Opinion on the California ISO's Market Redesign and Technology Upgrade (MRTU) Conceptual Filing

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1. Introduction

This opinion comments on the California ISO's conceptual filing to the Federal Energy Regulatory Commission (FERC) on the Market Redesign and Technology Upgrade (MRTU). There are three main elements of this filing: (1) the method used to translate Load Aggregation Point (LAP) demand bids into nodal prices in the day-ahead market, (2) the structure of the Hour Ahead Scheduling Process (HASP), and (3) the policies and mechanisms for managing system-wide and local market power in the ISO's short-term energy, ancillary services, and residual unit commitment (RUC) markets.

Modifying the mechanism for clearing LAP-level demand bids in the integrated forward market (IFM) is necessary to ensure the accuracy of nodal day-ahead energy schedules. Although we strongly prefer a market design that treats load and generation symmetrically by requiring nodal-bidding and pricing for both loads and generation unit owners, we recognize that implementing this market rule can subject some load-serving entities (LSEs) to higher wholesale prices. Clearing all loads at LAP-level prices eliminates the risk of high relative prices for certain LSEs. However, this scheme implies that loads in high-cost areas will receive a cross-subsidy from loads in low-cost areas.

These subsidies may be appropriate for existing consumers, because the current transmission network in California was not build to serve a wholesale market with locational marginal pricing (LMP). We believe that a superior long-term solution to the cost impacts of LMP for demand would be to allocate congestion revenue rights (CRRs) to loads in order to limit average price differences across locations within each LAP at current consumption levels. With this scheme, consumers would pay the LMP for additional consumption and receive the LMP for reduced consumption. This is one mechanism that achieves our long-term term goal of causing demand to pay or receive, on the margin, the true cost of supplying their location with additional energy.

Aggregation of prices to the LAP level also requires the ISO to specify load-distribution factors (LDFs) to compute the LAP-level price used to clear the LAP-level demand bids in the IFM. If the ISO has accurate load distribution factors for all possible system conditions, the inaccuracies in day-ahead nodal energy schedules from clearing LAP-level demand bids at LAP prices are likely to be manageable. However, as final demand becomes a more active participant in the wholesale market, the LDFs for each LAP are likely to depend on the LAP price, and therefore the market efficiency cost of using fixed LDFs for a given set of system conditions is likely to increase. In addition, higher locational prices to some LSEs under nodal pricing of load can be addressed through the CRR allocation process. For this reason, we recommend that the ISO explore adding more LAP areas and eventually work toward implementing nodal-bidding and pricing of load and address the issue of higher locational prices to some LSEs though the CRR allocation process.

There are a number of potential advantages of the ISO's Hour Ahead Scheduling Process (HASP). This mechanism allows scheduling coordinators (SCs) to provide additional supply resources and wheeling transactions without a formal hour-ahead settlement process. The HASP uses the ISO's load forecast and pre-dispatches both energy and ancillary services bids from the interties. However, we are concerned that adopting the HASP may increase the cost of implementing a long-term solution to the problems associated with pre-dispatching import bids at the interties. For this reason, we believe it may be more cost-effective for the ISO to formulate a long-term solution to the pre-dispatch of intertie bids before committing to a design for the HASP.

For the remainder of this opinion we focus on the market power mitigation elements of the MRTU conceptual filing. As we have previously noted, the lack of a comprehensive framework for managing local market power is a major shortcoming of the current California ISO market design.[1] If the MRTU process is to be successful the ISO must obtain from FERC the authority to impose an effective local market power mitigation (LMPM) mechanism. An effective LMPM mechanism, together with fixed-price forward contracts for energy between suppliers and California load-serving entities (LSEs) and active participation in the wholesale market by California consumers, are all necessary conditions for a workably competitive wholesale market.

The California Public Utilities Commission (CPUC) is responsible for ensuring that California LSEs have adequate fixed-price forward contract coverage (negotiated far enough in advance of delivery to obtain a reasonable price) of their retail energy and ancillary services obligations and that final demand actively participates in the wholesale market. These features of the retail market design primarily limit the ability of suppliers to exercise system-wide market power in the short-term energy and ancillary services markets. However, the technology of electricity production and delivery can create circumstances when one or more suppliers are essential to meet a local energy or ancillary services need. Under these system conditions, one or more suppliers can possess substantial local market power and without an effective prospective LMPM mechanism only the bid cap limits what they can charge to meet this local energy or ancillary services need. Given the uncertainties associated with generation unit and transmission line availability, these system conditions are very difficult to predict and can often last for significant periods of time. For example, a large nuclear facility or a transmission line may be unexpectedly forced out for an extended period of time, and this may make a single generation unit essential to meet demand at a certain location. Because of these uncertainties it is possible that virtually any generation unit in the ISO control area can possess substantial local market power under some system conditions. FERC must therefore give the ISO the authority to implement a prospective LMPM mechanism that applies to all generation units in the control area, or California consumers

[1] "Opinion on the Necessity of Effective Local Market Power Mitigation for a Workably Competitive Wholesale Market," May 29, 2003 (available from http://www.caiso.com/docs/2003/05/29/200305291236069966.pdf)

will be subject to periodic episodes of substantial local market power when these unexpected system conditions arise.

The next section describes the necessity for a prospective LMPM mechanism to prevent significant harm to consumers from the exercise of unilateral market power. This section also describes the essential role of fixed-price forward contracts for energy versus an installed capacity market or capacity payments in limiting the ability of suppliers to exercise system-wide unilateral market power in the *short-term* energy and ancillary services market. Section 3 discusses important details of the design of a LMPM mechanism, including the appropriate bid level for mitigated generation units regardless of how frequently they are mitigated. This section also discusses the question of scarcity of generation and reserves either locally or system-wide and the appropriate market prices when these system conditions occur. Section 4 discusses the rationale for changing the level of the bid cap on the ISO's energy and ancillary services markets. This section highlights need for the CPUC to mandate higher minimum levels of coverage of final demand with fixed-price forward contracts for energy if it would like to maintain the integrity of lower levels of the bid cap on the ISO's short-term energy and ancillary services markets. Section 5 considers the costs and benefits of an automatic mitigation procedure (AMP) as a means to limit the exercise of system-wide unilateral market power. Our conclusion is that the costs of an AMP mechanism is not worth any potential benefits it might provide.

2. Managing Market Power in Wholesale Electricity Markets

We believe the best approach to managing market power in electricity markets is to focus strong mitigation on the aspects of the energy and ancillary services procurement process that are unlikely to produce competitive outcomes, while minimizing interference with those aspects with a sufficiently competitive market structure. The ISO's proposed market power mitigation package reflects this philosophy. The approach is to limit the amount of system-wide mitigation while focusing strong mitigation on local markets where transmission constraints preclude effective competition in both short and longer-term markets. Outside of locally constrained regions, potential and actual competition from new entrants will result in adequate competition for fixed-price forward contracts for energy and ancillary services with delivery horizons of at least two to three years into the future, where new entrants can credibly compete.

The most effective way to limit the incentive for suppliers to exercise market power in *short-term* energy and ancillary services markets is to take advantage of the fact that the forward market for energy and ancillary services is substantially more competitive at delivery horizons longer than is necessary to bring new generation capacity on line. For this reason, LSEs can rely on the threat of new entry of generation capacity to obtain a competitive price for a fixed-price long-term contract for energy or ancillary services delivered several years in the future. However, at shorter delivery horizons, fewer suppliers are able to compete. Significant reliance on forward markets at these delivery horizons can subject consumers to substantial unilateral market power in the short-term energy and ancillary services markets. As the delivery horizon becomes shorter, the number of suppliers competing to provide the necessary energy or ancillary services shrinks, until the real-time market, when only suppliers operating their units with unloaded capacity can meet the energy or ancillary services need.

Consequently, the same level of exposure to energy and ancillary services markets at shorter delivery horizons increases risk that final consumers will be subject to the exercise of substantial unilateral market power.

It is important to emphasize that having adequate generation capacity installed to serve demand does very little by itself to prevent the exercise of unilateral market power in short term energy and ancillary services markets. Specifically, suppose there are two otherwise identical markets in terms of market demand and the amount and ownership of generation capacity, except that one has a capacity market and the other does not. These two wholesale electricity markets will be subject to the same amount of unilateral market power in the spot market, because the capacity payment only requires a supplier to bid into the spot market at or below the bid cap if its units are available to operate. The incentives for suppliers to bid at the bid cap are identical under either scenario. In addition, the supplier has the option in either case to declare some of its generation units unable to operate despite the fact that they are actually able to operate. A major lesson from the period June 2000 to June 2001 in the California market is the virtual impossibility of determining whether a supplier is truly able to supply energy from its generation units. In contrast, adequate levels of fixed-price forward contracts for energy and ancillary services significantly limit the incentives of suppliers to exercise unilateral market power in the short-term energy and ancillary services markets. Adequate installed capacity to serve demand alone does very little to prevent the exercise of substantial unilateral market power in short-term markets. This is true even if the installed capacity market penalizes the unit owner for declaring too many forced or planned outages by limiting the amount of installed capacity it can sell from the generation unit in future periods. In most systems, penalties for failing to comply with must-offer requirements are inadequate and measurement of compliance is difficult, if not impossible.[2]

While robust forward markets have proven to be effective in mitigating market power over broad regions where entry is relatively unconstrained and there are a number of potential suppliers, forward contracts do not produce the same benefits in areas subject to local market power. Certain generation unit owners possess substantial local market power because it is extremely costly to build a new generation unit in a local area at almost any time horizon to delivery. Consequently, it is not credible in such circumstances for an LSE to use the threat of entry to discipline the forward contract price that an existing local supplier would offer to provide energy or ancillary services.

A second reason the forward contract solution may not limit the local market power exposure of an LSE results from the LSE not buying sufficient energy for delivery points in the network where it actually withdraws power. This purchasing strategy can create circumstances where the LSE is exposed to significant locational price risk because the network is unable to deliver the wholesale energy from the points in the network where it is injected to the points where the LSE actually withdraws energy from the network. By making its forward market purchases at locations in the network where it actually withdraws

[2] For example, a common penalty for non-performance is to reduce the amount of installed capacity a unit can sell in future periods. The delay in applying the penalty, combined with the fact that capacity may be worth much less in the future, dilutes the effectiveness of this approach.

energy at levels less than or equal to its actual retail energy obligations at these locations, this exposure to local market power in the spot market can be avoided.

To the extent that LSEs do not precisely match their forward contract purchases to their anticipated locational energy needs and to the extent that certain locations in the transmission network face substantial barriers to entry by new generation facilities, LSEs will face significant local market power in the spot market. While LSEs should be given strong incentives by the CPUC to purchase their forward market energy needs to match their expected locational energy needs, it is difficult for the LSE to forecast precisely its demand for energy at all locations in the network. In the instances when LSEs unexpectedly need additional energy from certain locations in the network in the short-term market, they should not be subject to the exercise of substantial local market power.

An advantage of a locational marginal pricing (LMP) market design is that CPUC can specify the exact delivery locations that suppliers should purchase the necessary forward contract coverage for their energy and ancillary services obligations. Rather than specifying delivery within a zone, the CPUC can mandate forward market purchases at locations where the LSE actually withdraws energy from the network. This will ensure that forward energy and ancillary services purchases can actually be delivered in real time. Specifically, if the LSE has purchased energy in advance for delivery at locations where it withdraws energy or at locations where its CRRs are sourced, then the risk of failing to deliver in real-time now is transferred to generation unit owners. These market participants have the actual physical resources necessary to ensure that load will be served, and face a significant financial penalty if they are unable to do so.[3]

3. Features of an Effective LMPM Mechanism

In our previous opinion on the necessity of an effective local market power mitigation mechanism we highlighted a number of criteria for designing an LMPM mechanism.[4] We believe that the PJM-style mechanism proposed by the ISO is likely to satisfy those criteria better than a New York-style mechanism. The appeal of the PJM style mechanism is that mitigation is based primarily on the structure of the transmission network and geographic distribution of generation assets. Certain transmission constraints are deemed competitive and no bids to use such interfaces will be mitigated. All other constraints are non-competitive and the bids of generating units that most effectively relieve those constraints must be mitigated, because of the belief that there is insufficient competition among these suppliers. In contrast, the New York-style of mechanism relies on behavioral conduct and impact thresholds to determine which generation units should be mitigated. Potentially, all units in a geographic area could be mitigated, depending on their behavior. However, a weakness of the New York approach is that depending on the levels of

[3] For example, if (1) an LSE has purchased a fixed-price forward contract for energy delivered to a specific location and (2) it is unable withdraw this quantity of energy from the network at this location during the settlement hour because of a local transmission constraint or inadequate supply of energy, there are a number of ways to penalize the seller of the contract. For example, the supplier could simply be required to pay the LSE the difference between the spot price and the forward contract price at that location times the forward contract quantity. Because some demand by the LSE at that location is unmet, the spot price at that location would be at least equal to the market-wide bid cap, which would imply a substantial payment to the buyer of the contract. Therefore, a means of increasing the cost of these energy shortfalls to the seller of the contract is to raise the bid cap on the spot market.

[4] "Opinion on the Necessity of Effective Local Market Power Mitigation for a Workably Competitive Wholesale Market," *op. cit.*, Footnote 1.

the conduct and impact thresholds set in the regulatory process, a substantial amount of local market power could go unmitigated. Specifically, FERC selecting the levels of the conduct and impact thresholds that a generation unit must violate to have its bid mitigated amounts to it specifying an acceptable amount of local market power that is allowed to go unmitigated. Because the New York-style mechanism sanctions the exercise of local market power within the tolerances of the conduct and impact thresholds, we prefer the PJM approach which eliminates this regulatory discretion.

The ISO is filing a mechanism that is very similar to the PJM approach. It also shares important elements with LMPM mechanisms already approved by FERC for other ISOs, such as those in New England and New York. We understand the desire of the ISO to file a tariff that does not conflict with FERC decisions regarding mitigation in these other markets and we believe that the package of mitigation and other MRTU elements as a whole constitutes an improvement over the current design. However there are aspects of the LMPM that we believe significantly detracts from market efficiency. We discuss these in detail below. Most of these aspects are shared with the mitigation mechanisms in other US markets. We urge the FERC to reconsider the impacts of these shortcomings on market efficiency in the context of formulating a set of consistent principles for local market power mitigation in all ISOs.

Before discussing the workings of LMPM mechanisms, it is useful to consider the goal of these mechanisms, which is to produce locational prices that accurately reflect the incremental cost of withdrawing power at all locations in the network. Such prices are produced by sufficient competition. An efficient price should reflect the incremental cost (or benefit) to the system of additional consumption (or supply) at that location in the transmission network. Unless there is a shortage, a price that is above the short term incremental cost is inefficient because it can deter consumption whose value is greater than the cost of production, but below the price. Further, when an individual generation unit sets its price above its incremental cost, other more expensive units may be chosen to supply in its place. In the absence of shortages, prices that deviate from incremental costs cause inefficient consumption and inefficient production. In perfectly competitive markets, firms will choose to produce as long as the price is above their incremental costs. The only time the economically efficient price should be above the incremental cost of withdrawing energy at that location is when supply at that location is capacity constrained (*i.e.* there is a scarcity of supply). In this case, the efficient locational price is above the variable costs of all generation units. Ideally, it is set by the willingness of demand at that location to curtail its consumption. In practice, it is usually set equal to bid cap on the energy market.

The general idea of local market power mitigation is to induce an offer price from a generation unit with local market power equal to the one that would obtain if that unit faced sufficient competition. A unit that faces substantial competition would offer a price equal to its variable cost of supplying additional energy. When the LMPM mechanism is triggered, the offer price of such a unit is set to a regulated level. By the above logic, this regulated level should be equal to the ISO's best estimate of the unit's variable cost of supplying energy, assuming that a scarcity pricing mechanism is in place that would raise prices above bid levels in case of a capacity shortfall. Although the conditions under which mitigation is triggered are the main source of differences between the New York-style and PJM-style mitigation, we will focus on the level that the offer price is mitigated to. While the mitigation controls the extent to which offer prices deviate from incremental costs, several aspects of all existing LMPM mechanisms, including ISO's proposed mechanism, bias the offer price upwards to guarantee that mitigated offer prices will be noticeably higher than those from units facing substantial competition.

The ISO proposes to offer three options for mitigated bid prices: (1) incremental costs plus a 10% adder, (2) an average of previous LMPs at the unit's location, or (3) a negotiated price. For units that are frequently mitigated—more than 80% of their run hours—an even larger bid adder will be added to the ISO's estimate of that unit's variable cost.

The three mitigation options share one important feature: each is virtually guaranteed to be significantly above the incremental cost of the generation unit. We are very sympathetic to concerns about over-regulation in electricity markets. There will always be some uncertainty about the true minimum cost of producing energy from a generation unit. Linking offer prices to incurred costs could weaken the incentives of generators to lower those costs. The concern with accurately measuring incremental costs seems to have resulted in a desire to bias mitigated prices upwards. However, this does not address the fundamental problem that price regulation is an imperfect but necessary response to situations of chronic market power and that incremental cost estimates are as likely to be too high as too low.[5]

Using a bid adder that the ISO knows is larger than the generation unit's minimum variable cost contradicts the primary goal of locational marginal pricing to obtain the most efficient dispatch possible. A scheme that systematically biases the bids of mitigated generation units upward relative to the ISO's best estimate of the unit's minimum variable cost of supplying electricity does not achieve this goal. Generation units that face sufficient competition will bid close to their minimum variable cost. Combining these bids with mitigated bids set significantly above their minimum variable cost of supplying energy will result in units facing significant competition being overused.

One might think that a 10 percent adder is relatively small, but it is important to emphasize that if 100 MW generation unit is operating 2000 hours per year with a 10 percent adder on top of a variable cost estimate of $50/MWh, this implies annual payments in excess of these variable costs of $1 million to that generation unit owner. In addition, this mitigated bid level will set higher prices for units located near this generation unit, further increasing the costs to consumers.

The use of historic nodal prices as a substitute for the incremental cost of a generation unit is even more troubling. Historic market prices will typically bear little resemblance to the minimum incremental cost of a generation unit. The only conditions under which historic prices are likely to reflect incremental costs are those in which the unit is always marginal and likely to be frequently mitigated. At the very least, the ISO should

[5] Elsewhere, we have argued that using standard costs for generators of particular types as reference bids rather than unit specific reference bids would provide more appropriate incentives for reducing generating unit operating costs. See "Market Power Mitigation Under Locational Marginal Pricing", MSC Opinion, Nov. 23, 2004, www.caiso.com/docs/2004/11/23/2004112316123829554.pdf.

consider segmenting the pricing under this option by time of day so that peak prices do not get reflected in off-peak mitigated bids.

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

We strongly urge the ISO to avoid setting locational marginal prices above competitive levels by including ad hoc bid adders in mitigated bid levels as means for providing adequate revenues to owners of mitigated generation units. As discussed above, this strategy could have significant costs to consumers in terms of market efficiency and it results in the overuse of generation units facing substantial competition.

The ISO should design a mechanism for setting the mitigated bid level for a supplier that balances the two competing goals common to all regulatory price-setting processes. First the mitigated bid should allow the generation unit owner the opportunity to recover the minimum variable cost of supplying energy. Second this mechanism should provide the strongest possible incentives for the supplier to provide the necessary energy at minimum cost.[6]

3.1. Mitigation and Fixed Cost Recovery

An overriding concern driving the design of LMPM mechanisms is the fear that over-mitigation will artificially depress prices and result in under-investment in generation. The perception that under-investment is a more serious problem than over-investment has produced a preference to err on the side of higher prices. Yet distorting locational prices is unlikely to serve the purpose of improving efficiency if the higher prices are not focused in periods and at locations with high costs of supplying energy. Unfortunately, policies that inflate offer prices with adders will raise prices in all hours and could, through the LMP calculations, cause price spillovers to other locations not subject to local market power or experiencing scarcity.

[6] One example of this approach is for ISO to establish a benchmark variable cost estimation procedure based on validated heat rates and variable operating and maintenance costs for each gas-fired generation unit in California. This validated heat rate would be multiplied by a benchmark daily price of natural gas delivered to the generation unit. The Henry Hub price plus the regulated cost of transporting natural gas from Henry Hub to this generation unit, including the relevant intrastate gas transmission and distribution charges, could be used as this benchmark natural gas price. The heat rate times this benchmark delivered price of natural gas plus a benchmark variable operating and maintenance charge for generation units of this technology and vintage could be set equal to the mitigated bid level for this generation unit. If the supplier believes that it can produce the necessary energy at a lower variable cost, then it should be able to keep the difference between this benchmark variable cost and its actual variable costs. This scheme for setting mitigated bids would provide strong incentives for the least cost procurement of natural gas and operation by mitigated generation units. Because it uses the ISO's best estimate of the minimum variable cost of that generation unit, this mechanism also limits the distortions in the dispatch introduced as a result of mitigating generation units because they possess substantial local market power.

The most egregious of these practices is the proposal to add $40/MWh to the offer prices of all frequently mitigated units that are not receiving fixed cost compensation through Reliability Must-Run (RMR) contracts or some other capacity mechanism. The motivation for the adder is to ensure that frequently mitigated units receive compensation adequate to cover at least their going-forward fixed costs.[7] However, it is important to remember that any unit, even a frequently mitigated unit, is still eligible to earn prices well above its offer price. For example, the ISO is considering a scarcity-pricing mechanism that will set prices at the price-cap during any hours in which there is an operating reserve deficiency. Given a relatively low price cap, even this may not provide adequate revenues for a frequently mitigated unit to recover fixed costs. However, simply raising prices in hours where there is no scarcity is equivalent to stating that two wrongs make a right.

Frequently mitigated generation units are providing a regulated service, and they should receive cost recovery. But cost recovery need not distort prices in periods or at locations where there is no justification for prices to rise above incremental costs. Consider a mitigated unit with a $60/MWh incremental cost and a $40/MWh adder that is applied in an hour of ample supply. The market will be telling generation with costs less than $100/MWh that they are needed and telling demand with a value of electricity less than $100/MWh to shut down. Neither outcome is desirable.

The FERC has articulated the belief that it is appropriate that some portion of the fixed costs of mitigated units be allowed to set market prices. In other words, such units should not just be allowed to recover their fixed costs for themselves, but those costs should be reflected in the prices earned by other non-mitigated units. The FERC is essentially arguing that prices should be set at long-run average cost, as they would in the long run in a competitive market. There are two problems with this view. The first is that the FERC would set prices to recover at least these average costs during *all hours* the unit operates. In a competitive market the high prices during certain periods would offset prices at incremental costs during the majority of hours with abundant supply. The average of all these resulting prices would trend toward long-run average cost. The adder approach gets prices wrong all the time, producing the problems described above.

Second, the fixed adder approach ignores the plausible prospect that frequently mitigated units may operate in a natural monopoly environment. In other words a small local market is most efficiently served by a plant or plants owned by one firm. In any natural monopoly, incremental costs are insufficient to recover fixed costs. But this is not a signal of a need for new generation, only the lack of a competitive environment. It is widely accepted that setting prices of natural monopoly services at incremental costs would be efficient, if the fixed costs of the natural monopoly provider could be recovered through other means.

Consequently, even for a frequently mitigated unit, its mitigated bid should be set equal to the ISO's best estimate of its minimum variable cost of supplying electricity. This mitigation mechanism does not imply that the unit owner cannot recover sufficient costs to remain in the market. In fact, if this supplier is required to meet a local energy need during a number of hours of the year, then the local LSE will have a strong incentive to enter into a long-term contract with this local supplier that recovers its going-forward fixed costs. This

[7] Note that fixed costs, by definition do not vary with the output of a plant. They are therefore not incremental costs.

unit owner always has the option to exit the industry or simply mothball its unit if it does not believe it can recover sufficient revenues from spot market energy sales. However, if the unit is necessary to meet local demand, then this LSE must find an acceptable forward contract payment stream that recovers the unit's annual total costs. A $40/MWh adder may significantly increase the forward contract payment stream the local LSE must pay to the supplier to provide these local energy needs, because the supplier will be foregoing that payment, as well as distorting the spot prices this units and other nearby units receive for the energy they supply to the spot market.

3.2. Scarcity Pricing

The ISO is proposing to explore the implementation of "scarcity pricing" under some level of deficiencies in operating reserves. Under this proposal, prices would rise to the price cap when operating reserves dip below some pre-defined level. We are supportive of this concept of scarcity pricing as a means for fixed cost recovery for generation units. In particular, we believe that it is an essential element of a well-functioning electricity market that would also include active participation of final consumers in the wholesale market, sufficient forward contracting by LSEs, low barriers to new entry of generation capacity, and adequate transmission capacity to serve the wholesale market.

However, until all these elements are in place, this kind of scarcity pricing is not necessarily a second-best solution. In particular, we believe there are several aspects of the specific proposal for scarcity pricing under the MRTU design that argue against implementing it at this time. We have noted in previous opinions that scarcity rents should be paid only when there is true scarcity. This underscores the point that if scarcity conditions are particularly profitable for suppliers they will take actions to create these conditions. To the extent that LSEs have signed sufficient fixed-price forward contracts for their expected energy needs, our concern with suppliers taking actions to cause scarcity conditions in the energy market carries less weight, and the argument for implementing scarcity pricing mechanisms becomes stronger.

Under the current MRTU design, suppliers providing ancillary services are permitted to designate the energy they propose to supply from their units with a "contingency" flag, meaning that the energy will be taken from these units only if the ISO has a system emergency. The ISO is proposing to define a scarcity condition as when the ISO must call upon these contingency reserves. Because the contingency status is now voluntary, we are concerned that this creates an additional mechanism for suppliers to withhold energy from the real-time market and therefore creates an artificial, rather than true scarcity of energy. We feel that the conditions that constitute scarcity should be based upon an assessment of the physical needs of operators for system stability, rather than the self-election of suppliers. We are also concerned that the definition of scarcity will be different in the real-time market than it is in the day-ahead market. We therefore recommend that the ISO defer implementing scarcity pricing under reserve deficiencies until it can complete a more comprehensive definition of scarcity that can be applied consistently across both markets.

We also recommend that the ISO explore eliminating the contingency flag and allow suppliers to use their energy bid to manage their dispatch risk in the real-time market. With the elimination of the system-wide automatic mitigation procedure (AMP), there is little remaining rationale for this contingency flag on the energy portion of ancillary services bids. Suppliers that wish to provide reserves and only supply energy under extreme system conditions can submit an energy bid at or slightly below the energy bid cap.

If LSEs have procured enough installed generation capacity to meet their retail demand needs without sufficient levels of fixed-price forward contracts for energy, the likelihood that scarcity conditions may arise is significantly increased because, as noted earlier, having adequate installed generation capacity does little to limit the incentive of suppliers to exercise market power in the spot market. For example, one way to exercise substantial unilateral market power is to create artificial scarcity conditions to exploit the market rules that allow prices to rise during periods of apparent scarcity.

As a general rule, unless there is an active demand-side in the wholesale market, implementing a scarcity-pricing regime is very likely to enhance the ability of suppliers to exercise unilateral market power in the spot market. With an active demand-side in the wholesale market price-responsive consumers will submit their willingness to reduce their demand into the spot price, and this will ration the available supply without the need for an administratively determined procedure for reducing the demand for electricity. For scarcity pricing to achieve the maximum benefits, the following essential elements of a well-functioning market must be in place: (1) LSEs have fixed-price forward contracts covering a substantial fraction of their expected demand, and (2) the majority of the remaining demand that is not covered by these fixed-price forward contracts must pay the real-time price for electricity if they consume more and receive the real-time price if they consume less than their fixed-price demand level.

4. Setting the Level of the Price Cap in the Energy and Ancillary Services Markets

Virtually all stakeholders agree with the need for a damage-control cap on bids into both the short-term energy and ancillary services markets. An important issue is the appropriate level of that cap. While it is unclear what the appropriate levels of these bid caps should be, there are a number of factors that should be considered in setting these levels to ensure that both the spot market for energy and ancillary services operates efficiently. Specifically, there is an inverse relationship between the level of the price cap on the spot market that can be credibly maintained and the necessary amount of final demand that must be covered by fixed-price forward contracts for energy. As long as the level of the price cap is set above the variable cost of the highest cost unit necessary to meet demand, lower levels of the price cap on the spot market for energy require higher levels of coverage of final demand with fixed-price forward contracts in order to maintain the integrity of the bid cap on the energy or ancillary services market. For example, the experience of the past two years in the California market has shown that a bid cap of $250/MWh does not impose significant reliability problems or degrade the efficiency of the spot market if virtually all of the demand in the California ISO control area is covered by forward contracts.

If the bid cap is set too low for the level of forward contracts, then it is possible for system conditions to arise when one or more suppliers have an incentive to test the integrity of the bid cap on the spot market, by bidding in excess of the price cap. These system conditions arose frequently during the period June 2000 to June 2001 because only a very small fraction of final demand was covered in fixed price forward contracts or by generation facilities owned by the California utility distribution companies (UDCs). Maintaining the credibility of the current $250/MWh bid cap requires that the CPUC mandate forward contract coverage of final demand at very close to the present level. Transitioning to a wholesale market with an installed capacity obligation or market and sufficient installed capacity to meet final demand, but with a lower amount of final demand covered by fixed-price forward contracts for energy increases the likelihood that one or more suppliers will find it unilaterally profitable to test the integrity of the bid cap on the spot market. Low bid caps may also mean that the forward contract price is higher than average short-term energy prices over the term of the contract. This by itself is not necessarily inefficient, depending on the design of a forward contracting requirement and the risk preferences of LSEs versus generation unit owners.

A major cost associated with maintaining the current level of the bid cap is that it virtually eliminates any incentive for final demand to become an active participant in the wholesale market. At a $250/MWh bid cap, final consumers save only limited amounts of money by reducing their consumption during periods with high wholesale prices. This implies that virtually all solutions to supply and demand imbalances in the present market design must come from constructing additional generation capacity, rather than reducing final demand and eliminating the need to construct new generation facilities. Another cost of a low bid cap is the weakening of incentives to maintain high unit availability during peak load periods. Higher levels of the bid cap on the energy market provide greater incentives for suppliers to maintain their units. The energy bid cap is the maximum spot market replacement cost of energy not supplied by a generation unit owner that is unable to meet its fixed-price forward contract obligations. Furthermore, importers are also much more likely to provide energy to California during extreme system conditions if they can receive a price that is significantly higher than the current price cap of $250/MWh. However, these benefits of raising the bid cap must be balanced against the cost of greater opportunities to exercise market power in the spot market, if there is inadequate hedging by LSEs and insufficient spot market participation by final demand.

A second issue with respect to lower bid caps on the ISO's energy and ancillary services markets is that they reduce the unilateral incentive LSEs have to enter into forward contracts for energy and ancillary services because the potential downside of substantial purchases from short-term markets is reduced by the level of the bid caps. This logic implies that any finite bid cap on short-term energy and ancillary services markets will dull the incentive that LSEs have to engage in fixed-price forward contracts. Consequently, the CPUC must mandate minimum levels of forward contracting for LSEs subject to their regulatory oversight to ensure adequate levels of forward contracting. Direct access customers and LSEs not subject to CPUC regulation must bear either the increased risk of outages or higher spot prices during periods of energy or ancillary services scarcity, or they will have an incentive to rely too heavily on spot market purchases because of the level of the bid caps.

A third important issue concerns the level of bid caps on the ancillary services market versus the energy market. The marginal cost of providing an additional MW of ancillary services from a unit with unloaded generation capacity is zero. In addition, the opportunity cost of selling ancillary services is the foregone variable profits of that generation unit selling energy. Consequently, besides the usual arguments that the slope of the residual demand curve a supplier faces determines the extent of unilateral market power a supplier is able to exercise, in the case of ancillary services, the market power a supplier can exercise in the energy market creates an additional reason for the price of an ancillary service to be greater than zero. In particular, the supplier uses the foregone variable profits from selling one MWh of energy as the opportunity cost of providing an additional MW of ancillary services. The supplier then bids a markup over this opportunity cost of providing ancillary services based on how competitive it thinks the ancillary services market is. The more suppliers competing to provide this ancillary service, the lower is the markup.

This logic, together with the relative thinness of ancillary service markets (because only a subset of the generation units can sell each ancillary service), suggests that ancillary services are far more susceptible to the exercise of unilateral market power than energy markets. Combining this with the fact that variable cost of providing ancillary services is close to zero suggests it is appropriate to set a significantly lower bid cap on ancillary services as opposed to energy. For these reasons, we support the ISO's plan to reduce the bid cap on the ancillary services markets. We also support the ISO's proposal for a transition plan to raising the price cap on the short-term markets for energy, although we emphasize the need to maintain significant levels of forward contracting for energy and ancillary services. Despite that fact that at higher values of the bid cap suppliers have less of an incentive to test the integrity of the bid cap, the potential harm to consumers from prices near the cap are significantly higher, so that high levels of forward contract coverage are necessary to protect consumers from the risk of high spot prices.

To summarize, we support the ISO's proposal for a phased increase in the energy bid cap, accompanied by decreases in the ancillary services bid cap. However, rather than use a retrospective assessment of the competitiveness of the energy and ancillary services market to determine whether to raise the bid cap on the energy market, we recommend that the ISO focus on whether final demand has adequate protection against spot price risk either through fixed-price forward contracts or active participation in the real-time market. Because system conditions can change dramatically across years, primarily because of hydrology and demand growth outside of California, it is extremely difficult to determine on an *ex ante* basis whether there will be substantial opportunities in the future for suppliers to exercise market power at a higher bid cap. Consequently, the assessment of whether to raise the bid cap should focus on whether the final consumers have adequate protection against the accompanying increased risk of high spot prices, rather than on an assessment of the competitiveness of the energy and ancillary services markets. Because any finite bid cap on the energy and ancillary services market dulls the incentive LSEs have to hedge short-term price risk, the CPUC must play a major role in ensuring adequate levels of forward contracting and demand-side involvement in California's short-term energy and ancillary services markets for the LSE subject to its regulatory oversight and direct access customers.

5. Suspension of System-wide AMP

We support the ISO's proposal to suspend the use of system-wide automatic mitigation procedure (AMP) under MRTU. This move is consistent with the general approach of focusing mitigation on the least-competitive aspects of the markets and reduces reliance on an ineffective and potentially intrusive mitigation tool. In past opinions we have expressed our skepticism about the benefits of system-wide AMP as well as our concerns about the undesirable side effects that can be induced by procedures that utilize previously accepted bids to set AMP reference levels.[8] The use of historic bids 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.

We believe that setting AMP reference levels based on accepted bids limits the incentives for suppliers to compete vigorously during competitive periods. Using this mechanism to set reference levels results in an AMP mechanism that risks raising average prices in the majority of periods and reduces prices only during those relatively rare periods when the supplier is pivotal. In addition to our general concerns about AMP 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 these reasons we strongly endorse the move to relegate system-wide AMP to a suspended status during the initial operations of the market under MRTU.

6. Concluding Comments

As we have emphasized in a number of previous opinions, to be effective an LMPM mechanism must be integrated with the design of the energy and ancillary services market. Despite our reservations with parts of the proposed LMPM mechanism, we believe that proposed mechanism, integrated with the overall energy market design, constitutes a major step forward for the California market. For this reason, we strongly advocate that FERC adopt this comprehensive package rather than pick and choose aspects of the proposed market design combined with features from other US ISOs. The experience of the past seven years in California demonstrates that the unintended consequences of a piecemeal approach can be extremely costly for California consumers.

[8] See "Market Power Mitigation Under Locational Marginal Pricing", MSC Opinion, Nov. 23, 2004, www.caiso.com/docs/2004/11/23/2004112316123829554.pdf.