Report on Market Issues in the California Power Exchange Energy Markets

Prepared for the
Federal Energy Regulatory Commission

by
The Market Monitoring Committee
of the California Power Exchange

Roger E. Bohn
Alvin K. Klevorick, Chair
Charles G. Stalon

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I. Introduction

On July 17, 1998 the Federal Energy Regulatory Commission (FERC) issued an order accepting the proposal by the California Independent System Operator (ISO) to limit temporarily the prices the ISO will pay to bidders that had been granted authority to set market-based rates for Ancillary Services. In addition to granting that authority to the ISO, FERC directed the ISO Market Surveillance Committee and the California Power Exchange (PX) Market Monitoring Committee to conduct independent studies and to file reports with the Commission within thirty days of the date of the order.

The studies were to examine "the bidding behaviors and structural characteristics of the markets that they [the Committees] each administer and to further clarify the causes of the perceived market concerns in the pleadings." Those concerns, expressed in pleadings by the ISO and Southern California Edison (SoCal Edison), were directed at the performance of the ISO markets for Ancillary Services and especially Replacement Reserves in early July. At issue, in particular, were dramatic price spikes in the price for Replacement Reserve Capacity and insufficient bids in that market and other reserve markets. The FERC expressed special interest in "how the workings of the California market and activity in the generation market affected the prices in the Ancillary Service and Replacement Reserve markets," and its interest presumably extends to the impact of activity in the ISO markets on the PX energy markets. In addition, the FERC directed that the ISO and PX market monitoring committees should address how "phase-in plans implementing new procedures such as the hour-ahead market" will affect PX and ISO markets.

The PX Market Monitoring Committee is engaged in an ongoing analysis of the structure, behavior, and performance of the PX day-ahead energy market, and it is beginning a similar study of the PX hour-ahead market, which commenced operation only on July 30th. In this report, the Committee draws on its ongoing study and the associated work of the PX Compliance Unit staff to respond to the FERC's inquiries. To answer the Commission's specific questions about interdependence of the PX and ISO markets, the Market Monitoring Committee has examined bidding behavior and market performance in the PX energy market especially during July and early August. The Committee emphasizes that the time constraints on the preparation of the report have limited the depth and scope of quantitative analysis that could be undertaken. The members of the Committee regard this report as part of a continuing examination and analysis of the PX markets, directed at the maintenance of competitive and efficient energy markets in California, rather than as a discrete, time-limited study.

In the next section of the report we delineate the boundaries of our analysis and characterize the product we have tried to deliver. Section III provides a review of the structure and performance of the PX day-ahead energy market from its inception to the present. Relevant characteristics of the Ancillary Services markets are also discussed. (In this report, we use

"Ancillary Services" in the generic sense, including Regulation, Spinning Reserves, Non-Spinning Reserves, and Replacement Reserves.) In Section IV we present our analysis of bidding behavior in the PX market with special attention to July including the period that generated concerns about the ISO Ancillary Services markets. Section V contains our discussion of the interactions between the PX and ISO markets. We conclude, in Section VI, with implications that we draw from our analysis.

II. The Character and Boundaries of Our Analysis

First, our report focuses on the PX market for energy and, due to the very recent introduction of the hour-ahead market, primarily on the day-ahead market. We discuss and comment on the ISO markets only to the degree that there is reason to inquire about how developments in those markets may have an impact on the PX market and vice versa. In particular, it is fundamental to recognize that the capacity available for the ISO markets and for the PX markets comes from the same generating capacity. Capacity sold in one market means less capacity that can be sold in other markets, thereby driving up prices in the latter. Therefore, we would expect a close relationship among the different markets.

Second, we have written a descriptive, analytical report. We are not assessing whether particular participants behaved well or behaved badly. Rather, we attempt to analyze how they have behaved, based on historical data, and how we might expect them to behave, based on the market rules and their incentives as we understand them. Our report is normative only to the extent that our analysis will lead us to recommend one or another policy measure.

Third, it is essential to keep in mind just how new these markets are. They are still developing and evolving in important ways. We expect behavior to change as participants gain experience; as new markets open, such as the hour-ahead market; as supply and demand change due to seasonal forces and market pressures; and as unanticipated events occur. Over time we would expect the sophistication of both the demand and supply participants to increase, and their behaviors to change. This continued evolution should be recognized when considering policy changes. Problems we diagnose now may be inherent in the market or they may be transitional difficulties.

Fourth, the information we have is limited in important ways. We do not have data on some transactions outside the PX markets, especially bilateral sales (made outside the Power Exchange market) and Reliability Must Run transactions. As a consequence, we cannot accurately characterize the degree to which some of the PX market participants are using dedicated capacity as a strategic instrument.

III. Overview of Markets and Operations

This section provides an overview of California's electricity market structure and a summary of PX operations from the opening of the market on April 1, 1998 through August 11, 1998.

PX Market Descriptions

The PX operates two separate energy markets: a day-ahead energy market and an hour-ahead energy market. The PX has been operating its day-ahead energy market throughout the four months since restructuring was implemented, while the hour-ahead energy market commenced operations on July 30, 1998.

PX Day-Ahead Market

In the day-ahead market, PX Participants submit portfolio bids to buy and sell energy for each hour of the succeeding day. These portfolio bids, which must be submitted to the PX by 7:00 a.m. on the day prior to the actual dispatch day, are used by the PX to derive aggregate supply and demand curves from which the PX establishes an unconstrained market clearing price and quantity for each hour. Following the conclusion of the day-ahead auction, successful bidders provide the PX with Initial Preferred Schedules that reflect the quantities awarded in the auction process. These schedules specify the quantity and location of loads and supplies within the grid. The PX provides these schedules, which in aggregate must be balanced with respect to supply and demand in each hour, to the ISO by 10:00 a.m. on the day prior to the dispatch day. Other Scheduling Coordinators, representing bilateral transactions, submit their balanced schedules to the ISO in a similar manner.

These schedules also include Participants' Ancillary Services Bids and Schedule Adjustment Bids (for inter-zonal transmission congestion). Upon receiving the resource schedules from Scheduling Coordinators, the ISO conducts its Ancillary Services auction and performs congestion management, thereby, making any necessary adjustments to the Initial Preferred Schedules based on participants' bids. The ISO then issues Final Day-Ahead Schedules, including the schedules for Ancillary Services, by approximately 1:00 p.m. each day, and publishes final transmission Usage Charge rates if transmission congestion has occurred. The PX then calculates Zonal Market Clearing Prices based on its Participants' Schedule Adjustment Bids and the Usage Charge rates provided by the ISO.

PX Hour-Ahead Market

In the hour-ahead market, buyers and sellers are able to adjust the positions they received in the day-ahead market. This is especially useful to distribution utilities and electric service providers who may need to modify their day-ahead market positions when demand changes due to weather conditions or supply changes due to plant outages or line de-ratings. The PX hour-ahead market also provides benefits to bilateral market participants who may wish to adjust their day-ahead market positions. The PX hour-ahead market involves trading around-the-clock through 24 hourly auctions.

PX Schedule Coordination

In addition to operating the forward energy markets (day-ahead and hour-ahead), the PX also functions as a Scheduling Coordinator with responsibility for submitting balanced resource schedules to the ISO, providing real-time dispatch instructions to its Participants, and performing billing and settlements services for both the day-ahead and hour-ahead markets.

ISO Market Descriptions

The ISO operates the real-time Imbalance Energy market, the Ancillary Services market, and the Transmission Congestion Management market.

Imbalance Energy Market (Real-Time Market)

The ISO is responsible for balancing loads and resources in real-time. The ISO uses bids received in the Imbalance Energy market to increment and decrement resources as needed to maintain a system-wide energy balance. These bids include Supplemental Energy Bids, which Participants provide to the ISO up to one hour prior to the dispatch hour, as well as the energy bids submitted by Participants in conjunction with their Ancillary Services capacity bids, as described below. The Imbalance Energy market price is calculated in 10 minute intervals on an ex-post basis. This price is used to settle deviations between scheduled and actual quantities of supply and demand. A Participant that over-delivers relative to its scheduled quantity is paid the imbalance price, while a Participant that under-delivers relative to its scheduled quantity is charged this price.

Ancillary Services Markets

The ISO conducts four day-ahead and four hour-ahead auctions for Ancillary Services. These four Ancillary Services are: Regulation, Spinning Reserves, Non-Spinning Reserves, and Replacement Reserves. Each is a capacity-only market. Bidders must also include an energy bid with each capacity bid. The Energy Bids in the Regulation market are used for validation only while the Energy Bids for Spinning, Non-Spinning, and Replacement Reserves are used, along with Supplemental Energy bids, in the real-time Imbalance Energy market. In addition to these four Ancillary Service products, which are acquired through an hourly market-clearing auction process, the ISO also is responsible for acquiring Voltage Support/Reactive Supply and Black Start capability, which it procures though a longer term contracting process.

Transmission Congestion Management

The Transmission Congestion Management market operates on the basis of Schedule Adjustment Bids (SABs) provided to the ISO by Scheduling Coordinators. These SABs indicate the willingness of a Scheduling Coordinator to increment a resource if the price increases or decrement a resource if the price decreases (vice versa for demand and exports), and are an expression of the value that the Scheduling Coordinator places on obtaining inter-zonal transmission access. The ISO uses the SABs to adjust individual resource schedules to relieve congestion and calculate transmission congestion Usage Charge rates.

Table 1 shows the detailed operational timelines for the day-ahead and hour-ahead markets.

Table 1 Timeline for Day-Ahead and Hour-Ahead Markets[1]

Day-Ahead Timeline	Day-Ahead Activity
By 7:00 a.m.	Participants submit day-ahead portfolio energy supply bids and demand bids for each hour to the PX.
By 7:15 a.m.	PX conducts day-ahead energy auction and notifies successful bidders of hourly market-clearing prices and quantities.
By 9:20 a.m. (scheduled to move to 9:10 a.m., beginning August 23)	Participants submit Initial Preferred Schedules to the PX that provide details of the specific generating units and loads that fulfill the aggregate awards in the energy auction. In addition, Participants submit Schedule Adjustment Bids for inter-zonal transmission access.
By 9:30 a.m.	Participants submit to the PX bids for Ancillary Services (regulation, spinning reserves, non-spinning reserves, and replacement reserves).
By 10:00 a.m.	PX and other Scheduling Coordinators (SCs) submit their Participants' Initial Preferred Schedules to the ISO, along with their Participants' Schedule Adjustment Bids and Ancillary Services Bids.
By 11:00 a.m.	ISO completes first iteration of inter-zonal congestion management. If there is no inter-zonal congestion, ISO issues Final Day-Ahead Schedules, including the schedules for Ancillary Services selected in the ISO's Ancillary Services auction. If there is congestion, ISO provides the PX and other SCs with the estimated Day-Ahead Usage Charges, a Suggested Adjusted Day-Ahead Schedule, and a preliminary schedule for Ancillary Services.
By 12:00 noon	If there is inter-zonal congestion, PX and other SCs submit to the ISO their Revised Day-Ahead Schedules, in response to the ISO's Suggested Adjusted Day-Ahead Schedules.
By 1:00 p.m.	ISO performs second iteration of congestion management and provides the PX and other SCs with Final Day-Ahead Schedules, including the schedules for Ancillary Services, and issues final Day-Ahead Usage Charge rates.
By 1:15 p.m.	PX and other SCs send their Participants the Final Day-Ahead Schedules, including the schedules for Ancillary Services, and the Final Day-Ahead Usage Charge rates. PX calculates zonal market-clearing prices.
By 1:30 p.m. (approx.)	ISO determines if there are any deficiencies in the ancillary services auctions and evaluates Reliability Must-Run requirements relative to Final Schedules.
By 5:00 p.m. (approx.)	ISO notifies market participants of any changes in Final Day-Ahead Schedules resulting from ancillary services shortfall and Reliability Must-Run generation requirements.
Hour-Ahead Timeline	**Hour-Ahead Activity**
Not later than 3 hours prior to the dispatch hour	Participants submit energy supply and demand bids to the PX (bids are resource specific and are relative to Day-Ahead Final Schedules).
Not later than 2 hours, 50 minutes prior to dispatch	PX calculates market clearing prices and quantities, and determines Preferred Schedules.
Not later than 2 hours prior to the dispatch hour	Participants submit Schedule Adjustment Bids and Ancillary Services Bids to the PX, which in turn, submits the Preferred Schedules, Schedule Adjustment Bids, and Ancillary Services Bids to the ISO.
Not later than 1 hour prior to dispatch hour	ISO performs congestion management and conducts its Ancillary Services auction. ISO provides PX and other SCs with Final Hour-Ahead Schedules, including schedules for Ancillary Services, and final Usage Charge rates. PX, in turn, transmits this information to its Participants.
Prior to dispatch hour	PX calculates and publishes Zonal Market Clearing Prices.
Real-Time Timeline	**Real-Time Activity**
Not later than 60 minutes prior to the start of hour	Participants provide Supplemental Energy Bids to the PX and other SCs.
Not later than 45 minutes prior to the start of hour	PX and other SCs submit Supplemental Energy Bids to the ISO for use in the real-time market.

[1] Target timetable; actual performance varies depending on circumstances.

Bidding in multiple markets

Most participants will be eligible to bid in several of the markets. The exact sequence of bids and responses affects how they will do so. Prior to their 7 a.m. day-ahead bids, generators must make an approximate decision about the split between what they want to offer in the day-ahead and Ancillary Services markets. Bids in the day-ahead energy market are accepted before bids in the AS market need to be placed. If generators want to offer a larger quantity in any AS market, they must offer a smaller quantity in the day-ahead market. They can implement this directly, or they can offer the smaller quantity at "reasonable" prices, and then offer the rest at very high prices. Once the day-ahead market results are revealed at 7:15 a.m., the generators know how much capacity they can offer to the AS markets.

The method the ISO uses for sequencing the four AS markets also is important. Generators can bid simultaneously in all four markets, according to the following hierarchy:

- Regulation
- Spinning reserves
- Non-spinning reserves
- Replacement reserves.

The ISO resolves the four markets in order. Any bid in a lower numbered market that is not accepted is automatically assumed to be a bid in the higher numbered markets. In this way, the generator does not have to enter separate bids in each market, and the same MW of physical capacity can be entered simultaneously into all four markets. If some of the MW are not purchased in the spinning reserves market, for example, they are automatically offered to serve the non-spinning or replacement reserves markets. Thus, unlike the choice between day-ahead and Ancillary Services markets, participants do not need to decide in detail to which AS market they would like to offer, except insofar as their units are physically constrained to one or another market.

This ability to bid well above the predicted market clearing renders problematic the interpretation of the "quantity" a participant bids into the market. For example, the ISO's motion requesting a stay of the FERC's June 30 and July 10 orders states (p 25):

> Moreover, the Ancillary Services markets are already depressed by the bidding rules that govern the Utility Distribution Companies. They must first bid their available generation into the Power Exchange. They are not free to hold it out for the Ancillary Services auctions and can participate in those auctions only if and to the extent that their bids are not accepted by the Power Exchange.

This is technically correct, but irrelevant. By bidding a price of $250/MWh or higher for some of its capacity, any participant including an IOU can be almost assured that the capacity will not be accepted in the day-ahead PX market. The capacity will therefore be available for bidding in later markets, including the Ancillary Services and real-time markets. Of course, if the IOU is limited to cost-based rates for Ancillary Services, it will probably prefer to sell in the energy markets, but the choice is its own. In our analysis, we have generally interpreted offers above $250/MWh as the participant's effectively withdrawing capacity above that price from the day-ahead market.

Market Performance

During the period April 1 through August 11, 1998, the PX has successfully run its day-ahead energy market and published hourly market clearing prices and quantities every day. The hour-ahead market opened recently and is functioning properly as well. The overall trends in the PX markets during this period are summarized below.

Market Overview

The California electricity market is enormous, representing approximately $22 billion in annual revenues and 246,000 GWh of annual energy consumption, roughly 10% of the total U.S. market. The three major investor-owned utilities (Southern California Edison, Pacific Gas & Electric, and San Diego Gas & Electric) account for approximately 70% of the total California electricity market on an energy consumption basis, with the balance of the market served by municipal and governmental entities. Since the market opened, the PX share of the restructured California electricity market has been approximately 88%.

PX Participants include investor-owned utilities, Federal and municipal entities, independent power producers, and power marketers, from both within and outside California. There are approximately 45 Participants certified to trade in the PX markets, with about 35 Participants active in the markets on any given day. In addition, there are about 20 entities currently in the certification process. As a result of generation divestiture, the California IOUs' share of the PX supply market has declined from about 93% in the early months of the market to about 85% in July.[2] On the demand side, the California IOUs are the dominant players within the PX, representing about 95% of the load in the day-ahead energy market.

Demand

While population and economic activity are major underlying factors determining demand for electricity, weather is the primary determinant of seasonal and daily variations in load. Temperature patterns and deviations from the expected seasonal trends throughout the Western System are important for the California market. California and the inland Southwest have desert climates with substantial air conditioning load, whereas the Northwest and Northern Rockies have more moderate summer temperatures, but higher heating loads in the winter.

Temperatures throughout the region during April were mild and continued moderate through May and June. As a result, air conditioning loads in the California market were somewhat lower than average. Temperatures in the Northwest were also below average with more heating degree days in April, May and June than normal, thus increasing nighttime heating requirements. In late June and early July, temperatures began to increase somewhat and

[2] These percentages are for generation bid by the IOUs. Much of this generation is owned by other parties and bid in at a zero price under provisions such as those for qualifying facilities.

finally gave way to high temperatures in mid-July through early August. Electricity demand in late July and early August was up throughout the region, in some cases to record levels. Since this heat wave had an impact on the Southwest and the Northwest as well as on California, demand increased throughout the region.

Table 2 shows monthly information on PX market clearing quantities. As expected, the difference between the maximum hourly and minimum hourly clearing quantities has significantly increased since the Spring, from about 10,000 MW to 18,000 MW, thereby increasing the need for peaking resources.

Table 2 PX Market Clearing Quantities

Month	Maximum Hourly MCQ (Megawatts)	Minimum Hourly MCQ (Megawatts)	Average Hourly MCQ (Megawatts)
April	24,847	14,657	19,914
May	23,007	14,542	19,050
June	28,499	15,683	21,398
July	35,774	16,993	25,393
August*	36,376	18,075	26,784

* As of August 11.

Supply

Generation capacity in the Western region is ample, with total generation in excess of peak demands. The Western configuration is fortuitous with winter heavy load in the Northwest and Northern Rockies counterbalancing heavy summer loads in California and the Southwest. Because of the importance of the seasonal north to south interregional flows, transmission curtailments or de-ratings on the Pacific Interties can have an impact on generation supply to the California market. Similarly, unit outages, either scheduled for maintenance or unplanned, affect supply availability and thus prices in the California market.

Supply conditions were generally robust during the April through mid-July period. Hydro generation conditions in the Northwest have been generally good, with moderate impacts from spill requirements associated with salmon restoration efforts. Northern California hydroelectric generation has been abundant as the result of higher than usual snow pack and moderate temperatures.

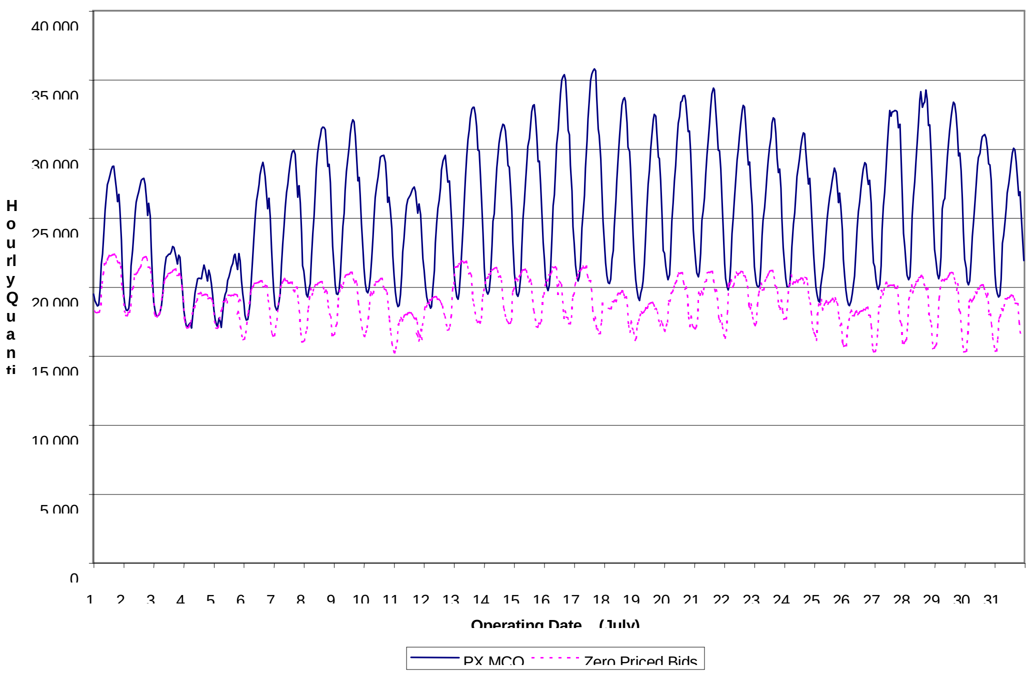
Pacific Intertie curtailments limiting the flow of power to California in July, coupled with hydro generation concerns in the Northwest in late July, contributed to upward price pressures during this period. Since late July, extreme temperatures in the Southwest and Northwest, combined with forced outages at key plants, pushed peak prices upward and led to voluntary load curtailments in several hours.

Power plant divestitures have also had an impact on the supply picture. Since the opening of the market, the California IOUs have divested approximately 12,000 MW of generation resources, mostly natural gas-fired plants. Four separate companies acquired the majority of this capacity and are now actively bidding these resources into the California market and other markets in the western states, as discussed in Section IV.

Regulatory Must-Take (RMT) generation is another important factor in the PX market. RMT resources, which include nuclear units, Qualifying Facilities, and run-of-the-river hydro, are bid into the PX at $0/MWh to ensure their selection in the auction process. Other resources, which may not be classified as RMT but which may for operational reasons want to be assured of being dispatched, may also bid into the PX at $0/MWh. These resources typically account for approximately 20,000 MW of capacity. At lower demand levels, these resources can set the market clearing price at zero, as happened in many hours in May and early June. As demand levels increased in July and August, coal units and natural gas units determined the market clearing price.

For example, in June, average hourly PX demand was 21,400 MWh, while the average hourly quantity of generation bid into the PX at zero price was 19,600 MWh, or 92% of PX market demand. In July, average hourly demand increased to 25,400 MWh, while the quantity of zero price generation bids was 19,800 MWh, or 78% of PX demand. In August, the fraction of zero price generation bids decreased to 73% of PX demand. As expected, the percentage of zero price energy bid into the PX relative to total PX demand is higher in the off-peak periods and lower in the on-peak periods. See Figure 1.

Figure 1 Zero Priced Bids vs Total PX Market Clearing Quantity, July 1998



The implication of the high volumes of zero priced bids is that the energy markets are "thinner" than they first appear. For example, suppose energy demand is 30,000 MW, zero bids are 20,000 MW, and one firm controls 3,000 MW of gas-fired capacity. It is more accurate to view this firm as having capacity equal to 30% of the price setting portion of the supply base, rather than 10% of the overall market.

Prices

The following discussion of PX market prices covers the period April 1 through August 11, 1998, and concerns PX unconstrained market clearing prices. The impact of transmission congestion on the unconstrained market clearing prices is discussed in a subsequent section.

We can roughly divide the period since the market opening into Spring (April, May, June), and July/August. Behavior of prices during the two periods was distinctly different. Table 3 summarizes the prices each month and shows the large rise from June to July.

Table 3 Unconstrained PX Market Clearing Prices ($/MWh)

Month	Minimum	Maximum	Average	Average Hours 7-22 (on peak)	Average Off-Peak hours
April	0.00	36.74	22.64	25.54	17.33
May	0.00	37.37	11.63	16.43	6.18
June	0.00	38.02	12.09	16.94	5.21
July	0.00	151.10	32.42	41.08	21.49
August*	6.79	163.01	43.13	60.93	25.50

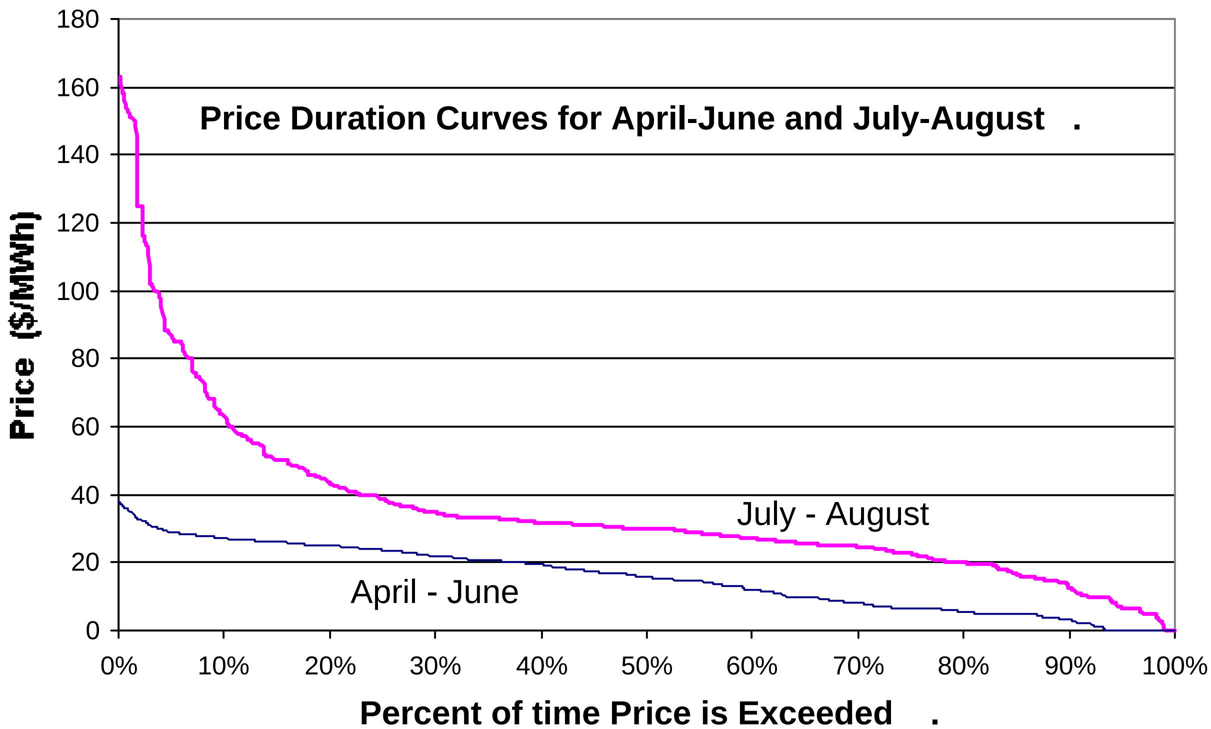
* Through August 11.

In April, the PX average hourly price was about $23/MWh, with hourly prices varying during the month from a low of $0/MWh for three hours, to a high of about $37/MWh, as shown in Table 3. In May and June, average hourly prices fell significantly from the April level, to about $12/MWh, due to moderate demand caused by mild temperatures and substantial hydro availability in Northern California. The market clearing price was $0/MWh for 43 hours in May and 87 hours in June.

Prices began to rise in mid-July as summer temperatures developed and demand levels rose. The PX hourly average price rose to $32/MWh in July and $43/MWh in August, with natural gas units setting the market-clearing price in most hours. Peak prices rose significantly as much of the West went through a severe heat wave with several control areas in California reporting all-time record loads. The maximum hourly price rose to $151/MWh in July and $163/MWh in August. In addition, zero prices virtually disappeared, with only nine hours of zero prices in July and no hours of zero prices in August so far.

Figure 2 is a price duration curve that shows the percentage of time that prices exceeded a particular level. The lower curve is for the period April 1 through June 30 while the upper one is for the higher demand period of July 1 through August 11, and illustrates the dramatic change between the periods. As shown in Figure 2, the maximum price through June did not exceed $40/MWh and price was zero about 6 percent of the time. In July-August, however, prices were above $40/MWh about 25% of the time, and price was zero only briefly.

Figure 2 Comparison of Price-Duration Curves



Price volatility

Figure 3 shows the relationship between the PX market clearing price and quantity for the period April 1 through June 30, 1998. As shown, the maximum hourly quantity was less than 30,000 MWh throughout the three month period and the maximum price less than $40/MWh, and there were significant variations in price for a given quantity. Figure 4 presents equivalent information for the period July 1 through August 11, 1998. It shows that the shape of the price-quantity relationship changed significantly as market clearing quantities (MCQ) exceed 30,000 MWh, as average prices rise steeply with market quantity above 30,000.

Figure 3 Market Clearing Price and Quantity for the Period April 1 – June 30

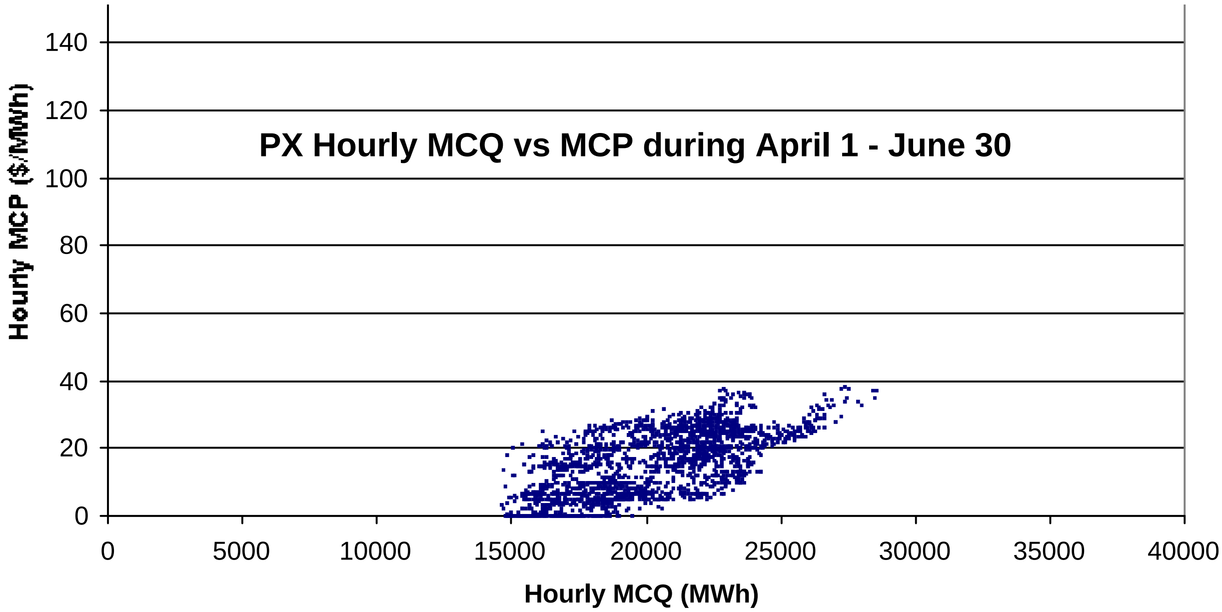
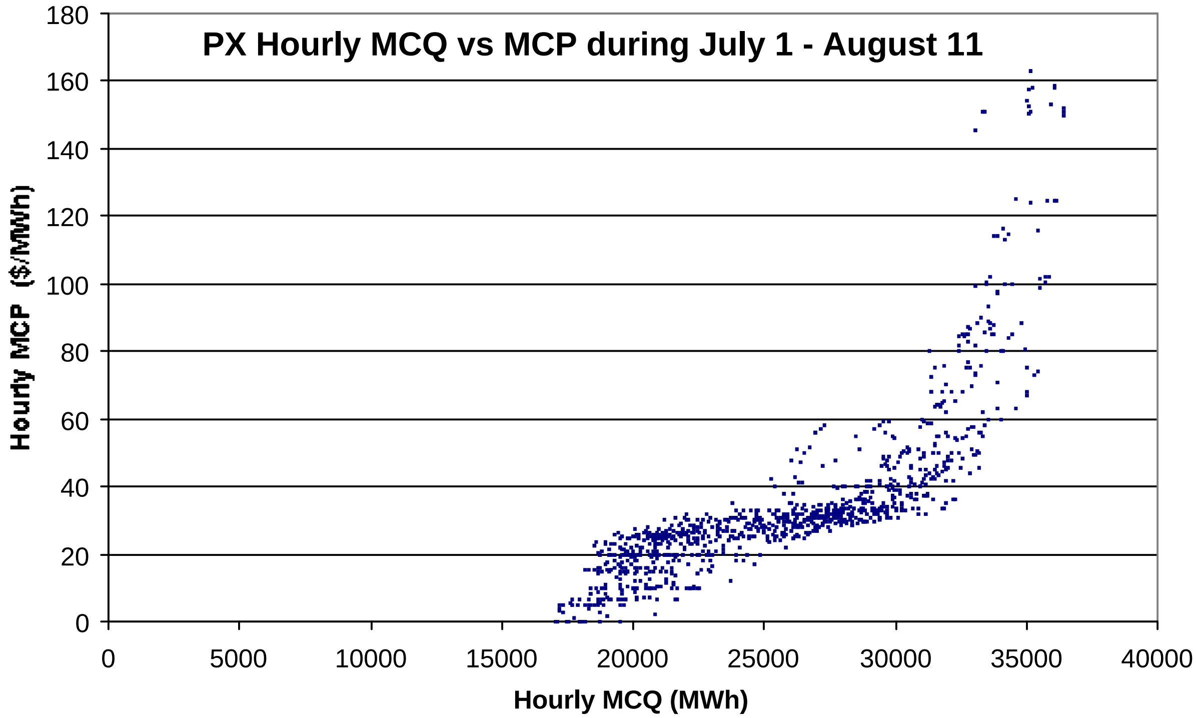


Figure 4 Market Clearing Price and Quantity for the Period July 1 – August 11



Congestion

Congestion on the major transmission paths has increased as electricity demand levels have increased. Table 4 shows the number of hours of congestion on the major transmission paths, while Table 5 shows the resulting impact of such congestion on the PX unconstrained market clearing prices.

Table 4 Congestion charges

Month	Transmission Path	Number of Hours Congested	ISO Transmission Usage Charges ($/MWh)		
			Minimum	Average	Maximum
April	So. Calif – No. Calif	0	0.00	0.00	0.00
	Calif – Oregon	1	4.14	4.14	4.14
	Calif – NOB	3	250.00	250.00	250.00
	Calif – Arizona	0	0.00	0.00	0.00
May	So. Calif – No. Calif	0	0.00	0.00	0.00
	Calif – Oregon	131	0.10	9.34	50.00
	Calif – NOB	127	0.01	40.80	250.00
	Calif – Arizona	0	0.00	0.00	0.00
June	So. Calif – No. Calif	59	0.14	3.65	25.90
	Calif – Oregon	119	0.02	4.71	14.30
	Calif – NOB	82	0.01	2.91	12.51
	Calif – Arizona	0	0.00	0.00	0.00
July	So. Calif – No. Calif	62	0.02	12.45	76.25
	Calif – Oregon	199	1.01	17.78	58.01
	Calif – NOB	95	0.01	11.51	11.51
	Calif – Arizona	0	0.00	0.00	0.00
August*	So. Calif – No. Calif	35	0.70	9.55	23.60
	Calif – Oregon	23	0.63	2.29	3.94
	Calif – NOB	7	1.87	27.91	80.86
	Calif – Arizona	0	0.00	0.00	0.00

* As of August 7.

In April and May, there was no congestion on the main transmission link between northern and southern California (Path 15, linking zones NP15 and SP15). In June and July, congestion on this path occurred in a total of 121 hours, or 8% of the time. On the California-Oregon Intertie (Northwest 1), one of two major transmission links between California and the Northwest, congestion occurred in only one hour during April. In May through July, however, congestion on this path occurred an average of 150 hours per month. On the California-NOB link, the other major transmission link to the Northwest, congestion occurred in only three hours in April, and an average of 100 hours per month during May through July. There was no congestion between California and Arizona.

The vast majority of electricity demand in California occurs in Zones NP15 and SP 15, Northern and Southern California respectively. As a result of congestion, the average PX unconstrained market clearing price in NP 15 increased an average of $1/MWh during the congested hours in the period May through July. During this same period, the average unconstrained price in SP 15 increased approximately $2/MWh during the congested hours.

Table 5 Average Price Impact on NP15 and SP15 Due to Congestion

Month	Price Impact Hours	Unconstrained Market Price ($/MWh)	Average Price Impact in SP15 ($/MWh)	Average Price Impact in NP15 ($/MWh)
April	0	n/a	n/a	n/a
May	162	16.85	1.86	1.86
June	150	21.84	1.20	0.80
July	199	42.28	2.75	0.43
August*	68	48.49	-1.41	2.18

* As of August 7.

Comparison with bilateral markets

The PX regularly compares its day-ahead energy market prices with those occurring in bilateral markets, as shown in Table 6[3]. Such comparisons must be viewed carefully since the PX prices are derived from individual hourly auctions, whereas bilateral market prices represent a relatively small volume of energy traded in aggregate on-peak and off-peak blocks, and are determined based on a survey of market participants. Nonetheless, the comparisons are tracked closely by the PX. The two primary hubs for bilateral trades in the California market are at the California/Oregon border (COB) and at the California/Arizona border (Palo Verde).

Table 6 Comparison of PX Unconstrained Prices with Bilateral Market Prices ($/MWh)

	On-Peak				Off-Peak		
Month	**PX**	**COB/ NOB**	**Palo Verde**		**PX**	**COB/ NOB**	**Palo Verde**
April	25.54	25.14	25.22		17.33	16.33	14.96
May	16.43	14.82	19.62		6.18	7.60	7.97
June	16.94	15.65	20.68		5.21	5.97	7.28
July	41.08	31.39	43.81		21.49	17.02	17.48
August*	60.93	55.31	55.44		25.50	27.91	24.80

* As of August 11.

[3] Source of bilateral market prices: Energy Market Report.

Comparison with real-time prices

As shown in Table 7, PX average hourly prices have been slightly above ISO real-time prices, although real-time prices have been more volatile, as would be expected. During the period April 1 through August 11, the PX average hourly price has been $21.67/MWh with a standard deviation of $18.80/MWh, while the average ISO real-time price has been $18.29/MWh with a standard deviation of $23.62/MWh.

Table 7 Comparison of PX Unconstrained Market and ISO Real-Time Prices ($/MWh)

Month	PX Average Hourly Day-Ahead	ISO Average Hourly Real-Time Price	PX Price Standard Deviation	ISO Price Standard Deviation
April	22.64	20.49	6.56	11.26
May	11.63	9.33	7.68	10.40
June	12.09	8.36	9.36	10.91
July	32.42	27.83	20.71	29.69
August*	43.13	42.61	34.97	48.75

As of August 11.

PX Hour-Ahead Market

The PX hour-ahead market has been in operation only a couple of weeks and has had low volumes during this initial period. Prices have exhibited significant volatility, as expected and as does the real-time market. The transaction volume in the hour-ahead market will likely increase as market participants gain additional experience with its operation.

IV. Behavior of the key participants in the markets

In this section we describe and analyze the behavior of the most relevant generating companies. These companies own or at least control gas-fired generating units. Their units play a crucial role since they provide about 17,000 MW of gas-fired capacity, which comes into play as demand rises above the level that can be met by baseload units. During the afternoon hours in July the zero-bid capacity, mainly from utilities, was greater than 20,000 MW while total demand was between 29,000 and 35,000MW. (See the discussion of regulatory must-take in Section III.) Therefore units of the "key participants" should generally be at or near the margin and always play a role in determining the market-clearing price during these hours. Our analysis, below, of the frequency with which particular participants comprise the marginal supply supports this characterization.

By examining the behavior of these generators we hope to understand better the behavior of prices in individual markets as well as the issue of spillovers from one market to the next.

We have limited our detailed analysis to ten weekdays in July: July 6-10 and July 27-31. During the first of these weeks, Ancillary Services prices were not capped, and Replacement Reserve prices reached $5000 per MW for 3 hours. During the July 27-31 period, Ancillary Services prices were capped at $250 per MW. Three of the four Ancillary Services markets hit this cap during some hours of the week. We examined the hours from 12 to 20 (11 a.m. to 8 p.m.) each day. These are the hours with the highest demands and highest prices in both Ancillary Services and energy markets.

Summary of the key participants

Nameplate capacity of the main gas-fired plant operators is displayed in Table 8. The first four owners are new participants in the California market, who purchased plants from the IOUs. The last two owners are Investor-Owned Utilities (IOUs). This table does not include 280 MW of combustion turbines owned by SDG&E, 280 MW of gas units owned by Thermo Ecotek, and various non-gas units. The table also does not include out-of-state participants, who may at times provide significant energy. Hydro units can also play a role in determining prices, particularly the 1200MW of pumped hydro owned by PG&E.

Table 8 Ownership and size of intermediate gas units

Owner	**Abbreviation**	**Capacity (MW)**	**Share**
AES (Williams)	WESC	3956	23%
Houston Industries	NES	3776	22%
NRG Energy/Destec	ECI	1550	9%
Duke Energy	DETM	2645	16%
Sum of these four	Independents	12,200	70%
PG&E	PGPG	3488	20%
San Diego Gas & Elec.	SDGE	1644	10%
Total		17,100	100%

Source: PX data.

Hypotheses concerning behavior of key participants

If a generator were acting like a perfect price taker, we would expect it to bid each hour with a supply curve approximately equal to the marginal generating cost up to the capacity of its units. For example, with delivered gas prices now about $3 per MMBtu, a generator with a heat rate of 10,000 Btu/kwh would bid slightly above $30 per MWh. Prices would rise above the $30 level whenever total demand, including Ancillary Services demand, exceeded the capacity of baseload (zero bid price) plus gas units. At these times, gas turbines and other special technologies would comprise the marginal supply and, together with demand, jointly determine the price. A unit with a marginal running cost of $30/MWh would then receive contributions to fixed costs whenever prices are above $30 for any reason.

We consider this the "competitive behavior model." Another important attribute of this model is that the quantity offered by each generator should add up to its capacity. But during the two July weeks we examined, the bidding of the key participants did not always fit this competitive behavior model. The firms behaved rather differently from each other, but only a few followed the predictions of the competitive model just sketched.

The behavior of the six key participants in the PX day-ahead market in July departed in two main ways from the competitive model. First, they almost never bid to supply their entire generating capacity in the PX market. Second, they often bid capacity at prices well above $30/MWh. In fact some firms bid some of their capacity at prices above $100/MWh during some hours.

For any given generating company and hour, there are at least five possible explanations why its bid quantity in the PX day-ahead market might total less than its capacity. They are:

- The participant expects one or more units to be unavailable.
- It has a bilateral contract to sell energy.
- It planned to sell capacity in one of the ISO markets. (Recall that the bids for the PX day-ahead market must be placed before bids in the Ancillary Services and other markets.)
- The participant is trying to push prices up.
- The participant hopes that by not bidding a unit, it will be called as a Reliability Must Run unit, and it will receive a higher price than it would have received in a competitive market.

With these explanations in mind, plus the default hypothesis of competitive behavior, we examined the behavior of each key participant during the hours from 12 to 20 in the weeks of July 6-10 and 27-31. Unfortunately we had very little information about the first two explanations: unit availability and bilateral contracts. This limits the inferences we can draw.

Observed behavior of participants

Different participants followed different patterns of bidding during the ten days and 90 hours we examined in detail. Several appeared to be pure price-takers. They bid a flat supply curve at a price approximately equal to the marginal cost of a gas-fired unit. Others used very elaborate bid curves that varied by hour and day. Not surprisingly, the latter were often the marginal price setters.

Some of the more elaborate bidding mechanisms used at different times by different participants included the following:

- Finely differentiated upward sloping supply curve.
- Hour to hour changes in the supply curve, shifting the curve to the left (less energy offered at a given price) at times when prices were likely to be higher.
- Day to day changes in the supply curve.
- Extensive bidding in Ancillary Services markets.
- Apparent adjusting of Ancillary Services and supplemental energy (real time) offers in response to sales in the day-ahead market.

We emphasize that without a full econometric model to explain bidding behavior -- one that accounts appropriately for exogenous factors and individual units -- and more data, we cannot draw firm conclusions from this examination. In particular, we cannot easily tell whether a given participant is "withholding" some of its capacity to force prices up or to induce the ISO to call a unit for Reliability Must Run status. Recall, specifically, the gaps in our data on bilateral contracts. Thus although we often observed PX-market offers and sales significantly below nameplate capacity, at this point no definite inferences can be drawn.

Our limited examination of bidding behavior, however, does provide considerable suggestive evidence that the energy markets are at times thin and not fully competitive. Therefore, any actions taken by the ISO to improve the Ancillary Services markets should be carefully scrutinized to be sure they do not adversely affect the energy markets. This is especially important since the volumes of the energy markets are about ten times larger than the volumes in the Ancillary Services markets.

It is also possible to *over-offer* capacity. That is, a participant can make AS bids by 9AM such that AS bids plus day-ahead sales exceed its capacity. For example, one afternoon a participant sold 80 percent of its capacity in the day-ahead market, and then bid 50 percent of its capacity in the AS markets. Because of its supply curve (bid prices) about half its Ancillary Services bids were purchased. This led to total commitments of 106% of its capacity. There is nothing necessarily wrong with this if the participant is willing to "buy back" its day-ahead energy sales in the hourly, real-time, or bilateral markets.

Who determined prices?

Since we have data on individual supply curves (bids), we can engage in some sensitivity analysis to determine which participants had the most effect on prices. In essence we ask the question, "At the actual price-quantity intersections in the marketplace, which firms were the ones with the most power to alter price by altering their bids?" We estimated this by looking at the incremental supply curve of the marginal firms, recognizing that several firms might be on the margin to different degrees in the same hour. This gave us a measure "percent of incremental energy from participant x." In a perfectly competitive market with six identical participants, we would expect that each participant would provide approximately 17% of the incremental energy. We interpret a disproportionate share of one firm as meaning that it had a larger opportunity to influence prices. Whether such firms used that opportunity is a separate matter.

We examined the incremental firms over the period July 1 to August 10. Only "high priced hours," i.e. those over $75/MWh, were included in the calculation. There were 70 such hours. Of the approximately 30 sellers in the market, only four were important on the margin during these 70 hours. Not surprisingly in light of the differences in bidding behavior discussed above, we found substantial differences in who was on the margin at different prices. At prices from $75 to $100/MWh, incremental supply was divided rather evenly among four firms, with two of the six key participants almost never on the margin. At prices between $100 and $125, one firm was dominant with about three quarters of the incremental energy. When the price was above $125, a different firm was dominant with about three quarters of the incremental energy.[4]

We conclude from these share numbers that at certain levels in the aggregate supply curve, a very small number of firms had the effective ability to determine the prices. In essence they dominate a horizontal slice of the aggregate supply curve, and other firms have vertical supply curves in those price regions, or bid all their capacity at lower prices. At other levels, many firms are bidding with sloped supply curves, and no one firm dominates. The Market Monitoring Committee is concerned about market concentration issues, and will monitor it closely in the future.

V. Interactions between PX and ISO markets

The prices in three ISO Ancillary Services markets and in the PX Day-ahead market are shown in Figure 5, for hours 12 to 20 on the ten weekdays we studied. All prices are shown on the same scale, which illustrates the wide variations among markets and over time. Corresponding quantities are shown in Figure 6. We show Ancillary Services prices and quantities only for the SP15 region, which is the largest demand region and was moderately more subject to high prices than NP15. As the graphs show, different markets had high prices on different days. For example, in the energy market, during these ten days prices exceeded $100/MWh only on Tuesday July 28. That day, non-spinning reserve and replacement reserve hit their caps of $250/MW, while the price for spinning reserve was about $10.

[4]: We took 90% of the original MCPs and calculated the generation from each participant at this price and at the actual MCP. The difference we considered that firm's incremental generation. This number divided by total incremental generation was the share for that participant in that hour. We then took the weighted average share for a participant across all hours in the price range, using the hours' total increments as the weights. There were 42 hours with prices between $75 and $100, 14 hours between $100 and $125, and 14 hours over $125.

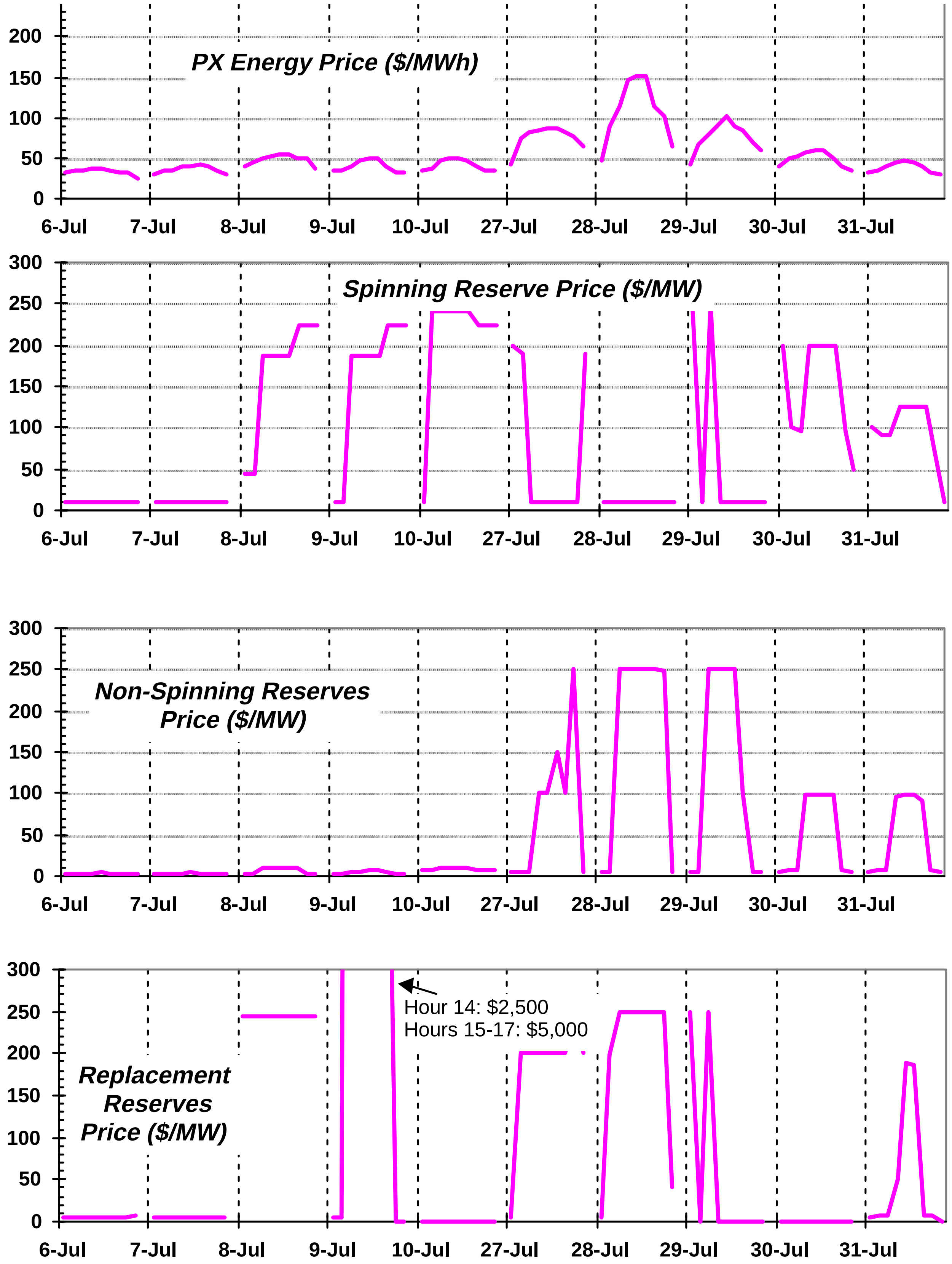


Figure 5 Energy and reserve Prices, selected days, hours 12-20

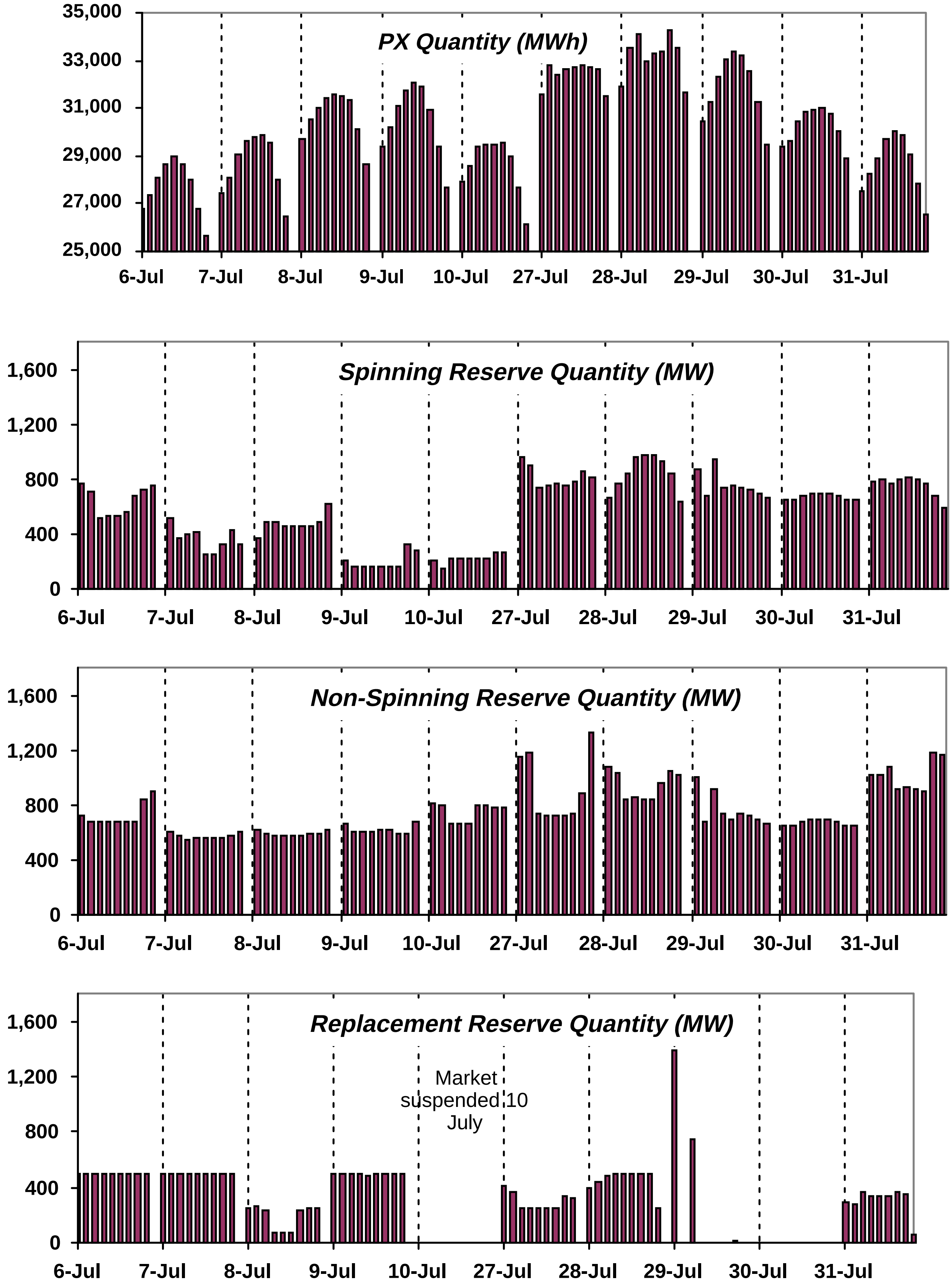


Figure 6 Energy and reserve Quantities, selected days, hours 12-20

One hypothesis about prices in these markets is that jumps in the Ancillary Services market prices are due to increases in capacity being used to serve the PX markets, leaving little capacity for Ancillary Services..[5] During the second week we examined, the $250/MW caps were binding in many hours. We do not have access to the firms' supply curves in the Ancillary Services markets, but our examination of the data on the PX energy markets does not suggest that the $250/MW caps were hit because of any widespread withdrawal of capacity from the Ancillary Services markets in an effort to provide more to the PX market.

Our examination of individual participants' sales in the PX and ISO markets reveals that some of them adjust their 9:30 a.m. bids in the Ancillary Services markets based on what they sold in the 7:15 a.m. day-ahead market. This is an attempt to make sure that capacity not selected in the day-ahead auction does not sit idle. To the extent this occurs, it helps equilibrate prices in the different markets. In principle such behavior does create a tradeoff between the two markets; more sold in one makes less available to the other. However the effect, if it exists, is weak.

We intend to study this issue further as more data become available. Prices in Ancillary Services and in energy markets have risen recently, and there is no reason to believe that the late-July Ancillary Services prices are stable or representative of their long-term behavior.

Comparing Prices: Reserves as Options

Another way to compare the various markets is to examine the profit-making opportunities in each one. If participants are rational, can sell capacity in any market, and have low transactions costs, we would expect prices to equilibrate across markets. More precisely, in equilibrium the expected profits from allocating the last MW of capacity to all markets should be equal. Participants should move capacity from one market to another until this condition holds; until then there would be opportunities to profit from arbitrage across the markets. Casual observation of Figure 5 suggests that prices are far from this equilibrium. Although energy prices seem to follow a regular pattern, Ancillary Services prices change by an order of magnitude from each other, from day to day, and even from hour to hour.

Spinning, non-spinning and replacement reserves are all theoretically call options that the ISO is purchasing. They give the ISO the right to buy energy on a few minutes notice, if it is needed to respond to a contingency. The payments made by the ISO for reserves are per MW of capacity, and are the cost of buying the options. When these reserves are called upon by the ISO, there is also an energy payment per MWh, at the real-time price.[6]

When, for example, the price of reserves is at $250/MW, this option character of reserves has two consequences. First, the underlying commodity (energy) has consistently been cheaper

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[5] Recall that Ancillary Services bids are made after day-ahead energy bids have been resolved. Therefore, the energy sales matter more than the energy market bids.

[6] Suppliers are required to include an energy bid with each capacity bid they submit in the reserves markets, but the energy payments they receive if they are called to provide energy are based on the ISO’s real-time imbalance price. They are only called if the real-time price is at or higher than their energy bid. This means that the actual “strike” price is equal to or higher than the energy price submitted by the provider.

than the call option, thereby in principle creating an arbitrage opportunity. Second, when deciding how much to offer in each market, participants will make more profit by selling reserves at $250 per MW than by selling energy, even if the energy price reached $250 per MWh. The value of selling a MW as reserves is the expected reserve price plus the expected value of real time price minus marginal running cost. For example, if the reserves price is $200/MW and there is a 40% chance of being called to deliver at a $100/MWh expected Real Time price, the expected revenue is the same as selling in the energy market at $240/MWh. The reserve contract gives about the same profit as an energy price of $258 (if the marginal generating cost is $30/MWh).

The maximum price in the PX day-ahead energy market has been about $160/MWh while Ancillary Services prices have often reached the ISO cap of $250/MW. The price of reserves has exceeded the energy price in many peak hours. **Table 9** shows the percentage of hours that the price for each reserve service was higher than the PX day-ahead energy price in early August. Most of the weekday afternoons had such relative prices. The reserve prices averaged close to $250/MW, because they were usually hitting the ISO's price cap. During such hours, in principle the ISO could have purchased energy and "thrown it away" more cheaply than buying the Ancillary Service.

Table 9 also shows the average day-ahead reserves price (option cost) and the real-time ISO energy price (exercise price for the option) during these high-priced hours. To calculate the total payment made to a Supplier who is called upon for reserves, one has to add the cost of the option (capacity payment) to the cost of energy when it is called during the affected hours. For example the first column shows the relevant prices for spinning reserves.

Table 9 Comparison of Revenues from 1 MW in PX and Reserve Markets

August 1 - 12, 1998	**Spinning Reserve**	**Non-spinning Reserve**	**Replace-ment Reserve**
Percentage of Hours that Reserve Price Exceeded PX Price	28%	20%	23%
Average PX Price During Such Hours ($/MWh)	63	90	91
Average Reserve Price During Such Hours ($/MW)	238	249	238
Average Real-Time Price During Such Hours ($/MWh)	72	108	111
Payment Above PX if Called for Capacity Reserve Only ($/MW)	175	159	147
Payment Above PX When Also Called for Energy for full Hour ($/MWh)	247	266	258

As shown in **Table 9**, the average payment to spinning reserve suppliers in these hours was $310/MWh ($238 + $72). The PX average energy price during the same hours was only $63/MWh. Thus, suppliers of spinning reserve energy received an average payment that was $247/MWh above the average PX price ($310 - $63). Even suppliers who were not called upon to provide energy received payments that were $175/MW above the average PX price. In a smoothly functioning group of markets, suppliers should have recognized that they could make significantly greater profits providing spinning reserves compared to bidding in the PX market during these on-peak hours.

Arbitrage should have eliminated the differential profit opportunities. It is apparent that the markets for Ancillary Services are not in equilibrium with the energy market. Perhaps because there are too few players in the Ancillary Services markets, the paradoxical price inversion persists.

If the cost of buying reserve services is higher than the cost of energy itself the same hour, the ISO would be better off buying energy in the PX day-ahead market to meet its reserve requirements. The ISO could even sell such energy to outside control areas at zero prices on the condition that it could be called back to meet ISO's reliability requirements -- in essence exploiting the arbitrage opportunity between the option and the commodity. This might cause PX prices to increase, but as reserve prices dropped to equilibrium with the PX market, capacity would shift toward the PX market, thereby compensating for the ISO's purchases in the market. An entrepreneurial firm could also take advantage of this arbitrage strategy and keep the profits itself.

VI. Concluding Observations

Based on the information gathered and the study undertaken to date, the Committee has a number of concluding observations to offer. Before we present them, however, it is important to emphasize the Committee's strong belief that competitive and efficient markets can set prices and determine quantities for electricity in California. Although market experience to date indicates the desirability of adjusting some of the current structures and procedures, this does not weaken our belief that properly designed and functioning markets can do the job. The main goal should be to make long-term changes that will remedy the current deficiencies. But we recognize that the market effects of some defects may be so severe that temporary interventions are required. It is important, however, to take all steps possible to ensure that short-term actions do not impede long-term effectiveness of the markets.

We turn now to more specific observations about the PX energy markets and their relation to the ISO's ancillary-services markets. These remarks are based on our time-limited study concentrating on the performance of the PX market, the behaviors of key participants in that market, and the interactions between the PX market and the ISO's markets for ancillary services.

First, the PX Day-Ahead market has functioned smoothly since its inception in April. The Hour-Ahead market is too new to analyze, though we are concerned about how slowly activity is developing there. The Day-Ahead market is large with a number of participants. It has, however, seen some very high prices during July and August. Our review of the data gives us some cause for concern about the ability of a small number of participants to affect prices at times of high demand. This is an area that we have been watching and will continue to follow carefully, particularly since high prices on the PX market have a larger impact on the overall cost of electricity in California than do comparable Ancillary Services prices.

Second, while high prices have been of concern in the PX Day-Ahead market, they have been of even more concern in some of the ISO's Ancillary Services markets. Indeed, the level of those prices gave rise to the ISO's request to the FERC, which in turn led the FERC to call for this report. The very high Ancillary Services prices reflect an insufficiency of supply offers relative to demand at particular times, which can then bestow significant market power on the generators that provide ancillary services. The principal solution to this problem is the entry of new units and new participants into the ancillary services markets. That is, insofar as the supply-side problem is structural in character, it requires a structural solution.

Steps must be taken to encourage entry in the short and long run. Removing restrictions on who is allowed to participate in the various markets, as the ISO has recently done with out-of-control-area generators, is one way to enhance entry in the near term. To the extent that some loads can be reduced as fast as generators can ramp, encouraging demand-side bidding for ancillary services is another means to increase supply, perhaps even in the short term. Furthermore, Regulatory Must-Run contracts should be considered in the overall context of the provision of system reserves. The incentives in those contracts should be structured so that owners of such units are not inefficiently induced to withdraw from the energy market or the ancillary services markets.

While supply-side development is essential to the long-term success of the Ancillary Services markets, it is also important that the ISO's demand for Ancillary Services be rational and responsive to economic incentives, while staying within the bounds of regulatory constraints and reliability objectives. The overall level and composition of ancillary services bought by the ISO should be determined in an integrated and economic way. System security constraints should be met by procuring the least-cost mix of the several ancillary services. For example, the ISO should be able to substitute among types of reserves when a more flexible type is available at a lower price. When energy prices are below reserves prices, energy too should be considered in the mix. Furthermore when some Ancillary Services' prices are very high, the ISO should continue to make the judgment to purchase less of them, as it apparently did for Replacement Reserves when the price would have reached $10,000 per MW.

Third, the current market problems are sufficiently severe that they call for short-term intervention in the market, such as price caps. This will reduce deleterious market outcomes and provide "breathing room" for the development and introduction of long-term improvements. If generators in the Ancillary Services markets have and exercise considerable market power in the short run it will induce inefficient behavior that will spill over to the energy market. Since the Day-ahead energy market clears before Ancillary Services bids are submitted, a firm wishing to bid in the Ancillary Services markets will have to offer less capacity in the Day-ahead market. Although most of the time such a bid might earn little, the prospect of a lottery-type win for a few hours in one or another of the reserve markets could suffice to make the strategy worthwhile. While we expect that prices would eventually equilibrate on average in the different markets, they would do so only with considerable distortion among the various markets. Unit commitments and other decisions would be distorted by the inaccurate price signals. Furthermore, allowing the exercise of unbridled market power could lead to substantial wealth transfers and cause political pressure for re-regulation, thereby undermining the possibility of having successful markets in the long term. In short, the Committee is persuaded of the need for short-term market interventions, perhaps in the form of price caps, to cope with serious, market-impairing structural problems.

It is important, however, to minimize the long-term effects of any short-term intervention that is made to cope with such market power. For example, the introduction of price caps may impede future entry if potential entrants worry about the possible imposition of additional caps. The extenuating circumstances justifying the intervention should be made clear and distinguished from the ordinary course of market events in a well-functioning market, and the temporary character of the intervention should be emphasized. Maintaining the credibility of the market and its institutions is essential.

The price cap level, if that is the intervention chosen, must be carefully selected. The price cap needs to be set at a level that will provide the entry that we seek as the long-term solution to the structural problem. Given the linkages among markets, a price cap imposed on one ancillary service market will have an effect on the others and on the several energy markets as well. A cap that is too high or too low may distort behavior in one of those complementary markets. In particular, in setting the price cap, and comparing it with energy prices, it is important to bear in mind that Ancillary Services give an option to buy energy at the real-time price.

Finally, although the Committee believes that some short-term market interventions, perhaps in the form of price caps, are appropriate, it believes that low, participant-specific price caps consisting of cost-based rates for Ancillary Services are inappropriate. The cost-based -rate rules that are still in effect for some participants set the prices for those suppliers well below the prices that generally clear the energy markets during times of high demand. Thus, if those cost-based rates are imposed on a participant, that agent has an incentive to not offer capacity to Ancillary Services and instead to sell all its capacity in one of the energy markets. Although this restrains prices in the energy markets, it does so at the cost of distorting the signals about the relative value of ancillary services and energy. With cost-based caps imposed on some participants, inefficient quantities are offered to the Ancillary Services markets. This in turn could lead the ISO to resort to mandatory orders to generators to provide such services and further distortions of participant behavior and of prices. We recommend removing the cost-based rate caps that remain in effect.