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May 1, 2002

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

Re: ***San Diego Gas and Electric Company, Complainant v. Sellers of Energy and Ancillary Services Into Markets Operated by the California Independent System Operator and the California Power Exchange, Respondents,***
Docket No. EL00-95-001, *et al.*

California Independent System Operator Corporation,
Docket No. ER02-____-000

Dear Secretary Salas:

Pursuant to Section 205 of the Federal Power Act ("FPA"), 16 U.S.C. § 824d; Sections 35.11 and 35.13 of the Commission's regulations, 18 C.F.R. §§ 35.11, 35.13; and the Commission's December 19, 2001 Order on Clarification and Rehearing,[1] the California Independent System Operator Corporation ("ISO")[2] respectfully submits for filing its Comprehensive Market Design Proposal ("MD02").[3] The market design changes included in MD02 are intended to address known deficiencies in the ISO's existing market design and to support the ISO's core

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[1] *San Diego Gas & Electric Co. v. Sellers of Energy and Ancillary Services Into Markets Operated by the California Independent System Operator and the California Power Exchange, et al.*, 97 FERC ¶ 61,275 (2001) ("December 19 Rehearing Order").

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

[3] As the Affidavit of Eric Hildebrandt, Attachment P to this filing, contains confidential data, the ISO is filing both public and confidential versions.

function – that of providing open, reliable and non-discriminatory transmission service. To that end, and as discussed further below, the ISO is proposing a package of market design changes that will provide for more stable operations (by promoting forward-market scheduling, commitment, and contracting) and provide greater operational and price transparency (by accurately modeling the transmission system and thus revealing true and accurate price differences on the system).

It is also essential that the Commission recognize that no market design changes, no matter how refined or time-tested, will work effectively until the California electricity market is stabilized and a truly robust and competitive market develops. At present, the ISO is convinced that the market is incapable of producing, on a sustained basis, prices that are just and reasonable. Thus, the ISO requests that the Commission extend the existing price mitigation measures. As long as the existing price mitigation measures remain in effect, the ISO can work towards implementing the proposed market design changes, as approved by the Commission, without the concern of further destabilizing the market. Once the market design changes are complete and tested, the price mitigation measures should be relaxed, and the new market should be able to function effectively. To ensure that outcome, the ISO requests that the Commission leave the existing price mitigation measures in place until the new market structure is in effect and the Commission has determined that the market is workably competitive and capable of producing just and reasonable prices.

The Commission must remember, in the context of considering the extension of the existing price mitigation measures, or the alternative measures proposed herein, that one objective of the MD02 proposal is to reduce reliance on, and the size of, the ISO's spot markets. Thus, at the same time as the ISO is advocating for the continuation of mitigation measures in these markets, the ISO is attempting to foster an environment for sustainable *forward-market* contracting and investment in the California market. While others may argue that the existing price mitigation is restrictive and limits incentives for infrastructure investment, the ISO strongly believes that it is in the forward energy markets – the long-term markets – where investors will demand that sufficient incentives for investment exist. Over the last several years, the industry has moved away from project-specific financing to the financial backing of developers that offer, as collateral, a safer more diversified portfolio of assets. Moreover, investors are requiring that developers rely upon a stable long-term revenue stream, as opposed to unpredictable spot-market revenues. This evolution has taken place not because of price mitigation measures in spot markets, but because the financial industry is seeking a more conservative, and hence stable, investment strategy.

I. SUMMARY OF THE FILING AND REQUESTED COMMISSION ACTION

As described in detail in the following sections, the ISO's filing is comprised of three primary elements, the latter two of which are subsets of the first:

1. The MD02 proposal, as described in Attachment A;
2. The ISO Tariff changes necessary to implement the elements of the MD02 package proposed to be effective July 1, 2002 and October 1, 2002; and
3. An alternative market power mitigation proposal, proposed to be effective October 1, 2002, should the Commission decline to extend the existing price mitigation measures.

The ISO proposes to implement the MD02 proposal in three discrete phases. The ISO's proposed phased implementation plan is described in detail in Section 5.2.3 of Attachment A, and is summarized as follows:

Phase 1 includes the design elements proposed to be implemented on October 1, 2002 (except for locational market power mitigation which has a proposed effective date of July 1, 2002) and that are necessary to prevent *physical* and *economic* withholding from the market and thus are appropriate both on a short-term (to replace, if necessary, the existing mitigation) and on a long-term basis. These measures will also provide reliability benefits by moving operating decisions from real time back into the forward market. The October 1 elements include, among other elements: a residual unit commitment process; a modified Must Offer Requirement; real-time economic dispatch; use of a single Energy bid curve; penalties on Generators for failure to comply with Dispatch Instructions; a rolling 12-Month Competitive Index with pre-authorized mitigation; and a cap on decremental bids. The ISO requires at least three months after Commission approval to implement certain of these elements and thus requests Commission action by July 1, 2002.

Phase 2 has a target date of Spring 2003, and would include, as described further below, most of the comprehensive design proposal except for the full network model and the features that require that model, *i.e.*, nodal energy pricing and the new Firm Transmission Right ("FTR") design. Thus, the ISO anticipates having the necessary software ready to support the changes associated with the integrated day-ahead market, and would implement these changes using the existing three-zone network model. At that time, the Market Separation Rule in the Day-Ahead and Hour-Ahead Markets and the balanced schedule requirement would be eliminated so that Scheduling Coordinators could submit unbalanced supply and demand bids, thus facilitating a formal energy market. In addition, the ISO proposes to conduct a transitional release of FTRs under the current design that would be effective for roughly six to nine months, from April 1, 2003 up to a Phase 3 implementation date.

Phase 3 has a target date of Fall 2003/Winter 2004, and would complete the comprehensive design with the full implementation of the detailed network model, using a state estimator, and the redesign of FTRs. Thus, after Phase 3 is complete, the ISO will have implemented an integrated day-ahead and real-time Congestion Management, Energy and Ancillary Services market based on locational marginal prices ("LMP"). This phase will require extensive software and systems development, and is prudently completed over a timeframe that provides for proper testing, both within the ISO and with Market Participants.

In order for the ISO to proceed with the implementation plan proposed above, the ISO respectfully requests that: (1) the Commission grant approval of the MD02 proposal as soon as possible and, in any event, by July 1, 2002; (2) accept the revisions to the ISO Tariff proposed for the locational market power mitigation element of the market redesign, to take effect on July 1, 2002; and (3) accept the remaining elements of the first phase of the market redesign to take effect October 1, 2002.

The following section provides further detail on the structure of the ISO's filing and its requested actions.

1. <u>A detailed proposal for the redesign of the ISO Congestion Management, Energy and Ancillary Service markets</u>.

As stated above, Attachment A is a comprehensive package of market reforms the ISO seeks authority to implement beginning Summer 2002 and extending through 2003. In order to understand and frame properly the context in which the ISO is proposing these measures, the MD02 Proposal includes an in-depth discussion of the problems that have contributed to the crisis in Western wholesale power markets and explains the modifications to the ISO's markets and transmission services that are meant to address those issues. It is important to recognize that the changes proposed herein are only those within the ISO's purview. In order to effect a truly comprehensive solution to the problems that still plague the California electricity market, all parties must come together to forge a solution; a solution based on the collaborative efforts of both federal and state policymakers and all Market Participants.

The centerpiece of the market redesign proposal is an integrated Day-ahead and real-time Congestion Management, Energy and Ancillary Services market based on LMP. The need to begin the process of working with vendors and Market Participants to design, install, and test the hardware and software necessary to implement LMP is of critical importance in establishing the date upon which the ISO can fully implement the redesigned market. Under the Commission's April 26 Order, however, the ISO is prohibited from expending funds on such activities without Commission authorization.[4] Accordingly, the ISO requests that the Commission promptly grant such authorization to proceed with preliminary system planning, even while the Commission subsequently considers the implementing tariff provisions that, as explained below, the ISO intends to submit in the near future. The ISO specifically requests that the Commission approve the market redesign proposal set forth in Attachment A by no later than July 1, 2002.

For the long-term elements of the proposed MD02, the ISO intends to submit tariff revisions to the Commission in mid-June. Copies of the tariff revisions will be provided simultaneously to stakeholders, and the ISO will then commence a series of technical conferences to explain the proposed tariff revisions and to receive comments from stakeholders. The ISO will propose a schedule of technical conferences when it makes the tariff language available and requests that the Commission staff participate in those technical conferences. After reviewing stakeholders' comments, as well as the guidance that it hopes to receive from a Commission ruling on the concepts upon which the market redesign is based, the ISO intends to submit any necessary revisions to the tariff language by mid-August, so that the Commission will be in a position to rule on the tariff revisions early next fall, well before the subsequent phases of the proposed MD02 are proposed to go into operation the following year.

The Commission and all interested parties must recognize that the proposed market design changes lay a mere foundation and framework upon which necessary future changes can be laid. As discussed further below, at the same time as the ISO is proposing MD02, the Commission is considering the market design proposals of other proposed Western Regional Transmission Organizations ("RTOs") and, on its own initiative, is creating a Standard Market Design ("SMD") that would apply to wholesale electricity markets nationwide. To the extent practicable and necessary, all of these efforts need to be integrated. Further, these efforts need to recognize legitimate regional differences. Thus, subsequent to the filing of MD02, the ISO recognizes that additional changes to its proposed design may be necessary in order to accommodate the outcome of the Commission's SMD rulemaking proceeding and to reduce seams issues between the ISO and its neighboring systems in the West.

Finally, as conditions change in the California market and the impact of the collective actions of all parties, including the participants in the ISO's markets and

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[4] *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*, et al., 95 FERC ¶ 61,115 (2001) ("April 26 Order") at 61,365.

affected state institutions, become known, additional changes to the proposed market design may be warranted. At present, both Pacific Gas & Electric Company ("PG&E") and Southern California Edison Company are not creditworthy and thus unable to procure power in the marketplace on behalf of their customers. As a result, the State of California continues to procure energy on behalf of their customers, and will continue to do so through December 31, 2002, and most likely longer. In addition, PG&E's financial status is still subject to the outcome of its ongoing bankruptcy proceeding. It is uncertain when that proceeding will definitively conclude. Therefore, until these matters are resolved, it is difficult to determine whether additional changes to the ISO's proposal will be needed.

2. <u>Specific ISO Tariff amendments to begin to implement elements of the comprehensive redesign.</u>

As discussed in detail below, the ISO is proposing specific tariff revisions for elements of MD02 that can be implemented this year to begin the process of reforming current operational and market practices. The specific changes are as follows:

1) *Locational Market Power Mitigation;*
2) *Residual Unit Commitment;*
3) *Modification of the Must Offer Requirement;*
4) *Real-Time Economic Dispatch;*
5) *Use of a Single Energy Bid Curve ;*
6) *Penalties on Generators for failure to comply with Dispatch Instructions;*
7) *Extension of the Current Commission Mitigation Measures;*
8) *A Rolling 12-Month Competitive Index with Pre-Authorized Mitigation; and*
9) *A Price Cap on Decremental Bids.*

The proposed tariff sheet implementing the locational market power mitigation component of the MD02 proposal is provided as Attachment B and the redline showing the changes from the current tariff is Attachment C. The ISO respectfully requests that the Commission approve this modification to be effective July 1, 2002, sixty days from this filing. Such approval will provide necessary consumer protection for this summer. Tariff sheets implementing the remaining changes proposed as the first phase of the MD02 proposal are contained in Attachment D. Redlines showing the changes from the current provisions are provided as Attachments E, F, G, H, I, J, and K. The ISO respectfully requests that the Commission accept these reforms to be effective October 1, 2002.

3. Alternative Market Power Mitigation.

If the Commission is unwilling to extend the effectiveness of the current price mitigation regime, as proposed above, the ISO urges the Commission to consider the alternative market mitigation measures proposed in this filing. The ISO does not believe that these alternative mitigation measures will provide as firm an assurance as the existing west-wide mitigation measures that prices will not exceed just and reasonable levels. Accordingly, the ISO requests that the Commission consider these alternative measures if and only if it refuses to extend the existing mitigation measures. This alternative market mitigation approach consists of two additional elements: a damage control price cap and automatic bid mitigation to prevent economic withholding. The ISO notes that the elements of this alternative proposal work together in a complementary fashion with the locational market power mitigation and 12-month competitiveness index discussed above. The ISO is not confident that this alternative plan will provide any substantial measure of protection against market power if any element is rejected or modified substantially. Accordingly, it is imperative that the Commission approve these measures as a complete package if it decides not to extend the current west-wide mitigation. The ISO Tariff sheets implementing these alternative measures are provided as Attachment L. Redlines showing the changes from the current provisions are provided as Attachment M and Attachment N.

II. BACKGROUND

A combination of factors came together in the second half of 2000 to create conditions in which wholesale suppliers could command manifestly excessive prices in the California and other Western electricity markets. These factors included: (1) tight supply conditions in California and throughout the West;[5] (2) lack of significant demand response to hourly prices; (3) high natural gas prices[6] (4) inadequate infrastructure (including inadequate transmission capacity); (5) lack

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5 For example, the year from October 2000 through September 2001 produced runoffs in the Pacific Northwest and California that were only 50 percent of normal.

6 Natural Gas, the critical fuel for thermal generation in California, reached a historic high of $58.76 per million British Thermal Units on December 11, 2000 at the Southern California Border. While these prices have declined significantly, reaching a low of $1.74/MMbtu on November 16, 2001 and stabilizing in the range of $2 to $3/MMbtu, wholesale electric prices have not tracked this reduction in operating expenses consistently. *See Third Quarterly Report of the California System Operator Corporation*, FERC Docket Nos. EL00-95-000 *et al.*, filed March 26, 2002 in response to the Commission's April 26, 2001 and June 19, 2001 mitigation orders in *San Diego Gas & Electric v. Sellers of Energy and Ancillary Services into Markets Operated by the California Independent System Operator Corporation and the California Power Exchange*, 95 FERC ¶ 61,115 and 95 FERC ¶ 61,418 (2001) ("Third Quarterly Report") at 11. A copy of this document is included as an appendix to the Affidavit of Gregory Cook, Attachment R.

of long-term supply arrangements and underscheduling in the forward markets;[7] (6) the exercise of market power and inadequate tools to mitigate market power; and (7) poor market design.[8]

The Commission devoted significant attention to the crisis in California throughout the fall and winter of 2000, issuing a series of orders reforming the market and seeking to moderate prices. It was not until the spring of 2001, however, that the Commission established a comprehensive mitigation regime applying for all hours on a West-wide basis -- an approach that has been largely successful in restoring prices to lawful levels, but which has *not* been accompanied by improvements in all of the structural conditions that gave rise to the California crisis.

The June 19 Order

On June 19, 2001, the Commission issued a further order on prospective price mitigation.[9] Upon review of comments and upon brief experience with the mitigation put in place on May 29, the Commission determined that mitigation measures were necessary *throughout the West* (rather than just in California) and *in all periods* (rather than just in system emergencies). For transactions outside of the ISO's single price auction, the Market Clearing Price ("MCP") of the auction would serve as the maximum price, and sellers would be given the opportunity to justify higher than maximum bids. Marketers would be unable to set the MCP, but would instead be "price takers". In addition, sellers that are generation-owners were required to submit bids during deficiency periods that were "no higher than the marginal cost to replace gas used for generation."[10] With regard to the costs of

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7 The failure of load serving entities to schedule generation sufficient to meet their demand increased the volume of the ISO Imbalance Energy market far beyond its original design and raised the cost and difficulty of ensuring reliable operation of the grid. Several factors contributed to this problem of the California investor owned utilities ("IOUs"), including the lack of forward contracting and a clear obligation to serve load and assure adequate capacity.

8 Even before the crisis of 2000, the ISO, Market Participants, and the Commission recognized the need for significant reform of the ISO Markets, in particular the need to revise the congestion management system. *California Independent System Operator Corporation,* 90 FERC ¶ 61,006 (2000). It is readily apparent from this list of factors that contributed to the 2000-2001 crisis that this filing will not in and of itself resolve the problems that led to the dysfunctions in the Western electricity market. Even the best design doesn't guarantee efficient markets. In particular, tight supply conditions, limited demand responsiveness, and the need for additional transmission infrastructure will require the continued cooperation of state and federal authorities.

9 *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, et al.,* 95 FERC ¶ 61,418, 62,549 (2001) ("June 19 Order").

10 95 FERC at 62,548.

emissions requirements and start-up costs, sellers were to invoice the ISO directly, in light of the difficulty in standardizing the various costs into a single MCP.[11]

The Commission has described this mitigation program as the least intrusive means it could devise to assure that wholesale rates would not exceed just and reasonable levels; while, at the same time, rejecting more stringent limitations that would have returned California and the West to cost-of-service pricing.[12] The provisions of the June 19 Order went into effect on June 20, 2001,[13] and the mitigation will end, unless extended, on September 30, 2002.

In the December 19 Rehearing Order, the Commission acted on requests for rehearing of the December 15[14], March 9[15], April 26, and June 19 Orders. This Order further modified the mitigation approach developed in the April and June Orders. The modifications: (1) excluded governmental entities and cooperatives from the price mitigation as it is applied to bilateral transactions (*i.e.*, transactions that do not take place in the ISO spot market), and also excluded these entities from the must-offer requirement outside of California; (2) eliminated the penalty for underscheduling; and (3) allowed "marketers, load serving entities and hydroelectric generators [to] submit evidence that the refund method results in total revenue shortfall in the organized California spot markets for their transactions during the refund period."[16]

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11 The method required by the June 19 Order for calculating the approved MCP for periods that were not System Emergencies, that is, when reserves exceeded 7 percent, was as follows. The MCP would be 85 percent of the MCP in the most recent Stage 1 (not Stage 2 or 3) Emergency would be the MCP for such non-emergency periods. Sellers (other than marketers) would be permitted to provide justifications for any above-MCP bids. The requirement that all sellers that owned or controlled non-hydroelectric generation in California must bid any available power into the ISO's spot markets was retained in the June 19 2001 Order, and was expanded so that non-Californian sellers would have a similar requirement with regard to "the spot market of their choosing". 95 FERC 62,549.

12 95 FERC at 62,549.

13 In its Order of July 25, 2001, the Commission made the mitigation measures (with some adjustment based on the recommendations of Chief Judge Wagner), retroactive to October 2, 2000, with regard to the calculation of refunds. *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, et al.*, 96 FERC ¶ 61,120 (2001).

14 *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, et al.*, 93 FERC ¶ 61,294 (2000).

15 *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, et al.*, 94 FERC ¶ 61,245 (2001).

16 97 FERC at 62,172. On December 19, 2001, the Commission also issued an order on the

In addition, in order to remedy previously identified flaws in the ISO's markets, the December 19 Rehearing Order also directed to the ISO to file, by May 1, 2002, a new Congestion Management system and a plan for a day-ahead energy market.[17]

III. THE NEED FOR PRICE MITIGATION CONTINUES

It was not until the comprehensive mitigation program established in the June 19, 2001 Order that the market in California began to stabilize. As illustrated in Figure 1, the Commission's June 2001 mitigation measures, in combination with the actions of California officials, greater conservation, and other factors, have had a profound effect on controlling the excessive prices experienced during 2000 and early 2001.

FIGURE 1 - SUMMARY OF WHOLESALE ENERGY COSTS

Month/Year	Total costs - Energy and Ancillary Services ($million)	Avg. Cost of Energy and Ancillary Services ($/MWh Load)
1998 (9 months)	$5,551	$33
1999	$7,432	$33
2000	$27,083	$114
January 2001	$3,713	$198
February 2001	$3,772	$229
March 2001	$3,797	$213
April 2001	$3,471	$201
May 2001	$3,548	$181
June 2001	$1,896	$96
July 2001	$1,583	$75
August 2001	$1,414	$67
September 2001	$1,087	$56
October 2001	$888	$46

ISO's compliance filings implementing the mitigation measures (*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, et al.*, 97 FERC ¶ 61,293 (2001)), and modifying the west-wide price limitations (*Investigation of Wholesale Rates of Public Utility Sellers of Energy and Ancillary Services in the Western Systems Coordinating Council*, 97 FERC ¶ 61,294 (2001).

17 *Id.*

November 2001	$776	$44
December 2001	$812	$43
2001	$26,756	$118
January 2002	$763	$39
February 2002	$682	$40

While these indicators suggest that California's energy markets are improving in a variety of areas, the conditions that resulted in prices above competitive levels persist. The fundamental factors underlying the extraordinary prices experienced in 2000 and early 2001 have not improved sufficiently to provide a reasonable assurance that California's electricity markets will produce the just and reasonable prices that would be expected in a truly robust and competitive market.

First, the unprecedented conservation California enjoyed in the summer of 2001 cannot be assumed to continue on a sustained basis. Lower temperatures and a weak economy during the summer of 2001 contributed to the reduced demand. While the ISO's Participating Load Program meets many of the principles outlined by the Commission, programs in the state have not developed to the extent that they can temper demand sufficiently to prevent the exercise of market power.

Second, while California has made tremendous efforts at constructing new generation, adding approximately 4,342 MW since January 2001,[18] the recent construction only partially remedies the previous lag in building facilities required to meet the increased demand. In addition, the ISO has experienced a significant decline in imports.[19] While the California Department of Water Resources has entered into a portfolio of long-term power supply contracts to reduce the amount of load that must be served by real-time purchases, not all hours are completely hedged and therefore opportunities for suppliers to exercise market power in real time remain.

Fourth, efforts to eliminate the transmission bottleneck on Path 15 between northern and southern California, though underway, will not be completed for several years.

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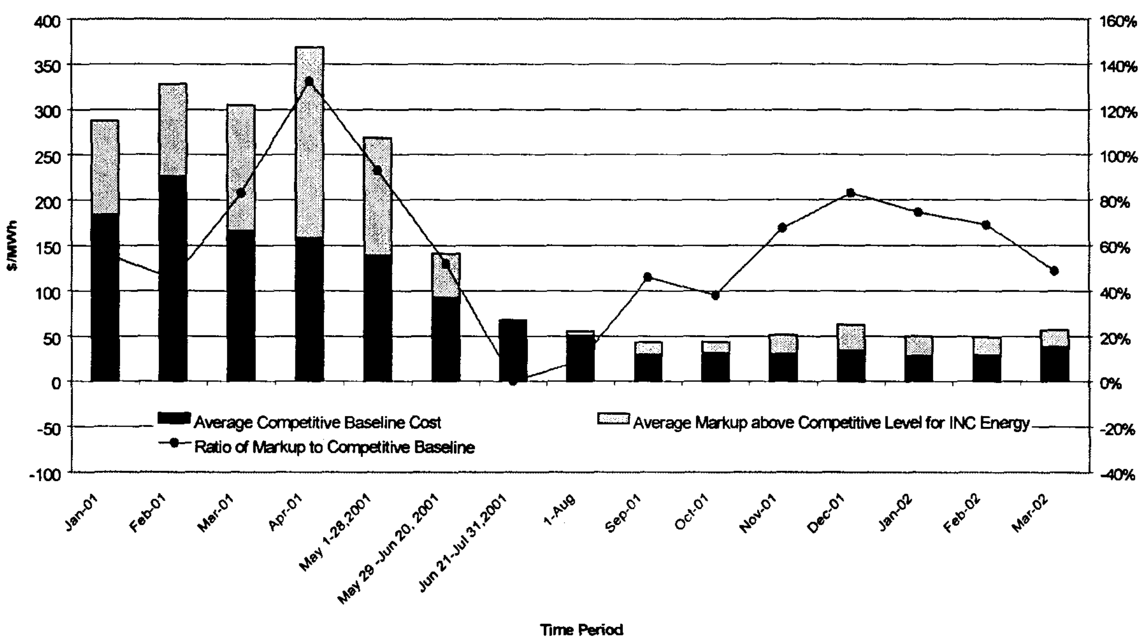
18 A total of 2,554 MW of new generation was added within the ISO Control Area in 2001 and an additional 2,961 MW of generation is expected prior to 2002. Approximately 1,173 MW was lost due to retirements and environmental restrictions. *See California ISO 2002 Summer Assessment*, Version 1.0, April 25, 2002, at 2. This document, prepared by the ISO's Operations Engineering Department, is available on the ISO Home Page at http://www.caiso.com/docs/2002/04/19/2002041917130017460.pdf.

19 Metered interchange into the ISO Control Area for the June through September time period declined by 45% from 1999 to 2000 and declined by 12.7% from 2000 to 2001. *Id.* at 16.

Fifth, documented anti-competitive bidding practices persist in spite of the current price mitigation provisions. Numerous suppliers consistently bid excess capacity from steam units that are on-line and scheduled to operate at prices far in excess of marginal costs. In addition, most capacity from gas-fired combustion turbines is bid consistently at or near the effective price caps and well in excess of marginal operating costs of thermal generation. It is reasonable to believe that such practices will continue absent enhanced mitigation measures.

FIGURE 2

Price/Cost Markup in Real-Time Energy Market



This last factor is particularly significant. The ISO's DMA continues to observe that certain units that are dispatched frequently continue to bid with strategies that are indicative of market power. As illustrated in Figure 2, the markup between the average price and an estimate of the baseline price that would exist under competitive conditions has improved. Nevertheless, prices continue to exceed supplier's marginal costs by significant amounts. As explained in the affidavit of Gregory Cook, this persistent, substantial mark-up over price levels that would prevail under workably competitive conditions demonstrates that suppliers in California power markets continue to possess and exercise market power.[20] The Third Quarterly Report further details the anti-competitive bidding practices of generators in the California market and provides additional, specific support for continuation of the existing west-wide mitigation.

IV. DESCRIPTION OF THE COMPREHENSIVE MARKET REDESIGN

A. Overview

While the Commission's price mitigation regime, combined with measures undertaken by the State of California, have restrained wholesale prices in comparison to the extraordinarily high levels experienced through the first half of 2001, the structural problems that created the need for the price mitigation regime in the first place, and enabled suppliers to exercise market power, persist. The ISO has resumed its efforts, interrupted by the 2000-2001 crisis, to reform its congestion management system, as well as other elements of its transmission service and energy markets. Specifically, the ISO has recognized that, although the current congestion management system did not substantially contribute to the high prices borne by California consumers, it was nevertheless severely flawed and needed to be reworked as part of a comprehensive reform of the current energy market in order both to fulfill the ISO's real-time balancing function and to create transparent forward energy markets to fill the void left by the now-defunct markets formerly operated by the California Power Exchange.[21]

In response to the crisis in the California market and the Commission's requirements to redesign elements of the ISO Markets, the ISO formed an inter-departmental group, the Market Design 2002 team. Drawing from (1) analysis of

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20 Mr. Cook notes from July 2001 through February 2002, the prices paid for Incremental Energy dispatched in the ISO's real time Imbalance Energy market averaged about $61/MWh compared to a benchmark price of approximately $48/MWh based on the marginal cost of the highest-cost gas-fired unit dispatched by the ISO, and that this resulted in consumers paying about $20 million or 29% more than they should have based on marginal cost. Attachment R at 14.

21 The Market Surveillance Committee has stated:

> We would like to emphasize that the ISO's congestion management protocols were not the cause of the crisis of the past two years. The primary cause was an underlying market structure that was insufficiently competitive. Reforming the ISO's congestion management protocols can somewhat mitigate the consequences of these structural problems, but these changes will not be sufficient to achieve a robust, competitive, and reliable market in California.

Comments of the Market Surveillance Committee of the California ISO on the Proposed October 1, 2002 Market Power Mitigation Measures, April 22, 2002, at 2. A copy of this document is provided as Attachment V.

the root causes of the California power crisis, (2) experience in operating the ISO Markets, (3) review of the practices of other ISOs and Commission rulings, and (4) prior ISO redesign efforts, the MD02 team has prepared this filing.

The ISO proposes to redesign comprehensively the markets that it operates for electric Energy and Ancillary Services to create an integrated, efficient market structure that can serve as a framework for sustainable, competitive markets that meet the needs of the Market Participants and consumers that rely on the ISO Controlled Grid and the ISO's Control Area. The ISO's MD02 initiative formally and substantively began in December 2001. As noted in the MD02 proposal (Attachment A), however, the MD02 process actually began far earlier. The concepts embodied in the ISO's MD02 proposal are the result of four years of experience and the ISO's previous Congestion Management reform initiative. Thus, most of the concepts and the specific elements embodied in the MD02 proposal are not new and have been heavily vetted over the past four years. Section 1.1.5 of the MD02 proposal in Attachment A briefly summarizes the major milestones of the MD02 process.

The MD02 proposal would create integrated forward and real-time markets for Energy and Ancillary Services in which clearing prices for Energy are determined on the basis of LMP principles. The MD02 proposal is consistent with, and advances, the principles underlying the Commission's SMD initiative, as they have been articulated to date in Docket No. RM01-12-000.[22] The ISO proposes to integrate a fully detailed and accurate model of the ISO transmission grid to identify constraints so the ISO can adjust generation and load (and import and export) schedules to mitigate transmission overloads, ensure local reliability and, in the process, produce locational marginal energy prices at each node of the grid. With this change the ISO will eliminate the distinction between inter-zonal and intra-zonal congestion, the "Market Separation Rule," and the requirement that each Scheduling Coordinator submit Balanced Schedules.

At its meeting on April 25, 2002, the ISO Board of Governors authorized ISO management to file the MD02 proposal, including the proposed available capacity obligation ("ACAP"). The Board stated that the proposal was subject to reconsideration when the markets are returned to a stable condition and stressed that nothing in the MD02 proposal was meant to shift or modify the jurisdictional authority between functions traditionally performed by state authorities and those performed by FERC.[23] In addition, Management was directed to evaluate a recent

[22] A comparison of the principal elements of the MD02 proposal and the corresponding elements of the standard market design initiative is included in Attachment A at pages 24 through 34. A separate chart comparing MD02 with SMD is provided as Attachment T.

[23] Copies of the Board motions are provided in Attachment U.

Advisory Forward Energy Commitment proposal from the state inter-agency working group regarding the need to ensure load-serving entities make available to the ISO on a forward basis sufficient capacity to meet demand.

As the Commission can appreciate, implementation of the ISO's MD02 proposal will require a massive investment of resources, both staff and capital. The timeline for the required development of new systems and software will be the primary constraint in implementing MD02. To date, the ISO has identified approximately thirty systems and applications that it will need to modify to incorporate the MD02 proposal. To the maximum extent practicable, the ISO will rely on existing software applications -- applications that are already in use in other ISOs. For example, when developing the ISO's proposed automatic mitigation procedures, the ISO intends to rely heavily on the platform already in use in the New York ISO. Similarly, the ISO believes it will be able to use other existing applications, such as New York's Transmission Constrained Unit Commitment program ("TCUC"), for use in the ISO's proposed Residual Unit Commitment process. Nonetheless, use of these programs will still require the ISO to integrate these applications into the ISO's existing (or modified) software platforms and to allow sufficient time for market participants to perform necessary changes to their own software and to be trained on the revised market rules. Moreover, in order to accommodate certain specific rules that are unique to the California system, the ISO will have to modify the base applications. Notwithstanding these constraints, the ISO intends, to the maximum extent possible, to minimize upfront capital costs and to design market systems that are flexible and scalable.

As further detailed in Section 5.2.3 of the MD02 proposal, the ISO anticipates that implementation will occur in three phases:

1. Phase 1 involves the design elements the ISO proposes to implement on October 1, 2002 (except for locational market power mitigation that has a proposed effective date of July 1, 2002).

2. Phase 2 has a target date of Spring 2003, and would include most of the comprehensive design proposal except for the full network model and the features that require that model, *i.e.*, nodal energy pricing and the new Firm Transmission Right ("FTR") design. Thus, the ISO anticipates having the necessary software ready to support the changes associated with the integrated day ahead (DA) market, and would implement these changes using the existing three-zone network model. At that time, the Market Separation Rule and the balanced schedule requirement would be eliminated so that SCs could submit unbalanced supply and demand bids. In addition, the ISO proposes to conduct a release of FTRs under the current design that would be effective for roughly six to nine months, from April 1, 2003 up to a Phase 3 implementation date.

3. Phase 3 has a target date of Fall 2003/Winter 2004, and would complete the comprehensive design with the full implementation of the full network model, using a state estimator, and the redesign of FTRs.

Finally, based upon the Commission's previously directive to the ISO *not* to expend any capital dollars on software development until the Commission approves a design proposal, the ISO reminds the Commission that the ultimate date for full MD02 implementation will be largely dependent upon the Commission's review and approval timeline.

B. Major Elements of the Market Redesign 2002 Proposal

The principal elements of the Market Design 2002 proposal are as follows:[24]

- **A Forward Spot Market Employing LMP for the Integrated Procurement of Energy and Ancillary Services.** Since the demise of the California Power Exchange, the California electricity market has lacked a vehicle for transparent day-ahead energy trades to enable load-serving entities to shape supplies to meet the next day's demand. The ISO proposes to establish a day-ahead energy market to fill that void. The ISO will use the day-ahead energy market to manage congestion on the ISO Controlled Grid, using a fully detailed and accurate model to identify constraints so the ISO can adjust generation and load schedules (and export and import schedules) to ensure that local area reliability and the security of the grid are maintained. The ISO's security-constrained dispatch of the grid will produce marginal energy prices at each node. The differences between these locational marginal prices will be the congestion costs payable by transmission customers. The ISO will no longer differentiate between "inter-zonal" and "intra-zonal" congestion; nor will it observe a "market separation rule" to restrict trades between market participants in the context of congestion management. The ISO's proposed security-constrained economic dispatch simultaneously will manage congestion and select the most economical mix of resources to provide the needed Energy and Ancillary Services for the next day. The day-ahead market will be designed so as to afford Scheduling Coordinators the ability to establish firm physical schedules, if they wish, and will accommodate the creation of trading hubs.[25]

- **Firm Transmission Rights.** The FTRs currently issued by the ISO will

[24] The pages of Attachment A where each element is discussed in greater detail are indicated after the description of each major element of the proposal.

[25] These elements are discussed at pages 79-89 of Attachment A.

be modified to incorporate a point-to-point design that is consistent with the new approach to congestion management and to enable the FTRs to serve the functions envisioned for transmission rights in the SMD.[26]

- **Bid Mitigation for Local Reliability Needs.** Like other ISOs that have implemented or proposed to implement LMP-based markets, and consistent with the Commission's findings, the ISO recognizes that LMP does not preclude suppliers whose generation is needed to maintain reliability in local areas from exercising market power. The MD02 proposal includes provisions to mitigate suppliers' bids in forward and real-time spot markets when resources must be taken out of economic merit in order to satisfy local reliability needs.[27]

- **Residual Day-Ahead Unit Commitment.** Currently, the ISO relies on the existing must-offer obligation and the "waiver" procedure approved by the Commission to commit long lead-time resources if it believes that scheduled resources will not be adequate to meet forecasted demand. The MD02 proposal will consolidate this authority through its Residual Unit Commitment ("RUC") mechanism. Following the close of the day-ahead scheduling process, the ISO will evaluate whether the day-ahead schedules include enough on-line resources to meet the ISO's forecast of the next day's demand. If they do not, the ISO will have the authority to commit additional resources, from, beginning October 1, 2002, those made available through the proposed extended must-offer provision and, on a longer term, those identified by load-serving entities to meet their Available Capacity obligations (discussed below).[28] This element of the market redesign proposal is virtually the same as those in place in the eastern ISOs, including the PJM Interconnection and the New York ISO. The RUC process is necessary to ensure reliable system operation by, in part, moving operating and commitment decisions from real-time to the forward market.

- **Real-Time Economic Dispatch and Congestion Management.** Every ten minutes during real-time operations, the ISO will run a security-constrained economic dispatch program to select resources to be dispatched to meet real-time needs. The security-constrained dispatch will take into account all transmission constraints, local reliability needs, and generator operating constraints, as well as system energy needs.

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26 This element is discussed at pages 89-105 of Attachment A.

27 This element is discussed at pages 134-135 of Attachment A. As noted above, the ISO proposes to implement this element on July 1, 2002, as part of the first phase of MD02.

28 This element is discussed at pages 106-109 of Attachment A.

The dispatch of resources will produce LMPs at each node that will establish the prices at which suppliers would be paid and which can be aggregated to establish prices paid by load-serving entities purchasing imbalance energy. To ensure that resources comply with the ISO's Dispatch Instructions and thereby enable the real-time market to operate reliably and efficiently, the MD02 proposal includes penalties for excessive uninstructed deviations by suppliers.[29]

- **Simplified Hour-Ahead Market.** Although the standard market design does not require an hour-ahead market for adjustments to day-ahead schedules, Market Participants have expressed a preference for retaining the hour-ahead market and for moving the close of that market as near as possible to real time operations. The MD02 proposal therefore includes a simplified hour-ahead market that would perform congestion management and energy trading and would close as late as sixty minutes before the operating hour. The hour-ahead market would enable those parties desiring the equivalent of a sixty-minute dispatch market to match energy and load bids for the next hour or have their energy bids pre-dispatched by the ISO for imbalance energy needs.[30] This will facilitate the integration of the ISO's redesigned energy markets with energy markets that may be established in other portions of the Western Interconnection, which may not clear on the same ten-minute basis as the ISO's Real Time Energy Market. The ISO is committed to working with other Western market operators to eliminate, to the extent possible, seams that might form barriers to regional trading.

- **ACAP Obligations for Load-Serving Entities.** As noted above, the California electricity market has been plagued by inadequate generation supplies. To enable the ISO to verify that load-serving entities are making the necessary advance arrangements to ensure that adequate generating capacity is available to meet system load and reserve requirements, the ISO proposes to require entities using the ISO Controlled Grid to serve Load to demonstrate in advance that they own or have procured sufficient resources to meet their respective share of the ISO's monthly peak load plus operating reserve requirements. The resources identified by load-serving entities to satisfy this requirement must be made available to the ISO in the day-ahead market. The primary objective of this requirement is to facilitate and support reliable system operation. In particular, the ACAP requirement should encourage load serving entities ("LSEs") to shift their energy procurement to forward

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29 This element is discussed at pages 113-118 of Attachment A.

30 This element is discussed at pages 110-113 of Attachment A.

markets, an objective the Commission and the ISO have long recognized as critical to stable and reliable operations. Thus, working in conjunction with the proposed RUC process described above, the ACAP requirement will facilitate forward procurement, commitment, and scheduling of the resources necessary to satisfy forecast load and support reliable system operation. By moving operating and commitment decisions to the forward market, prices and operations in the ISO's spot market should be stabilized. In addition, on a longer-term basis, the ISO also believes that the ACAP requirement will provide opportunities for LSEs and both generation and demand-based suppliers to contract, thus supporting critical and needed infrastructure investment in California.

The ISO proposes to phase in the ACAP requirement for LSEs over a four-year period to give them sufficient time to assemble the necessary portfolios of resources. The ISO also intends to implement the ACAP obligation in a manner that recognizes that ensuring long-term supply adequacy is not a function that the ISO can carry out alone. With respect to state-jurisdictional load-serving entities, the question of planning for long-term supply adequacy is principally one of state policy. The ISO intends to cooperate with state authorities to ensure that the ACAP obligation complements and furthers state requirements and initiatives to ensure adequate long-term electric supplies.[31] In addition, recognizing the close relationship between ACAP, Reliability Must-Run Generation ("RMR") and transmission planning issues, the ISO proposes to develop an integrated policy for addressing these issues that fairly and equitably addresses the requirements in each of these areas and whose express purpose is to eliminate, where appropriate, the transmission constraints that give rise to local requirements.

Finally, the ISO recognizes that there are alternative means to achieving the desired outcome – reliable system operation. Toward that end, the ISO will work with all interested parties to identify and examine any such proposal and will remain flexible as to the final form of this mechanism.

- **Procedures for Monitoring and Mitigating Market Power.**
  - Initial Period. The ISO proposes to maintain the existing market power methodology established pursuant to the Commission's June 19 Order as modified by the December 19 Orders. The only proposed change is to "narrow" the "must offer" requirement in Section 5.11 of the ISO Tariff in accordance with the new RUC process contained in the proposed Section 5.12. The MD02 proposal also includes a mechanism through which the ISO continuously will

[31] This element is discussed at pages 44-79 of Attachment A.

measure the competitiveness of its markets over time against an objective and explicit standard. If average market prices exceed this cost benchmark over a twelve-month period (measured on a rolling-average basis each month) by more than $5/MWh, bids in the ISO's markets would be limited in accordance with the proxy bid mitigation measures in all hours, for a period of six months, and the Commission's price mitigation measures would also be reinstated for California.[32] In addition, to prevent excessive decremental bids, the ISO proposes a negative damage control bid cap of -$30/MWh.

- Long-Term Proposals

The ISO proposes to transition to a market power mitigation regime based on two elements in addition to the 12-month competitiveness index. If the Commission refuses to extend the current mitigation measures, the ISO proposes to accelerate the effectiveness of these market power mitigation measures, so that they would take effect October 1, 2002. Accordingly, the ISO will need to be informed of the Commission's determination by July 1, 2002 to undertake the additional software development. The two elements are as follows:

1. **Damage Control Bid Cap.** The MD02 proposal includes a damage control bid cap ("DCBC") to protect against the exercise of market power in the ISO's Energy and Ancillary Services markets. The ISO proposes a DCBC with a floor price of $108/MWh that can increase with the price of natural gas. As additional elements of the MD02 are phased in and capacity conditions improve, the ISO expects to increase the DCBC.[33]

2. **Automatic Bid Mitigation Procedures.** MD02 includes individual resource bid screens and automatic mitigation procedures similar to the Automatic Mitigation Procedures ("AMP") employed by the New York ISO. In light of the documented concerns about competitiveness in the California markets, however, the ISO proposes to start with more stringent bid screens and price impact thresholds, retaining the flexibility to increase those levels as the competitiveness of the markets improves.[34]

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[32] This element is discussed at pages 142-145 of Attachment A.

[33] This element is discussed at pages 135-137 of Attachment A.

[34] This element is discussed at pages 137-141 of Attachment A.

C. Stakeholder Comments

As described in Attachment A at page 11, the ISO has sought and considered stakeholder input throughout the process of developing the MD02 proposal, by making drafts of the proposal available for public review, conducting focus groups on elements of the proposed market design, soliciting and receiving public comments, and conducting public meetings, including a two-day public meeting on April 4- 5, 2002, in which the Commission's technical staff participated.

Nonetheless, the ISO recognizes that many market participants have been and remain frustrated over the process for developing the MD02 proposal. Certainly, the Commission's December 19 Rehearing Order in this proceeding expedited the timeframe for developing and finalizing the MD02 proposal by requiring that the ISO file a Congestion Management proposal and a plan for a day-ahead energy market by May 1, 2002. Nonetheless, no matter the timeframe for the process, the ISO acknowledges that it would never be able to allay certain of the concerns raised by stakeholders.

For example, with respect to assessing the ultimate cost impact that moving from a zonal to a LMP-based system will have on certain loads, the ISO acknowledges upfront that it has not performed such an analysis. However, notwithstanding the fact that any such study would of necessity be more qualitative than quantitative, the ultimate impact on consumers is largely a retail rate setting matter. In the context of considering this proposal, it is important that the Commission and all market participants remember that the MD02 proposal is not a panacea but is limited to changes to the ISO's markets and functions. The environment in which the ISO submits the MD02 proposal is fluid and very uncertain: the ultimate disposition of the financial status of the two largest IOUs in California, the obligations imposed on load-serving entities in the State, and the California Public Utility Commission's IOU procurement practices may also have a large cost impact on consumers.

As to the concerns and frustrations expressed by market participants that the ISO has not been responsive to their comments, the ISO acknowledges that it has been unable to respond to every set of comments put forth by stakeholders. Given the need to finalize the proposal, it was not possible for the ISO to develop direct responses to all stakeholder comments and include them here. In addition, the ISO did not receive certain comments until just days prior to submitting the proposal to its Board. The ISO has, however, prepared a separate document containing stakeholder comments and ISO responses that were provided to the Board and released publicly prior to the April 25 Board meeting, and included such document herein as Appendix C to the Comprehensive Market Design Proposal (Attachment A). It is worth noting that the ISO has attempted to address stakeholder issues, concerns and alternative proposals in the substance of its recommendations. Although not acknowledged in every circumstance, the ISO has modified the MD02 proposal in many important respects in order to respond to specific stakeholder comments. For example, with respect to certain of the equity and fairness issues raised by market participants that might be adversely impacted by the ISO's proposed move to an LMP-based system, the ISO modified its FTR proposal so as to directly allocate FTRs to load, thus providing them a means to manage their financial exposure. In addition, the ISO has used the MD02 process to commit to certain obligations with respect to transmission planning, recognizing the need to proactively address the transmission constraints that give rise to price differences across the system.

Furthermore, the ISO is recommending that the stakeholder process not conclude with the filing of the MD02 proposal at the Commission. As discussed above, the ISO is proposing a process, subsequent to the filing of the MD02 proposal at the Commission, wherein additional stakeholder feedback can be incorporated.

D. Interregional Coordination

Among other lessons learned, the 2000-2001 electricity crisis in the West reinforced the fact that the West functions as one integrated market. Thus, in the context of proposing market design changes for the California market, it is imperative that the ISO recognize and acknowledge the impact that such changes could have on its neighboring systems and markets.

Beginning in June of 2001, the ISO, RTO West and WestConnect (collectively, Western RTOs) initiated discussions to ensure effective coordination and collaboration among the parties as each began to develop (or redevelop, as in the ISO's circumstance) their proposed market designs. The discussions to date have been fruitful and have built a foundation and structure for establishing a seamless Western market and for collectively addressing, going forward, Western electricity market issues as they arise. To that end, the proposed Western RTOs have collaboratively developed a shared "Western Market Vision" that envisions the development of a seamless Western market where all market participants and consumers can obtain the benefits of "one-stop shopping" and can capture the efficiencies inherent in a larger regional market. Among other initiatives, the proposed Western RTOs have: (1) focused on the development of a venue for effective transmission expansion in the West; (2) developed proposals for reciprocal pricing that are intended to reduce transaction-based barriers to trade between the regions; (3) begun the development of a West-wide market monitoring organization; and (4) established a forum for identifying and fostering opportunities for joint system and infrastructure development.

The ISO is committed to continued participation in these ongoing efforts and the goal of developing a seamless Western market. As noted above, the ISO anticipates continued collaboration with these parties in addressing seams issues and understands that, as the Western markets develop, modifications to the ISO's proposed market design may be necessary in order to accommodate an efficient Western market design.

E. Standard Market Design

The ISO is of course cognizant of the fact that the Commission itself is in the midst of a massive and potentially revolutionary initiative to create a standard wholesale market design. As noted in the MD02 Proposal, the ISO has paid close attention to developments in the Commission's rulemaking process, including the Staff Paper issued in December, 2001, and the Commission Working Paper issued on March 15, 2002. At this juncture, recognizing that the SMD is still a work in progress, the ISO believes that MD02 substantially comports with general concepts and specific elements set forth by the Commission. In an attempt to align the ISO's MD02 proposal with the Commission's SMD, Section 2.5 of the MD02 Proposal provides a detailed side-by-side comparison of the ISO's proposal and the SMD. In addition, Attachment T to this filing includes an abbreviated comparison of the MD02 and SMD proposals. The ISO will continue to follow developments in the Commission's SMD rulemaking proceeding and understands that changes to its proposal may be necessary as a result of the final rule in that proceeding.

F. Proposed Effective Dates

The ISO respectfully requests that the Commission grant approval of the proposed comprehensive market redesign described in Attachment A as soon as possible and, in any event, no later than July 1, 2002. The ISO can then commence the development of the necessary modifications to its software and systems to implement LMP. The ISO projects that this process, including testing of the modifications, will require approximately eighteen months.

As discussed below, this filing includes revisions to the ISO Tariff to implement the first phase of MD02. Locational market power mitigation is proposed to take effect July 1, 2002 and the remaining elements are proposed to take effect October 1, 2002.

III. FIRST PHASE ELEMENTS OF THE MARKET DESIGN 2002 PROPOSAL

The planned transition to a new market design consists of several phases: Location market power mitigation and the "October 1 elements" are a sub-set of the MD02 Proposal. While there may be certain modifications necessary to incorporate the final long-term design, these initial elements are *not* interim measures; rather, they are components of a fully integrated and comprehensive redesign of the ISO markets. The initial elements are as follows: (1) locational market power mitigation; (2) Residual Day-Ahead unit commitment; (3) modification of the must offer requirement; (4) economic dispatch; (5) changes to the Day-Ahead and Hour Ahead Energy Market; (6) penalties for excessive uninstructed deviations; (7) extension of the current mitigation program; and (8) a 12-month competitiveness index and a decremental bid cap. These changes are described in greater detail below.

Four of these initial elements -- locational market power mitigation, economic dispatch, use of a single bid curve, and penalties for excessive uninstructed deviations -- were proposed by the ISO in its Amendment No. 42 filing. In an order issued on March 27, 2002, the Commission rejected these portions of Tariff Amendment No. 42, stating that it did:

> not believe another piecemeal approach presented in isolation from other respects of the California market design, is just and reasonable. The Cal ISO needs to address this issue in conjunction with other market design problems, and should do so in the impending May 1, 2002, filing of Cal ISO's comprehensive market redesign proposal.[35]

Accordingly, the ISO has included these important elements of the market redesign in the instant filing.

In Amendment No. 42, the ISO also proposed measures to limit a generator's schedule in the forward market if it determined that intra-zonal congestion would occur. This issue is being addressed in an ongoing stakeholder process. The ISO expects it will be discussed as part of the agenda for the technical conference being sponsored by the Commission staff on May 9 and 10. Accordingly, even while the ISO believes this issue must be addressed as soon as possible, the ISO has refrained from including it in this filing. The ISO expects to make a separate filing relating to intra-zonal congestion in the very near future.

A. Locational Market Power Mitigation

The problems presented by the potential exercise of locational market power were described in a study by the Department of Energy:

> Electricity markets are dynamic and can change dramatically over the course of just a few hours, creating opportunities to exercise market power even though the market may be very competitive under most circumstances. For example, the geographic scope of the electricity market is determined by the transmission system. Any change in available transmission capacity can quickly alter the geographic boundaries of the market. To cite another example, certain plants

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35 *California Independent System Operator Corp., et al.*, 98 FERC ¶ 61,327, 62,380-81 (2002).

> may be required to run at certain times in order to meet reliability needs, effectively giving them market power during those periods, because no other plants can act as substitutes.[36]

The Commission Staff has recognized the locational market power issue, and stated "it is important to note that the presence of transmission constraints can redefine the market so as to affect both concentration and market share."[37]

Within the ISO Controlled Grid, as on any transmission system, locational market power arises because of local transmission constraints, which generally occur along transmission paths entering areas of dense population and hence high load. These constraints require the services of specific generation resources to ensure the reliability of the grid in these areas, and in practically all such situations there is not a workably competitive market to provide such services. As a result, the owners of resources that are needed to ensure local reliability are in a position to exercise locational market power. Mitigation is therefore essential.

While the ISO does have certain existing measures to mitigate the exercise of locational market power (*i.e.,* Reliability Must-Run Contracts), these measure do not provide complete protection from the exercise of locational market power. This issue is discussed in the Affidavit of Eric Hildebrandt, provided as Attachment P. Dr. Hildebrandt explains and cites examples of the "INC Game" and the "DEC Game."[38]

Accordingly, the ISO seeks from the Commission authority to mitigate bids in real-time to the unit's cost-based proxy price if the ISO is required to use those bids to mitigate intra-zonal congestion. The ISO proposes to modify Tariff Section 7.2.6.2 to provide:

> If the Adjustment Bid or Imbalance Energy bid from a Generating Unit the ISO must Dispatch to manage Intra-Zonal Congestion is not the next bid in merit order, the ISO shall set the price of that bid equal to the proxy price of that Generating Unit as determined in accordance with Section 2.5.23.3.4 and Dispatch that Generating Unit pursuant to that adjusted bid to manage Intra-Zonal Congestion. The Scheduling Coordinator for that Generating Unit shall then be 1) paid the higher of its proxy price as determined in accordance with Section 2.5.23.3.4 or the BEEP Interval Ex Post Price for incremental Dispatch, or 2) charged the lower of its proxy price as determined in

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36 "Horizontal Market Power in Restructured Electricity Markets", Office of Economic, Electricity and Natural Gas Analysis, U.S. Department of Energy, March 2000 at 2.

37 Staff's Recommendation on Prospective Market Monitoring and Mitigation for the California Wholesale Electric Power Market dated March 9 2001 at 11.

38 Certain elements of Dr. Hildebrandt's Affidavit contain confidential information. The ISO is submitting those elements under seal, pursuant to 18 C.F.R. § 385.1112.

> accordance with Section 2.5.23.3.4 or the BEEP Interval Ex Post Price for decremental Dispatch.

The ISO's proposal is not duplicative of the existing mitigation measures from the Commission's June 2001 Order. Those measures are designed to replicate prices that would be found in a workably competitive market. Yet, even competitive markets must have protections against the occasional exercise of locational market power. Thus, the authority that the ISO seeks is completely consistent with the authority already granted by the Commission to other Independent System Operators. The authority to cap bids when local congestion occurs clearly reflects the reality that local reliability problems give rise to market power for which there is no competitive solution – not in California, or in any other state.

PJM has always had authority to mitigate prices to constrain local market power. The ISO notes that in June 2001, PJM filed a proposed amendment to its operating agreement and tariff that would extend PJM's existing authority to cost-cap must-run units beyond the day-ahead market to the real-time market as well. PJM stated that its experience over the last few years shows that it should also have the ability to cost-cap must-run units in real time, in order to prevent the exercise of market power if an unexpected transmission constraint should occur, so as to render, unexpectedly, a resource a must-run unit.[39]

The Commission approved this request on August 28, 2001, stating:

> If, however, a transmission constraint occurs so as to make that unit a must-run resource, the generator could earn its high price, and that price would also become the LMP for the particular load pocket for that day. As PJM notes in its answer, this scenario has, in fact, occurred. PJM's MMU thus concluded that PJM should have the authority to cost-cap must-run units in real time in order to prevent the exercise of market power, and this proposal was approved by PJM's stakeholders. We find that PJM has persuasively demonstrated that, absent the authority to cost-cap in real time, consumers would be subject to the exercise of market power by generators, and that PJM requires authority to cost-cap must-run units in real time to prevent the exercise of market power in real time.
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> * * *
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> While no one (including PJM) can predict precisely when and where a transmission constraint may occur in real time, as stated above, a generator located within a load pocket can assume that a

[39] PJM defines must-run units as "generation resources that...as a result of transmission constraints...must be run to ensure the reliability of service in the PJM control area." *PJM FERC Electric Tariff* at 249.

> transmission constraint may occur so as to make its unit a must-run resource. Moreover, as described above, a generator need not predict with certainty that it will be designated a must-run resource in order to be able to exercise market power – it need only bid its generation into the market at an excessively high price, and over the course of time, it will, likely, at certain times, be designated a must-run resource. Thus, the fact that generators cannot predict exactly when they might be designated a must-run resource does not eliminate the need for PJM to be able to cost-cap units in real time so as to prevent must-run generators from exercising market power.[40]

The ISO also notes that the Commission has approved locational market power mitigation programs for other Eastern independent system operators. Further, the Commission's SMD Working Paper recognizes that, in order to address locational market power concerns, it might be appropriate to impose bid caps (as the ISO is proposing). SMD Working Paper, slip op. at 23. In ISO New England, out-of-merit dispatch is flagged and subject to several screens before payment.[41] The New York ISO tariff also has provisions for addressing locational market power. *See* NYISO Services Tariff § 2.97 "Locational Based Marginal Pricing." The problems these ISO's have addressed through implementation of locational market power mitigation measures are not unique. As explained above, they are found on all transmission systems, including the ISO Controlled Grid, regardless of the congestion management approach employed. Consistent with the authority granted to other regional transmission organizations, and consistent with the SMD Working Paper, the Commission should authorize the ISO to implement mitigation measures to address the problem of locational market power on the ISO Controlled Grid.

The ISO's Market Surveillance Committee also agrees that "[t]he California ISO must have mechanisms to mitigate the local market power of suppliers."[42]

The proposed Tariff sheets implementing locational market power mitigation are provided as Attachment B, and the redlined sheets are Attachment C. The ISO respectfully requests these changes be made effective July 1, 2002.

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[40] *PJM Interconnection, L.L.C.,* 96 FERC ¶ 61,233 at 61,936 (2001).

[41] *See* New England Power Pool's ("NEPOOL's") April 5, 2000 submittal in Docket No. ER00-1874 of an amended Market Rule 17, "Market Monitoring and Market Power Mitigation", at 9. NEPOOL's submittal was accepted for filing by letter order issued May 31, 2000. 91 FERC ¶ 61,193.

[42] Attachment V at 2.

B. Residual Day Ahead Unit Commitment ("RUC")

The RUC process will operate after the day-ahead market has been run and has established the final day-ahead schedule. The RUC will allow the ISO to commit additional resources beyond those scheduled in the day ahead if needed to meet the ISO's system load forecast (plus reserve requirement) in compliance with NERC and WECC (formally the WSCC) criteria.

The October 1 version of the RUC process is largely structurally identical to that contained in the long-term Comprehensive Market Design proposal described in Attachment A at pp.106-110. The ISO will perform the RUC process approximately one hour after the day-ahead market has been run. As specified in the proposed ISO Tariff Section 5.12, RUC will procure a combination of energy and unloaded capacity (including demand response) to meet 100 percent of the capacity procurement target (with energy being limited to 95 percent of the next day's hourly load forecast).

Under the ISO's proposal, as of October 1, 2002, all resources subject to the Must Offer Obligation will be required to bid into the RUC process. Unloaded capacity selected in the RUC will receive a capacity payment per MW. For gas-fired units, this payment will be equal to the product of the amount of capacity selected, the proxy figure for natural gas prices and the difference between the unit's incremental heat rate at the output which the ISO determines it expects the unit to be loaded at in the RUC process and the greater of either: (1) the unit's minimum load level or (2) the unit's final day ahead schedule as specified in Section 5.12.7.1.3. For non-gas-fired units, the payment will be equal to the amount of capacity selected in the RUC process and the difference between the unit's incremental cost at the output at which the ISO expects the unit to be loaded at and the greater of: (1) the unit's minimum load level or (2) the unit's final day ahead schedule as specified in Section 15.12.7.1.4. The payment will be withdrawn as each MW is dispatched in real-time, since the supplier will be paid for the Energy dispatched. Since the capacity payment is intended as an incentive to make supply available to meet the Demand on the ISO Controlled Grid, suppliers of capacity selected in RUC that export the supply will forfeit the capacity payment. The incremental energy bids associated with capacity in RUC will not be permitted to increase in price once selected, but may be decreased prior to real time if the bidder wishes to increase its probability of real time dispatch. RUC will optimize its selection of resources by minimizing the total expected costs of procuring and dispatching resources by considering: start-up costs, minimum load costs, capacity payments and energy bids. Units committed in RUC will be selected based on system reliability on a zonal basis when necessary.[43] Metered Subsystems will be

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[43] On October 1, 2001, however, local needs currently met by RMR will continue to be met by RMR.

allowed to follow their own load without incurring RUC costs, provided that resources are established in advance, all load and exports are scheduled, and a bandwidth requirement is met. Uninstructed negative deviations will be subject to penalties and the cost of replacement.

In accordance with Section 5.12.8, costs for RUC will be borne in the following manner: Total Underscheduling Hourly Unit Commitment Cost (described at Section 5.12.8.2) will be allocated each hour to all Scheduling Coordinators based on the ratio of a SC's Net Negative Demand Deviations to total Net Negative Demand Deviations; the Total Excess Hourly Unit Commitment Cost (described in Section 5.12.8.3) will be allocated each hour to Scheduling Coordinators based on the ratio of that SC's Metered Demand to total Metered Demand; and all start-up, minimum load and Energy costs from units the ISO selects to meet local reliability requirements shall be charged to the Participating Transmission Owner in whose Service Area the unit selected is located.

There is, however, one important difference between the October 1 and the long-term Market Design Proposal version of the RUC process. The short-term RUC provides for competition between intertie energy bids and in-state units, to enable the ISO to obtain committed imports to supply real-time balancing energy on a day-ahead basis. Some of the key reasons for allowing interties to participate in the RUC in the short-term are (1) that this provides a means for intertie energy, on which the ISO's load is often dependent, to be bid into the market on a day-ahead basis; (2) obtaining import supplies prior to real time will help mitigate market power; (3) to enhance the equity between external and internal resources until the day-ahead energy market is operational; and (4) allowing intertie resources to participate will likely reduce the cost of real-time imbalance energy. Once the ISO's day-ahead market is operating, the RUC will only consider supply resources that have been designated ACAP resources by an LSE or are otherwise subject to the Must Offer Obligation.[44] It is important to remember that, even as of October 1, 2002, there is nothing to prevent a Scheduling Coordinator representing Load in California from bilaterally contracting with out-of-state resources to supply energy and scheduling that energy in the day-ahead process.

C. Modification of the Must Offer Requirement

The ISO proposes to revise the existing must offer requirement in Section 5.11 of the ISO Tariff to be consistent with the new RUC process. The proposed must offer obligation applies to all available capacity of non-hydro PGA sources and is thus is less expansive that the current "must-offer" provision, which applies to System Units and System Resources in California that utilize the ISO Controlled Grid.

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44 Relined Tariff provisions implementing the RUC process are provided in Attachment E.

In accordance with the revised Section 5.11, the ISO's Must Offer Obligation requires that these resources to bid Available Generation into the ISO's RUC process and the real time market and authorizes the ISO to insert cost-based proxy bids for resources obligated to bid that fail to bid. In essence, this is capacity: (1) from units with short start-up times that has not been already dispatched through RUC and (2) from units that are not fully committed, but whose ramp rates would permit the requested changes in output.

Must offer resources may choose to either provide market-based energy bids, subject only to the market power mitigation provisions in effect, or may elect a default bid. Default bids for the RUC process will be three-part bids for start-up, minimum load, and energy. The bids will be based on the heat-rate curve of the generating unit and the same monthly bid-week gas price index currently used to calculate proxy bid curves under the current mitigation provisions.

The ISO believes that this provision is required as a minimal prohibition against physical withholding both in the short- term and long-term. While both the current and proposed must offer obligations are weak requirement on suppliers as they do not limit the ability of resources to export from the ISO control area or to sell to the buyer of their choice, and because they do not hold the operators of these resources responsible for replacement energy in the event of a forced outage, they are clear proscriptions against physical withholding.

Beginning October 1, 2002 and lasting until an ACAP Obligation is fully effective, the ISO is proposing to strengthen this relatively weak obligation by providing a capacity payment to those affected resources whose available capacity is selected in the RUC process (discussed above). In exchange for the capacity payment, the resource will refrain from exporting power in the hour ahead and real time markets if needed to serve ISO Control Area Load.[45]

D. Real-Time Economic Dispatch

In Amendment No. 42 to the ISO Tariff, the ISO had proposed to address a long-standing problem in the design of the ISO's real-time energy market. As noted at the time the ISO filed Amendment No. 42, and as discussed below, the so-called "Target Price" problem was an artifact of the manner in which the ISO conducted its real-time energy market. Although the Commission rejected this element of Amendment No. 42 on procedural grounds, as discussed above, the ISO has incorporated this design element into its long-term market redesign and believes it is necessary for the reasons discussed below.

At times, there are Scheduling Coordinators participating in the ISO's Imbalance Energy Market who are willing to buy real-time Energy or reduce their generator output (by submitting decremental or "DEC" bids) at prices higher than the

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[45] Redlined Tariff provisions implementing the Must Offer Obligation are provided at Appendix F.

prices at which other Scheduling Coordinators are willing to sell real-time energy or increase their generator output (by submitting incremental or "INC" bids). This phenomenon is referred to as "Price Overlap". At present, the ISO has a "market separation rule" which limits the ISO to making balanced trades within a given SC's portfolio, rather than balancing one SC's incremental bids against another SC's decremental bids. The market separation rule, together with the absence of a real-time imbalance trading market, prevents these Scheduling Coordinators from making mutually-beneficial trades and thus eliminating the Price Overlap. The price at which these INC and DEC bids would meet, if they are permitted to do so, has been traditionally called the "Target Price" and it lies somewhere within the Price Overlap.

Given the ISO's market structure, the Price Overlap must be eliminated in order to produce a monotonically non-decreasing aggregate Imbalance Energy bid curve. Such a bid curve is essential to ensure that each of the interval prices is consistent with and reflective of the Imbalance Energy requirements in the interval. Under the ISO's current one-sided Imbalance Energy auction mechanism,[46] the ten-minute interval price may change from low to high as the Imbalance Energy requirement changes sign from positive to negative across ten-minute intervals, though the magnitude of the ISO's imbalance energy needs may not change appreciably. Such arbitrary changes in price yield flawed economic signals that fail to provide proper incentives for real-time response. Figure 3 demonstrates that, absent elimination of the Price Overlap, for an Imbalance Energy requirement alternating between 10 MW and –10 MW, the price will alternate between $30/MWh and $200/MWh, with the high price at intervals of Energy surplus and the low price at intervals of Energy shortfall. Such price signals are confusing and do not create appropriate incentives in the ISO markets.

In addition, the Price Overlap has been a problem because the ISO has not been permitted to take the economically rational action of clearing the Price Overlap by accepting all overlapping bids and requiring the bidders to actually buy and sell Energy at the resulting Target Price. The ISO's inability to clear the Price Overlap has allowed Scheduling Coordinators to manipulate the Target Price when the ISO needs to procure Imbalance Energy by submitting unrealistically high offers to buy Energy, thereby artificially raising the Target Price, while at the same time obtaining Dispatch priority by submitting unrealistically low offers to sell Energy, knowing that the ISO will not Dispatch their decremental bids, but would pay their Dispatched incremental bids the elevated price.[47]

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46 The current Imbalance Energy procurement is based on selecting bids in merit order to meet the Imbalance Energy requirement, rather than a full economic dispatch.

47 The ISO has tried to correct the Price Overlap problem in the past, but has not succeeded in crafting a suitable solution until now.

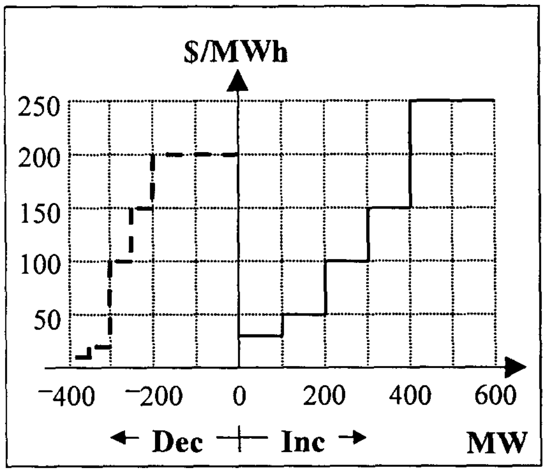

Figure 3. Price Overlap

This problem will be addressed once the LMP-based energy market is implemented. To remove this price confusion, the perverse incentives and market manipulation that would exist until then, the ISO proposes to dispatch all economic bids by creating an aggregate Imbalance Energy merit order bid stack that is a monotonic non-decreasing bid curve. In this manner, the ISO will issue Dispatch Instructions to all overlapping bids, thus requiring bidders actually to buy Energy (*i.e.,* reduce generation) or sell Energy (*i.e.,* increase generation) at the applicable ten-minute price. Figure 5 illustrates the result of the ISO proposal: the monotonically non-decreasing aggregate supply curve where the dispatched

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In April 2000, the ISO tried to eliminate this gaming opportunity by changing its method for calculating the Target Price. This modification set the Target Price to be the greater of $0/MWh or the lowest price incremental bid. However, as market conditions changed during the summer of 2001 the Target Price again became problematic. By submitting a $0/MWh incremental bid, even for a very small MW quantity, Scheduling Coordinators were able to set the Target Price to $0/MWh in periods in which the ISO needed no incremental Imbalance Energy, thus resetting all decremental bid prices to zero. This distorts the price signals and enables Market Participants to buy back Energy for free.

On September 1, 2000, the ISO changed its Real Time Energy Market to include ten-minute settlements. A component of the ten-minute settlements is the creation of two real-time prices: an incremental and a decremental price ("INC price" and "DEC price," respectively). If the ISO Dispatches bids only in one direction, the INC price and the DEC price are the same. If in a ten-minute interval the Imbalance Energy requirements force the ISO to change from an incremental mode to a decremental mode, however, the ISO could have different INC and DEC prices. To the extent the INC and DEC prices are different, Uninstructed Energy is settled based on the unfavorable price. For example, positive Uninstructed Energy is paid the DEC price while positive Instructed Energy is paid the INC price. While the two-price system provided incentives not to deviate, many Market Participants complained about the complexity of the two-price system. Furthermore, the two-price settlement, in conjunction with the modified Target Price, reduced incentives to bid into the Regulation Up market since Regulation Energy was paid at the $0/MWh decremental MCP.

incremental bids become available as decremental offers and dispatched decremental bids become available as incremental offers. Thus, by clearing the Price Overlap for each ten-minute interval, the separate INC and DEC prices converge to a single MCP. As a result, the proposed changes will simplify, and make more transparent, ISO real-time pricing by setting a single interval MCP.[48]

In effect, the ISO's Dispatch will reflect the Dispatch that could prevail in real time the absence of the market separation rule.[49] This will foreshadow the MD02 long-term Dispatch design. Scheduling Coordinators will be encouraged to make all economically rational trades. This Economic Dispatch reform proposal is described in the Affidavit of Mark Rothleder, included with this filing as Attachment O. Mr. Rothleder discusses the gaming opportunities and incorrect economic signals that result from the current regime under the market separation constraint. The proposed tariff language to implement Economic Dispatch is found in the sub-sections of Section 2.5.22, 2.5.23, 2.5.27, 2.5.28, 11.2.4, Appendix A, (the Master Definitions Supplement), Dispatch Protocol ("DP") 4.4, DP 8.6.3, Settlement and Billing Protocol (SBP) 6.1.3, and Scheduling Protocol ("SP").

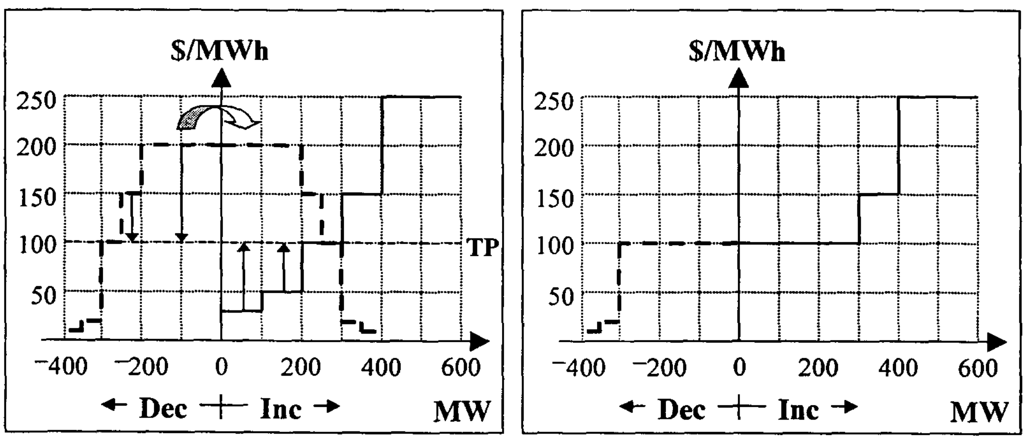

Figure 4. Price Overlap Elimination by Target Price

48 In essence, suppliers with higher decremental bids would rationally deviate from their bids and not produce from their higher-cost units if the Imbalance Energy price was lower.

49 This is reflected in the change to Section 2.5.22 (c) of the ISO Tariff.

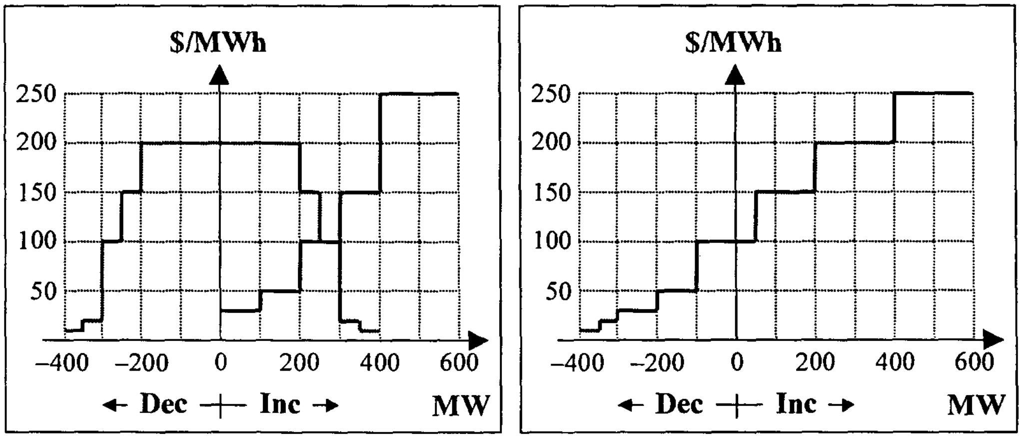

Figure 5. Elimination of the Price Overlap

E. Use of a Single Bid Curve

The ISO proposes that bidders into the day ahead and hour ahead markets be required to submit a single energy curve for all services offered by a single resource. The curve could be changed with each hourly bid but a supplier could not submit different curves from the same unit in different markets for the same hour. The ISO believes that this change should reduce gaming between different ISO Markets. This single energy curve would be placed into the ISO's real time dispatch in merit order if the Ancillary Service bid is accepted. Separate capacity bids for each service will still be permitted.

The proposed changes to the ISO Tariff are shown in Attachment H. As illustrated in the attachment, the revision consists of a new Section 5.13 specifying that a single Energy Bid curve per resources per hour would be used in the RUC Process, Real-Time Hourly Pre-Dispatch, and Real-Time Economic dispatch (10-minute imbalance energy market).

F. Penalties for Excessive Uninstructed Deviations

Similar to the discussion for real-time price changes, the ISO previously proposed in Amendment No. 42 to penalize Scheduling Coordinators for uninstructed deviations beyond a reasonable tolerance band. As noted at the time the ISO filed Amendment No. 42, and as discussed below, large deviations from Schedules and Dispatch Instructions can have a significant adverse impact on reliability and prices. Although the Commission rejected this element of Amendment No. 42 on procedural grounds, as discussed above, the ISO has incorporated this design element into its long-term market redesign and believes it is necessary for the reasons discussed below.

Figure 6 shows that uninstructed deviations have increased in both the hourly and ten-minute Settlement regimes at the ISO.[50] The Affidavit of Mr. Tom Siegel (Attachment Q hereto) also discusses the significant level of uninstructed deviations in the ISO's markets and the problems that uninstructed deviations cause. Failure to follow schedules presents a serious reliability problem as the ISO must make undertake significant compensatory actions in real time.[51] As a result, the ISO proposes Tariff modifications to provide for narrowly tailored explicit penalties to be levied against Scheduling Coordinators for uninstructed deviations that are beyond a tolerance band for generating unit performance.

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50 Net deviations are shown because Scheduling Coordinators are allowed to offset positive deviations from some of their resources with negative deviations from other resources, in real time. The net positive deviations are averaged for intervals in which individual Scheduling Coordinators have positive values, and net negative deviations are averaged for intervals in which individual Scheduling Coordinators have negative values. Because the output of resources that are providing Regulation will vary within a time period, the results reported here exclude resources for which Regulation bids have been accepted during the specific interval. Although generators that are providing Regulation are included in the overall calculation of uninstructed deviations for settlements purposes, Automatic Generation Control ("AGC") equipment will attempt to keep a generator's output within its regulating range, and will vary its output within the regulating range in response to system conditions. Thus, only deviations outside the regulating range would be truly uninstructed from an operational perspective, without a review of plant-specific operations. Such deviations have initially decreased since the implementation of ten-minute markets, but are small compared to the uninstructed deviations of generators that are not providing Regulation due to the effectiveness of AGC equipment, as shown in the following table (showing the sum of plant-specific uninstructed deviations rather than netting deviations across each Scheduling Coordinator's portfolio):

Month (Year 2000)	Average Positive Deviation Outside Regulating Range	Average Negative Deviations Outside Regulating Range
June	35.8 MW	44.7 MW
July	30.8	36.3
August	41.5	40.4
September	31.4	27.0
October	12.0	20.8
November	5.8	18.4

51 As Mr. Siegel states,

> For the ISO to successfully perform its role of Control Area operator, it is essential that generators follow forward schedules and respond to ISO Dispatch instructions in an accurate, timely and predictable manner. Failure of generators to produce Energy in a manner consistent with their forward schedules, as adjusted by ISO Dispatch instructions, can adversely impact the ISO's ability to operate the Control Area in a manner consistent with standards established by NERC and WSCC and Good Utility Practice. Additionally, if generators deviate from their expected operating points in a manner that contributes to transmission overloads or otherwise adversely affects the transmission system, the ISO's ability to manage inter- and intra-zonal congestion is adversely affected.

Attachment Q at 7. The issue is also discussed in the affidavit of Mark Rothleder, Attachment O at 6-7.

FIGURE 6: Average Monthly Positive and Negative Uninstructed Deviations

Period	Average Net Positive Deviation from Generation	Average Net Negative Deviation from Generation
• Jun – Aug 2000	**959.9 MW**	**557.0 MW**
June	895.0	632.8
July	882.8	564.4
August	1099.8	476.2
Sept – Nov 2000	**479.1**	**620.1**
September	569.3	591.1
October	362.5	609.8
November	509.6	659.6
Dec 2000 – Feb 2001	**659.9**	**829.7**
December	721.7	659.7
January	531.6	866.8
February	729.0	978.3
Mar – May 2001	**297.1**	**808.9**
March	298.4	720.2
April	287.8	859.7
May	304.7	848.7
Jun – Aug 2001	**382.6**	**981.2**
June	549.9	1087.2
July	322.0	974.5
August	278.1	882.1

In developing the instant proposed modifications to the ISO Tariff which are designed to deter excessive uninstructed deviations, the ISO seeks to balance operational requirements for maintaining System reliability, with the need to allow some reasonable operational flexibility for suppliers and accommodate specific operating requirements of certain Market Participants. The proposed modifications to the ISO Tariff, which are specified in Attachment I, include penalties for certain types of uninstructed deviations. The ISO carefully has designed the penalties so they are not only fair, but are targeted to the specific type of behavior the ISO is attempting to discourage. The penalties should provide incentives for Market Participants to minimize uninstructed deviations.

The ISO is proposing to implement penalties for the following types of uninstructed deviations: (1) declining an ISO dispatch instruction; (2) accepting an ISO dispatch instruction but deviating from it by more than a pre-defined tolerance band; and (3) deviating from a final hour-ahead schedule without being instructed by the ISO. The ISO proposes to treat declined instructions as accepted instructions that are not delivered unless the resource in question undergoes a forced outage and the Scheduling Coordinator so notifies the ISO in time. As proposed by the ISO, the penalty for positive uninstructed deviations will be the quantity of Uninstructed Imbalance Energy in excess of the tolerance band multiplied by a price equal to100% of the applicable BEEP Interval Ex Post Price. The practical result is that a supplier will not be paid for Energy in excess of the tolerance band. The penalty for negative uninstructed deviations initially will equal the amount of Uninstructed Imbalance Energy below the tolerance band multiplied by a price equal to 50% of the applicable BEEP Interval Ex Post price. Thus, negative Uninstructed Imbalance Energy will be charged at 150% of the applicable BEEP Interval Ex Post price. The ISO proposes a tolerance band equal to the greater of 5 MW or 3% of the maximum operating limit of the resource.[52]

The proposed modifications specifically are designed to provide to Market Participants flexibility in complying with their Dispatch Operating Point[53] ("DOP") along with reasonable operational flexibility for generating resources. The ISO proposes to continue to issue unit-specific Dispatch Instructions and to continue to settle on a unit-specific basis. Scheduling Coordinators can aggregate generators interconnected at a single ISO grid bus point for purposes of determination of the Uninstructed Deviation Penalty, however, effectively gaining the ability to net deviations from units located at a single point. The ISO also will allow for the net determination of penalties for other aggregations of generating units, as approved by the ISO on a case-specific basis.[54] In addition to the flexibility provided to generating units, the instant proposed modifications will allow Metered Sub-System and self-serving Load Market Participants the ability to follow changes in their load with their own internal generation, with Uninstructed Deviation Penalties only applying to the net ISO-expected Energy deliveries. Finally, the ISO proposes that

52 The ISO believes that this latitude of compliance flexibility is sufficient to take into account unintentional deviations that occur as a result of unit operations while being sufficiently stringent enough to provide incentives to Scheduling Coordinators to maintain expected unit output. In the initial Amendment No 42 filing, the ISO proposed that the Commission grant the ISO authority to modify the tolerance band, without the need for a subsequent Section 205 filing. In response to the concerns raised by intervenors regarding that submission, the ISO does not propose to have the flexibility to modify the tolerance band or penalties without subsequent Commission authorization.

53 "Dispatch Operating Point" has been proposed as a defined term in the Master Definition section of the Tariff.

54 The ISO will develop a process to allow Market Participants to propose aggregations of generating units that are not at individual transmission bus points. Market Participants proposing unit aggregations will be required to demonstrate that the units aggregated are interchangeable, function as a single entity, and will not affect grid reliability.

entities with limited control over their output, such as intermittent resources and units providing regulation, be exempted from the uninstructed deviation penalty provision.

It is appropriate that the ISO not pay generators for positive uninstructed deviations beyond the tolerance band, because Market Participants should not be required to pay for Energy and services that the ISO did not request and which the ISO does not need. In approving the NYISO's proposal not to pay generators for power delivered above the amount scheduled and requested by the NYISO, the Commission stated: "We agree...that strong rate disincentives are needed to induce generators to be vigilant in avoiding over-generation and shall accept this proposal."[55] The ISO believes that some penalty beyond the replacement cost of energy must be imposed on a unit for failing to deliver according to a Dispatch instruction. A supplier with more than one generating unit could otherwise profit by increasing the MCP for all of its generating units by failing to deliver from that one unit. Since the ISO deems Dispatch Instructions to be delivered (*see* proposed Section 2.5.22.11), the unit that failed to deliver both is paid the MCP for the amount of Energy in its Dispatch instruction and charged the MCP for the amount of Energy it fails to deliver. Without a penalty, if the unit is dispatched but delivers nothing, the payments and charges completely offset each other. There is therefore no economic incentive for a generator to follow Dispatch Instructions. However, as a negative consequence, because the ISO still requires the Energy, it then is forced to call on the next bid in merit order in the BEEP stack, thereby raising the MCP. To provide an incentive for Scheduling Coordinators to comply with Dispatch Instructions and specifically to discourage this market-manipulating behavior, the ISO proposes this penalty.

Penalties for uninstructed deviations have been demonstrated to be effective in reducing the scope and frequency of such deviations. On December 8, 2000, the ISO made an emergency filing with the Commission to provide penalties on generators that did not comply with ISO Dispatch Instructions. The ISO Compliance Department conducted an analysis of generator compliance with ISO Dispatch Instructions during system emergencies in which penalties were assessed for non-compliance compared to compliance during system emergencies in which no penalties were assessed. This analysis shows that there was a significant improvement in compliance with Dispatch Instructions in the hours in which penalties were assessed. For example, during the study periods, generators provided 90% or more of the Energy expected from ISO Dispatch instruction only 3% of the time in hours in which penalties were not imposed, but they provided that Energy 43% of the time in hours in which penalties were imposed.[56]

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55 *Central Hudson Gas & Electric Corporation, et al.*, 86 FERC ¶ 61,061, 61,266 (1999).

56 *See* Affidavit of Tom Siegel (Attachment Q) at 2-4.

G. Extension of the Current Mitigation Methodology

The ISO believes that the implementation of the MD02 will reduce opportunities for suppliers to exercise market power in wholesale electricity markets in California and the West. By itself, however, the market redesign cannot and will not ensure that wholesale electricity prices are just and reasonable at all times. For that reason, MD02 includes elements to enhance the ability of the ISO to detect and mitigate market power. In addition, the MD02 proposal cannot be implemented overnight. Wholesale purchasers of electricity, and the consumers who rely on them, are entitled to effective protection against the exercise of market power while the work to implement comprehensive market reform, including long-term market power mitigation measures, proceeds.

The need for effective and comprehensive market power mitigation cannot be overemphasized. Significant exercise of market power historically has created an energy market in California that has fallen far below the reasonable and efficient operating standards of a competitive market, let alone the "just and reasonable" standard of the Federal Power Act. Moreover, despite the market mitigation measures that have been in place as the result of the Commission's June 19 Order, significant market power continues to exist. The exercise of market power has resulted in many millions of dollars of excessive costs that have been borne by wholesale purchasers and ultimately by consumers in California and elsewhere in the West. Moreover, the Commission has held that large portions of these unreasonable costs -- those incurred prior to October 2, 2000 -- are not subject to refund. The history of studies identifying the exercise of market power are described in Attachment W.

As noted in section III above and in the Affidavit of Gregory Cook provided as Attachment R, the ISO's DMA continues to observe that certain frequently dispatched units continue to bid with strategies that are indicative of market power and that this persistent, substantial mark-up over price levels that would prevail under workably competitive conditions demonstrates that suppliers in California power markets continue to possess and exercise market power to the substantial detriment of California consumers.

Mr. Cook explains that the current mitigation measures are effective because the west-wide scope prohibits suppliers from circumventing location-specific mitigation measures.[57] As California experienced in 2000 and early 2001, location-specific mitigation measures can be averted by simply exporting power out of the mitigated location, and then importing the power back at unmitigated prices, a practice commonly referred to as "megawatt laundering." Mr. Cook states that the current mitigation measures also benefit the market by providing an incentive for

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[57] *Id.* at 16.

suppliers to increase supply during tight supply conditions. The incentive arises from fact that the current price limit was set during the last full hour of an ISO declared Stage 1 reserve emergency on May 31, 2001. This formula limit, which incorporates monthly gas price indices, was set at a time when the price of natural gas was \$6.641/MMBtu, considerably higher than the current \$3-\$4/MMBTu prices.[58] Thus suppliers have a strong incentive to avoid resetting the limit using current gas prices.

It is apparent that the conditions that enabled suppliers to exercise market power and to command prices well in excess of just and reasonable levels have not abated. In these circumstances, the ISO urges the Commission to authorize the continued application of the current market price mitigation measures, as authorized under the June 19 Order, until the ISO has fully implemented MD02, including LMP and the proposed long-term market mitigation measures (a damage control price cap and automatic mitigation measures described below) and the market is determined to be competitive. Continued application of the current market price mitigation measures is the least intrusive, most efficient, and minimum legally-required step required to protect wholesale customers (and their ultimate customers) against the exercise of the market power that has not been constrained by the amelioration of the conditions upon which the institution of those measures was premised.[59]

In addition, the Commission must recognize the current situation in the California electric market. As a result of the unjust and unreasonable wholesale prices experienced during 2000 and 2001, the two largest California IOUs are in financial distress and lack the creditworthiness to engage in construction or long-term contracting. Currently, the California Energy Resource Scheduler ("CERS") division of the California Department of Water Resources is responsible for procurement of the "net short" needs -- demands over and above generation owned or previously contracted for by the California IOUs. However, CERS' statutory authority to buy on behalf of the net short needs expires at the end of this year. The State of California must address this vital procurement responsibility. It would be manifestly unjust and unreasonable for the Commission to retract existing mitigation measures while the forward purchasing responsibility for such a significant portion of the State's electric demand is uncertain.

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58 *Id.* at 15-16

59 The ISO's Market Surveillance Committee concurs that "the best course of action for short-term market power mitigation is to extend the June 2001 FERC west-die mitigation order until it is determined what entities will be responsible for purchasing electricity after December 31, 2002." *See* Attachment V at 5.

The ISO notes that the extension of the current market price mitigation measures should nevertheless provide suppliers with more flexibility than they currently enjoy if the Commission approves two proposals that the ISO has made. First, the ISO has asked the Commission to rule expeditiously on the ISO's proposal for the elimination of the $0/MWh bidding requirement the Commission previously placed on marketers and importers. If this request is granted, the ability of marketers and importers to provide supplies to the ISO's markets will be enhanced. Second, the proposed implementation of the residual unit commitment and the modification of the "must offer" requirement will give suppliers an additional capacity payment.

Black-lined tariff language showing the changes necessary to extend the current market price mitigation measures is contained in Attachment J.

H. 12-Month Market Competitive Index and Pre-Authorized Mitigation Provisions and Decremental Bid Cap

Missing from the current mitigation regime is a methodology that evaluates the market over a long period to ensure that overall prices remain at just and reasonable levels. As described in the Affidavit of Dr. Anjali Sheffrin provided as Attachment S, the proposed 12-month price-cost markup index and the recommended mitigation measure is intended as an instrument to monitor electric markets, serve as an early warning device that outcomes are not just and reasonable, and provide a prospective tool for mitigation, rather than a retrospective rule which may need extended litigation for refunds. The index is intended to be calculated in a transparent manner so that all parties can monitor market performance and have confidence when mitigation will be applied. The prospective nature of mitigation allows all parties to self- police their actions in order for the indicator not to be triggered. This can serve as a powerful self-regulating type of mechanism that would use the self-interest of Market Participants to regulate the market rather than rely on an hourly examination of market behavior which could be considered as over interventionist. It allows normal demand and supply forces to equilibrate markets and intervenes only when market power is shown to be significant on a significant and sustained basis.

The proposed 12-month competitiveness index meets many of the objectives stated in the Commission's most recent working paper on market power monitoring and mitigation.[60] This paper provides a good summary of what is market power and what is just and reasonable rate:

> Market power is the ability to raise market price above the competitive level. Market power can be exercised by withholding capacity or

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[60] Strawman discussion paper for market power monitoring and mitigation panel, Technical Conference on Market Structure and Design, Docket No. RM01-12, February 7, 2002

> output from the market (physical withholding) or raising the price or offer (economic withholding). For a price to be above the competitive level, the price must reflect an excess over true scarcity value.

In this paper there is an outline of what characterizes just and reasonable rates:

> Competitive prices reflecting no market power should be considered just and reasonable. The Commission should intervene in markets, beyond standard preventive measures, when market power is significant and sustained. Further mitigation should be used only when it is clear that short-term supply and demand forces cannot prevent significant and sustained market power.
>
> * * * * *
>
> Significant market power involves prices some significant degree above competitive levels. Sustained market power includes circumstances which cannot be remedied by short-term supply, demand, or market rules. Probably it should be measured in months rather than hours or years. Sustained market power includes recurring market power that may appear and disappear with cyclical demand variation. Investment and entry of generation or transmission, given significant construction and siting timelines, typically takes too long to prevent significant and sustained exercises of market power. The Commission may wish to develop more specific standards of significant and sustained market power. For example, the Commission may wish to adopt a standard that balances the tradeoff between the magnitude and the length of time of the price increase.

The proposed 12-month price-cost markup addresses all of the considerations discussed above. It measures sustained and significant deviation of market price above competitive levels, balances the tradeoff between the magnitude and the length of the time the price increase, and it does consider scarcity value.

To provide this needed check on overall market performance, the ISO proposes to compute a 12-month rolling average Market Competitiveness Index ("12MMCI") as specified in Tariff Section 28.2.1 and evaluate that index against a threshold of $5/MWh defined in Tariff Section 28.2.1.6. If and when the trigger threshold is exceeded, the mitigation measures specified in section 28.2.3 will apply for the lesser of: six months or until the Commission has determined that the market has been restored to competitive conditions.

The ISO Department of Market Analysis will compute the 12MMCI at the end of each month for the previous 12 months. The 12MMCI is a 12-month rolling price-cost markup index that compares actual average market cost ("AAMC") as specified in section 28.2.1.2 to a competitive baseline average cost ("CBAC") as specified in section 28.2.1.3. The AAMC is the weighted average of short-term forward and real-time energy prices. The CBAC is the competitive baseline average cost and is based on prices that represent the estimated variable operating cost of the marginal (highest cost) thermal generation unit within the ISO system needed to meet system demand each hour.

To assess the degree to which high prices may be attributable to absolute scarcity of supply rather than market power, the DMA shall identify the portion of the price-cost markup that occurred during hours of potential resource scarcity. In this analysis, scarcity shall be defined to occur during the hours when the total available supply in the ISO system (including import bids and out-of-market purchases) is less than the total system demand for energy plus a margin of 10 percent approximating requirements for three percent upward regulation and seven percent Operating Reserves). To ensure transparency to the market, the ISO shall calculate and publish the 12MMCI every month.

The ISO proposes a threshold for the 12MMCI of $5/MWh. While this figure may appear small, the estimated cost exposure of such a markup is approximately $150 million per year.[61] If the threshold for the 12MMCI is exceeded, then the ISO will: (1) apply cost-based proxy bid mitigation in all hours, (2) notify the Commission that the threshold has been exceeded, and (3) request that the Commission re-institute the West-wide mitigation components of its June 19, 2001 Order in Docket No. EL00-95 if the Commission has not extended these measures previously. The ISO shall also request that, to the extent not already provided, the Commission establish liability for refunds in future periods based on the principles provided for in the Commission's June 19 Order until the Commission makes a finding that rates are just and reasonable.

The ISO believes that its 12-month competitiveness index provides a vital check on the potential for the type of crises that infected the California market during 2000 and 2001. As noted in Dr. Shefrin's affidavit, this measure does not restrict prices below levels needed to encourage reasonable plant investments.[62] The ISO's Market Surveillance Committee "strongly endorse[s] the concept of a

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[61] This is based on an annual net short amount of 55,123 GWh less a projected amount covered by long-term contracts and quarterly purchases of 25,056 GWh.

[62] Attachment S at 9.

rolling 12-month competitiveness index."[63]

In addition, the ISO needs the ability to mitigate DEC bids in intra-zonal congestion situations. As part of such mitigation, the ISO proposes a negative damage control bid cap of -$30/MWh for the Real Time Market. Situations where the ISO could potentially be faced with nagative energy bids are: (1) imports submitting low DEC bids in order to be predispatched as price takers; (2) decremental bids being dispatched in real-time to manage inter-zonal congestion; and (3) a system wide over-generation condition. Reasons that Market Participants may reasonably justify a negative decremental energy bid include: (1) a generator that reduces generation may face gas imbalance charges if it does not consume gas it has already nominated to flow; (2) transmission costs, exterrnal to the ISO Control Area, associated with an import schedule to the ISO control area, which would still apply even if the ISO curtails the import schedule; and (3) Load may justifiably want to be subsidized for consuming extra energy (*i.e.* a large commercial enterprise may ramp up production processes that would not be otherwise enonomic absent an energy consumption subsidy). While the ISO believes these types of costs could justifiably result in a negative energy bid, the ISO does not believe it is reasonable to expect that such factors could result in a negative energy bid below -$30/MWh. Therefore, the ISO is proposing that the negative Damage Control Bid Cap be set at -$30/MWh. This negative Damage Control Bid Cap is not based on any index being exceeded. It would be in effect in all hours under all conditions.

The purpose of the 12-month Competitiveness Index is different than the purpose of damage control bid caps. Bid caps are in effect regardless of overall competitiveness of the market. Bid caps provide a constant safety net to guard against occasional large price spikes. The 12-month Competitiveness Index and accompanying mitigation measures provide protection against sustained market power. Thus, it is less of a mitigation element than a barometer of overall market performance. Remedial measures would not be invoked through the 12-month Competitiveness Index due to infrequent price spikes if the overall market is competitive. If and only if conditions result in a sustained exercise of market power with significant adverse impact on consumers, the measures would be enacted to ensure just and reasonable rates in market outcomes.

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[63] *See* Attachment S at 7.

VI. IF THE COMMISSION REFUSES TO EXTEND THE CURRENT MARKET PRICE MITIGATION MEASURES, IT SHOULD ACCEPT THE ALTERNATIVE MITIGATION MEASURES PROPOSED BY THE ISO.

The ISO strongly believes, for the reasons set forth above, that extension of the currently effective market price mitigation measures is the minimum interim approach that would satisfy the statutory standard that just and reasonable wholesale rates be assured. In the event the Commission nevertheless declines to extend the current mitigation program, the ISO has developed an integrated package of two alternative measures that would provide a less robust and less certain level of protection for wholesale customers. The ISO wishes to stress that these elements, together with the 12-month competitiveness index, decremental bid cap, and all the other elements of the first phase of the Market Redesign 2002 proposal, discussed in Section V, above, must be accepted and permitted to operate in an integrated manner if even this reduced (and inferior) protection against unjust and unreasonable wholesale prices is to be achieved. If any element of this alternative proposal is rejected or substantially modified, the ISO is not confident that market power can be mitigated.

The two elements of the ISO's alternative market power mitigation proposal are as follows: (1) a damage control bid cap; and (2) automatic market mitigation procedures. These are elements of the long-term market redesign. If the Commission refuses to extend the current mitigation measures, however, the ISO proposes to accelerate the effectiveness of these market power mitigation measures, so that they would take effect October 1, 2002. Accordingly, the ISO would need to be informed of the Commission's determination well in advance of September 30, 2002, to undertake the additional software development.

A. Damage Control Bid Cap ("DCBC")

When the current Commission- imposed price mitigation expires, the ISO's spot markets will again be vulnerable to extreme peak prices. To mitigate market power abuse, the ISO is proposing a Damage Control Bid Cap ("DCBC") that will apply to all resources (including imports) submitting bids into ISO's energy and ancillary service capacity markets. All ISO's use a DCBC at some level to limit the harmful effect of abnormal price spikes. Because the ACAP obligation, and other structural elements that will ensure workable markets, will be phased in over time, the ISO is proposing to start with a relatively low bid cap that would gradually increase as market conditions improve, *i.e.*, as the market becomes more competitive. Beginning October 1, 2002, the ISO is proposing a DCBC with a floor of $108/MWh, indexed to the price of gas as provided in the Commission's December 19 West-wide Order.

The ISO believes that this DCBC range provides appropriate protection against market power abuse while allowing for increases should gas costs increase. The ISO notes that its last ceiling price pursuant to June 19 Order of $92/MWh was set based on the price during Hour Ending 1000 on May 31, 2001. At that time, gas prices were approximately 97% higher than current prices[64]. If the ISO were to recalculate a limit today, the price would be approximately $58/MWh. Thus, the $108/MWh value already has the potential to overstate significantly suppliers' current operating costs. While the history of the ISO markets has shown that a bid cap can create a target for supply bids in the ISO's real-time market, the ISO's proposal also will utilize bid screens and mitigation provisions that will result in only resources with extremely high reference levels effectively bidding at or near the DCBC.

B. Bid Screens and Automatic Market Power Mitigation

The ISO intends to implement individual resource bid screens and mitigation procedures in the RUC process and the real time predispatch process, applicable to any resource eligible to set the real time MCP, including import bids. This would be achieved by a new Appendix A to the Market Monitoring and Information Protocol. The mitigation would be imposed on bids that: (1) exceed an explicit threshold, and (2) have a material impact on projected MCPs. The threshold for measuring a given resource's bid would be equal to the lower of a 100 percent increase or $50/MWh from that resource's reference level. The reference level would be based on historical accepted bids. While the ISO recognizes that using historical accepted bids instead of bids based on gas-fired resources' costs could undermine the effectiveness of AMP as a market power mitigation tool if such resources have established excessive bidding patterns, the ISO did not want to establish an asymmetrical treatment between gas-fired and non-gas fired resources. Moreover, the ISO's DMA will monitor bidding patterns to determine if a persistent non-competitive bidding pattern requires modification of the reference level and, if so, would request such an action from the Commission.

The market impact threshold would be equal to the lower of 100 percent increase or $50/MWh in projected real time market clearing prices.

The ISO's AMP is similar to the program adopted by the NYISO. Unlike the NYISO AMP, however, the ISO AMP will apply only to economic withholding. Although the ISO will monitor for physical withholding, it will impose penalties for such withholding through its Uninstructed Imbalance Energy penalties, discussed above, not through the AMP. In addition, the ISO proposes that AMP be applied to imports because of the potential for internal resources to circumvent AMP by megawatt laundering.

The ISO's proposed thresholds for determining market power and market impact are lower than those applied in the NYISO's AMP. After consideration of stakeholder comments, the ISO determined that higher thresholds would not

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[64] The proxy figure for natural gas costs for April 2002 is $3.37/MMBtu. The proxy figure for natural gas costs establishing the $108/MWh mitigated price is $6.64/MMBtu.

effectively mitigate market power in the California energy market.

The ISO proposes not to apply AMP during hours in which the ISO had a day-ahead forecast in excess of 40,000 MW, however, nor would bids accepted during such hours be considered in determining the AMP reference levels. This will help ensure that sufficient supplies are bid into the ISO Real Time Market during potential hours of scarcity.[65]

VII. REQUESTED ACTIONS AND EFFECTIVE DATE

Accordingly, the ISO respectfully requests that the Commission:

1. Grant preliminary approval to the ISO's long-term market redesign and authorize the ISO to expend funds to implement the long-term market redesign program;
2. Accept the proposed tariff revisions for: Locational Market Power Mitigation effective July 1, 2002 and the proposed revisions for Residual Day Ahead Unit Commitment, Modified Must Offer, Penalties for Excessive Uninstructed Deviations, Economic Dispatch, extension of the current price mitigation regime, the 12-month competitiveness index, and the decremental bid cap effective October 1, 2002;
3. Extend the current price mitigation until the ISO implements its new market design and the Commission determines that the resulting markets are workably competitive;
4. In the alternative, if the Commission does not extend the current price mitigation regime pending full implementation of the market redesign and further findings that the redesign will be successful in keeping prices to just and reasonable levels, the Commission should approve the proposed tariff provisions for the DCPC and AMP.

The ISO will continue the preparation of the detailed tariff revisions to implement the long-term MD02 elements. These efforts will be informed by the Commission's Standardized Market Design rulemaking, which will be proceeding in parallel with the ISO's activities. The ISO expects to file the tariff with the Commission in mid-June 2002. At that time, the ISO would respectfully request that

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65 AMP and DCBC are complementary tools for mitigation against economic withholding. They are not redundant. The DCBC limits the magnitude of price spikes. AMP limits the frequency of price spikes by limiting the ability of suppliers to suddenly change their bidding patterns in ways that cannot be explained by costs. AMP is intended to address the type of tacit collusion that can arise when supply margins are sufficiently tight to give suppliers confidence that bids submitted at or near the DCBC are likely to be accepted.

the Commission initiate a 60-day stakeholder process to provide necessary constructive feedback on the ISO's proposed tariff language and implementation details.

VIII. SERVICE

The ISO has served this filing on Public Utilities Commission of the State of California, the California Energy Commission, the California Electricity Oversight Board, and all parties with effective Scheduling Coordinator Service Agreements under the ISO Tariff. In addition, the ISO has served all parties in Docket No. EL00-95 and posted a copy of the filing on its Home Page.

IX. NOTICES

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

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X. SUPPORTING DOCUMENTS

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

Attachment A -	ISO's Comprehensive Market Design Proposal;
Attachment B -	Tariff Sheet for Locational Market Power Mitigation
Attachment C -	Redline showing changes to mitigate the exercise of locational market power;
Attachment D -	Tariff Sheets for Elements To Be Effective October 1st
Attachment E -	Redline showing changes to implement Residual Unit Commitment
Attachment F -	Redline showing changes to implement modifications to the Must Offer requirement;

Attachment G -	Redline showing changes to implement Economic Dispatch;
Attachment H -	Redline showing changes to require use of a single energy curve;
Attachment I -	Redline showing changes to penalize generators for failing to comply with Dispatch Instructions;
Attachment J -	Redline showing changes to implement extension of the Commission's current market power mitigation methodology;
Attachment K -	Redline showing changes to implement the 12 Month Competitive Index and the decremental bid cap;
Attachment L -	ISO Tariff Sheets for alternative market power mitigation proposal;
Attachment M -	Redline showing changes to implement the Damage Control Price Cap;
Attachment N -	Redline showing changes to implement the Automatic Mitigation Measures;
Attachment O -	Affidavit of Mark Rothleder;
Attachment P -	Affidavit of Eric Hildebrandt;
Attachment Q-	Affidavit of Thomas Siegel;
Attachment R -	Affidavit of Gregory Cook;
Attachment S -	Affidavit of Anjali Sheffrin;
Attachment T -	Comparison with SMD;
Attachment U -	April 25, 2002 Board of Governors Motions;
Attachment V -	Comments of the Market Surveillance Committee;
Attachment W -	History of Market Power findings; and
Attachment X -	Notice of this filing, suitable for publication in the Federal Register (also provided in electronic format).

Two additional copies of this filing are enclosed to be stamped with the date and time of filing and returned to our messenger. If there are any questions concerning this filing, please contact the undersigned.

Respectfully submitted,

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