UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

California Independent System Operator Corporation	))	Docket No. ER02-1656-000

COMMENTS OF THE CALIFORNIA INDEPENDENT SYSTEM OPERATOR CORPORATION REGARDING TECHNICAL CONFERENCE

Pursuant to the procedures established at the March 3-5, 2004 Technical Conference convened by the Staff of the Federal Energy Regulatory Commission ("Commission"), the California Independent System Operator Corporation ("ISO")[1] hereby submits its Comments regarding the matters discussed at the January 28-29 and March 3-5, 2004 technical conferences held in the captioned proceeding.

In support hereof, the ISO respectfully states as follows:

I. EXECUTIVE SUMMARY

The instant Comments set forth the ISO's positions (and in some instances revised proposals) regarding the following MD02 market design elements that were discussed at the January 28-29 and March 3-5 technical conferences: (1) the Commission's Flexible Offer Obligation ("FOO") proposal; (2) the Residual Unit Commitment ("RUC") process; (3) pricing for constrained output generators; (4) marginal losses; (5) Ancillary Services ("A/S") procurement; and (6) a simplified Hour Ahead market. As discussed in greater detail below, the ISO has retained certain of the elements that it originally

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[1] Capitalized terms not otherwise defined herein are defined in the Master Definitions Supplement, ISO Tariff Appendix A, as filed on August 15, 1997, and subsequently revised.

proposed in its Revised Comprehensive Market Design Proposal ("MD02 Proposal") that was filed on July 22, 2003 ("July 22 MD02 Filing") and has revised other elements of its MD02 Proposal. [2] Many of the revisions proposed herein resulted from the discussion at the two technical conferences and parties' written comments filed as part of the technical conference process. The instant Comments also seek to respond to stakeholder positions that the ISO has not incorporated into its revised proposal regarding the market design elements identified above.

The ISO proposes to implement a Day-Ahead ("DA") must offer obligation ("MOO") that will sunset on the earlier of January 1, 2008 or the date the CPUC's resource adequacy program is fully phased-in. A DA MOO is superior to FOO or a Real-Time ("RT") only MOO because either of the latter may result in (1) inefficient/inaccurate optimization of unit commitment and dispatch to manage congestion, (2) insufficient protection from locational and system market power, and (3) excess minimum load energy and/or on-line capacity in Real-Time ("RT"). The adoption of certain bidding rules applicable to long start time ("LST") and medium start time ("MST") units –which rules are specified *infra* -- would address some of the concerns identified in (3) above and make FOO a better alternative than mere retention of the existing RT MOO, but in no event would FOO result in a more effective and efficient commitment and dispatch of resources than a DA MOO.

[2] The ISO's proposed modifications to its Revised Comprehensive Market Design Proposal are set forth in Attachment A.

The ISO also is proposing numerous changes to the RUC proposal contained in the January 22 MD02 Filing. These changes are set forth in Section III.C.2 *infra*. The revisions include, *inter alia*, a $150 Availability Payment bid cap, non-rescission of the Availability Payment if a unit committed in RUC is dispatched, a total payment cap of $250 (Energy plus Availability Payment), a mechanism for mitigating local market power in the Availability Payment bid market, revised compensation for Start-Up ("SU") and Minimum Load ("ML") costs, and the procurement of capacity only (*i.e.*, not Energy) under RUC. The ISO's revised RUC proposal – which the ISO views as a non-severable package --reflects a delicate balance of various RUC objectives and of parties' divergent positions on the issue of RUC compensation. In particular, the ISO's revised proposal (1) recognizes that RUC capacity is different than A/S capacity, (2) includes sufficient measures to mitigate the exercise of local market power in the Availability market, and (3) addresses the concern that suppliers might submit excessively high bids in the DA market in order to avoid being selected in the integrated forward market ("IFM") so they can receive a RUC Availability Payment. The ISO's revised proposal accomplishes these objectives while providing fair compensation to suppliers for the RUC service being provided.

The ISO also proposes to revise its MD02 Proposal to permit constrained output generators ("COGs") to set the clearing price in the IFM, provided some portion of the COG unit's output is needed in order to serve load. COGs are defined as units that can only run at full output. Under the ISO's proposal, in the IFM, a COG unit will be treated as flexible in the dispatch run (*i.e.*, able to operate at any point between 0 and its P-max) and in the pricing run. However, in the RT market dispatch run, the COG unit will be treated as constrained so that the RT Economic Dispatch will either dispatch the unit down to 0 or up to its P-max (*i.e.*, a feasible dispatch). In settlements, the COG will receive the DA locational marginal price ("LMP") for its DA schedule (per MWh) and the RT LMP for its RT dispatch (per MWh). The ISO notes that its proposal differs from the proposal that the ISO submitted in its technical conference comments filed on February 24, 2004. In that regard, statements by certain parties at the March 3-5 Technical Conference and discussion at the April 5, 2004, Market Surveillance Committee meeting identified certain problems with the February 24 proposal which are resolved by the current proposal. The ISO's revised proposal complies with the Commission's finding in its October 28, 2003 "Further Order On The California Comprehensive Market Redesign Proposal." *California Independent System Operator Corporation*, 105 FERC ¶ 61,140 (2003) ("October 28 Order") that COGs should be eligible to set the clearing price in the DA market.

The ISO also is making certain revisions to its MD02 Proposal regarding A/S procurement. Specifically, the ISO will procure A/S in the DA IFM to meet 100 percent of its anticipated need, based on its load forecast for the next day, minus DA self-provision of A/S by Scheduling Coordinators ("SCs"). The ISO will not engage in any economic deferment of A/S procurement from the DA to a subsequent market. Thus, the ISO will procure A/S after the DA IFM only for post-DA changes in load forecast or system conditions. In response to stakeholder requests, the ISO now proposes to permit SCs who sell or self-provide A/S capacity to the ISO in the DA to substitute a different resource(s) in the HA, provided the substitute capacity meets the relevant A/S performance and locational requirements.

The ISO does not propose any changes to its MD02 Proposal regarding the treatment of marginal losses. Thus, the ISO proposes to use marginal losses for purposes of determining locational marginal prices ("LMPs"). The ISO proposes to re-distribute excess loss revenues in the Congestion Revenue Rights ("CRR") Balancing Account. This proposal is easier to implement than other alternatives, will make CRRs more valuable and, if there are surplus funds in the Balancing Account, such funds will flow back to loads (who pay for losses) by being paid to Participating Transmission Owners to reduce their transmission Access Charge.

Finally, as discussed in greater detail in Section III.G *infra*, the ISO is proposing to simplify the design of the HA market. The proposal essentially combines the HA market with the RT pre-dispatch process so that submitted HA changes to resource and inter-tie schedules and submitted supply bids that are cleared in the HA IFM will be issued binding pre-dispatch instructions. Thus, resources and inter-tie schedules that receive such pre-dispatches will have the same pre-RT certainty regarding transmission availability and schedule feasibility that they would have had under the ISO's July 22 MD02 Proposal. At the same time, resources that submit energy bids in the HA market and are dispatchable in RT will also be participants in the RT market and may receive additional RT instructions from the ISO based on their submitted bids. The approach proposed by the ISO is similar to the approach employed by the New York Independent System Operator, as was discussed at the March 3-5 Technical Conference. There would be no HA settlement. Resources issued RT pre-dispatch instructions as a result of the HA process will be settled at RT prices, will be guaranteed recovery of their bid prices through an uplift if necessary, and the pre-dispatch quantities will not be subject to any RT uninstructed deviation penalties. Compared to the HA proposal contained in the July 22 MD02 Filing, this simplified HA market proposal reduces complexity, implementation costs and ongoing operating costs for market participants as well as the ISO by: (1) moving to a two-settlement system instead of a three-settlement system; (2) reducing the number of optimization iterations by combining the HA process with the RT pre-dispatch process; and (3) enabling the ISO to move the close of the HA market much closer to RT, which all parties supported as a desirable feature. The simplified Hour Ahead market proposal also solves a problem which, up to now has had no satisfactory solution, namely, how to ensure that capacity procured in the Day Ahead RUC procedure is reserved for ISO Control Area load and not used to meet export demand in the Hour Ahead market.

II. BACKGROUND

On July 22, 2003, the ISO filed its Revised Comprehensive Market Design Proposal ("July 22 MD02 Filing") with the Commission. On October 28, 2003, the Commission issued its Order on the ISO's July 22 MD02 Filing. In its October 28 Order, the Commission approved in principle many of the conceptual market design elements submitted by the ISO. The Commission also provided guidance as to other issues and sought additional explanation of and information regarding other elements. The Commission emphasized that its October 28 Order provided guidance only and that the order was advisory in nature. Accordingly, the Commission stated that the parties would be permitted to revisit the issues addressed by the Commission *de novo* after the ISO files its comprehensive tariff. October 28 Order at P 2.

The Commission Staff convened a technical conference in Washington, D.C., on January 28-29, 2004. Issues discussed at the January 28-29 Technical Conference included, *inter alia*, (1) the Commission's FOO proposal; (2) the RUC process; (3) pricing for constrained output generators; (4) marginal losses; and (5) A/S procurement. The parties spent a significant amount of time addressing each of these matters. At the end of the technical conference, the Commission Staff directed the parties to file comments on the technical conference.[3]

On February 24, 2004, the ISO filed substantive comments setting forth the ISO's positions on the issues addressed at the technical conference and responding to specific arguments raised in other parties' comments. As a result of parties' comments and the discussion at the January 28-29 Technical Conference, the ISO submitted for the parties' consideration and for discussion at the March 3-5 technical conference several proposed modifications to July 22

[3] On February 17, 2004, the following parties filed comments: Northern California Power Agency ("NCPA"); Dynegy Power Marketing, Inc., El Segundo Power LLC, Long Beach Generation LLC, Cabrillo Power I LLC and Cabrillo Power II LLC ("Dynegy"); Sacramento Municipal Utility District ("SMUD"); Southern California Edison Company ("SCE"); Williams Power Company, Inc. ("Williams"); Mirant Parties ("Mirant"); Bay Area Municipal Transmission Group ("BaMX"); City of Santa Clara, California, Silicon Valley Power ("SVP"); California Public Utilities Commission ("CPUC"); Sempra Energy ("Sempra"); Duke Energy North America LLC and Duke Energy Trading Company ("Duke"); Powerex Corp ("Powerex"); Reliant Energy Power Generation, Inc. and Reliant Energy Services, Inc. ("Reliant"); California Department of Water Resources, State Water Project ("SWP"); and the City of Redding California ("Redding").

MD02 Proposal. The proposed modifications included (1) a revised proposal for compensating RUC resources that attempted to balance several legitimate objectives and concerns, (2) a requirement that RUC capacity serve ISO-Control Area load, (3) revised treatment of COGs, and (4) slight modifications to the ISO's A/S procurement policy. In its February 24 Comments, the ISO also (1) responded to specific comments submitted by the parties, (2) described its operational concerns with the FOO proposal, (3) submitted additional support for its proposed treatment of marginal losses and the need to procure energy from imports in the RUC process, and (4) identified some concerns and provided some initial ideas regarding simplification of the Hour Ahead market (for discussion at the March 3-5 technical conference).

At the March 3-5 Technical Conference, the ISO explained its revised proposals to stakeholders and discussed its positions on the other issues from the January 28-29 Technical Conference. In addition, the ISO sought stakeholders' input regarding the possible simplification of the ISO's proposed Hour Ahead market and described the market power mitigation elements of its MD02 Proposal. The Commission Staff also provided a conceptual presentation of two market design elements – a scarcity pricing mechanism and a locational capacity obligation. The Commission Staff also established a schedule for the ISO to provide additional information to stakeholders and for stakeholders to provide input to the ISO regarding the structure of the market design elements discussed at the March 3-5 Technical Conference. Further, the schedule provided for an opportunity for the ISO to reply to parties' comments and specify any further modifications to its MD02 Proposal.

Pursuant to the schedule established at the March 3-5 Technical Conference, the ISO posted the following documents to its website on March 19, 2004: (1) *Potential Design of a Simplified Hour Ahead Scheduling Procedure – Initial Discussion Draft* ("Hour Ahead Discussion Draft"); and (2) *CAISO Answers to Questions Regarding the CAISO's Residual Unit Commitment ("RUC") Proposal and Other Related Questions from the FERC Technical Conference on MD02 (March 3-5, 2004 in San Francisco).* In the Hour Ahead Discussion Draft, the ISO identified some revisions that could be made to the proposed Hour Ahead Market that could simplify the market design, move the Hour Ahead Market closer to Real Time, and result in cost savings. On April 2, 2004, the ISO posted to its website a document entitled *CAISO Proposed Revision to its MD02 Market Power Mitigation Provisions* ("Market Power Mitigation White Paper"). In the Market Power Mitigation White Paper, the ISO identified some modifications that it was willing to make to the market power mitigation measures which the ISO had proposed in its July 22 MD02 Filing.

Several parties submitted informal comments to the ISO regarding one or more of the documents that the ISO posted to its website on March 19 and April 2, 2004.[4] In the instant comments, the ISO (1) submits the ISO's proposed modifications to its MD02 Proposal, (2) responds to parties' comments submitted

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[4] The following parties submitted comments to the ISO: Mirant; Powerex; SMUD; SVP; SCE; SWP; the CPUC; California Municipal Utilities Association ("CMUA"); the City and County of San Francisco ("CCSF"); West Coast Power and Williams Power Company, Inc. ("WCP/Williams").

subsequent to the January 28-29 and March 3-5 technical conferences, and (3) provides additional support for those elements of the market design discussed at the technical conference that the ISO is not proposing to revise.

III. COMMENTS

A. Fundamental Assumptions

The ISO's recommendations contained herein pertain to specific individual elements of the ISO's MD02 Proposal. At the same time, the ISO's MD02 proposal constitutes an integrated market design proposal that is comprised of elements that complement and work with each other. While the ISO is always reluctant to propose changes to various elements of its market design in isolation from the rest of the design, the ISO nonetheless believes that the Commission can rule on the issues discussed herein provided it understands the context in which these proposals are made.

First and foremost, the ISO's proposals are based on certain assumptions regarding resource adequacy. As explained further below, resource adequacy is a necessary and critical prerequisite to the successful long-term stability of California's electricity sector, key components of which are a reliable, open-access transmission grid and well-functioning spot markets based upon the ISO's MD02 Proposal. At present, the California Public Utilities Commission ("CPUC") anticipates full implementation of a resource adequacy requirement (at least for the State's Investor Owned Utilities) by 2008, with implementation beginning to be phased in beginning in 2006. Second, the ISO offers its views on the appropriate role of market power mitigation measures under a market that is resource adequate. As noted above, the Commission's October 28 Order acknowledged the inexorable link between resource adequacy and market power mitigation. If such resource adequacy requirements are structured around the principles outlined below, the ISO believes the following assumptions will apply under MD02 after resource adequacy is fully phased in:

1. All load-serving entities will procure sufficient resources in the long-forward market (*i.e.*, before the Day-Ahead Market) so as to satisfy the *planning reserve* requirements established by their Local Regulatory Authority. In the case of the Investor Owned Utilities, that requirement is the 15% planning reserve margin established by the CPUC in its January 22, 2004, order in the Procurement Proceeding.
2. The obligations and responsibilities that are embodied in the ISO's proposed Day-Ahead Must Offer Obligation would apply to all resources procured under the established resource adequacy requirements. Therefore, all such resources would be available for possible commitment through the ISO's Day Ahead Integrated Forward Market and RUC mechanism. Conversely, resources not procured or under contract pursuant to such requirements would not be obligated to make themselves available to the ISO in the Day-Ahead timeframe. These resources could, however, voluntarily participate in the ISO's Day-Ahead Market if they so choose.
3. All resources, whether operating under the resource adequacy requirements or not, are obligated to make all available capacity available to the market in Real-Time. Stated differently, a minimal version of the Commission's existing real-time Must-Offer Obligation would apply as a necessary means to mitigate physical withholding from the market.[5] 4. The resource adequacy requirements will be structured in a manner consistent with, and that support, the ISO's specified locational and operating requirements. Specifically, as further detailed below, the resource adequacy requirements will incorporate both the ISO's *deliverability* requirements and any other

[5] As envisioned by the ISO, a minimal real-time MOO would require all resources that are operating and have capacity that is unloaded and not otherwise committed (*e.g.*, for A/S) to offer energy from that capacity into the RT market (with appropriate accommodation for use-limited resources). This minimal RT MOO would not include a DA waiver process. Thus, in contrast to today's real-time MOO or a FOO, long-start-time units not subject to the DA MOO would be able to decide whether to operate or shut down without requesting permission from the ISO. However, for reliability purposes, under extreme conditions (such as major unplanned transmission outages) the ISO would have the authority to commit such units within the ISO Control Area on a DA basis even though they may not be subject to a DA MOO. Such events would be extremely rare.

requirements necessary to reliably serve load on the grid. Such other requirements could include, if not already incorporated into the ISO's deliverability requirements, locational capacity requirements.

5. Appropriate market rules will be established so as to prohibit *physical* and *economic* withholding from the market and to prevent other anomalous market behavior. The resource adequacy requirements will serve as the primary means to prevent physical and economic withholding from the market. As stated in item (2) above, resources procured under the resource adequacy requirements will be made available to serve load, including for possible commitment by the ISO in the Day-Ahead Market and RUC process, thereby substantially eliminating opportunities for *physical* withholding. Furthermore, because such resources will be presumably under contract to load-serving entities and thus available at pre-negotiated prices, load-serving entities will be substantially hedged from exposure to spot market prices, thus reducing the likelihood of *economic* withholding.
6. Notwithstanding the presumption in item (5) that resource adequacy will substantially address market power concerns, the ISO nonetheless believes that appropriate *local market power* measures are a necessary feature of the market going forward. Such measures are necessary to address local market power concerns when unforeseen and unpredictable events occur, such a transmission line or generator outage. Persistent local market concerns, such as those that exist today with Reliability Must-Run ("RMR") Generation, will be addressed through either a continuation of RMR contracts or, preferably, a load-serving entity's locational capacity contract with the affected resource. The ISO acknowledges that, during a transitional phase (yet to be defined), the ISO may have to continue using RMR contracts to mitigate such persistent local market power concerns. Finally, the ISO recommends retention of a damage control price cap as a appropriate safeguard and backstop against market power.

The ISO assumes that the above framework can and will exist and work in the market in a post full implementation of resource adequacy environment. However, should any of these conditions not exist, the ISO acknowledges that appropriate modifications to the market design may be appropriate. For example, prior to the full implementation of a resource adequacy requirement, it may be appropriate to provide additional compensation (i.e., above that for start-up and minimum load energy) to those resources committed, on a Day-Ahead basis, by the ISO to serve ISO forecast load. The ideas and recommendations outlined below are offered in this context.

Consistent with the Commission's directive in the October 28 Order, the ISO will make a compliance filing no later than sixty days after the CPUC issues a final order in its ongoing Procurement Proceeding. That filing will address the necessary changes to the ISO's MD02 proposal resulting from the CPUC's final decision in the procurement proceeding. In particular, the ISO's compliance filing will address the need for appropriate changes to the ISO's proposed market power mitigation measures in light of the CPUC's actions regarding resource adequacy.

Finally, it is the ISO's understanding that the CPUC intends to conclude the ongoing procurement proceeding workshop process by the end of May so that the CPUC can then issue an order regarding the issues discussed in the resource adequacy workshops sometime this summer. At present, the ISO is hopeful that the CPUC will take action this summer and decide the remaining critical threshold policy issues regarding utility procurement. Moreover, the ISO remains optimistic that the CPUC's final decision regarding procurement will be consistent with and support the ISO's main recommendations. Specifically, building off of its earlier order to adopt a 15% planning reserve margin, the ISO urges the CPUC to adopt clear counting and load forecasting conventions and methodologies, as well as clear reporting and compliance measures. In addition, the ISO urges the CPUC to adopt and support an explicit requirement for the IOUs to make the resources they procure available to the ISO in a manner that supports reliable and efficient grid operation. Most importantly, the ISO urges to CPUC to adopt the specific deliverability criteria, as proposed by the ISO in the Procurement Proceeding. Such a deliverability test, or larger resource adequacy framework, must also include a requirement for load serving entities to satisfy the ISO's specific locational capacity requirements; locational capacity requirements that arise out the need to serve load in transmission-constrained pockets on the grid. Absent timely action on these matters, the ISO may be forced to consider and propose enhancements to its MD02 proposal in order to satisfy the above stated objectives.

B. The Must Offer Obligation Under MD02

In its July 22 MD02 Filing, the ISO proposed to retain the existing RT Must Offer Obligation ("MOO") for suppliers, with appropriate accommodations for use-limited resources such as hydro and emissions-constrained generators. In addition, the ISO proposed to implement a DA MOO that would require Must Offer resources to participate in the DA IFM and RUC processes. In the October 28 Order, the Commission rejected the ISO's proposal to extend the RT MOO to the DA market. October 28 Order at P 73. As an alternative to the ISO's proposal, the Commission offered for consideration a blending of the RT MOO with the proposed DA MOO. *Id.* The Commission's so-called Flexible Offer Obligation ("FOO") would give suppliers the option to fulfill their Must Offer Obligation by bidding into either the DA market or the RT market. *Id.* at P 74.

At both the January 28-29 and March 3-5 Technical Conferences, parties discussed the FOO, and the Commission Staff clarified how the FOO was intended to function. In the ISO's February 24, 2004 Comments and at the March 3-5 Technical Conference, the ISO offered conditional support for the FOO as a superior alternative to RT MOO, but identified a number of operational concerns regarding the FOO mechanism. Based on the discussion at the March 3-5 technical conference, parties generally found FOO to be problematic relative to a DA MOO. However, what may not have clear at the technical conference is the observation that the problems associated with FOO are also problems with a RT-only MOO. However, upon further consideration, the ISO has concluded that although FOO is problematic relative to a DA MOO, it is clearly superior to a RT-only MOO.

For the reasons stated above, the ISO proposes that, when MD02 is implemented, the DA and RT Must Offer Obligation that the ISO originally proposed in its July 22 MD02 Filing be implemented on a transitional basis until the earlier of January 1, 2008 or the date on which California's resource adequacy requirements are fully effective. In other words, a Commission-imposed DA MOO would be in effect for a very short transitional period, a period in which the State's resource adequacy program will already be partially implemented. In the event the Commission rejects a transitional DA MOO, then the Commission should approve implementation of the FOO (subject to the provisions and clarifications discussed *infra*) on a transitional basis rather than simply retain the existing RT MOO. Once resource adequacy is fully implemented, only a minimal Real Time MOO would apply. This is appropriate to protect against physical withholding. The minimal RT MOO would apply to all participating generators whether or not they have resource adequacy contracts.

1. The Commission Should Approve Implementation Of The DA/RT Must Offer Obligation On A Transitional Basis

Given the market efficiency and implementation problems associated with FOO and with a RT-only MOO (*see infra* Section III.B.2), the ISO believes that its original proposal for both a DA and a RT must offer obligation is the most appropriate approach, with the qualification that any DA MOO would sunset on the earlier of January 1, 2008 or the date the CPUC's resource adequacy requirement is fully phased-in. In particular, a DA/RT MOO is consistent with the objectives and the design of the comprehensive MD02 proposal and is superior from an operational and market efficiency standpoint to FOO or a RT-only MOO. In contrast, the proposed implementation of the FOO or a RT-only MOO under MD02 may introduce unavoidable market flaws, which could lead to (1) inefficient/inaccurate optimization of unit commitment and scheduling to manage congestion, (2) insufficient protection from locational and system market power, and (3) inefficient/inaccurate unit commitment decisions resulting in excess minimum load energy and/or on-line capacity in Real Time. Perhaps most importantly, a DA MOO provides the ISO with the means to both *reliably* and *efficiently* commit the resources necessary to serve the next day's load. As noted previously, on a long-term basis, the ISO anticipates that such resources will be made available to the ISO pursuant to the rules and obligations established under a resource adequacy requirement. Therefore, the ISO sees any Commission-imposed DA MOO as only a temporary and necessary mechanism until resource adequacy rules are in place in California.

A fundamental purpose of the MOO, be it DA MOO, FOO, or RT MOO, is to protect consumers from the physical withholding of supply resources, thereby promoting a stable and competitive market. In RT, the possible effects of physical withholding of supply resources, namely higher prices and the potential for curtailment of load, are primarily due to demand being largely inflexible. Under the ISO's current market design, *i.e.*, the context in which the Commission first enacted the RT MOO, there is less concern about having a DA MOO than there will be under MD02. This is because the ISO does not have a formal unit commitment process (like the unit commitment processes in-place in the eastern markets) or a DA Energy market. The absence of a forward energy market and the inability of the ISO to commit units (other than RMR units) on a DA basis have long been recognized as deficiencies of the ISO's current design. It was only with the implementation of the Must Offer Waiver ("MOW") process that the ISO was able to establish a crude and inefficient form of unit commitment process. The ISO quickly recognized that MOW was necessary in order to relieve Must Offer resources that have long start-up times from the obligation to be on-line all the time. The overall structure of a RT-only MOO combined with the MOW process has at least been workable, but it has not been ideal.[6]

[6] The ISO acknowledges that the RT MOO and the MOW process have not functioned flawlessly or without controversy. Indeed, the ISO has recently concluded an extensive stakeholder process in which the parties identified needed improvements to the MOW process, several of which will be captured in Tariff Amendment No. 60.

The comprehensive design proposed in the ISO's July 22 MD02 Filing will dramatically change the context for the MOO because it introduces formal unit commitment optimizations and a forward energy market. From the beginning, one of the foremost objectives of the MD02 design has been consistency in the rules and procedures for the scheduling of transmission and generation resources and the setting of prices across market time frames (*i.e.*, from DA through RT). Although a RT-only MOO or a FOO may address the problem of physical withholding of supply in RT, as discussed in greater detail below, the absence of a DA MOO makes it difficult for the ISO to achieve consistency across market time frames and undermines the effectiveness of local market power mitigation (LMPM) in the forward markets.

In order to understand the importance of a DA MOO to the comprehensive MD02 design and the negative impacts the lack of a DA MOO will have under such market design, it is important to review the ISO's proposed DA "pre-IFM" runs that are performed after Scheduling Coordinators ("SCs") have made their DA submissions, but prior to the actual running of the DA IFM. The pre-IFM are based on the ISO's load forecast and are used to determine the optimal mix of available supply resources (*i.e.*, the optimal unit commitments) which are usedto meet the next day's expected operating requirements, including system load, locational needs, and required reserves. Further, these runs are used to determine the need for RMR dispatch and for market power mitigation at both the system and local levels. One must consider the differences among the sets of resources that are viewed as being available in (1) the DA pre-IFM runs, (2) the actual running of the DA IFM, and (3) the DA RUC process, and compare such against the larger set of resources that are ultimately subject to a MOO in RT (whether under FOO or a RT-only MOO).[7] All of the problems discussed below that will arise in the absence of a DA MOO are rooted in the fact that the value – as expressed in bids – of the resources that are required to be available in RT may not be accurately or consistently reflected across this sequence of DA optimizations.[8] The first instance in which problems arise due to the lack of a DA MOO is the result of discrepancies between the set of resources that is taken as available in the pre-IFM runs versus the smaller set of resources that is actually available in the running of the DA IFM. Second, problems can arise because of discrepancies between the set of resources optimized in the DA RUC process versus the larger set of resources that is required to be available in RT. These problems are eliminated if resources subject to a MOO are not allowed to opt out of the DA process.

To be more concrete, while price determination in the actual IFM run will generally be based on elastic demand (*i.e.*, demand bids), the pre-IFM locational market power mitigation ("LMPM") and post-IFM RUC processes both optimize resources to serve an inelastic demand forecast. With DA MOO, both the pre-IFM LMPM and the RUC processes optimize the unit commitment solution based

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[7] For the purpose of this discussion, it is sufficient, and much simpler, to consider only the comparison between DA and RT, rather than incorporate the HA market into the explanation. The same points described in this section will apply in the context of the HA market as well, regardless of whether the HA market is structured as in the July 22 MD02 Filing or in the simplified form proposed in the current comments.

[8] The outcomes of the successive steps in the DA pre-IFM, IFM and RUC processes will depend on how each step treats those Must Offer resources that opt out of the DA process and what assumptions it makes about their bids.

on the same universe of resources (and their associated bids) that will be available for commitment and dispatch in the IFM and will be available in RT. This assures that LMPM will be applied to the appropriate resources for the appropriate portions of their capacity, and that the outcomes of the three sequential unit commitment runs (pre-IFM, IFM and RUC) will be consistent. As illustrated in the following sections, the absence of a DA MOO introduces inconsistencies between these markets, which can reduce efficiency by causing under-scheduling of load in the DA market and/or excessive capacity commitment. Further, the absence of a DA market can undermine the effectiveness of LMPM by inadequately mitigating units that have local market power and can set prices in the IFM.

a. Inefficient Unit Commitment

The ISO offers the following example to show the inefficient unit commitment that will result from lack of a DA MOO: In the absence of DA MOO, units A, B and C bid into the DA market, while units D and E, both subject to FOO or RT-only MOO, do not. Under the terms of the FOO, as clarified by the Commission staff at the Technical Conferences, the assumption of D and E opting out of DA is that D and E are self-committed and covering their own start-up and minimum load ("SU/ML") costs. Therefore, the unit commitment optimizations do not consider the SU/ML costs of D and E. The pre-IFM runs utilize the load forecast, view all five units as available, and will likely include D and E in the optimal commitment since their SU/ML costs are essentially zero.

Suppose units A, B, D and E are identified as the optimal unit commitment to meet the next day's needs.

Next, the actual IFM is run based on load schedules and bids, but D and E are no longer available. Because unit C was dropped from the commitment pool in the pre-IFM run, the IFM must clear using only units A and B. To the extent there is enough price-taker load in the IFM, units A and B could be scheduled at their P-max levels no matter how high their bid prices at the top of their operating ranges. Alternatively, if load is price responsive, the most likely result will be that less load will clear the DA IFM than would have cleared if the full pool of must-offer units was in the market. One might consider retaining unit C in the commitment pool as a way of addressing this concern, but then the IFM will incur unit commitment costs for units A, B and C when in fact the self-committed units D and E are known to be self-committed for RT. Under this approach, the market incurs more SU/ML cost liability than would have been necessary if the pre-IFM and the IFM runs would have utilized the same pool of resources. Under a DA MOO, if the pre-IFM run committed units A, B, D and E, then all of these units would be available in the IFM run to meet scheduled and bid demand.

b. Deficient or Inaccurate Local Market Power Mitigation

Not having a DA MOO can also result in insufficient and/or inaccurate local market power mitigation. To illustrate this point it is helpful to review the design of the pre-IFM process, which consists of a number of passes. Pass 1 commits units and then dispatches the committed resources (A, B, D and E in the above example) to meet the load forecast, enforcing only the competitive constraints.[9] Pass 3 of the pre-IFM process re-dispatches the same set of resources, again using the load forecast but this time enforcing all constraints of the Full Network Model.[10] Because units D and E did not submit energy bids Passes 1 and 3 must assume bids for them. Two plausible and contrasting assumptions are cost-based bids and bids at the $250 bid cap. Suppose the pre-IFM process assumes $250 bids.[11] Even with this assumption, suppose that unit D is so effective in relieving a particular constraint that Pass 3 utilizes it instead of units A and B. In determining the need for LMPM, the pre-IFM process will see that unit D is needed to relieve the constraint and has local market power, and will apply appropriate mitigation (*i.e.*, anticipating that unit D will be needed at the same operating level in RT when the full amount of the load forecast is realized). In the process, units A and B will not even be considered for mitigation because they were not re-dispatched in Pass 3 to a higher operating level than they had in Pass 1. However, when the actual IFM is run, units D and E are no longer available, so units A or B will likely be needed to clear congestion and will be dispatched above their Pass 1 operating levels. This result has two perverse features. First, it uses resources that are less effective in mitigating local congestion than other resources that are known to be available in RT but cannot be scheduled in DA because they opted out. Thus the total MW dispatched from

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9 As discussed in the July 22 MD02 Filing, the set of competitive constraints may initially consist of the constraints that are enforced in today's zonal market design, *i.e.*, the inter-ties, Path 15 and Path 26.

10 Pass 2 is the market impact test for the System AMP, which is not immediately relevant to the point of this discussion because the focus is on local market power rather than system market power.

11 In fact this may be the most prudent assumption to make. One likely reason a Must Offer unit may decide to opt out of the DA market is to preserve as much pricing flexibility as possible right up to RT. It would therefore be risky for the DA mitigation procedures to assume more competitive bids for such resources.

A and/or B will be higher than the MW needed from D. Second, although A and/or B are needed in the IFM to resolve non-competitive constraints, the pre-IFM Pass 3 did not recognize this because it included the RT-MOO units D and E. Thus A and B were not mitigated for local market power, then were dispatched by the IFM along unmitigated bid curves to relieve local constraints.

Absent a DA MOO, one possible response to this problem is to rely on load-serving entities to submit sufficient price responsive demand bids to protect against the price impacts of potentially under-mitigated resources, which will likely result in more procurement being deferred to real time. Another possibility is for the ISO to mitigate the "entire" residual bid range (*i.e*. the unselected portion of the bid curve after the first set of competitive constraint passes of the Pre-IFM process (Pass 1 and 2) of units that have offered into the DA IFM and are subject to local market power mitigation.[12] In other words, the ISO would mitigate units A and B in the example anyway, anticipating that units D and E will not be included in the actual IFM run. The latter approach would essentially punish units that elect to offer into the DA IFM, whereas the former approach would result in higher real time market volumes, both of which would be undesirable outcomes.

c. Potential for Over-Generation and Excess On-Line Capacity

As discussed in the ISO's February 24 Comments, a need for selective "pre-emptive" waivers is inherent in all three MOO options, DA, FOO, or RT. Regardless of whether a resource bids into DA or requests a waiver of its MOO,

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[12] The LMPM procedures submitted in the July 22 MD02 Filing call for mitigating only the incremental dispatch needed to resolve congestion on non-competitive paths.

it may be appropriate for the ISO to issue a waiver to a resource that is subject to the MOO because (1) its capacity is not needed, or (2) its minimum load energy cannot be reliably accommodated on the grid. In a DA MOO design, all MOO resources that are not self-committed or committed by the ISO in either the IFM or RUC are effectively granted a waiver for the next day. In so doing, the RUC Security Constrained Unit Commitment ("SCUC") can identify units suitable for waivers due to either excessive minimum load issues or expensive commitment or capacity costs.

Under a FOO or RT MOO design, the pool of resources used in the DA RUC will include some Must Offer units that did not appear in the DA IFM and, therefore, have not submitted bids by the time DA RUC is run. Because RT FOO units are considered as self-committed capacity due to their MOO obligation to be on-line in RT, they are not eligible for SU/ML cost compensation and, as such, are assigned $0 values for their SU/ML bids in RUC. In addition, the RUC availability bid is set to $0 for RT FOO units because only resources that offer into the IFM are eligible to bid and receive the availability payment in the RUC process.

Because RT FOO units are considered as having a $0 bids in the RUC optimization, they may be the least expensive resources to clear against the residual capacity requirements. As such, RT FOO units may be committed in lieu of (1) resources that had bid into the DA IFM with non-zero SU/ML bids and were not committed to serve self-scheduled and bid load, or (2) available un-loaded capacity on resources already committed in the IFM with non-zero RUC availability bids. This may lead to excessive SU/ML costs and/or excess minimum load generation and on-line capacity than would otherwise be required or optimal.

d. Additional Reasons Supporting Approval Of A DA MOO

Adoption of a DA MOO also would provide consumers and state policy makers with increased confidence that California markets will not be subject to market manipulation through physical withholding immediately upon implementation of a new market design. As the Commission is well aware, there is significant skepticism regarding and opposition to implementation of LMP in California. A Day-Ahead MOO could help allay stakeholder and State policy maker concerns that the new market design, including LMP pricing, will be problematic and susceptible to market manipulation. A Day-Ahead MOO would bring necessary stability to the market as the CAISO transitions to LMP and would help to restore the State's confidence in markets. Further, a hard sunset provision would address the concerns expressed by some stakeholders that a forward market MOO would be used by LSEs as a substitute for long-term contracting.[13]

The ISO recognizes that the Commission might have concerns about imposing even a transitional Day-Ahead MOO on resources that do not have a contract with a LSE that was negotiated pursuant to the CPUC's resource adequacy program. In that regard, the Commission might be concerned about

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[13] Given that the CPUC has approved a resource adequacy program that LSEs must implement on a phased-in schedule beginning in 2006, the ISO does not believe that this is a significant concern.

the opportunities for such resources to earn revenues adequate to cover their going-forward fixed costs. However, there are numerous opportunities for suppliers to earn capacity payments (and other revenues) that make up for the lack of a fully phased-in resource adequacy program. Accordingly, the lack of a fully phased-in resource adequacy program should not preclude approval of the proposed interim Day-Ahead MOO.

First, as part of the ISO's revised RUC proposal, the ISO is proposing to provide a non-rescindable availability payment to suppliers per MW of capacity that is committed in RUC. Suppliers can submit Availability Payment bids of up to $150/MW.[14] Second, the ISO already provides – and is proposing to continue to provide – capacity payments to suppliers via a number of mechanisms. For example, in 2003, the ISO paid out approximately $ 282 million dollars in capacity payments to RMR units and approximately $156 million in A/S payments. Indeed, the ISO offers more options for forward market A/S capacity payments than the Eastern markets. Finally, the ISO notes that, in Tariff Amendment No. 60, the ISO will be proposing measures that will provide additional compensation to Must Offer generators that are denied waivers, namely changes to the methodology for calculating Start-up ("SU") costs and Minimum Load Cost Compensation ("MLCC") and permitting units that are denied a waiver to retain their MLCC revenues when they provide Ancillary Services. These revenue opportunities, in conjunction with the fact that the

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[14] The ISO notes that the proposed Availability Payment bid cap is higher than the Ancillary Services bid caps in most of the eastern markets. For example, PJM and ISO New England have $100 bid caps for Regulation.

DA/RT MOO will be in effect for a only a short period, support approval of the DA/RT MOO on a transitional basis until January 1, 2008.

WCP/Willliams argue that if any DA obligation is imposed, the damage control bid cap should be raised to $1,000MWh. WCP/Williams comments suggest that a $250 bid cap is not sufficiently high to ensure that a DA MOO does not pre-empt them from pursuing more profitable bilateral opportunities outside of California. The ISO offers the following response to WCP/Williams. First, in the past two and a half years, prices throughout the Western Electricity Coordinating Council ("WECC") have been well below $250/MWh in all hours of the year. Further, a well-functioning resource adequacy program within California should further help to ensure that this price stability continues into future years. Second, suppliers can submit bids above $250/MWh to the ISO's energy markets subject to cost justification if dispatched (*i.e.,* the bid cap is a soft bid cap). Third, the $250/MWh soft bid cap is not applicable only to sales in California; rather, the $250 bid cap serves as a maximum price for all sales in the WECC spot markets. *See California Independent System Operator Corporation,* 100 FERC ¶61,060 at P 49 (2002). Under these circumstances, it is difficult to see how a $250 soft bid cap in the ISO Day Ahead energy market prevents suppliers from pursuing more profitable opportunities elsewhere in the WECC. For these reasons, it is wholly inappropriate to raise the bid cap to $1,000MWh if the Commission approves a DA MOO.

2. The Commission Should Approve FOO, Subject To The Clarifications Specified Below, If The Commission Rejects The ISO's DA/RT MOO Proposal

In the event the Commission does not approve the ISO's proposal for a transitional DA/RT MOO, then the ISO requests that the Commission approve the FOO mechanism, subject to the clarifications and requirements specified below, rather than simply retain only the existing RT MOO. Although FOO is a sub-optimal solution compared to the DA MOO, with the "fixes" described below, FOO would be a better alternative than the RT-only MOO.[15] The ISO has several operational concerns regarding the functioning of a FOO. These concerns, which need to be addressed and resolved satisfactorily in order for a FOO to function effectively, are described below.

In their written comments filed prior to the March 3-5 technical conference, certain parties alleged that FOO is unnecessary (Powerex Comments at 6) and that FOO should only be a temporary measure pending implementation of a comprehensive resource adequacy program (Duke Comments at 2).[16] As indicated above, a fundamental assumption underlying the ISO's proposed

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[15] In written comments filed on February 17, 2004, NCPA claimed that the ISO had backpedaled, and it was uncertain whether FOO applies to Metered Subsystems ("MSS") entities. CMUA has requested that the ISO clarify that any variation of the Must Offer Obligation will not be applied to MSS entities and entities outside of the ISO Control Area. As the ISO indicated in its Comments filed on February 24, 2004, the ISO does not know whether or not the Commission intended FOO to apply to MSS entities. FOO is the Commission's proposal not the ISO's proposal. The ISO notes that MSS entities and entities outside of the ISO Control Area *per se* are not subject to the existing Must Offer Obligation. Further, in the MD02 Filing, the ISO proposed to exempt MSS entities from the RT and DA Must Offer Obligation. The ISO does not propose herein to make MSS entities and entities outside of the ISO Control Area subject to a Must Offer Obligation.

[16] In its comments filed on February 17, 2004, Reliant argued that FOO should not be implemented in isolation without a properly designed resource adequacy program. Reliant Comments at 1. Williams also argued that FOO should be contingent upon the development of a resource adequacy mechanism that compensates suppliers for the provision of capacity in the Day Ahead time frame. Williams Comments at 6. As the parties are well aware, the California Public Utilities Commission approved a resource adequacy program at its January 22, 2004 meeting. Further, its White Paper on Wholesale Power Market Platform ("White Paper") issued on April 28, 2003 in Docket No. RM01-012, the Commission placed the responsibility for developing a resource adequacy plan solely with the states. Thus, the Commission should not condition FOO on the State's implementation of a resource adequacy program that contains specified mechanisms that certain parties desire.

market design is that the CPUC's resource adequacy program will be fully phased in by January 1, 2008 and, under that program, suppliers with resource adequacy contracts will be under an obligation to bid into the DA market. Accordingly, as with the DA/RT MOO, the ISO would propose to sunset any FOO mechanism effective on the earlier of January 1, 2008 or the date the CPUC's resource adequacy program becomes fully effective.

Upon termination of the DA/RT MOO or FOO, the ISO proposes to require that all units that are on-line (*i.e.,* operating at minimum load or higher) be subject to a RT MOO, with appropriate accommodation for use-limited resources. Further, the ISO would need to have the ability to commit, in the forward market RUC process, PGA resources that have opted out of the Day Ahead market in exigent circumstances (*e.g.* major transmission outages) where having such units on-line is critical to maintaining system reliability. The costs of such commitments could be settled as an out-of-market call. The ISO expects that under a well-designed fully functional resource adequacy program, the need to commit units that have not offered into the Day Ahead market will be very rare. The ISO stresses that a RT MOO is not a resource adequacy issue. The primary purpose of a RT MOO is to prevent physical withholding of supply resources. Accordingly, it is appropriate that some form of RT MOO become a permanent feature of the market. That should not impose an undue burden on suppliers because, as the Commission has recognized on numerous occasions, if suppliers have available capacity in RT, they should have no problem bidding it into the ISO's RT market because, at that point in time, they have no other opportunities to sell the energy elsewhere. *See San Diego Gas & Electric Company v. Sellers of Energy and Ancillary Services into Markets Operated by the California Independent System Operator and the California Power Exchange,* 95 FERC ¶ 61,115 at 61,355-56 (2001).

Pending the full implementation of resource adequacy (and absent Commission approval of a DA MOO), the ISO believes that FOO could be a useful (although imperfect) tool to help the ISO maintain reliable grid operations. As noted above, the ISO has identified some potential operational concerns with the FOO that need to be addressed and satisfactorily resolved.[17] The main concern arises in relation to long-start-time units ("LSTs") that do not bid into the DA market.[18] Under the FOO mechanism proposed by the Commission, these units would be required to be on-line in Real-Time for all 24 hours of the following day, operating at least at minimum load. During off-peak hours, this could result in an over-generation situation with too many units being on. In particular, the ISO is concerned that too many units would be running at Minimum Load late at night or early in the morning (when demand is low) if all of the units that did not participate in the DA market show up in Real-Time in every hour of the next day. In contrast, if a LST unit that is shut down does participate in the DA IFM, the ISO can develop a 24-hour, shaped schedule for the resource, keeping it off-line

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[17] It should be noted that, although these concerns are expressed with respect to the inferiority of FOO relative to a DA MOO, these same concerns (and more) apply to the efficacy of a RT MOO relative to a DA MOO. The CAISO believes FOO, as modified below, is a more appropriate obligation than a RT-only MOO because it requires a two step approach for units to be exempt from the RT MOO. Specifically, a unit must (1) first offer into the forward IFM and(2) not be committed in either the IFM or the RUC procedure. A RT-only MOO only requires the second step, and then only the RUC part of that step.

[18] For the purposes of the FOO, the ISO proposes to define LST units as those which require five hours or more start-up time. The rationale for this definition is set forth below.

during low-load hours to avoid over-generation conditions and bringing it on-line when the ISO expects to need the unit. In order to avoid over-generation problems in these circumstances, the ISO will need to incorporate into the RUC procedures mechanisms for (1) granting waivers to FOO resources that have opted out of the Day Ahead market and are not needed to be on-line and (2) specifying the hours of the next day when the ISO expects that such units will need to be available in Real-Time, regardless of whether the resources elect to participate in the DA IFM.

The ISO understands the Commission's FOO proposal, as originally described in the October 28 Order, to refer to a two-market system (*i.e.*, DA and RT only). At the January 28-29 Technical Conference, ISO described its concept of how FOO would work in a three-market system that includes an HA market. Although the ISO is now proposing to eliminate the Hour-Ahead Market settlement, the ISO's new HA proposal still contemplates the ability to commit resources to serve load in the Hour-Ahead timeframe. The concept that revolves around the ability of the ISO to consider FOO resources having different start-up times in the DA and HA markets, thereby making more efficient use of those resources, while still providing the resource owners with greater flexibility in fulfilling their obligations under FOO, remains valid and viable under the ISO's new HA timeframe proposal.

If the Commission approves the FOO mechanism, the Commission should confirm that the following features will be incorporated into the FOO design. First, LST FOO resources, *i.e.*, units with a start-up time longer than five hours, should not be exempt from FOO. Rather, in order for a LST to obtain the equivalent of a Must Offer Waiver (*i.e.*, permission from the ISO not to be available in RT), such unit must (1) not self-schedule or self-commit in the DA market, and (2) bid into the DA market, but not be committed by the ISO in either the IFM or RUC. Alternatively, if the concept of a pre-emptive waiver is incorporated into the FOO design, the unit could avoid the DA market and still be exempted from its RT obligation for some or all hours of the next day. Under these circumstances, the unit would be granted a waiver of its FOO for the following day and may shut down (or not start up if already shut down) for that day. If, on the other hand, the unit stays out of DA market, then absent a pre-emptive waiver it should be required to self-commit and be on-line and available in RT.

LSTs should be defined as those units requiring at least five hours start-up time. This is appropriate because five hours is the time horizon of the HA RUC procedure which the ISO proposes to perform each hour immediately following the HA IFM.[19] FOO resources that have start-up times less than five hours (which can be deemed to be "medium start-time" or MST units) can therefore opt out of the DA market and still be committed by the ISO in the HA IFM or RUC if needed. In this regard, it is important to note that, under the ISO's simplified HA market proposal described in a subsequent section, the HA market and the RT pre-dispatch process will essentially be combined, with a single bid submission at roughly T-60 or T-75 for both HA and RT. All FOO resources that have opted out

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[19] As described in a subsequent section, under the simplified HA market proposal the ISO still intends to run the IFM as a means to clear congestion and energy and establish resource and inter-tie schedules ahead of RT.

of DA and have not been given a DA pre-emptive waiver by the ISO will therefore be required to bid at this time.

By analogy to the discussion in the previous paragraph, a MST unit could receive an ISO waiver of its RT obligation for a period equal to its start-up time by (1) not self-scheduling or self-committing in the HA market, and (2) bidding into the market and not being committed by the ISO in either the IFM or RUC. The concept of pre-emptive waiver would also apply in this instance in a manner analogous to its application in the DA. Absent the extension of the Commission's FOO proposal to the HA market as described above, all MST FOO resources that did not schedule or bid in the DA market would automatically be required to be on-line and available for dispatch for all 24 hours of the following day. Thus, applying the FOO to the HA market provides the owners of these resources with greater flexibility and enables the ISO to utilize such units more efficiently.

Second, the only way for LST units to receive ISO-guaranteed start-up and minimum load ("SU/ML") costs should be for such units not to self-commit, and to bid into the DA market and be committed by the ISO in either the DA market or RUC.[20] If such a resource stays out of DA market and is not issued a waiver by the ISO, then it is self-committing (*i.e.*, covering its own SU/ML costs) to satisfy its obligation to be available in the Real Time market. To clarify, LST resources would be eligible to have their SU/ML costs covered by the ISO only if they (1) do not self-commit in the DA market (*e.g.*, by submitting an energy self-schedule or being identified as a Scheduling Coordinator for self-provided A/S),

[20] The October 28 Order was not clear regarding the conditions under which LSTs and MSTs would have their SU/ML costs compensated by the ISO under the FOO.

and (2) bid into the DA market and are committed by the ISO in the DA market or DA RUC. This provision would apply analogously to MST units with respect to the HA market. Specifically, MST resources would be eligible to have their SU/ML costs covered by the ISO only if they (1) do not self-commit in the HA market, and (2) bid into the HA market are committed by the ISO in the Hour Ahead market or the HA RUC.

Third, resource owners that are subject to FOO should not be permitted to transfer the ability to physically withhold to another party through a contract. For example, if a supplier has a bilateral contract with a buyer that allows the buyer to dispatch the resource, the resource owner should not be able to use the contract as an excuse to withhold (*i.e.,* the resource owner cannot withhold the resource from the RT market and claim "my contract made me do it" because the buyer did not dispatch the resource).[21] As the ISO clarified at the January 28-29 MD02 Technical Conference, in all cases it is the SC for the resource who should be accountable for FOO compliance.

As a final matter, in the event the Commission approves FOO, the Commission should confirm that a FOO resource that has not received a preemptive waiver from the ISO and does not self-commit or bid to sell energy or A/S in a forward market will be required to be available for RT dispatch by the ISO. In other words, the only way for a LST or MST resource that has not been

[21] The issue of LSEs retaining all dispatch rights to contracted resources has been raised specifically with regard to the ability of LSEs to follow their own load. Although the ISO's Revised Comprehensive Market Design Proposal filed on July 22, 2003 would allow MSS to follow their own load in real time, it is the ISO's role and responsibility to perform real-time load following (*i.e.*, system balancing) for all other ISO Control Area loads. Customers of the non-MSS LSEs benefit from this approach because the ISO's system-wide economic dispatch will balance the system in the most economically efficient manner. Therefore, with the exception of MSS resources, exemptions from FOO for such purposes is not appropriate.

given a preemptive waiver to obtain a waiver of its RT obligation is to bid into the last market in which it can be committed (*i.e.,* DA for LSTs and HA for MSTs) and not be committed by the ISO in that market's IFM or RUC process.

C. Residual Unit Commitment

1. Background

In its October 28 Order, the Commission approved the ISO's RUC proposal in concept, but recommended several modifications to the proposal. First, the Commission rejected, without prejudice, the ISO's proposal to procure energy (as opposed to capacity) from imports in the RUC process. October 28 Order at P 127. However, the Commission recognized that the ISO raised a concern that the mere purchase of capacity might not provide sufficient incentive to imports to acquire the necessary transmission capacity across the ties. Accordingly, the Commission urged the ISO to submit additional clarification on this point.[22] *Id.*

Second, the Commission made several revisions to the ISO's RUC proposal to provide an Availability Payment to units that are selected in the RUC process. In that regard, the Commission rejected the ISO's proposed $100/MWh Availability Payment bid cap and, instead, approved a $250/MWh bid cap. October 28 Order at P 123. Further, the Commission ruled that the Availability Payment should not be rescinded if the RUC unit is ultimately awarded Ancillary

[22] The ISO addressed this issue in a Clarification of CAISO Market Design Issues filed on January 14, 2004 in the captioned docket ("January 14 Clarification").

Services or dispatched for energy in the Hour-Ahead or Real-Time Markets.[23] *Id.*at P 124. Moreover, the Commission concluded that Availability Payment bids should be permitted to set a market clearing price ("MCP") rather than be paid "as bid."[24] *Id.*at P 123.

Third, with respect to the recovery of Start-Up and Minimum Load costs, the Commission denied the ISO's proposal to net the recovery of SU/ML costs against market profits, without prejudice to the ISO re-submitting its proposal upon implementation of a resource adequacy program. October 28 Order at P 115. The Commission declined to rule on the issue of whether the cost-based bid option should recognize daily spot gas prices. *Id.* at P 110. Finally, the Commission rejected suppliers' claims that in-state transportation costs should be included as a component of the cost-based option for start-up and minimum load cost recovery. *Id.* at P 112.

In its February 24, 2004 Comments, the ISO proposed several modifications to its RUC proposal. The ISO's revised RUC proposal was discussed generally at the March 3-5 Technical Conference. The primary issues that were discussed were (1) the appropriate objective function for RUC, and (2) how to deal with the potential export of energy from units that were committed

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23 The Commission noted that, in its July 22 MD02 Filing, the ISO made the statement that it "does not prohibit energy from capacity committed in the Day-Ahead RUC from being sold by the unit owner via any bilateral transaction in the hour-ahead market, including sales to other Control Areas." October 28 Order at P 123. The Commission found this statement to be contrary to the ISO's statements elsewhere that the ISO needs RUC capacity as a reliability backstop when the day-ahead market closes significantly below the ISO's forecasts. In other words, units committed in RUC are free to sell elsewhere, *i.e.*, not be committed. The Commission requested further clarification of this aspect of the ISO's July 22 MD02 Filing. The ISO addressed this issue in its January 14 Clarification.

24 At the January 28-29 Technical Conference, Commission Staff clarified that the Commission's intent was not to set a single system-wide MCP; rather, the Commission contemplated a nodal MCP for RUC capacity.

under RUC. In addition, parties raised a number of clarifying questions regarding the ISO's revised RUC proposal. At the March 3-5 Technical Conference, no party raised any wholesale objections to the ISO's revised RUC compensation "package."

As indicated *supra,* on March 19, 2004, the ISO posted on its website responses to the questions regarding RUC that were raised by parties at the March 3-5 Technical Conference. Only a few parties submitted comments regarding the ISO's revised RUC proposal (as reflected in the ISO's February 24 Comments) following the ISO's posting of its responses. The comments were limited to specific, narrow aspects of the revised proposal. The ISO addresses such comments below. Based on the discussion at the March 3-5 Technical Conference and subsequent comments, the ISO is proposing additional modifications to the revised RUC proposal that the ISO submitted on February 24. For the convenience of the Commission and the parties, the ISO is setting forth the entirety of its revised RUC proposal below.

2. The ISO's Revised RUC Proposal

Based on the discussion at the January 28-29 and March 3-5 Technical Conferences and after reviewing parties' comments, the ISO is proposing the following revisions to its RUC proposal:[25]

1. The bid cap on the Availability Payment will be $150. (The ISO originally proposed a $100 cap and FERC approved a $250 cap in its October 28 Order.)

[25] In its February 24 Comments, the ISO proposed to implement a constraint that would preclude RUC capacity procured in the DA from being used to serve export schedules in the HA. This constraint is no longer necessary given the ISO's proposal for a simplified HA market.

2. The Availability Payment will be paid on a locational MCP basis. The ISO anticipates that RUC Availability bids will be treated as though they were energy bids and will be cleared against forecasted load using the full network model, so that the result will be nodal Availability Payment MCPs. It is important to note that RUC procurement based on the full network model and payment of a locational MCP creates a need for local market power mitigation with respect to RUC capacity (This is a new provision responds to the October 28 Order and the Commission Staff's clarification of such order at the January 28-29 Technical Conference.)

3. The Availability Payment for a given operating hour will not be rescinded if a unit is dispatched in the energy markets subsequent to the RUC process (for the same operating hour). (In its July 22 MD02 Proposal, ISO proposed that 100% of the "Availability Payment" would be rescinded if the unit was dispatched in the energy market subsequent to RUC. The Commission ruled that no portion of the "Availability Payment" should be rescinded.)

4. The combined Availability Payment received in RUC and Energy MCP received in energy markets subsequent to RUC cannot exceed $250. This is necessary to avoid potential economic withholding from the DA IFM. Specifically, this measure is necessary to avoid potential disincentives against supplier participation in the DA market and preferential participation in the RT market. Without such a measure, the Availability Payment would effectively raise the RT price cap to $400 (the sum of the Availability Payment and real-time energy bid caps under the ISO's proposal). (This is a new provision that was not included in the ISO's July 22 MD02 Filing but that is now necessary given that Availability Payments will no longer be rescinded when RUC capacity is dispatched for energy.)

5. The portion of a unit's output that is mitigated in the DA pre-IFM run for local market power in the Energy market and does not clear the IFM, will be slated as RUC capacity and will be eligible to receive a RUC Availability Payment in addition to the Energy payment that it receives in the market (hour-ahead or real-time) where its Energy is eventually scheduled or dispatched. However, because of its local market power, the unit's RUC Availability Payment bid will be subject to mitigation, *i.e.*, it will be set at the lower of the unit's Availability Payment bid price or a mitigated reference level. The unit can, however, collect a higher Availability Payment MCP (LMP) that may be set at its location by other accepted Availability Payment bids. Mitigated Availability Payment bid prices will be calculated by an independent entity and will based on competitive Availability Payment bid reference levels, *e.g.*, the mean or median of the highest accepted "non-mitigated" availability bids for the preceding 90 days. (This is a new provision that was not included in the

ISO's July 22, 2003 MD02 Filing).[26] The 90-day rolling average is consistent with the energy reference price methodology currently in place in the ISO and the NY ISO. However, if market participants would like a different time frame (*e.g.*, a 30 day rolling average), the ISO would be amenable to changing it. Using a rolling average over a significant time period (*e.g.*, 30 days or more) results in a more stable (less volatile) reference level. In the event that there are no accepted "non-mitigated" RUC bids in the previous 90-days to calculate a Bid-based Reference Value, the last available Bid-based Reference Value will serve as the default value until either:

a. The Independent Entity and the affected unit owner reach agreement on an alternative Consultative Value; or

b. The CAISO awards RUC capacity to non-mitigated RUC bids, which will mean that data are once again available to calculate a new Bid-based Reference Level.

Under this approach, the Availability Payment bid reference level will be the same for all units, calculated separately for peak and off-peak hours, and posted daily on the CAISO OASIS.

6. Recovery of Start-Up and Minimum Load Costs shall be net of market revenues (A/S, energy profits (defined as MCP – bid) and RUC Availability Payments). (This is consistent with the ISO's July 22 MD02 Proposal. The Commission rejected the netting proposal without prejudice until a resource adequacy program is implemented.)

7. Intrastate gas transportation and municipal use fees shall be included in minimum load energy costs. (These costs were not included under the ISO's July 22 MD02 Proposal or under the October 28 order.)

8. Use RMR Contract gas costs for RUC. This would involve using a two-day average of three daily indices (NGI So Cal Border, BTU So Cal Border and Gas Daily So Cal Gas large package) for SCE or SDG & E units, and a two-day average of two daily indices (NGI PG & E Citygate and Gas Daily PG & E Citygate) for former PG & E units, plus any applicable intrastate transportation and municipal use fees. (This is a new provision that was not included in the ISO's July 22 MD02 Filing.)

9 RMR dispatches that occur in RUC would not be eligible for setting or receiving the Availability Payment MCP. Similarly, any unit pre-designated as a capacity resource under a load serving entity's ("LSEs ") resource adequacy plan established by the CPUC would not be eligible to receive

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[26] The concept proposed in the February 24, 2004 filing of a "System-wide Availability MCP" cannot be literally implemented because Availability Payment MCPs will be at the nodal level. The approach of using the highest accepted "non-mitigated" availability bid in each hour approximates a System-wide Availability Payment MCP.

or set the RUC Availability Payment MCP, provided both the resource owner and the LSE agree to this treatment in their contract. It will be the responsibility of the SC who designates such resources to indicate to the ISO whether each resource should be eligible to receive the RUC Availability Payment. Finally, resources designated as "self-provided" RUC capacity by a load-serving SC (described further below) will not be eligible to set or receive the RUC Availability Payment MCP. In all cases, units not eligible to reserve the RUC Availability Payment will never be eligible to set the corresponding MCP. (This is a new provision that was not included in the July 22 MD02 Filing).

10. The objective function of RUC will be to minimize commitment costs, i.e., the sum of (1) the product of the Availability Payment bid price and the RUC MW for all capacity that is not RMR, plus (2) the sum of SU and ML costs for all RUC resources (including RMR) committed in the RUC process. The ISO will not purchase Energy in the RUC process. (This is a change to the RUC proposal that the ISO agreed to make at the March 3-5 Technical Conference).

11. RUC self-provision will be permitted. This is described in greater detail in a subsequent section of these comments.

The above proposal reflects a delicate balance of the following objectives: (1) providing adequate incentives for load to forward schedule; (2) ensuring that market power – including local market power – is adequately mitigated; (3) providing fair compensation to suppliers for the specific service that is being provided in RUC; and (4) avoiding the creation of perverse incentives, *e.g.*, incentives for suppliers to submit excessively high bids in the DA market to avoid being selected in the IFM and thus become eligible to receive a RUC Availability Payment. The ISO submits that its proposal appropriately balances these objectives and should be approved by the Commission on a conceptual basis.[27]

[27] In addition to balancing the aforementioned objectives, the ISO's revised RUC proposal also represents a comprehensive "compromise" among parties' competing positions on the various elements of RUC compensation. For example, some parties argue for a $250 bid cap on the Availability Payment, others argue for a lower cap. Some parties argue that the Availability Payment should be rescinded if the unit is dispatched for energy, others argue that it should not be rescinded. Some parties favor "netting" the Start-up and Minimum Load costs from other revenues earned by the supplier; suppliers oppose netting. Suppliers also argue that certain

The ISO also stresses that it has developed and views the instant proposal as a "packaged deal" that should not be cherry-picked. In particular, the ISO has attempted to strike a balance of competing interests on the compensation-related issues. Stated differently, the ISO would not have made certain of the proposals reflected in the revised RUC proposal on a standalone basis. It made such choices only because it was making certain other counterbalancing changes in the proposal. The ISO has made significant movement from it originally filed position, and has gone to great lengths to balance competing interests. The ISO urges the Commission not to undo the balance that it has attempted to strike by the instant proposal. The ISO will discuss the specific elements of its revised proposal below.[28]

3. The Availability Payment

The October 28 Order suggested that a $250 cap on Availability Payment bids (rather than the $100 cap proposed by the ISO) was appropriate because that is the level of the bid cap for Ancillary Services, and RUC is "similar to the procurement of capacity in the ancillary services market." October 28 Order at

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other costs such as intrastate transportation costs should be included in Start Up and Minimum Load Costs; although, the Commission rejected such arguments in the October 28 Order.

[28] In its Comments submitted to the ISO on March 29, 2004, CMUA suggests that the ISO should leave open the option of not having a RUC procedure. CMUA argues that RUC is not needed once a resource adequacy program is in place that addresses both system and locational requirements. As the ISO argued in its Answer to Protests filed on September 17, 2003 in this proceeding, a RUC mechanism is needed even if there is a resource adequacy program in place. ISO Answer to Protests at 40-41, 117, filed September 17, 2003. There is no need to repeat these arguments here. The ISO notes that the SMD NOPR contemplates the co-existence of both a resource adequacy plan and a unit commitment procedure, and the eastern independent system operators have resource adequacy plans in place, but still have (and need) Commission-approved unit commitment procedures. The ISO also notes that, in the October 28 Order, the Commission approved in principle the proposed RUC process with the full knowledge that the CPUC was in the process of implementing a resource adequacy program. October 28 Order at P 130. CMUA has not raised any issues that require reconsideration of that determination.

P.123. Further, the Commission concluded that the Availability Payment would not be rescinded if a unit was dispatched. The ISO submits that a $250 Availability Payment bid cap is inappropriate, but a $150 bid cap on the Availability Payment and a total payment cap of $250 for Availability Payment and energy, as proposed herein, are just and reasonable for several reasons.

First and foremost, a lower bid cap and a total hourly payment cap are necessary because the ISO is no longer proposing to rescind the Availability Payment if the unit is dispatched for energy. The ISO still believes that rescission of the Availability Payment is the appropriate result if a RUC unit is dispatched for Energy. However, a lower Availability Payment bid cap and a total payment cap mitigates the concern the ISO has regarding non-rescission of the Availability Payment, namely suppliers will submit unreasonably high bids in the DA market in order to avoid being selected, thereby creating an opportunity for them to obtain a RUC Availability Payment in addition to an Energy Payment. The ISO's proposal also recognizes that RUC capacity and A/S capacity are not identical.

In its October 28 Order, The Commission suggested that rescission of the Availability Payment was inappropriate because the ISO does not rescind the A/S capacity payment if a unit is subsequently dispatched for energy. However, the October 28 Order ignores the important fact that the ISO, under current rules, rescinds the capacity payment for Replacement Reserves if the Replacement Reserve capacity is subsequently dispatched as energy. Replacement Reserves are more akin to RUC capacity than any other Ancillary Service the ISO provides because the ISO procures Replacement Reserve capacity based, *inter alia*, projected shortfalls in Day-Ahead schedules.[29] *See* ISO Tariff Section 2.5.3.3. Original Sheet No. 63. As a result of the energy crisis, the ISO has not procured Replacement Reserves with the intent that they will be held in reserve pending a "contingency." Rather, the ISO generally has anticipated that it would deploy Replacement Reserves – just like the ISO expects that it will deploy RUC capacity. Consequently, unlike Operating Reserves, there is a very high likelihood that a unit owner awarded RUC capacity will receive both a capacity payment (*i.e*. RUC Availability Payment) and an energy payment. Given this, it is appropriate that the bid cap for RUC Availability Payment be set lower than the bid caps for Ancillary Services. Moreover, it is worth noting that having different bid caps for different capacity services is not a concept unique to the ISO. For instance, PJM has different bid caps for its Ancillary Services[30].

The ISO does not understand why the Commission believes it is appropriate to rescind the capacity payment for Replacement Reserves that are dispatched, but not appropriate to rescind the Availability Payment for comparable RUC capacity.[31] Indeed, the ISO believes the rationale that the Commission set forth for rescission of the Replacement Reserve capacity payment supports rescission of the RUC Availability Payment. Specifically,

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29 Although RUC is somewhat comparable to Replacement Reserve and certainly is more like Replacement Reserve than any other Ancillary Service, for the reasons set forth in the MD02 Filing, Replacement Reserve is not an adequate substitute for RUC. *See* MD02 Filing, Transmittal Letter at 53, n. 116.

30 In PJM, the bid cap for Regulation capacity is $100/MW and the bid cap for Spinning Reserve is $7/MW.

31 Moreover, in bidding Replacement Reserves, the bidders had to internalize their Start Up and Minimum Load costs among their capacity and energy bids. Under RUC, the Availability bid need not internalize such costs because a unit committed in RUC is kept whole for the SU/ML costs it may incur.

rescinding the Availability Payment for units that that are dispatched removes the incentive for suppliers to submit unreasonably high bids in the DA market (so that the bids will not be accepted) in order to be committed in RUC, thereby earning an Availability Payment (as well as an Energy payment). A similar problem plagued the ISO's Replacement Reserve market (*i.e.*, suppliers were holding back until Real Time so they could receive both a capacity and an energy payment) until the Commission approved Tariff provisions rescinding the capacity payment upon dispatch. In that regard, the Commission ruled that suppliers could receive either a capacity payment or an energy payment but not both. *See San Diego Gas & Electric Company v. Sellers of Energy and Ancillary Services into Markets Operated By the California Independent System Operator and the California Power Exchange,* 93 FERC ¶ 61,294 at 61,995 (2000). The Commission approved this approach to remove the financial incentive for suppliers to wait until Real-Time to submit bids.

The ISO believes that the best approach to eliminate the incentive for suppliers to avoid the DA market by submitting excessively high bids is to rescind the Availability Payment when a unit is dispatched for energy. However, in light of the Commission's directive in the October 28 Order and the discussions at the Technical Conferences, the ISO is now proposing a non-rescindable RUC Availability Payment as one element of a complete comprehensive "compromise" RUC compensation proposal. Because the ISO has taken great care in crafting this compromise proposal to balance the various arguments and concerns expressed by the parties and the Commission, it is important that the

Commission view it as a comprehensive compensation package. In particular, with a non-rescindable Availability Payment, some other mechanism to mitigate market power and provide more appropriate incentives must be implemented. Absent rescission of the Availability Payment, it is imperative that a lower Availability Payment bid cap and a total payment cap of $250/MW for the combined energy and RUC Availability Payment be in place.

The proposed compensation scheme also is fair and appropriate given what RUC is – a one-day energy reliability service. The potential to earn what essentially amounts to a double payment (*i.e.*, being able to bid up to $250 for both energy and Availability Payments and receive both payments), is inappropriate given the nature and intent of RUC.

Second, a $150 bid cap (as opposed to a $250 bid cap) is appropriate because RUC capacity and A/S capacity are very different services.[32] In this regard, it is useful to elaborate on a point mentioned above, *i.e.*, absent a "contingency", the ISO does not expect to dispatch Operating Reserves capacity for energy.[33] Therefore, it is highly unlikely that the supplier of capacity that must be maintained as Operating Reserves will receive both an energy payment and a capacity payment, because it is expected that such capacity will be deployed as

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32 In its comments submitted on April 16, 2004, Mirant suggests that a $250/MW total payment cap is inconsistent with the A/S bid cap of $250/MW where suppliers can earn an incremental energy payment if they are dispatched. The discussion in the next couple of paragraphs demonstrates that RUC capacity is not the same as A/S capacity and, as such, should not be priced the same as A/S capacity.

33 Exceptions may occur in cases where available A/S exceeds the minimum A/S requirements due to load forecast errors, errors in estimating the level of firm and non-firm interchanges, or A/S self-provision. The ISO must maintain an Operating Reserve equal to (1) five percent of the Demand (except the Demand covered by firm purchases from outside the ISO Control Area) to be met by Generation from hydroelectric resources, plus seven percent of the Demand (except the Demand covered by firm purchases from outside the ISO Control Area) to be met by Generation from other resources or (2) the largest single contingency, if this is greater. Ancillary Services Requirements Protocol, Section 5, Original Tariff Sheet No. 409.

energy only following a "contingency."[34] On the other hand, when the ISO commits a unit under RUC, the ISO expects to dispatch that unit for energy because the amount of energy from such unit is necessary to meet the ISO's load forecast. In other words, unlike Operating Reserves, there is a general expectation that the RUC capacity will be dispatched for energy, thereby making it more likely that the unit owner will earn both a capacity payment and an Availability Payment. Thus, the Availability Payment is essentially an up-front reservation payment for an Energy service; it is not intended as a payment to hold capacity in "reserve." Indeed, RUC units are not required to keep their capacity unloaded. To the contrary, they are required to bid it in the HA and RT markets for dispatch against load appearing in those markets. Because RUC energy will be selected before energy from capacity that must be retained as Operating Reserve,[35] RUC capacity is not like Operating Reserve capacity. These facts justify a lower bid cap and a total payment cap for RUC.

In their comments submitted subsequent to the March 3-5 Technical Conference, the CPUC and SCE oppose the RUC Availability Payment. They argue, *inter alia*, that a RUC Availability Payment is not necessary given the CPUC's resource adequacy program. SCE also argues that allowing suppliers to keep both the Availability Payment and the Energy payment will result in distortions in the DA market. As indicated above, the ISO believes that that a properly designed RUC would rescind the Availability Payment when a unit is dispatched. However, in an attempt to balance the competing interests of the

[34] Some Operating Reserve is explicitly marked as "contingency only" by the A/S suppliers so that the ISO cannot dispatch them for energy even in the case of surplus A/S capacity.

[35] Under MD02, Operating Reserve capacity is treated as being at the end of the bid curve.

parties without skewing the incentives, the ISO is submitting an alternative proposal herein that does not provide for rescission of the Availability Payment. The ISO believes that its revised proposal is a workable compromise and should be approved by the Commission. In particular, the combination of a lower Availability Payment bid cap and a total payment cap for energy and Availability Payments, should mitigate SCE's concerns regarding non-rescission of the Availability Payment. Further, the ISO's revised RUC proposal addresses the CPUC's and SCE's concern that units under a resource adequacy obligation might receive a double capacity payment – once under RUC and once under their resource adequacy contract. In that regard, resources that have a contract under the CPUC's resource adequacy program would not receive a RUC Availability Payment provided that the resource adequacy contract negotiated by the LSE and the supplier provides for non-payment of a RUC Availability Payment.[36] However, the Availability Payment should not be eliminated entirely because there may be units that are committed under RUC that do not have a resource adequacy contract. Such units need to be compensated for the RUC service they provide. Mirant states that Energy and Capacity are different products and should be compensated separately. The ISO notes that its proposal does price capacity and Energy separately. In that regard, a supplier will receive both an Availability Payment and Energy Payment. Only if the total of the two payments exceeds $250, will the total payment then be capped. However, that

[36] WCP/Williams support the requirement that LSE-procured capacity that satisfies a resource adequacy requirement include an obligation for the suppler to bid into the DA market and RUC. WCP/Williams also state that resource adequacy suppliers that are selected in RUC should be required to pass on the RUC Availability Payment revenues to the LSE if it is agreed to in the contract between the two parties.

does not mean that the ISO is pricing Energy and Capacity as the same product. As discussed above, a total payment cap is appropriate for mitigation purposes and to minimize distortions in the DA market.

In comments submitted on April 22, 2004, WCP/Williams state that they do not oppose in principle combining Availability Payments and energy bids for purposes of determining whether a mitigation cap should be imposed. However, they state that a $250 cap fails to recognize scarcity because there could be periods of scarcity where a supplier submits a $150 Availability Payment bid but, because the total payment cap is set at $250, can only be paid $100/MWh for the Energy despite the fact that scarcity conditions exist. WCP/Williams suggest that the total payment cap be set at no less than 150% of the damage control bid cap.

The ISO appreciates WCP/Williams efforts to suggest an alternative approach, rather than just criticize the ISO's proposal. From the ISO's perspective, the proposed $250 total payment cap already reflects significant movement form the ISO's originally filed position (*i.e.*, a $100 Availability Payment bid cap and rescission of the Availability Payment when a unit is dispatched). For the reasons discussed above, the ISO still believes that a total payment cap of $250 is appropriate. However, the ISO believes that there is one additional factor which demonstrates that a $250 total payment cap is reasonable. In that regard, the ISO will commit units in RUC whose Energy bids do not clear the DA market. Under the existing (and proposed) pricing rules, such non-accepted DA bids will not exceed $250 (unless they are cost justified). In other words, the supplier that is committed in RUC would have submitted a bid in and would have been willing to sell its Energy in the DA market for less than $250. Under these circumstances, the supplier does not have any legitimate expectation to be earning more than $250 in the DA timeframe. Given that RUC is run immediately after the close of the DA IFM, a supplier should find it acceptable to receive any amount above its DA bid. Although the ISO's proposed $250 total payment cap allows the supplier to earn more than it could in the DA energy market, it also recognizes – appropriately -- that the supplier was willing (and committed) to sell the same Energy for less than $250. Under these circumstances, a total payment cap of $250 will help ensure that suppliers do not submit unreasonably high bids in the DA market so that their bids will not be accepted, and they will be eligible to receive a RUC Availability Payment and a subsequent energy payment in the Real Time market.

To the extent the Commission does not find the ISO's proposed total payment cap to be just and reasonable, the Commission should consider the alternative proposed by WCP/Williams. Such alternative certainly is more reasonable and justifiable than the approach the Commission adopted in the October 28 Order (*i.e.*, a $250 bid cap for Availability and a $250/MWh cap for Energy.

4. The Availability Payment Market

The ISO also is revising its RUC proposal to permit Availability Payment bids to set a locational MCP. This is consistent with the October 28 Order. October 28 Order at P 123. Because the ISO contemplates that there will be instances where the ISO will need to procure RUC capacity to satisfy locational needs that are not accounted for by RMR (*e.g.*, as the result of a DA load forecast error or a short-term situation such as an unexpected outage), some mechanism must be in place to protect against the exercise of local market power.[37] The ISO's proposal accomplishes that goal, while still providing supply resources with adequate compensation in those instances in which their Availability Payment bids are mitigated for local market power reasons.

A resource whose Availability Payment bid is mitigated can set the Availability MCP, and collect a higher Availability Payment MCP than its mitigated bid if the MCP at its location is set by other accepted Availability Payment bids. Mitigated Availability Payment bid prices ("Bid-based Reference Level") would be calculated by an independent entity and based on competitive Availability Payment bid reference levels (*e.g.*, the mean or median of the highest accepted "non-mitigated" Availability Payment bids for the preceding 90-days). The ISO notes that use of a 90-day period is consistent with the calculation of "bid-based" AMP reference prices (*see* MMIP Appendix A, Section 3.1.1.1(a) and DEC reference prices for managing Intra-Zonal Congestion (*see* Section 7.2.6.1.1). Nonetheless, if market participant consensus supports use of a different time frame (*e.g*. 30-day rolling average), the ISO would be amenable to changing the timeframe for determining mitigated Availability Payment bid prices. Using a rolling average over a significant time period (*e.g*. 30 days or more) results in a more stable (less volatile) reference level. In the event that there are

[37] WCP/Williams indicate that they do not oppose mitigation of location-specific Availability Payment bids *per se*. However, they state that the definition of "non-competitive paths" is overly broad. They also state that any Availability Payment bid mitigation must promote new infrastructure investment and send the proper price signals.

no accepted "non-mitigated" Availability Payment bids in the previous 90-days to calculate a Bid-based Reference Value, the last available Bid-based Reference Value will serve as the default value until either (1) the Independent Entity and the affected unit owner reach agreement on an alternative Consultative Value, or (2) The ISO awards RUC capacity to non-mitigated RUC bids, which will mean that data are once again available to calculate a new Bid-based Reference Level.

Under this approach, the Availability Payment Bid-based Reference Level will be the same for all units, calculated separately for peak and off-peak hours, and posted daily on the ISO OASIS.

5. Start-Up And Minimum Load Costs Under RUC

The ISO also proposes to "net" Start Up and Minimum Load Costs from A/S revenues, energy profits earned in the ISO markets (defined as MCP-bid) and RUC Availability Payments. In the October 28 Order, the Commission rejected the ISO's "netting" proposal because, unlike the eastern markets, there was no mechanism in place for suppliers to earn capacity payments that would "balance" the netting of revenues following the RUC process. However, given that the Availability Payment is no longer being rescinded, RUC units will be receiving a capacity payment for the RUC service they provide. Therefore, the rationale for the Commission's decision to reject "netting" in the October 28 Order does not apply. As the ISO has indicated previously, the Eastern independent system operators "net" Start Up and Minimum Load Costs. MD02 Filing, Transmittal Letter at 97-98; ISO's September 17, 2003 Answer to Protests at 124-25. It is appropriate to accord the ISO the same treatment as the Eastern independent system operators with respect to “netting”, especially now that suppliers in RUC are guaranteed a capacity payment. Failure to require “netting” provides additional incentives for suppliers to bid strategically to avoid commitment in the IFM in order to capture the additional compensation offered in RUC. Specifically, it means that suppliers, having been guaranteed recovery of their Start-Up and Minimum Load costs through RUC are free to participate in ISO markets, retaining all of their profits by selling energy from their capacity at market based rates. This essentially causes consumers to subsidize the suppliers’ other out-of-the-ISO’s-market activity or pay twice for the same energy.

The ISO also is modifying its proposal with respect to Start-Up and Minimum Load Costs compensation. Specifically, the ISO proposes to retain its original proposal to include auxiliary power costs as an appropriate component of Start Up costs, and would add intrastate gas transportation and municipal use fees as recoverable costs to be included in the Minimum Load Costs. Suppliers have been seeking inclusion of these costs in Start Up and Minimum Load costs, and the ISO believes that it is reasonable to allow for the recovery of such costs as legitimate Start-Up and Minimum Load Costs. The ISO also proposes to use a two-day average for determining gas costs, rather than the monthly average that the ISO initially proposed in its MD02 Filing and which has been in place in California for the past several years. The ISO believes that a two-day average will more closely reflect the actual gas costs being incurred by suppliers under

RUC than will use of a monthly average.[38] The ISO notes that it will be proposing these cost compensation modifications as part of Tariff Amendment 60.

6. The RUC Optimization Function

In its July 22 MD02 Filing, the ISO proposed to procure Energy from imports in the RUC process (as well as capacity from internal resources). The ISO proposed to optimize its selection of RUC resources by minimizing the total cost of procuring the resources, including the bid-based Availability Payment, Energy bids (submitted by importers) and SU/ML costs. Based on the discussion at the March 3-5 Technical Conference (as well as comments submitted by several parties), the ISO now proposes only to procure capacity under RUC.[39] Accordingly, as indicated above, the objective function of RUC will now be reformulated to optimize only the sum of Availability Payments and SU/ML costs. Also, as the ISO indicated at the March 3-5 Technical Conference and in its responses to the RUC questions, the ISO will build into its MD02 software the

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[38] In its February 17, 2004 comments, Williams suggested that RUC eligible resources should have the opportunity to submit new bids in the RUC process. Williams at 13. Under the ISO's proposal, suppliers are permitted to submit new Energy bids associated with their RUC capacity, provided such bids do not exceed the level of their bid in the DA market. Given the earlier point that RUC capacity has a high probability of being dispatched for energy in RT, if suppliers were permitted to raise their bids once they have been selected in RUC, they would have no incentive to bid competitively to increase their likelihood of dispatch. Given that suppliers are being guaranteed a non-rescindable Availability Payment, it does not make sense that they should be permitted to increase their Energy bids. Indeed, that would be contrary to the call-option concept on which the Commission and suppliers claim RUC is based.

[39] CMUA recognizes that the ISO will procure capacity under RUC for both system needs and locational needs that are not covered by RMR. However, CMUA requests that the ISO clarify the protocols it will employ to distinguish locational and system-wide requirements for RUC. The ISO is committed to transparency on this issue and will specify such protocols prior to implementation of RUC. The lack of specific protocols at this time should not preclude conceptual approval of the RUC elements proposed herein and should not be allowed to slow down the software development process which needs Commission approval to proceed on the proposed RUC design elements. Moreover, the ISO recently committed, as part of the revised Must-Offer Waiver Process, to provide additional detail and transparency regarding its locational and system-wide capacity and operating requirements.

functionality to include consideration of Energy bids in the RUC optimization. The ISO submits that this is a prudent approach given the ISO's heavy dependence on imports and the possibility that, in the future, it might be necessary and appropriate for the ISO to procure Energy in RUC (in addition to capacity). However, whether the ISO procures Energy (from importers) in RUC is and will be entirely dependent on the DA supply bidding, scheduling and self-provision actions of the load-serving entities.

In its comments, CMUA objects to some language in the ISO's Market Power Mitigation White Paper which suggested that the ISO might switch to a RUC objective function that seeks to minimize total bid costs if the ISO finds that volumes turn out to be lower than expected or costs turn out to be excessive. The ISO has no intention whatsoever of implementing such a measure unilaterally. If the ISO determines that such a change in the RUC objective function is appropriate, the ISO will make a Section 205 filing at the Commission requesting the authorization to implement such an approach. All the ISO is seeking to do at this time is to build the software functionality that will allow the ISO to optimize Energy costs under RUC should that be necessary in the future.

7. RUC Procurement Target And Potential RUC Self-Procurement Provision

In its February 17 comments, SWP argued that market participants should have the ability to opt out of RUC and assume full responsibility for their loads. SWP at 4. Stated differently, such market participants should be permitted to "self-provide" their RUC capacity. At the two technical conferences, other parties also argued that the ISO's DA RUC procurement and cost allocation to DA under-scheduled load would pre-empt LSEs' ability to shop for cheaper energy after the close of the DA market. These parties expressed an interest in a so-called RUC self-provision mechanism.

The ISO recognizes these concerns, but must ensure that it can fulfill its responsibility for reliable RT operation by identifying and procuring capacity it expects to need in RT but that may only be available in DA. At the January 28-29 Technical Conference, some parties suggested the idea, similar to A/S self-provision, of SCs committing on a DA basis to provide a quantity of RUC capacity that they would self-provide in the HA market.

Although the ISO cannot support deferring A/S self-provision to the HA market (see the section on A/S later in these comments), the ISO believes that DA self-provision of RUC is workable and is consistent with the proposed simplification of the HA market discussed later in these comments. In that regard, LSEs would make a DA commitment to schedule specific quantities of additional energy in the HA market, and to support this commitment would identify equal quantities of capacity from specific resources that will be available to the ISO for dispatch in the HA and RT markets in the event these LSEs fail to schedule the committed energy. Such "self-provided RUC capacity" would need to be available – *i.e.*, able to operate and not otherwise scheduled or bid into the DA market – and deliverable to serve the LSE load not scheduled in DA. The ISO would then reduce its DA RUC procurement target by the amount of this self-provided RUC capacity (and the corresponding cost allocation to the self-providing LSEs).

Self-provided RUC capacity might include, for example, capacity the LSE has obtained under contract to meet its resource adequacy obligation. By relying on such already-purchased/procured capacity, the LSE retains the flexibility to shop for cheaper energy after the DA market without risking a RT shortage if no cheaper energy is found. Verification procedures would be needed to ensure that the capacity slated by the LSEs to show up in the HA Market is flagged properly so that it is not selected by the ISO in the DA IFM or RUC to compensate for other LSEs' under-scheduled load, and to enable the ISO to ensure that its Energy, if needed, would be deliverable without causing congestion in real time. The ISO requests that the Commission approve the concept of RUC self-provision consistent with the foregoing discussion with the ISO to further define the details of such a mechanism in its MD02 Tariff language filing.

In it comments filed on February 17, 2004, SMUD requested that the ISO clarify whether the ISO will procure RUC on behalf of, or allocate RUC costs to, entities like SMUD that operate their own Control Areas. SMUD Comments at 16. SMUD noted that metered subsystems ("MSS") that cover their own load will not be assessed any RUC charges. SMUD alleged that it is comparable to a MSS because SMUD takes full responsibility for its load, and will essentially self-provide RUC resources. SMUD repeated these thoughts in its comments submitted after the March 3-5 Technical Conference. As the ISO indicated in its

February 24 Comments, RUC capacity is intended to satisfy ISO Control Area load only. As such, RUC capacity will not be procured for loads in other Control Areas. As indicated in the July 22 MD02 Filing, if the ISO commits more RUC capacity than the actual amount of underscheduled load, the ISO will allocate only the costs associated with the "excess" capacity to metered load and exports. This is an appropriate allocation because such costs were incurred to maintain the reliability of the entire transmission system upon which exports are being served. For example, the ISO charges the Control Area Services ("CAS") component of its Grid Management Charge on the basis of Control Area gross load and exports because CAS costs are necessary to maintain the system and operate it reliably.

D. Constrained Output Generators

In its July 22 MD02 Filing, the ISO stated that it was inappropriate for Constrained Output Generators to set the Energy price in the forward markets because (1) if the COG were treated as a flexible unit it would lead to acceptance of an infeasible schedule with the knowledge that the COG would have to be re-dispatched in Real-Time, or (2) if the COG were treated as constrained, the resulting prices would not be consistent with the dispatch and would not be true marginal prices in the economic sense, because Energy would be priced based on the COG; whereas, the actual marginal price for serving the next increment of load would be the price of the lower-priced generator that was decreased to make room for the COG. In its October 28 Order, the Commission noted that each of the Eastern independent system operators has developed mechanisms that allow non-dispatchable units to set the clearing price in the DA Market. October 28 Order at P 89. Accordingly, the Commission directed the ISO to

> review its approach to setting prices in the forward market and develop a pricing mechanism for Constrained Output Generators that is consistent with its approach to real-time pricing (*i.e.*, a constrained output generator can set the market clearing price for those dispatch intervals in which any portion of its output is needed to serve real-time load) and promotes the convergence of prices in the forward and real-time markets.

Id. At the January 28-29 Technical Conference, the parties discussed (1) when is it appropriate for COGs to set the market clearing price, and (2) whether and why different pricing rules between the Day-Ahead and Real-Time Markets may be appropriate.

Based on the discussions at the January 28-29 Technical Conference and the comments filed by the parties on February 17 2004,[40] the ISO proposed in its February 24 Comments to revise its treatment of COGs to allow them to set prices in the forward markets. That proposal was based on treating COGs as constrained in the IFM dispatch run and then treating them as flexible in the subsequent IFM pricing run. The ISO discussed its revised proposal with stakeholders at the March 3-5 technical conference. Although there was no significant opposition to the ISO's proposal, the discussion revealed the potential for an inappropriate outcome when a COG is located within an import-constrained area (*i.e.*, a load pocket). Specifically, in such situations, the pricing run of the IFM could "export" the high load-pocket LMP set by the COG to a

[40] For example, in their February 17, 2003 comments, Williams and Reliant argued that the ISO should permit COGs to set the price in instances where the unit is required to serve load. Reliant Comments at 13; Williams Comments at 17.

larger area of the ISO Control Area. This can occur because the COG, by running at its P-max rather than its optimal dispatch point if it were flexible, eliminates the congestion into the load pocket. With the transmission line into the load pocket no longer congested, there is no price difference between the load pocket and the neighboring area. Thus, the COG would "export" the load-pocket price outside the load pocket, even though the COG is really needed only to serve the load pocket. That is an unjust and unreasonable result.

Upon further exploration of possible outcomes of the February 24 approach, the ISO identified another type of undesirable outcome. Namely, if there is price-responsive load bidding in the IFM, that load may be scheduled in the dispatch run and then charged a price higher than its bid in the pricing run.

Accordingly, the ISO has subsequently revised its COG proposal in a manner that addresses both of the aforementioned concerns, yet still enables COGs to set the price in the DA Market. The ISO's proposal is as follows.

1. COGs eligible to set prices, both in the IFM and in RT would be Combustion Turbines (CTs) that can only run at full output. This definition is consistent with the definition of Constrained Output Generators adopted by the Commission in its order on the ISO's Tariff Amendment No. 54.[41] *See California Independent System Operator Corporation*, 105 FERC ¶ 61,091 at P70 (2003).

2. The specification of the circumstances in which a COG may set prices is as follows:

   a. Eligibility to set price in any settlement interval would depend on some portion of the unit's output being needed in merit order to serve load. In other words, if the unit is modeled as fully flexible

[41] The Commission stated that COGs "are generating resources that cannot easily or economically change load levels and are typically restricted to generating at their full capacity for their unit-specific minimum run time. 105 FERC ¶ 61,091 at P 70.

to operate over its entire capacity range, it would receive a non-zero merit-order dispatch to clear the market.

b. If the unit was needed in accordance with criterion 2.a in a previous settlement interval, and is still operating due to a minimum-run-time constraint, but none of its energy is needed in merit order in the current interval, the unit would not be eligible to set price in the current interval.

This criterion is consistent with the direction given in the October 28 Order as quoted above.

3. The ISO proposes to implement this proposal in the following manner in the IFM design:

a. In the IFM dispatch run, COG units will be treated as flexible, *i.e.*, capable of operating at any point between 0 and their P-max. As a result of this run, a COG unit that it is needed per criterion 2.a will be dispatched at its economically optimal operating level, even though that operating level may not be feasible.

b. In the IFM pricing run following the dispatch run, there is no change to the treatment of COG units. Thus, this proposed treatment of COG units does not result in inconsistency between the IFM dispatch and pricing runs.[42]

Because the COG unit's P-max is the same as its minimum load, the appropriate Energy bid for the COG unit, in both the dispatch and the pricing run of the IFM, is its minimum load bid divided by its P-max. This would be a constant-price Energy bid curve that covers the entire operating range of the COG unit from 0 to P-max.

c. In the DA RUC process following the IFM, any COG units offered in the IFM that were not dispatched will be treated as constrained. This treatment is appropriate because the RUC is an optimization of unit commitment, not a dispatch of Energy.

d. In Real Time, the COG unit will be treated as constrained to ensure that its Real Time dispatch is feasible. Thus, relative to the unit's potentially infeasible DA schedule, the ISO will dispatch the unit in Real Time either up to its P-max or down to 0.

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[42] There is still a need for a separate IFM pricing run following the dispatch run as long as there are some dispatched resources that are not eligible to set prices (*e.g.,* resources that submit Energy bids above the Damage-Control Bid Cap).

e. For the purpose of setting Real Time prices, these COG units will be treated as flexible and, therefore, eligible to set prices (as proposed in Phase IB). As in the IFM, the COG's energy bid would be a constant-price energy bid curve that covers the entire operating range of the COG unit from 0 to P-max, with a price equal to the COG's minimum load bid divided by P-max.

f. COG units will be settled at the appropriate forward market price for their forward scheduled quantities, and at the Real Time price for the difference between their Real Time dispatch and their final forward schedules.

At its April 5, 2004 meeting, the ISO's Market Surveillance Committee ("MSC") discussed the issue of COGs setting the price in the DA market. The MSC concurred with the ISO that the best approach is the one that the ISO is proposing herein, namely, to treat COGs as flexible in both the dispatch and pricing runs of the IFM, and then to apply the COG constraint in Real-Time dispatch so as to ensure a feasible dispatch.

The ISO submits that its proposal is consistent with the Commission's guidance in the October 28 Order and compatible with the overall MD02 design. The ISO's proposal also is consistent with the NYISO's treatment of fixed block generation, *i.e.*, fixed block generation is permitted to set the price when needed to meet load or avoid the operation of higher-cost units. *See New York Independent System Operator, Inc*. 100 FERC ¶ 61,182 (2002).

The comments filed on February 17 indicate that some parties oppose allowing COG units to set prices because (1) the resulting prices are not true marginal prices in the theoretical sense, and (2) the resulting forward prices will be somewhat higher when COG units are allowed to be price setters than when they are not.[43] While the ISO recognizes these concerns, the ISO submits that the revised approach proposed herein is appropriate because it reflects a reasonable balance between several conflicting objectives. As the ISO explained in its January 14 Clarification, the conflicting objectives are as follows:

> Ultimately the problem derives from the fact that we are trying to satisfy several objectives that are not fully mutually consistent. First, the CAISO wants LMPs to express the cost of serving the next MW of load at the location, according to the formal definition of marginal prices. Second, the CAISO wants the prices to reflect such costs in a realistic manner, by incorporating all the generation that must be dispatched to serve the load. When lumpy generation is needed to serve load, these two objectives come into conflict, because the mathematical optimization requires marginal generators to be continuously dispatchable above and below their optimal operating points, and hence will exclude lumpy generation from setting prices. Third, the CAISO wants settlement for CRRs (in the day-ahead market) to be consistent with the actual pattern of congestion. If the CAISO allows lumpy generation to set day-ahead prices we compromise this objective. Fourth, the CAISO wants to send meaningful real-time price signals to encourage forward scheduling of load and real-time demand response. This would argue for allowing lumpy generation to set prices in real-time (as the CAISO proposed and the Commission approved for Phase 1B). Fifth, the CAISO does not want to create impediments to convergence in prices between forward and real-time markets.[44]

The revised proposal does have the undesirable property of allowing COG units to establish forward schedules that are not feasible given their operating constraints. As the ISO noted in both the passage quoted above and the ISO's February 24 Comments, it is impossible to fully resolve all the issues in this situation because COG operating constraints are theoretically incompatible with the continuous nature of the optimization solution. After weighing the pros and cons of the various alternatives, the ISO has concluded that the infeasible

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43 SCE Comments at 9.

44 January 14, 2004 Clarification of CAISO Market Design Issues In Response to December 16, 2003 Notice of Technical Conference, at 7.

schedule issue is of less concern than the other problems because: (1) the magnitude of this problem will be small given the small population of COG that are eligible for this treatment (21 units with a total of 831 MW of capacity), and (2) Real-Time dispatch of these resources will be feasible and will thus "correct" the infeasible forward schedules. The modified proposal presented herein achieves the objective of creating prices that realistically reflect the cost of serving load in each interval in a manner that is consistent across the forward and real-time markets. This proposal also resolves an earlier concern expressed by the ISO by reducing the possibility that the Congestion Revenue Right ("CRR") settlement will be distorted by setting nodal price differences that are opposite to the direction of congestion. The ISO's proposal achieves a just and reasonable balance of these objectives and should be approved by the Commission.

E. Ancillary Services Procurement

In the July 22 MD02 Filing, the ISO indicated that it was proposing to incorporate A/S procurement in the DA and HA integrated forward markets and would select resources using an integrated approach that co-optimizes Energy and A/S procurement costs. The ISO noted that it intended to satisfy the bulk of its A/S procurement requirements in the DA timeframe. However, the ISO stated that it

> may defer satisfying all of its projected Day-Ahead A/S requirements until the Hour-Ahead market if the CAISO believes that its load forecast (and, thus, A/S requirement) is likely to change. This will allow the CAISO to minimize the risk of over-procuring A/S. Deferment of A/S procurement also allows the CAISO to adjust Day-Ahead A/S procurement to account for SC

> self-provision of A/S in the Hour-Ahead market. Finally, the CAISO may defer procuring A/S if it anticipates that the price of A/S may be lower in the Hour-Ahead market. This is consistent with the CAISO's obligation to procure A/S at least cost. The CAISO will not defer Hour-Ahead A/S procurement to Real-Time unless there are insufficient A/S bids in the Hour-Ahead market.

July 22 MD02 Filing, Transmittal Letter at 83. The ISO noted that the practice of "economic deferment" of a portion of its A/S requirements to the Hour Ahead Market for the purpose of minimizing total procurement cost was consistent with its existing practice, whereby the ISO historically has procured most of its A/S requirements in the DA timeframe.[45]

In the October 28 Order, the Commission expressed some concern that price divergence between the DA and HA markets might occur under the ISO's proposal because the ISO would be the only purchaser of A/S in the HA market and could have the power to suppress prices. October 28 Order at P 83. The Commission also expressed concern that the ISO might be speculating in the market. Although the Commission ultimately allowed the ISO the flexibility to procure a portion of its A/S requirements in the HA market, the Commission also ruled that suppliers should be allowed the same flexibility to buy-back A/S in the HA.[46] *Id.*

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45 Under the ISO's current market design, the A/S markets are conducted sequentially, following the running of the congestion management market. Economic deferment is relatively straightforward because there is an explicit supply curve for each Ancillary Service from which the ISO can calculate the cost of procuring any particular quantity of A/S in the DA market. In the context of the proposed IFM, there would be no such explicit supply curves for A/S. Economic deferment would be performed in the DA IFM by the ISO submitting a price-elastic demand curve for each A/S instead of a specific MW procurement target (which would be equivalent to an inelastic demand curve). Of course, in the HA market the ISO would be required to complete its required A/S procurement so its HA demands would be fixed quantities.

46 The Commission also directed the ISO's Department of Market Analysis to monitor the convergence/divergence of A/S prices in the DA and HA and report to the Commission on a monthly basis following implementation of the DA market.

At the January 28-29 Technical Conference, parties discussed the following issues: (1) to what extent should the ISO have well-defined, transparent A/S procurement rules; (2) how much flexibility the ISO should have in determining when to purchase needed A/S (and what the impacts are); (3) whether market participants should have the opportunity to buy-back their A/S position in the HA Market; and (4) what impact the HA buy-back of A/S would have on markets and system operators.

In their comments filed on February 17, 2004, several suppliers expressed concern about the ISO's proposal to defer A/S purchases from the DA to the HA to benefit from potentially lower HA prices. Williams Comments at 15. Some parties suggested that the ISO consider establishing a notification procedure in the DA market for LSEs to notify the ISO of the amount of self-supplied A/S that will be available in the HA. Williams at 16. Other parties recognized that reasonable limits on the ISO's purchase of A/S in the HA might be appropriate. SMUD Comments at 14-16. Several suppliers argued that it may be appropriate for the ISO to procure varied amounts of A/S in the Day-Ahead and Hour-Ahead, so long as suppliers have the same flexibility to buy-back A/S. Reliant Comments at 10-12; Mirant Comments at 7; Duke Comments at 3. The CPUC expressed concerns about A/S buy-back by suppliers (CPUC Comments at 6), and SCE argued that suppliers should not be permitted to buy-back A/S. SCE Comments at 8.

Based on the discussion at the January 28-29 Technical Conference and subsequent internal discussions, in its February 24 Comments the ISO proposed to revise its A/S procurement proposal as follows:

1. Under MD02, the ISO would not continue the currently approved practice of economic or price-based deferment of A/S procurement from DA to HA. The ISO has some concerns about this concession, however, due to the fact that its demand for A/S is determined by Western Electricity Coordinating Council ("WECC") reliability criteria and is therefore inelastic. This issue is discussed further below.

2. The ISO would set its DA procurement target at 100% of its estimated A/S requirements, based on its DA load forecast and allowing for A/S self provision. Because this approach is based on an estimation process and system conditions can change after the running of the DA market, the ISO still may be required to procure some additional A/S in HA or RT.

3. SCs who wish to defer some self-provision of A/S from DA to HA and avoid having the ISO procure A/S for their deferred quantities, would have to commit to a specific quantity of HA self provision in the DA scheduling time frame.[47] Such commitment would be binding, in the sense that failure to deliver the committed capacity would result in a penalty, such as a per-MW charge on the shortfall.

4. The ISO would procure additional A/S in the HA only when needed to supplement DA procurement due to unscheduled outages, changes in estimated A/S requirements (for example, due to revised load forecast or changes in the expected hydro-thermal supply mix), or possibly failure of the SCs to meet their DA commitments to self provide HA A/S capacity.

5. Sale of A/S in DA would be viewed as a binding commitment. HA buy-back by suppliers of DA A/S capacity would be allowed only in the event of unplanned outages that render the originally sold capacity unavailable. In this instance, the seller would buy back its DA A/S capacity at the higher of the DA or HA price.

The primary issues discussed at the March 3-5 Technical Conference were (1) what is meant by the buy-back of A/S capacity, and (2) whether a firm

[47] Even with such commitments, the ISO would still face some risk of under-procurement of A/S. Therefore, it may be appropriate to set a limit on the amount of deferred self-provision a SC would be able to declare in DA. Moreover, ongoing discussions at NERC regarding A/S adequacy may lead to a new requirement to procure A/S fully in the DA time frame, which would render the issue of deferred A/S procurement, including deferred self-provision, moot.

DA commitment by SCs to a quantity of HA A/S self-provision would be workable and meet the needs of the SCs and the ISO.

With regard to A/S buy-back, suppliers indicated that their intent was not to opt out of their obligation to provide the A/S they sold DA, but merely to "substitute" A/S from resources other than those that the ISO had procured in DA. This clarification relieved one of the ISO's primary concerns, namely, that the buy-back of A/S could result in the ISO being short of A/S after the HA market in instances where the HA A/S market had insufficient supplies available. The ISO therefore agreed to reconsider its February 24 position on A/S buy-back. Based on further consideration of the matter, the ISO is now offering a revised proposal that allows for A/S substitution in the HA under certain conditions, which are summarized below.

With regard to DA commitments by SCs to fixed quantities of A/S self-provision in HA, the technical conference discussion did not result in a proposal that was satisfactory to both the SCs or the ISO. The ISO "floated" a proposal that would allow SCs the flexibility to wait until the HA to identify the specific generating resources they would use to self-provide A/S, but would not provide LSEs with the flexibility to determine the final quantity of self-provision in HA. At least one of the major LSEs indicated that it needed both types of flexibility. The ISO responded that allowing such flexibility would impose too much uncertainty on the ISO regarding its ability to meet its A/S requirements. As discussed further below, the ISO now proposes to require that all A/S self-provision be scheduled in the DA Market, although SCs can substitute different resources in the HA Market.

Based on the above considerations the ISO offers the following revised proposal regarding A/S procurement, A/S buy-back, and A/S self-provision.

1. As a fundamental principle, the ISO must have certainty in the DA market time frame regarding the adequacy of its reserves for the next day. The subsequent points derive from this principle.

2. The ISO will procure A/S in the DA IFM to meet 100 percent of its anticipated need, based on its load forecast for the next day, minus any acceptable SC self-provision of A/S (defined below). In particular, the ISO will not engage in economic deferment of A/S procurement from DA to a subsequent market. Thus, A/S procurement in the HA or RT will be necessary only for post-DA changes in load forecast or system conditions (including outages of capacity previously committed to supply A/S).

3. Acceptable self-provision is defined as specific resources that are certified capable of providing A/S, meet any applicable locational A/S procurement requirements,[48] and are identified by the SC in the DA market in fulfillment of its anticipated requirements.

4. SCs who sell or self-provide A/S capacity to the ISO in the DA may offer to substitute different resources in the HA, and this will be acceptable to the ISO provided the substitute capacity meets the relevant A/S performance and locational requirements and has not already been committed for another use (*e.g.*, scheduled to provide Energy). The assessment of the acceptability of the substitution will be performed by the IFM optimization in the context of the Simplified Hour Ahead Scheduling Procedure discussed elsewhere in these comments.

The ISO's revised proposal addresses the concerns raised in the October 28 Order, yet will still ensure that the ISO has sufficient flexibility to address reliability concerns. Because the Commission's October 28th 2003 Order explicitly linked unrestricted HA buy-back by suppliers to the ISO's proposed

[48] The ISO's July 2003 MD02 filing indicates that the ISO intends to procure A/S locationally for specific sub-areas of the ISO grid that are defined so as to ensure the deliverability of energy from the procured A/S capacity. Attachment A at 14.

deferment of A/S purchases for economic reasons, such buy-back (other than for purpose of substituting A/S resources) should not be permitted now that the ISO will no longer be deferring A/S purchases for economic reasons.

As noted above, the ISO has some concerns about completely foregoing the ability to defer a portion of its A/S procurement from DA to HA for economic reasons. This concern is based on the fundamental fact that the ISO's demands for A/S are set by external reliability criteria and, as such, are inelastic. The Commission's October 28 Order seems to have overlooked this fact in linking supplier buy-back of A/S with ISO economic deferment of A/S procurement. This linkage is not appropriate because the ISO's A/S demands are inelastic. In particular, the idea that the ISO is in a position to exercise "buyer" market power in the A/S markets is simply not correct. To the contrary, the inelastic demand for A/S means that the ISO is vulnerable to the exercise of supplier market power in the A/S markets. At the same time, the ISO wishes to resolve this issue and, therefore, proposes to forego economic deferment, with the caveat that this may expose the ISO to withholding of supply from the DA A/S market. If experience shows this to be a problem, the ISO will bring this matter to the Commission's attention and may want to reconsider its ability to optimize A/S procurement between successive markets.

F. Marginal Losses

In its July 22 MD02 Filing, the ISO proposed to incorporate marginal losses in the Locational Marginal Prices ("LMPs") calculated in the IFM. Thus, these LMPs would reflect the marginal cost of serving the next MW of load at each location, including the costs of congestion and losses incurred in delivering Energy to that location. Moreover, this approach means that losses are paid for by loads through the settlement for withdrawing energy from the grid. Recognizing that this approach would result in over-collection of loss revenues from loads, the ISO proposed to "rebate" these costs back to loads by adding any over-collection of losses to the CRR Balancing Account. In the October 28 Order, the Commission found (1) the ISO's proposal to reflect marginal losses in its calculation of LMPs to be appropriate, and (2) the ISO's proposal to add over-collection of losses to the CRR Balancing Account (and its method of allocating the surplus revenues) to be reasonable. October 28 Order at PP 77-78. The following issues were discussed at the January 28-29 and March 3-5 MD02 Technical Conferences: (1) How the excess revenues created through marginal loss pricing can be returned to the appropriate participants without distorting efficient price signals; (2) how entities that self-provide losses should be treated; and (3) the feasibility of alternative proposals.

At the two technical conferences, no party appeared to disagree strongly with the ISO using marginal losses for purposes of determining LMPs. The primary issue seemed to be how to redistribute any over-collected loss revenues. In its July 22 MD02 Filing, the ISO identified the following benefits associated with including excess revenues in the CRR Balancing Account: (1) it would make CRRs more valuable because it would increase the possibility that CRR holders would receive full payment on their CRRs over the course of the year; (2) the proposed approach was easier to implement than other options because the ISO would not have to keep track of locations where loss revenues are over-collected; and (3) if there are surplus funds in the CRR Balancing Account (after CRR holders are paid their entitlement at the time of the yearly clearing), such funds will ultimately flow back to loads by being paid to Participating Transmission Owners to reduce their Transmission Access Charge. The CPUC, and SCE and Sempra support the ISO's proposal for allocating over-collected loss revenues. CPUC Comments at 6; SCE Comments at 9-11; Sempra Comments at 2-4.

At the January 28-29 Technical Conference, certain suppliers seemed to suggest that excess losses should be returned to suppliers. They believe that resources located far from loads will suffer high loss factors, which will consequently force them to lower their bids in order to be competitive with similar units located closer to loads. These claims lack merit because this effect merely reflects the reality of the cost to deliver the output of such units to load, and ought to be reflected in the costs of dispatch. Resource owners should take such factors into account when they decide where to locate and how to set their prices. If ISO rebates loss revenues to such units, it may skew accurate locational price signals. This is not an optimal result, especially if it requires extensive (and expensive) transmission upgrades.

The suppliers' argument also is based on a crucial misunderstanding of the Proposal. Their argument seems to be based on a belief that suppliers will pay loss charges under MD02 and, therefore, should be entitled to a share of the "rebated" loss revenues. Although it is true that today the methodology of

Generation Meter Multipliers (GMMs) does assess loss charges to suppliers, under LMP the cost of losses will be paid by loads. In that regard, when the IFM calculates nodal prices, each nodal price will reflect the marginal cost of serving an additional MWh of load at that location, including the effects of Congestion and losses to deliver the supply to the load. Thus, the cost of losses will be included in the settlement charges to load. Therefore, it is appropriate to refund the over-collected revenues to loads, not to suppliers.

Once it is understood why it is appropriate to refund the loss revenues to loads rather than suppliers, the use of the CRR balancing account as the means to do this should be less of an issue. The ISO agrees that it may be more precise to create a separate balancing account for losses, but the required settlement system would be more complex and costly. Moreover, using the CRR account should achieve a very similar result. The reason for this is that any balancing account surplus paid to the Participating TO becomes an offset to the Transmission Access Charge which is paid by all load on a per-MWh basis. While there may be different distributional impacts from such an approach, such impacts would not have a material impact on the locational price signal to load under a load aggregation pricing scheme.

FPL Energy offered a conceptual proposal for a market mechanism that would be operated by the ISO, whereby buyers and sellers of energy would voluntarily trade losses and thus re-allocate some of the loss over-collection. The concept is fairly complex, and FPL's representative at the MD02 Technical Conference acknowledged that it is still a work in progress, and not all the details have been worked out. FPL's representative further acknowledged that if all parties were to trade in this market, the ISO could often be revenue insufficient. Alternatively, if no one were to trade in the market, the ISO would need to have some means to allocate excess loss revenues. Therefore, although the ISO would not dismiss this proposal as potentially having value at some point in the future, the ISO does not believe it would be prudent to incorporate it into the MD02 design at the present time. Even if it were a fully developed proposal and could be demonstrated to be theoretically sound, practically workable, and an unambiguous enhancement to market efficiency, it would still require the ISO to incorporate an additional entirely new market, with the associated bidding and settlement functionalities, into its MD02 design and implementation plan when there is no significant problem to be solved by doing so.

The Bay Area Municipal Transmission Group ("BAMx") supported by Silicon Valley Power, et al., believe that loss over-collections should be allocated in proportion to the difference between marginal losses and average losses to loads that have been overcharged, and refunds of marginal losses over-collections should not be tied to the holding of CRRs. BAMx Comments at 6. BAMx claims that this approach more effectively tracks cost causation because crediting over-collections to CRR holders bears no relationship to the parties that have been over-charged. *Id.*

In the ISO's Answer to Protests (p. 59) filed on September 17, 2003 in the instant proceeding, the ISO acknowledged that a separate tracking and refund process for losses would be more accurate than the proposed use of the CRR

Balancing account. At the same time, it would add significant complexity to the settlement procedures and systems. The ISO's proposal offers a reasonable, cost-effective approximation, in view of the fact that excess revenues in the CRR Balancing Account flow back to loads through a reduction of the Transmission Access Charge.

SMUD alleges that the ISO's proposal (1) results in double collection of losses from existing transmission contract ("ETC") holders, and (2) does not satisfactorily accommodate the self provision of losses.[49] The ETC-related issues raised by SMUD are a matter for the stakeholder process to be convened to address settlements issues associated with ETC schedules. In its January 14 Clarification, the ISO indicated how its marginal loss proposal accommodates the self-provision of losses. SMUD has not raised any arguments demonstrating that such proposal is unjust and unreasonable.

G. Simplifying The Hour Ahead Market

In discussions at the January 28-29 Technical Conference the ISO and other parties identified several instances where having a fully functional HA settlement market, including all of the features of the DA Market, creates design

[49] SMUD indicates that it would not object to refunding excess loss revenues to the CRR Balancing Account provided that CRRs are allocated to any entity that contributes materially to the embedded cost of the transmission system, not solely to those entities within the ISO Control Area. As the ISO indicated in its September 17, 2003 Answer to Protests (pp. 98-99) in this proceeding, to the extent the Commission finds that CRRs should be allocated to load located outside of the ISO Control Area, the ISO would work with stakeholders to address the issue. The ISO again states for the record that all customers paying a wheeling charge should not automatically receive CRRs. Rather, consistent with Commission precedent, only parties taking long-term firm transmission service should receive CRRs. *See New England Power Pool, et al,* 100 FERC ¶ 61,287 at P 85 The ISO indicated that it might be appropriate for parties that pay the wheeling charge on a daily basis to receive CRRs. However, to the extent a party does not pay wheeling charges every day, it should not be entitled to CRRs. For example, a party that only sporadically uses the transmission system should not be entitled to CRRs because that party is not making a significant contribution to embedded costs equal to that of native load customers that use the grid every day.

challenges and complexities. Therefore, the ISO requested that the parties (1) provide comments in their filings on the business and operational needs they believe are served by having such an HA Market, (2) identify what specific elements of that HA Market are most essential to meet their needs, and (3) consider how their needs might be met with a simplified or “reduced” HA Market design.

The idea of simplifying or even eliminating the HA Market was previously raised in the context of the Stakeholder Working Groups in fall of 2002. At that time, there seemed to be virtually unanimous demand to retain the HA Market. There was some limited discussion (in the IFM Working Group) of the business and operational needs for the HA Market but, given the universal demand to retain the HA Market and the numerous other issues on which work was required, the group did not seriously consider whether and how the HA Market might be simplified and in a manner satisfactory to the parties.

In its February 24 Comments, the ISO offered some initial thoughts to stimulate the discussion regarding a simplified HA Market. The ISO also noted that there were several design challenges raised by the HA Market that had been identified in the technical conference process. For example, there was the question of how to prevent DA RUC capacity from selling energy for export in the HA Market. Also there was the issue of whether the ISO should be able to defer some DA A/S procurement to the HA Market. The ISO also indicated that there might be potential benefits as a result of simplifying the HA Market. In that regard, the ISO noted that the HA Market will increase the cost of MD02 in a nontrivial manner.[50] A simplified HA Market might reduce these costs. Another potential benefit of simplifying the HA market might be the ISO's ability to move the closing time of the market closer to Real Time. In that regard, during the Fall 2002 Working Group process, parties expressed considerable interest in having the HA Market close at T-60 rather than T-120. The ISO's earliest proposals on MD02 tried to accomplish this but, as the ISO examined the sequence of iterations the HA Market would have to perform and the complexity of each, it became apparent that T-60 would be unattainable. If there is a way to "reduce" the HA Market to its bare bones, *i.e.*, the minimal functionality to satisfy most of parties' business and operational needs, then it might be possible to move the HA Market closer to Real Time.

Accordingly, in its February 24 Comments, the ISO requested that parties consider the following questions for discussion at the March 3-5 Technical Conference:

1. Could the ISO limit HA submissions to self-schedules of incremental changes to parties' final DA schedules, *e.g.*, new bilateral transactions that were executed after the close of the DA market, or reductions in scheduled demand and supply due to reductions in the load forecast? In effect, could we do without an HA energy market?

2. Could the ISO limit the HA market to performing congestion management on these submitted self-schedule changes? If so, in the absence of energy bids what might be the basis of congestion adjustment (*e.g.*, effectiveness)?

3. Could the ISO eliminate HA settlement? For example, could the ISO issue RT pre-dispatch instructions based on schedule changes

50 For example, the HA settlement creates data management requirements nearly equal to the requirements of the DA settlement.

found to be feasible in the HA congestion run, so as to enable these changes to avoid RT deviation penalties, but otherwise settle all deviations between final DA and RT at RT prices?

4. The eastern ISOs all have two-settlement systems consisting of Day Ahead and Real Time settlement markets only. Are there any particular features of the California markets that would make the two-settlement approach inadequate?

The parties discussed these and other issues at the March 3-5 Technical Conference. In the course of that discussion, the parties identified their main business and operating needs for the HA Market. Parties identified their primary needs as follows: (1) to be able to schedule additional bilateral transactions as close as possible to RT, so as to provide SCs with certainty regarding the feasibility and availability of transmission for these transactions and to exempt them from any RT uninstructed deviation penalties (even though the Energy settlement would be at RT prices); (2) to buy and sell Energy in an HA spot energy market; (3) to substitute and/or buy back A/S capacity that had sold or self-provided A/S in the DA market (this issue is addressed in the discussion of A/S procurement in another section of the present document); (4) to schedule intermittent resources as close as possible to RT; and (5) to enable SCs to have some control over the congestion charges to which their HA schedules will be exposed (for example, by using bids for HA congestion management rather than simply relieving constraints). Additional needs and concerns identified by the parties are discussed below in a review of the written comments submitted to the ISO on this topic.

Another important discussion topic at the March 3-5 Technical Conference was a similar procedure currently in operation at the NYISO whereby parties can schedule generating resources and the use of the transmission system on an hour-ahead basis, using real-time prices for the associated energy settlements. The NYISO procedure, called the Balancing Market Evaluation ("BME"), enables participants to secure transmission ninety minutes prior to real time for transactions they wish to schedule subsequent to the close of the day ahead market. The BME performs a security analysis utilizing economic bids to modify schedules submitted to the BME as needed to ensure that the results are feasible. The scheduled quantities resulting from the BME are then settled at real-time prices, using an uplift, if needed, to ensure bid-cost recovery.

In fulfillment of the ISO's commitment at the March 3-5 Technical Conference, on March 19, 2004, the ISO posted an initial discussion draft setting forth a potential design for a simplified HA scheduling procedure. The stated objective of the discussion draft was to simplify the design of the HA Market as proposed in the July 2003 filing so as to (1) reduce design complexity, (2) reduce implementation costs for the ISO and market participants, (3) reduce ongoing operating costs for the ISO and market participants, and (4) meet to the maximum extent possible the primary operational and business requirements of market participants and the ISO.

The discussion draft also identified some key features of a HA Market design that would best meet these objectives, namely: (1) elimination of the HA Market settlement; (2) reducing the required computational activities in the running of the market; (3) moving the close of the HA Market closer to RT, at least up to T-75 and even T-60 if possible; (4) retaining the ISO's ability to procure additional A/S as needed due to changes in load forecast, operating status of facilities, or other unforeseen factors; and (5) retention of the ISO's ability to perform HA unit commitment using the five-hour time horizon proposed in the July 2003 filing.

Based on the comments submitted by parties in response to the March 19 discussion draft and further assessment by the ISO to ensure consistency with the MD02 comprehensive design, the ISO developed the following proposal which the ISO now submits for the Commission's consideration and approval on a conceptual basis. The proposal effectively combines the HA Market with the Real Time pre-dispatch process that was already part of the July 22 MD02 proposed design. It provides an opportunity for SCs to self-schedule additional supply resources and wheeling transactions and, to the extent SCs wish to bid to supply energy in the HA Market, such bids will be treated as bids to supply energy to the ISO's RT imbalance market. Those submitted HA self-schedules, as well as bids that are determined by the HA IFM to be feasible, will be issued binding pre-dispatch instructions. Once these pre-dispatch instructions are issued, they become the reference for measuring RT deviations and differences between DA Final Schedules and pre-dispatch instruction levels are not subject to any RT uninstructed deviation penalties. In addition, those resources that submit energy bids to the HA Market (in contrast to resources that submit self-schedule changes with no associated prices) and are dispatchable within the hour may receive additional intra-hour RT dispatch instructions from the ISO based on their submitted bids.

The ISO's proposal is best described in terms of the following sequence of steps and activities that would occur.

1. SCs submit Energy bids and desired HA self-schedule changes (*i.e.*, MW quantities with no associated prices) for supply resources and imports. SCs may also submit changes to wheeling schedules at this time. Submitted Energy bids are used for both the HA and RT markets; *i.e.*, there is no separate submission of distinct RT supplemental energy bids. The deadline for HA submissions would be T-75 or, if possible, T-60. [51]

   There are no bids or self-schedule changes for load in the HA Market because this is not necessary. Submitted Energy supply bids and supply self-schedules are cleared against the ISO's forecast of imbalance energy requirements (*i.e.*, the difference between the final DA schedule and the forecast for RT). Because there are no separate HA settlement prices, participants have no need to submit HA load bids or load self-schedule changes. Stated differently, there is no reason for load to seek to avoid the RT price by locking in the HA price because there is no HA price – all RT load that is not scheduled DA is settled at RT prices. Thus, a party who wants to schedule a bilateral Energy transaction, *i.e.*, schedule its own generation in HA to serve its own load, simply self-schedules the generation. Once the HA IFM accepts this generation self-schedule, the self-schedule will not be changed by the ISO in RT because it has no bids (except in the event that a RT transmission de-rate or other contingency creates a need for non-economic re-dispatch).

2. ISO runs the IFM optimization to simultaneously clear congestion and energy and procure any incremental A/S that may be needed. The load used in this optimization is the ISO's load forecast, distributed to nodes

[51] This will preclude having a "re-bid" opportunity between the publication of HAM results and the close of RT supplemental bid submissions. As participants in the MD02 IFM Working Group conducted in Fall 2002 will recall, the ISO determined at that time that performing the full functionality of the IFM in the HA time frame would not allow moving the close of the HAM any nearer to RT than T-90. Allowing for a 30-minute re-bid period would mean that the HAM could close no later than T-120. Therefore, in order to move the close of HAM closer to RT, the ISO needs to both simplify the HAM procedures and eliminate the re-bid period, so that RT supplemental bids will need to be submitted at the same time as HAM submissions. Moving the HAM closer to RT and not having a separate HAM settlement will mean that supply resources can submit a single set of energy bids to be used in both the HA and RT markets.

based on load distribution factors ("LDFs").[52] Hourly pre-dispatches of inter-tie supplies are also determined in this process.

a. As in the July 22 MD02 Proposal, the HA IFM is incremental to DA in the sense that the Final DA Schedule is modeled as a set of fixed quantities having highest priority protection against non-economic adjustment.
b. As in the July 22 MD02 Proposal, the HA IFM first attempts to clear based on submitted HA bids, treating self-schedules as price-takers in this process and preserving all appropriate priorities consistent with the original proposal. For example, the scheduling priority of ETCs will be honored consistent with the July 2003 proposal for honoring ETCs.
c. As in the July 22 MD02 proposal, non-economic adjustments are performed if bids are not sufficient to resolve all congestion and clear the IFM.
d. The MW quantities cleared in the HA IFM constitute a binding pre-dispatch for Real Time that is feasible with regard to transmission constraints and generator performance. These pre-dispatched quantities are then used as the reference for issuing further RT dispatch instructions and for calculating RT deviations. In particular, the differences between DA final schedules and these pre-dispatches are not subject to any RT Uninstructed Deviation Penalties ("UDP"). (The UDP would still apply as usual to any uninstructed deviations, outside of allowable tolerance bands, from the pre-dispatches and other RT dispatch instructions.)
e. Although the HA IFM produces complete LMPs for the system, these prices are not used for settlement. The pre-dispatched quantities cleared in the HA IFM, as modified by any further RT dispatch instructions, are settled based on RT LMPs. Consistent with the July 22 MD02 Filing, quantities pre-dispatched for RT are not eligible to set RT prices, but they are eligible for bid cost recovery through an uplift, if necessary.
f. The HA IFM also produces advisory Real Time A/S awards for any incremental A/S capacity needed by the ISO to address load forecast changes and outages. These HA A/S awards are considered advisory because they will be finalized in RT dispatch. Consistent with the RT A/S procurement proposed in the July 22 MD02 Filing, there are no separate A/S capacity bids considered in

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[52] Performing the HA optimization based on the ISO's load forecast rather than submitted load bids and self-schedules has the additional benefit of solving the problem of trying to prevent capacity procured in the DA RUC process from scheduling HA exports. This problem was debated at great length during the technical conferences without ever arriving at a satisfactory solution. Under this new HA market proposal, it is no longer a problem because the HA becomes an extension of the RT imbalance market and, just like in the original design of the RT pre-dispatch, supply bids are cleared against forecast load which is not price-elastic (*i.e.*, a price taker) and therefore will be served before any export bids can be cleared.

the HA process. Resources selected for A/S in HA or RT are paid the relevant opportunity costs as described in the original proposal.

g. The HA IFM also determines hourly pre-dispatch of inter-tie bids. Under this proposal there is no reason to make inter-tie pre-dispatch a separate process from the clearing of the HA IFM.

3. The ISO publishes pre-dispatch notices for generating units and for hourly inter-ties, and advisory RT A/S awards at approximately T-45 (45 minutes before the start of the operating hour).

4. In Real Time, the ISO issues 5-minute dispatch instructions. Energy bids submitted to the HA IFM by resources that are intra-hour dispatchable are available for further dispatch in RT. This includes Decremental as well as Incremental bids; that is, a supply resource may be DEC'd in RT using the same energy bid that was used to establish its pre-dispatch in the HA IFM. Settlement rules for RT dispatch instructions are not modified by this proposal.

The ISO believes that the aforementioned simplified HA Market proposal best meets the stated objectives and is most consistent with the comprehensive MD02 design. An alternative would be a "transmission-only" HA Market along the lines of the proposal described as Option 2 in the March 19 discussion draft.[53] While this alternative may be appealing to some parties, it is important to recognize that it would require retaining the infamous balanced-schedule requirement and market separation rule which the Commission already has found are problematic and should be eliminated. In a transmission-only HA Market, preserving the balance of each individual SC would require SCs to

[53] The idea of a transmission only HA market arose in response to the desire of parties to be able to schedule bilateral transactions, *i.e.*, balanced load and supply, prior to RT. The idea is that SCs would submit balanced HA schedule changes along with "adjustment bids" expressing the value they place on having their schedules go through unadjusted when there is congestion, much as is done under the ISO's current forward market design. Trying to do this would seriously conflict with the objectives of MD02, because it would require the ISO to keep each SC's submitted HA schedule in balance in the congestion management process. This would mean retaining the market separation rule, which has been a prominent feature of the ISO's original zonal design. While the market separation rule may be workable n the context of a congestion management process that uses a simple network model consisting of a few radially-linked zones, it becomes extremely problematic when congestion management enforces all the constraints of a complex network. The present proposal achieves the desired result through a much simpler and more elegant design.

submit balanced self-schedule changes only (*i.e.*, there would be no energy bids). Thus, it would not provide an opportunity for parties with excess supply to offer that supply to meet RT load. Moreover, early on in the MD02 project, the ISO recognized that trying to preserve the market separation rule while enforcing a full network model for congestion management, would likely require non-economic adjustment of schedules on an all-too-frequent basis, thereby resulting in substantial reductions to the HA schedule changes submitted by SCs. Therefore, the ISO concluded that a transmission-only HA Market does not offer much promise of meeting the needs parties identified for the HA Market.

Several parties submitted comments on the March 19 discussion draft. Comments generally fell into two categories: (1) the plan as presented prohibits loads from scheduling in the Hour Ahead time frame; and (2) the ISO must explain how Metered Sub-system ("MSS") contracts would be honored. With respect to the first issue, the ISO recognizes that the discussion draft did not provide sufficient explanation of how self-scheduled resources would be able to schedule their own resources to serve their load, thereby making it unnecessary to self-schedule the load in HA. The crucial point to emphasize in understanding the ISO's proposal is that, absent distinct HA settlement prices, there is no difference between load that simply consumes in RT versus load that might be scheduled by the SC in HA. It is only the supply resources that are subject to RT uninstructed deviation penalties. As such, only supply resources need to be scheduled in the HA to insulate themselves from such penalties and to provide certainty ahead of RT of the feasibility of their schedules. Treating the feasible

HA supply and inter-tie schedules as RT pre-dispatch instructions is the simplest way to achieve these objectives, while utilizing design elements already included in the MD02 comprehensive design (specifically the RT pre-dispatch), substantially simplifying the HA process, and moving the HA time line much closer to RT.

With respect to the MSS issue, the ISO is in the process of working with stakeholders to consider on a comprehensive basis all MSS-related issues in the context of the overall market redesign.

CDWR, CMUA, PG&E and SVP either contend that the proposal does not allow for loads to adjust for forecast error in the current proposal or ask for further clarification on how the proposal accommodates this primary requirement.[54] The instant comments should provide the needed clarification. As noted above, due to the elimination of the HA settlement, any load deviations to the DA Market are settled at the real-time price and, as such, there is no need for bids or self-schedule changes for load in the HA Market.

CMUA and SVP expressed concern that the proposal does not adequately address the treatment of load under the MSS agreement, potentially forcing a penalty situation for not performing within their deviation bandwidth. The previous clarification on how load is settled with respect to differences from the DA schedule should provide these parties with the flexibility and protection that they seek. As indicated above, other MSS-related issues pertaining to the simplified HA Market proposal (*e.g.*, A/S buy back and adjustments to

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54 Powerex submitted comments generally supporting the concept of a simplified HA Market as detailed by the ISO.

accommodate forced outages of transmission) are either addressed in other sections of these comments, or will be taken up in the broader MSS discussion with Stakeholders.

While Powerex generally supported the concept of a simplified HA market, Powerex noted that the combination of the HA and RT bid process could effectively move the bid-submission time-line for supplemental energy further away from real-time than it currently is (T-45). While it is true that RT supplemental bids would have to be submitted at the same time as HA Market submissions, it is not unreasonable to expect that changes to resource availability would be minimal in the 15 to 30 minutes between the proposed close of the HA Market (T-60 or T-75) and the current closing of RT bids at T-45. Furthermore, the certainty of an hourly pre-dispatch greater and the compatibility of the proposed HA Market timeline with West-wide scheduling practices would seem to offset this concern.

The Real-time pre-dispatch approach would also address the preliminary comment from Calpine that, at a minimum, Calpine would need to see the final Hour Ahead schedule prior to the start of the hour, as currently is the case. The timing of the real-time pre-dispatch should fulfill this objective.

CMUA and SVP also requested further clarification on the treatment of Inter-SC trades in the simplified HA Market proposal. It is important to recognize that Inter-SC trades under MD02 are purely a financial settlement device and have no effect on congestion management or the prices and schedules resulting from the IFM. Given that the simplified HA Market proposal is effectively an imbalance energy market and does not have a distinct HA settlement (and indeed, there are no Inter-SC trades in RT), there is no need for an Inter-SC trades facility in the HA Market. Moreover, even in the DA market the Inter-SC trade facility is offered by the ISO only as an accounting convenience for SCs. The same functionality can be accomplished between counter-parties on a bi-lateral basis without utilizing the Inter-SC trade facility. For example, they can formulate contracts for differences in relation to the imbalance energy price and self-scheduled supply bids submitted on behalf of another party in the simplified HA Market.

The ISO received some comments that pertained directly or indirectly to the “transmission-only” HA Market set forth in the discussion draft. Powerex opposed the “transmission-only” HA Market because it is a transmission-only HA market that is inconsistent with the DA and RT market design. CMUA suggested that the ISO should not give up so easily on the “transmission-only” HA Market. CMUA stressed that it is important that any simplified HA Market reduce exposure to congestion charges between DA and RT. CMUA expressed concern that neither option achieved this result.

The ISO submits that CMUA’s concern assumes greater significance to the HA settlement than it merits. The complete HA settlement market as originally proposed would still expose SCs to congestion charges between DA and HA. Given the proximity of the HA Market to the RT market, there will probably be greater deviations in prices between DA and HA than between HA and RT; so, the full HA settlement market would not likely provide benefits in this regard comparable to the costs of retaining it. Moreover, the ISO's current proposal does offer parties the opportunity to obtain pre-real-time certainty with respect to their generation and inter-tie schedules. To the extent parties wish to self-schedule these, they would be price takers for RT congestion charges just as they would be price takers for HA congestion charges if the HA settlement were retained. Based on the discussion at the March 3-5 Technical Conference, the ISO believes that this scheduling certainty combined with insulation from RT uninstructed deviation penalties for HA schedules are more important to parties than being able to settle at HA rather than RT prices. SVP stated that it would support further discussion regarding a simplified HA Market proposal that eliminates some "markets" but still allows Scheduling Coordinators to change schedules within the current HA timeframe. Given that the principal features of "transmission-only" HA Market are less compatible with the IFM design and require enforcement of a balanced schedule requirement and market separation rule, the ISO has concluded that the "transmission-only" HA Market is vastly inferior to the approach the ISO now proposes (which was sketched out as Option 1 in the March 19 discussion draft).

IV. CONCLUSION

Wherefore for the foregoing reasons, the ISO requests that the Commission act on the ISO's Revised Comprehensive Market Design Proposal in a manner consistent with the discussion herein.

Respectfully submitted,

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ATTACHMENT A

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CALIFORNIA INDEPENDENT SYSTEM OPERATOR CORPORATION'S PROPOSED MODIFICATIONS TO ITS REVISED COMPREHENSIVE MARKET DESIGN PROPOSAL FOLLOWING THE MARCH 3-5, 2004 TECHNICAL CONFERENCE

DOCKET NO. ER02-1656
MAY 11, 2004

I. PROPOSED REVISIONS TO THE DAY AHEAD MUST OFFER OBLIGATION PROPOSAL

1. A Day Ahead Must Offer Obligation ("MOO") should apply to all participating generators until the earlier of January 1, 2008 or the date on which the California Public Utilities Commission's resource adequacy program is fully implemented.

2. If the Federal Energy Regulatory Commission ("Commission") does not approve a Day Ahead MOO, then the Commission should approve a Flexible Offer Obligation with the following requirements:

   a. Under FOO, units would be obligated to bid into either the ISO's DA or Real Time ("RT") markets subject to the conditions specified below.
   b. The ISO would have the ability to grant a pre-emptive waiver to a unit, thereby exempting the unit from participation in either or both the DA and RT markets. If a unit stays out of the DA market, then absent a pre-emptive waiver, the unit will required to self-commit and be on-line in RT.
   c. In order for a unit that has a start-up time of more than five hours, *i.e.*, a long start time unit ("LST"), to receive a waiver from the ISO not to be available in RT), the LST must (1) not self schedule or self-commit in the DA market, and (2) bid into the DA market and not be committed by the ISO either in the integrated forward market ("IFM") or RUC.
   d. In order for a unit with a start-up time between one and five hours, *i.e.*, a medium start-time unit ("MST") to receive a waiver from the ISO not to be available in RT, the MST must (1) not self-schedule or self-commit in the Hour-Ahead ("HA") market, and (2) bid into the market and not be committed by the ISO either in the IFM or RUC.
   e. LST resources would be eligible to have their start-up ("SU") and minimum load ("ML") costs covered by the ISO only if they (1) do not self-commit in the DA market, and (2) are committed

by the ISO in the DA IFM or RUC. MST resources would be eligible to have their SU/ML costs covered by the ISO only if they (1) do not self-commit in the HA market, and (2) are committed by the ISO in the HA market or HA RUC.

3. Resource owners that are subject to the FOO would not be permitted to transfer the ability to physically withhold to another party through a contract.

4. The FOO would apply until the earlier of January 1, 2008 or the date on which the CPUC's resource adequacy program is fully implemented.

5. The DA MOO or FOO (whichever is applicable) would be replaced with a minimal real time must offer obligation on the earlier of January 1, 2008 or the date on which the CPUC's resource adequacy program is fully implemented.[1]

II. PROPOSED REVISIONS TO RESIDUAL UNIT COMMITMENT PROPOSAL

1. The bid cap on the Availability Payment will be $150. (The ISO originally proposed a $100 cap and FERC approved a $250 cap in its October 28 Order.)

2. The Availability Payment will be paid on a locational MCP basis. The ISO anticipates that RUC Availability bids will be treated as though they were energy bids and will be cleared against forecasted load using the full network model, so that the result will be nodal Availability Payment MCPs. It is important to note that RUC procurement based on the full network model and payment of a locational MCP creates a need for local market power mitigation with respect to RUC capacity (This is a new provision responds to the October 28 Order and the Commission Staff's clarification of such order at the January 28-29 Technical Conference.)

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[1] As envisioned by the ISO, a minimal real-time MOO would require all resources that are operating and have capacity that is unloaded and not otherwise committed (*e.g.*, for A/S) to offer energy from that capacity into the RT market (with appropriate accommodation for use-limited resources). This minimal RT MOO would not include a DA waiver process. Thus, in contrast to today's real-time MOO or a FOO, long-start-time units not subject to the DA MOO would be able to decide whether to operate or shut down without requesting permission from the ISO. However, for reliability purposes, under extreme conditions (such as major unplanned transmission outages), the ISO would have the authority to commit such units within the ISO Control Area on a DA basis even though they may not be subject to a DA MOO.

4. The Availability Payment for a given operating hour will not be rescinded if a unit is dispatched in the energy markets subsequent to the RUC process (for the same operating hour). (In its July 22 MD02 Proposal, ISO proposed that 100% of the "Availability Payment" would be rescinded if the unit was dispatched in the energy market subsequent to RUC. The Commission ruled that no portion of the "Availability Payment" should be rescinded.)

4. The combined Availability Payment received in RUC and Energy MCP received in energy markets subsequent to RUC cannot exceed $250. This is necessary to avoid potential economic withholding from the DA IFM. Specifically, this measure is necessary to avoid potential disincentives against supplier participation in the DA market and preferential participation in the RT market. Without such a measure, the Availability Payment would effectively raise the RT price cap to $400 (the sum of the Availability Payment and real-time energy bid caps under the ISO's proposal). (This is a new provision that was not included in the ISO's July 22 MD02 Filing but that is now necessary given that Availability Payments will no longer be rescinded when RUC capacity is dispatched for energy.)

5. The portion of a unit's output that is mitigated in the DA pre-IFM run for local market power in the Energy market and does not clear the IFM, will be slated as RUC capacity and will be eligible to receive a RUC Availability Payment in addition to the Energy payment that it receives in the market (hour-ahead or real-time) where its Energy is eventually scheduled or dispatched. However, because of its local market power, the unit's RUC Availability Payment bid will be subject to mitigation, *i.e.*, it will be set at the lower of the unit's Availability Payment bid price or a mitigated reference level. The unit can, however, collect a higher Availability Payment MCP (LMP) that may be set at its location by other accepted Availability Payment bids. Mitigated Availability Payment bid prices will be calculated by an independent entity and will based on competitive Availability Payment bid reference levels, *e.g.*, the mean or median of the highest accepted "non-mitigated" availability bids for the preceding 90 days.[2] In the event that there are no accepted "non-mitigated" RUC bids in the previous 90-days to calculate a Bid-based Reference Value, the last available Bid-based Reference Value will serve as the default value until either:
    a. The Independent Entity and the affected unit owner reach agreement on an alternative Consultative Value; or

[2] As indicated in its Comments, the ISO is amenable to using a timeframe shorter than 90 days if there is market participant support for such an approach.

b. The CAISO awards RUC capacity to non-mitigated RUC bids, which will mean that data are once again available to calculate a new Bid-based Reference Level.

Under this approach, the Availability Payment bid reference level will be the same for all units, calculated separately for peak and off-peak hours, and posted daily on the CAISO OASIS. (This is a new provision that was not included in the ISO's July 22, 2003 MD02 Filing).

6. Recovery of Start-Up and Minimum Load Costs shall be net of market revenues (A/S, energy profits (defined as MCP – bid) and RUC Availability Payments). (This is consistent with the ISO's July 22 MD02 Proposal. The Commission rejected the netting proposal without prejudice until a resource adequacy program is implemented.)

7. Intrastate gas transportation and municipal use fees shall be included in minimum load energy costs. (These costs were not included under the ISO's July 22 MD02 Proposal or under the October 28 order.)

8. Use RMR Contract gas costs for RUC. This would involve using a two-day average of three daily indices (NGI So Cal Border, BTU So Cal Border and Gas Daily So Cal Gas large package) for SCE or SDG & E units, and a two-day average of two daily indices (NGI PG & E Citygate and Gas Daily PG & E Citygate) for former PG & E units, plus any applicable intrastate transportation and municipal use fees. (This is a new provision that was not included in the ISO's July 22 MD02 Filing.)

9. RMR dispatches that occur in RUC would not be eligible for setting or receiving the Availability Payment MCP. Similarly, any unit pre-designated as a capacity resource under a load serving entity's ("LSEs") resource adequacy plan established by the CPUC would not be eligible to receive or set the RUC Availability Payment MCP, provided both the resource owner and the LSE agree to this treatment in their contract. It will be the responsibility of the SC who designates such resources to indicate to the ISO whether each resource should be eligible to receive the RUC Availability Payment. Finally, resources designated as "self-provided" RUC capacity by a load-serving SC (described further below) will not be eligible to set or receive the RUC Availability Payment MCP. In all cases, units not eligible to reserve the RUC Availability Payment will never be eligible to set the corresponding MCP. (This is a new provision that was not included in the July 22 MD02 Filing).

10. The objective function of RUC will be to minimize commitment costs, *i.e.*, the sum of (1) the product of the Availability Payment bid price and the RUC MW for all capacity that is not RMR, plus (2) the sum of SU and ML costs for all RUC resources (including RMR) committed in the RUC process. The ISO will not purchase Energy in the RUC process.

(This is a change to the RUC proposal that the ISO agreed to make at the March 3-5 Technical Conference).

11. RUC self-provision will be permitted.

III. REVISED PROPOSAL REGARDING THE TREATMENT OF CONSTRAINED OUTPUT GENERATORS

1. COGs eligible to set prices, both in the integrated forward market ("IFM") and in Real-Time would be CTs that can only run at full output. This definition is consistent with the definition of Constrained Output Generators adopted by the Commission in its order on the ISO's Tariff Amendment No. 54.[3] *See California Independent System Operator Corporation*, 105 FERC ¶ 61,091 at P70 (2003).

2. The specification of the circumstances in which COG may set prices is as follows:

   a. Eligibility to set the price in any settlement interval would depend on some portion of the unit's output being needed in merit order to serve load. In other words, if the unit is modeled as fully flexible to operate over its entire capacity range, it would receive a non-zero merit-order dispatch to clear the market.

   b. If the unit was needed in accordance with criterion 2.a in a previous settlement interval, and is still operating due to a minimum-run-time constraint, but none of its energy is needed in merit order in the current interval, the unit would not be eligible to set price in the current interval.

3. The ISO proposes to implement this proposal in the following manner in the IFM design:

   a. In the IFM dispatch run, COG units will be treated as flexible, *i.e.*, capable of operating at any point between 0 and their P-max. As a result of this run, a COG unit that it is needed per criterion 2.a will be dispatched at its economically optimal operating level, even though that operating level may not be feasible.

   b. In the IFM pricing run following the dispatch run, there is no change to the treatment of COG units. Thus, this proposed

[3] The Commission stated that COGs "are generating resources that cannot easily or economically change load levels and are typically restricted to generating at their full capacity for their unit-specific minimum run time. 105 FERC ¶ 61,091 at P 70.

treatment of COG units does not result in inconsistency between IFM dispatch and pricing.[4]

Because the COG unit's P-max is the same as its minimum load, the appropriate energy bid for the COG unit, in both the dispatch and the pricing run of the IFM, is its minimum load bid divided by its P-max. This would be a constant-price energy bid curve that covers the entire operating range of the COG unit from 0 to P-max.

c. In the DA RUC process following the IFM, any COG units offered in the IFM that were not dispatched will be treated as constrained. This treatment is appropriate because the RUC is an optimization of unit commitment, not a dispatch of energy.

d. In Real Time, the COG unit will be treated as constrained to ensure that its Real Time dispatch is feasible. Thus, relative to the unit's potentially infeasible DA schedule, the ISO will dispatch the unit in Real Time either up to its P-max or down to 0.

e. For the purpose of setting Real Time prices, these COG units will be treated as flexible and, therefore, eligible to set prices. As in the IFM, the COG's energy bid would be a constant-price energy bid curve that covers the entire operating range of the COG unit from 0 to P-max, with a price equal to the COG's minimum load bid divided by P-max.

f. COG units will be settled at the appropriate forward market price for their forward scheduled quantities, and at the Real Time price for the difference between their Real Time dispatch and their final forward schedules.

IV. REVISED PROPOSAL REGARDING ANCILLARY SERVICES PROCUREMENT, SELF-PROVISION AND BUY-BACK

1. As a fundamental principle, the ISO must have certainty in the DA market time frame regarding the adequacy of its reserves for the next day. The subsequent points derive from this principle.

2. The ISO will procure A/S in the DA IFM to meet 100 percent of its anticipated need, based on its load forecast for the next day, minus any acceptable SC self-provision of A/S (defined below). In particular, the ISO will not engage in economic deferment of A/S procurement

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[4] There is still a need for a separate IFM pricing run following the dispatch run as long as there are some dispatched resources that are not eligible to set prices (*e.g.,* resources that submit energy bids above the damage-control bid cap).

from DA to a subsequent market. Thus, A/S procurement in the HA or RT will be necessary only for post-DA changes in load forecast or system conditions (including outages of capacity previously committed to supply A/S).

3. Acceptable self-provision is defined as specific resources that are certified capable of providing A/S, meet any applicable locational A/S procurement requirements,[5] and are identified by the SC in the DA market in fulfillment of its anticipated requirements.

4. SCs who sell or self-provide A/S capacity to the ISO in the DA may offer to substitute different resources in the HA, and this will be acceptable to the ISO provided the substitute capacity meets the relevant A/S performance and locational requirements and has not already been committed for another use (*e.g.*, scheduled to provide energy). The assessment of the acceptability of the substitution will be performed by the IFM optimization in the context of the Simplified Hour Ahead Scheduling Procedure discussed elsewhere in these comments.

V. CONCEPTUAL PROPOSAL FOR A SIMPLIFIED HOUR AHEAD MARKET

The ISO's proposal for a simplified Hour-Ahead market would reflect the following sequence of steps and activities:

1. SCs submit energy bids and desired HA self-schedule changes (*i.e.*, MW quantities with no associated prices) for supply resources and imports. SCs may also submit changes to wheeling schedules at this time. Submitted energy bids are used for both the HA and RT markets; *i.e.*, there is no separate submission of distinct RT supplemental energy bids. The deadline for HA submissions would be T-75 or, if possible, T-60. [6]

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5 The ISO's July 22, 2003 MD02 filing indicates that the ISO intends to procure A/S locationally for specific sub-areas of the ISO grid that are defined so as to ensure the deliverability of energy from the procured A/S capacity. Attachment A at 14.

6 This will preclude having a "re-bid" opportunity between the publication of HAM results and the close of RT supplemental bid submissions. As participants in the MD02 IFM Working Group conducted in Fall 2002 will recall, ISO determined at that time that performing the full functionality of the IFM in the HA time frame would not allow moving the close of the HAM any nearer to RT than T-90. Allowing for a 30-minute re-bid period would mean that the HAM could close no later than T-120. Therefore, in order to move the close of HAM closer to RT, the ISO needs to both simplify the HAM procedures and eliminate the re-bid period, so that RT supplemental bids will need to be submitted at the same time as HAM submissions. Moving the HAM closer to RT and not having a separate HAM settlement will mean that supply resources can submit a single set of energy bids to be used in both the HA and RT markets.

There are no bids or self-schedule changes for load in the HAM because this is not necessary. Submitted energy supply bids and supply self-schedules are cleared against the ISO's forecast of imbalance energy requirements (*i.e.*, the difference between the final DA schedule and the forecast for RT). Because there are no separate HA settlement prices, participants have no need to submit HA load bids or load self-schedule changes. Stated differently, there is no reason for load to seek to avoid the RT price by locking in the HA price because there is no HA price – all RT load that is not scheduled DA is settled at RT prices. Thus, a party who wants to schedule a bilateral energy transaction, *i.e*., schedule its own generation in HA to serve its own load, simply self-schedules the generation. Once the HA IFM accepts this generation self-schedule, the self-schedule will not be changed by the ISO in RT because it has no bids (except in the event that a RT transmission de-rate or other contingency creates a need for non-economic re-dispatch).

2. ISO runs the IFM optimization to simultaneously clear congestion and energy and procure any incremental A/S that may be needed. The load used in this optimization is the ISO's load forecast, distributed to nodes based on load distribution factors ("LDFs"). Hourly pre-dispatches of inter-tie supplies are also determined in this process.
    a. As in the original MD02 proposal, the HA IFM is incremental to DA in the sense that the Final DA Schedule is modeled as a set of fixed quantities having highest priority protection against non-economic adjustment.
    b. As in the original MD02 proposal, the HA IFM first attempts to clear based on submitted HA bids, treating self-schedules as price-takers in this process and preserving all appropriate priorities consistent with the original proposal. For example, the scheduling priority of ETCs will be honored consistent with the July 2003 proposal for honoring ETCs.
    c. As in the original MD02 proposal, non-economic adjustments are performed if bids are not sufficient to resolve all congestion and clear the IFM.
    d. The MW quantities cleared in the HA IFM constitute a binding pre-dispatch for Real Time that is feasible with regard to transmission constraints and generator performance. These pre-dispatched quantities are then used as the reference for issuing further RT dispatch instructions and for calculating RT deviations. In particular, the differences between DA final schedules and these pre-dispatches are not subject to any RT Uninstructed Deviation Penalties ("UDP"). (The UDP would still apply as usual to any uninstructed deviations, outside of allowable tolerance bands, from the pre-dispatches and other RT dispatch instructions.)

e. Although the HA IFM produces complete LMPs for the system, these prices are not used for settlement. The pre-dispatched quantities cleared in the HA IFM, as modified by any further RT dispatch instructions, are settled based on RT LMPs. Consistent with the July 22 MD02 Filing, quantities pre-dispatched for RT are not eligible to set RT prices, but they are eligible for bid cost recovery through an uplift if necessary.
f. The HA IFM also produces advisory Real Time A/S awards for any incremental A/S capacity needed by the ISO to address load forecast changes and outages. These HA A/S awards are considered advisory because they will be finalized in RT dispatch. Consistent with the RT A/S procurement proposed in the July 22 MD02 Filing, there are no separate A/S capacity bids considered in the HA process. Resources selected for A/S in HA or RT are paid the relevant opportunity costs as described in the original proposal.
g. The HA IFM also determines hourly pre-dispatch of inter-tie bids. Under this proposal there is no reason to make inter-tie pre-dispatch a separate process from the clearing of the HA IFM.

3. The ISO publishes pre-dispatch notices for generating units and for hourly inter-ties, and advisory RT A/S awards at approximately T-45 (45 minutes before the start of the operating hour).
4. In Real Time, the ISO issues 5-minute dispatch instructions. Energy bids submitted to the HA IFM by resources that are intra-hour dispatchable are available for further dispatch in RT. This includes DECs as well as INCs; that is, a supply resource may be DEC'd in RT using the same energy bid that was used to establish its pre-dispatch in the HA IFM. Settlement rules for RT dispatch instructions are not modified by this proposal.

May 11, 2004

The Honorable Magalie Roman Salas
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, DC 20426

Re: Docket No. ER02-1656-000
California Independent System Operator Corporation

Dear Secretary Salas:

Enclosed for electronic filing please find the Comments of The California Independent System Operator Corporation Regarding Technical Conference in the above captioned docket.

Thank you for your assistance in this matter.

Respectfully submitted,

Anthony J. Ivancovich
Counsel for The California Independent
System Operator Corporation

CERTIFICATE OF SERVICE

I hereby certify that I have this day served the foregoing document upon each person designated on the official service list compiled by the Secretary in the above-captioned docket.

Dated at Folsom, California, on this 11th day of May, 2004.

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Anthony J. Ivancovich