Memorandum

To: The ISO Board of Governors

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

cc: Board Assistants; ISO Officers

Date: April 12, 2004

Re: ***Summary of the Market Surveillance Committee Meeting of April 5, 2004***

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

The Market Surveillance Committee (MSC) held a public meeting on April 5, 2004 at the ISO's Folsom headquarters. All MSC members were present. Brad Barber called the meeting to order and asked for any public comment. There were no public comments.

Public Session

During the public session of the meeting the following items were acted on or discussed.

1. Election of an MSC Chairman

Brad Barber nominated Frank Wolak for MSC Chairman. Jim Bushnell seconded the motion. The motion to elect Dr. Frank Wolak as the Chairman of the MSC was carried by a vote of 3 to 0.

2. Market Performance Summary for 2003 and Early 2004

Greg Cook, Manager of Market Monitoring, summarized the performance of the California market during 2003 and the first few months of 2004. Although the price-cost markup indexes for 2003 Cook presented indicated generally acceptable levels of market performance, the ISO faced a number of challenges during 2003 that have persisted into 2004. The first is the low levels of bid sufficiency in the ISO's ancillary services market. The second is the increasing amount of intra-zonal congestion. For the first year since the start of California market, annual intrazonal congestion costs were larger than interzonal congestion costs. Finally, transmission line outages—both planned and unplanned—have made it increasingly difficult for ISO operators to ensure that demand at all locations in California is met at all times.

Although average electricity prices during 2003 were higher than 2002, this can be primarily attributed to higher natural gas prices during 2003 relative to 2002. Outage rates in 2003 were generally lower in 2003 than in 2002 and net imports in 2003 were roughly equal to net imports in 2003, implying that competitive conditions in the California markets were roughly the same across the two years. With the exception of Regulation Up and Regulation Down, average ancillary services prices were only slightly higher in 2003 relative to 2002. Average prices for RegUp and RegDown were significantly higher in 2003 relative to 2003.

Total intrazonal congestion costs for 2003 were $151 million as compared to total interzonal congestion costs of $28 million. The primary cause of these substantially higher intrazonal congestion costs was congestion at the Miguel Substation in SP15 that began during August of 2003. More recently, the outage of the San Onofre Nuclear

Generating Station (SONGS) Unit 2 has resulted in greater flows on the South West Power Link (SWPL) transmission line between Arizona and San Diego, resulting in further intrazonal congestion.

Bid insufficiency in the ancillary services markets is largely the result of about 1000 MW of RMR capacity switching from Condition 1 to Condition 2 status. Condition 2 status RMR units are prohibited from participating in the ISO's ancillary services markets. Bid insufficiency increased significantly during March 2004 relative to the first two months of 2004, although ancillary services prices have fallen during the first few months of 2004 relative to 2003.

3. Update of Transmission Economic Assessment Methodology (TEAM) Activities

Grant Rosenblum, Regulatory Counsel, updated the MSC on the progress of the Transmission Economic Assessment Methodology (TEAM) activities. He stated that the goal of this process is to develop a common methodology for assessing the need and economic benefits of major transmission upgrades to be used by California regulatory agencies. Rosenblum summarized the TEAM activities up to the present time and then outlined a timeline for submitting the methodology to the California Public Utilities Commission (CPUC) by the June 2, 2004. He noted that the CPUC would like the MSC to prepare an opinion on the ISO's methodology and that ISO management would like this opinion before the May 27, 2004 Board of Governors meeting. The MSC agreed to prepare an opinion detailing the important factors that should be considered in assessing transmission expansions in a wholesale market regime and describing how well the ISO's methodology accounts for these factors.

4. Must-Offer Waiver-Denial and Use of RMR Condition 2 Units

Brian Theaker, Director of Regulatory Affairs, presented the ISO's proposed modifications to its must-offer process. Theaker emphasized that must-offer waiver denial costs are substantial, totaling roughly $180 million in 2003. In September of 2003, the ISO committed to a re-examination of the must-offer process and the package of recommendations Theaker presented is largely the result of that stakeholder process, although he emphasized that there was not a complete consensus on all of the issues. The major issues addressed by the proposed modifications were the transparency, mechanics, compensation and cost allocation of the must-offer waiver denial process.

The must-offer waiver denial transparency is addressed by the ISO posting detailed information about historical must-offer waiver denials on OASIS with a 30-day lag. The ISO also plans to use Security Constrained Unit Commitment (SCUC) software to commit must-offer units based on their start-up and minimum load costs, rather the current first-come, first-serve mechanism. Another change to mechanics of this process is that must-offer waiver denial units will be compensated for their natural gas costs and auxiliary power costs in line with the mechanisms currently used for RMR contracts.

In an effort to reduce the frequency of bid insufficiency in the ancillary services markets, two changes were proposed for the must-offer waiver denial process. The first is not to rescind the minimum load cost compensation (MLCC) paid to units whose must-offer waiver is denied if they subsequently provide ancillary services. In order to facilitate must-offer generation units bidding into the ancillary services markets, the ISO will move the time of the must-offer waiver denial process from 6 pm to 8 pm to from 10 am to 11:30 am that same day. This change means that generation units will know their must-offer status before they bid into the ancillary services market.

Currently there is a dispute between the ISO and generation unit owners that self-commit in the day-ahead market and subsequently want to turn off. The ISO does not permit these units to request a must-offer waiver. The ISO proposes to allow these units to request a waiver, but if they are denied, they do not receive the MLCC.

The ISO also proposes to allocate more closely the costs of must-offer waiver denials to the entities that cause these costs. In particular, all waiver denials issued for local reliability needs will be allocated to the Participating Transmission Owner (PTO). More generally, all must-offer waiver denial costs for a specific zone will be allocated to demand in that zone, while must-offer waiver denial costs for system needs will first be allocated to the entities with net negative deviations, subject to a capped level of total costs, with any costs above this cap allocated to metered demand of a system-wide basis. The remaining unresolved issue is whether suppliers should receive a capacity payment if their must-offer waiver is denied. There is considerable disagreement among the stakeholder groups on these issues.

The MSC was generally supportive of these proposed changes, although several members expressed concerns about the need to revisit the cost allocation mechanism. A major reason must-offer waiver denials occur is because loads have not procured sufficient energy and ancillary services from locations in the network that are physically capable of serving these loads. There are two potential explanations for must-offer waiver denials. The first is that the suppliers able to provide the necessary energy possess local market power and therefore unwilling to sell this energy in the forward market to the load at a reasonable price. Consequently, in order to obtain a price that is less reflective of the local market power this supplier has, the load purchases the necessary energy through the must-offer waiver denial process where market power mitigation measures apply. The second explanation can be traced to the method used to allocate must-offer waiver denial costs. To the extent that a load is able to push some of the costs of extremely expensive energy it needs to purchase on to other loads in the network through the waiver denial process, the load will be reluctant to procure this necessary energy in advance of real-time, even if the supplier of this energy does not possess local market power.

Several of the MSC members noted, the distinction between waiver denials issued for local reliability and those issued for system-wide or zonal reliability problems is often very arbitrary. In particular, denying a must-offer waiver to a large generation unit can confer significant system-wide benefits, even though the unit was denied for local reliability reasons. As a consequence, no additional system-wide or zonal must offer waiver denials need to be issued. Because precisely how must-offer waiver denial costs are allocated among market participants can have a dramatic impact on a load's willingness to purchase the necessary energy before the real-time market, the MSC members felt that the ISO should continue to study both the potential local market power and cost allocation aspects of the must-offer waiver denial process.

Brian Theaker then described modifications that would allow RMR Condition 2 units to be used for system reliability, rather than only local reliability. Several MSC members reiterated their perspective that under the ISO's current protocols for using Condition 2 RMR Units, if a supplier declares an RMR Unit as Condition 2, this is a very effective mechanism that generation unit owner to withhold capacity from the market in order to raise wholesale energy prices, while receiving full cost recovery for the withheld unit.

Given FERC's strong desire to prevent wholesale electricity suppliers from withholding generation capacity, the MSC members could see no rationale for FERC not requiring Condition 2 RMR Units to make their capacity available to the ISO operators under all system conditions to ensure reliable operation of the grid and limit the ability of suppliers to exercise unilateral market power.

Brian Theaker then discussed the ISO's proposal to subject Condition 2 RMR Units to the must-offer waiver obligation, but only use them to supply energy in real-time after all effective non-Condition 2 generation units had been used. The Condition 2 RMR units would be called out of market to provide energy at their RMR Contract rates, with the higher Schedule G rates becoming operable when the sum of the unit owner's RMR and non-RMR calls exceed its annual service limit.

All MSC members expressed support for the ISO's proposal to make more efficient use of Condition 2 RMR Units. However, several argued that the ISO should go even further in this direction by putting default bids for Condition 2 RMR units in the real-time market at the unit's variable cost and call on it to supply energy if the market price exceeds its bid. These MSC members noted that the generation units are guaranteed full cost recovery under the Condition 2 RMR process, so the ISO's proposal to only use these units when there are no more bids in the market from effective non-RMR Condition 2 generation units, seems to only artificially increase the market price above the level that would occur if these units had a default bid in the ISO's markets at their variable operating costs. These MSC members noted that this use of Condition 2 RMR units could result in some units exceeding their annual RMR service limits. If this outcome occurs, the minimum load and bid levels for these units could be increased to their Schedule G level or whatever level is necessary to compensate for increased operating costs.

5. MD02 Market Power Mitigation Elements

Farrokh Rahimi, Consultant to the Department of Market Analysis, discussed proposed modifications to the ISO's local market power mitigation (LMPM) mechanism made in response to FERC orders and technical conferences and stakeholder comments following the submission of MD02 to FERC on July 22, 2003. In response to the ISO's MD02 filing, FERC stated that the ISO's current day-ahead must-offer obligation is not likely to exist under MD02. FERC also ordered the ISO to charge a market-clearing price for all Residual Unit Commitment (RUC) capacity that it purchases instead of using a pay as-bid mechanism for RUC capacity as the ISO had proposed. Finally, FERC ordered the ISO not to rescind the RUC capacity payment if a unit was subsequently dispatched for energy.

A number of concerns about the MD02 design were raised at the March FERC Technical Conference. Specifically, FERC staff advocated that either a scarcity pricing mechanism or locational capacity obligations needed to be implemented as part of a comprehensive LMPM mechanism. A number of market participants also expressed concerns about applying the Automatic Mitigation Procedure (AMP) to imports. Finally, a number of internal and external commenters on the ISO's MD02 proposal found its LMPM mechanism excessively complex.

The ISO now proposes a firm sunset date for its day-ahead must-offer obligation and an elimination of the AMP mechanism for the day-ahead market. FERC's October 28, 2003 order proposed a flexible must-offer obligation for generation unit owners under MD02 where they must choose to offer their capacity in either the day-ahead or real-time market, but they are not required to offer in both. In response to this flexible must-offer obligation, the ISO now proposes a local market power mitigation mechanism for both RUC availability bids and energy bids. Various iterations of the integrated forward market (IFM) will then be run to determine which generation units will be subject to local market power mitigation for their RUC capacity. The ISO also proposes to submit high energy bids for those units that have opted not to participate in the day-ahead IFM in this pre-IFM LMPM process so they will be dispatched and mitigated last. A unit that has a portion of its energy bid mitigated for local market power will have its entire RUC capacity availability bid mitigated to a pre-determined reference level. Units that opt out of the day-ahead IFM are not eligible to submit RUC availability bids or receive RUC availability payments and will be considered in the RUC optimization as having a $0 availability bid.

Several MSC members felt that this new LMPM mechanism was unnecessarily complex. These MSC members urged the ISO to clarify precisely what it hoped to accomplish through the RUC process. In particular, what minimums and maximums on the scheduling or both energy and ancillary services capacity, at what locations in the ISO network, and at what time in advance of real-time system operation was the RUC process attempting to achieve. Once the ISO operators defined these scheduling constraints on both a day-ahead and hour-ahead basis, the ISO could build these constraints into its day-ahead and hour-ahead IFM processes and explicitly price these constraints along with all other relevant operating constraints in the locational marginal pricing (LMP) process. Those load-serving entities that failed to procure sufficient energy or reserve in the day-ahead or hour-ahead markets could then be allocated the increased costs caused by their failure to procure the energy or reserves necessary for the ISO to operate the system reliably.

By explicitly incorporating these RUC constraints into the IFM process, the ISO would eliminate the need for a separate RUC process, which would greatly simplify the day-ahead and hour-ahead scheduling process. The day-ahead IFM would then be reduced to a two-step process of determining which units to subject to local market power mitigation for the coming day. The next step would solve the day-ahead IFM and corresponding LMPs using mitigated bids and market-based bids for the remaining units incorporating the constraints on locational scheduling energy and ancillary services necessary for the ISO to operate the system reliably in real-time. A similar two-step process would occur in the hour-ahead market.

Eliminating the sequential RUC process proposed by the ISO eliminates an important source of opportunities for suppliers to exercise local market power through their bids into the day-ahead IFM versus and the subsequent RUC capacity auction. Under the previously proposed pay-as bid mechanism where RUC payments were rescinded if the supplier was dispatched for energy, these local market power concerns are less pressing. Because FERC rejected the initial ISO RUC proposal, these MSC members urged the ISO to give strong consideration to day-ahead and hour-ahead markets than incorporate the local market power mitigation mechanism and RUC mechanism as constraints in the IFM, rather than implement a sequential RUC procurement process that conditions on the results on an IFM that does not incorporate all of the constraints the ISO uses to operate the system.

6. Revised Design Residual Unit Commitment (RUC) Design

Farrokh Rahimi, Consultant to the Department of Market Analysis, discussed proposed modifications to the ISO's RUC process. These issues arose as a result of the FERC's October 28, 2003 order and the March FERC Technical Conference. The major concerns with the RUC design are: (1) how to integrate RUC into a market with flexible the must-offer requirement instead of the must-offer requirement, (2) how to implement RUC with a market-clearing price instead of a pay-as bid price, (3) whether RUC should procure energy and capacity or just energy, and (4) how to deal with no rescinding of the RUC availability payment if a unit is dispatched for energy.

The revised RUC design places a $150/MW hard bid cap on RUC capacity, as well as a $250/MWh cap on the sum of the energy and availability payment market-clearing price in the settlement stage. RUC availability will be paid a market-clearing price. Both internal and external resources are eligible to bid for availability, and only capacity is purchased in the RUC process. The energy bid of RUC capacity cannot be subsequently increased. A major unresolved issue in the RUC process is the potential hour-ahead export of energy from RUC capacity committed in the day-ahead market. The ISO operators are worried about suppliers that win in the day-ahead RUC capacity market lining up export sales from this capacity in the hour-ahead or real-time markets, so that the ISO operators are unable to call on this energy for internal needs.

This topic causes several MSC members to raise a number of the same issues that arose in the discussion of the ISO's proposed LMPM mechanism. In particular, several MSC members reiterated their request for the ISO be more explicit about what it wanted to accomplish with RUC, and in particular, to specify precisely the spatial and temporal scheduling constraints for energy and ancillary services capacity implicit in the RUC mechanism, so that these constraints could be explicitly incorporated into the day-ahead and hour-ahead IFM.

The major issues that these MSC members believed the revised RUC process needed to address are: (1) how to mitigate RUC availability bids for local market power, (2) how to set the level for mitigated availability bids, (3) how to prevent the export of day-ahead RUC capacity, and (3) how to quantify the operating constraints in the IFM that are implicit in the sequential RUC process. This discussion concluded with another plea from at least one MSC member for the ISO to adopt an IFM that incorporates the all relevant operating constraints, including the constraints implicit in the RUC process. With an IFM that incorporates these scheduling constraints in the day-ahead and hour-ahead markets, the issue of hour-ahead exports of day-ahead RUC capacity would be addressed because these scheduling constraints on energy and ancillary services capacity would be explicitly accounted for in both the day-ahead and hour-ahead IFM.

As the MSC has emphasized in a number of opinions, the major source of potential benefits from an LMP-based market is that all relevant operating constraints are accounted for in the IFM. If suppliers bid close to their variable operating costs, then all units in the system will be dispatched to meet these constraints in a least cost manner, to the benefit of wholesale electricity consumers. The ISO's proposed RUC process attempts to achieve a dispatch that respects all operating constraints though a sequence of optimization problems—the day-ahead IFM and then the RUC process—neither of which honors all of the ISO's operating constraints. This is likely to increase significantly the inefficiencies in wholesale market outcomes and increase the opportunities for suppliers to raise wholesale prices, particularly given FERC's recent orders on the RUC process.

7. Constrained Output Generation (COG) Units

Lorenzo Kristov of the Policy Office described the ISO's current proposal for allowing constrained output generation (COG) units to set market prices. FERC's October 28, 2003 order directed the ISO to allow constrained output generators to set prices in the forward market. The ISO's MD02 proposal allowed constrained output generators to set prices in the real-time market but not in the forward market.

The ISO proposes to allow COG units to set prices through a two-step process, where the initial IFM run enforces COG constraints to determine the optimal dispatch and then a subsequent IFM run treats committed COG units as flexible and allows them to set prices. The ISO acknowledges that this creates a generic inconsistency between dispatch and pricing and that the details of this proposal must be further flushed out.

Several MSC members inquired about the amount of COG capacity in the California ISO control area, and were told that approximately 830 MW fit this definition. Ben Hobbs gave a detailed presentation on the set of potential options for allowing COG units set the market price. He ultimately settled on a recommendation that was supported by several other MSC members. His proposal would have the ISO treat the COG generators as flexible in the day-ahead and hour-ahead IFM and issue day-ahead and hour-ahead schedules as if these units were flexible. In real-time the ISO would then issue dispatch instructions to these units that reflected their physical operating constraints. Any deviations from the ISO's dispatch instructions would then be treated as uninstructed deviations even if they were the result of physical operating constraints on the units.

Lorenzo Kristov noted that this proposal amounted to giving suppliers the option to set price in the forward market, because they always had the option to submit a vertical supply schedule at their preferred operating point and be a price-taker in the relevant IFM or real-time market.

The public meeting was adjourned at 3 pm.

Executive Session

From 3:30 pm to 5:00 the MSC had an executive session where a number of pending investigations of market participant behavior by the Department of Market Analysis were discussed. The MSC was also briefed on the market behavior of Stage 1 alert of March 29th.