The Competitiveness of the California Energy and Ancillary Services Markets

by

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Introduction

The Market Surveillance Committee (MSC) of the California Independent System Operator (ISO) has been asked by the ISO Board to offer its assessment of whether the California energy and ancillary services markets are workably competitive. The MSC has also been asked to offer its opinion on the appropriate level of the price cap on the ISO's energy and ancillary services markets for the Summer of 2000.

The "Report of the Redesign of California Real-Time Energy and Ancillary Services Markets" ("October Report") stated a general procedure that can be used to determine whether a market is workably competitive.[1] In that report we noted a clear distinction between a workably competitive market, in which no firm has significant market power, and a perfectly competitive market, in which all firms have no market power. For the purposes of this assessment our definition of market power is consistent with that given in the United States Department of Justice and Federal Trade Commission Horizontal Merger Guidelines: "Market power to a seller is the ability profitably to maintain prices above competitive levels for a significant period of time."[2] Our October Report also emphasized that deciding whether a market is workably competitive requires an integrated analysis of data on market outcomes, taking into account the institutional features that govern the operation of the market.

Applying this integrated approach, we have found that California's energy and ancillary services markets were not workably competitive during the Summers of 1998 and 1999. Despite the market design and other changes made since last summer, under current market rules we cannot conclude that the ISO's energy and ancillary services markets will be workably

[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.

[2] United States Department of Justice and Federal Trade Commission, "Horizontal Merger Guidelines," Section 0.1.

competitive during periods of peak demand in the Summer of 2000. That assessment must await actual experience with the reconfigured markets under conditions of high demand.

Procedure for Determining Competitiveness of Electricity Markets

The October Report states that "Economists have been grappling with the concept of 'workable competition' for over 50 years, and have yet to identify a set of diagnostics that can be applied to determine reliability whether or not a market is in fact 'workably competitive'." Consequently, the October Report did not purport to offer bright-line rules for making this determination but instead gave a checklist of both quantitative and qualitative conditions that tend to support a conclusion that an electricity market is "workably competitive." This checklist is summarized and developed below.

Significant Quantity Bid but Not Called Upon. This condition implies that there is a significant quantity of electricity bid into the market above the current market-clearing price (MCP). Under these conditions, if a single supplier were to raise its bid, the MCP would change very little if at all. Rather, that supplier's electricity (or capacity) would simply be replaced with electricity (or capacity) bid by others at or near the MCP.

Bids at or Near Marginal Cost. The strongest single piece of evidence that a given supplier lacks market power is the observation that this supplier bids its energy and/or capacity into the market at or near its marginal cost.[3] The larger is the supplier's share of the market, and the larger is the percentage gap between the supplier's marginal cost and its bid, the greater is the inference of market power. We hasten to add that we do not in any sense regard such bidding as objectionable; its is merely the result of profit-maximization by the supplier possessing some power (at least probabilistically) over price. But the observation, or inference, that this supplier (and perhaps others) enjoys market power may well be relevant for policy decisions such as the lifting of a price cap or the creation of a new zone. Some commentators have asserted that in electricity markets firms are unable to recover their fixed costs unless they bid in excess of marginal cost. The analysis given in Borenstein (1999) explains the flaw in this logic.[4] Simply put, a firm without market power can and will earn "scarcity rents" for the capacity associated with one of its facilities when the market clearing price exceeds the marginal cost of operating that facility. These rents will contribute to recovery of fixed costs, and arise even if the firm bids the relevant unit into the market at marginal cost. The fact that fixed costs can be recovered in the absence of market power is a very well established proposition in economics, and indeed explains investment decisions in many commodity markets.

Supply is Not Concentrated. Market concentration is the single most commonly-used measure of whether a market is "competitive" or not. In many antitrust cases, for example, including both mergers and monopolization cases, both the antitrust enforcement agencies and the Courts look

[3] By "marginal cost" we mean the true (economic, not accounting) incremental cost of fulfilling the bid. For a supplier that is capacity-constrained, the marginal cost may be an opportunity cost, e.g., of not selling that same power or capacity in another market. For a supplier that bears start-up or shut-down costs, the marginal cost associated with at least some bids may include these costs.
[4] Severin Borenstein (1999) "Understanding Competitive Pricing and Market Power in Wholesale Electricity Markets," University of California Energy Institute August 1999.

to market shares as a measure of market power. We would like to stress that a single firm's market share is usually employed in monopolization cases as a *proxy* for that firm's market power *because the direct measurement of market power is difficult or impossible with available data*. Fortunately, we have excellent data on production costs, market prices and quantities in California's electricity markets. So, we regard market shares as a useful additional measure, but not the very best available measure of market power in California's electricity markets.

Buyers are Flexible. Market power by sellers is inevitably reduced if buyers have the flexibility to reduce their demand in the presence of high prices and/or to turn to other sources of supply (either a substitute product or the same product provided from a different geographic area). The most commonly-used measure of buyer flexibility for the purposes of assessing market power is the elasticity of demand.

No Unnecessary Institutional Barriers to Rivalry or to Demand Flexibility. Given the elaborate regulatory regime in place in California's electricity markets, it is all too easy for regulations to impede "workable competition." Generally speaking, an assessment of whether a market is "workably competitive" will include an evaluation of whether there are institutional features that reduce rivalry among actual and potential suppliers, or that hinder buyer flexibility. Our October Report noted that there are currently significant regulatory barriers to demand flexibility in California's electricity markets.

Collusion is Difficult. Collusion has no place in a "workably competitive" market. If collusion is easily achieved, or if there is a dangerous probability that collusion will occur (e.g., because of a concentrated market structure or because the suppliers have ample opportunities to meet and reach illegal agreements), a market may fail to be "workably competitive."

Entry into the Market is Easy. The final factor that should be considered in evaluating whether a market is "workably competitive" is the ease of entry into that market. In California's electricity markets, we would expect entry typically to occur one of two ways: (1) the supply of energy or ancillary services from outside the State (these suppliers would just as well be called market participants as "entrants") or the region under study, and (2) the construction of new generation facilities.

The Competitiveness of California Energy and Ancillary Services Markets

Many of these characteristics argue in favor of the California energy and ancillary services markets being workably competitive. The frequency of bid insufficiency in the energy and ancillary services markets has declined to close to zero because of market rule changes, most notably the Rational Buyer algorithm for procuring ancillary services. The October Report referred to estimates of the extent of market power exercised in the California energy market from June 1998 to November 1998 computed by Borenstein, Bushnell and Wolak (1999).[5] Since the October Report was submitted, these estimates have been updated with data through

[5] Borenstein, Severin, Bushnell, James and Wolak, Frank A. (1999) "Diagnosing Market Power in California's Restructured Wholesale Electricity Market," July 1999.

September 1999. Borenstein, Bushnell and Wolak (2000) describes the methodology used to perform this calculation and gives a detailed analysis of these results.[6] Their study computes, on an hourly basis, the extent to which market prices are in excess of the marginal cost of the highest-cost unit operating.

Three major conclusions emerged from the Borenstein, Bushnell and Wolak (2000) analysis ("BBW"). First, significant market power was present in the California energy market during the summer months—July to September—of both 1998 and 1999. Second, the extent of market power exercised in the California energy market during the summer of 1998 was significantly higher than that exercised during the summer of 1999.[7] This reduction in the exercise of market power was due in part to the many market rule changes made between the conclusion of the summer of 1998 and the end of the summer of 1999. The summer of 1999 also had significantly lower peak loads than the summer of 1998 because of milder weather throughout California during the summer of 1999. However, the total amount of energy produced during the summer of 1999 was higher than the amount produced during the summer of 1998. Third, market power in the California energy market appears to arise primarily during periods of peak demand. For all months from November 1998 to June 1999, with the exception of December 1998, BBW found little, if any, exercise of market power in the California energy market.

Although BBW measured market power in California's *energy* markets, we believe their findings are informative regarding the market power in the *ancillary services* markets as well. There are sound reasons to believe that the danger of market power in the ISO's ancillary services markets are at least as great as those in the energy markets. First, the set of generating units eligible to participate in each of the ancillary services markets is significantly smaller than the set of generating units able to supply energy in the California market. Second, because a generator providing ancillary services may well *not* be called in the real-time energy market, the profits earned by a supplier in the energy market constitute an opportunity cost to that unit owner from winning in any of the ancillary services markets in which it is eligible to participate. So, the exercise of market power in energy markets raises (opportunity) costs in ancillary services markets and thus tends to raise the price there, too.

Between the summer of 1998 and the summer of 1999, there has been one significant new entrant into the California energy and ancillary services markets. The Southern Company has purchased approximately 3,000 MW of capacity from Pacific Gas and Electric. Of course, entry by acquisition, while typically reducing market concentration, does not actually expand the available supply.

The October Report also contained an extensive discussion of the incentives for hourly price-responsiveness of wholesale demand in the California electricity and ancillary services

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[6] Borenstein, Severin, Bushnell, James and Wolak, Frank A. (2000) "Diagnosing Market Power in California's Restructured Wholesale Electricity Market," February 2000.

[7] The study found that during the summer of 1998 total revenues exceeded competitive levels by an average of 54%. Whereas, during the summer of 1999 this measure fell to 15%. Although a value of zero for this index during peak summer months is not necessary for the market to be workably competitive, we believe that a value 15% indicates a lack of workable competition in light of the mild load conditions during the summer of 1999.

markets because of the Competition Transition Charge (CTC) recovery mechanism and associated retail rate freeze.[8] Section 7 of the October Report discussed the current regulatory impediments to an hourly price-responsive demand for energy and ancillary services. This report noted that the current CTC recovery mechanism eliminates virtually all incentives for the vast majority of final loads to be price-responsive with respect to wholesale energy prices. Because monthly CTC payments are effectively defined as the difference between total retail electricity revenues at the current rate freeze prices and the sum of costs for wholesale energy and ancillary services, transmission, distribution and other regulatory services, the CTC mechanism translates wholesale energy and ancillary services price reductions almost dollar for dollar into higher CTC payments by the customer.[9] Consequently, the only market participants subject to the CTC who have a financial incentive to take actions to lower wholesale electricity prices in any hour are the investor-owned utilities (IOUs). Under the current combined retail rate freeze and CTC recovery mechanism, the only way for these IOUs to make it attractive for their retail customers to reduce their hourly demand in response to high wholesale prices is to explicitly provide financial incentives for them to reduce demand.[10] We discuss below the demand responsiveness programs currently under consideration by the CPUC.

The October Report also noted that the prohibition on forward contracting by utility distribution company (UDC) load outside of the Power Exchange (PX) limits the avenues for price-responsiveness available to loads in the California market. Recently, the California Public Utilities Commission (CPUC) increased the opportunities for UDCs to hedge their forward energy purchases by allowing them to participate in the PX's block forwards market. However, CPUC imposed position limits on block forwards market participation for each UDC at one-third of its historical minimum hourly load by month. These position limits unnecessarily restrict the ability of UDCs to forward-purchase electricity and therefore to mitigate the potential exercise of market power by generating companies in the California electricity market. Both Pacific Gas and Electric and Southern California Edison have applied to the CPUC to have these position limits increased. The effectiveness of this program will not be known until the CPUC takes final action on this and we have had some months of experience.

Because of these regulatory barriers to price-responsiveness, it is quite possible that there will be a number of hours during the Summer of 2000 when any currently contemplated price cap for the real-time energy and ancillary services markets will be hit. The basis for this concern is both the actual and forecast growth in demand in the ISO control area and the current pattern of bidding behavior in the real-time energy and ancillary services markets. Despite unusually mild weather during the summer of 1999 (which resulted in the number of hours with ISO loads above 40,000 MW dropping from 120 during the summer of 1998 to 48 during the summer of 1999), total energy consumed from April 1999 to December 1999 was 3.5% above that same level during that same time period in 1998.[11] The ISO forecasts that the annual amount of energy consumed in its control area will grow by 4% to 5% from 1999 and 2000. This growth

[8] San Diego Gas & Electric recently declared an end to its CTC recovery period. The CTC recovery mechanism still applies to Southern California Edison and Pacific Gas & Electric.
[9] The October Report discusses the interaction of the rate freeze and the CTC recovery mechanism in detail.
[10] This mechanism for encouraging wholesale price-responsiveness is not financially viable for the competitive energy service providers (ESPs) because they do not receive CTC payments.
[11] "CAISO Market Update: 1999 Market Performance," Prepared by Department of Market Analysis of the California Independent System Operator," December 1999.

implies that if the summer of 2000 is as hot as the summer of 1998, system conditions will be significantly tighter. In addition, if historical bid patterns in the real-time energy and ancillary services markets are any indication of future patterns, there will continue to be standing bids in these markets at the current ISO price cap during periods of high demand.[12] Consequently, there is a real possibility of hitting the price cap during high-demand hours during a hot summer of 2000, if we assume that wholesale demand will not be responsive to hourly energy prices and that the proposed price-responsiveness programs have limited scope.

In all industries, a major factor in mitigating the exercise of market power, particularly during periods of high demand, is the price-responsiveness of final demand. The willingness of demanders not to consume if market prices are too high provides a fundamental incentive for suppliers to bid closer to their marginal cost. Suppliers facing a price-responsive final demand that bid significantly above their true willingness to supply risk being left out of the market. In contrast, during the last two summers, generators in the California energy and ancillary services markets faced little risk of not being taken at any price during periods in which the vast majority (but clearly not all) generating capacity in California is necessary to supply energy and ancillary services. Suppliers knew that the hourly demand for both energy and ancillary services was virtually perfectly inelastic with respect to the wholesale electricity price. Because these firms also knew that a significant fraction of their capacity was necessary to provide this inelastic energy and ancillary services demand, they were able profitably to bid significantly above the marginal cost of providing energy or ancillary services. During these high demand periods, generating unit owners were able to exercise market power because of the inelastic final demand for energy and ancillary services. In contrast, if these firms faced a price-elastic wholesale demand for energy and ancillary services, their attempts to raise prices through higher bids would be met with a lower quantity of energy and ancillary services sold. The resulting risk of selling significantly less by bidding higher prices reduces the incentives these firms have to exercise market power through their bids to supply energy or ancillary services.

During the off-peak periods this virtually price inelastic aggregate demand for energy and ancillary services cannot be used by generators to exercise significant market power. Unit owners recognize that unless they bid very close to the marginal cost for each generating unit they own, they risk having their facilities not accepted to meet a significantly lower demand for energy and ancillary services. Competition to supply a level of demand that is significantly smaller than the total amount of capacity available to serve the energy and ancillary services markets is sufficient to cause generators to bid each unit at a price very close the marginal cost of supplying energy or ancillary services.

An indication of how prices can spike, even during conditions of moderate aggregate demand, is found in the movement of energy and ancillary services prices on October 1, 1999, the day the price cap in the ISO's real-time energy and ancillary services markets was raised to $750/MWH. On this day, Path 15, the primary transmission path between northern and southern California, was de-rated to 900MW in the south to north direction for most hours of the day. In addition, the California-Oregon Intertie (COI) was congested in the north to south direction. This circumstance led to day-ahead energy prices in the NP15 congestion zone of close to

[12] "Annual Report on Market Issues and Performance," Prepared by Market Surveillance Unit of California Independent System Operator, June 1999, Figure 4.10.

$700/MWH in four hours of the day. Price spikes also occurred in the NP15 ancillary services markets for Spinning and Non-Spinning Reserve for several hours during the day. A detailed discussion of the events in all ISO and PX markets on October 1, 1999 is given in Section 3.G of the October Report.

The regulatory barriers to price-responsive final demand and the limits on UDC forward contracting are two of the major reasons for our uncertainty as to whether the California energy and ancillary services markets will be workably competitive in summer 2000.[13] If both of these barriers were eliminated, a case could be made in favor of the real-time energy and ancillary services markets being workably competitive. However, unless and until a significant fraction of retail load has the financial incentive to respond to hourly wholesale prices, it is very possible that even a high price cap on the energy and ancillary services markets will be hit a number of times during the summer of 2000, even if the summer as a whole involves relatively mild weather conditions.

The Impact and Level of the Price Cap

In October 1999, the Committee recommended that the price caps be set at the $750 level for a full 12 months unless the ISO elects to use its "safety net" authority to lower them. We would remain of this view, if we were confident that the full range of market reforms we have recommended would be in place this summer. However, the second phase of RMR reform (pre-dispatch and netting out) was just filed last month and may not take effect before this summer. The CPUC has preliminarily approved only very narrow demand response and forward contracting proposals for the UDCs. Thus, we do not know what the market rules will be this summer nor can we predict their impact. In our view, there is no clear choice between the $500 cap and $750 cap on economic efficiency grounds; rather, the choice is a practical and policy judgment for the ISO Board. We therefore discuss below the costs and benefits to the California market of lowering the purchase price-cap to $500 versus maintaining it at $750. We hope this discussion will clarify the basic policy considerations involved in setting the level of the price cap.

As noted above, because the current market rules have fixed retail electricity rates and the CTC recovery mechanism, final consumers that purchase from SCE and PG&E are largely indifferent to prices in the wholesale energy and ancillary services markets. Absent effective CPUC–approved demand-response programs and forward-contracting programs, a higher price cap on the energy and ancillary services markets will not significantly reduce demand in these markets. However, it could have the effect of reducing the expected amount of CTC payments made during the Summer of 2000. This, in turn, could increase the length of time the California

[13] Although entry is an issue the resolution of which will not effect market conditions this summer, entry into the California electricity market is not as easy as it would be if there existed clear rules by which new generating facilities could connect to the ISO grid. A new generation connection policy that has been approved by the Federal Energy Regulatory Commission (FERC) would reduce the uncertainty faced by a potential entrant about the costs of becoming a participant in the California energy and ancillary services markets. The current uncertainty about these costs unnecessarily raises the expected costs associated with entry by new generating units into the California energy and ancillary services markets, and thus further hampers competition.

market must operate without a final electricity demand that has strong economic incentives to respond to high wholesale electricity prices (because of the combined retail rate freeze and CTC recovery mechanism already discussed). If the $750 price cap would result in a significant extension of the CTC period, then the ISO may wish to consider a lower price cap during the summer of 2000. The extent to which lowering the cap to $500 might shorten the CTC period is difficult to predict because it requires projecting the frequency and magnitude by which a $500 market clearing price would otherwise be exceeded in summer 2000. If a $750 cap were hit in summer 2000 as often as the $250 cap was hit during the mild summer of July to September of 1999, (14 hours), when few of the ISO's market reforms were in place, CTC collections would be $70 million lower than they would be with a $500 cap and the CTC extension period would be extended by 10 days.[14] If the $750 cap were hit for as many hours as the price hit the $250 cap in the relatively hot summer of 1998 (31 hours), forgone CTC payments would be $155 million, and the CTC recovery period would be extended by 22 days. If the MCP did not hit $750 every time it exceeded $500, the period of the CTC extension would less than 10 days and 22 days, respectively.

The CPUC's recent proposed ruling accepting, with modification, the demand-responsiveness programs proposed by PG&E and SCE for the summer 2000 provides some support for maintaining the price cap at $750 through the Summer of 2000. These programs have the *potential* to build some demand-responsiveness into the price-setting process in the California energy and ancillary services markets. However, it is important to note that these programs are of limited scope and that participation in these programs is voluntary. Loads will participate only if they anticipate savings in total energy costs that exceed the costs they must bear to actually reduce their demand in response to higher wholesale electricity prices. The amount these programs pay customers to reduce their demand during high-priced periods is, depending on the UDC, based on the PX Day-Ahead unconstrained or zonal Energy Price. Under a higher price cap, these customers can expect to receive higher payments for their demand reductions and therefore achieve lower total energy bills from participating in the

[14] The maximum CTC savings per hour from lowering the cap from $750 to $500 are about $5 million per hour ($250/MWH x 20,000 MW) during the summer hours when the price cap is most likely to be hit. We chose 20,000 MW because it is slightly below the average net demand position (total load less total generation under UDC control) for the two UDCs still subject to the CTC recovery mechanism during the 50 highest hours of total ISO load during the summer of 1999. These 50 hours are the periods when any price cap is most likely to be hit. Over the summer months of July to September of 1998 and 1999, average daily CTC collections for these two UDCs were about $7 million. Thus, the lower cap shortens the CTC by at most 0.71 days for every hour the MCP hits a cap of $750 versus a cap of $500. If we assume that the price hits the $750 cap every hour the $250 cap was hit in 1999 (14 hours), the forgone CTC payments would be $70 million, and the CTC payment period would be extended by 10 days, assuming the historical summertime CTC collection rate of $7 million per day. If the $750 cap was hit as many hours as the price hit the $250 cap in the summer months of 1998 (31 hours), forgone CTC payments would be $155 million, and the CTC recovery period would be extended by 22 days. It important to note that the CTC recovery is based on a weighted average of the zonal PX price and the ISO's zonal real-time price, and that although these two prices tend to have the same mean values, the real-time prices tend to significantly more volatile, so that this analysis may overstate the difference in CTC recovery rate under a $750 versus $500 cap. On the other hand, the price cap level tends to be a magnet for bids during a high demand periods. For example, during the summer of 1998, there were 35 hours when the ISO's price was below $250 and above $200. There was one-third as many hours during the summer of 1998 with prices below $200 and above $150. By definition, a cap of $750 will result in more prices in the range of $501 to $750 than would a price cap of $500. For this reason, our procedure may significantly understate the increase in the extension of the CTC recovery period for the two UDCs under a $750 versus $500 price cap.

program. Consequently, the $750 price cap should *increase* the number of customers willing to participate in these programs relative to a $500 price cap.

Most significantly, a strong argument in favor of maintaining the ISO's price cap at $750 through the Summer of 2000 is that this higher price cap will provide a more serious test of the effectiveness of the full set of market rule changes implemented over the past year to correct the defects in the ISO's real-time energy and ancillary services markets. Any remaining defects are more likely to show up in a market with a price cap of $750 than one with the cap at $500. Thus, for example, a summer experience under a price cap of $750 will be more informative than under a $500 price cap regarding the need for any future price caps, should the ISO seek such authority from FERC beyond November 15, 2000.

Conclusions

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.

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.

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.

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.