UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

California Independent System	**)**	**Docket No. ER02-1656-015**
Operator Corporation	**)**	**Docket No. EL01-68-028**

COMMENTS OF THE CALIFORNIA ENERGY RESOURCES SCHEDULING DIVISION OF THE CALIFORNIA DEPARTMENT OF WATER RESOURCES

The California Department of Water Resources California Energy Resources Scheduling Division (CERS) hereby submits to the Federal Energy Regulatory Commission (the Commission or FERC) its comments[1] on the Amendment to Comprehensive Market Design Proposal (Amended MD02 Proposal) filed July 22, 2003, by the California Independent System Operator (CAISO).

I. Communications

The persons to whom correspondence, pleadings and other papers regarding this proceeding should be addressed and the persons whose names are to be placed on the Commission's official service list are designated as follows pursuant to Rule 203:

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[1] *See* Notice of Extension of Time, Docket No. ER02-1656-015 (Aug. 7, 2003) (granting extension of time to file comments, protests and interventions until A
ugust 27, 2003).

II. Introduction

The CAISO's Amended MD02 Proposal is the latest development in the CAISO's ongoing market redesign as directed by the Commission's order of December 19, 2001.[2] On May 1, 2002, the CAISO filed its Comprehensive Market Design Proposal, designated Amendment No. 44 to the ISO Tariff (May 1 Proposal). The Amended MD02 Proposal incorporates modifications to certain design elements of the May 1 Proposal following additional stakeholder and internal CAISO activities.

At the core of the Amended MD02 Proposal is the establishment of an Integrated Forward Market (IFM) that includes a settlement regime based on Locational Marginal Pricing (LMP). Implementing LMP-based settlements will harm the investor-owned utilities' (IOUs) ratepayers and the State of California in two ways:

- First, it will diminish and possibly nullify the benefits of the hedge provided by the existing long-term power purchase contracts entered into by CERS (the State Contracts) after the market melt-down of 2000-2001.
- Second, because the State Contracts are a significant investment in physical energy supplies, any substantial financial shifts, which affect any parties' ability to perform under the contracts, would unacceptably impact the reliability of service to the IOUs' customers.

The proposed LMP regime will radically alter the existing short-term power market from the zonal system, under which the State Contracts were negotiated and

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[2] 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, 97 FERC ¶ 61,275 (2001).

entered into, to a nodal-based platform. The nodal system, in which the State Contract sellers have the option of choosing the nodes or points of delivery, will expose the retail customers of the IOUs to congestion costs that cannot be hedged under CAISO's proposed regime for forward and real-time markets settlement and allocation of congestion revenue rights (CRRs). Additionally, CAISO's proposal will allow the sellers to reap one-sided net settlement windfalls in the form of paper counter-flow payments. The paper counter-flow windfalls are an inevitable, if unintended, consequence of CAISO's Amended MD02 Proposal.

Implementation of LMP will replace the current CAISO congestion management zones, upon which key terms and conditions of the existing State Contracts were negotiated and based, with locational nodes for managing and pricing congestion, and for settlement of forward and real-time energy markets. CERS is therefore very concerned that the market redesign, which features LMP, not be implemented prior to a satisfactory resolution of potentially severe impacts on the essential bargained-for elements of the State Contracts.

In its filing, the CAISO recognizes that several key aspects of the development of the market redesign are not complete, and therefore remain open to ongoing discussions among the CAISO and affected parties. *See generally*, Transmittal Letter, pp. 16-20. In discussing what is referred to as "The Continuing MD02 Process," the CAISO identifies important tasks that remain to be completed prior to implementation of MD02 design, including:

- Finalizing the CAISO's internal Congestion Revenue Rights (CRRs) study, working with the California Public Utilities Commission (CPUC) and initiating the CRR allocation process

- Resolving cost allocation and other issues related to the CAISO's proposed procedure for honoring Existing Transmission Contracts (ETCs), and

- Identifying and aligning the market and scheduling rules that best accommodate both pre-existing as well as going-forward bilateral sales that occur outside of the CAISO's markets.

Transmittal Letter, pp. 16-17.[3]

With respect to LMP and the State Contracts in particular, the CAISO's proposal acknowledges the concerns expressed by CERS, that implementation of an LMP-based market design will have an adverse impact on long-term contracts entered into by CERS on behalf of California's IOU retail customers, and the importance of resolving those issues "**prior to implementing LMP**." Transmittal Letter, p. 20 (emphasis added). CERS submits that implementation of LMP without fully assessing the subsequent impacts on these long-term contracts and providing the necessary accommodation would be an imprudent step in conflict with Commission policy and precedent.

The Commission in its orders has specifically identified long-term contracts as the key element of the wholesale market design going forward throughout the country. The Standard Market Design rulemaking order makes clear that long-term contracting is essential to limiting volatility in the short-term spot market and maintaining stable,

[3] In the same regard the CAISO states that it has incorporated flexibility into the IFM/LMP request for proposals (RFP) "to allow for further discussion on certain design elements, such as CRR allocation, that do not need to be fully resolved prior to software procurement." Transmittal Letter, p. 11.

reasonable, wholesale rates. The Commission, therefore, should not implement any untested spot market design changes without carefully considering the impacts on long-term contracts. By acting prematurely, and approving market design changes without fully understanding the consequences, the Commission would not only place California ratepayers at risk, but send a message that it is more focused on perfecting a spot-market design to the exclusion of how those design changes may affect long-term contracts. Such an action by the Commission will deter market participants from entering into long-term contracts.

III. Background

On January 17, 2001, at the height of the California Energy Crisis, the Governor of California declared a state of emergency and authorized the Department of Water Resources (DWR) to purchase power on behalf of the retail customers of the California IOUs. From January 17, 2001 through late February 2001, DWR purchased the IOUs' net short energy requirements – i.e., the difference between customer demand and the energy provided by IOU retained generation assets—in the volatile, costly, and utterly dysfunctional California spot market. With spot market prices for energy averaging around $400 per megawatt-hour (MWh), DWR spent more than $50 million per day on power purchased during that period.

To bring stability to the market, the California Legislature and FERC recognized the need to reduce reliance on the spot market. On February 1, 2001 Assembly Bill 1X (AB 1X) took affect. AB 1X gave the Department of Water Resources the authority to build a portfolio of energy contracts with the mandate that such a portfolio would result in reliable service at the lowest possible price. FERC, in its December 15, 2000 order,[4] relieved the California IOUs from the mandatory California Power Exchange buy-sell requirement and admonished all market participants to enter into bilateral long-term contracts, stating that "[T]his is critical to limiting extreme price volatility for California consumers."[5] By that time, however, the cash-strapped California IOUs were not creditworthy and were unable to enter into bilateral long-term contracts. As a result, with the purchasing authority established under AB 1X, the creditworthy DWR stepped in and assembled a portfolio of long-term bilateral contracts.

The Department of Water Resources, through CERS, entered into 56 long term contracts – the State Contracts - to provide reliable energy to California IOU customers.[6] Currently, there are 46 remaining State Contracts that are estimated to provide a peak level of capacity of approximately 11,100 MW in 2004. The total value of the remaining contracts is approximately $33 billion based on the following: 1) The cost of firm must-take energy products in the Must Take State Contracts; 2) The capacity payments for the

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[4] San Diego Gas & Electric Co. v. Sellers of Energy and Ancillary Services, 93 FERC ¶ 61,294 (2000).
[5] "[T]hose who remain in the spot market for buying their residual load or selling their residual supply should be there in full recognition of the effects on price of last minute sales and purchases." Id. at 61,996.
[6] The State Contracts, through proceedings at the California Public Utility Commission (CPUC), have been allocated to the individual IOUs to incorporate into their portfolios to serve their retail load. Although these contracts have been allocated to the IOUs, they have not been assigned to them, and as such, CERS remains legally and financially responsible for them. CERS recovers the costs associated with the State Contracts from two separate revenue streams: 1) the bond charge revenue stream that covers all the costs associated with the State Contracts up to the time of the bond issuance; and 2) the power charge revenue stream that covers all the ongoing costs associated with the State Contracts. The IOU ratepayers remit into both of these streams as dictated by CPUC rulings. As such, payment for the State Contracts is a direct obligation of the IOU retail end use customer.

For more contract background see Attachment A. Additionally, the State Contracts are public documents and can be found on the Department of Water Resources California Energy Resources Scheduling web site at http://www.cers.water.ca.gov/contracts.html.

Dispatchable State Contracts; and 3) An estimate of the cost of dispatchable energy from the Dispatchable State Contracts. The State Contracts not only played a key role in stabilizing an out-of–control California energy market, but also provided the revenue certainty needed by generators to finance the construction of new power plants.

The State Contracts continue to play a critical role in assuring reliable supplies of electricity to the State's IOU customers. In negotiating the State Contracts during the height of the California Energy Crisis, the State paid a premium for removing substantial volumes of energy from the then abnormal, unstable, and utterly dysfunctional California spot market. **In return for this premium, however, the ratepayers are effectively hedged against future market instabilities and price volatilities.** CERS therefore is extremely concerned that the value of that hedge be preserved and that California ratepayers—who are already paying among the highest electricity rates in the nation—receive the benefits of the State Contracts without incurring additional costs. California ratepayers would be placed at risk because the Amended MD02 Proposal represents a drastic structural shift in regulatory policy and CAISO market design after the State Contracts were executed. Untested fundamental changes to the CAISO market design, as are now proposed, could cause the erosion of the State Contracts' benefits, unless an accommodation is incorporated into the market design to preserve the public interest considerations of the State Contracts.

IV. An LMP-Based Settlement System is Incompatible with the State Contracts

Currently, the CAISO's market is comprised of three active congestion management zones and multiple intertie scheduling points. Under the existing zonal model, contracts that provide for delivery of energy to load located within the same congestion zone have no exposure to congestion charges in the forward day-ahead or hour-ahead markets. In this case, both the generation hand-off or delivery point, and the load are scheduled and settled in the same zone. For contracts in which the energy is not delivered in the same zone in which load is served, one of the parties is exposed to congestion costs in the forward day-ahead and hour-ahead markets. Under the current market model, the CAISO conducts a yearly Firm Transmission Rights (FTR) auction to allow market participants to secure a hedge against congestion costs. Forty-two of the forty-six remaining State Contracts serve energy in the same congestion zone in which the load is served and are therefore fully hedged.[7]

The CAISO's Amended MD02 Proposal, specifically the implementation of LMP-based settlements, will radically alter the existing market rules such that all, as opposed to only four, of the State Contracts will be exposed to congestion costs in the forward Day-Ahead and Hour-Ahead markets. To alleviate the exposure of Load Serving Entities (LSEs) to congestion costs in the Amended MD02 Proposal, the CAISO will replace FTRs with on-peak and off-peak CRRs that the CAISO will allocate on a monthly and yearly basis to LSEs. However, the proposed allocated CRRs have the following limitations: 1) The CRRs require a predetermined specific delivery location

[7] The remaining four State Contracts are the subject of different interpretations between CERS and the sellers.

for the source and sink; 2) The CRRs carry an obligation to use them; and 3) The CRRs apply only to the day-ahead market. All three of these characteristics render the proposed CRRs incompatible with the State Contracts.

CRRs that only provide protection in the day-ahead market leave all forty-six of the State Contracts exposed to congestion costs in the hour-ahead market.[8] Furthermore, approximately 6,000 MW of the State Contracts – roughly 15 percent of the CAISO's peak load – have been identified as containing provisions that allow the seller to determine the point of delivery on a daily basis. These State Contracts cannot be hedged with CRRs because the LSE, to whom the State Contract is allocated, cannot identify the "source" delivery location. The 6,000 MW is a combination of must-take and dispatchable State Contracts, with the majority of it being must-take State Contracts. To maximize paper counter-flow payments under the Amended MD02 Proposal, the seller will have the greatest incentive to schedule the delivery of energy under these contracts to the Buyer at nodes that have the lowest price either within or outside of the load aggregation zone. This purely financial (or paper) transaction benefits the seller, but does not affect the physical flow of energy from the seller's injection point. It does, however, shift the financial burden of congestion charges ultimately to the ratepayers of the three IOUs. **For the dispatchable State Contracts in question, the IOUs will have to choose between incurring significant congestion costs, or stranding the dispatchable**

[8] This aspect of the Amended MD02 Proposal is particularly frustrating because the State, through its recent renegotiation of some of the contracts, specifically sought to replace fixed, block energy products with those providing hour ahead dispatchability in order to better respond to changes in system conditions and reliably serve customer load without having to sell large blocks of energy in the day-ahead and hour-ahead markets. CERS pursued these changes with encouragement from CAISO.

State Contract and procuring energy in the spot market. For the must take energy State Contracts in question, the IOUs will have to choose between incurring significant congestion costs, or selling off the must-take energy at a loss and procuring replacement energy in the spot market.

Reliance on the spot market for the amount of energy in question could result in a reprise of some of the worst aspects of the California Energy Crisis. Approximately 6,000 MW of State Contracts – more than half of the State's portfolio – in which the seller has the option of choosing the delivery point, will be unhedgeable, and due to the risks associated with the proposed allocated CRRs, more may be exposed. In particular, this devaluation and stranding of the State Contract power would defeat the purpose of the contracts and could potentially lead to market destabilization and service interruptions. Ironically, FERC in its December 2000 Order expressed its satisfaction that the remedial measure it had ordered would

> shrink the ISO's real-time market to approximately 5 percent of load. In other words, only 2,000 MWs (instead of 6,000 MWs) will be purchased in the real-time, sometimes volatile, markets.[9]

In altering the rules of a market so radically, consideration must be given to the impact on existing bilateral contracts that FERC so vigorously advocated and encouraged parties to enter into. **Otherwise, the public interest likely will not be satisfied.**

Attachment D illustrates how a State Contract seller, who is free to determine the hand-off point to the utility, can reap windfall profits even when the market price

[9] San Diego Gas & Electric Co. v. Sellers of Energy, 93 FERC ¶ 61,294 at 61,982-83.

happens to be above the contract price. It demonstrates that the State Contract seller is protected from any downside risks, and that the CAISO's proposed LMP system is inherently biased in favor of the State Contract sellers. The combination of congestion costs and counter-flow payments borne by the IOUs' ratepayers could obliterate the value of the long-term contract hedge. Furthermore, the paper counter-flow opportunities of LMP-based settlements amount to nothing more than a wash trade that defeats the objectives of the Amended MD02 Proposal to eliminate gaming and provide transparent pricing signals to incent the construction of needed transmission and generation.

V. The Bargained-For-Benefits of the State Contracts Must be Preserved

In addition to encouraging parties to enter into long-term contracts as a means of limiting the amount of energy exposed to uncertainties in the spot market, FERC more recently ruled on the importance of preserving the parties' bargained-for benefits and obligations of the State Contracts entered into by CERS. In Public Utilities Commission of the State of California v. Sellers,[10] the Commission upheld the State Contracts, stating that

> The ALJ noted that while the Mobile-Sierra doctrine arose in the context of a completely regulated environment, where, as here, the contracts were entered into under the parties' market-based rate authority, the **Commission has stated that "[p]reservation of the contracts has, if anything, become even more critical."**[11]

[10] Public Utilities Commission of the State of California v. Sellers of Long Term Contracts to the California Department of Water Resources, et al., 103 FERC ¶ 61,354 (2003) ("Order on Partial Initial Decision, Remaining Substantive Issues and Motions") (June 26, 2003) ("June 26 Order").

[11] June 26 Order, P 64 (emphasis added) (citing Partial Initial Decision, 102 FERC ¶ 63,013 at P 31 (----) (quoting Public Utility Commission of California v. Sellers of Long Term Contracts, 99 FERC ¶ 61,087 at 61,383 (April 25, 2002)). The Commission's June 26 order noted that the Mobile (United Gas Pipe Line Co. v. Mobile Gas Service Corp. et al., 350 U.S. 332 (1956)) and Sierra (Federal Power Commission v. Sierra Pacific Power Co., 350 U.S. 348 (1956)) cases were decided in a cost-based rate regime and consequently dealt with changes proposed to contracts that were already on file with the Commission, but

Yet, the Amended MD02 Proposal, with its nodal-based platform, will seriously undermine the preservation of the State Contracts which the Commission has declared to be "critical."

Significantly, the Commission in its June 26 Order relied in part on the fact that the State's Requests for Bids ("RFBs") "**emphasized that bidders, and not [CERS], would be responsible for ensuring delivery *to the specific congestion zone* and that [CERS] would [therefore] assume neither transmission nor congestion risk…."** June 26 Order, P 48 (emphasis added). This key assurance, upon which the Commission's June 26 Order partially relied, is now at serious risk of evisceration if the nodal-based LMP is instituted in lieu of the zonal approach without adequate modifications.

VI. Solutions to Accommodate the State Contracts Remain Under Active Consideration

In an effort to resolve the conflicts between the State Contracts and the Amended MD02 Proposal, staff from CERS have met with staff from the CAISO, IOUs, the CPUC, and the Electricity Oversight Board (EOB) and participated in the CAISO's stakeholder process in an attempt to find a solution that would mitigate the potential for significant cost increases to electricity consumers as a result of the unhedgeable State Contracts and paper counter-flow payments. Considerable effort has gone into identifying and discussing a number of options to address this problem including only allowing Inter scheduling coordinator (Inter-SC) trades at trading hubs equivalent to the existing

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that the Mobile-Sierra doctrine was later extended to contracts that were not on file with the Commission. June 26 Order, P 6 n.15 (citing Richmond Power & Light v. FPC, 481 F.2d 490, 493 (D.C. Cir. 1973)).

congestion zones. If this option is filed at FERC, it may address the CERS' CRR allocation issue of not being able to identify the delivery "source" location. However, it does not address the CERS' paper counter-flow issue, nor does it answer the question of whether there will be enough CRRs to adequately hedge the LSEs load. CERS supports further exploration of this option to see if it is a viable solution.

CERS appreciates the CAISO's sensitivity to the potential for severe adverse consequences to the State Contracts. In discussions with the CAISO, CERS has attempted to resolve these concerns while preserving the core elements of the CAISO's proposed market redesign. These efforts were recently discussed at the CAISO's Market Surveillance Committee's ("MSC") meeting on July 8, 2003 (See Attachment B). Based on that discussion, MSC reported to the CAISO Board that the "primary challenge associated with incorporating these contracts into an LMP market design is caused by the fact that the congestion zones that existed at the time the contracts were negotiated are no longer relevant to an LMP market." July 14, 2003 Memorandum from Frank Wolak to the Board of Governors, p. 3 (See Attachment E). This statement recognizes the presence of a fundamental problem, although CERS strongly disagrees that zonal settlements are incompatible with LMP. The MSC was unable to provide a viable solution to this problem. Nevertheless, CERS remains committed to resolving the matter, but is very concerned, particularly given the potentially substantial impacts on California ratepayers.

Due to the many uncertainties of implementing LMP in California, the CAISO Board of Directors, in its June 26, 2003 motion (Attachment C, page 9 of the CAISO

Comprehensive Market Design Proposal), authorized the CAISO management to submit to FERC a conceptual proposal that would require Board approval at least 60 days prior to implementation of the LMP component. CERS strongly supports the CAISO Board of Directors' motion and wishes to underscore the CAISO's representation to FERC in its Amended MD02 Proposal filing that issues related to the long-term contracts are not yet resolved, and will require additional consideration and negotiation. As the CAISO states, it is imperative that these issues be resolved "*prior to implementing LMP*." Transmittal Letter, p. 20 (emphasis added).

VII. Local Market Power Mitigation Measures in Conjunction with LMP

CERS recognizes that existing measures for mitigating local market power are inadequate. The CAISO states in a LMP world that their existing local market power mitigation measures are flawed in several respects and will result in unjust and unreasonable rates if the CAISO implements LMP. Transmittal Letter, p. 53.

While improved local market power mitigation measures are needed, the cost of any inefficiencies or uplifts occurring because of the weaknesses of the current measure to mitigate exercise of locational market power need to be weighed against the impacts due to the incompatibility of LMP with existing bilateral contracts. LMP should not be implemented solely as a means to address local market power mitigation. Premature implementation of LMP may result in greater harm than that caused by the existing inadequate local market power mitigation measures.

VIII. CERS Supports CAISO Moving Forward on Assembling the LMP Infrastructure

Many of the proposed elements of CAISO's market redesign are worthy of consideration and some are needed (e.g., abandonment of the radial network model in favor of a realistic system representation). CERS supports such features of the proposed market redesign, including CAISO's investment in acquiring LMP computation capability and publishing LMP prices, **if a zonal pricing mechanism for settlement purposes were retained in the interim**. This approach will allow for a transition that will identify problems and develop solutions prior to implementation of LMP-based settlements. It will also allow the IOUs the ability to negotiate and structure new forward contracts (to replace the State Contracts as they expire) using real LMP data. **However, until the State Contracts expire in 2011, or a viable solution is found to solve the problems created by LMP for the State Contracts, implementation of LMPs for CAISO market settlements will effectively abrogate a significant feature of the State Contracts and will thereby result in higher energy costs to the IOU ratepayers.**

IX. Precedent for Accommodating Existing Contracts Under New Market Regimes

The Commission has experience in accommodating existing contracts when transitioning to a new market regime. In restructuring the natural gas industry to establish open-access transportation, the Commission, at the direction of the Court of Appeals, considered the impacts on existing contracts that were made unworkable or uneconomic to the buyer as a result of the change in market operation, and imposed certain requirements to ensure that the parties' benefits and obligations were essentially preserved.

In Order No. 436,[12] the Commission allowed natural gas pipelines to choose to offer open-access transportation service, and required pipelines seeking blanket certification of transportation to commit to provide transportation on a nondiscriminatory basis. However, most then-existing contracts, with high transportation prices based on the pre-open access era, left pipelines with increasing take-or-pay liability. By instituting open access and thus placing pipelines that did not offer open access at a competitive disadvantage, Order No. 436 removed any leverage that the pipelines might have had against gas producers to induce the producers to renegotiate the contracts.

On review, the Court of Appeals vacated and remanded Order No. 436 due to FERC's failure to address the existing contract problem, directing the Commission to re-assess the need to modify existing contracts that would be rendered uneconomic to the buyers by the new regulatory regime.[13] The reviewing Court found that the pipelines had presented an "inherently plausible suggestion that [the changed market] conditions will have an adverse impact on the pipelines' take-or-pay problems."[14] Further, the Court noted that that the pipeline's ability to pass-through take-or-pay liabilities to consumers

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[12] Regulation of Natural Gas Pipelines After Partial Wellhead Decontrol (Order No. 436), 50 Fed. Reg. 42,408 (Oct. 18, 1985), FERC Stats. & Regs., Reg. Preambles, 1982-1985 ¶ 30,665 (Oct. 9, 1985), modified, Order No. 436-A, 50 Fed. Reg. 52217 (Dec. 23, 1985), FERC Stats. & Regs., Reg. Preambles 1982-1985 ¶ 30,675 (Dec. 12, 1985), modified further, Order No. 436-B, 51 Fed. Reg. 6398 (Feb. 24, 1986), FERC Stats. & Regs. ¶ 30,688 (Feb. 14, 1986), reh'g denied, Order No. 436-C, 34 FERC ¶ 61,404 (Feb. 14, 1986), reh'g denied, Order No 436-D, 34 FERC ¶ 61,405 (Mar. 28, 1986), reconsideration denied, Order No. 436-E, 34 FERC ¶ 61,403 (Mar. 28, 1986).

[13] Associated Gas Distributors v. FERC, 824 F.2d 981, 1023 (DC Cir. 1987) (hereinafter AGD I).

[14] *Id*. at 1024.

was limited, as was FERC's ability to order such recovery, and this "solution" might well conflict with FERC's duty to protect consumers under the Natural Gas Act.[15]

In remanding Order No. 436, the Court emphasized that

> the pipelines have been caught in an unusual transition. They entered into the now uneconomic contracts in a [different regulatory] era….Thus, **their being abruptly and retroactively subjected to the downside risk is at least jarring**.[16]

The court therefore instructed FERC to consider "to what extent . . . policy considerations may justify its inaction on the uneconomical producer-pipeline contracts."[17]

On remand, the Commission adopted Order No. 500, an interim rule preserving many aspects of Order No. 436, but including a strong incentive for producers to renegotiate the uneconomic contracts, by *requiring* producers to offer to credit gas transported by a pipeline against that pipeline's take-or-pay liability to the producer accruing under certain contracts. As a result, producers and pipelines renegotiated a substantial portion of the uneconomic contracts, resolving between of 80% and 95% of the potential liability.[18] Thus, through mandatory incentives overseen by the Court of

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[15] *Id*. at 1025-26 (citing Maryland People's Counsel v. FERC, 761 F.2d780 – 781 (D.C. Cir. 1985) (quoting FPC v. Hope Natural Gas Co., 320 U.S. 591, 610 (1944) (noting the Commission's duty to "adequately attend [ ] to the agency's prime constituency--the consumers whom the [NGA] was designed 'to protect ... against exploitation at the hands of natural gas companies.'")).
[16] Id. at 1027 (citing Carpenter, Jacoby & Wright, Adapting to Change in Natural Gas Markets, in Energy, Markets & Regulation: Essays in Honor of M.A. Adelman 1 (1986) (tracing evolution of natural gas pipelines' exposure to risk)).
[17] Id. at 1030.
[18] American Gas Ass'n v. FERC, 888 F.2d 136 at 145-46 (vacating and remanding to FERC for failure to comply with the "reasoned decision making" mandate of AGD I). On the second remand, FERC modified and explained the rule to the court's satisfaction. American Gas Ass'n v. FERC, 912 F.2d 1496 at 1520 (D.C. Cir. 1990) (reviewing Order No. 500-H, FERC Stats. & Regs. ¶ 30,867 (1989), reh'g granted in part and denied in part, Order No. 500-I, 55 Fed. Reg. 6605 (Feb. 26, 1990), FERC Stats. & Regs. ¶ 30,880 (1990). In petitioning for review, the producers "concede[d] that the crediting mechanism (or the threat of

Appeals, the Commission was able to essentially preserve the bargain of the existing contracts and achieve the desired result of the open-access regulatory regime. The adverse impacts of the Amended MD02 Proposal on the State Contracts call for a similar accommodation here.

X. Other Concerns with the Amended MD02 Proposal

1. Integrated Forward Market:

The State Contracts were entered into to ensure *physical delivery* of energy to the State's IOU customers. Under the current CAISO market design, Inter-SC trades are linked to a physical resource because of the CAISO balanced schedule requirement. That physical delivery may be several times removed from the physical load, but it is traceable. The IFM removes the market separation rule and balanced schedule requirement. As such, Inter-SC trades under the CAISO Amended MD02 Proposal are no longer required or linked to a physical resource. If a SC and its counterparty submit Inter-SC trades to the CAISO, the CAISO will treat them as equal and opposite financial positions. This is problematic to CERS since, based on CPUC rulings, CERS relies on State Contract energy being physically delivered to the allocated IOU's retail load to collect power charge remittance revenue.

CERS supports the concept of forward markets, however, it is imperative that compliance with terms in existing contracts can be tracked, and that supplier

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its use) helped pressure them into settling much of their take-or-pay rights against the pipelines." 912 F.2d at 1510.

performance can be verified, for remittance purposes, in instances where the contracts allow for market substitution. In order to collect remittance for the ongoing power costs, there must be a mechanism which allows the State to verify physical delivery of energy from the supplier to retail load.

2. Residual Unit Commitment (RUC): The CAISO's Residual Unit Commitment (RUC) proposal does not address if and how it integrates with the State Contracts. The CAISO states that it will use the status of a supplier who has a contract with the Department of Water Resources as part of its criteria for determining compensation for a non-RMR unit. Transmittal Letter, p. 61. A supplier who has a State Contract and has been RUC'd should not receive a capacity payment. Ratepayers should not have to compensate these suppliers twice.

3. Need for Additional Clarification: In addition to the above concerns, CERS requests clarification on the following:

   A. The transmittal letter (page 81, footnote 101) states "A resource will be able to both self-provide A/S and offer capacity into the CAISO's A/S markets." Appendix A (page 14, item 48) states "The ISO will allow SCs the option of self providing A/S to meet their obligations or relying on the ISO's procurement of A/S." It is unclear whether the CAISO intends to allow a resource to both self-provide A/S and offer capacity into the CAISO's A/S markets.

B. The transmittal letter (page 101, item (1)) states the energy bid curve will be composed of not more than 20 segments. Amendment 54, Phase 1B filing limited the energy bid curve to 10 segments. It is unclear whether the CAISO intends to increase the maximum number of bid curve segments.

C. The transmittal letter (page 13, item 2) states "and will allow commercial energy trading at a few key "trading hubs." Appendix A (item 65) states, "Trading hubs will be defined as needed and appropriate to support commercial trading. Initially, the ISO proposes to designate the existing congestion zones as trading hubs (i.e., NP15, ZP26 and SP15), to provide continuity for current bilateral energy contracts that utilize these zones as points of delivery." Please clarify if all energy trading will initially be limited to only the NP15, ZP26 and SP15 trading hub and if so, for what duration.

D. Appendix A (item 13) states the DCBC will be kept at $250/MWh and -$30/MWh. Appendix A (item 16) states "Because the nodal prices produced by the IFM can exceed the DCBC in the presence of congestion and inelastic load, the nodal prices used for settlement will be capped at the level of the DCBC, i.e., $250/MWh initially. Please clarify that the CAISO intends to apply the bid cap floor of -$30/MWh in item 16. CERS believes nodal prices should be capped on both ends.

Additionally, page 39 of the transmittal letter states "…the CAISO will cap the nodal prices used for settlement of aggregated load at the level of the DCBC." Item 16 of Appendix A states "the nodal prices used for settlement will be capped at the level of the DCBC…." Please clarify if the CAISO intends to cap generator nodal prices.

XI. Summary and Conclusion

Until LMP is thoroughly analyzed using models and data for the California and Western Region Markets, and the results of various CAISO studies and the effects of LMP in California are better identified and addressed, it would be highly imprudent to proceed with implementation. In the CAISO Amended MD02 Proposal transmittal letter to FERC, the CAISO agrees that it should not rush implementation of the new market design. "If there are flaws, the CAISO will not implement such new market design until the flaws are corrected."[19] The CAISO, however, has not defined or provided the criteria of what constitutes a flaw. CERS submits that any aspect of the Amended MD02 Proposal that results in higher costs to California's IOU ratepayers and has the potential to destabilize the market clearly constitutes a flaw. As such, CERS believes the incompatibility of LMP with the State Contract is a critical "flaw" that the CAISO must address before implementing LMP-based settlements.

[19] Transmittal Letter, p.43 n.54.

The CAISO defends its choice of using LMP for managing congestion and pricing energy with the assumption that LMP functions well in the East.[20] However, even if it is *assumed* that LMP functions well in the East, there are a number of distinguishing characteristics in California that dictate against implementation without accommodation of the State Contracts and further study. First, most of the IOUs in the Eastern ISOs cited did not divest their generation, as has occurred in California. Second, Eastern systems are also dominated by thermal units, so the complications of unit commitment and dispatch of a hydro-thermal system are avoided. Third, the transmission network in the East is highly meshed, in contrast to the transmission network in the West. Fourth, a significant portion of the transmission line capacity in the California is owned and operated by municipal utilities.

LMP has been touted as the market mechanism of choice for creating incentives for the construction of new transmission and generation resources. Although LMP, in theory, may incent investment in transmission and generation, it is at best only one of many factors that will influence when and where new generation and/or transmission facilities are built. Economic trends, environmental and safety considerations, land use restrictions, and local community opinion more significantly influence when and where new transmission and generation is built.[21] Given these factors, it is questionable that LMP alone will bring about new transmission investment. Deficiencies in the transmission network within California and throughout the Western region are already well known. CAISO's proposed LMP regime could potentially result in an unintended

[20] Transmittal Letter, p.26

[21] See Attachment C

transfer of wealth from ratepayers to generators without any assurance that those needed transmission improvements will be built.

The State Contracts were negotiated and executed at a time when regulatory policy and the CAISO's market system were based on congestion management zones, whereby contracts were not exposed to congestion charges in the Day-Ahead or Hour-Ahead forward markets. The State entered into these contracts under FERC's strong admonition to market participants to enter into long-term bilateral contracts, as a solution that was "critical to limiting extreme price volatility for California consumers."[22] The CAISO's Amended MD02 Proposal marks a significant change in this underlying concept by substituting a nodal-based system for the zonal system. Such a wholesale change will expose the State Contracts to unforeseen congestion costs, jeopardizing the physical energy and financial hedge that is the principal purpose and benefit of the contracts. Unless conditions are included to accommodate the existing contracts, this would increase costs for California ratepayers and could lead to increased price volatility in the spot market. California – and the Commission – cannot afford a repeat of this mistake from the past.

The Commission, in its orders, has specifically identified long-term contracts as the key element of wholesale market design. By acting prematurely, and approving market design changes without considering the consequences for such contracts, the Commission will place California ratepayers at risk and send a

[22] San Diego Gas & Electric Company v. Sellers of Energy and Ancillary Services, 93 FERC ¶ 61,294 at 61,982.

message that it is more focused on perfecting a spot-market design to the exclusion of how those design changes may affect long-term contracts. The Commission, therefore, should not implement any untested spot market design changes without carefully considering the impacts on long-term contracts.

Respectfully submitted,

*Paul Stein*____________________

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Certificate of Service

I hereby certify that I have served the foregoing document by first class mail or fax upon each party identified in the official service list compiled by the Secretary in this proceeding.

Dated at San Francisco, CA this 27th day of August 2003.

*Paul Stein*________________

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Deputy Attorney General
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Attachment A

CONTRACT BACKGROUND:

The terms of the State Contracts vary, but it can be generally stated that most expire at the end of 2011, and that they can be divided into two categories: must take and dispatchable.[23]

Must Take Contracts:

Must Take Contracts guarantee physical delivery of energy at an agreed upon price. Except for the renewable must take contracts, energy is delivered in standard market block products (6x16) or (7x24); the renewable must take contracts deliver energy as available. Must Take Contracts have provided market stability by locking in large blocks of standard energy products to serve retail customers. In order to get physical commitments in the amount of energy required to serve retail load, the seller was granted the option of backing up generation with market resources that were for the most part located within the same congestion zone. At the time these contracts were entered into, this was a reasonable thing to do. In an LMP market, this is problematic since the point in which the seller supplies the energy and the point in which he delivers the energy are distinctly different for hedging and settlements purposes. The Calpine 2 Product 1 Contract that was allocated to PG&E is a must take contract that delivers 1000 MW of energy seven days a week, 24 hours a day (7x24) until December 31, 2009. The contract delivery point as stated in the contracts is as follows: "Any point or points designated by Seller on North Path 15, except as the Parties may otherwise agree. Seller may schedule

[23] The State Contracts are public documents and can be found on the Department of Water Resources California Energy Resources Scheduling web site at http://www.cers.water.ca.gov/contracts.html.

one or more delivery points on an hourly basis pursuant to CAISO protocols (or any successor protocols)." Starting in June 2004, Sempra will be supplying a 1200 MW 7x24 product and a 700 MW 6x16 product to SCE at any point in the CAISIO grid.[24] These are examples of the types of must take State Contracts that cannot be hedged for congestion costs and will be exposed to paper counter-flow costs.

Dispatchable Contracts:

The Dispatchable Contracts were entered into to provide flexibility to adapt to the load fluctuations that the Must Take Contracts are incapable of on a day-ahead basis. For added flexibility they were renegotiated to include hour ahead dispatchability; a requested feature by the CAISO. In general, the energy associated with the dispatchable contracts is typically resource and delivery specific. However, in order to get the physical commitments in the amount of flexible energy required to serve retail load, the seller was allowed to choose from a portfolio of generators. With the current market design, this was a reasonable thing to do. In an LMP market, this is problematic since the point in which the seller supplies the energy and the point in which he delivers the energy are distinctly different for hedging and settlements purposes. The High Desert Contract that was allocated to SCE is a dispatchable contract that can deliver approximately 700 to 800 MW, depending on the month, of energy to SCE's retail load. The contract delivery point as stated in the contracts is as follows: "For the Project: The point of interconnection of the Project with the Southern California Edison transmission system within the CAISO-controlled grid. For Substitute Energy: The high side of the

[24] The MW of energy varies during different months of the Sempra contract. The MW cited are the maximum amounts of energy supplied by the contracts. See footnote 6 for the link to the Sempra contract.

transformer at any valid delivery point in SP15;…." The Calpine-3 Peaker that was allocated to PG&E is a dispatchable contract that can deliver 495 MW of energy to PG&E's retail load. The contract delivery point as stated in the contract is as follows: "With respect to each Unit, the high side of a substation in reasonable proximity of such Unit. The Delivery Point for any Substitute Energy shall be a point that connects to the transmission system managed by the California Independent System Operator ("CAISO") or any successor to the CAISO. Seller may schedule one or more different delivery points meeting the foregoing requirements on an hourly basis pursuant to CAISO protocols (or any successor protocols)." These are examples of the types of dispatchable State Contracts that cannot be hedged for congestion costs and will be exposed to paper counter-flow costs.

Additionally, most of the Dispatchable Contracts are limited to the number of hours and time they can be dispatched. The GWF I/II/III Contract that was allocated to PG&E limits the Phase I/II/and III units to 2000 hours/year subject to various restrictions. This type of restriction is typical of most of the dispatchable State Contracts. Monthly and yearly obligation CRRs will expose the CRR holder to congestion costs in the opposite direction, if the CRR holder does not submit a schedule in direction of the CRR, or sell the CRR to another party to use. Currently the ISO does not conduct a secondary CRR market so it would be up to the CRR holder to seek interested parties. This will be a burdensome task that may be too risky for the IOU; thus, stranding the State Contract.

Lastly, CRRs apply only to the day ahead market. Any existing contract that has provisions to dispatch generation on an hourly basis to serve load in the same zone could

lose their value due to the exposure to the new congestion costs associated with LMP.
This will again result in stranding the State Contract.

Attachment B

Keith Casey's Presentation:

Review of Inter-SC Trades under MD02 and Their Relationship to

CDWR Long-term Contracts

CAISO Market Surveillance Committee Meeting

July 8, 2003

CALIFORNIA ISO

California Independent
System Operator

Review of Inter-SC Trades under MD02 and Their Relationship to CDWR Long-term Contracts

CAISO Market Surveillance Committee Meeting

July 8, 2003

Keith Casey

ISO Department of Market Analysis

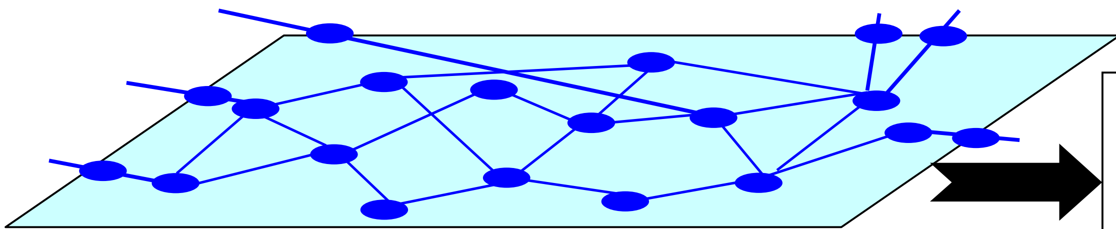
Objectives of Discussion

- Explain CAISO proposed Inter-SC Trade Design
- Discuss how this mechanism relates to certain CDWR Long-term Energy Contracts.
- Request comment from the MSC on the CAISO's proposed Inter-SC Trade Design.

Inter-SC Trades under MD02

- Inter-SC Trades under MD02 (Phase 2 & 3) are –
  - Very different than the CAISO's current inter-SC trade functionality, which links Inter-SC Trades to physical resources and loads through the balanced schedule requirement.
  - Intended to accommodate bilateral contracting.
  - Financial instruments only for effectuating Contracts for Differences (CFDs).
  - Applicable in the forward markets only.
  - Completely independent of optimal dispatch, congestion management, and LMP price determination.
  - Not essential or necessary for the ISO to operate the grid and conduct forward and real time markets.
  - A functionality that could be provided by any market entity but there may be an "economy of scale" cost savings from having the CAISO provide the functionality.

MDO2 Inter-SC Trades

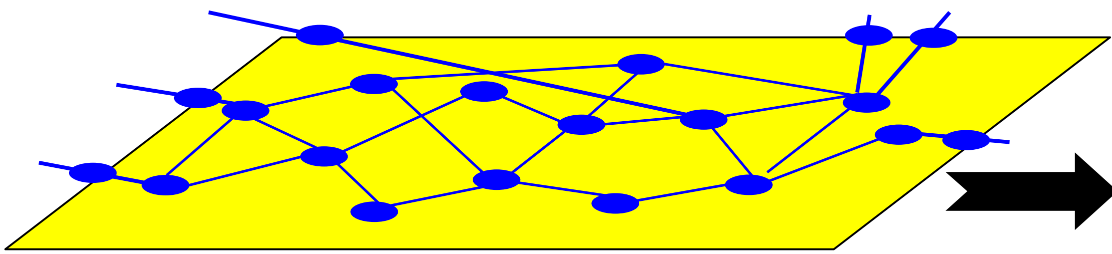


Inter-SC Trade Settlement

Inter-SC Trades are

- *Based solely on two SCs willing to take <u>equal and opposite</u> financial positions at specified location (node, hub).*
- *Devoid of any deliverability or feasibility requirement.*

Dispatch and LMP Determination <u>completely</u> independent of inter-SC trades



Primary Market

Primary Market - SCUC/Full Network Model determines LMPs based on

- Real generation

- Real load

- Real constraints

Inter-SC Trades under MD02

- Inter-SC Trades are **not** "Virtual Bidding"
  - Inter-SC trades do not directly effect LMPs or dispatch
  - Inter-SC trades are not instruments for arbitraging inter-temporal price differences (e.g. between Day Ahead and Real Time)
- Inter-SC Trade Positions could indirectly effect LMPs since once a trading location is agreed upon, trading parties have an opposing financial interest in what the price at that location is.
  - Inter-SC Trade Buyer will seek to minimize the LMP
  - Inter-SC Trade Seller will seek to maximize the LMP
  - Trading parties may schedule or bid so as to impact the LMP to their advantage but this is true for any node in the network at which a market participant has a financial position at (including a load or resource) whether it is through an inter-SC trade or not.

Why are Inter-SC trades Linked to Physical Resources and Loads under Current CAISO Design?

- The linkage of inter-SC trades to physical resources under the current market design occurs because of the CAISO balanced schedule requirement.

SC1:	Inter-SC Trade Keeps SC1 and SC2 Balanced	SC2:
Load = (2,000)		Load = (0)
Gen1 = 300		Gen1 = 800
Gen2 = 400		Gen2 = 500
Net Balance = (1,300)	⟷	Net Balance = 1,300

- Physical resources may be several times removed from the physical load under the current design due to multiple Inter-SC trades but they are traceable.
- Inter-SC trade of 1300 MW of supply from SC2 to SC1 (or 1300 MW of load from SC1 to SC2) enables both SCs to have balanced schedules.
- There is no energy settlement of inter-SC trades in the the CAISO current design but potentially a congestion market settlement.
- Inter-SC Trades in the current design mainly serve as a balancing mechanism.

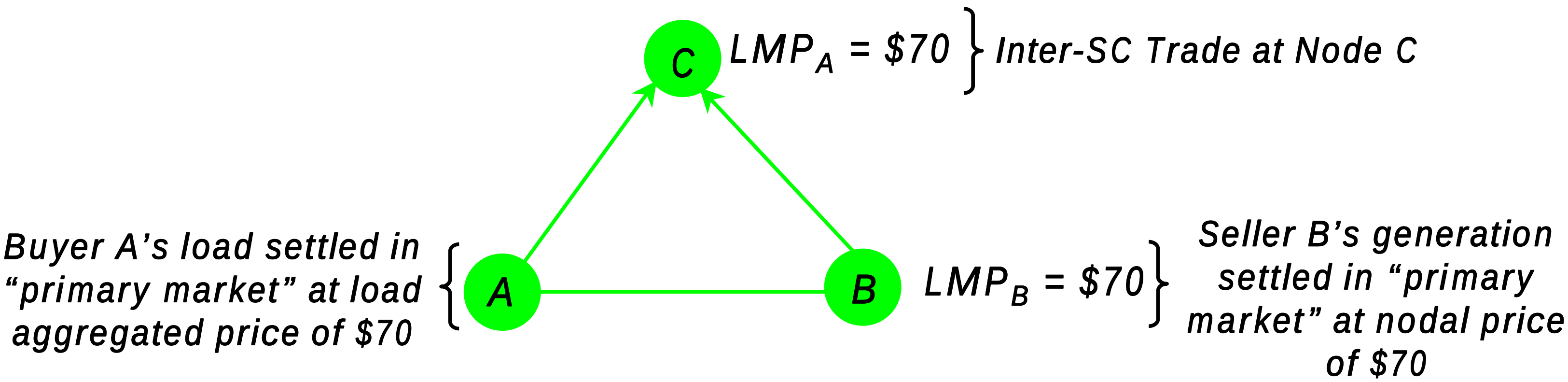
Why are Inter-SC trades Decoupled from Physical Resources under MD02 Phase 2 & 3?

- Because there is no balanced schedule requirement under Phase 2 & 3 (i.e. the CAISO will be running forward energy markets), there is no design requirement for inter-SC trades as a balancing mechanism.
- Having inter-SC trades used as a balancing mechanism under Phase 2 and Phase 3 (i.e. voluntary inter-SC balanced scheduling) is problematic because
  - There will be no guarantee that submitted inter-SC trade self-schedules will remain balanced in the IFM (i.e. load and generation self schedules may be adjusted due to congestion, but inter-SC trades will not).
  - Providing a mechanism to preserve balanced inter-SC schedules will tend to
    - Reduce market liquidity
    - Preclude opportunities for contract sellers to substitute their own generation with cheaper energy from the ISO markets.

Example of Inter-SC Trade Transaction

- **Buyer A and Seller B agree to an inter-SC trade in the Day Ahead Market for 100 MWh at Node C in Operating Hour 16.**
- **Bilateral Contract Price = $40/MWh (unknown to CAISO)**
- **Outside of CAISO settlement system, Buyer A sends Seller B a check for $4,000 ($40*100)**
- **In the CAISO Day Ahead Market the price at node C in Operating Hour 16 is $50/MWh.**
- **Under the CAISO Inter-SC Trade settlement,**
  - **Buyer A: is paid $5,000 by the CAISO**
  - **Seller B: is charged $5,000 by the CAISO**
- **Buyer A's Net Position = +$1,000 or +$10/MWh**
- **Seller B's Net Position = -$1,000 or -$10/MWh**
- ***Note-***
  - ***This transaction occurred irrespective of whether either party had actual physical resources (load or generation) in the market that particular hour***
  - ***This transaction is revenue neutral.***

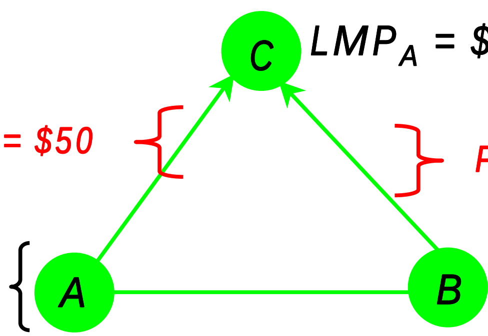
Example 2 – No Congestion



		Buyer A	Seller B
A	***Bilateral Contract Settlement***	($40.00)	$40.00
B	***Inter-SC Trade Settlement****	$70.00	($70.00)
(A+B)	***CFD Settlement***	$30.00	($30.00)
C	***Primary Market Settlement****	($70.00)	$70.00
(B+C)	***Net CAISO Settlement***	$0.00	$0.00
(A+B+C)	***Net Position Including Bilateral***	($40.00)	$40.00
D	***Seller B's Operating Cost***		($30.00)
(A+B+C+D)	***Seller B's Final Net Postion***		$10.00

**** CAISO Settlements***

Example 3 – Buyer A Loses, Seller B Wins



LMP_A = $20 } *Inter-SC Trade at Node C*

Price Differential = $50

Price Differential = $60

Buyer A's load settled in "primary market" at load aggregated price of $70

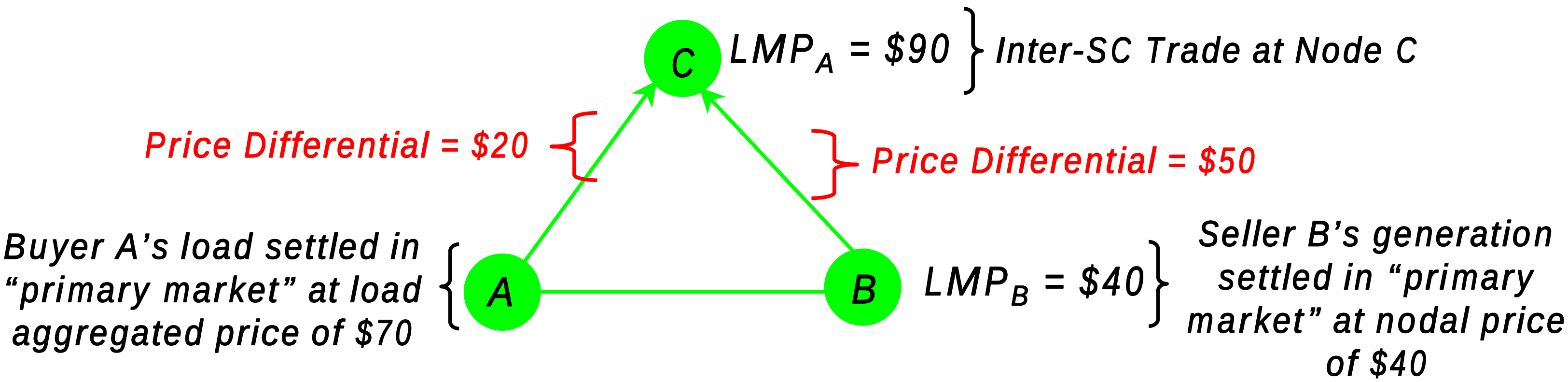
LMP_B = $80 } *Seller B's generation settled in "primary market" at nodal price of $80*

		Buyer A	Seller B
A	*Bilateral Contract Settlement*	($40.00)	$40.00
B	*Inter-SC Trade Settlement**	$20.00	($20.00)
(A+B)	*CFD Settlement*	($20.00)	$20.00
C	*Primary Market Settlement**	($70.00)	$80.00
(B+C)	*Net CAISO Settlement*	($50.00)	$60.00
(A+B+C)	*Net Position Including Bilateral*	($90.00)	$100.00
D	*Seller B's Operating Cost*		($30.00)
(A+B+C+D)	*Seller B's Final Net Postion*		$70.00

Optional – Seller does not have to produce to do and Inter-SC Trade

*** CAISO Settlements**

Example 4 – Buyer A Wins, Seller B Loses



		Buyer A	Seller B
A	*Bilateral Contract Settlement*	($40.00)	$40.00
B	*Inter-SC Trade Settlement**	$90.00	($90.00)
(A+B)	*CFD Settlement*	$50.00	($50.00)
C	*Primary Market Settlement**	($70.00)	$40.00
(B+C)	*Net CAISO Settlement*	$20.00	($50.00)
(A+B+C)	*Net Position Including Bilateral*	($20.00)	($10.00)
D	*Seller B's Operating Cost*		($30.00)
(A+B+C+D)	*Seller B's Final Net Postion*		($40.00)

*** CAISO Settlements***

Implications of CAISO Inter-SC Trade Mechanism for CDWR Contracts

- Some CDWR contracts apparently give the seller substantial discretion to specify where the energy will be delivered under the contract (Seller's Choice Contracts).
- To the extent market participants view the CAISO Inter-SC Trade procedure as the mechanism for sellers to fulfill their obligations under the contracts,
  - the selling party of a Seller's Choice Contract would naturally pick the node with the lowest expected price to execute the inter-SC trade (e.g. Example 3).
  - some parties have asked the CAISO to consider limiting Inter-SC Trades to trading hubs to mitigate the potential ratepayer harm from Seller's Choice Contracts under LMP.
  - An important feature of the Hub as an anchor for inter-SC trades is that it is fixed for a long time (which provides consistency with CRRs) and the Hub Price is very difficult to manipulate because it is an aggregate price over a large area.

Implications of CAISO Inter-SC Trade Mechanism for CDWR Contracts

- Limiting Inter-SC Trades to Trading Hubs –
  - Will be problematic for CDWR contracts that require delivery at specific locations.
  - Will not necessarily fix the Seller's Choice issue because sellers may argue that contract obligations can be accomplished without the CAISO Inter-SC Trades mechanism (i.e. buyers and sellers can independently settle a CFD at any node in the network).
- The CAISO has not ruled out limiting the Inter-SC Trade mechanism to trading hubs but,
  - Having the parties to a Seller's Choice Contract negotiate a mutually acceptable set of nodes and hubs for executing CFDs via the CAISO Inter-SC Trade mechanism is a preferable solution.
    - Specifying a limited set of CFD nodes and hubs allows congestion hedging with CRRs.
    - CRR allocations to both sellers and buyers can facilitate reaching agreement.
  - Parties to Seller's Choice Contracts will also likely need to agree on the "delivery obligations" of the contract. Specifically,
    - Are sellers required to physically deliver the contracted power? or
    - Is the contract simply a financial hedge with no physically delivery requirement?

MSC Comments on the ISO Inter-SC Trade Mechanism

Attachment C

1. **The lack of adequate New York Grid CEO Says New Power Lines, State Authority Needed**

   Richard Schwartz

   Bloomberg - June 24, 2003

   June 24 (Bloomberg) -- New York state's lack of adequate transmission line capacity costs power customers more than $1 billion a year in congestion expense, the president and chief executive of the state's grid said.

   "Nothing is being built in New York," William Museler told an industry conference in Boston. "Markets appear unable to solve the problem, so transmission must stay regulated."

   Congestion costs are incurred when transmission lines can't handle the flow of power, and electricity must be rerouted. The expense to utilities or marketers is ultimately passed on to end users. Transmission makes up about a fifth of power costs.

   One problem in building new transmission networks is that the lines often cross localities that receive none of the benefits of the new power supplies, said Museler, who heads the New York Independent System Operator in Schenectady.

   "You need to get all the stakeholders involved" to win support for a new line, Museler said later in an interview. If that fails, "some authority must be imposed. This should be like interstate commerce" because without regulatory authority, "no pipelines would have ever been built."

   PJM Interconnection LLC, operator of the neighboring mid- Atlantic grid and the largest wholesale power market in the U.S., is seeking authority to order transmission improvements to assure that competitively priced power can move along its network.

   The proposal, filed in March with the Federal Energy Regulatory Commission, would add to PJM's current authority, which allows it to order upgrades strictly for reliability purposes.

   "The market can't fix all infrastructure needs," said Scott Miller, PJM's executive director of market applications, at the Northeast Power conference, sponsored by the TradeFair Group.

2. New England States Are at Odds on Paying to Improve Power Grid

The Boston Globe - August 19, 2003

Andrew Caffrey

Aug. 19--The area of Connecticut that went dark in last week's blackout has long been among the weakest links in the New England power grid, and utilities in the state have proposed spending at least $700 million to build two transmission lines to improve delivery of electricity in the southwestern corner of the state.

The problem: who gets stuck paying for it.

Energy companies in New England and regulators from several states are proposing that ratepayers in Boston, Bangor, Brattleboro, and the rest of New England should equally bear the cost of the Connecticut improvements, because they would improve the reliability of the overall transmission system in the region. Under that approach, Massachusetts ratepayers would pay almost half of the $700 million cost.

But regulators in Maine and Rhode Island are balking, saying customers in their states would receive little benefit from the Connecticut projects, yet would be picking up the tab for residents in some of the wealthiest communities in Connecticut.

"The poor little immigrant from Central Falls shouldn't be subsidizing" wealthy residents "from Darien with their hot tubs," said Elia Germani, chairman of the Rhode Island Public Utilities Commission.

The fight, being played out in proceedings before federal energy regulators, illustrates one of the central problems that has hampered needed upgrades to the nation's aging system of power lines: how to fairly apportion the costs of improvements, and minimize the lengthy approval process, which critics use to delay or kill projects.

The blackout, which industry officials believe started in Cleveland but rippled as far east as Connecticut, also revealed the interdependence of the patchwork of high-voltage lines that move electricity from power plant to consumer across large sections of the country -- and how weaknesses in one can trigger failures in others.

"The most recent example of cascading transmission outages point out to us how in an interconnected system, we need strength throughout the system, so the weakest link doesn't bring the entire system down," said Ron LeComte, director of the electric power division at the Massachusetts Department of Telecommunications and Energy.

The problem area in Connecticut is roughly bounded by Interstates 91 to the east and 84 to the north, and includes the important financial center of Stamford and wealthy suburbs such as Westport. Just last month Connecticut officials approved Northeast Utilities' plan to build a 20-mile, 345-kilovolt power line from Bethel to Norwalk, at an estimated cost of $200 million. Separately, Northeast Utilities and the United Illuminating Co. are proposing a 69-mile, 345-kilovolt line from Middletown to Norwalk at a cost conservatively estimated at $500 million.

Traditionally, ratepayers throughout New England have shared in the costs of large transmission projects, and proponents said the practice should continue with the Connecticut lines. Fixing southwest Connecticut's chronic power problems, they

argued, would reduce a major stress point on the regional power grid, thereby improving reliability throughout New England.
"It is a part of a collective enhancement that benefits all ratepayers," said Robert E. Earley, an attorney for the Connecticut Business & Industry Association, which supports the cost-sharing arrangement.
At the prodding of the Federal Energy Regulatory Commission, the New England Power Pool, which represents energy companies in the region, and ISO New England Inc., which runs the power grid, jointly filed a plan with federal regulators last month that would "socialize" the costs of the Connecticut projects, as well as other proposed transmission upgrades that would benefit the region, among all ratepayers. The costs would be based on the proportion of power that each state consumes within the region. Connecticut would pay 27 percent of the cost, Massachusetts 46 percent.
Massachusetts is supporting the cost-sharing arrangement on the time-honored principle of one hand washing the other: State officials here expect local utilities to soon propose three major new transmission projects on the North Shore and in and around suburban Boston, two of which are loosely estimated to cost $160 million, and they'd like Connecticut ratepayers to chip in.
"I think it's appropriate that, as we're supportive of Connecticut, we expect Connecticut would be supportive" of the Massachusetts projects, LeComte said.
But Maine regulators, backed by Rhode Island, will try to block the cost-sharing plan in a filing before the federal commission this week, arguing that Connecticut should have long ago fixed the problems there.
"Maine's view is, you should make the effort to identify who is the primary beneficiary and assign the costs primarily to those," said Thomas Welch, chairman of the Maine Public Utilities Commission.
Northeast Utilities had initially hoped to begin construction on the first project by the end of the year. It's too soon to tell if the opposition from Maine and Rhode Island would stall construction, but regulatory fights before FERC can often take months, if not years to resolve.
For now, Maine and Rhode Island propose that ratepayers in the affected area in Connecticut pay half of the costs, with the rest spread equally throughout New England. Otherwise, under the cost-sharing arrangement, Welch said Maine consumers could be facing a $10 million to $20 million bill for the Connecticut projects, "and for Maine that's a serious amount of money."

3. **Selling the Public on More Lines**
   Despite Needs, Many People Don't Want Cables, Towers Near Them
   By Michael Barbaro
   Washington Post Staff Writer
   Wednesday, August 20, 2003; Page E01

   When Energy Secretary Spencer Abraham warned last week that modernizing the nation's electric grid will cost consumers $50 billion, he forgot to warn them about a second, perhaps more dramatic consequence: living with 30,000 miles of new high-

voltage transmission lines that some energy experts say will be needed over the next decade to keep the system operating.

The lines, crisscrossing federal forests, farm land and residential communities, may prove the toughest sell of all to the American public. Local opposition to the towering steel-and-wire structures has blocked efforts to lighten the transmission load at some of the electric grid's most congested locations, from Iowa to Wisconsin to Connecticut.

As a result, some energy experts are pressing for creation of regional authorities that prevent local squabbles over zoning from delaying -- and in some cases killing -- vital system upgrades. Others are calling for newer, more efficient technologies such as "superconducting cable" -- nitrogen-cooled lines that carry 25 times as much electricity as traditional copper wire and therefore require fewer lines.

But in the short term, expert say, the solution to the growing gap between high energy demand and low transmission investment is more of what the nation already has: high-voltage cables, soaring high above farms, houses and businesses, that have reliably carried electricity around the country for decades.

The lines, which cost about $1 million per mile, already crisscross the country. But there are not nearly enough of them to handle the thousands of interstate transactions requested each day to move the cheapest possible electricity to consumers, energy experts say. While energy demand has doubled in the past 25 years, investment in high-voltage transmission lines has fallen by 45 percent, according to the Edison Electric Institute.

"It's all technically feasible. Technology is not the obstacle. It is the political will to push things through and deal with local issues," said Eric Hirst, an electric industry consultant. Today, the country has about 157,000 miles of high-voltage transmission lines, but needs 20 percent more over the next decade, he said.

Where would 30,000 miles of new transmission lines go? "That's the problem," said Jonathan M. Weisgall, vice president of MidAmerican Energy Holdings Co., which owns the largest utility in Iowa. "Nobody wants them."

Sometimes residents have no choice. The federal government has used eminent domain to seize 13 properties in the path of an 84-mile transmission line connecting central and northern California. But that kind of flexibility is rare: Unlike most transmission upgrades, the California project is congressionally mandated.

MidAmerican recently attempted to run a 125-mile transmission cable from western to central Iowa. The plan: Put the cable about five miles from an existing line, rather than on the same steel towers. "You'd have all your eggs in the same basket with one line. You are subject to the same ice storm, the same tornado," Weisgall said.

But residents opposed the second line, forcing MidAmerican to build it along the existing system. The heavier loads and larger rights of way pushed the project's cost $20 million over what the separate line would have cost, expense that is likely to be passed on to consumers.

In some cases, local opposition has halted construction of proposed transmission lines. In Wisconsin, for example, a four-year-old campaign to build a 220-mile line to Minnesota has stalled in the face of community opposition.

Nobody in the state doubts the need for a new line. Wisconsin has just four interstate cables connecting it to the national grid. By comparison, Minnesota has 18 and

Illinois has 25, said Maripat Blankenheim, a spokeswoman for American Transmission Co. of Milwaukee.

Without these new lines, bottlenecks develop, costing consumers hundreds of millions of dollars a year because rather than buying the cheapest available energy, which is often produced out of state, their energy companies must turn to higher-priced, local electricity.

For example, Wisconsin Public Power Inc. can buy electricity in Illinois for $40 per megawatt-hour. But when the four cables that connect the state to the grid are congested, as they often are, the company is forced to buy power within the state at up to $80 per megawatt-hour.

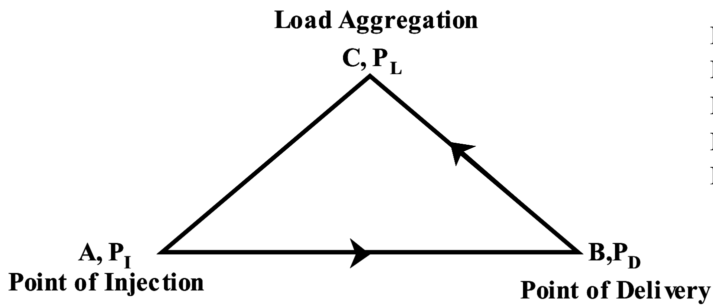
"When you need the electricity, there is sometimes no choice," said Michael Stuart, senior vice president of legal and regulatory affairs at Wisconsin Public Power.

The promise of deregulation was cheaper electricity, bought and sold on the open market, rather than from behemoth state utility companies. But now the open market has overwhelmed the lines, while there has been little investment in transmission.

"The system was designed for backup reliability, not long-distance wholesale commercial transactions," Stuart said.

Attachment D

Exhibit 1. Example of A Seller Winning Even at Below-Market Contract Prices



P_I = Point of Injection LMP
P_D = Point of Delivery LMP
P_L = Load Aggregation LMP
P_C = Contract Price
P_p = Average Production Price

Given:

1. Seller injects its sold energy at Point A for delivery to Buyer at Point B to serve load at the Load Aggregation bus C.
2. Seller is free to choose any bus as the the Point of Delivery B**.**

Assumptions:

1. $P_I > P_L$: the Load Aggregation price is a weighted-average LMP price.
2. $P_L > P_D$: Seller will seek a Point of Delivery with the lowest possible LMP
3. $P_C > P_P$: Seller would not have entered into a contract without a profit margin.
4. P_I = \$70, P_C = \$60, P_P = \$50, P_L = \$40, and P_D = \$30

Seller's Position (SP)

SP = Contract Profit Margin ($P_C - P_P$) + Opportunity Cost ($P_P - P_I$) + Counter Flow Income ($P_I - P_D$)
SP = (60 – 50) + (50 – 70) + (70 – 30)
SP = \$30

Buyer's Position (BP)

BP = Long Term Contract Hedge ($P_I - P_C$) + Congestion Cost ($P_D - P_L$) + Counter Flow Payment ($P_D - P_I$)
BP = (70 – 60) + (30 – 40) + (30 – 70)
BP = – \$40

Exhibit 1 illustrates how a State Contract seller, who is free to determine the hand-off point, can reap windfall profits under the proposed LMP-based settlement scheme. This scenario represents a seller's downside risk of entering into long-term, fixed-price sales.[25] This is the type of situation where a long-term seller could be losing relative to the Day Ahead (DA) market. The scenario used in Exhibit 1 represents a good test of the fairness of the CAISO proposed LMP-based settlement regime. By demonstrating that settling at nodal prices would protect sellers from the downside of long-term sales it suggests that there is an inherent bias in the CAISO's proposed LMP system that favors suppliers.

Exhibit 1 shows a combination of three simultaneous transactions in the CAISO proposed DA market/LMP-based settlement regime: (The numerical values used reflect a moderate case of spatial dispersion of nodal prices resulting from transmission congestion during one hour of the DA market.)

In the first of the three simultaneous transactions the seller would schedule – per CAISO's DA scheduling protocols – generation injection at Bus A (from owned, leased or contracted resources or a combination thereof). The scheduled amount would have to meet the seller's obligations to CERS under the applicable contract terms. The proposed CAISO LMP-based settlement process would assign to the seller's account a credit equal to the number of MW injected times the applicable nodal price at Bus A. For the

[25] In scenarios where the contract price equals or exceeds DA market prices, the seller is always the winner from a long-term fixed price sale, and as such LMP-based settlements could only make the situation worse for buyers.

example used in Exhibit 1, this credit would amount to $70 per MWh injected. Assuming, hypothetically, that the contract price at which the State is purchasing the must-take generation is $60 per MWh and that the seller's average cost of producing or procuring the energy is $50 per MWh at the hour under consideration, the seller's profit margin from its the long-term contract would amount to $10 per MWh for that same hour.

As noted in the title of Exhibit 1, the depicted circumstance symbolizes an hour at which the seller's contract price is below what DA market is offering. The seller's short-run opportunity cost would be $20 per MWh since it could have sold generation costing it $50 per MWh at an injection-bus price of $70. Thus, in the absence of further actions, the seller's net position relative to the DA market would be a loss of $10 per MWh ($20 of opportunity cost vs. a $10 profit margin from the long-term State Contract). Any prudent supplier of energy under fixed-price forward contracts would have to account for and hedge itself against such market downsides by securing a sufficient premium from the buyer above and beyond the profits expected from market upsides (i.e., when short-run market prices are lower than the attainable forward fixed prices). However, regardless of how large the secured premium is, a rational seller would use all means available to improve their positions in the CAISO-administered markets. Under an LMP-based settlement regime, this would be accomplished by purchasing energy at the lowest available nodal price and handing it off to the buyer to meet seller's obligation under the applicable State Contract.

As shown in Exhibit 1, the lowest available nodal price is assumed to be $30 per MWh and it occurs at Bus B. The seller's second simultaneous transaction would then be the scheduling of a purchase of the required amount of generation from the CAISO DA market at Bus B. The CAISO-proposed settlement process would charge the seller's account a debit equal to the amount scheduled times a nodal price of $30 per MWh. The combination of a $70 per MWh credit and $30 per MWh debit leaves the seller with a net position of + $40 per MWh against the CAISO DA market.

The third simultaneous transaction would also be carried out at Bus B. Here, the seller would schedule an inter-SC trade to hand off the generation effectively purchased from the DA market at Bus B to the buyer (i.e., the IOU). With this action, the seller would have fulfilled its obligations under its State Contract: handing off to the assigned utility the required amount of power at a legitimate delivery bus (Bus B) with backing from a physical source at the injection point A.

At first glance, the $40 payoff would appear to be a form of a counter-flow reward as it coincides with injecting power a high-price bus and withdrawing it from a low-priced node. However, this is a case of pseudo or paper counter-flows since financial transactions at Bus B will not be taken into account by the Integrated Forward Security Constrained Economic Dispatch model. Moreover, because it does not provide CAISO with any information that could reduce congestion in the DA market, the seller's windfall is totally useless from a system's perspective.

The net profit of the seller would be $30 per MWh under unfavorable DA market prices.[26] Meanwhile, the buyer on behalf of the ratepayers would wind up with a net loss of $40 per MWh relative to an LMP-based DA market. The consumers' deficit has two sources: a $10 per MWh congestion charge (to take – on paper -- the power from Bus B to the load aggregation Bus C) and a $40 payment for the pseudo counter-flow from Bus A to Bus B. The combined $50 per MWh liability more than wipes out the $10 cushion the long-term contract would have created for consumers in the hour under consideration.[27] The end result of such combination of Bus A and Bus B transactions is a net wealth transfer of $70 per MWh from ratepayers to seller. The pseudo counter-flow opportunities that an LMP-based settlement scheme creates are no different than a wash trade.

[26] As illustrated in Exhibit 1, this value can be derived by subtracting a $20 opportunity cost from the sum of the $40 credit for the pseudo counter-flow schedule and the $10 profit contract margin.
[27] In the absence of the $60 per MWh State Contract, ratepayers would have paid $70 per MWh in the DA market. See Exhibit 1.

Attachment E

Market Surveillance Committee Memo

July 14, 2003

California Independent
System Operator

Memorandum

To: The ISO Board of Governors

From: Dr. Frank Wolak, Chairman, Market Surveillance Committee of ISO

cc: Terry Winter, CEO;

Charlie Robinson, VP, Legal and Regulatory;

Date: July 14, 2003

Re: ***The Market Surveillance Committee Meeting of July 8, 2003***

This is only a status report. No Board action is requested.

The MSC meeting for the month of July was conducted at the ISO Folsom offices on July 8, 2003. All four of the committee members were in attendance. Several ISO staff and stakeholders attended the public session.

Public Session

The meeting opened with public comments. Tony Braun of CMUA and Zora Lazic of CERS spoke. Mr. Braun highlighted the concerns of the municipal utilities with the ISO's proposal for dealing with existing transmission contracts (ETCs). Ms. Lazic described the seller's choice deliverability conditions in the CERS contracts and expressed concerns about the impact of these requirements on the total price of power delivered under these contracts in a locational marginal pricing (LMP) regime.

During the public session of the meeting the following items were discussed.

1. Market Update

Greg Cook of the Department of Market Analysis briefed the MSC on the market activities for the months of April through June of 2003.

2. Relationship of Integrated Forward Market and RUC

The MD02 currently proposes a sequential procurement through RUC. It was discussed whether changes were required on the current RUC design. The ISO staff raised the following questions to the MSC.

What are the MSC concerns with the current ISO RUC design (as presented to the ISO Board)?

Should RUC capacity payment be rescinded when called for energy?

Should the design be an auction or paid as- bid?

Should RUC optimize the purchase of capacity and energy (or concentrate on capacity purchases with a Rational Buyer view to energy purchase when it is cheaper to purchase energy)?

What are the relative advantages and disadvantages of sequential vs. simultaneous IFM/RUC?

Does the MSC want to file an MSC opinion recommending improvements to the RUC Design?

The options were discussed in detail. The MSC prefers simultaneous procurement to sequential procurement for the following reasons.

(1) Simultaneous procurement will always yield lower or the same total bid-based costs (relative to sequential RUC) for procuring the ISO's total energy and ancillary services requirements subject to the all of the ISO's operating constraints.

(2) Simultaneous procurement avoids the problems created by sequential markets that reflect differing amounts of system operating constraints in the market prices. Under sequential procurement the day-ahead energy and capacity prices do not reflect the ISO's requirements to have sufficient capacity and import energy available to operate the system in real-time. These capacity and energy requirements are purchased in a pay-as-bid RUC process after the day-ahead market has cleared. This creates opportunities for ex post regret by market participants, which in turn, creates incentives for market participants to alter their bids and schedules in the day-ahead market to sell in the RUC process. Simultaneous procurement of the ISO's capacity and import energy requirements in the day-ahead market along with all other ISO-operating constraints eliminates the possibility of ex post regret and the incentive for suppliers to distort their bidding and operating behavior in the day-ahead market to exploit the sequential RUC process. However, simultaneous procurement requires the ISO to incorporate its energy and capacity reliability requirements in the day-ahead market price, rather than purchase incremental energy and capacity to meet these requirements in the RUC process after the close of the day-ahead market. The re-formulating this sequential process into a single simultaneous day-ahead price-setting process has not been vetted with market participants.

(3) The combination of the pay-as-bid nature of the RUC process and the market-clearing price payment mechanism for the day-ahead market increases the likelihood that suppliers selling energy or capacity in the day-ahead market or the RUC process will regret the sales they have made after learning the day-ahead energy and capacity prices and the payment they could have received selling capacity or energy in the RUC process. This creates incentives for suppliers to alter their bids into the day-ahead market and RUC process in order to sell their energy and capacity at the high possible price, which can degrade system reliability.

(4) The ad hoc nature of the sequential RUC process increases the likelihood that FERC will make changes that increase the opportunities for suppliers to exercise market power. One of FERC's recommendations to the MD02 design process was to create a day-ahead market that recognized and priced all of the ISO's operating constraints. The sequential RUC process does not recognize and price the ISO's capacity and import energy requirements in the day-ahead market. These are ignored in the ISO's current day-ahead market design.

(5) The simultaneous RUC process would considerably simplify the operation of the day-ahead market and the design of the software to operate it.

The MSC is willing to provide an example of how its recommended simultaneous RUC process would work. However, the MSC does not want to issue opinion if it would only de-rail or slow up the implementation of the MD02 design. ISO's current conceptual filing should allow the ISO to implement day-ahead and hour-ahead markets that reflect all operating constraints in the pricing process, as would be the case with a simultaneous RUC process

3. Review ISO ETC proposal in MD02

The current ISO ETC proposal was discussed. Tony Braun outlined his concerns with the current proposal and requested that the ISO proposal honor all contractual rights ETC holders currently have. The MSC asked Tony

Braun to elaborate on specific aspects of the ISO's proposal that he found objectionable. The MSC also asked for his suggestions for addressing his concerns. The MSC also asked for stakeholder comment on these issues.

MSC believes the current ISO proposal for integrating ETCs into its markets has substantial potential to increase the efficiency of the ISO's market, to the benefit all California consumers and electricity suppliers. Based on their discussion with Tony Braun, the MSC felt that his concerns could be addressed within the context of the current MD02 ETC proposal. The MSC also felt that his concerns regarding the cost allocation of the ISO's ETC proposal would require substantial input from the California Public Utilities Commission and other California parties to reach a satisfactory resolution.

The MSC discussed filing an opinion on this issue, and requested that further clarification from Tony Braun and other stakeholders on their concerns with the ISO's ETC proposal be submitted prior to the finalization of an opinion.

4. Review ISO inter SC trade mechanism and its relation to CERS long term contracts deliverability

The ISO staff briefed the MSC on the current proposal for inter SC trades to accommodate the CERS and other bilateral contract deliverability and pricing provisions in a nodal pricing system.

The MSC discussion first centered on whether these deliverability requirements would change any physical flows, or only result in changes in the financial obligations of buyers and sellers of wholesale energy. The MSC acknowledged that the first-order impact of the must-take CERS contracts and the proposed LMP mechanism in the ISO's proposed market design was the result of the supplier's option delivery point feature in these contracts, which should primarily influence payments to suppliers from LSEs, with only secondary impacts on actual power flows. The primary challenge associated with incorporating these contracts into an LMP market design is caused by the fact that the congestion zones that existed at the time the contracts were negotiated are no longer relevant to an LMP market. The MSC felt that the ultimate solution to this problem would come from negotiations between the state of California, the contracting parties and FERC. It would be extremely difficult if not impossible to modify the ISO market design rules and still preserve the beneficial aspects of an LMP market to address these problems.

Finally, the MSC questioned the need for the ISO to offer an inter-SC trading service under the MD02 design. MD02 gets rid of the balanced schedule requirement on SCs, which makes inter-SC trades purely financial transactions. The MSC felt that if the ISO offered an inter SC trading platform it should be priced separately to recover the costs only from market participants that used the service.

5. Update on Amendment 50 FERC ruling: Mexican Generation & AMP for DEC Bid

The ISO staff briefed the MSC on the implementation of the Amendment 50 FERC ruling and the accompanying Automatic Mitigation Mechanism (AMP) for DEC bids implemented effective July 1, 2003. Jing Chen of the DMA made a presentation comparing the AMP thresholds for INC and DEC bids. The MSC expressed concern about the large difference between the INC and DEC threshold values at the upper end of the supply curve for instate generation capacity. Several members also reiterated their concerns about the ability of the AMP mechanism to limit all but very extreme cases of the exercise of market power in the INC and DEC directions.

Executive Session

During the executive session the current investigation activities of ISO were discussed. The MSC was also briefed on market power implications of WAPA becoming a control area. The MSC has decided to respond to the Federal Register Notice of Intent with a letter by August 8th, as requested in the Federal Register.