REVIEW OF THE CALIFORNIA ISO'S MD02 PROPOSAL

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EXECUTIVE SUMMARY

The California Independent System Operator (CAISO) Comprehensive Market Design Proposal (MD02) contains many positive elements that should improve the performance of the California electricity market. These elements will move the California wholesale electricity market towards greater conformity with the Northeast market model as implemented in PJM and New York as well as the standard market design under active consideration by the Federal Energy Regulatory Commission (Commission). The Commission has a great opportunity to work with the CAISO to make major improvements.

Although the broad vision is well conceived, an examination of the details reveals a number of issues that need urgent attention and modification. Importantly, the priorities for the transition need reconsideration. The schedule leaves most of the defects of the existing CAISO markets in place for a year or more, and focuses on imposing rules in forward markets and for market power mitigation intended to constrain or compel the choices of market participants. But the schedule defers until later the needed reforms of the real-time market that create the bad incentives giving rise to the need for restrictive rules. To the extent possible, the priority should be the reverse order. Implementing the reforms in the real-time market would make everything else much easier.

The close conformance of the broad design with the Northeast model, combined with the need for early implementation, dictate that the CAISO should prefer to keep the Northeast model intact, and should consider changes to that model only to the extent that there is very strong evidence that modifications are necessary to accommodate distinctive needs in California. At present the MD02 proposal includes many changes that appear unnecessary or even counterproductive.

The present report addresses many, but not all, of the issues that need further attention at the level of the detail design or the timing of implementation. These elements include many features that would transform market incentives to better reflect the reality of the electrical system and the needs for both reliability and efficiency.

- Day-ahead Market
    - Positive features include the elimination of market separation rules, elimination of balanced schedule requirements, management of congestion on a full network model, implementation of security constrained unit commitment, and full locational marginal pricing of energy and transmission.

  - Issues include the lack of detail or explanation of deviations from the working Northeast model, lack of a decision to embrace a workable method for treating losses, and a slow transition to the locational pricing model.

- Residual Unit Commitment

  - Rapid introduction of the residual unit commitment model should provide important reliability benefits.

  - Differences with the criteria used in the Northeast residual unit commitment approach do not appear necessary and are likely to be counterproductive. Further, these criteria may work against the success of the day-ahead market, as they may encourage market participants not to schedule in the day-ahead market.

- Real-time Market

  - Positive features include the elimination of balanced schedule requirements, use of full economic dispatch to clear the market for energy and congestion management, full locational pricing of energy and transmission, and simultaneous optimization of energy and ancillary services.

  - Issues include the slow implementation of the positive features. Most importantly, continuation of the current zonal pricing mechanism will maintain the perverse incentives that complicate participation in the day-ahead market.

- Ancillary Services Markets

  - Positive features include the procurement of ancillary services in a day-ahead market in which energy and ancillary service schedules are simultaneously optimized based on multi-part bids, a provision to establish locational ancillary service requirements settled based on locational ancillary service prices, retention of capacity bids for ancillary services, and a price determination mechanism that is based on capacity bids along with opportunity costs.

  - Issues include ambiguities needing resolution: Will the MD02 ancillary services markets be based upon a two-settlement system? Will there be a market or process between the day-ahead market and real-time for adjusting ancillary service schedules to reflect changes in resource availability and opportunity costs? Will ancillary service prices be "cascaded"?

- Financial Transmission Rights

  - The CAISO proposes a sensible approach to use financial transmission rights that exploits the experience with point-to-point obligations in the Northeast markets and preserves most of the advantages found in the FTRs used in those markets, while considering later extensions to include options and flowgate rights.

  - Issues include ambiguity about how to allocate FTRs and the extent to which FTRs will treated as physical rights or be bundled with other products.

- Market Power Mitigation

  - The proposal includes many features to help mitigate market power. Must-offer requirements, locational market power mitigation, reliability must-run units, and automated mitigation procedures could be useful tools. However, the details of implementation and the interaction among these rules need added attention.

  - Issues include the expansion of this list of tools to include damage control bid caps and a competition index with automatic triggers for re-imposing the existing market power mitigation rules. These additional elements create further problems without offering any benefit in terms of providing additional protection from the exercise of market power. The bid caps have been set at a level that is likely to preclude development of new generating capacity or price-responsive load, which will lead to continued reliance on these mitigation mechanisms. And the competition index could trigger the re-imposition of the current west-wide mitigation procedures, even if market power is not exercised.

- Available Capacity Obligation

  - The transition may require some procedures for securing adequate generation capacity through an available capacity obligation (ACAP). But the current discussion is inadequate to evaluate the efficacy of the proposal.

  - Given the other reforms, a long-term ACAP obligation may not be needed.

In considering the expanded comments offered here, the Commission should emphasize the strength of the long-term vision, the great progress in confronting the major design flaws of the existing market, and the need to implement the full reforms in the real-time market as soon as possible.

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OVERVIEW

The CAISO MD02 filing contains many positive elements that will improve the performance of the California markets. These elements will move the California market towards greater conformity with the Northeast market model as implemented in PJM and New York as well as the standard market design under active consideration by the Federal Energy Regulatory Commission. These elements include many features that would transform market incentives to better reflect the reality of the electrical system and the needs for both reliability and efficiency.

The major features include simultaneous solution of energy and ancillary services markets, use of a full network model for both day-ahead and real-time operations, elimination of the various artificial constraints that arose from the so-called "market separation" requirement, and reliance on consistent rules between and within the day-ahead and real-time markets. Most importantly, the associated pricing rules will better provide incentives for market participants to work in support of efficient operation of the electrical system and would permit the CAISO to rely more on market incentives, and less on command and control, to maintain reliability. The basic design outlined for the full reforms would be a major step forward in the development of effective electricity markets within California and as part of the larger western system.

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[1] The proposal reviewed is that filed with FERC on May 1, 2002. Any errata filings made by the CAISO subsequent to that date have not been considered in this review.

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The market reform proposals in MD02 capture the major lessons learned at such great expense about the importance of the details of electricity wholesale market design. Certainly the most uncontroversial lesson learned so far is that market participants will react to incentives. The theory is that with good incentives, individual creativity and choice can produce better results than can a highly regulated system with little choice. Unfortunately, bad incentives can produce bad decisions. In the early days of electricity restructuring there was a tendency to assume that market participants would ignore bad incentives or that the myriad of market structure details did not matter. This is now seen as a mistake, and a major thrust of the CAISO reforms is to eliminate features of the current market design that provide incentives for undesirable behavior from the system operator's perspective, create opportunities for gaming and encourage the exercise of market power. Instead, the goal of an efficient market structure is to implement operating protocols and pricing rules that provide proper incentives for development of new resources, permit the most efficient use of existing resources, and support rather than undermine the physical requirements of system operations.

A major advantage of the MD02 proposal is that it sets out a clear vision of where the reform is headed, and that vision is coherent and largely consistent with best practices developed from real-world experiences. Knowing where we are going can only help in laying out the path of how to get there. However, most of the positive elements of the MD02 proposal will not be implemented during the fall of 2002, and many will not be implemented even by the Spring of 2003. A close comparison of the helpful table in Section 2 of ISO's Comprehensive Market Design Proposal (CDP) shows how similar Phase I elements are to current design. Furthermore, most of the immediate reforms address market power mitigation while deferring the most important and valuable improvements in the market design. This may substantially complicate the transition, and defer the most needed reforms.

In certain aspects the long-term reforms deviate from the design elements that work well in the Northeast model. A number of these changes do not appear desirable, lack justification, and may serve to delay rather than speed reform of the California market. For example, the decision rules of the residual unit commitment proposed differ significantly from the design that has worked well in the Northeast model, and the differences may have a material effect on the incentives to participate in the day-ahead energy and ancillary services markets.

Of course, differences in design may be appropriate if there are material differences in conditions in California and the New York or PJM markets. However at this stage, to the extent possible the CAISO should limit changes to the Northeast design in order to expedite the implementation of the positive elements of the CAISO proposal. Given the similarity of the CAISO's long-term market design and market monitoring concepts to the market design and market monitoring concepts in place in the Northeast, the CAISO could adopt the Northeast procedures in their many details. This should reduce implementation time, which might permit an earlier rollout of the standard market design. The market power mitigation mechanisms used in these areas have been vetted in context of currently functioning markets and tested in operation. Where needed, the CAISO should adjust the Northeast model to address California market and reliability needs. But the burden should be on the CAISO to justify any deviations from the mechanisms that have worked elsewhere. This is not the time or the place for experimentation.

In the discussion below, basic principles provide a foundation for considering the efficacy of the reforms in MD02. For example, as emphasized here, the incentives matter. In this regard, the CAISO strategy appears to have the wrong priorities. The CAISO transition emphasizes fixing the forward market and then imposing rules and penalties to make real-time operations conform to the forward plans. However, rational market participants work in the opposite direction. They look at the incentives in real time and then work backward to evaluate their decisions in the day-ahead market. Starting with bad incentives in the real-time market makes everything more complicated in designing the day-ahead protocols. Hence, moving immediately to economic dispatch in the real-time market is a good idea, but not enough. Everything should be done to move as soon as possible to the locational pricing version of that market rather than the flawed zonal pricing model that creates perverse incentives and exacerbates locational market power problems.

The importance of this lesson was illustrated most prominently by the experience in the PJM market. In 1997, PJM began operations under its OATT with a flawed design for its wholesale market that shared important features with the current California design. Most significantly, a single zone pricing structure created strong incentives for market participants to deviate from the economic dispatch and to avoid or circumvent the PJM ISO's dispatch instructions. The incentives and the resulting behavior in PJM were comparable to the real-time operating problems experienced in the California market during 2000-2001. In its reform in 1998, PJM adopted a new pricing regime based on locational pricing at every node in the real-time market. This reform of the real-time market eliminated the perverse incentives that proved so disastrous in 1997, and the market performed well once the new pricing model was in place. By contrast with the focus in the CAISO reforms, PJM did not first implement changes in the forward market. In fact, there was no formal forward market in PJM. The PJM-ISO implemented a formal forward market more than a year later, and it was easier because the real-time market provided the proper incentives. Hence, the successful sequence of reforms was real-time markets first and forward markets later, just the opposite of the priorities driving the process in California.

Market power mitigation mechanisms should focus on preventing the exercise of market power, without constraining prices from providing efficient incentives. The CAISO proposal contains a number of duplicative restrictions, the overall impact of which is likely to constrain prices below competitive levels. The CAISO should develop a basic market design that promotes efficient operation, not a particular pricing outcome. Given this efficient platform, the market power mitigation rules should be carefully targeted to deal with the unacceptable exercise of market power without also foreclosing behavior that might be efficient, especially when the system is stressed. At every turn, it is important that the end result be rules that allow the market to support efficient and rational system operation.

In short, the broad goals of the CAISO proposals are a welcome and major improvement. But the details and sequencing need further attention. Hence, these comments emphasize the role of incentives, consistency in design principles, targeted market power mitigation and a default preference for the standard market design.

EVALUATION OF THE MD02 PROPOSAL

A. Day-ahead Market

Positive Elements of the MD02 Proposal

The CAISO MD02 proposal contains a number of *important* positive steps towards the development of an efficiently functioning day-ahead market for California. In particular, the proposed elimination of market separation rules, elimination of balanced schedule requirements, management of congestion based on a full network model, implementation of security constrained unit commitment, and utilization of LMP pricing of energy and transmission will eliminate many of the problems that have reduced the efficiency and reliability of California electricity markets over the past few years.[3] The proposal will also eliminate the artificial distinction between intra- and inter-zonal congestion, increasing market efficiency, providing meaningful forward prices, and reducing the potential for the exercise of locational market power or gaming of intra-zonal congestion.[4] These changes will resolve problems that have plagued CAISO markets since 1998. These changes will eliminate most infeasible schedules and INC/DEC gaming and provide meaningful day-ahead prices that will permit development of financial hedging mechanisms in forward markets.

The CAISO is correct that the development of an LMP-based forward market and the elimination of balanced schedule and market separation rules will obviate the need for the current inter-scheduling coordinator (SC) trading mechanism, as inter-SC transactions will become purely financial transactions, analogous to PJM's e-Schedules.[5] Similarly, as the CAISO notes, the implementation of LMP-based congestion management eliminates the need for iterating preferred schedules.[6]

Issues

There are three issues with the CAISO's proposed day-ahead market that need to be addressed. First, the CAISO has described the structure only in very general terms. While the CAISO need not expend resources at this time detailing all of the elements of the day-ahead market, it should be required to identify and justify any deviations from the PJM/NYISO day-ahead market design, particularly if these deviations affect implementation timelines. Second, the CAISO needs to commit to implementing a workable approach to dispatching the system to account for transmission system losses and to developing a pricing system that reflects those losses. Third, the Commission and the CAISO must recognize that the various interim intra-zonal congestion management systems contemplated for Phase II will work badly and thus that there is urgency to implementing LMP by the spring of 2003, even if the network model that can be implemented by that time is imperfect.

Consider the first issue. While the CAISO MD02 Proposal appears to point the CAISO firmly in the right direction as it reforms and replaces the existing market structure, the proposal is very general and is vague in describing many important elements of the day-ahead market. Before the MD02 proposal is approved, it must be clarified to avoid future surprises for market participants and the Commission. In particular, differences between the MD02's proposed day-ahead market and those operating in New York and PJM need to be clearly identified. Some of the important market elements that are not clearly described in the MD02 proposal include:

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[3] CAISO, CDP, pp. 79-88. (The CDP is Attachment A to the CAISO's May 1, 2002 filing describing its MD02 proposal.)

[4] CDP, § 5.2.2.1, p. 81.

[5] CDP, § 5.2.2.7, p. 82.

[6] CDP, § 5.2.2.2, p. 82

- Will all market participants be permitted to submit supply and demand bids (i.e., will virtual load and supply bids be permitted)?
- Can price-sensitive load bids set prices in the day-ahead market?
- Can external supply and demand bids set prices in the day-ahead market?
- Would there be availability bids for operating reserves?

These features of the PJM and New York markets are important in:

- Permitting arbitrage between day-ahead and real-time prices that will minimize the uplift costs associated with the CAISO's proposed RUC mechanism;
- Permitting a wide variety of market participants to provide physical and financial hedging services to consumers while enabling these market participants to manage their risks through virtual supply and demand bids in the day-ahead market;
- Providing incentives for the development of price-responsive loads by permitting these entities to buy energy in the day-ahead market and sell back energy not consumed at real-time prices;
- Permitting these price-responsive loads to withdraw from the day-ahead market when prices exceed the value of energy to the consumer; and
- Providing an efficient market for external suppliers that encourages suppliers located outside California to offer their supplies in CAISO markets.

The Commission need not require the CAISO to expend staff resources to draft a detailed description of every element of the day-ahead market immediately, but it would be appropriate for the Commission to require the CAISO to identify any and all differences between the end-state structure of the CAISO day-ahead market and those in place in PJM and New York. To the extent material differences exist, the CAISO should be required to provide justification for those differences and to specify the impact of these differences on the implementation timeline. The point is not that differences in market design or implementation should not be permitted, if they have a reasonable basis in institutional or resource differences that need to be taken into account or if these differences will serve to speed implementation. Rather, the Commission needs to ensure that the implementation of a functioning day-ahead market will not be delayed by superficial changes of little or questionable value, and that the CAISO design does not include fundamental changes in the design of the existing successful day-ahead markets that would undermine the integrity of that design, resulting in another bout of avoidable tariff amendments.

Second, the CAISO needs to commit to implementing a workable approach to dispatching the system to account for transmission system losses and to developing a pricing system that reflects those losses. The CAISO describes two potential approaches to pricing losses.[7] One approach would be to include the cost of losses within the resource dispatch process, and

[7] CDP, § 5.2.2.b, p. 84.

explicitly in the LMP prices determined in the day-ahead market. This would be consistent with the current implementation in New York,[8] and the method that PJM has indicated it will be adopting,[9] as will ISO New England[10] and the Midwest ISO.[11] This is the preferred approach as it will facilitate an efficient market, avoid gaming, provide consistency with the consensus market design outside California, and avoid artificial inflation of the cost of meeting load, which California consumers can ill afford. The alternative approach described by the CAISO would be to “continue using the GMM/TMM procedure used today.”[12] This approach has proved unworkable and there is no reason to perpetuate the problems associated with the current system in the reformed market.

Third, the FERC and the CAISO need to recognize that the various proposals for interim intra-zonal congestion management will work very badly. It is therefore important to implement LMP by the spring of 2003 based upon the best network model that can be in place by that date, with improvements to follow. In the MD02 proposal, the CAISO describes a phased implementation in which the day-ahead market will initially be based upon a three-zone model with a subsequent transition to a day-ahead market based on a full network model.[13] While such a transition path may prove necessary, neither the CAISO nor FERC should have any illusions regarding the workability of the interim intra-zonal congestion management systems proposed by the CAISO. None of them will work well because under each such proposed interim mechanism, market participants will receive forward schedules to which they are economically bound, but which they cannot cover with their generation in real time. As a result, the use of these mechanisms will undermine the efficiency, liquidity and workability of the day-ahead market coordinated by the CAISO.

The CAISO’s interim intra-zonal congestion management mechanisms propose to eliminate constrained-off payments, but these mechanisms merely shift the responsibility for infeasible schedules from the CAISO to the suppliers. Abandoning constrained off-payments while delaying LMP implementation sets the stage for another round of bad outcomes in California. It is similar to the approach that failed in PJM in 1997. Day-ahead markets that financially bind suppliers to infeasible schedules will drive suppliers out of the day-ahead markets and undermine system reliability and other FERC and CAISO objectives. These changes may also make the determination of zonal prices problematic, hinder forward contracting and undermine the ability for market monitors to identify firms attempting to exercise market power.

Since the residual unit commitment that will be implemented in the fall of 2002 will apparently be based on a network model that is more elaborate than the current three-zone model, the CAISO should justify the need to implement the initial day-ahead market based on a less detailed three-zone model. Even if it is not possible to implement a day-ahead market based on a “full network model” by the spring of 2003, if it is possible to implement the day-ahead market based on the more detailed model used in the RUC, that would reduce the magnitude of intra-zonal

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[8] NYISO Services Tariff, Attachment B, § I.

[9] PJM OATT Attachment K, § 3.2.5(a), p. 249.

[10] ISO-NE SMD Tariff, § 2, p. 31.

[11] MISO, “MISO Long-Term Market Design and Congestion Management Straw Proposal,” November 29, 2000, pp. 17-19, 25-26.

[12] CDP, § 5.2.2.6, p. 84.

[13] CDP, § 5.2.3.2, p. 85.

congestion problems and reduce the probability that the interim market design will prove unworkable from a market standpoint.

B. Residual Unit Commitment

Positive Elements of the MD02 Proposal

The CAISO has proposed a residual unit commitment process (RUC), which it would operate after the day-ahead market. The intent of RUC is to ensure that sufficient capacity is committed a day ahead for the CAISO to be able to meet its forecast load during the next day. If sufficient capacity to meet forecasted load for the next day were committed in the CAISO's day-ahead market, there would be no need to operate the RUC. But in circumstances in which the CAISO finds that it will not be able to meet the next day's load forecast reliably utilizing the resources identified in the day-ahead market, it would operate the RUC process.

As observed by the CAISO, both PJM and the NYISO have processes analogous to the RUC for identifying and addressing potential resource shortages in a day-ahead time frame. The rationale for these processes is that it would be unreasonable to expect the CAISO, or any other ISO, to enter a day knowing that, if its load forecast is accurate, the ISO will have to undertake involuntary load shedding unless resources that the ISO is not able to identify materialize in real-time. At some point in the future, it will likely not be necessary for the CAISO to operate a RUC process to ensure that it will not need to involuntarily shed load. Once substantial amounts of price-responsive dispatchable load have developed within California, high real-time prices during shortage conditions would cause these price-responsive loads to reduce consumption voluntarily, avoiding the need for involuntary load shedding. In these circumstances, there would rarely if ever be a need for the CAISO to commit additional inflexible generation resources on a day-ahead basis in order to ensure its ability to meet forecasted load levels. But at this time, in the absence of a RUC, the CAISO could be required to order involuntary load shedding in circumstances in which it had the ability to take actions that would avoid the need to shed load, which would be inconsistent with the CAISO's responsibility for maintaining electric system reliability in California.

The RUC proposal includes procedures which define when the CAISO should commit additional resources in the RUC, and the process it should use when it does so.[14] The CAISO proposes to procure the additional capacity required to meet forecast load through a centrally coordinated process operated by the CAISO, which would use bids submitted by prospective suppliers, while undertaking a security analysis to ensure that the resources committed could be reliably dispatched to meet forecast load.[15]

Comparison to Procedures Used in New York and PJM

As mentioned above, both PJM and the NYISO have well-defined processes that enable them to commit additional resources in a day-ahead time frame if required to ensure that they can meet their forecasts of loads for the next day. The CAISO should have such a process. At the

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[14] CDP, § 5.5.2, pp. 107-108.

[15] CDP, § 5.5.2, pp. 107-108.

same time, PJM and the NYISO recognize that there is a tension between providing a reliability safety net to avoid involuntary load shedding, and providing an economic safety net for loads that fail to participate in the day-ahead market. Their reliability commitment processes are designed to provide this reliability safety net to ensure that the ISOs have the ability to meet forecast load, while minimizing the extent to which this reliability commitment provides an economic safety net that insulates loads that fail to participate in the day-ahead market from the economic consequences of their actions.

This makes their procedures differ substantially from those proposed by the CAISO. In general, New York and PJM first commit generation to meet loads that have been bid into the day-ahead market. Each then only commits additional generation to meet the ISO's forecast of load for the next day if the combination of the *capacity* on internal generating units that have already been committed to meet load bids in the day-ahead market,[16] on imports that have already been committed for this purpose, and on internal quick-start units would not be sufficient to meet forecasted load reliably.

In the event that these resources are not sufficient to meet forecast load reliably, it is necessary for each ISO to commit additional slow-starting internal resources, schedule additional imports, or both. In this reliability commitment process, both ISOs consider only the availability costs of committing additional generation, and both ISOs would consider all slow-starting units that had offered capacity.[17] The concept underlying availability costs is that they should only include the additional costs that the ISO would incur through committing additional units. This evaluation does not consider the bid cost of the energy that would be required to meet forecast load given the units available in the day-ahead market, because the energy cost of meeting real-time load is the economic responsibility of the real-time load and if that load wishes to minimize this cost, it would participate in the day-ahead market. Therefore, this RUC reliability evaluation only considers whether forecast load could be met at some price. This is accomplished by literally setting the incremental energy bids of resources scheduled to be on-line to meet bid load equal to zero.[18]

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[16] This may exceed the amount of *energy* those units are scheduled to provide in the day-ahead market.

[17] The NYISO operates its residual commitment as part of its day-ahead market, while PJM operates a separate residual commitment after its day-ahead market has concluded (but still the day before the capacity is needed). Other than requiring that each entity offering capacity into this market have physical capacity available that can provide energy to meet the ISO's requirements, neither ISO imposes restrictions on entities wishing to provide capacity.

[18] The availability costs considered by the Eastern ISOs are calculated as follows:

- *Internal generators.* Availability costs consist only of start-up bids and minimum generation bids. Incremental energy bids are not included because the ISO generally need not commit a generator to operate above its minimum generation level in order to have it available to meet forecast load in real time. In addition, the minimum generation offer prices for these generators are adjusted to reflect the fact that the minimum generation block energy output of such a generator will displace the incremental energy output of other generators committed to meet bid load. As a result, there will be some reduction in bid production cost resulting from the operation of these units at minimum generation, and this is offset against the minimum generation offer price of units committed to meet forecast load in order to determine the incremental additional cost of committing those units. The LMP at each generator's location that was determined in the day-ahead market pass used to commit generators to meet bid-in load can be used to estimate this cost reduction. So, if this LMP were $30/MWh, and the minimum generation offer price for that generator, averaged over the generator's

These commitment criteria can also be described as rules to reduce the uplift costs associated with the reliability commitment. While the PJM and New York reliability commitments seek to minimize market distortions, they result in the commitment of capacity that is uneconomic at day-ahead prices. To the extent that additional units are committed through the reliability commitment procedure, the units thus committed would be uneconomic to operate at day-ahead prices (or they would have been committed to meet bid load) and will require payment of a bid cost recovery guarantee to ensure that the total unit revenues are at least equal to the as-bid costs of the units. This bid cost recovery guarantee will give rise to uplift costs that must be recovered from market participants. Both PJM and the NYISO have mechanisms in place which are designed to determine the share of those costs that were attributable to market participants that purchased energy in the real-time market (as opposed to errors in the ISO's load forecast) and to assign those costs to these entities.

Although the CAISO describes its RUC process as "virtually the same as those in place in the Eastern ISOs, including the PJM Interconnection and the New York ISO,"[19] there are a number of material differences between the CAISO proposal and the reliability commitment processes in PJM and NYISO. The most significant differences are:

- The RUC process in the CAISO proposal would not minimize the cost of being able to maintain reliability (i.e. minimize the uplift cost of being able to meet forecast load) but instead may incur additional uplift costs in order to insulate loads that fail to schedule in the day-ahead market from real-time prices.[20] This will tend to pull loads out of the day-ahead market, which in turn will motivate the CAISO to impose penalties for failure to participate in the day-ahead market.

- The CAISO proposal appears to require the CAISO to assume that additional energy will be available in real time from resources neither committed in the day-ahead market nor scheduled in the reliability commitment. This is a novel departure from the PJM and NYISO processes that may prove very difficult to implement without creating new problems.

- The CAISO RUC process also differs from those in place in PJM and New York in that: initially it will not operate in conjunction with a full day-ahead market, it will prevent suppliers

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minimum generation level, was $50/MWh, then the contribution of that generator's minimum generation offer price towards its availability cost would be only $50/MWh – $30/MWh = $20/MWh.

- *Imports.* The full amount of the import offer price is considered in determining its availability costs. This is because, to the extent that imports are not scheduled in the ISO's day-ahead market, the imports may be sold in other markets or the resources necessary to supply these imports may not have been committed, so there may be no energy available to offer into the ISO's real-time market. In addition, by scheduling imports day-ahead and financially committing the import supplier to deliver energy in real-time, or settle its deviations between its real-time deliveries and day-ahead schedules at real-time prices, importers are provided a financial incentive to deliver energy in real time. Real-time performance incentives will, however, be gutted if the damage control bid cap is set at too low a level. Setting the DCBC at $108/MWh ensures that external suppliers will rarely have an incentive to deliver power into California during shortage conditions, as the $108/MWh DCBC will be likely be below the value of power outside California.

[19] Filing Letter, p. 17.

[20] CAISO's Proposed Tariff Changes (attached to the MD02 Filing), § 5.12.6.2, sheet 184L; CDP, § 5.5.2, p. 108.

from raising their incremental energy offer prices on capacity dedicated in the RUC process but not scheduled to provide energy in the day-ahead market,[21] and it will provide for capacity payments for energy scheduled in the RUC process.[22] Although the CAISO proposal provides for a form of bid recovery guarantee for units committed in the RUC process,[23] unlike the PJM and New York mechanisms, neither the energy bids nor the bid recovery guarantee would apparently permit generators scheduled in the RUC to recover either the cost of scheduling gas day-ahead that is not burned in real time or the cost of burning gas that is not scheduled day-ahead.

- The CAISO proposal would limit participation in its RUC market to ACAP providers, once the ACAP requirement is activated. This raises the cost of acquiring RUC resources by imposing artificial restrictions on participation. While non-ACAP providers should not be required to participate in the RUC process, it is not clear why it is in the interest of California consumers to restrict potential suppliers in this artificial manner.

- The CAISO proposal would retract bid recovery guarantee payments from any unit that provides ancillary services in the hour-ahead market. This provides an artificial penalty that would reduce supplies in real-time ancillary service markets and raise prices.

The significance of these differences is discussed in further detail below.

Significance of these Differences and Recommendations

Commitment Criteria

The NYISO and PJM procedures for determining which units will be committed in the reliability evaluation are, as noted above, structured to minimize the uplift costs associated with committing sufficient resources to ensure that it will not be necessary to involuntarily shed load in the event that the ISO's load forecast is accurate. As such, the NYISO and PJM reliability commitment does not try to protect loads from the financial consequences of failing to participate in the day-ahead market.

The CAISO's MD02 proposed RUC process on the other hand, apparently would base the commitment criteria not simply on minimizing the cost of having sufficient capacity available to meet forecast load if required, but would also minimize the total cost of meeting forecast load, including the cost of dispatching energy.[24] As a result, the CAISO could incur additional uplift costs in the RUC process in order to ensure that the real-time price would be no higher than if consumers had cleared the entire forecast load in the day-ahead market. This would provide a powerful incentive for consumers to not participate in the day-ahead market, particularly when the load forecast is uncertain, and seems guaranteed to keep the CAISO in the position of buying capacity in the RUC process to cover load not scheduled in the day-ahead market. This

[21] CAISO's Proposed Tariff Changes, § 5.12.5.1.3, sheet 184F and § 5.12.5.2.3, sheet 184I; CDP, § 5.5.2, p. 108.

[22] CAISO's Proposed Tariff Changes, § 5.12.7.1.3, sheets 184P-R.

[23] CAISO's Proposed Tariff Changes, § 5.12.7.1.1, sheets 184M – 184O.

[24] CDP, § 5.5.2, p. 108.

would be counter-productive.[25] Additionally, the development of these new commitment criteria for the RUC may substantially increase the time required to develop, test and debug the software the CAISO will use to implement this market, as it differs from the mechanism used in the New York and PJM markets. The CAISO should adopt the existing procedures used in the New York and PJM markets, and simply minimize the availability costs associated with committing whatever slow-starting capacity is needed to meet its forecast of next-day load. The Commission should require the CAISO to justify any departures from the PJM/New York approach.

Assumptions Regarding Capacity Becoming Available After RUC

The MD02 proposal would determine the amount of additional capacity to commit in the RUC based on "a forecast of expected incremental hour-ahead schedule changes" and "a forecast of additional supplemental energy bids expected on the operating day."[26] The mechanisms used in New York and PJM do not make such assumptions regarding bid and schedule changes; if the resources committed to meet bid-in load in the day-ahead market, plus quick-start capacity within each area, are insufficient to meet forecasted peak load, the ISO commits additional internal capacity or imports and does not make assumptions regarding whether some of those resources might or might not be committed in any event. Consequently, the procedures used in New York and PJM do not depend on assumptions regarding resources that may or may not materialize after the close of the day-ahead residual commitment in order to ensure reliability.

A critical issue that logic of the type proposed by the CAISO must resolve is that if the CAISO assumes that 500 MW will be available in the real-time market from a given resource, even though that resource was not scheduled in the day-ahead market, will the CAISO consider that resource to be available in its reliability commitment or not? If the CAISO includes that resource in its reliability commitment, it may in effect count the capacity twice, once as available in real-time and then as capacity committed in the reliability evaluation. This would be avoided if this capacity were not included in the reliability evaluation, but what would be the basis for such a procedure that would apparently treat the resources of different suppliers differently?

The CAISO ought to justify this departure from the procedures in place elsewhere and explain why this change would not give rise to either reliability risks or discrimination, as well as creating potential implementation risks. Absent a compelling justification, the CAISO should commit resources using the procedures used in New York and PJM which are more likely to result in a

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[25] It should be noted that the CAISO proposes limitations on the amount of energy it would purchase in the RUC market. § 12.6.12, sheet 184L. Although the tariff language is not clear, the discussion of the RUC process at CDP, p. 109, indicates that the limit on energy purchases is based on minimum load blocks and import energy (system resources). This suggests that the RUC would lock in energy imports paying the full offer price in the day-ahead process. This does not appear to be consistent with the tariff provisions relating to payments to system units, which appear to only provide for a capacity payment (§ 5.12.7.4). This element of the CAISO RUC process needs to be clarified so that the Commission and market participants can understand what is intended.

[26] CDP, p. 107. In particular, it is unclear how the CAISO would define the supplemental bids that are expected to come in, independent of the unloaded capacity of on-line units and gas turbines. The CAISO has described the process as counting unloaded capacity, but in that case the CAISO cannot also make allowance for additional bids, as this is the capacity that would permit those bids.

reliable commitment and avoid creating novel software problems that may delay implementation of day-ahead markets.

RUC Processes without a Day-ahead Market

Aside from the specific rule differences between the CAISO RUC proposal and the reliability processes operating in PJM and New York, there is a fundamental difference in that the PJM and New York processes operate in conjunction with a day-ahead market in which market participants can submit unbalanced supply offers and demand bids, including virtual demand and supply offers at external and internal locations. This enables market participants that use their capacity to hedge bilateral contract obligations to cover these contractual obligations in the day-ahead market, thus avoiding the need to withhold capacity from the reliability process to cover these obligations. If the CAISO implements its RUC process in the fall of 2002 and defers implementation of a day-ahead market until 2003 or later, California market participants will be forced to use other, less flexible mechanisms outside the RUC process to hedge their contractual obligations. The CAISO RUC logic will operate in a fundamentally different manner from the reliability commitment logic employed by PJM and New York, not only because of the different objective function but also because it will operate on top of balanced, rather than unbalanced schedules. The Commission should have no illusions that the CAISO RUC process will produce outcomes similar to those in PJM and New York.

Aggravating the complications provided by the balanced schedule requirement are the bid cap, bid change and capacity payment provisions. The capacity payment provisions also differ from the mechanisms in place in PJM and New York and could also cause the CAISO RUC process to operate very differently from the reliability commitment process in PJM and New York. Some generators might qualify for large capacity payments under these provisions, while others might fail to recover the cost of scheduling gas to be available to burn, while being unable to recover the cost of gas that was not scheduled. These provisions are unlikely to be workable in the long run.

Limiting Participation to ACAP Providers

Once the ACAP market has been activated, the CAISO proposes to restrict participation in the RUC market to ACAP providers.[27] This differs from the PJM and New York markets: in general, the residual commitment procedures used in PJM and New York permit resources that do not provide installed capacity (their analog of the CAISO's proposed ACAP market) to participate, and those procedures make no distinction between bids submitted by installed capacity suppliers and bids submitted by resources that do not provide installed capacity.

CAISO representatives have stated that they wish to limit participation in the RUC market because it is the CAISO's belief that ACAP resources should be providing RUC, but this only supports a rule that would require ACAP providers to offer residual capacity into the RUC market (to the extent this capacity was not previously committed in the CAISO's day-ahead market), not a rule that excludes others from participating. If non-ACAP providers are willing to provide RUC, and are willing to do so at a lower price than ACAP providers, it is inappropriate

[27] CDP, § 5.5.2, p. 107.

for the CAISO to impose restrictions that raise the cost of meeting these reliability constraints by limiting competition.

Instead, the CAISO should procure the capacity needed to ensure that it can meet its forecast of the next day's load at the lowest possible as-bid cost. To the extent that entities with no obligation to bid into this market are nevertheless willing to do so, the CAISO ought to permit them to participate, and to the extent these entities are willing to offer RUC at a lower price than those obligated to offer into this market, the CAISO ought to accept the lower offers.

Retracting Bid Recovery Guarantee Payments to Ancillary Service Providers

The CAISO proposes to make bid recovery guarantee payments to resources selected to provide RUC.[28] These payments will ensure that, in the event that real-time energy market revenues of these suppliers are insufficient to recover their as-bid costs at the levels at which they are dispatched, they will receive a supplemental payment to make up the difference.[29] The bid recovery guarantee payment is intended to ensure that a generator that submits bids to provide energy will at least recover those as-bid costs if it is dispatched to operate by the CAISO. This encourages suppliers to offer their capacity in CAISO markets, increasing competition, liquidity and reliability.

However, the CAISO also proposes to retract this bid recovery guarantee payment in the event that a generator scheduled to provide RUC is scheduled to provide ancillary services in the CAISO's hour-ahead market.[30] It is possible that this provision is motivated by concern that margins that the generator would earn in the ancillary service market might offset energy market losses. Such a concern would warrant taking ancillary service market revenues into account in calculating the bid production cost guarantee but not in imposing restrictions on participation in ancillary service markets. The CAISO proposal would either drive units committed in the RUC process out of the real-time ancillary service market entirely, or would require units committed in the RUC process to submit ancillary service bids that could considerably exceed their incremental costs of providing those services, because the cost to the generator of providing the ancillary service would also need to include loss of the bid recovery guarantee payment. As a result, this proposal would unnecessarily increase ancillary service prices in the hour-ahead market, and would have adverse impacts on market efficiency as ancillary service requirements would not be met at least cost.

Instead, it is recommended that the CAISO adopt the method used by the NYISO and PJM and to calculate the bid recovery guarantee so that the revenues earned from the sale of ancillary services in the hour-ahead market (net of the bids to provide those services) are taken into account when calculating the bid recovery guarantee payment. This mechanism would ensure

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[28] CDP, § 5.5.2, p. 107.

[29] While start-up and minimum generation bids will be constrained to cost-based levels, the definition of "cost" used in this case may not actually reflect the costs that a given unit incurs to start up or to run at minimum generation. Units whose actual costs exceed these proxy levels should be permitted to submit bids that reflect their costs, which in turn will permit them to ensure that the revenues they receive for operating during a given day are at least equal to the costs they incurred in order to operate that day.

[30] CDP, § 5.5.2, p. 108. See also definition of self-commitment period, CAISO's Proposed Tariff Changes, § 5.12.7.1.2.4, Sheet 184N.

that in instances in which margins earned on the sales of ancillary services exceed the losses that a generator would incur from the sales of energy, it receives no bid recovery guarantee payment, thereby addressing the possible CAISO's concerns. But such a generator would still receive a payment if the margins it earns on the sales of ancillary services are less than the losses it incurs in the energy market. The payment would be equal to that generator's losses in the energy market minus the margins it earned in the ancillary services markets. This would ensure that the total revenue it receives, from the energy and ancillary services markets, is at least equal to the cost it bid to provide the energy it was dispatched to provide along with the ancillary services it was scheduled to provide.

Allocation of Uplift Payments

To the extent that the CAISO makes bid recovery guarantee payments to units commitment in the RUC process, it will need to recover these costs through an uplift charge. As described in § 5.12.8.2 of the CAISO's proposed tariff revisions, to the extent that the need to commit capacity in RUC is not attributable to the CAISO's load forecast error, the CAISO will allocate these costs to entities that are short in its real-time market. This is generally the same procedure that the NYISO and PJM use to allocate these costs, and is both fair and provides the proper incentives.[31]

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[31] It should be noted that the CAISO's Comprehensive Design Proposal states that these uplift charges "will be borne by buyers whose load is not scheduled in the day-ahead market." CDP, § 5.5.2, p. 108. The CDP language differs from that in the tariff and implies that all RUC costs would be assigned to net buyers in the real-time market. This would result in several problems if implemented. For example, if units were committed in RUC not because day-ahead schedules from market participants were less than real-time load, but because the ISO's load forecast was ultimately inaccurate, all of the uplift costs would be assigned to the short loads, including the costs of the ISO's misforecast. Allocating uplift charges associated with ISO load forecast error to loads that purchase energy in the real-time market would not only be unjust, but might also be inefficient, as it would give market participants an incentive to schedule more load in the day-ahead market than they would expect to serve in real time. In the extreme, if the CAISO were to commit 3000 MW of capacity in RUC, and the real-time consumption of all but one participant matched their day-ahead schedules, under this rationale, that one participant would bear the costs of the uplift associated with all of the units scheduled in RUC, even if that market participant consumed only 1 MW more than it had scheduled in the day-ahead market. In this circumstance, there is no reason why market participants whose real-time consumption differs slightly from their day-ahead schedules should bear the cost of uplift associated with units committed due to load forecast error.

It is our understanding that, despite the description appearing in the CDP, the tariff language proposed by the CAISO would allocate these uplift costs using a mechanism similar to those used in New York and PJM. The CAISO should affirm that its tariff language reflects the procedure it proposes to use to allocate these costs. Additionally, it appears that there are some minor problems with the formulas the CAISO proposes to include in § 5.12.8.2 of the tariff. In cases in which forecasted load is less than bid load, the formula used to allocate costs appears to have a denominator of zero. And in cases in which dispatchable price-responsive load consumes more in real time than in the day-ahead schedule, it would be unreasonable to assess these charges to this load since resources were not committed to serve this load. Instead, for the purposes of allocating these uplift costs, it should be treated as would generation that was scheduled in the day-ahead market and was available in real time, but which was not dispatched. In general, the CAISO should compare its formulas to those used by PJM and the NYISO to ensure that it allocates these costs as intended in all cases.

C. Real-time Market

Positive Elements of the MD02 Proposal

The CAISO MD02 proposal includes a number of market design changes relating to the real-time market that are a constructive response to past problems and will improve the performance of the real-time market for all market participants. In particular, the proposed elimination of the balanced schedule requirement and market separation in the real-time market, along with the introduction of market-clearing prices under economic dispatch to procure imbalance energy and manage congestion simultaneously[32] will both simplify the operation of the markets coordinated by the CAISO and improve their efficiency, benefiting both consumers and generators in the long run.

The proposal to implement a security-constrained economic dispatch (SCED), fully taking into account all transmission constraints, local reliability needs, loop flows, generators' operating constraints, and imbalance energy needs is also an important and material positive step in the reform of the California market design.[33] Moreover, the intent to move to a dispatch system under which suppliers can actually follow the dispatch instructions they are provided, and the CAISO can reasonably expect suppliers to follow the dispatch instructions they are sent, is an important constructive step for the California market.[34] While not all successful markets require restrictions on uninstructed deviations, this approach has been workable in New York and may, given its history, provide the most appropriate transition path for the California market.

In the short run, the CAISO proposes to implement economic dispatch, provide incentives for suppliers to follow CAISO dispatch instructions, use a single energy price for settlements at each location, and utilize a single bid curve for energy dispatch.[35] These changes are in general moving the CAISO markets in the appropriate direction, but as discussed below, there needs to be greater urgency in breaking with some of the critically dysfunctional elements of the current market design.

Issues

Although the CAISO proposal has many constructive elements, there are several issues that FERC must address. While it is reasonable to provide suppliers with financial incentives to reduce uninstructed deviations, this approach will be workable only if the implementation of these incentives is accompanied by eliminating the causes of uninstructed deviations.[36] First,

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[32] CDP, §§ 5.6.2.1, 5.7.2.1, pp. 111, 114.

[33] CDP, § 5.7.1, p. 113.

[34] CDP, § 5.7.4, p.117

[35] Filing Letter, p. 30-38.

[36] It also needs to be kept in mind that the motivation for these financial incentives should be to motivate suppliers to operate in a manner that reflects the costs imposed on the system by excessive deviations from dispatch instructions. Imposing punitive charges for downward deviations will be counter-productive, because it would effectively tell suppliers that undergeneration imposes very high costs on the CAISO and thus that they should provide the CAISO with conservative performance characteristics for their resources to assure that the supplier will be able to operate in accord with its dispatch instructions.

the CAISO must eliminate all provisions that reflect a viewpoint arising from past balanced schedule requirements—that suppliers will follow their schedules rather than simply following their dispatch instructions, particularly at the end of the hour.

- If a generator has a forward balanced schedule for the current hour but not the next, this does not really mean that the generator's supply is not needed next hour and that it needs to ramp down or be penalized for uninstructed deviations. In reality, the load it is meeting this hour will also be there next hour, and the generator's output should be managed incrementally from interval to interval based on dispatch instructions, not through fictitious changes in hourly schedules.

- Furthermore, if suppliers are to be held accountable for uninstructed negative deviations, then it is essential that suppliers be able to communicate all outages, deratings and operating problems, including deratings attributable to ambient air temperature, tides, and water outlet temperature, to the CAISO, and that the CAISO immediately reflect these changes in its dispatch instructions. This is standard practice in PJM and New York, and while perhaps intended by the CAISO, is not mentioned in the MD02 proposal.

- In addition, suppliers should only be held accountable for uninstructed deviations if the dispatch instructions are consistent with unit operating parameters. It is therefore necessary that the dispatch instructions take account of the ramp rates applicable to each unit at its current operating point.

Second, and most fundamentally, it is essential that the CAISO eliminate the need for uninstructed deviations by eliminating market separation, balanced schedule requirements, and reliance on physical schedules for internal CAISO generation in the real-time market. The reality is that because of the CAISO balanced schedule requirement, there is no mechanism for off-dispatch suppliers to sell energy in the real-time spot market, except as uninstructed deviations. This energy is needed to meet California load and should not be forced out of the market by echoes of the past commitment to market separation and balanced schedules. At a time that California has been short of energy and preoccupied with market power these rules make it difficult or impossible for market participants to supply energy as price-takers. There can be no further delay in reforming these elements of the CAISO market and the CAISO should be required to eliminate balanced schedules and market separation in the real-time market effective October 1, 2002.[37]

If the financial consequences imposed on suppliers for undergeneration exceed the true costs imposed on the system, the CAISO will find that the imposition of the undergeneration penalties reduces available ramp capacity to a degree that imposes greater losses on the system than the benefits provided by reduced undergeneration. This is exactly the past pattern that the CAISO needs to avoid.

Rhetoric about physical withholding misses the reality that any supplier's ability to comply in all circumstances with its dispatch instructions without undergeneration depends on the ramp rate it specifies to the CAISO. The higher the ramp rate specified, the more often the generator will be unable to remain within the allowed band around its dispatch instruction.

[37] That is, the FERC should require that the CAISO accommodate unbalanced real-time schedules from both import suppliers and off-dispatch suppliers as price takers at the real-time price. These suppliers would be obligated to follow their unbalanced schedules, but they would not be required to schedule a bilateral sale to a particular load.

These changes would be consistent with, and simplify the implementation of, the changes proposed by the CAISO relating to the target price and “price overlap.” Rather than a dispatch that will “in effect” “reflect the Dispatch the could prevail in real time [in] the absence of the market separation rule,”[38] the CAISO should simply implement such a dispatch. While it is recognized that during the transition this dispatch will not reflect locational pricing, it is a necessary first step in reforming the CAISO real-time market. This change will also reduce the CAISO’s problems with ramp availability because neither the CAISO nor market participants will be trying to manage the system around artificial end-of-hour schedule changes, but instead dispatching units gradually up and down from interval to interval, without regard to hour-ahead schedules, which will become purely financial. This change in focus will improve reliability, improve market efficiency, facilitate forward contracting, and simplify the market.

Third, the CAISO proposes to base its security constrained economic dispatch on an AC optimal power flow (OPF).[39] This differs from the approach taken in both PJM and New York which base their dispatch instructions on DC models. While there may be system conditions that warrant utilization of an AC OPF in the SCED, the CAISO should report the impact on project timetables of reliance on an AC OPF and justify the need for this approach. It is particularly important that the CAISO be required to justify the need for the AC OPF if part of the prospective delay in implementing SCED and LMP until fall of 2003 or beyond arises from the need to develop and test new AC OPF dispatch tools.

In addition, the CAISO should also be required to identify any intended differences between the proposed dispatch algorithms and those employed in existing LMP markets and justify such changes. For example, the description of the objective function for the real-time dispatch does not appear to correspond to the objective function utilized in New York and PJM, but it is not clear whether the CAISO intends to utilize a different objective function or merely provided a general description that was not intended to signify a change in the structure of the objective function.[40]

D. Ancillary Services Markets

Positive Elements of the MD02 Proposal

Overview

The CAISO MD02 proposal relating to ancillary service markets also has a number of positive elements. First, the procurement of ancillary services in a day-ahead market in which energy and ancillary service schedules are simultaneously optimized based on multi-part bids is a

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[38] Filing Letter, p. 33.

[39] CDP, § 5.7.2.1, p. 114.

[40] The CAISO describes the objective function as minimizing the “cost of imbalance energy” and appears to define the imbalance energy requirement as the sum of the energy required to restore AGC units to their preferred operating points, the forecast change in system load, and scheduled changes in inter-tie schedules (CDP, § 5.7.2.3, pp. 115-116). This criterion is not necessarily the same as minimizing the as bid cost of meeting forecast system load over the next 10 minutes. It is not clear whether the difference is intentional.

desirable reform and will address a number of problems that have hindered the development of California electricity markets. Second, conducting settlements using locational ancillary service prices (to the extent that it is necessary to establish locational ancillary service requirements) maintains and improves upon a good feature of existing CAISO markets. Third, the retention of capacity bids for ancillary services in the day-ahead markets is appropriate and enables market participants to accurately reflect their costs in their bids. Fourth, the proposed price determination mechanism based on capacity bids and opportunity costs as determined in the day-ahead market is a desirable reform that will eliminate the need for suppliers to submit bids reflecting guesses regarding the level of opportunity costs in the day-ahead market.

Simultaneous Optimization

The CAISO proposes that under the MD02 proposal, ancillary services would be procured simultaneously with energy.[41] The procurement of ancillary services in day-ahead markets in which energy and ancillary services are simultaneously optimized will improve the performance of the California electricity market and benefit both consumers and suppliers. The introduction of simultaneous optimization and three-part bids will both increase market efficiency and reduce the potential for the exercise of market power, because the CAISO will be provided broader product substitution possibilities in a market in which generators are permitted to submit multi-part bids and leave the unit commitment decision to the CAISO, knowing that if committed they will be assured of recovering their as bid costs. The elimination of the “rational buyer” rule will also benefit consumers by eliminating the economic inefficiency introduced by efforts to price discriminate among suppliers.[42]

Suppliers will also benefit from the elimination of the economic inefficiency introduced by the rational buyer rule and from the increased efficiency of a market based on three part bids and avoidance of uneconomic commitment decisions. Both consumers and producers will also benefit from a market structure in which normal competitive behavior is less likely to be confused with the exercise of market power.

Locational Ancillary Service Requirements

The MD02 proposal provides for the possibility of locational ancillary service requirements and provides for locational ancillary service prices in this event.[43] To the extent that reliability criteria give rise to locational ancillary service requirements, it is necessary and efficient to reflect these constraints in the day-ahead unit commitment process and to settle ancillary service procurement at corresponding locational prices. This is consistent with current practice of the NYISO, which also has locational ancillary services requirements that are binding at times.

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[41] CDP, § 5.4.2, p. 105.

[42] The economic reality is that rather than depressing average ancillary services prices below the competitive level, the more likely effect of the “rational buyer” rule is to change the way ancillary service suppliers bid, and to raise costs by reducing market efficiency. Since reductions in market efficiency are ultimately reflected in higher prices for consumers, the dominant effect of the rational buyer rule has likely been to raise consumer prices.

[43] CDP, § 5.4.2, p. 105.

Capacity Bids for Ancillary Services

The CAISO proposes to continue to allow suppliers to submit capacity bids for ancillary services, in additional to energy bid curves.[44] This is consistent with current CAISO practice and permits suppliers to reflect in their bids the costs that a market participant may need to incur in order to supply reserves or the cost penalties (e.g., reduced heat rate efficiency) that a market participant would incur in providing regulation.

Ancillary Services Price Determination

The MD02 proposes that ancillary service prices will be set based on capacity bids and opportunity costs determined in the day-ahead market.[45] This change in ancillary service pricing is a desirable reform that will eliminate the need for suppliers to submit bids reflecting their guesses regarding the level of opportunity costs in the day-ahead market. This change will benefit both producers and consumers by increasing the efficiency of the market. While this pricing mechanism for ancillary services is different from that currently employed by either the NYISO or PJM, it is consistent with the pricing mechanism that is likely to be in place in the NYISO by the time MD02 is implemented.[46] In practice, it would likely speed rather than delay implementation.[47]

The MD02 proposal provides that as today, higher-quality services can substitute for lower-quality services,[48] which is desirable. However, the proposal is unclear as to whether the pricing of different categories of operating reserves would recognize that 10-minute spinning reserves count towards 10-minute reserves, and should therefore be paid at least as much as providers of 10-minute non-spinning reserves. Likewise, 10-minute reserves count towards 30-minute reserve requirements, so providers of 10-minute reserves should be paid at least as much as providers of 30-minute reserves. This approach to calculating operating reserve prices is sometimes referred to as the cascading of prices.

Issues

The CAISO MD02 proposal for ancillary service procurement and pricing appears to largely be heading in the right direction as described above. There are, however, a number of ambiguities

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[44] CDP, § 5.4.2, p. 105.

[45] CDP, § 5.4.2, p. 105. The explanation of the determination of ancillary service opportunity costs needs to be clarified as the discussion of the example suggests that the CAISO might envision setting ancillary service prices based on average, rather than marginal, opportunity costs. Such an approach would be problematic, as it would motivate suppliers lacking market power to reduce the quantity of reserves or ancillary services they offer the CAISO.

[46] See, for example, materials listed under the May 9, 2002 meeting at http://www.nyiso.com/services/documents/groups/bic_mkt_struct_group/meeting_materials.html.

[47] The NYISO day-ahead market software already has the capability to calculate ancillary service shadow prices that reflect the combined capacity bid and opportunity costs of the marginal supplier, so moving directly to such a pricing system would not require new software development and would avoid the need to develop alternative processes.

[48] CDP, § 5.4.2, p. 105.

in the intended approach that ought to be addressed to enable market participants and the Commission to evaluate the consistency of the overall market design and avoid future problems. Some of these high-level ambiguities are:

- Will the MD02 ancillary services markets be based upon a two-settlement system?
- Will there be a market or process between the day-ahead market and real-time for adjusting ancillary service schedules to reflect changes in resource availability and opportunity costs?
- Will ancillary service prices will be "cascaded" as in New York, or is some other pricing method intended?[49]

Hopefully, the CAISO's answer to all of these questions will be yes.

E. FTRs

Positive Elements of the MD02 Proposal

The CAISO has proposed to define and allocate financial transmission rights called FTRs that will hedge nodal congestion charges.[50] Financial transmission rights are an important element of markets based on LMP pricing, and are used in the markets in this country where LMP is currently utilized (PJM and New York). Financial transmission rights are also included in the market designs in other areas that plan to adopt LMP, such as New England and the MISO. The FTRs that the CAISO proposes are in many ways similar to the financial transmission rights that are currently available or will be available in these other markets. As in these regions, each point-to-point FTR offered by the CAISO will be defined by an injection location and a withdrawal location. The holder of that FTR will receive the day-ahead LMP calculated at the withdrawal location minus the day-ahead LMP calculated at the injection location for each hour in which that FTR is valid.[51]

The CAISO's proposed system of FTRs shares many of the advantages of the systems of financial transmission rights utilized in PJM and New York. The CAISO will calculate transmission usage charges in the day-ahead market by subtracting the day-ahead congestion price for that hour at the location at which the transmission customer schedules an injection of power in the day-ahead market from the day-ahead price for that hour at the location at which the transmission customer schedules a withdrawal of power.[52] This pricing system will enable FTRs to provide a hedge against these transmission usage charges, since the payment to the

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[49] Cascading of ancillary service prices appears to pay ancillary services more than would otherwise be the case, given their bids, but it causes ancillary service suppliers to change the way they bid and makes cost based bids more attractive. This benefits consumers by increasing market efficiency, avoiding gaming, and making it easier to identify the exercise of market power.

[50] CDP, § 5.3.1, p. 89.

[51] The discussion in this section assumes zero losses. With non-zero marginal losses included in LMP prices, then the holder of an FTR would only receive payments reflecting the difference in these LMPs attributable to transmission congestion.

[52] CDP, § 5.3.2.1, p. 90.

holder of an FTR between two locations would exactly offset the transmission usage congestion charge that a transmission customer would pay for transmission service between the same points. This provides market participants with a mechanism that they can use to hedge against volatility in transmission usage charges attributable to transmission congestion.

The CAISO does not propose to limit the injection and withdrawal locations between which FTRs will be available to nodes, and also proposes to permit FTRs to be awarded to or from aggregations of nodes, such as zones used for the purposes of pricing load and hubs used for trading purposes.[53] It will therefore be possible to use FTRs to hedge congestion cost volatility associated with a wide variety of transactions.

FTRs will permit entities currently receiving service under existing transmission contracts to be included in the LMP market while continuing to receive the economic benefits provided by the firm transmission service under the pre-LMP contracts. An entity with a contract to receive 100 MW of firm transmission service from location A to location B would be able to convert that firm transmission service to 100 MW of FTRs from location A to location B. Ownership of these FTRs would permit the transmission customer in effect to deliver energy from A to B without paying for congestion or, alternatively, to pay the cost of 100 MW of energy at location A for energy delivered to location B.

FTRs also can be used to mitigate the exposure to high prices that might come about as a result of the pricing of additional constraints either through zonal pricing or under LMP. For example, the LMP prices in a load pocket may at times be high as a result of transmission congestion, but if those loads held the FTRs between a location outside the load pocket and a location inside the load pocket, they would be insulated against paying those high LMPs for the portion of their load that is met with imports. Thus, although these loads would pay prices reflecting congestion costs on all of their load, ownership of FTRs in effect would enable loads in load pockets to be hedged so that on net they would pay the average cost of meeting their load.[54]

FTR payments will be made to market participants regardless of whether they have scheduled matching injections and withdrawals—or any transactions—in the market. As a result, FTRs leave the incentives provided on the margin by LMP in place, because the payment that each FTR holder receives is independent of the FTR holder's transmission usage, and in particular, is independent of its generation dispatch. An entity that has 600 MW of FTRs from A to B, for example, will have a hedge for the cost of transmitting 600 MW of energy from A to serve load at B, but the marginal cost that it faces for serving an additional MW of load will be the LMP at B, because the FTR payment that it receives is independent of whether it serves the load at B or how it serves the load at B. Consequently, the incentives that LMP provides for generators to locate in locations with high LMPs, and for loads to locate in locations with low LMPs, will not be distorted by the ownership of FTRs.

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[53] CDP, § 5.3.2.1, p. 90.

[54] For example, during a congested hour, if 2000 MW of load in a load pocket held 1000 MW of FTRs from a location outside its load pocket, it would pay the LMP inside the pocket—which would be relatively high, reflecting the high-cost generation in operation there due to congestion—for 1000 MW of power that must be generated within the pocket. But, after taking its FTR revenues into consideration, it would only pay the lower LMP calculated outside the load pocket for the remaining 1000 MW. The average amount that load inside the load pocket would pay would be the average of the LMPs inside and outside the pocket, reflecting the fact that half of the energy to meet that load must be generated inside the pocket, while the other half can be generated outside the pocket.

In particular, because FTR holders will receive payments for their FTRs regardless of whether injections and withdrawals match their FTRs, FTR ownership will not affect the incentive of generators to follow the ISO's dispatch instructions. In addition, the financial character of FTRs will permit them to be used to hedge the congestion costs associated with financial hedging contracts such as contracts of differences, enhancing the liquidity of forward markets. This feature of FTRs will also help ameliorate the problems with existing transmission contracts (ETCs) in California. The use-it-or-lose-it features of the current ETCs make it undesirable for ETC holders to release their capacity to the market, since they will not be compensated for what they are giving up. If the ETCs are converted to FTRs, the ETC holders will be assured that they will receive the economic value of their ETCs, while other market participants will benefit from the earlier release of ETC capacity.[55]

FTRs should not impose significant financial risks upon the rest of the market, because the revenues that the CAISO collects as part of operating a market based on LMP pricing will fund the amounts that it needs to pay to FTR holders, as long as the set of FTRs awarded on the grid meets a simultaneous feasibility condition[56] and actual transfer capability is not less than that assumed when FTRs were defined.

FTRs will be tradable rights, which will enhance market liquidity and will increase the likelihood that the hedges are held by the parties that value them most highly. In addition, they will provide a mechanism to award well-defined property rights to entities that finance transmission expansions. Since the number of FTRs than can be awarded is limited by the transfer capability of the network, expansions of the network can increase the number of FTRs that can be awarded, and those FTRs can be awarded to the entity financing the expansion. This can help to provide the basis for an alternative to the traditional regulatory approach to financing transmission expansion by permitting merchant developers to shoulder the risk associated with an expansion.

Finally, FTRs would be offered in an auction, which would permit FTRs to be awarded to the entities that place the highest value on those FTRs and ensures that all FTRs are made available.

Comparison to Procedures Used in New York and PJM

While the FTRs that the CAISO proposes are similar to those used in PJM and New York, there are a few differences. Most significant is that the CAISO's proposed FTRs have a physical dimension. In the MD02 proposal, FTR holders would get scheduling priority over other participants in the energy market that did not submit bids.[57] In addition, FTRs would be required

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[55] The transition to the operation of the NYISO in New York, and the imminent implementation of LMP in NEPOOL both provide precedents for the conversion of physical rights to financial rights. The holders of physical transmission rights in New York were offered the opportunity to convert their physical rights to financial transmission rights and many have done so. Website: http://www.nyiso.com/services/documents/tcc/tccprimehldrs01.pdf. Similarly, the transmission rights of municipal systems in NEPOOL will be converted to auction revenue rights with the implementation of LMP by ISO-NE. SMD, § 7, p. 55.

[56] CDP, § 5.3.2.4, p. 96 and § 3.1, p. 89.

[57] CDP, § 5.3.2.1, p. 90. As discussed below, part of the motivation for the physical right may be the effects of a low damage control bid cap, but making FTRs physical during tight conditions may undo much of the value of the proposed reforms.

to deliver ACAP from one area to another.[58] In both PJM and New York, FTRs are purely financial instruments, which do not convey any preferential rights to schedule energy or to deliver capacity.

Additionally, the mechanism that the CAISO will use to allocate FTRs is unclear.[59] New York and PJM use quite different mechanisms. The NYISO allocates FTRs (called TCCs in New York) to entities with grandfathered transmission contracts, but all other FTRs are auctioned. Utilities that had historically used transmission to serve their native load can purchase TCCs in this auction, and have a right to revenues in this auction that would offset the cost of their purchases. These revenue rights have been fixed in advance. Meanwhile, PJM allocates FTRs to LSEs that have purchased firm point-to-point or network service, based upon the location of the generators that each has designated as a capacity resource and the location of the load served by that LSE. This allocation is re-performed each year, subject to grandfathering rules. PJM also auctions FTRs, but only those FTRs that can meet the simultaneous feasibility test after taking into account the capacity needed to support previously allocated FTRs are available in this auction.

The MD02 proposal states that the CAISO, when operating the FTR auction, will have the objective of maximizing revenue realized in that auction.[60] This differs from the objective function used in the NYISO and PJM auctions, which is to maximize the value of FTRs awarded to entities that purchase FTRs in the auction, as measured by their bids.[61] While the NYISO or PJM is operating as an auctioneer, it is merely trying to facilitate a competitive market, and the objective function each is using reflects this, as one would expect that in a competitive market, gains from trade (the amount that buyers were willing to buy for the amount they bought, minus the amount that sellers were willing to accept for the amount they sold) would be maximized. The CAISO's objective function, in contrast, calls for the CAISO to operate the auction as would a monopolist attempting to maximize revenues.

The CAISO's discussion of both FTRs and flowgate rights in Appendix A is useful and supports beginning the transition with point-to-point obligations. However, the analysis in part reflects possible misunderstandings about the nature of the various rights. For example, the discussion of the benefits of FTRs defined as obligations refers in several places to obligations allowing more schedules to "flow." FTRs are financial and have no impact on schedules that can flow either day-ahead or in real time.[62] Perhaps the reference was intended to refer to the schedules that could be hedged rather than those that would flow. This is correct. Defining FTRs as obligations will allow the sale of forward hedges that more closely reflect the actual transfer capability of the system than would FTRs defined solely as options. On another point, if the assertion that the "cost of [PTDF] insurance to other participants or the ISO of fulfilling the

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[58] CDP, § 5.1.7.23, p. 60.

[59] CDP, § 5.3.2.1, p. 92.

[60] CDP, § 5.3.2.8, p. 98.

[61] If entities offering FTRs are permitted to state prices below which those FTRs would not be sold, then this objective function would be restated as maximizing the value of FTRs awarded to entities that purchase FTRs in the auction, as measured by their bids, less the amount that FTR sellers required in order to sell their FTRs, as measured by their offer prices.

[62] CAISO, Appendix A, p. 3.

obligation inherent in such insurance could be substantial for major network changes"[63] is intended to refer to the effect of transmission upgrades, this is either an error reflecting a common misunderstanding about the simultaneous feasibility test and revenue adequacy or refers to some cost of which we are not aware.[64] Finally, the discussion of the claimed advantages of flowgates on one page is contradicted by the discussion on the following page of the disadvantages on the same issues.[65] Both cannot be true, and in virtually every case the analysis of the disadvantage is supported by the available evidence.

The CAISO also discusses the possibility of offering flowgate rights, which would pay their holder the cost of congestion across a specific interface or transmission facility, and of offering point-to-point FTR options, which would pay their holder the price at the FTR's withdrawal location minus the price at the FTR's injection location only when that difference is positive.[66] Neither the PJM nor the New York markets currently offer flowgate rights or options (although the feasibility of offering options is being explored in each locations, and the Ontario IMO is currently offering options across interties connecting Ontario to adjoining control areas). The CAISO proposes to defer flowgate rights for the initial implementation, and only to offer FTR options if technical considerations permit.[67]

Significance of the Differences and Recommendations

Bundling FTRs together with scheduling priority, or the ability to deliver ACAP or ancillary services from one area to another, causes a number of problems.

- It discriminates against those market participants who want only a financial hedge, or only scheduling priority, or only the ability to deliver ACAP or ancillary services, because it forces them to acquire a bundle of rights, even though they may only really want part of that bundle. This leads to inefficiency as a result, because bundling financial hedges with these other rights may preclude the entities that really want hedges from getting them, or the entities that really want those other rights from getting them.

- It will potentially motivate market participants to submit self-schedules that match their FTRs, and thus make themselves unavailable for redispatch, in precisely the circumstances in which the CAISO will want generators to be flexible so as to permit the CAISO to best manage congestion. As discussed below, this impact will likely be aggravated if the damage control bid cap is set at a relatively low level.

- Finally, the number of FTRs that can be defined from one location to another may differ from the amount of ACAP or ancillary services that can be delivered between those locations.

[63] CAISO, Appendix A, p. 4.

[64] For further details, see William W. Hogan, "Financial Transmission Right Formulations," Center for Business and Government, Harvard University, March 31, 2002.

[65] CAISO, Appendix A, with the advantages claimed on page 13 contradicted by the disadvantages on page. 14.

[66] CDP, § 5.3.2.1, pp. 90-91.

[67] CDP, § 5.3.2.1, pp. 90-91.

The CAISO should follow the practice in New York and PJM and define FTRs as financial instruments only. To the extent that locational constraints bind in the ancillary services or ACAP markets, the CAISO has already proposed pricing ancillary services to reflect these constraints. It could define locational requirements for ACAP, as the NYISO does for its installed capacity requirements, and it could calculate prices that reflect locational constraints if it were to operate ACAP markets. And to the extent that there is a need to allocate scheduling priority for units that have not submitted bids, the CAISO should consider auctioning that service as well (although this problem may largely disappear if the damage control bid cap is set at a higher level, which is discussed later in this paper).

The CAISO should fix whatever allocation mechanism it uses for allocating FTRs in advance. Failure to do so can undermine the incentives provided by LMP. As we discussed above, it may be reasonable to allocate FTRs that are more valuable to LSEs that purchase energy in high-LMP locations, and thereby incur significant congestion cost, because this will help insulate them against this congestion cost—but this allocation should be determined in advance. If this allocation is periodically revised, so that an entity that incurred significant congestion costs last year receives more valuable FTRs this year, the incentives not to consume energy in high-LMP locations are undermined. Similarly, if FTRs are allocated based on the location of each LSE's designated capacity resources, and those designations can change from year to year, then generators that locate in locations in low LMPs will be more valuable as capacity resources, because the FTRs that specify their locations as injection locations will be more valuable. This incentive for generators to locate in low-LMP locations would partially offset the incentives that use of LMP in the energy market provides for generators not to locate in such locations.

The CAISO should adopt the objective function used by the NYISO and PJM when it conducts its auction of FTRs. This would be consistent with a mandate to operate electricity markets in a fair and independent manner that does not discriminate against any market participant or class of participants. The CAISO may have inadvertently incorrectly described in the MD02 filing the objective function that it plans to use. The objective functions used in the New York and PJM markets are sometimes incorrectly described as "maximizing revenue from the sale of FTRs," so this may be merely a misunderstanding and the CAISO may intend to operate its FTR auctions consistently with those in PJM and New York. If so, it should correct its proposal to reflect this.

Additionally, while the CAISO has stated that FTRs cannot be used to hedge against real-time prices, participants in the New York and PJM markets can settle FTRs against real-time prices merely by submitting schedules matching the FTR in the day-ahead schedule. The holder of an FTR from location A to location B, for example, can schedule a matching transaction from A to B in the day-ahead market, in which case the transmission usage charges it would be charged (ignoring the effect of marginal losses) would exactly offset the FTR payments it would receive. If it then did not consummate this transaction in the real-time market, as would be the case if its generation were backed down in the real-time dispatch, or if its transaction became uneconomic, it would be paid the real-time price at location B for the energy it was scheduled to withdraw there in the day-ahead market, minus the real-time price at location A for the energy it was scheduled to inject there in the day-ahead market. The net outcome is that it would receive the real-time price at location B minus the real-time price at location A—just what it would receive if the FTR were settled against real-time prices It is assumed that California market participants would have the same opportunity under MD02.

F. Market Power Mitigation

Overview

An effective program of market power mitigation that prevents the exercise of market power without interfering with efficient and rational system operation and without preventing prices from providing efficient incentives is an important part of any well-designed market. Even in a generally competitive market, transmission constraints that may prevent capacity in one location from generating energy to meet demands at other locations give rise to opportunities for the exercise of locational market power. In order to protect against the exercise of market power on the supply side of the market, market power mitigation program must protect both against the physical withholding and the economic withholding of generation. A generator that is physically withholding capacity might state that some of its generating capacity is unavailable even though the capacity could operate, making it necessary to schedule or dispatch higher-cost capacity, which would drive up prices paid to the remaining resources. A generator that is economically withholding capacity would make that capacity available, but at inflated offer prices, in the hope that some or all of that generation would not be scheduled or dispatched, again raising prices paid to the remaining resources. As a result, a market power mitigation program should consider both physical and economic withholding.

At the same time, it should not be the purpose of a market power mitigation system to simply lower prices by requiring that suppliers offer their output into the market at offer prices that do not reflect their costs. Similarly, a well designed market power mitigation system would not prevent prices from rising to levels that reflect shortage conditions, and would provide incentives for needed generation to enter and remain in the market.

Description of Proposal

The CAISO's proposed package of market power mitigation measures include both methods to address physical withholding (the must-offer provisions)[68] and economic withholding (the local market power mitigation mechanisms, RMR, and the AMP).

- Must-offer requirement. Generators within California (other than those that are on outage) are required to offer their capacity into the CAISO's markets. All participating generators are required to offer available non-hydro capacity in the RUC process, while all on-line capacity and generating units with a start-up time of ten minutes or less must be offered in real time.[69]

- Local market power mitigation. In the event that it is necessary to dispatch generation out of merit within zones NP15, SP15 and ZP26 as a result of transmission congestion, the units dispatched out of merit will be subject to bid caps. In most cases, those caps will be based on the unit's short-run variable costs.[70]

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[68] In addition, changes made to outage coordination and reporting requirements, as well as generator maintenance standards under development by the CPUC, will have an impact on physical withholding.

[69] CDP, § 7.2.3, p. 155; CAISO's Proposed Tariff Changes, § 5.11.4, p. 184B.

[70] CDP, § 5.9.2, p. 134.

- Reliability Must-Run (RMR) Contracts. In cases in which certain units have local market power, the CAISO has negotiated contracts with those units which call for them to offer power at a specified price whenever the intra-zonal constraints are binding. These contracts will apparently remain in place for a number of years.[71]

- Automated mitigation procedures (AMP). The CAISO will apply the AMP to its forward markets, when they are instituted, and to its RUC market for the Fall 2002 implementation of MD02. Under the AMP, the CAISO will compare the bids submitted by each generator segment to a reference price for that segment.[72] If the bid exceeds the reference price by a conduct threshold to be established by the CAISO, that segment will be deemed to have violated the AMP's conduct test. The CAISO will then compare the energy prices that it would calculate using the offer prices that were submitted to it to the energy prices that it would calculate if all offer prices that violated the conduct test were replaced by their respective reference prices. If the decrease in prices that results when all offer prices that violate their conduct test are mitigated (i.e., are replaced by their respective reference prices) exceeds an impact threshold defined by the CAISO, the offer prices exceeding would be mitigated before the schedules and prices for the relevant markets are calculated and posted.[73]

In addition, the CAISO also proposes the following measures:

- A damage control bid cap (DCBC). The DCBC would limit offer prices into the CAISO's markets to $108/MWh (this floor for the cap would be increased based on an index of natural gas prices, using the mechanisms currently used by the CAISO to implement the current mitigation mechanisms). It is a "hard" cap, meaning that it applies regardless of a generator's actual costs.[74]

- Competition index. The competition index establishes a benchmark, which appears to be the CAISO's estimate of prices that would be observed in a perfectly competitive market with creditworthy purchasers. If prices actually observed in the market exceed prices calculated by the benchmark by more than $5/MWh, calculated on an annual basis, then the CAISO would have the authority to implement various other mitigation measures, including reinstating the west-wide mitigation measures with cost-based bid caps for as long as six months.

Moreover, there are at present extensive forward contracts that define the price and terms upon which much power is offered into the California market.

Positive Elements of the MD02 Proposal

The CAISO's AMP proposal is derived from the NYISO's AMP, which attempts to target market power mitigation to circumstances in which market power has a significant impact on market

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[71] CDP, § 5.1.4.3, pp. 51-52, and § 5.1.12, pp. 69-70.

[72] CDP, § 5.11.2.2, pp. 140-141.

[73] CDP, § 5.11.2.1, p. 139.

[74] CDP, § 5.10.2, p. 136.

prices. Mechanisms such as the NYISO's AMP recognize that there is a cost to imposing mitigation and attempt to limit mitigation to circumstances in which bidding behavior appears to have been consistent with an attempt to increase prices through the use of market power and to avoid mitigating offer prices in a manner that would interfere with efficient operation. In addition, the AMP approach as employed by the NYISO is structured to permit prices to rise to the level of the damage control bid cap in a shortage.

On a broad, conceptual level, the further use of other indicators such as the proposed competition index to gauge health of the market and the success of the market power mitigation program, and to consider whether changes to that program are needed, is generally reasonable. The natural benchmark that one would use to gauge the competitiveness of a market is the degree to which prices in that market approach the prices one would expect to see in a perfectly competitive market. The greater the difference between actual prices and this theoretical benchmark, the greater the concern that market power may be the cause of the divergence, calling for more stringent measures to mitigate that market power. However, it is not a simple matter to estimate competitive prices. Broad indices that may, or may not, provide a good proxy for the competitive price level should provide guidance for further analysis, but not triggers for automatic mitigation.

Comparison to Procedures Used in New York and PJM

The differences between the supply-side mitigation measures in place in New York and PJM and the mitigation measures included in the MD02 proposal can be categorized in two ways. The first difference is the number of distinct mitigation mechanisms proposed by the CAISO. New York uses the AMP, as well as other mitigation mechanisms to deal with locational market power issues in New York City. It does not have additional locational market power mitigation mechanisms such as those proposed by the CAISO, which are patterned after the mitigation procedures used in PJM, although its measures to deal with market power in New York City perform a similar function. PJM has localized mitigation procedures similar to those proposed by the CAISO, but it does not have the NYISO's broad-based AMP. But neither New York nor PJM has implemented a competition index and trigger along the lines of that proposed by the CAISO. Moreover, the New York and PJM market power mitigation mechanisms operate in the context of a full day-ahead market.

The second area of difference is in the specifics of each of these mitigation mechanisms. Although elements of the CAISO's market power mitigation proposal emulate the practices in NYISO and PJM, they have been significantly altered. In almost all cases, when there is a difference between the MD02 version of a mitigation procedure and the version of that procedure that is used in New York or PJM, the MD02 version is the more restrictive, and more likely to mitigate offer prices in circumstances in which market power has not been exercised.

Must-Offer Requirement

The NYISO defines threshold levels for physical withholding. If a generator does not offer all of its energy, but the energy it did not offer fell below this threshold, the penalties that the NYISO has defined for physical withholding will not be applied. Additionally, these penalties will not be applied if physical withholding in excess of the threshold level does not have a significant impact on prices.[75]

Local Market Power Mitigation

The local market power mitigation mechanism proposed by the CAISO appears to be patterned after a mechanism used by PJM to mitigate when there is localized market power. However, there are several differences between the MD02 version of this mitigation procedure and the PJM version:

- When PJM mitigates offer prices under this procedure, it usually mitigates offer prices to a level that represents their estimated costs plus ten percent, while the MD02 proposal does not include this ten percent buffer.

- In recognition of the fact that some units must include opportunity costs in their bids, PJM will mitigate offer prices for some units to a negotiated price level instead of using the cost-plus-ten-percent bids for those units.[76]

- PJM has determined that its markets will remain workably competitive even if any of three major interfaces within PJM are constrained, and so it does not mitigate offer prices if the only binding constraints are one or more of these three interfaces. The MD02 proposal contains no such exceptions, and may mitigate all offer prices within a large region whenever one unit is dispatched out of merit within that region.

- PJM excludes new generators from mitigation under these mechanisms, under the rationale that the entry of generation can only improve any existing market power problems, as the most the owner of that generation can do is to withhold all of the new generation—which is equivalent to not having built the generation in the first place. The MD02 proposal contains no such exceptions.

The NYISO's mechanisms for mitigating local market power differ significantly. The NYISO mitigates the offer prices for generation in New York City that was previously owned by Con Edison subject to provisions that were developed prior to the sale of that generation and before the NYISO took operational control of the grid in New York. Under those legacy provisions, offer prices of these generators are automatically mitigated whenever the price of energy in New York City exceeds 105% of the price calculated at Indian Point, north of New York City. This is intended to ensure that mitigation is applied whenever congestion exists on the cables that feed into New York City from Westchester but would not be applied if there is no congestion on this interface and generators in New York City must compete with all generators East of Central East.

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[75] Both PJM and New York require providers of installed capacity to offer energy into their day-ahead markets. However, our focus here is on must-offer provisions that apply independent of whether a resource has offered into other obligations to offer energy, such as the installed capacity markets in PJM and New York or the proposed ACAP market in California.

[76] A third option also exists, under which PJM would mitigate offer prices to an estimate of the market value of the power that would be produced by that unit segment. However, this option is rarely used in practice.

The NYISO proposed minor modifications to this mechanism in a filing that was recently approved by the Commission.[77] That filing included a mitigation mechanism for generators in New York City in real time that would be similar to the AMP used in the day-ahead market there. This real-time in-city mitigation uses a lower conduct threshold than that in the day-ahead AMP, and does not use an impact threshold, due to the impracticality of performing an impact test in the real-time market. Finally, the NYISO's filing indicated that the NYISO plans to develop a replacement for the current mitigation procedures for generators in New York City in the day-ahead market. The replacement would be similar to the AMP that is used for statewide markets and the real-time mitigation procedures for New York City.

Reliability Must-run Units

In both PJM and New York, individual transmission owners have contracts with generation owners that apply when those generators are necessary to manage constraints that are not managed by the ISOs for those areas.

AMP

The AMP included in the MD02 proposal is described as based on the AMP used by the NYISO.[78] However, there are many material differences between the MD02 version of this mitigation procedure and the NYISO version.

The NYISO's reference prices are adjusted daily so that they will reflect fuel prices, pipeline costs, local transportation costs, and allowance costs as accurately as possible, with the shortest possible lag. The CAISO states that reference prices will be adjusted for gas prices (for gas-fired units), but it does not state the mechanism that will be used to perform this adjustment. Elsewhere, the CAISO proposes to use the procedures applied to calculate reference prices for the current west-wide mitigation procedures to index the DCBC, leading one to think that this procedure might also be used to index reference prices. The procedure currently used for the west-wide mitigation uses monthly gas indices instead of daily indices, and may not include other costs such as those listed above.

In cases in which the reference price that would be calculated using competitive bids or estimated costs would not fairly represent a generator's cost, the NYISO permits the generator to petition for review of that price. If a generator presents evidence acceptable to the NYISO that the reference price in fact no longer fairly represents its costs, the NYISO will modify its reference price. This, in effect, permits suppliers to prejustify charges in offer price patterns that reflect legitimate changes in conditions. The MD02 proposal contains no mention of any such process for review of a reference price.

[77] Compliance Filing of the New York Independent System Operator, Inc. Regarding Comprehensive Market Mitigation Measures and Request for Interim Extension of Existing Automated Mitigation Procedure, March 20, 2002, Docket Nos. ER01-3155-002, ER01-1385-070 and EL01-45-009. This filing was approved at the Commission's meeting on May 30, 2002. At the time of this writing, the Commission's written order was not available, so it is not possible to address modifications to the NYISO's filing that the Commission may have ordered.

[78] CDP, § 1.3, p. 17.

The NYISO sets a conduct threshold for offer prices triggering mitigation of either the lesser of 300 percent of the reference price or $100/MWh. (In the case of start-up bids, the conduct thresholds are 200 percent of the reference level.) The CAISO's conduct thresholds are significantly lower: the lesser of 100 percent of the reference price or $50/MWh. Likewise, the NYISO sets an impact threshold for the impact of unmitigated offer prices on LMP prices of the lesser of 200 percent of the LMP at a location or $100/MWh. Again, the CAISO's impact threshold is significantly lower: the lesser of 100 percent of the LMP at a location or $50/MWh.

The NYISO has a minimum price screen, below which it does not apply mitigation. If the energy price that it calculates without mitigating any offer prices is less than $150/MWh everywhere in the New York Control Area, it does not proceed to determine which offer prices have exceeded the conduct threshold or whether mitigating those offer prices would cause a decrease in prices that exceeds the price threshold. Instead, it does not mitigate offer prices in these circumstances. The CAISO proposes no such minimum price screen.

The NYISO exempts hydro resources from AMP mitigation, because such resources need to be able to submit offer prices reflecting their opportunity costs, these opportunity costs may change significantly over time (making offer prices that have been accepted over the last 90 days an inappropriate reference price), and the NYISO has no good way of assessing what those opportunity costs are. This is consistent with the intent of not interfering with the efficient and rational operation of the grid. The MD02 proposal contains no such exemptions.

The NYISO also exempts imports from mitigation. The exemption of imports is partly driven by the recognition that imports are also likely to include opportunity costs in their offer prices. In addition, it recognizes practical limitations on the NYISO's ability to mitigate. The NYISO has no way to identify the specific resources that are supplying an import, and the source could be the PJM or ISO NE spot market. The CAISO apparently would subject import offer prices to its version of the AMP, but does not propose any mechanism for identifying the resource supporting the import offers. Moreover, there should be a presumption that import supply is competitive if there are no transmission constraints on imports and imports are the marginal source of supply whose offer price determines market prices. The exemption by the NYISO of import supply offers from AMP mitigation is therefore consistent with purpose of the NYISO AMP, which is to limit the exercise of market power, not to suppress prices during shortage conditions.

The NYISO also exempts capacity scheduled to provide operating reserves and regulation from mitigation. This capacity is exempted from price mitigation by the AMP to minimize the extent to which the AMP inefficiently mitigates the offer prices of energy limited units, while preventing owners of energy-limited units from potentially exercising market power by withholding their capacity from the market. This is also consistent with the objective of preventing the exercise of market power while not interfering with the efficient and rational operation of the grid. The MD02 version of the AMP apparently contains no exemption for units providing ancillary services, which will magnify the economic inefficiency and potentially adverse reliability consequences of inappropriate mitigation of the offer prices of energy-limited units.

Finally, the NYISO exempts generators with a portfolio of less than 50 MW from its AMP, in the belief that generators with such small portfolios will generally be unable to exercise market power. The MD02 proposal contains no such exception.

As mentioned above, the NYISO also proposed a number of modifications to its AMP in a filing that was recently approved by FERC. The NYISO proposed temporal and spatial selectivity provisions, which would limit the application of the AMP to times and locations at which energy prices were significantly affected by the exercise of market power. Incremental energy offer prices in the day-ahead market would only be mitigated in the specific hours in which the impact on prices exceeded the impact threshold.[79] In cases in which transmission constraints are binding and the impact threshold is only exceeded in parts of the New York Control Area, offer prices would only be mitigated in the areas in which the impact threshold was exceeded and all downstream areas, given the prevailing pattern of energy flows and congestion in New York. The MD02 version of the AMP contains no such provisions, and as a result may mitigate offer prices throughout the state throughout the day when the impact threshold is exceeded within one transmission-constrained load pocket for one hour.

The NYISO also proposed never to mitigate energy offer prices below $25/MWh, so as to ensure that its 300 percent conduct threshold would not trigger mitigation of a unit increasing its bid from a very low level to a slightly higher level (e.g., from $3/MWh to $15/MWh). Such small increases in offer prices are unlikely to reflect the exercise of market power. The MD02 proposal contains no such exception.

The NYISO further proposed special provisions to cover new generators. The reference price for such generators, for the first three years after they enter service, would be set at the higher of their estimated costs or the average LMP at their location during the 12 months before they went into service during hours in which they would be expected to run. The rationale underlying these special provisions is similar to that underlying the special provisions that PJM uses in its local market power mitigation mechanisms for new generation. However, the NYISO has chosen to limit the mitigation of such generators—as opposed to eliminating mitigation of these generators entirely—and has placed a sunset date on these provisions. Again, the MD02 contains no such provisions pertaining to new generation.

The NYISO proposed not to mitigate any generator's minimum generation offer prices if that generator is scheduled to start after 8 p.m. and has a minimum run time of more than 4 hours. Units started late in the day may need to remain on-line over night to satisfy minimum run-time constraints or to remain available for the next day while satisfying minimum downtime constraints. Since the NYISO only makes a bid recovery guarantee payment to these units for losses during the day in which the unit is started; units must include any anticipated losses during the early morning hours of the next day in their minimum generation or start-up offer prices for the day in which they are started if they are to recover those losses. Since it also appears that the CAISO will limit bid recovery guarantee payments to as-bid costs for the day in which the unit is committed,[80] there will likely be a similar need to allow bidding flexibility for start-up and minimum generation offer prices for hours at the end of the day.

Finally, the NYISO proposed extending the 50 MW exemption described above to all market participants, so that a market participant will not have its bids mitigated if the NYISO determines that its offer prices (and the offer prices of its affiliates) have exceeded the conduct threshold for

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[79] For units with long minimum run times, minimum generation bids might be mitigated in hours in which the impact threshold is not exceeded, because a high minimum generation bid submitted for one hour may induce a generator with a long minimum run time not to be committed to operate in another hour. Start-up bids will be mitigated for all hours because the NYISO currently only permits units to submit one start-up bid per day, which applies to all hours of that day.

[80] CAISO's Proposed Tariff Changes, § 5.12.7.1.1.2.3 sheet 184N

50 MW of capacity or less. This exemption can be revoked for an entity and its affiliates if the NYISO finds that they have used this exemption to exercise market power. The MD02 proposal contains no such exemption.

DCBC

Both PJM and New York have damage control bid caps, but those bid caps are set at $1000/MWh rather than the $108/MWh proposed for CAISO, although they are not indexed to gas prices. Additionally, the $1000/MWh level is a temporary measure, and the stated intention is to increase these caps over time. The MD02 proposal anticipates that the DCBC might eventually rise to $1000/MWh, but does not discuss the possibility of higher bid caps.

Competition Index

Neither PJM nor the NYISO calculate an index that would automatically lead to the imposition or modification of mitigation procedures, either inside those areas or on a broader regional basis.

Significance of these Differences and Recommendations

Must-Offer Requirement

While there are differences between the requirements to offer generation included in the MD02 proposal to the requirements in place in New York and PJM, the differences are not large. The CAISO may want to consider some of the modifications to the must-offer requirement in place in PJM and New York, which would not require all generators to offer all capacity that is not on outage at all times.

However, while requiring generation to offer capacity may be reasonable, requiring that capacity to be offered below cost is not. Consequently, other aspects of the proposal need to be modified. In particular, basing the price on monthly bid week gas prices (and excluding all associated transportation and balancing costs) would be inappropriate, especially in the winter, and would lead to situations in which generators would only recover the lower of this average cost or the market price on a given day.

Local Market Power Mitigation

If the CAISO implements the PJM provisions for local market power mitigation, then it should consider provisions for new generation as in PJM, so as not to discourage investment. Additionally, to the extent that the CAISO can define conditions under which it anticipates markets will be workably competitive even though a given constraint binds and it is necessary to dispatch generation out of merit to manage that constraint, it should not apply local market power mitigation in such circumstances. Finally, the CAISO should include the 10 percent buffer in use in PJM on top of the cost-based bids it uses when mitigation is indicated.

If the CAISO intends to implement the AMP, then it might want to consider mitigation mechanisms for local market power mitigation that are more consistent with the AMP—i.e., which identify generators that have bid in a manner that is consistent with the exercise of market power, and mitigate those generators only to the extent that they have bid in such a manner and have had a significant impact on prices as a result of that bidding behavior. These AMP-like market power mitigation measures have the virtue, discussed above, of reducing the frequency of mitigation because they do not mitigate offer prices when bidding behavior does not significantly deviate from what one would expect in competitive circumstances, or when bidding behavior has little impact on prices. As a result, they reduce the frequency of inefficient mitigation and interfere less with supplier management of unit downtime and preventative maintenance.

The likelihood of unanticipated conflicts between broader market power mitigation measures and measures intended to address local market power issues may also be reduced if both measures follow the same approaches. For example, use of a measure for local market power that is not based on the AMP's approach to mitigation might negate many of the advantages to the AMP described above for some market participants. Additionally, as the California market adopts LMP, the distinction between intrazonal congestion and interzonal congestion will disappear. Consequently any need that may currently exist for the CAISO to use fundamentally different mitigation procedures to deal with intrazonal congestion and interzonal congestion is also likely to disappear.

Reliability Must-run Units

The MD02 proposal envisions a gradual phase-out of the CAISO's reliance on RMR contracts. Following the phase-out, either the local market power mitigation mechanism included in the MD02 filing or a modified version of the AMP as discussed above, should be sufficient to mitigate the exercise of market power on the portion of the transmission system that is visible to and managed by the CAISO (as long as the local market power mitigation mechanism is properly designed).

AMP

Any test to determine whether a given condition holds will be subject to error. It may yield false positive results, as well as false negatives. For example, an inexpensive cancer screening test might be calibrated so as to yield many more false positives than false negatives. If the consequences of a false positive were simply the need to perform a slightly more expensive test, while the consequences of a false negative were a substantial increase in the likelihood that the individual being tested would die of cancer, this calibration would be appropriate. However, if the adverse consequences of a false positive were far more significant—for example, if the subsequent testing procedure itself were to endanger the patient—the trade-off between the consequences of false negatives and false positives would not be so lopsided, and the test would be recalibrated in a way to yield fewer false positives, and more false negatives.

When testing for the exercise of market power, one can also obtain false positive and false negative readings. The calibration of what constitutes a positive reading should therefore be performed with an eye to the relative consequences of false positive and false negative readings. An example discussed above, which led the NYISO to propose modifications to its AMP which call for it not to mitigate the minimum generation bids of units with minimum run times longer than four hours that are started after 8:00 p.m., illustrates the point. In that case, a unit might trip the market power tests and falsely test positive for market power, although that unit was simply bidding in such a way to recover its costs, given the way in which the NYISO calculates bid recovery guarantee payments.

As mentioned above, the fact that the CAISO has proposed a version of the AMP suggests that it recognizes that there are consequences to false positive readings for the exercise of market power—leading to mitigated offer prices when market power has not been exercised. However, much of the rest of the CAISO's proposal seems to drop this perspective, and to assume that the costs of false positives, and the inappropriate mitigation of offer prices that results, are trivial and can be ignored. As the discussion above comparing the NYISO's version of the AMP to the CAISO's version makes clear, there are many differences between the CAISO version and the NYISO versions of the AMP. Many of these differences result from the desire of the NYISO and market participants to reduce the likelihood that the NYISO would mitigate in circumstances in which mitigation would be unwarranted. The CAISO AMP should include similar provisions. In particular:

The CAISO's proposed procedures for setting reference prices raise the possibility that they will understate costs. Tighter conduct thresholds magnify the impact of such misstatements, as does the lack of a minimum bid below which mitigation will not be applied. The CAISO should adopt mechanisms for setting reference prices that will more closely align them with actual costs, and adopt a minimum bid below which mitigation will not be applied.[81] Additionally, the CAISO should provide justification for the conduct threshold it has proposed, or adopt alternative conduct thresholds.

The CAISO's lower impact threshold, and the lack of temporal and spatial selectivity in its mitigation procedures, increase the likelihood that mitigation will be applied when there is a relatively small impact on market prices. The CAISO should adopt the NYISO's mechanism for temporal and spatial selectivity. It should also provide justification for the impact threshold it has proposed, or adopt alternative impact thresholds.

The lack of a minimum price screen may lead to wasted effort on the part of the CAISO, delayed posting of day-ahead market results, as well as to inappropriate mitigation of offer prices and inefficient unit schedules. The CAISO should implement a minimum price screen, below which it would not apply mitigation in the AMP.

Applying the AMP to the offer prices of hydro resources may lead to suboptimal scheduling of these resources, which could be inefficient and which could adversely impact reliability in some circumstances. Without a reliable method for the CAISO to estimate opportunity costs for hydro (which could be difficult to develop), the CAISO should exempt hydro resources from the AMP. At the very least, the other provisions of the AMP (e.g., conduct thresholds) should be loosened substantially for hydro resources, to reflect the difficulty in using past accepted bids to estimate current opportunity costs when calculating reference prices for hydro resources.

Applying the AMP to the offer prices of imports would discourage imports, and would not be directed at the exercise of market power in California, so the CAISO should explicitly exempt imports from the AMP. The Commission should also reject arguments that this will permit

[81] In addition, the CAISO should clarify the procedure it will use to set reference prices during the start-up of the markets to be operated under the MD02 proposal. Generally, the MD02 proposal calls for these bids to be set using bids accepted during competitive circumstances during the last 90 days, but it is not clear how this would be applied during the transition period when the bidding rules are changing.

"megawatt laundering." Complaints about megawatt laundering are really attempts to prevent energy from flowing to markets that are willing to pay more for that energy, but this is precisely the outcome that well-designed, efficient open access regional markets are designed to realize.

Subjecting capacity scheduled to provide operating reserve or regulation to AMP offer price mitigation may result in the inefficient scheduling of energy limited resources, reduce the supply of ancillary services, raise energy prices and reduce reliability. Exempting units scheduled to provide ancillary services from mitigation of their energy bids enables energy-limited units to submit energy bids that reflect the true cost of supplying energy, while making their capacity available to provide ancillary services. The CAISO should exclude such capacity from the AMP.

Mitigating the offer prices of generator owners with very small portfolios will mitigate offer prices that are unlikely to reflect the exercise of market power. The CAISO should exempt small suppliers from offer price mitigation under the AMP, unless such an exemption would permit the supplier to exercise market power (such as within a transmission-constrained region).

Mitigating the offer prices of new generation may also discourage the development of this generation, despite the fact that its entry cannot reduce competition. The CAISO should consider provisions for new generation similar to those in place in the NYISO or PJM.

Finally, the comments above do not imply that the NYISO's version of the AMP or PJM's locational market power mitigation are perfect and that no modifications should be permitted by the Commission. There are a number of modifications to the NYISO's AMP or PJM's locational market power mitigation that could be appropriate in the right circumstances. But such modifications need to be described, justified, and their impact on implementation timelines specified. The CAISO's focus at this time ought to be on speedy implementation of mechanisms known to support a workable market, so modification of the procedures in place in PJM or the NYISO ought only to be considered for the initial rollout of MD02 if there is a clear justification for and time to permit implementation of those modifications.

DCBC

In a well-designed electricity market in which there were no concerns regarding the potential exercise of market power and in which all consumers face real-time prices (although they may be hedged) and were able to modify their usage of electricity in real time to reflect the value of that energy to them, there would be no need for a bid cap.[82] Given these assumptions, prices would be calculated fairly, and if prices rose to a level higher than loads wished to pay, they would stop consuming electricity, and hence they would not pay those prices. To the extent that there is a need for a bid cap, it is because these assumptions do not hold.

Because consumers generally cannot yet be charged the real-time price of electricity and modify their consumption accordingly, there is a need for limitations on the prices that can be reached in electricity markets. In the absence of the ability for consumers to respond to real-

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[82] Practically speaking, the software used to accept bids would implicitly impose a bid cap because it would only be able to accept bids up to a given level. However, this level could be set at a very high number.

time prices, bids ought to be capped[83] at no more than the value that end-use customers place upon the electricity they consume.[84]

There are disagreements as to what this value is, and certainly it may vary from time to time, from place to place and from customer to customer. But if the end customer is willing to pay $3000/MWh for the energy it consumes, then the bid cap should be set at $3000/MWh (barring other considerations to be discussed in the paragraphs below). This means that prices generally would not exceed roughly $3000/MWh, but they could reach that level during shortages with the associated curtailment of energy and reserves.[85]

The bid caps in place in the New York and PJM markets, as well as in New England, are $1000/MWh, which is less than most estimates of the value that end customers place upon energy. There is, however, some justification for temporarily setting bid caps below the value that end-use customers place upon the energy they consume, as this recognizes that in the past, end-use customers have not had an incentive to develop the ability to modify their consumption in response to real-time prices, because they have not faced real-time prices. Given the incentive to modify their usage, they may be willing to do so, but they may need time to develop the ability to modify their usage and implement related changes in billing and metering systems. While they are developing this ability, placing temporary bid caps on energy that are below the value that end-use customers place upon the energy they consume may provide those customers with some protection from high prices while they develop the ability to respond to real-time prices. If these caps are placed at too low a level, or if they are made permanent, loads will not have efficient incentives to develop the ability to respond to high prices, so it is important not to set this bid cap too low. The $1000/MWh bid caps in the east strike a balance, in that they give end-use customers some protection in the interim while they develop the capability to be dispatched in response to price. And they are intended only to be temporary measures.

[83] In a market in which energy and ancillary services are procured simultaneously, prices for these related services can be calculated so that they are consistent with each other (so that, for example, the price of operating reserve will take into account margins lost from the sale of energy as a result of having been scheduled to provide operating reserve). The MD02 proposal seems intended to produce prices that are consistent in this way. However, imposition of a price cap can destroy this consistency, so that prices of energy and ancillary services are no longer consistent with each other. Similarly, it may make locational prices inconsistent with each other. Bid caps permit implicit limits on prices without the potential for destroying the consistency of prices across different products and different locations, and for this reason, they are generally preferred to price caps.

[84] Different end-use customers will have different preferences, so that one might value energy at $1,000/MWh while another might value it at $5,000/MWh. In a market in which each customer's real-time usage would respond to real-time prices, the first customer would stop using electricity before the second one. However, in a market in which the usage of individual consumers will not depend on their willingness to pay high prices for electricity, the most reasonable way to determine a bid cap would be to consider the willingness to pay of the average consumer (excluding all price-responsive dispatchable loads which would stop consuming electricity at prices below the bid cap).

[85] Additionally, constraining the price during shortage situations would reduce anticipated generator revenues in the energy market, which in turn would reduce the amount of capacity that is developed unless generators are provided with some other revenue stream, such as that which results from the institution of an installed capacity or available capacity requirement. This is discussed in more detail in the ACAP section of this paper.

Another reason why it might be desirable to implement damage control bid caps would be to mitigate the exercise of market power. In the absence of other mechanisms for the mitigation of market power on the supply side of the market, bid caps can limit the profits that a generator might earn by economically or physically withholding capacity from the market since the damage control bid cap would limit the level that prices could reach either in shortage conditions or as a result of the exercise of market power. In the absence of other mitigation mechanisms, damage control bid caps provide a mechanism to limit the exercise of market power.

However, this market power justification does not apply here and does not justify the $108/MWh bid caps included in the MD02 proposal. The CAISO has proposed a broad array of other market power mitigation mechanisms. It has proposed a must-offer requirement to deal with physical withholding, as well as other regulatory changes to deal with these issues. It has proposed local market power mitigation measures to deal with potential economic withholding in the context of local market power issues, in addition to the existing RMR mechanism. It has proposed an AMP to deal with potential economic withholding in the context of broader market power issues. In short, the CAISO has proposed a wide variety of market power mitigation mechanisms, has failed to demonstrate why these mitigation measures are not sufficient, and has failed to show why such a low DCBC is appropriate.

This suggests that the $108/MWh bid cap is not intended as market power mitigation at all, but instead is intended simply to limit prices paid by consumers even if market power is not exercised and prices are high as a result of a shortage. The institution of such a low price cap in shortage conditions would thwart development of price-responsive load, since it is unlikely that most loads will want to stop or reduce consumption at prices below $108/MWh. As a result, it will tend to be self-perpetuating, since the ability to wean the CAISO from these market interventions depends on the development of price-responsive load.

The CAISO needs to recognize, moreover, that the level of a damage control bid cap has consequences beyond the price paid by consumers and will give rise to many operational and reliability problems if the damage control bid cap is too far below the actual value of lost load. In addition to capping the price paid by consumers in shortage conditions, the DCBC will also cap the price paid by suppliers that sell energy in day-ahead markets but fail to deliver in real-time. An important element of the damage control bid caps of the Eastern ISOs is that the $1000 bid cap provides a strong incentive for market participants to only sell energy in the day-ahead market that they will be able to deliver in real-time. This is particularly important in providing incentives for importers to fulfill obligations assumed in the day-ahead market. The low bid cap to mitigate market power also mitigates the day-ahead financial commitment of an import supplier to deliver energy to the CAISO, since the maximum consequence of a failure to deliver would be paying $108/MWh to cover the shortfall. If $108 truly reflected the value of energy to CAISO consumers in shortage conditions, such a cap on the price used to settle shortfalls would be appropriate, but it is doubtful that this is the case. A predictable consequence of the $108 DCBC is that the CAISO will find import supplies to be unreliable and will need to develop some other mechanism for incenting supplier performance.

Similarly, the damage control bid cap will cap the price charged for exports from the CAISO control area sourced from the CAISO spot market. It is readily predictable that the CAISO will be unwilling to see power exported from its control area during shortage conditions at a price of $108, so there will inevitably be a request for restrictions on access to the spot market.

A similar incentive problem will arise with FTRs under such a low DCBC. It was noted above that financial transmission rights play an important role in supporting economic dispatch and effective congestion management by separating generator dispatch decisions from the value of transmission rights. Generators and other suppliers will find it economically attractive to be dispatched down to manage congestion, if the compensation they receive for their transmission right reflects the cost of buying replacement energy. Thus, if a generator hedged with an FTR is backed down by PJM's dispatch, the generator is assured that it will be able to buy replacement power at a price net of the payment it receives for its FTR that is less than or equal to the incremental energy cost bid it submitted to PJM.[86]

This will not be the case, however, if the damage control bid cap is set at such a low level that there will routinely be excess demand for use of the transmission system at the price cap level. The CAISO's proposal to use FTRs to break ties in scheduling transmission usage may reflect a recognition that the low level of the DCBC will prevent financial transmission rights from operating as intended. The physical tie breaker means, however, that whenever prices are high, generators holding FTRs will take their generation off dispatch to ensure that their schedules match their FTR so they can utilize the tie breaker, thereby reducing the efficacy of the CAISO's congestion management system, just when it is most needed.

Taken together, non-delivery penalties in excess of the real-time price, restrictions on spot market access, and a need to match schedules to FTRs will greatly inhibit the development of financial hedging instruments in forward markets and have the potential to force market participants into continued reliance on the physical scheduling system that has been the source of so many CAISO problems. Unfortunately, therefore, the level selected for the DCBC is likely to have effects that ripple through the entire market design.

Additionally, the potential use of different price caps in adjoining regions would create incentives for imports or exports across regional boundaries, so use of the $108/MWh bid cap in California could lead either to exports of power from California, or the application of a similarly harmful cap throughout the WSCC. Application of this cap across the WSCC would stifle the ability of other western states to develop price-responsive load, would prevent them from developing markets that rely less upon government intervention, and would either discourage generation development in those states or would force them into adopting installed capacity or available capacity markets in order to provide generators with a revenue stream sufficient to make investment worthwhile.

The CAISO should adopt a significantly higher damage control bid cap than that included in the MD02 proposal, such as the $1000/MWh cap similar to that used in the East. This would give price-responsive load an incentive to develop and avoid the need for restrictions that undercut the overall reform while still shielding consumers from the impact of unlimited real-time prices. The other CAISO mitigation measures address market power concerns. Eventually, the CAISO should plan to increase the bid cap and eventually, the bid cap should be set at the value that non-dispatchable load places upon the electricity it consumes.

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[86] For example, if a generator submitted an incremental energy cost bid of $35 for an output level matching its FTR ownership, but was dispatched down to $30/MWh in the day-ahead market, while the day-ahead price rose to $100/MWh at the delivery point for its FTR. This generator would receive $70/MW for its FTR, so the net cost of buying power at the delivery point would be $30 ($100-$70=$30). The net cost of this purchased power would be less than its incremental energy bid for meeting this load.

Competition Index

As noted above, the broad concept of developing a benchmark against which one would assess the actual performance of the market, and proposing changes based on that comparison, is worth considering. Other market operators prepare regular assessments of their markets, using similar but not identical indicators. For example, PJM provides an estimate of the contribution to the fixed operating and capital costs of a peaking unit that would have been earned under perfect dispatch given the actual prices. This can be compared both historically and against the known fixed costs of these relatively simple units. The general trend is instructive, but the analysis is part of a larger evaluation and there is no automatic trigger for extensive mitigation efforts.[87]

As the CAISO has recognized, the particular competition index it proposes is a new and untested mechanism. Nevertheless, the CAISO has proposed instituting wide-ranging market mitigation measures *automatically* whenever the competition index indicates that prices on an annual basis would exceed the CAISO's estimates of perfectly competitive prices by more than $5/MWh, which is a fairly tight tolerance. While the competition index may be a useful indicator of market competitiveness, to use it to institute wide-ranging mitigation measures automatically, without any assessment of whether the exercise of market power has actually given rise to the difference between actual prices and the benchmark, or whether there are problems in the calculation of the benchmark, would be premature, could be destabilizing and would raise the substantial possibility of reinstating the current west-wide mitigation procedures even when no market power has been exercised.[88]

The circumstances that would cause the index to inappropriately trigger additional market power mitigation procedures include:

- Cost estimates may not be indexed to daily gas prices (especially important in the winter).
- Cost estimates may not include actual gas transportation costs to the burnertip.
- Cost estimates may not include actual emission allowance costs.
- Cost estimates may not reflect the increased likelihood of forced outages at some operating levels.[89]

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[87] See, for example, Market Monitoring Unit PJM Interconnection, LLC, "PJM Interconnection State of the Market Report 2000," June 2001; and David B. Patton, "New York Market Advisor Annual Report on the Markets for Calendar Year 2000," April 2001.

[88] A more cynical view would be that the competition index and trigger, as proposed by the CAISO, is designed to bring about reinstatement of the current west-wide mitigation measures, since the CAISO has indicated its preference to continue reliance on those measures for the time being.

[89] The CAISO should consider calculating the competitiveness index using reference prices, which in most cases will be based on bids made by each generator that were accepted in the market in competitive conditions, instead of administrative estimates of variable costs. Since the reference prices are determined during competitive conditions, there is no reason why they should not reflect the marginal cost of operating a generator. And using generators' bids would avoid the difficulty of estimate hard-to-estimate costs such as the increased likelihood of outages at some operating levels.

Additionally, even if the CAISO correctly estimates supplier marginal costs, its estimates of perfectly competitive prices will be calculated using a simplified model of supply and demand. Models abstract away from reality, but these abstractions may cause estimates of prices derived from models to be lower than prices that result in competitive markets under actual operating conditions. As a result, the CAISO's estimates of perfectly competitive prices may be erroneous—which could cause the competition index to trigger extensive mitigation even in the absence of the exercise of market power. Although the detailed procedure that the CAISO's model would use to estimate perfectly competitive prices has not been fully specified, experience reviewing prices calculated using optimizing models indicates that modeled prices may understate actual prices for the following reasons:

- Price calculations may not consider the impact of ramping limits or transmission constraints.[90]
- Price calculations may ignore the impact of start-up or minimum generation costs, or other operating inflexibilities such as minimum run time and minimum down times.[91]
- Price calculations may not consider environmental or other regulatory limits on production.[92]
- Price calculations may not reflect the need for capacity to provide operating reserve or regulation.[93]
- Price calculations may not consider temperature-related or tidal impacts on capacity.
- Price calculations often assume that next-day loads and outages were known with perfect certainty, so that the optimal combination of units has been committed to meet the next day's load.[94]
- Price calculations may assume that each generator is able to follow its dispatch signals perfectly.

A related, but separate issue pertains to the procedure the CAISO proposes to use to calculate prices if price-responsive load is on the margin. It proposes to set the benchmark price at "the

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[90] There is no apparent mention of ramping limits or transmission constraints in the determination of the CBAC. See CAISO tariff § 28.2.1.3, p. 298A-D.

[91] The calculation of the CBAC would assume that all capacity that has not been derated and is not out due to a forced outage can be made available costlessly in real-time to meet demand spikes, without regard to start-up costs, start-up times, minimum run or down times or other actual constraints. CAISO tariff § 28.2.1.3, item 3.

[92] The CAISO CBAC will apparently account for some environmental limits (CAISO tariff § 28.2.1.3, item 9, p. 298C) but these provisions do not appear to cover all environmental output restrictions (such as outlet temperature limits).

[93] The CAISO CBAC will apparently include capacity required to provide reserves in system demand (§ 28.2.1.3, item 6, p. 298B) but it is not stated how the CBAC will be determined if demand exceeds supply.

[94] As a result, models often dispatch quick-starting units with high incremental costs far less often than they are actually operated in reality, because it is never necessary to start such units to respond to higher-than-expected loads or unexpected generation or transmission outages.

marginal cost of the highest cost unit available to serve system load each hour,"[95] but this is not the market-clearing price if price-responsive load is on the margin. In particular, this is not the market-clearing price when there are shortages, and the index should either be adjusted to account for the market-clearing price in these hours correctly, or to exclude these hours.

Finally, there are concerns regarding the procedure the ISO will use to calculate the actual costs that it will compare to its benchmark.

- The average price described in § 28.2.1.2 of the CAISO's proposed tariff appears to include DWR contract prices. Thus the index could be triggered if the contract price exceeds the benchmark price, even if market prices were consistent with or even below the index.

- Net actual utility supply is deducted from the demand curve when calculating actual prices. But utility generators submit offer prices, and are dispatched according to their offer prices. And if these offer prices set prices, this means real-time prices could exceed the simulated prices for reasons that are unrelated to the exercise of market power by non-utility generators.

Given these concerns about the procedures the CAISO will use to compile its estimates of competitive prices, as well as the procedures it will use to calculate actual prices, it is possible that the competitive price level would exceed the benchmark prices by $5/MWh even if all non-utility generators were to bid in a competitive manner all of the time. The CAISO should refine the procedures it uses to calculate benchmark and actual prices along the lines suggested above. Additionally, the automatic consequences that would follow whenever actual prices exceed benchmark prices by more than $5/MWh should be removed, at least until the behavior of this prototype index is better understood. The CAISO could use the results of this index in its assessment of market behavior, and to support any filing it might make at FERC regarding changes to its market mitigation mechanisms, but it would need to compare the analysis of this index with the implications of other market indicators.

If the index were to trigger automatic regional mitigation, then both the threshold that would be used as the trigger and the consequences that would ensue should be reconsidered.

- The CAISO has not provided any justification for the selection of a $5/MWh threshold. The CAISO ought to provide such justification. The threshold that is used ought to reflect the likelihood of error in the CAISO's estimate of competitive prices, so to the extent that the CAISO cannot implement the proposed mechanism for modeling competitive prices, it should expand the threshold to reflect this likelihood of error.

- The CAISO also ought to consider more graduated modifications instead of reinstating full current west-wide mitigation. For example, the CAISO could request tightening of the AMP thresholds if the competitiveness index were to exceed a threshold level.

- The CAISO should also use this test to assess when it might be possible to relax mitigation—e.g., it could loosen the AMP thresholds if doing do is justified.

[95] CDP, p. 142.

- Finally, the CAISO should modify its proposal so that whenever possible it will avoid mitigating those entities who have not exercised market power. Under the current proposal, the CAISO would subject all market participants to mitigation, even if only some market participants were deemed to have exercised market power. The CAISO claims that suppliers would be able to "self-regulate their own behavior in order to preclude intervention,"[96] but suppliers can only regulate their own offer prices, not the offer prices of other suppliers (unless suppliers explicitly coordinate their offer prices, an approach which the CAISO likely does not mean to endorse). Moreover, focusing intervention on those who have exercised market power is a more effective disincentive to such behavior.

Conclusions

The discussion above leads to three broad policy conclusions.

First, while the CAISO will be able to go to the Commission to request changes in its proposed market power mitigation and will be able to put before the Commission whatever competitiveness indicators it believes are appropriate, there should be no automatic trigger of additional offer price caps or must-offer requirements—particularly not a trigger based on the CAISO's competition index, which appears to have the potential to trigger mitigation in a variety of circumstances in which no market power has been exercised.

Second, while a damage control bid cap for the California market is appropriate, it should be set at a level much more consistent with the $1000/MWh level in the Eastern ISOs. During the period prior to ACAP implementation, a good case could be made for a bid cap in excess of $1000/MWh, reflecting the lack of an ICAP market and the need of CAISO generators to recover a larger proportion of their fixed costs during shortage conditions than do generators located in the Eastern ISOs. In any case, the $108/MWh bid cap makes the other market power mitigation mechanisms almost irrelevant. Moreover, such a bid cap would appear to make it impossible for many California generators to recover their going forward costs in either day-ahead or real-time markets, would require a system of long-term contracts at higher prices to maintain reliability and may lead to a variety of restrictions on participation in the market that would defeat the purpose of the CAISO's reforms..

Third, while a market power mitigation mechanism is likely be necessary and desirable in the current circumstances, the Commission should recognize that the AMP proposed by the CAISO is very different from the AMP implemented by the NYISO. Moreover, the differences are not minor cosmetic changes, but would very fundamentally change the AMP in ways that would make it much more likely to inappropriately mitigate offer prices in ways that do not address market power, but could adversely impact reliability. The CAISO should be not be precluded from adapting the NYISO AMP to California conditions where required, but the Commission should require the CAISO to explicitly identify and justify these changes, to avoid subjecting California market participants to another round of experiments.

[96] CDP, § 5.12.1.

G. ACAP

Positive Elements of the MD02 Proposal

If prices are permitted to reach the value that end-use customers assign to the energy they consume, there is no reason why energy and ancillary services markets alone would not provide incentives for the optimal amount of generating capacity to be constructed. However, bid caps below that level will tend to depress the amount of capacity that will be built. The reason is simple: generators that would have been marginal projects if bids had been capped at a higher level (and prices had therefore been permitted to reach similar levels) would have their revenues reduced once prices are capped at a lower level. As a result, those generators would no longer be marginal projects, and would no longer be built, or if built, may no longer remain in operation.[97] If the bid cap is sufficiently low, under the rules proposed for California, it would be impossible to meet reliability standards for capacity adequacy without providing an alternative revenue stream that would permit the development of sufficient generating capacity to meet those standards.

While bid caps, such as the $1000/MWh bid caps in place in the East, would have a dampening effect on the viability of building new units (and keeping old ones in service) if those markets did not also include installed capacity (ICAP) requirements, it is likely that the bid caps proposed by the CAISO would eviscerate plans to build capacity in California in the absence of an ACAP requirement. Therefore, given the proposed level of the DCBC and the resulting limits on prices, an ACAP requirement or something like it is probably necessary simply to ensure the continuing economic viability of sufficient generation to provide reliable service in California.

Comparison to Procedures Used in New York and PJM

As noted above, the NYISO and PJM operate ICAP markets. In these ICAP markets, the ISO determines an aggregate ICAP requirement, and then allocates that requirement out to LSEs based upon forecasts of their share of peak loads in their areas. LSEs are then required to contract with sufficient generation or demand reduction resources to meet their requirement. They may also purchase capacity in auctions operated by the ISO. To the extent an LSE fails to purchase sufficient ICAP to meet its requirement, the NYISO (but not PJM) may procure ICAP on its behalf, charging it for the costs thereby incurred. In the event that it is unable to do that, the ISO will assess a deficiency charge on LSEs that have failed to meet their requirement.

The primary difference between the New York and PJM markets and the ACAP market included in the MD02 proposal is in the nature of the performance obligation and the mechanism used to determine the amount of capacity each resource can provide. ICAP providers in New York and PJM are required to offer energy into the day-ahead market of the area in which they provide ICAP, if they are not on outage. They may also be required to provide energy in the real-time market, if they are operating. But the amount of ICAP that each resource can provide, as well as the ICAP requirement for each LSE, is stated in terms of unforced capacity (UCAP). The

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[97] In addition, to the extent that they mitigate even when market power is not being exercised, the CAISO's other proposed mitigation mechanisms would also depress prices below competitive levels and would therefore lead to the development of less capacity than would be developed in a competitive market.

UCAP for any given resource is determined by multiplying its current maximum generating capacity by one minus an estimate of the likelihood that a generator will not be available due to a forced outage ($EFOR_D$) when called upon. In New York and PJM, the $EFOR_D$ used to determine a generator's UCAP for any given period is based on outage data from previous periods, which permits that generator to know how much UCAP it can provide before the beginning of that period, but which means that an ICAP provider does not necessarily have to be available during highly-stressed portions of the period for which it is providing ICAP. In contrast, providers of ACAP are required to be available during the highly-stressed portions of the period for which they are providing ACAP, and the amount of ACAP they are credited with providing depends upon the extent to which they meet this requirement.

Recommendations

The best way to design a capacity market—whether ACAP or ICAP—is not to design it at all. It is better to put bid caps in place at a level that will give price-responsive load an incentive to develop, calculate prices correctly during shortage and near-shortage conditions, and rely on energy and ancillary services markets to compensate new generation. Some sort of capacity market might be indicated as a transition measure, which would be accompanied by a gradual transition of bid caps from lower levels to levels that reflect the value that end-use customers place upon the energy they consume.

The MD02 filing indicates that the CAISO is not confident that required amounts of new generation would be built by developers in the absence of an ACAP requirement. But if sufficient generation would not build in response to markets for energy and ancillary services, it is hard to see why simply creating a requirement for LSEs to purchase some sort of capacity product would suddenly cause sufficient generation to be built. It is simply another market. There are energy requirements and energy markets, and ancillary service requirements and ancillary service markets, and developers would build—or not build—generation based on the revenues they expect to realize in the markets in which they sell energy, ancillary services, and the capacity product, if there is one. The experience of other markets throughout the world which do not have capacity markets or payments and which nevertheless enjoy reliable service further buttresses the argument that the development of sufficient generating capacity is perfectly consistent with the absence of a capacity market.

Additionally, it is often asserted that capacity markets—ACAP or ICAP—are needed in order to provide long-term price signals, or to ensure revenue certainty for generation. But the prices determined in spot capacity markets are not long-term signals. They are determined less frequently than prices in day-ahead or real-time markets, but the price that a generator will receive for the capacity it will provide is not known at the time that the decision to proceed with the development of a generator must be made. So for the purposes of providing price signals that will guide generation development decisions, prices in spot capacity markets are no more useful than prices in spot energy or ancillary services markets.[98] Similarly, to the extent that

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[98] However, both of the primary proposals under consideration in the Joint Capacity Adequacy Group (JCAG)—a group formed by the PJM, New York and New England ISOs and the Ontario IMO to consider modifications to their ICAP markets—would procure ICAP two or more years in advance, in which case the ICAP price actually might serve as a long-term price signal, permitting generation to develop in

revenue certainty is important to generators, there is no need to develop markets for capacity markets to permit them to lock in revenue. Instead, long-term contracts for the sale of the energy and ancillary services can provide them with revenue certainty (although such contracts require creditworthy counterparties and some certainty regarding the regulatory treatment of those contracts).

If the other provisions of the MD02 filing are taken as given, then it may be necessary to create a requirement for some sort of a capacity product in order to create incentives for development and retention of sufficient capacity to meet CAISO load reliably. Nevertheless, markets for capacity products (such as ACAP) are generally a relatively inefficient way of ensuring generation adequacy, because they tend to be less effective than energy and operating reserve markets at giving generators incentives to be available when it is most important for them to be available (although ACAP may have some advantages relative to ICAP in this regard). Consequently, this may increase overall costs to end-use customers.

Moreover, even if reliance upon an ACAP market did not result in decreased efficiency, use of a lower DCBC, or use of mitigation measures that do not permit prices to reach competitive levels, will lead to higher ACAP prices. There is no free lunch. In order for prices to reach levels sufficient to induce investment in new generation, as well as keeping existing generators in service, generators will have to be able to realize a given revenue stream, and the greater the extent to which they are prohibited from doing so in the energy and ancillary services markets, the greater the extent to which they will need to earn those revenues in the ACAP market.

Finally, if there is to be an ACAP requirement and an associated market, a number of issues regarding the structure of that market need to be examined more closely. Consequently, the Commission should not approve the detailed proposal for the CAISO's proposed ACAP market at this time, even if it agrees with the general approach of defining an ACAP requirement and market.

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response to that signal. If the CAISO's ACAP market were to adopt such a structure, then there is at least the potential that it could serve as such a long-term price signal.