Market Power Mitigation under Locational Marginal Pricing

by

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1. Introduction

This opinion comments on the California Independent System Operator's (CAISO) currently proposed local and system-wide market power mitigation mechanisms under the Locational Marginal Pricing (LMP). As has been emphasized in several previous opinions, without an effective local market power mitigation mechanism (LMPM), we strongly doubt that California consumers will realize any net benefits from adopting a wholesale market with LMP, even if the seller's choice long-term contracts issue is successfully resolved. Moreover, the lack of an effective LMPM mechanism that applies to all generation units in California is a major shortcoming of the current market design. Consequently, we believe that a comprehensive package of market power mitigation mechanisms specifically designed to balance the competing goals of protecting consumers from the harmful exercise of unilateral market power and limiting the inefficiencies associated with intervening with market mechanisms is the most crucial component of the Market Redesign and Technology Upgrade (MRTU) process.

This package of market power mitigation mechanisms should be designed and its properties assessed as part of an integrated market design. Treating the choice of a market power mitigation mechanism as separable from the overall market design is very likely to lead to a final market design with a number of unintended sources of inefficiencies. This point is best illustrated by the many potential inefficiencies that could result from the market design changes ordered by FERC (particularly to the Residual Unit Commitment mechanism) in response to past MRTU market design filings. For this reason, we strongly urge FERC to consider the CAISO's market design proposal as a complete package, including its market power mitigation mechanisms, and avoid as much as possible making significant changes to specific details of the design because of the potential for significant unintended adverse consequences.

We believe that a number of unresolved issues associated with the CAISO's proposed market power mitigation mechanism should be addressed before this mechanism is filed with FERC. Many of these are a direct result of changes in the ISO market design ordered by FERC. We believe that several of the changes ordered by FERC require significant revisions to the MTRU design, specifically the residual unit commitment (RUC) process and the mechanism used to allocate zonal demand bids in the day-ahead energy market. These market design changes imply modifications to the ISO's proposed market power mitigation mechanisms.

This opinion first discusses the major outstanding unresolved issues associated with the proposed MRTU design. We then propose a strategy for addressing these issues and an approach to designing a comprehensive market power mitigation mechanism for a LMP market. Our view is that the CAISO's market power mitigation mechanisms should focus on limiting the ability of suppliers to exercise *local* market power in the energy and ancillary services markets. We believe there are other less intrusive and more effective approaches than the CAISO's proposed Automatic

Mitigation Procedures (AMP) for addressing system-wide market power concerns, and more effective mitigation procedures for limiting the exercise of local market power than the CAISO's proposed AMP mechanism. While we do not recommend a specific package of market power mitigation mechanisms, we do provide general guidelines for constructing a market design and package of market power mitigation mechanisms that we believe has the best chance of benefiting consumers from an LMP market.

2. Outstanding Unresolved Market Design Issues

A major unresolved market design issue is the RUC capacity procurement process. Originally, the CAISO envisioned that suppliers of RUC capacity would be paid as-bid and the RUC payment would be rescinded if a unit was subsequently dispatched for energy. The CAISO also proposed a must-offer requirement for all generation capacity in the day-ahead energy market. In case of day-ahead ancillary services bid insufficiency, the ISO proposed to increase its day-ahead RUC capacity procurement and obtain additional ancillary services in the hour-ahead or real-time markets. FERC rejected the must-offer requirement and ordered the CAISO to pay a market-clearing price for RUC capacity and not to rescind the RUC payment if the capacity was subsequently dispatched for energy. These market rule changes have created an even greater need for revisions to the CAISO's LMPM mechanisms because of the increased opportunities for suppliers to exercise local market power that these rule changes have enabled.

The CAISO's original proposal called for rescinding the entire RUC capacity payment if a supplier was dispatched for energy. This limited the need to mitigate RUC capacity bids because all energy bids were subject to local market power mitigation. The CAISO's logic was that a unit would not be purchased as RUC capacity unless there was an extremely high likelihood this capacity would be subsequently needed to supply energy in real-time. Therefore, if the CAISO accepted a RUC capacity bid that reflected the exercise of local market power, that supplier did not have a very high probability of ultimately being paid this bid because the unit would instead be dispatched to supply energy in real time. The CAISO's original pay-as-bid RUC mechanism further limited the benefits a supplier might realize from submitting high RUC capacity bids, because a generation unit's RUC capacity bid would not impact the price it would receive for other RUC capacity it sold. Finally, FERC's elimination of the requirement that suppliers must offer all available capacity into the CAISO's day-ahead energy and ancillary services market allows these suppliers the option to withhold capacity in order to drive up the day-ahead price for energy and ancillary services as well as RUC capacity. While a must-offer requirement may be unnecessary for system-wide mitigation, the lack of such a requirement or equivalent measures is a concern when local market power is present.

Throughout the MRTU process, the MSC has argued for greater integration of the RUC constraints into the day-ahead energy and ancillary services market. These FERC orders make the case for greater integration even stronger. A RUC market that operates following the close of the day-ahead market without a must-offer requirement is likely to be susceptible to the exercise of local market power. All generation units facing significant competition from other independent suppliers have a strong incentive to be committed to provide energy or ancillary services in the day-ahead market, because these suppliers face a significant risk of not being dispatched unless they bid aggressively. However, this is not likely to be the case for units owned by suppliers with significant local market power. Although the ISO's flexible must-offer requirement will enter zero default RUC bids for units that do not bid into the day-ahead energy market, this does not prevent suppliers from bidding high enough in the day-ahead market so that a significant fraction of this local energy need remains unserved and must therefore be satisfied through the RUC process. Unless this remaining unserved local energy need satisfies the ISO's criteria for local market mitigation, the supplier can then submit an extremely high RUC capacity bid and set a very high locational RUC price. For this reason, our expectation is that the RUC capacity market will be extremely thin, particularly at locations in the CAISO control area where one or two suppliers own all of the local generation necessary to serve load. Moreover, a single unconstrained market-clearing RUC price for the entire CAISO control area should be extremely rare, because it will often be the case that low-priced bids to supply RUC capacity must be skipped over because these units are not at locations where the capacity is needed.

We also question the need to create a separate product that is distinct from energy and ancillary services. In particular, it is unclear what direct costs or opportunity costs a provider of RUC capacity must be compensated for. If the ISO accurately determines its reserve requirements at all locations in the CAISO control area, including the requirement that sufficient capacity is committed in the day-ahead market to meet the CAISO's locational demand forecasts, it is unclear why RUC capacity is needed. We believe that if the CAISO operators have locational reserve requirements, these should be specified in the day-ahead market, rather than obtained through a separate RUC market.

Based on the historical pattern of must-offer waiver denials issued, it appears that CAISO operators do have locational ancillary services. Currently, these locational ancillary services requirements appear to be procured through an inefficient two-step process. In the first step, must-offer waiver denials are issued to units located in the areas where the CAISO operators know that they need locational ancillary services capacity and energy. With these units committed, the CAISO operators are then able to procure ancillary services on a system-wide or zonal basis given the geographic distribution of must-offer waiver denials. The CAISO operators also appear to prefer to hold more generation reserves than the minimum amounts required by Western Electricity Coordinating Council (WECC) rules. Under the must-offer requirement, this is accomplished by issuing waiver denials to more units than those necessary to meet the minimal WECC reserve requirements. Even if the CAISO were to be able to continue the must-offer requirement, a lower-cost energy and ancillary services procurement policy is for the CAISO to purchase both energy and ancillary services in the minimal quantities and at locations that it deems are necessary to reliably operate the transmission network. If CAISO operators believe that more than the minimal levels of ancillary services required by the WECC are necessary to operate the transmission network reliably, it should procure this level of ancillary services capacity. A procurement process that recognizes both locational constraints and other operating constraints is likely to result in locational ancillary services prices because of congestion in the transmission network. Consequently, the ancillary services procurement process should also be subject to a LMPM mechanism integrated with the one that exists for the energy market.

Procuring the ancillary services needed at locations where the operators need this capacity will eliminate the need to pay the minimum load costs of suppliers that were formerly issued must-offer waiver denials, because all units will either be scheduled for energy or ancillary services in the day-ahead market. Committing sufficient generation capacity in the day-ahead market to meet the CAISO's locational demand forecasts will eliminate the need for a RUC mechanism. All needed generation capacity will either be paid for as energy or ancillary services in the day-ahead market. In summary, it is difficult to see the need for a RUC process if the CAISO is procuring sufficient ancillary services at locations where it can be used and if sufficient generation capacity to meet the CAISO's load forecast is committed in the day-ahead market. Moreover, by eliminating the need for a RUC process, the CAISO avoids having to operate a market that pays a market-clearing price for RUC capacity and allows the supplier to keep the RUC payment if this capacity is subsequently required to produce electricity. Finally, suppliers will have no incentive to withhold capacity from the day-ahead market if load-serving entities (LSEs) have procured sufficient forward financial contracts that clear against prices at locations in the network where the LSEs actually withdraw energy from the network or locations in the network where their congestion revenue rights (CRRs) are sourced.

3. Shortcomings of Automatic Mitigation Procedures

System-Wide AMP. The experience of the California market with the Automatic Mitigation Procedure (AMP) has failed to convince us that it is an effective mechanism for limiting anything but isolated, excessive exercises of unilateral market power. These are the same types of events that are mitigated by the price-cap in the energy market. However, with the AMP mechanism this mitigation comes at the expense of sanctioning, and perhaps even promoting, more widespread and subtle forms of unilateral market power. For example, under the CAISO's proposed AMP mechanism all suppliers are allowed to bid within the lower of $100/MWh higher than or 200% of their reference level and not be subject to mitigation by the system-wide AMP mechanism. These conduct thresholds provide suppliers with substantial discretion to raise market prices without triggering mitigation. Consequently, even though AMP has failed to mitigate any bids in the CAISO real-time market, it is still possible that significant amounts of unilateral market power could have been exercised while the AMP mechanism has been in place.

In our view, an AMP mechanism with the large conduct thresholds described above does not constitute adequate mitigation of the unilateral market power a supplier might possess, because this mechanism allows a supplier to move market prices above competitive levels enough to impose significant consumer harm without violating the conduct thresholds. Therefore, this AMP mechanism allows substantial system-wide market power to be exercised without triggering mitigation. While an AMP mechanism with wide tolerances may be ineffectual, one with tighter tolerances would be more intrusive and perhaps even more anti-competitive. The MSC also has expressed substantial concern about using functions of previously accepted bids to set AMP reference levels. This imposes a cost on a supplier for submitting a low bid, because this bid is likely to reduce that supplier's reference level and therefore limit the extent to which the supplier can raise prices during other hours of the year.

For example, if a supplier's AMP reference level is set at the median of accepted bids over the past 90 days, one can imagine a circumstance where a very low accepted bid could significantly reduce that supplier's reference level. This lower reference level would limit the bid that supplier could submit during higher demand periods to raise the price it receives for selling electricity without exceeding the conduct threshold. For this reason, we believe that setting AMP reference levels based on accepted bids limits the incentives for suppliers to vigorously compete during competitive periods. Using this mechanism to set reference levels results in an AMP mechanism that is likely to raise average prices in the majority of periods and reduce prices only during those relatively rare periods when the supplier is pivotal.[1] In addition to our general concerns about AMP

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[1] The AMP mechanism is a unique tool in the portfolio of economic regulation whose potential to produce unintended consequences is not well understood. For example, the AMP mechanism provides incentives to make offer curves more 'flat' because firms benefit from raising the offer price of infra-marginal units that they are confident will be accepted in the market. Without AMP, firms are largely indifferent to the offer price of a unit,

mechanisms, there are several aspects that make it particularly inappropriate for the California market. For example, there is no logical basis for applying AMP mechanisms to import portfolios or to energy-limited resources, both of which play an important role in the California market.

For all of these reasons, we do not believe a system-wide AMP mechanism is an appropriate tool for mitigating system-wide market power in California. Instead, we advocate a procurement policy for LSEs that focuses on limiting their exposure to the spot market prices through forward purchases and hedges against spot prices at locations where these LSEs actually withdraw energy from the transmission network. This is a lower cost alternative for limiting the exposure of final consumers to the exercise of system-wide unilateral market power. Under this mechanism all suppliers have a common interest in lowering, rather than raising, the spot price of electricity at locations where they have forward market obligations or options to make difference payments based on the spot price of electricity at that location. Only if a supplier has covered its forward market position does it have an incentive to raise the spot price of electricity at that location, and that incentive is weakened as the forward contract coverage of its expected output increases.

Local AMP. We also do not favor an AMP mechanism for local market power mitigation, even if the conduct thresholds are set tighter. Suppliers are typically better able to forecast when they possess substantial local market power relative to when they possess substantial system-wide market power. Moreover, for most suppliers, the system conditions when they possesses substantial local market power are likely to arise far more frequently than the conditions when these suppliers possess substantial system-wide market power. This logic is consistent with setting lower conduct thresholds for an AMP mechanism designed to mitigate local market power. However, suppliers are still able to exercise a significant amount of local market power without mitigation, unless these thresholds are set extremely low. Even the $10/MWh or 20 percent of the unit's default energy bid contemplated in the CAISO's proposed LMPM mechanism gives suppliers considerable discretion to exercise local market power. Given the substantial number of hours of the year that many units are likely to be subject to mitigation, this could imply a unit will be able to raise the average price it receives by the minimum of $10/MWh or 20 percent of its default energy bid, without triggering mitigation. The AMP mechanism once again effectively sanctions the exercise of local market power within these tolerance levels with no corresponding market efficiency benefit to allowing this exercise of local market power.

One positive feature of the CAISO's proposed AMP mechanism for local market power mitigation is that the default energy bids are cost-based as opposed to bid based. However, the ISO still envisions allowing a 10 percent adder to its best estimate of the incremental cost of the generation unit in computing the unit's default energy bid. At current natural gas prices in the range of $6/MMBTU to $5/MMBTU, this can add as more than $6/MWh to the default energy bid of a 10,000 BTU/kwh heat rate generation unit, which is close to the average heat rate of generation units in the California ISO control area. Combining this with a $10/MWh LMPM mechanism conduct threshold allows a supplier with local market power to bid more than $15/MWh above the CAISO's best guess of the unit's incremental cost without being subject to mitigation, which can allow a substantial amount of local market power to be exercised without triggering mitigation.

conditional on the fact that it is accepted. With AMP, a higher offer price for an accepted unit raises its reference price and allows more flexibility for bidding that unit in other hours.

This 10 percent adder can also distort energy and ancillary services prices and unit-level dispatch decisions and ancillary services commitment decisions throughout the CAISO control area. Even if all other suppliers in the CAISO control area are bidding their incremental cost to provide energy, the use of a 10 percent adder for units with local market power would cause an inefficient dispatch because minimum incremental costs (from competitive suppliers) are combined with estimated incremental costs plus a 10 percent adder (from mitigated suppliers) in the market-clearing process. For example, this 10 percent adder could cause congestion into a local area that would not occur if the unit had to submit a bid equal to its minimum incremental cost of supplying energy, because less energy is taken from the unit at this higher bid price.

A superior strategy for the CAISO to follow in the setting the default energy bid for a unit subject to LMPM is to determine what it believes is the minimum incremental cost of supplying energy from that unit assuming prudent procurement of the necessary inputs and operation of the generation unit. Rather than base this cost estimate on the actual incurred costs of the unit owner, the CAISO should use publicly available indexes of prices that suppliers cannot move through their unilateral actions. For example, for natural gas-fired facilities the CAISO could use heat rates for each unit based on comparable units from the CAISO control area and other neighboring control areas. For the price of natural gas, the spot price at Henry Hub plus the appropriate transportation charge to the unit's location should be used. Finally, figures on variable operating and maintenance costs could be taken from comparable units located in and outside of California.

This process could be followed to compute the CAISO's best estimate of the minimum incremental cost of supplying electricity for each unit in the control area. This unit-specific minimum incremental cost estimate should be used as the default energy bid for that generation unit in order to avoid distorting dispatch decisions and the ancillary services procurement process. To the extent that market participants feel that these default energy bids are leading to prices that are not sufficiently remunerative to their generation unit on an annual basis, these suppliers should make filings with the FERC to receive full cost recovery. Rather than distort locational marginal prices by using estimates of the minimum incremental cost of providing energy that the CAISO knows are too high as default energy bids, the ISO should use its best estimate of these magnitudes and make up any annual revenue shortfalls through annual fixed payments that can be cost-justified.

Basing a supplier's default energy bid on magnitudes that are outside of its control, yet reflect the ISO's best estimate of the unit's minimum incremental cost, has the additional benefit that it provides strong incentives for the supplier to minimize the actual costs of providing energy from its units at all times. If the supplier reduces its costs below the default bid, it keeps the difference. This is an application of the same economic principle underlying price-cap regulation, where the maximum price a regulated entity can charge depends on factors outside of its control according to a formula that the regulator is confident will yield a price that provides sufficient revenues to recover at least the firm's minimum cost of producing its output.

One of the lessons from the period June 2000 to June 2001 in the California electricity market is that basing the payment a supplier receives on the actual costs that it incurs creates strong incentives for these costs to be inflated. FERC's soft price cap, which allowed suppliers able to cost-justify bids above the soft price cap to be paid as bid, rapidly amounted to no price cap as reported natural gas prices and other input prices rose dramatically. Subsequent FERC investigations demonstrated that a significant fraction of the natural gas prices reported during this time period were drastically inflated. In fact, the reported spot price of natural gas in California persistently exceeded the reported price at Henry Hub by an average price of $8/MMBTU over the time period covered by the FERC soft price-cap. For comparison, the average difference between California and Henry Hub prices was less than $0.50/MMBTU over the first 2.5 years of the California electricity market. If the soft-cap policy for justifying bids into the California electricity market had been based on the Henry Hub price of natural gas plus the price of transportation, instead of reported natural gas prices in California, suppliers would have had a far harder time raising electricity prices during the period covered by the soft price cap.

4. Strategy for Market Power Mitigation Under MRTU Design

Our preferred strategy for system-wide market power mitigation has two major elements. First, use FERC's market-based price authority to order structural remedies for dominant suppliers. Second, forward market hedging by LSEs is the primary mechanism to limit the potential harm to consumers from the exercise of system-wide market power in California's short-term energy and ancillary services markets. If LSEs hold portfolio of swaps, caps, and other financial instruments that clear against prices at locations where the LSEs actually withdraw power from the network, consumers will be protected against the exercise of unilateral market power in the short-term markets through two mechanisms. First, suppliers have little incentive to raise spot prices at these locations until they cover their forward position. Second, if suppliers are successful at raising prices at these locations, consumers are unlikely to experience significant harm because they have very little exposure to the spot price and suppliers are likely to be able raise these prices only for a short period of time because of the hedging by LSEs. As we have emphasized in a number of previous opinions, sufficient fixed-price financial contracting between LSEs and suppliers that clear against prices at locations in the network where the LSEs withdraw power or locations where the LSEs have its CRRs sourced, guarantees there will be adequate generation resources to meet the LSE's energy and ancillary services requirements. This contract adequacy approach, where LSEs buy the necessary fixed-price, forward financial instruments to hedge their spot price risk, limits the incentives for the suppliers (that sold these contracts) to exercise market power in the spot market. This contract adequacy approach also provides very strong incentives for suppliers to minimize the costs of meeting these forward energy obligations, because any difference between the spot price at a location where a contract clears and contract price is paid to the seller of the forward contract.

For local market power mitigation we continue to support the prospective approach recommended in our opinion on the necessity of a LMPM mechanism.[2] The CAISO should follow the three-step process for designing a LMPM mechanism outlined in that opinion. The first step is defining a set of system conditions when an individual market participant is deemed to possess sufficient local market power to be worthy of mitigation. As stated in our previous opinion, all suppliers should be subject to this prospective LMPM mechanism, meaning that if these system conditions are met for a supplier, the bids for certain generation units or a certain amount of generation capacity from a collection of units owned by that supplier should be subject to mitigation. In our prior opinion, we suggested either defining certain transmission interfaces as non-competitive or identifying suppliers who are pivotal for local energy needs.

The next step is determining how suppliers that are mitigated will be paid. The major goal is to replicate as closely as possible competitive bidding behavior for mitigated units. Any additional payments to owners of mitigated units that are necessary to meet their annual revenue requirements should not distort locational marginal prices. The final step is to compute the market prices

[2] "Opinion on the Necessity of Effective Local Market Power Mitigation for a Workably Competitive Wholesale Market," May 29, 2003.

suppliers receive once they have been mitigated. This opinion discussed a number of approaches to each of these decisions.

One approach closely follows the one currently used in the PJM market. The ISO first deems some transmission paths as competitive and others non-competitive. Bids taken to resolve competitive constraints cannot be mitigated. Bids taken to resolve non-competitive constraints are subject to mitigation. Competitive constraints are typically those where there are a number of independent suppliers able to compete for the transmission capacity available. Non-competitive constraints are those where only a small number of independent suppliers are able to compete for the transmission capacity. For example, in the California market, one could imagine starting with the original zonal interfaces, as well as all interties into the CAISO control area as the competitive constraints. All constraints inside the three original congestion zones would be deemed non-competitive and bids taken to resolve these constraints would be subject to local market power mitigation.

For those bids subject to the LMPM mechanism, the CAISO would use a default energy bid that is the ISO's best estimate of the minimum incremental cost of supplying energy for that day for that generation unit, computed as described in the previous section. This approach minimizes the distortions to the day-ahead and real-time market outcomes that result from the use of a mitigated bid in the place of a supplier's actual minimum incremental cost, which is the optimal bid of a supplier facing significant competition from a number of independent suppliers. For this reason, if a unit were subject to mitigation because some of its capacity is needed to resolve a non-competitive constraint, then it would have its entire bid curve replaced by this default energy bid.

Following the determination of which units are subject to mitigation and the replacement of those bids with default energy bids, the day-ahead market would be used to set prices and schedule generation units using the full-network model of the CAISO control area. These mitigated bids would carryover to the real-time market. If the CAISO's process for computing minimum incremental costs is relatively accurate, the distortions to competitive market outcomes caused by this local market power mitigation mechanism should be minimal.

A final issue to be addressed is LMPM for ancillary services. The CAISO should follow the same three-step procedure for ancillary services. Specifically, ancillary services bids should not be mitigated along competitive transmission constraints, but ancillary services procurement along non-competitive constraints should be subject to mitigation. Because there is no variable cost of supplying ancillary services and the opportunity cost of supplying ancillary services are the lost variable profits from supplying energy, non-competitive ancillary services bids should be treated as price-takers. That is because generating units needed to resolve non-competitive constraints are typically price-setting units within a small geographic region and therefore have no opportunity cost of supplying energy. This logic implies that ancillary service capacity taken on the congested side of a non-competitive constraint should be paid the market-clearing price for that service for the largest un congested geographic region that the unit is contained within.

Our recommended three-step process for local market power mitigation can be incorporated into the California Public Utilities Commission's (CPUC) resource adequacy process. For example, as a pre-condition for a signing a forward contract to supply energy or ancillary services to California load, the CPUC could require a supplier to be subject to the LMPM procedure for both energy and ancillary services.

5. Concluding Comments

The changes to the RUC process ordered by the FERC in its decisions on the MRTU makes it extremely difficult to control effectively local market power in the energy, ancillary services, and RUC markets under the CAISO's proposed market power mitigation mechanism. For this reason, we strongly recommend that the ISO consider greater integration of the RUC constraints into the day-ahead energy and ancillary services market by specifying locational reserve requirements at the locations and at the levels necessary to operate the system reliably. This market should then be combined with a local market power mitigation mechanism that satisfies the criteria presented in our previous opinion on LMPM.

For both system-wide and local market power mitigation we do not support the use of an AMP mechanism. In fact, we believe that AMP mechanisms may in fact enhance the ability of suppliers to raise market prices above those that would exist in a competitive wholesale electricity market. We believe that a properly designed contract adequacy approach will most effectively limit the exercise of system-wide market power in the short-term energy and ancillary services market and a LMPM mechanism designed along the lines recommended in our previous opinion will best address local market power concerns.