Recent Events in the California Electricity Industry and the Level of Price Caps on the ISO's Energy and Ancillary Services Markets

by

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Introduction

In a statement issued March 9, 2000 entitled, "The Competitiveness of the California Energy and Ancillary Services Markets," (March Statement) the Market Surveillance Committee (MSC) of the California Independent System Operator (ISO) considered whether the price cap on the ISO's energy and ancillary services markets should be lowered from $750 to $500 for the Summer 2000. The concluding section is reproduced below.

> In conclusion, California's energy and ancillary services markets have not been workably competitive during the last two summers. As we have noted in the Committee's prior reports, a number of factors have contributed to this condition, including market design flaws, lack of price-responsive final demand, and limitations on the IOU's ability to enter into forward contracts. We would expect the experience of the last two summers to be replicated in 2000 unless these various conditions have been corrected.
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> The ISO has implemented most, but not all, of the market design changes this Committee has recommended. However, the effectiveness of these reforms in the tight system conditions expected this summer is unknown. Likewise, the CPUC is currently considering approval of demand-response programs by PG&E and SCE, and may permit expanded IOU participation in the PX block forwards market. Whether these measures will reduce generators' ability to exercise market power depends upon the terms and scope of the programs the CPUC ultimately authorizes and their effectiveness in high-demand periods.
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> For these reasons, we are unable to conclude that California's energy and ancillary services markets will be workably competitive during high-demand periods this summer. That assessment must await the outcome, under conditions of high demand, of the operation of the reconfigured ISO markets, and the CPUC's demand-responsiveness and forward-contracting policies.
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> We make no recommendation on whether to lower the cap from $750 to $500. This is a policy decision for the ISO Board of Governors, taking into

account the potential for extension of the CTC period, greater incentives a higher cap might provide for participation in UDC demand-responsiveness programs, and the likelihood that a test of the ISO's market reforms with a $750 cap will give clearer results than with a $500 cap.

Recent events in the California energy and ancillary services markets have provided strong evidence that the ISO's energy and ancillary services markets are still not workably competitive. Since May 1, 2000, the real-time energy price has been greater than or equal to $745/MWh during 48 hours. In contrast, during summer months of July to September of 1998 and 1999, the price cap of $250/MWh was hit during 31 and 14 hours, respectively. Clearly, load conditions during many hours of May and June of 2000 were significantly higher than the highest hours in May and June of 1998 and 1999, because of overall load growth in California. For this reason, the number of hours of extreme load conditions in July to September of 2000 should be significantly higher than in these same three months in 1998 and 1999.

Unresolved and Newly Created Market Design Flaws

Many of the reasons for the current lack of workable competition in the ISO's energy and ancillary services markets can be traced to unresolved retail and wholesale market design issues outlined in the March Statement. These regulatory barriers to workably competitive energy and ancillary services market are described in detail in the "Report of the Redesign of California Real-Time Energy and Ancillary Services Markets" ("October Report").[1] There has been some progress with these issues, as noted in the March Statement. However, the events of May and June of 2000 clearly confirm that concern expressed in the March Statement, that the terms and scope of these reforms might be insufficient to be effective during high demand periods. The existing regulatory barriers to price-responsive final demand and forward contracting described in detail in the October Report prevent Utility Distribution Company (UDC) loads from taking the most cost-effective actions necessary to hedge against high prices in the energy and ancillary services markets during high load conditions. Immediately giving the UDCs complete flexibility to hedge in forward markets would provide significant long-term benefits to California consumers. However, it would not correct market design flaws that have arisen over the past year which have significantly contributed to the current lack of workable competition in the ISO's energy and ancillary services markets.

Two market rules changes have been implemented since the end of the Summer of 1999 which have significantly enhanced the ability of generation owners to set high prices in the energy and ancillary services markets during high demand periods. First is the Replacement Reserve penalty which was implemented in the mid-August of 1999 in attempt to encourage more accurate forward scheduling by loads and generation in order to eliminate the reliability problems caused by large quantities of generation and load showing up in real-time during high

[1] "Report on the Redesign of California Real-Time Energy and Ancillary Services Markets." by Frank A. Wolak, Chairman, Market Surveillance Committee of the California Independent System Operator, October 18, 1999. The relevant portion of the report, Section 13 entitled "Workable Competition and New Zone Creation," represents the views of the entire Committee.

load hours. Second is the alternative Out-of-Market (OOM) payment mechanism which became effective January 1, 2000.

The Replacement Reserve penalty was designed to encourage more accurate forward (day-ahead and hour-ahead) scheduling by generators and loads. Under this mechanism, the ISO purchases additional Replacement Reserves when it estimates that an insufficient amount of generation and load have been scheduled on a day-ahead and hour-ahead basis relative to its forecast of system-wide load. It important to emphasize that because the ISO rules require all forward schedules to be balanced, it is necessarily the case that if generation is underscheduled then so is load, and vice versa.[2] Without the additional procurement caused by under-scheduling of generation and load, typically the ISO procures less than 400 MW of Replacement Reserve during peak-hours and zero MW during the off-peak hours. However, during some of the high load hours of June 2000, the ISO procured more than 6,000 MW of Replacement Reserve because of under-scheduling of load and generation. Under this scheme, these additional purchases of Replacement Reserves are charged to the Scheduling Coordinators (SCs) with hour-ahead schedules less than their real-time energy consumption in proportion to the magnitude of this real-time demand for energy. The Replacement Reserve penalty is also charged to SCs with day-ahead generation schedules in excess of the amount of real-time energy they provide in proportion to the magnitude of this under-supply of scheduled energy. However, during high load periods, the only generators producing less than their day-ahead or hour-ahead energy schedules are those that have had a forced outage after submitting their day-ahead or hour-ahead energy schedule.

The March 1999 Report of the MSC described the perverse incentives the Replacement Reserve penalty would create for generators and loads participating in the PX and ISO energy markets and advocated against the implementation of this market rule change.[3] This scheme effectively increases the costs to loads of shifting their purchases of energy to the real-time market, because the ISO purchases additional replacement reserves and charges these costs to the loads that schedule less than their actual consumption on an hour-ahead basis. However, the current ISO price caps on adjustment bids and real-time energy still provide loads with a strong incentives to bid a zero demand into the PX at a price of $750/MWh. The PX market rules require all incremental adjustment bids (INCs) to be greater than the unconstrained PX price and all decremental adjustment bids (DECs) to be below the unconstrained PX price. However, the ISO rejects all INC bids above $750 and all DEC bids below -$750. Therefore, loads must bid a zero demand into the PX at $750 to guarantee that the unconstrained market-clearing price in the PX is no greater than $749.99, so that PX participants can submit $750 INC bids into the ISO congestion management process. If the PX price is greater than or equal to $750/MWh, because the ISO's congestion management process cannot accept INC adjustment bids above the PX unconstrained price, UDCs would be exposed to potentially high congestion usage charges and constrained PX prices significantly higher than $750/MWh. Because of this exposure, UDCs

[2] Consequently, it is impossible to assign blame to load or generation for underscheduling in the forward markets. Fundamentally, the underscheduling problem is due to disagreement between load and generation about the appropriate forward price of energy in a given hour. If the price were lower, load would be willing to schedule more in the forward market. If the price were higher, generation would be willing to schedule more in the forward market.

[3] Wolak, Frank A., Nordhaus, Robert, and Shapiro, Carl, "Report on Redesign of Markets for Ancillary Services and Real-Time Energy," March 25, 1999.

have an incentive not to bid demand into the PX at a price at or above the ISO's price cap even if it means incurring additional replacement reserve costs for unscheduled load.[4]

The generators supplying real-energy at $750/MWh that have also sold their capacity in the Replacement Reserve market at $750/MWh are effectively receiving $1,500 for each MWh of energy they supply. This creates a strong incentive for generators not schedule their projected real-time output on a day-ahead or hour-ahead basis. By submitting an accurate forward energy schedule, they forgo the opportunity to earn a high price in the Replacement Reserve market and the real-time energy market. The frequency of these high prices is increased by the ISO's policy of purchasing additional replacement reserves to make up for the extent that load and generation under-schedule. During the very high load hours, the Replacement Reserve penalty scheme pays generation (that is virtually certain to be providing energy in real-time) not to schedule in day-ahead and hour-ahead markets. This Replacement Reserve payment to generators is financed through the penalty that is charged to all loads that consume more in real-time than they schedule on an hour-ahead basis. The Replacement Reserve scheme also creates an additional incentive for generators to avoid scheduling all of their expected production in advance. SCs that fail to meet their hour-ahead energy schedules in real-time are assessed a Replacement Reserve penalty on this magnitude of under-production. However, these SCs also must purchase this amount of under-production as imbalance energy at the real-time energy price. During extreme load conditions, when the price of Replacement Reserve is $750 and the price of real-time energy is $750, the per unit charge for under-supply energy can be significantly in excess of $750, because of this Replacement Reserve penalty. Consequently, a very easy way for a generation unit owner to avoid any risk of this penalty is to schedule on a day-ahead or hour-ahead basis only what it is virtually certain it can supply in real-time. Of course, in practice a generator unit owner will weigh the probability of a unit outage and the corresponding penalty against the opportunity cost of keeping generation capacity out of the forward market and will bid and schedule capacity so as to maximize its expected profits. By increasing the cost to a generator of failing to meet its hour-ahead energy schedule, the Replacement Reserve penalty scheme increases the incentives for generators not to schedule their expected real-time output on a day-ahead or hour-ahead basis.

The preceding discussion has shown that despite its intentions to the contrary, the Replacement Reserve penalty scheme increases the incentives for generators to under-schedule in the day-ahead and hour-ahead markets. Additionally, the fact that PX participants cannot submits adjustment bids above the ISO's price cap creates an incentive for loads to bid to avoid setting PX prices at or above the ISO price cap. It is important to emphasize that neither load nor generation is to blame for under-scheduling, because the ISO only accepts balanced schedules from SCs on a day-ahead and hour-ahead basis. By paying the Replacement Reserve price and the real-time energy price to generators supplying imbalance energy, the opportunity cost of selling energy in the day-ahead or hour-ahead markets can at least double during very high load hours. This explains in part the very high prices in the PX day-ahead and hour-ahead market during high load hours in May and June of 2000.

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[4] Because the ISO typically buys less replacement reserve than the amount of unscheduled energy (even during the high load periods of June 12-14, 2000) even if the replacement market cleared at $750/MW, the replacement reserve charge for each MWh of unscheduled load would be less than $750/MWh.

The final market design flaw that has contributed to recent high prices during certain hours in the California electricity market is the alternative OOM payment mechanism. This payment scheme has increased attractiveness of not participating in any of the California energy and ancillary services markets. The OOM payment scheme pays generators called out of market both a capacity component and energy component as well as verifiable fuel related start-up costs and gas imbalance charges that result from the ISO OOM call. The capacity component is a weighted average of the day-ahead spinning reserve and non-spinning reserve prices in three preceding comparable days. The energy component is a weighted average of the day-ahead and hour-ahead PX energy prices and the ISO real-time energy price for three preceding comparable days. During a period of high demand, the revenues earned from an out-of-market call under this payment mechanism can be significantly greater than what a generator would earn from participating in the PX energy and ISO energy and ancillary services markets. Similar to the incentives provided by the Reliability Must-Run Contract "A" payment scheme, generators will therefore prefer to stay out of any of the PX or ISO markets to instead be called under the terms of this alternative OOM payment scheme. Generators called under the OOM mechanism have also negotiated runtime commitments beyond a single hour. This creates an additional incentive for generators not to participate in the PX or ISO markets and therefore artificially drive up prices in these markets.

Even without the Replacement Reserve penalty scheme, generators have an incentive to schedule less than their expected real-time energy production, because failure to supply their forward schedule in real time (most likely because of a forced outage) will require them to purchase this under-supplied energy at the real-time imbalance price. Particularly, during high load periods this incentive to under-schedule is very high, because the real-time energy price usually hits the price cap. Loads do not face this same incentive to under-schedule because there is virtually no risk that a large fraction of expected real-time consumption from end-users will fail to appear in real-time. There is no analogue to a forced outage for loads. If energy is available, loads will always consume it.

For the above reasons, one can argue that generation must be provided with an additional financial incentive to schedule its expected energy production in the forward energy market. This incentive can be provided within the current Replacement Reserve penalty mechanism by assessing the penalty to SCs in proportion to the amount that their real-time generation is in excess of their hour-ahead energy schedule. Under this scheme, even those generators that respond to real-time dispatch instructions from the ISO to supply more than their day-ahead energy schedules would be assessed this Replacement Reserve penalty. These generators could factor the expected value of this penalty into their real-time energy bids that they submit to the ISO. This mechanism could be refined to allow SCs to produce some real-time generation in excess of their hour-ahead energy schedules without being assessed the Replacement Reserve penalty. For example, an over-supply of less than 10 percent of an SC's hour-ahead energy schedule (recall that all forward market schedules are balanced) would not result in the assessment of a Replacement Reserve penalty. However, over-generation relative to schedule in excess of this amount would result in the assessment of a Replacement Reserve penalty regardless of the cause. This mechanism would create very strong incentives for generation to schedule their expected real-time supply on an hour-ahead basis. By failing to do so, the generator would effectively be receiving the real-time energy price less the Replacement Reserve penalty. During high load periods when the price of Replacement Reserve is likely to be high, the effective price that generators receive for supplying real-time energy could be very low. The generator could avoid this low price by scheduling their expected real-time output in advance, when they could hedge this expected supply at the PX day-ahead or hour-ahead price and avoid any risk of the Replacement Reserve penalty.

Unless the attractiveness of an OOM call is reduced, there will still be incentives during certain hours for generators not to participate in the PX energy and ISO energy and ancillary services markets. To insure active participation in the PX and ISO markets, an out-of-market call must always be less attractive to a generator than participating in the formal California energy and ancillary services markets. Consequently, the current OOM payment mechanism should eliminated and replaced with the scheme that is less attractive than participating in these markets. An example of such a mechanism is the following. At any time after day-ahead energy schedules are submitted, the ISO can make an out-of-market call to a generating unit owner for the real-time provision of energy for any capacity not bid into the ISO's ancillary services market or scheduled to provide energy at the lower of that unit's variable cost of production or the lowest hourly real-time energy price during the previous seven days. This option for the ISO to call on capacity that is not bid or scheduled under these same payment terms also holds for the hour-ahead market. If a unit has notified ISO at least one week in advance of the days or hours that it will be out for scheduled maintenance, then the unit will not be at risk for an OOM call during this period. However, all generation unit owners must also submit to the ISO the maximum number of days annually that each unit it owns can be out of service for scheduled maintenance. If a generator is unable to meet an OOM call for any other reason, then it must the purchase of the requested OOM energy it failed to provide at the real-time energy price for that hour. There are no restrictions on the price that capacity is bid into the ISO's energy or ancillary services markets. For example, a unit owner could put in standing bids at the appropriate price cap for all available capacity. An OOM mechanism that is sufficiently unattractive will provide strong incentives for all unit owners to submit bids for all of their capacity into the ISO's energy and ancillary services markets. The ISO can then call on all available capacity within its existing energy and ancillary services market protocols. A properly designed out-of-market mechanism should never need to be used. It is only a credible disincentive to generation unit owners to withhold capacity from the ISO's markets. However, out-of-merit bids may still sometimes have to be taken to satisfy real-time locational energy needs. The converse of making OOM calls sufficiently unattractive is that the price caps on the ISO's energy and ancillary services markets must be sufficiently high to provide sufficient revenues to unit owners for them to remain financially viable and to encourage sufficient new investment to meet the rapidly growing demand for electricity in California.

Costs versus Benefits of Reducing Price Caps to $250/MW(h)

The regulatory barriers described in the October Report and the limited progress towards addressing them noted in the March Statement, combined with the two more recently created market design flaws described above, clearly indicate a lack workable competition in the ISO's energy and ancillary services markets. For this reason, these remaining regulatory barriers should be eliminated and the market rules changes along the lines described above implemented as soon as possible. However, the major outstanding issue is whether the current price cap on the ISO's energy and ancillary services markets should be lowered to $250/MW(h). Clearly, the apparent lack of workable competition in the ISO's energy and ancillary services markets over the past two months argues in favor of this reduction in the price caps. However, there are several equally strong arguments against reducing these price caps.

The most important issue is short-term reliability. Electricity demand in California has grown rapidly over the last two years, with no accompanying increase in generation capacity within the state. In addition, the surrounding states which traditionally supply a significant amount of energy to the state, particularly in high load periods, have also experienced significant load growth over the past two years. In addition, the amount of available hydro-electric capacity from the Pacific Northwest is lower than in the Summer of 1999, because of less than normal runoff. Consequently, during hours when system peaks in California and the surrounding states are coincident, the California ISO stands an increased likelihood of being unable to compete for energy in the WSCC, if the maximum amount that it can pay is less than or equal to $250/MWh as opposed to $750/MWh. The major uncertainty is how much less out-of-state supply the ISO can attract at $250 versus $750. This is an extremely difficult question to answer, but given demand versus supply conditions in the areas surrounding California, it seems very likely that there may be many hours during the Summer of 2000 when $250 may not be sufficient to attract the necessary energy imports for California to meet its demand. Even during the months of May and June of 2000, when the real-time price was $750, there were many hours when wholesale prices appeared to be significantly above $750/MWh in the areas surrounding California. Conditions in California and its neighboring regions are likely to be even tighter during July and August, which are the peak load months for the WSCC. This argues in favor of maintaining the price cap at the $750/MWh level through these summer months.

The second issue is long-term reliability. All industry observers agree that California must attract new investment in generation and transmission to meet its growing demand. A price cap of $250 provides less incentive for new generation and transmission investment than does a higher price cap. However, a $250 price cap during the Summer of 2000 that will be raised before the Summer of 2001 will not affect the revenues earned by a new entrant that can start supplying electricity at the beginning of next summer. However, lowering the price cap in response to a large number of hours with high real-time energy prices during the Summer of 2000 undermines the credibility of any promise to increase and maintain the price cap during the Summer 2001. Consequently, a prospective new entrant faces a lower expected revenue (because of the reduced likelihood that the promised price cap increase will be maintained for the entire Summer of 2001), and therefore diminished incentives for investing in California.

The final issue associated with lowering the price cap concerns the difficulty in preventing in-state generators from selling outside of California when prices are expected to be higher outside of the state. This problem is particularly acute if the ISO is permitted to pay out-of-state generators higher prices than the $250/MWh price cap in order to maintain reliability within the ISO control area. Instate generators would have an incentive to circumvent the $250/MWh price cap by selling their energy outside the state for prices above the $250/MWh price cap and then the ISO would have to purchase this energy back from out-of-state participants at prices in excess of $250/MWh. This would defeat the intent of the $250/MWh price cap. The ISO could solve this problem by suspending exports during certain load conditions, but this would simply penalize instate generators for their location in California by paying them a lower price for supplying energy to California consumers than is paid to out-of-state producers.

Conclusion

There are significant short and long-term reliability risks associated with reducing the price cap to $250/MWh. Many market-participants have made long-term production and investment decision based on the assumption of higher price caps. They may be less likely to do so in the future because of the increased uncertainty about the level of future price caps. Continuing with current market rules and current the price caps will only result in an unnecessarily large number of hours with prices at or close to the $750 price cap in the energy and ancillary services markets. If the market design flaws described above can be quickly corrected, then the need to reduce the price caps is significantly reduced. Maintaining higher price caps will have both short and long-term system reliability benefits of an unknown magnitude. The potential exists to make all of these necessary market rule changes quickly. Both the short-term and long-term efficiency of the California electricity supply industry will be improved if these design flaws are quickly corrected. Lowering the price cap will do nothing to correct these flaws, it will only reduce the cost to final loads and UDCs, with an uncertain risk to system reliability. In addition, further delays in removing these regulatory barriers and new market design flaws described above will only increase the costs to California consumers of eventually correcting them.