California Independent
System Operator

Memorandum

To: The ISO Board of Governors

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

cc: ISO Officers

Date: December 6, 2006

Re: ***Summary of the Market Surveillance Committee Meeting of November 13, 2006***

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

The Market Surveillance Committee (MSC) held a public meeting on November 13, 2006 at the California ISO. All MSC members were present. Frank Wolak called the meeting to order. He then asked the MSC members to approve the minutes from the October 6, 2006 teleconference public meeting to hear stakeholder comments and vote on the "Opinion on Alternative Treatment of New Transmission for Interconnection of Renewable Generation." The MSC members unanimously voted to approve these minutes. Frank Wolak then asked if there were any public comments from stakeholders at the meeting or listening on the telephone.

Public Comment

Glenn Goldbeck of Pacific Gas and Electric (PG&E) asked to make a short presentation on the MRTU marginal loss surplus allocation issue and provide comments on the long-term financial transmission rights (FTRs) agenda items. He emphasized that PG&E supported the CAISO issuing long-term FTRs with durations longer than 10 years.

Jeff Nelson of Southern California Edison (SCE) spoke on four topics. The first was long-term FTRs. Nelson stated that SCE supports a long-term FTR allocation process that gives preference to load-servings entities (LSEs) that have existing or proposed long-term energy supply arrangements between the source and sink of the FTR. The second topic was virtual or convergence bidding. Nelson stated that SCE supports restricting both INC and DEC convergence bidding to the Load Aggregation Point (LAP) level. He stated that SCE is concerned that it would be difficult to obtain physical feasibility in the combined day-ahead market and residual unit commitment (RUC) process if nodal convergence bidding was allowed. The third topic was the CAISO's proposed change in real-time LAP pricing. Nelson noted that SCE is supportive of this change. The final issue was the marginal loss surplus allocation. Nelson stated that SCE is supportive of any reasonable way to allocate these losses among the market participants that pay them. However, SCE feels that the allocation mechanism in the current MRTU tariff is reasonable and does not see any clear rationale for changing it.

Sue Mara of RTO Advisors stated that giving priority to existing supply arrangements in the long-term FTR allocation process disadvantaged power marketers and competitive electricity retailers. She supported an allocation process that did not require showings of long-term supply arrangements.

Long-Term Financial Transmission Rights (LT-FTR)

Frank Wolak gave a presentation that summarized recent discussions among MSC members on the design of the LT-FTR allocation process. Wolak first proposed three sets of goals for the LT-FTR allocation process: (1) satisfy the Federal Energy Regulatory Commission (FERC) guidelines for the LT-FTR allocation, (2) address stakeholder concerns with releasing too many FTRs and the potential inequities in the LT-FTR allocation process and (3) address CAISO concerns with the revenue adequacy of FTRs that it issues and limit the adverse energy market efficiency consequences of the LT-FTR allocation process. Wolak emphasized a number of important design characteristics that should be considered in balancing these sometimes conflicting goals.

The first was the need to make the megawatt (MW) quantity firm and to fund fully both long-term and annual FTRs issued by the CAISO. Making the expected congestion payments associated with a 1 MW FTR from a given source and sink equal and the same magnitude, regardless of the duration of the FTR, will reduce the cost of selling FTRs in the secondary market. If some FTRs are fully funded and others are only partially funded, there is likely to be less competition among suppliers to provide both kinds of FTRs in the secondary market.

The second issue was the need to require LT-FTRs to be multi-year obligations, not a sequence of one-year FTRs with the option to renew for a number of years. Once allocated, these long-term obligations can only be removed by selling them to another market participant. There are a number of reasons to prefer ten-year obligations. The first is that the option to renew can create revenue adequacy problems for the CAISO if market participants are able to refuse to renew FTRs with negative expected congestion payments. Without these payments from the market participant, the CAISO may be unable to fund its other LT-FTR obligations. Consequently, the CAISO may be forced to reduce the number FTRs it allows other market participants to renew in response to the renewal decisions of other market participants. A second reason to prefer the multi-year obligations is that this will increase liquidity in the secondary market for FTRs. As noted above, unless LSEs sell long-term FTRs that have negative expected values, they will have to make payments to the CAISO as part of their LT-FTR obligations. This downside risk also limits the likelihood that LSEs initially allocated LT-FTRs will not be active participants in the secondary FTR market. A final advantage of allocating a 10-year instrument (or other multi-year obligations) instead of a sequence of one-year FTRs with the option to renew each year is that the 10-year instrument will increase the likelihood that market participants will designate sources and sinks for their LT-FTRs along the major transmission interfaces with predictable directions of congestion, rather than sources and sinks that may yield large congestion payments during some years and large congestion obligations in other years. This is consistent with FERC's goal for market participants to use LT-FTRs for baseload energy supply contracts, because baseload contracts are more likely to use the major transmission inferfaces both into and within California.

Assuming all LT-FTRs are 10-year obligations, a related question is the extent to which market participants should be allowed to shape the annual MW values for this 10-year obligation in the LT-FTR allocation process by requesting different amounts of MWs from a given source and sink for each of the ten years. Because of FERC's desire for LT-FTRs to be used to hedge baseload supply arrangements, several MSC members questioned the need to introduce this complication into the LT-FTR allocation process. The annual FTR allocation process and the secondary market for FTRs were thought to be the better venues for market participants to use to adjust their annual FTR needs.

The third issue concerns whether priority in the LT-FTR allocation process should be given to market participants with existing or planned long-term energy supply arrangements between the source and sink of the LT-FTR. This issue was very controversial among the stakeholders present at the meeting and on the telephone. Some of the controversy could be due to lack of clarity from FERC on the use of existing and proposed or future long-term supply arrangements in the LT-FTR allocation process. **Jeff Nelson** of SCE and **Glenn Goldbeck** of PG&E both supported giving priority to existing or planned long-term energy supply arrangements. **Tony Braun** of the California Municipal Utility Association supported allocating LT-FTRs to serve long-term supply arrangements. **Steve Williams** of San Diego Gas and Electric (SDG&E) did not support giving priority to existing or planned long-term supply arrangements. He proposed a mechanism that would settle ties among market participants requesting the same FTRs using a Transmission Access Charge (TAC) weighted share allocation. For example, if three market participants wanted 100 MWs of FTRs between a source and sink and the CAISO could only allocate 50 MW, then each would receive a share of the available 50 MWs of FTRs that is equal to its fraction of the total TAC payments of three requesting market participants. **Sue Mara** of RTO Advisors supported a pro-rata allocation of the available FTRs based on the TAC payments by each market participant, rather than a mechanism giving priority based on existing contracts. **Carolyn Kehrein** of Energy Management Services also supported the TAC-weighted share approach, but down to the customer level. She felt that any mechanism based on existing contracts would disadvantage new load-serving entities (LSEs) who had not been in business very long. In addition, she did not see the logic behind giving priority for more valuable FTRs to certain customers—those with existing or planned long-term supply arrangements because all LSEs pay the same $/MWh TAC.

Further discussion emphasized that although the MSC prefers a mechanism that does not allocate LT-FTRs based on pre-existing long-term supply arrangements, MSC members oppose allocations based on planned long-term supply arrangements. The major concern with giving priority to proposed long-term supply arrangements is that retailers could sign these arrangements far from load centers and then use the allocation process to obtain very lucrative FTR payments. This FTR allocation mechanism will undo the very beneficial locational price signals that inform suppliers not to locate new generation units at low-priced locations that meet the CAISO's deliverability requirements. In addition, the CAISO will be faced with the very difficult task of verifying which planned long-term supply arrangements are legitimate and deserving of a LT-FTR and which are not. Allocations based on historical supply arrangements also face these difficulties, but they do not undermine the beneficial locational price signals for new generation investments. Several MSC members have supported pro-rata FTR allocation processes that do not require a showing of existing or planned long-term supply arrangements. These MSC members continue to support a pro-rata allocation process for LT-FTRs and see no market efficiency or equity advantages to allocations based on existing or planned long-term supply arrangements. In fact, as one MSC member noted during the discussion, a strong case can be made against this allocation mechanism on equity grounds because it allocates more valuable FTRs to older and larger LSEs with significant existing and planned long-term supply arrangements.

One MSC member suggested a compromise solution to this equity concern that would involve the CAISO using an auction mechanism to allocate LT-FTRs. Under this scheme only LSEs would be allowed to bid vertical demand curves for FTRs. This would give them priority in the LT-FTR allocation process, because a vertical demand curve would effectively outbid any other type of market participant in the auction. To address the equity concern that LSEs that receive more valuable LT-FTRs (as measured by the market-clearing price in the proposed LT-FTR auction mechanism) should pay more for them, this scheme would refund LT-FTRs revenues to market participants in proportion to the fraction of total TAC payments they make. For example, if an LSE paid 30% of total TAC charges in the California ISO control area, it would be entitled to 30% of revenues from the FTR auction. This would ensure that all LSEs receive their TAC-weighted share of total LT-FTR revenues, but those that received more valuable LT-FTRs would pay for this greater value.

A final issue is the credibility of full funding and MW firmness of the LT-FTRs without some backstop mechanism and clearly specified force majeure conditions. Several MSC members encouraged the CAISO to clearly specify the conditions under which the MW of an LT-FTR would be reduced. For example, it seems reasonable to reduce the MW of an LT-FTR if the corresponding transmission path experiences an outage for one year. There are significant risks to the CAISO from failing to recover sufficient revenues to fund these LT-FTR obligations for ten years if a sustained transmission outage occurs. For example, would an outage for one month or one week be sufficient to reduce the MW of the LT-FTR? If so, by how many MW should the LT-FTR be reduced? One MSC member noted that the promise to fund fully an LT-FTR is not credible unless there is a source of funds to guarantee it. One suggestion from the MSC was to use the TAC to fund any congestion revenue shortfalls on an annual basis. The TAC could also be reduced if there were any congestion revenue surpluses on an annual basis.

MRTU Convergence Bidding

Gillian Biedler of the Department of Market Monitoring (DMM) discussed the DMM's analysis of the issues involved in the design of convergence bidding under MRTU. She first discussed the results of DMM's analysis of the convergence bidding regimes at the Eastern ISOs and then discussed the market power mitigation and monitoring issues that would arise under the convergence bidding designs considered for MRTU.

Biedler explained that both PJM and ISO-New England (ISO-NE) allow both incremental (INC) and decremental (DEC) convergence bidding at the nodal level, whereas the New York ISO (NYISO) allows convergence bidding at the zonal level, although there are 15 zones for NYISO control area. PJM and ISO-NE also monitor the Congestion Revenue Rights (CRRs) holdings of market participants to ensure that they do not use convergence bids to inflate the payments they receive from their CRRs. NYISO and ISO-NE require market participants to post collateral in order to submit convergence bids. These ISOs also have circuit breaker provisions that suspend the ability of market participants to submit convergence bids. Finally, all market monitoring units at the three Eastern ISOs have the ability to re-run the day-ahead energy market without convergence bids to determine their impact on market prices.

Biedler then discussed the market power mitigation and monitoring issues associated with convergence bidding. The major determinant of the scope of the necessary market power mitigation mechanisms is the spatial granularity permitted for convergence bidding. The more aggregated the pricing locations at which convergence bidding is restricted to, the less concern there is that market participants will use convergence bidding to increase the revenues they earn from their CRR holdings. For example, with nodal convergence bidding a market participant could submit a large amount of DEC bids at the sink for its CRRs and large amount of INC bids at the source of its CRRs to increase the price difference between these two locations and therefore the payments received from their CRRs. With convergence bidding restricted to a regional level, say at the LAP level in California, market participants would have their convergence bids distributed using load-distribution factors. This would make it extremely difficult for convergence bids to impact specific nodal prices without also impacting other nodal prices. Consequently, using convergence bidding to enhance CRR revenues in the manner described above would be extremely difficult. This logic implies that by restricting convergence bids to the LAP level, there is less need to implement node-level market power mitigation and monitoring mechanisms. An important mechanism for monitoring the impact of convergence bids is the ability to compute the locational marginal prices from the day-ahead market without convergence bids and compare the resulting prices to actual prices. DMM did not yet have this capability, but hoped to have it before convergence bidding was implemented. Biedler concluded her presentation by saying that because of the need for significant market power mitigation and monitoring mechanisms with nodal convergence bidding, DMM supported limiting convergence bidding to the LAP level for both INC and DEC bids as an initial design approach.

David Withrow of the Market and Product Development department then outlined the CAISO's proposed convergence bidding design under MRTU. The main elements of the proposal are: (1) convergence bids must be explicitly identified, (2) convergence bids can only be submitted at the LAP level, (3) the same load distribution factors used to settle physical generation and loads in the day-ahead and real-time markets will be used to settle convergence bids in the day-ahead and real-time markets, and (4) convergence bids will not be subject to the same market power mitigation measures that physical bids are subject to, specifically local market power mitigation. The CAISO was still considering the full range of market power mitigation mechanisms it would implement. One measure under consideration is the authority to suspend or limit convergence bidding by a market participant. Withrow discussed the various options the CAISO was considering for credit and collateral requirements for convergence bidding and the allocation of the obligation to pay uplift charges from the day-ahead market and the residual unit commitment (RUC) process and ancillary services costs.

The major topic of discussion among stakeholders and MSC members was the spatial granularity in convergence bids permitted. **Brian Theaker** of Williams Power Company argued that convergence bidding at the zonal level would limit the market efficiency benefits of allowing convergence bidding. He urged the CAISO to put the necessary market power mitigation mechanisms in place to monitor convergence bidding at the nodal level and implement nodal convergence bidding from the start. **Ellen Wolfe** of Western Power Trading Forum (WPTF) noted that many of the potential benefits of convergence bidding were not available to market participants unless it was allowed at the nodal level. **Jeff Nelson** noted that nodal convergence bidding could result in physically infeasible day-ahead schedules because convergence generation might displace actual generation in the day-ahead integrated forward market, which would imply the need for the CAISO to make greater use of the RUC process. Besides the market power mitigation challenges of implementing nodal convergence bidding, Nelson also noted that there were likely to be computational challenges associated with allowing nodal convergence bidding within the context of the locational marginal pricing model used by MRTU. **Brian Theaker** responded that virtual bids could also reduce the need to use the RUC process and that nodal level convergence bids had been successfully implemented in PJM and ISO-NE without significant computational problems.

At previous meetings, one MSC member pointed out that the full range of benefits of convergence bidding will not be realized unless it is allowed at the nodal level. Generation owners wishing to sell energy scheduled in the day-ahead market at the real-time price may find this prohibitively costly to do if convergence bidding is restricted to the LAP level. Market participants that would like to clear a CRR against the real-time prices at the source and sink of the CRR instead of against the day-ahead prices at these two locations are unable to do so if convergence bidding is restricted to the LAP level. One MSC member remains concerned that a significant fraction of the potential benefits of convergence bidding may not be realized if it is restricted to the LAP level. He feels that if the CAISO implements convergence bidding at the LAP level, it runs a significant risk of paying to implement convergence bidding without realizing enough market efficiency benefits to justify its existence. The New York ISO allows convergence bidding at each of its 15 zones, which provides significantly more spatial granularity to generation unit owners than the three LAPs in California.

All MSC members recognize the potential local market power mitigation problems that can arise with nodal convergence bidding. For this reason, the MSC does not recommend nodal convergence bidding unless the necessary local market power mitigation mechanisms are in place. It can also understand the desire of the DMM to gain experience with convergence bidding at the LAP level only, before moving to the node level. As discussed below, there are potential local market power mitigation (LMPM) mechanisms that could be used to deal with these problems. If sufficient LMPM measures are implemented, and the DMM is comfortable with them, then the MSC sees few reasons for not allowing convergence bidding at the nodal level for both INC and DEC bids. This would maximize the market efficiency benefits of allowing convergence bidding while limiting the associated potential for the exercise of local market power.

Since the start of the convergence bidding discussions at the CAISO, several MSC members have suggested position limits as opposed to monitoring of CRR holdings and convergence bids to prevent market participants from exercising local market power with nodal convergence bids. For example, the CAISO could place market participant-level limits on the total MW (INC plus DEC bids) that could be submitted across all nodes in the system and at individual nodes. These magnitudes need not be based on the amount of collateral a market participant is willing to post, but the extent to which the CAISO believes local market power problems could arise as a result of convergence bidding at that location.

These MSC members noted that local market power problems with convergence bidding could arise because one or a small number of suppliers submit a large volume of convergence bids at certain locations in the network. This concern can be addressed by limiting the MWhs of convergence bids that can be submitted at each location by each market participant. This logic implies that a prudent approach to allowing convergence bidding at the nodal level would be to set very low levels of the total MWhs that market participants can submit in convergence bids and the maximum amount they can submit at any node. As the CAISO and DMM gain more experience with the impact of convergence bidding on market outcomes, these maximum quantities can be increased. With position limits at the nodal and system-wide level, the CAISO could consider INC and DEC convergence bidding at the nodal level, which will allow the CAISO to capture more of market efficiency benefits of convergence bidding while guarding against the harm this could cause. Any market participant-level position limits on convergence bidding should be approved by the DMM because they are implemented to limit the exercise of local market power. One such process would involve market participants submitting their proposed convergence bid quantity limits at each node in the California ISO following the conclusion of the annual CRR allocation process. The DMM would then approve or modify these position limits and they would remain in force for the following year, unless the DMM decided to revise them because of local market power concerns.

The MSC also discussed the credit and cost allocation issues. Several MSC members noted that the credit and collateral requirements are less critical if the CAISO implements the position limits described above. Setting collateral limits too high could destroy beneficial market efficiency incentives of convergence bidding. If the transaction costs associated with convergence bidding are too high, market participants will have less of an incentive to submit INC and DEC convergence bids to exploit price differences between the day-ahead and real-time markets. Similar logic applies to the allocation of day-ahead market uplifts, RUC costs, and ancillary services costs. For example, if the transaction cost associated with a 1 MW convergence bid is $1/MWh, it is highly likely that market participants will not submit convergence bids unless they expect the difference between the day-ahead and real-time price to be greater than $1/MWh.

In general, the extent to which convergence bidding can deliver price convergence between the day-ahead and real-time markets is limited by the magnitude of transactions costs associated with convergence bidding–which depends on the magnitude of collateral costs, uplift and RUC costs, and ancillary services costs. For this reason, the CAISO should attempt to limit the magnitude of these costs assigned to convergence bids.

MRTU Locational Market Power Mitigation Study

Ming Hsu of the Department of Market Monitoring summarized the results of the MRTU Locational Market Power Mitigation Study. This study was concerned with an issue previously discussed at the March 15, 2005 MSC meeting regarding the CAISO's proposed local market power mitigation mechanism under MRTU. The specific issue of concern is whether suppliers that owned multiple generation units close to a load center could circumvent the CAISO's proposed local market power mitigation mechanism by submitting price bids for units with low reference levels above the price bids of units with significantly higher reference levels and in this way allow the local price to be set by a unit with a high reference level.

The following example taken from the March 15, 2005 MSC meeting illustrates the problem. Assume a load center with 300 MW of load, a 400 MW unit with a reference price of $50/MWh, and a 200 MW unit with a reference price of $150/MWh. If the 400 MW unit submitted a bid of $200/MWh and the 200 MW unit submitted a bid of $150/MWh, then the original version of the MRTU LMPM mechanism would mitigate the bid price to the reference price of $50/MWh only for 100 MW of the 400 MW unit, the amount of this unit taken in Pass 2 of the day-ahead market LMPM procedures. However, the market price would still be set by the 200 MW bid in at $150/MWh because the remaining 300 MW of the 400 MW was unmitigated and had a bid of 400 MW. The CAISO subsequently modified the MRTU LMPM mechanism to mitigate the entire capacity of the bid curve above the Pass 1 dispatch level. In this example, the entire capacity of the 400 MW unit would be mitigated to the reference level of $50/MWh. With this change, the market price would now be set at $50/MWh, the value of the reference level for the 400 MW unit. The 200 MW bid at $150/MWh would not be taken.

The discussion of this issue at the March 15, 2005 MSC meeting also provided an example of when the CAISO's fix may not fully address this concern. Assume there is 495 MW of load in the load center and two 300 MW units with $50/MWh reference prices and a 200 MW unit with a reference price of $150/MWh. If the two 300 MW units submitted offer prices of $200/MWh and the 200 MW unit submitted a $150/MWh offer price, then under the revised mechanism the entire capacity of one of the 300 MW units would be mitigated to its reference level of $50/MWh in Pass 2. In Pass 3, this 300 MW unit would be dispatched, the 200 MW unit would be dispatched to 195 MW and the price would be set equal to $150/MWh, instead of the $50/MWh reference price for the two 300 MW units.

At the March 15, 2005 MSC meeting, the DMM stated that it would undertake a study of the extent to which this market outcome could occur. The study concluded that there is very limited potential for the exercise of unilateral market power using the strategy outlined in the previous paragraph. The study showed that only one supplier in the CAISO control area could profitably employ this strategy and the ability of this supplier to employ the strategy depended on the historical bidding behavior of the other major supplier near the load center. If the other major supplier bid close to its marginal cost, then this strategy would become unprofitable. The study showed that because the cost-based reference bid curves for most of the larger suppliers in the major California load centers are relatively flat at roughly the same variable cost this limits the ability of market participants to employ the strategy. However, there are two suppliers in the major load centers that have reference price bid curves with significant cost difference across their generation units.

There was some discussion of alternative approaches to deal with this issue. One MSC member suggested mitigating the bids of all generation units from the same plant when the capacity of at least one unit at that plant was mitigated in Pass 2 of the day-ahead market. **Jeff Nelson** of SCE asked whether the type of behavior described above was a violation of the CAISO's tariff prohibiting market manipulation. **Keith Casey**, Director of Market Monitoring, stated that the CAISO would certainly refer this behavior to FERC and allow it to decide. The ultimate conclusion of the discussion was that DMM would use the results of this study to monitor the MRTU market for this type of behavior.

MRTU Real Time LAP Pricing

Farrohk Rahimi of the Market and Product Development department described the CAISO's proposed change to the computation of the real-time LAP price. The filed mechanism for computing the real-time LAP price would result in two different effective real-time prices, one for loads above their schedules and one for loads below their schedules. Although the existing mechanism would achieve revenue neutrality, meaning that the amount collected from loads is sufficient to pay generation unit owners for their real-time deviations, this real-time LAP pricing mechanism could lead to very high real-time LAP prices under certain circumstances. For this reason, the CAISO proposed to compute a single real-time LAP price using the day-ahead load-distribution factors (LDFs) and then collect or charge for changes in the LDFs between day-ahead and real-time as an uplift charge on all real-time LAP load. Rahimi noted that to the extent the day-ahead and real-time LDFs do not differ significantly from one another, this uplift charge should be very small. To the extent that day-ahead schedules of load are very close to actual loads, the day-ahead LDFs should not differ significantly from the real-time LDFs.

The stakeholders present at the meeting and on the phone were generally supportive of this change. One MSC member noted that a key factor in the success of this change is very small deviations between the day-ahead and actual consumption and production in real-time. Charging the same LAP price to all loads could create perverse incentives for loads in the real-time market. For example, at certain locations in the LAP the CAISO could want loads to reduce their consumption because they are above their schedules. In other parts of the LAP, the CAISO might want loads to increase their consumption because they are below their schedules. By charging all loads in a LAP the same real-time price, the CAISO is unable to provide spatially differentiated price signals to loads in the LAP that it was able to provide under the filed mechanism which charges different real-time prices to loads depending on the sign of the difference between their actual consumption and final schedules. Consequently, it is important to emphasize that the proposed mechanism may not provide incentives for loads to schedule accurately that are as strong as those under the originally filed proposal. However, the benefit of the proposed LAP price calculation is that it is more supportive of the goals of the CAISO's approach to convergence bidding under MRTU. The day-ahead and real-time LAP prices will be based on the same LDFs, so that entities submitting convergence bids at the LAP level will be able to more easily profit from differences in the day-ahead and real-time LAP prices. This will encourage convergence bidders to take actions to limit deviations between day-ahead and real-time prices.

MRTU Marginal Loss Surplus Allocation

Farrokh Rahimi of the Market and Product Development department summarized the results of the CAISO's marginal loss surplus (MLS) allocation study. In its February 9, 2006 reply comments to FERC, the CAISO committed to undertake a study to compare the distributional impact of allocating the MLS to demand on a regional versus system-wide basis. A preliminary report on five months of results was shared with the stakeholders. When FERC issued its September 21, 2006 Order on MRTU and accepted the MLS allocation based on measured demand on a system-wide basis further work on the study was suspended. Pacific Gas and Electric filed for re-hearing on the allocation method and requested completion of the study. The study that Rahimi reported on only considered two regions in California, the Northern Region (NP15 plus ZP26) and the Southern Region (SP26).

Rahimi considered three scenarios in the study. The first is allocation on a system-wide basis. The second is a regional allocation without an adjustment for flows on Path 26. The third is a regional allocation with an adjustment for flows on Path 26. This adjustment for Path 26 was included to account for the fact that when there are significant flows from north to south on Path 26, some of the losses in the North Region should be attributed to serving load in the South Region. The converse applies to flows from south to north on Path 26. Using five months of output from the Locational Marginal Pricing (LMP) study for the period May to September of 2004, Rahimi presented monthly values for MLS rebates for the North Region and South Region under the three scenarios. He also presented monthly average $/MWh MLS rebates. These ranged from $1.30/MWh to $0.88/MWh, depending on the region and scenario. The filed MLS rebate methodology had an average $1.22/MWh rebate for both the North and South regions for the five-month period. The regional rebate methodology without the Path 26 adjustment had an average $1.51/MWh rebate for the North Region and a $0.97/MWh rebate for the South Region. The regional rebate methodology with the Path 26 adjustment had an average $1.28/MWh rebate for the North Region and a $1.16/MWh rebate for the South Region. The MSC were requested to review the efficiency impacts of system versus regional allocation of the marginal loss surplus.

Glenn Goldbeck of PG&E gave a presentation expressing PG&E's preference for a regional allocation of the marginal loss surplus. He noted that the CAISO's preliminary study indicates regional allocation can result in a cost shift between the North and South regions ranging from $5 million to $35 million annually. He also noted that FERC had approved a regional approach to loss allocation in the Midwest ISO. He urged the CAISO to complete the study for a 12-month period using more general assumptions and present the results to stakeholders.

Jeff Nelson of SCE noted in response to Goldbeck's presentation that any increase in the MLS rebate to PG&E's customers would be funded by lower rebates to customers in the rest of the California ISO control area. Nelson noted that SCE does not object to an MLS rebate mechanism that improves overall energy market efficiency, but SCE does not believe there are any incremental market efficiency benefits to a regional approach to computing MLS rebates. In fact, a system-wide approach is lower cost to implement, because it only requires the CAISO to compute the marginal losses and refund it using the same $/MWh rebate for all load in the state.

Ben Hobbs explored the efficiency impacts with some numerical examples. One MSC member noted that while it may be difficult to identify the market efficiency benefits of one approach relative to another, it was the case that any increase in the rebate rate to one market participant would imply a lower rebate rate for other market participants. In addition, because the CAISO is currently moving to a single state-wide $/MWh TAC charge applied to load, a single state-wide MLS rebate was consistent with this approach.

LMP Study for MRTU

Jim Price of the Market and Product Development department presented an update of the CAISO's LMP study for the summer of 2004. This study integrated the CAISO's filed local market power mitigation mechanism and incorporated proposed CRR holding for the major California LSEs. The distribution of LAP prices in the SCE load zone and PG&E load zone were less volatile than actual real-time prices and the frequency of high prices in the two load zones was significantly less for the LMP study than for the actual prices. Following the presentation, several MSC members noted that they looked forward to seeing further studies that incorporated all aspects of the MRTU design.

MSC Chair, Frank Wolak, adjourned the public meeting at 4:30 pm and MSC met in Executive Session to discuss confidential matters for another hour.