 95% scheduling requirement described in the initial whitepaper. Thus, a potential violation of the 95% scheduling requirement would first be defined as follows:

1) Any hour in which the SC's day-ahead schedule for any UDC area was **<u>less than 3 MWh</u>** lower than 95% of the SC's day-ahead load forecast for the corresponding UDC area.

In addition, the tariff would further specify that the **<u>first six</u>** potential violations of the 95% scheduling requirement (determined based on the definition above) within **<u>each calendar month</u>** would not constitute a violation, provided that:

1) The SC's day-ahead schedule was at least 93% of its day-ahead load forecast within the UDC area

<u>or</u>

2) The SC's day-ahead schedule was not more than 25 MWh less than 95% of its day-ahead load forecast within the UDC area

[2] 70 SC/UDC combinations x 3 MWh = 210 MWh, and 70 SC/UDC combinations x 5 MWh = 350 MWh.

III. Further Steps

As noted in DMM's initial whitepaper, the process for developing any changes to Amendment 72 will be conducted on a relatively accelerated timeframe, so that any changes may be effective prior to the spring months when problems related to over generation tend to be highest. The specific steps remaining in this process, which were outlined in a November 30, 2006 Market Notice, include the following tasks:

- Submission of final stakeholder comments on straw proposal (January 5, 2007)
- Development of final CAISO recommendation to CAISO Board (January 10, 2007)
- Discussion and potential approval of Tariff modifications at CAISO Board Meeting (January 24-25, 2007)