CALIFORNIA ISO

California Independent
System Operator

Memorandum

To: The ISO Board of Governors

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

cc: Yakout Mansour, President & CEO, Charlie Robinson, VP, Legal and Regulatory

Date: March 21, 2005

Re: ***Summary of the Market Surveillance Committee Meeting of March 15, 2005***

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

The Market Surveillance Committee (MSC) held a public meeting on March 15, 2005 at the California Public Utilities Commission at 505 Van Ness Avenue in San Francisco. All MSC members were present. Brad Barber called the meeting to order and asked for public comment.

Public Comment

Gary Stern, Director of Market Monitoring and Analysis for Southern California Edison wanted to make sure that the MSC was aware of the growing magnitude of uplift payments that are the result of importers being paid the maximum of their bid price and the *ex post* market-clearing price in the pre-dispatch that clears all incremental (INC) and decremental (DEC) import bids in the real-time energy market before the start of each hour. Stern stated that because many of these trades result in no net change in the amount of energy flowing into or out of California they are wash trades not intended to buy or sell actual energy. He urged the ISO and MSC to investigate these activities and report them to the Federal Energy Regulatory Commission (FERC) in order to send the message to importers that these activities will not be tolerated

Caroyln Kehrein of Energy Management Services asked the MSC to review the recommendations from the Law and Economics Consulting Group (LECG) report on the Market Redesign and Technology Upgrade (MRTU) in terms of their financial viability in the current wholesale market and regulatory environment in California. She stated that the LECG recommendation to increase the granularity of load settlement in the MRTU market design ignores the significant transactions costs associated with this change. Kehrein stated that in the current market design, bid-ask spreads for wholesale energy are approximately $0.25/MWh because there are deep markets for short-term energy in two of the three congestion zones in California. Although the ZP26 zone has existed since late 1999, it has yet to develop a deep market for short-term energy. For this reason, she doubts that liquid forward markets will develop at the number of locations in California necessary if greater locational granularity in pricing to loads is implemented in the MRTU market design.

Kehrein also urged the MSC to study what conditions would trigger the proposed 100% day-ahead scheduling requirement for load. She stressed that the ISO should not restrict the purchasing and scheduling behavior of loads unless it was absolutely necessary to maintain system reliability.

Election of Chair

Brad Barber nominated Frank Wolak to serve as Chair of the Market Surveillance Committee from April 1, 2005 to March 31, 2006. Jim Bushnell seconded the motion. Barber, Bushnell ,and Hobbs voted in favor of the motion.

Market Design Issues

Lorenzo Kristov, Principal Market Design Architect, discussed the progress of the MRTU process with specific focus on the issues that would be addressed in the proposed conceptual filing at FERC in April. Kristov prefaced his discussion by stating that the ISO management decided not to include the 100% day-ahead scheduling requirement in the April conceptual filing at FERC. He also noted that several stakeholders have requested that the ISO delay its April 2005 conceptual filing date and that the ISO management is taking these requests under consideration.

The major issues discussed in Kristov's presentation were: (1) the clearing of Load Aggregation Point (LAP) level demand bids in the Integrated Forward Market (IFM) based on LAP prices rather than clearing based on nodal prices, (2) the hour-ahead scheduling process (HASP), and (3) the local and system-wide market power mitigation provisions. Kristov also discussed the provisions for allowing use-limited resources to participate in the California market.

The current proposal is to require owners of use limited resources to develop annual or seasonal usage plans in coordination with ISO. These usage plans would include seasonal estimates of energy production, run hours and ancillary services (A/S) capacity provided. Each scheduling coordinator (SC) for that unit would submit its hourly availability each day to the ISO's Day-Ahead (DA) energy and A/S markets. The ISO would compare this actual availability and energy and ancillary services provided to the planned availability and energy and ancillary services provided. Kristov emphasized that the ISO had yet to decide how SCs will be penalized for failing to meet their plans. A major unresolved issue is how to coordinate compliance with the CPUC's resource adequacy obligations with the reliability needs of the MRTU short-term energy and ancillary services markets.

The discussion of managing use-limited resources led to a number of questions from MSC members. In particular, a major question concerned the need to give special treatment to use-limited resources in the ISO's day-ahead markets. In particular, one MSC member noted that owners of use-limited resources could use both their price and real-time quantity bids into the ISO's energy and ancillary services markets to manage the risk of being dispatched for energy when they are use limited. For example, hydroelectric suppliers could bid their best estimate of the opportunity cost of water into the day-ahead energy market to ensure that they are dispatched to provide energy only if the market price is above their opportunity cost of water.

This discussion lead to comments by members of the audience from Pacific Gas and Electric, Southern California Edison, and TURN concerning the need to have SCs file plans for the use of these resources with the ISO and potentially be penalized for failing to follow these plans. Gary Stern argued that the SCE may have different needs for its use-limited resources from those of the ISO. He also noted that the monthly plans for how to use these resources can change within the month as new information arrives, so the owner of a use-limited resource should not be penalized by the ISO for changing these plans within the month. Mike Florio of TURN expressed concern over the desire of the ISO's proposal to develop *valid* use-limitations on resources with the owner of the unit. He expressed concern with whether the ISO could serve as the ultimate authority on what constitutes a valid use limitation for a resource. This led several members of the MSC to suggest that resource plans should not be used for informational purposes only. The market participant should notify the ISO of its likely use of the resource and update this information whenever it changes. All parties agreed that this information would be valuable to the ISO operators to have, but it would be too costly to require the market to adhere to these plans.

The discussion of the granularity of load settlement in the MRTU design focused on its impact on market participants that are not subject to CPUC jurisdiction. One MSC member noted that the regardless of how the ISO decided to settle load, the CPUC could require retail prices for customers of the three investor-owned utilities to pay geographically averaged wholesale prices. Consequently, the issue is most relevant to municipal utilities and direct access customers in the California. Kristov noted that the ISO's congestion revenue rights (CRR) studies have found that if load settlement used more granular prices, this would allow the ISO to release more CRRs.

This discussion led several MSC members to urge the ISO and stakeholders to consider the long-term benefits of greater granularity in pricing energy to load and use the CRR allocation process to ensure that no existing market participants experience significant harm in the transition to locational marginal pricing (LMP). Specifically, because certain municipal or direct access customer are located in very expensive-to-serve areas, they could be allocated sufficient CRRs to expect to pay the same average price for wholesale power they paid with geographic averaging of wholesale energy prices, if they consumed the same amount of energy as they did in previous periods. However, this CRR allocation process would require customers located in high-cost areas to face marginal prices for consumption above and below this expected level to face prices that reflect the LMP at that location. This would provide incentives for these loads to undertake transmission upgrades and construct local generation to meet future energy needs relative to a scheme that does not set the price for more or less consumption equal to the LMP at that location. Consequently, locking-in geographical averaging of LMPs has significant long-term market efficiency costs in terms of dulling the incentives for necessary transmission upgrades and local generation capacity.

Several MSC members felt that further study of how to achieve the benefits of greater locational granularity in pricing to loads while protecting existing consumers from the locational cost shifts that could occur as a result of implementing an LMP market is necessary because of these potential long-term market efficiency losses from pricing loads on a geographically averaged basis. In addition, these members felt that resolving this issue should be top priority because market participants need to begin the process of negotiating long-term energy and ancillary services supply and other hedging agreements for the MRTU market design as soon as possible.

Market Power Mitigation

Jeff McDonald of Department of Market Analysis summarized the ISO's latest proposal on market power mitigation. The basic elements of this proposal include a must-offer obligation for resource adequacy generation units, an strong and effective local market power mitigation (LMPM) mechanism similar to the PJM model, a LMPM mechanism for Residual Unit Commitment (RUC) availability bids, a bid adder for frequency mitigated units, where frequently mitigated units those that are mitigated at least 80% of their run hours. This proposal also eliminates the system-wide Automatic Mitigation Procedure (AMP) for energy bids and system-wide market power mitigation for RUC bids. Finally, McDonald discussed the proposal to increase the bid cap on the ISO's energy market annually in $250/MWh increments until it reaches $1000/MWh. The $250/MW bid cap on RUC availability bids and ancillary services will transition to $100/MW when the energy bid cap increases to $500/MWh.

This presentation caused a number comments and questions from MSC members. Specifically, several MSC members expressed concerns with the usefulness of the ISO's must-offer obligation because of the difficulty associated with verifying whether a generation unit is truly able to operate. The experience of the CPUC staff with attempting to do this through generation unit inspections during period January 2001 to June 2001 suggests that this is an impossible task. Suppliers must therefore bear the financial consequences of being unable to operate when they are needed by the system. It was noted that such a penalty mechanism is built into a fixed-price forward contract between a supplier and a load-serving entity (LSE), because the supplier has effectively sold the LSE a right to buy the contracted quantity at the contracted price, and the supplier must bear the full cost of providing this guarantee to the LSE.

Several MSC members reiterated their objections to paying bid adders to mitigated units, even the 10% percent bid adder. The goal of bid mitigation is to replace the supplier's bid with what the market participant would submit if it faced effective competition. If the supplier did face effective competition it would bid its minimum variable cost of supplying energy, not its minimum variable costs plus an ad hoc adder. This implies that the mitigated bid level should be the ISO's best estimate of the generation unit's minimum variable cost of supplying energy. Using a bid adder the ISO knows is larger than this minimum variable cost contradicts the primary goal of locational marginal pricing, which is to obtain the most efficient dispatch possible. A scheme that systematically biases the bids of mitigated generation units upward relative to the ISO's best estimate of the unit's minimum variable cost of supplying electricity does not achieve this goal. Generation units that face sufficient competition will bid close to their minimum variable cost. Combining these bids with mitigated bids set significantly above their minimum variable cost of supplying energy will result in those units facing significant competition being overused relative to what they should operate if the mitigated suppliers faced sufficient competition and bid their minimum variable cost of supplying energy.

Including ad-hoc bid adders in the computation of mitigated bid levels also increases the incentives for unmitigated suppliers to distort their bids above their minimum variable cost. These suppliers recognize that the mitigated bid must be dispatched so they face little risk of a reduced amount of energy sold but a substantial likelihood of achieving a higher price for their energy by bidding higher than their minimum variable cost of supplying energy. This bidding behavior results in further distortions from an efficient dispatch of the units in the control area, all because of the use of this ad hoc bid adder.

All of these inefficiencies can easily be minimized by requiring the ISO to using its best estimate of the unit minimum variable cost of supplying energy as the mitigated bid level, regardless of how frequently a unit is mitigated. To the extent a generation unit is unable to recover its annual costs from spot market sales, the unit owner should make a cost-of-service filing to recover these costs or sign long-term supply agreement with an LSE to provide the necessary energy in return for recovering its full costs on annual basis.

The MSC generally supports the goal of the ISO's proposal to focus on obtaining the most stringent LMPM mechanism from FERC in exchange for giving up system-wide mitigation in the form of an AMP mechanism. Several MSC members reiterated their position that the AMP mechanism was not in fact worth market efficiency costs at the current level of the bid cap in the California market, because of the incentives it creates for raising prices during hours in which the ISO energy and ancillary services markets are likely to be competitive.

The final issue is raising the bid cap on the real-time energy market. One MSC member noted that if the California LSEs continue to purchase a large fraction of the expected demand in California in fixed-price forward contracts, it is very unlikely that the credibility of the $250/MWh bid cap will be tested in the sense that suppliers will bid above this level because of the options they have to sell outside of California at higher spot prices. This MSC member emphasized that if the California LSE reduce their level of forward contract coverage of final demand, there is a high likelihood that the credibility of the bid cap will be tested if the Western Electricity Coordinating Council (WECC) experiences a sustained period of low hydroelectric energy availability. Both because of the potential for low hydroelectric energy conditions and the low level of the bid cap on the spot market this MSC member advocated high levels of fixed-price forward contract coverage of load as a necessary condition to raise the bid cap on the spot market.

Further discussion of this topic emphasized that unless there was a significant commitment from the CPUC to implement retail pricing policies that pass hourly wholesale price signals to final consumers, the market efficiency benefits from allowing higher bid caps would be limited, assuming that California's LSEs continue to maintain significant fixed-price forward contract coverage of their retail load obligations.

The MSC expressed support for the ISO's proposal to reduce the bid caps on RUC capacity and ancillary services, as long as there was sufficient fixed-price forward contract of energy to limit the ability of suppliers to exercise market power in California's short-term energy market.

Resource Adequacy

Sean Gallagher, Energy Division Director of the California Public Utilities Commission, summarized the results of the Resource Adequacy (RA) process at the CPUC. He described the January 2004 CPUC decision (D.04-01-050) that established the Resource Adequacy framework at the CPUC. Important features of this framework are 15% to 17% planning reserve margin, the requirement that all CPUC-jurisdictional LSEs purchase forward commitments for capacity equal to their peak load plus a 15% planning reserve margin. The resource adequacy requirements were to be phased in starting in 2005, with full planning reserve requirements in place by 2008.

Gallagher then summarized the results of various CPUC decisions that have clarified a number of features of the resource adequacy process. An important CPUC decision occurred in July 2004, when it clarified that the deliverability of the energy purchased in the forward market must be taken into account. Least cost procurement without regard to deliverability is not a prudent procurement policy under (D.04-07-028). In October of 2004, the CPUC re-evaluated the phase-in of the resource adequacy obligations. The revised goal is to have all LSEs meet their Resource Adequacy Requirement by June 2006 and meet the entire 15% planning reserve requirement before the summer peak of 2007. This would imply that the Resource Adequacy Requirements are in place for the start of the MRTU market design. On February 28, 2005, CPUC President Michael Peevey issued an Assigned Commissioner's Ruling (ACR) that said that any ruling on Resource Adequacy should allow for the existence of capacity markets.

Gallagher then described a number of unresolved issues associated with the resource adequacy process. A major unresolved issue is how different technologies will count towards meeting a resource adequacy capacity obligation. For example, how will 100 MW of wind capacity versus 100 MW of a natural gas-fired combustion turbine be translated into installed capacity for the purposes of the meeting an LSE's planning reserve requirement? A related question is: How to verify compliance with the supplying the capacity that a resource was deemed able to provide? Another important issue is how liquidated damages (LD) energy contracts would count in the resource adequacy process.

Phil Pettingill, Manager of Policy Development at the ISO, presented the ISO's perspective on the resource adequacy process. He focused on two key issues: (1) the need to have generation capacity at locations able to serve the demand that cannot be met by the available transmission capacity (2) the need for the ISO to establish a capacity market to facilitate the resource adequacy process.

Frank Wolak, Chair of the MSC, then gave a presentation on the relationship between maintaining resource adequacy and controlling unilateral market power in wholesale electricity markets. Wolak argued that the primary goal of the resource adequacy process should be preventing a repeat of the events of June 2000 to June 2001. He noted that a 115% to 117% capacity reserve margin will not prevent a future crisis, for the simple reason that there is no evidence that inadequate generation capacity to serve demand lead to the crisis during the period June 2000 to June 2001. All of the rolling blackouts occurred during the trough of the annual demand cycle when peak demand on system was less than 34,000 MW, versus more than 45,000 MW during the summer months. The lack of fixed-price long-term contracts between suppliers and California's major LSEs that committed suppliers to provide energy to California was the major cause of the crisis. Suppliers earned the spot price for virtually all of the energy they sold in California, which gave them very strong incentives to raise spot prices.

Wolak stated that having adequate capacity to meet demand is a very weak necessary condition for ensuring that suppliers are willing to provide energy to California consumers at reasonable wholesale prices. This necessary condition is particularly weak for the WECC where a substantial fraction of demand is met by hydroelectric energy. Wolak emphasized the need for an even greater larger fraction of final demand to be covered by fixed-price forward contracts in regions where a substantial fraction of energy is provided from hydroelectric resources. Enough fixed-price forward contracts between suppliers and California's LSEs provide a contractual guarantee that a future crisis will not occur. Wolak then emphasized that a capacity market paradigm does not address the problem of the financial viability of LSEs, because without adequate levels of forward contracts, the LSE still faces a significant risk of extremely high wholesale electricity prices for a long enough period of time to bankrupt it.

Wolak acknowledged the need for the ISO operators to have generation units in the control area at locations necessary to meet demand. However, he emphasized that purchasing energy at the locations in the network where the LSEs actually withdraw this energy from the network is a superior strategy for ensuring that the generation units would be constructed in the appropriate locations to meet demand and satisfy the requirements of the ISO operators.

Following this presentation there was a discussion of these issues among members of the audience and members of the MSC. The generation conclusion that emerged was that the MSC urged the ISO and CPUC to focus on purchasing adequate energy in far enough in advance of delivery (to obtain a price that reflects little system-wide market power) with guarantees that the capacity necessary to provide this energy will be build, rather than focusing the resource adequacy process on purchasing generation capacity that may not have sufficient energy available to meet demand.

The public meeting was adjourned by Brad Barber at 3:30 pm. The MSC met informally until 4:30 pm to deal with scheduling and other administrative details.