3. Prices and Costs

Wholesale power prices were high throughout the West in the summer of 2000, but their implications for consumers were felt most acutely in the San Diego area of California. Because supplies were tight and prices were high throughout the West, recourse to imports could not relieve pressure on California prices when loads rose. The principal findings of the report on western prices and costs during the summer of 2000 are:

- *Prices in the Cal-ISO spiked in May and June and average June prices reached record high levels.* With an ISO price cap of $750 for the first time during the summer, prices became highly volatile and the hourly price hit the $750 cap on 3 days in June. Average June prices reached record levels of $120 in the PX in June.

- *Average hourly prices were lower in July than in June, but August prices were higher than June prices.* Caps of $500 in July and $250 in August had a dampening effect on high hourly prices, but average prices in August rose to $166 in the PX after falling below June levels to $106 in July. The lower price caps may have played a role in increasing exports in July and August.

- *Prices at other hubs in the West were highly correlated with California prices,* suggesting that opportunities to sell at high prices existed in these regions when California prices were high. However, it is not yet clear how scarce supplies were in these regions. Nor is it clear to what extent prices outside California were based on importing power into California rather than consuming it in other regions. Information from other regions in the West for the week of July 31 to August 4 suggests that supplies were in fact scarce, but it is not possible to assess the overall level of scarcity in the West throughout the summer without additional information.

- *Costs for fuel and environmental (NOx) compliance increased significantly in July and August.* Gas prices rose from around $2 per MMBtu early in the year to around $5 in August and the cost of credits for complying with the NOx standards rose from around $6 per pound in May to $35 in August and $45 in September. Lowered price caps in July and August reduced the ceiling on market prices while, at the same time, these fuel and environmental costs raised the floor. As a result, prices traded over a narrower range. Offpeak prices tracked upward with increases in offpeak demand while exports reduced available supply and outages increased during these months.

- *Prices in some hours appear to be above those that would have prevailed in a competitive short-term (hourly) market, if the competitive prices were determined from short-term marginal costs.* A Market Surveillance Committee (MSC) analysis indicates June prices were significantly above competitive levels using a simulation approach to defining the competitive price, but results are not available for July or August.[1]

- *Examination of bid patterns in the PX and in the ISO replacement reserve markets and a review of ISO out of market purchase activity do not suggest substantial or sustained attempts to manipulate prices in these markets.* Supply curves bid into the PX show higher bids, on average, when the price caps are lowered. However, the increases are not correlated with particular classes of bidders, suggesting that the pattern may reflect increased costs for most participants rather than a general pattern of attempts by individual bidders or classes of bidders to exercise market power.

These results are discussed in three subsections. The first subsection discusses prices in western markets and California, addressing the first three points above. The next subsection discusses the relationships between costs and prices, including input costs such as natural gas prices and environmental compliance, and relates these to the prices observed in western markets and markets at the California PX and ISO. The final section discusses bidding in PX and selected ISO markets.

A. Prices

During the summer of 2000, most of the Western Interconnection experienced unusually hot temperatures which triggered several price increases throughout the region. The volatile wholesale prices that plagued the Pacific Northwest caused some aluminum plants, pulp mills, cold storage facilities and mines to layoff workers and curtail production. With respect to California, the price increases that occurred in May and June were largely caused by unusually high temperatures coupled with robust economic growth that led to record high growth in electric loads. Prices in July were slightly lower than the previous month partly due to the California ISO (Cal-ISO) lowering its price cap from $750/MWh to $500/MWh effective July 1, 2000. However, in August, prices increased significantly higher than July even though the price cap was lowered again from $500 to $250 per megawatthour.

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[1] "An Analysis of the June 2000 Price Spikes in the California ISO's Energy and Ancillary Services Markets," Market Surveillance Committee of the California ISO, September 6, 2000.

Major California Market Players

IOUs. The three major investor-owned utilities (also known as Utility Distribution Companies) in California are PG&E, SDG&E and SoCal Edison. The IOUs must buy from and sell all of their generation through the California PX until the end of the transition period in March 2002, or until they have recovered their competitive transition charges.

Non-Utility Generators. Generators provide energy and ancillary services either through the CalPX market or by contracting directly with buyers for ancillary services. Generation owned by the three IOUs comprised more than 90 percent of the market share during the CalPX's first months of operation. Between the first and second years of operation the IOUs divested generation units totaling 17,863MW, resulting in a share of 71 percent for the IOUs and 11 percent for the non-utility generators.

Federal Owners. Much of the hydropower is federally owned, with a large portion held by the Bonneville Power Authority (BPA.) Since California is so dependent on the availability of external resources, these owners can have a large impact on the California market as well as the rest of WSCC.

Municipal and other Public Owners. Municipals, cooperatives and other public entities control a significant portion of transmission and load in addition to generation. This ownership means that a significant portion of the transmission system in California is not under the direct control of the Cal-ISO.

Power Marketers. Market participants buy and sell energy in the Cal PX and Cal-ISO and also transact in bilateral markets. Many power marketers operating in California markets also own

The following discussion provides an overview of the market, including: market participants, ownership and market structure, trading patterns, pricing points, risk management and recent price trends in western markets.

1. Market Players and Ownership

The Western Interconnection has an active wholesale market, comprised of a diverse group of market participants. Market players in the West fall into the general categories found in other regions, with some key differences, particularly the large role played by publicly owned hydropower resources.

The shares of capacity by class of ownership for each subregion are shown in Table 3-1. In the Rocky Mountain and Arizona-New Mexico-S. Nevada regions, generation capacity is dominated by utilities. In the Northwest, federal entities are the largest generation owners. The largest share of generation capacity in California is held by non-utility owners, as a result of the state's generation divestiture.

Table 3-1. Ownership of Plants in the WSCC by Class of Owner
(Megawatts)

			WSCC Subregion			
Owner Class	**Arizona**	**California**	**Northwest-US**	**Northwest-Can**	**Rockies**	**Grand Total**
IOU	12,292	10,088	16,019	13	4,699	43,110
NON-UTILITY	2,154	25,439	4,698	951	1,004	35,084
FEDERAL	4,278	2,083	22,050		1,026	29,437
CANADIAN				20,062		20,062
PUBLIC AUTH	4,473	4,346	6,553		831	16,203
MUNI	1,271	7,304	4,986		1,234	14,796
COOP-GEN	795		564		1,863	3,221
MEXICAN		1,506				1,506
All Other	383	1,915	236	543	19	3,192
Total All Classes	25,646	52,682	55,106	21,569	10,674	166,611

Source: RDI Powerdat, August 2000.

As shown in Table 3-1, ownership of generation in the WSCC is divided among IOUs, non-utilities, and federal, public and municipal utilities. IOUs are the largest class of owner in the WSCC (26%) with non-utilities holding the second largest share (21%). In California, however, non-utilities hold more than 50 percent of the generation assets. This is a significant change from the period before the enactment of California restructuring legislation, and is a direct consequence of the forced divestiture of most of the IOU generating capacity. Municipals also hold a larger share (14%) of the generation capacity in California than in the WSCC as a whole (9%). Prior to the divestiture by the IOUs, generation capacity in California was more highly concentrated. In 1994, PG&E owned 49 percent of the state's generation, SCE owned 44 percent and SDG&E owned 7 percent. After divestiture, in 1999, the total owned by the three IOUs was 43 percent of the generation capacity in the state, with the other 57 percent divided among several new generation owners.

2. Trading Patterns and Hubs

> ### Western Market Trading Hubs
>
> *Palo Verde (PV)* is the nuclear plant switchyard in southwestern Arizona of that name. This hub is a key selling point for wholesale sales into the Desert Southwest and southern California. It is accessible through several 500 kV lines. NYMEX has a futures contract for this hub.
>
> *COB (California Oregon Border)* is the location for deliveries at the Captain Jack and Malin substations in southern Oregon, immediately north of the California border. Several 500 kV lines have interties there. This is often a proxy for sales into northern California in addition to sales into the Pacific Northwest. NYMEX has a futures contract for this hub.
>
> *Mid-Columbia (Mid-C)* is a delivery hub at ties for a number of dams on the Columbia River. A NYMEX futures contract at Mid-C began trading on September 15, 2000.
>
> *Mead* is the delivery point for a number of transmission lines outside of Las Vegas.
>
> *Four Corners* is the hub at Shiprock and San Juan substations in northwestern New Mexico.
>
> *North Path 15 (NP15)* is a delivery point north of transmission path 15 in California on selected ties between Los Banos and Gates.

While energy is traded at many locations, prices are reported at hubs where significant wholesale or bilateral activity occurs either for ultimate delivery to load in that area or as a convenient selling/delivery point for resale elsewhere.

Trading patterns and prices in western markets are driven to a large degree by the geographic placement of resources. With a heavy reliance on hydroelectric power as its dominant generation resource, the Pacific Northwest has typically provided the cheapest power in the West. Because of the importance of hydroelectric power to the region, the amount of rainfall and snowmelt in the area tends to have a significant impact on the market.

Inexpensive power also originates in the Rocky Mountains and the Southwest, where coal-fired generation is a large contributor to the generation mix. Because many of the generation resources in California are oil- and gas-fired, power generated there tends to be more expensive.

The import and export patterns of the West help to explain prices in the region at any given time. California and Arizona are typically net importers. The Rocky Mountain Power Area is a net exporter. The Pacific Northwest exports a large volume of power, although it is seasonal in nature and varies from year to year.

With the deregulation of wholesale power markets, risk management has become a necessary part of trading in energy markets. Prior to Order 888, utilities traded to balance loads, buying power mostly from their neighbors with spare capacity. In that cooperative environment, risk management was not a priority. In the competitive market environment, risk management is an essential component of doing business.

Traders can hedge their contracts to reduce exposure to adverse price movements. A hedge is the purchase of a financial instrument to establish a position to offset the purchase or sale of energy. A hedge provides a form of insurance that the buyer or seller of power can obtain or pay a certain price for that power. Only a small percentage of hedge transactions actually result in the delivery of the energy. A number of hedging instruments are available to traders in western power markets.

A commonly used hedging instrument is the option contract. Options grant the right, but not the obligation, to buy or sell power for an agreed upon price over a specific period of time. An option allows a trader to exercise a “call” (the right to buy power) or a “put” (the right to sell power) at a given “strike” price before it expires. Options can take the form of futures contracts, swaps or the commodity itself.

Futures contracts are used by market participants to offset the price risk associated with buying and selling power. NYMEX also offers options contracts which give the holder the right to purchase or sell the underlying futures contract at a specified price within a specified period of time in exchange for a one-time premium payment.[2] There are three electricity futures contracts in the West—one based at the California-Oregon border (COB), one at Palo Verde, and one at Mid-Columbia. All of the contracts are offered by the New York Mercantile Exchange (NYMEX). The COB and Palo Verde contracts began trading on March 29, 1996. The Mid-Columbia contract, a recent addition, was launched on September 15, 2000. The standard trading unit for all of the contracts is 432 MWh onpeak power delivered over a monthly period.

Western market participants also rely heavily on forward contracts to protect themselves from price risk. A forward contract is a supply contract for future delivery of a fixed quantity of power at a predetermined price, time and location. Forward contracts are tailored transactions resulting from direct negotiation between a buyer and seller. They differ from futures contracts in that they are non standardized and non transferable. Forward contracts provide price certainty to both the buyer and seller, obligating them to accept the agreed-upon price, regardless of the market price when delivery takes place.

California has two specialized institutions that came into being during restructuring and alter the character of the California market when compared with the rest of the West: the Power Exchange (PX) and the Independent System Operator (Cal-ISO). The PX conducts day-ahead, day-of and block-forwards markets. The day-ahead market is

[2] Based on information from NYMEX web site: http://www.nymex.com.

essentially an auction system of 24 one-hourly markets, bid simultaneously and cleared all at once. The day-of market also consists of 24 auctions, although they are conducted in three batches over the course of the day. The block-forward market commenced on July 31, 1999, allowing market participants to hedge price risks. The original block-forward contracts were for the delivery of one MW for 16 hours per day, Monday through Saturday for a month. Contracts can be made in block multiples of 25 or singly in any quantity. The contracts were originally specified for delivery in either NP15 or SP15, through either the CalPX or the bilateral markets. Quarterly block- forward contracts became available on December 31, 1999. Super-peak and shoulder-peak contracts became available on March 1, 2000. In addition, the CalPX instituted a block-forward market for ancillary services on May 1, 2000.[3]

The ISO does not run a day-ahead energy market, but does conduct auctions for seven separate products: incremental and decremental energy; spinning, non-spinning and replacement reserves; and upward and downward regulation. These auctions are used to construct hour-ahead schedules for energy and ancillary services. Energy bids for ancillary services and supplemental energy are combined to create a real-time supply curve for energy. These bids are capped by the Cal-ISO price limits, which were $750 at the start of the summer, but were reduced to $500 in July and $250 in August. In extreme conditions, the Cal-ISO also engages in out-of-market (OOM) purchases for emergency supplies of energy. These emergency supplies are not subject to the price cap.

3. Recent Price Trends in Western Markets

Western price spikes during the summer of 2000 far exceeded prices seen in previous summers. Figure 3-1 shows index prices for all the western market hubs dating back to 1997. Previous price spikes exceeded $100 per MWh only once prior to the summer of 2000. Beginning in May 2000, prices spiked over $100 per MWh and the spikes increased continued through the summer.

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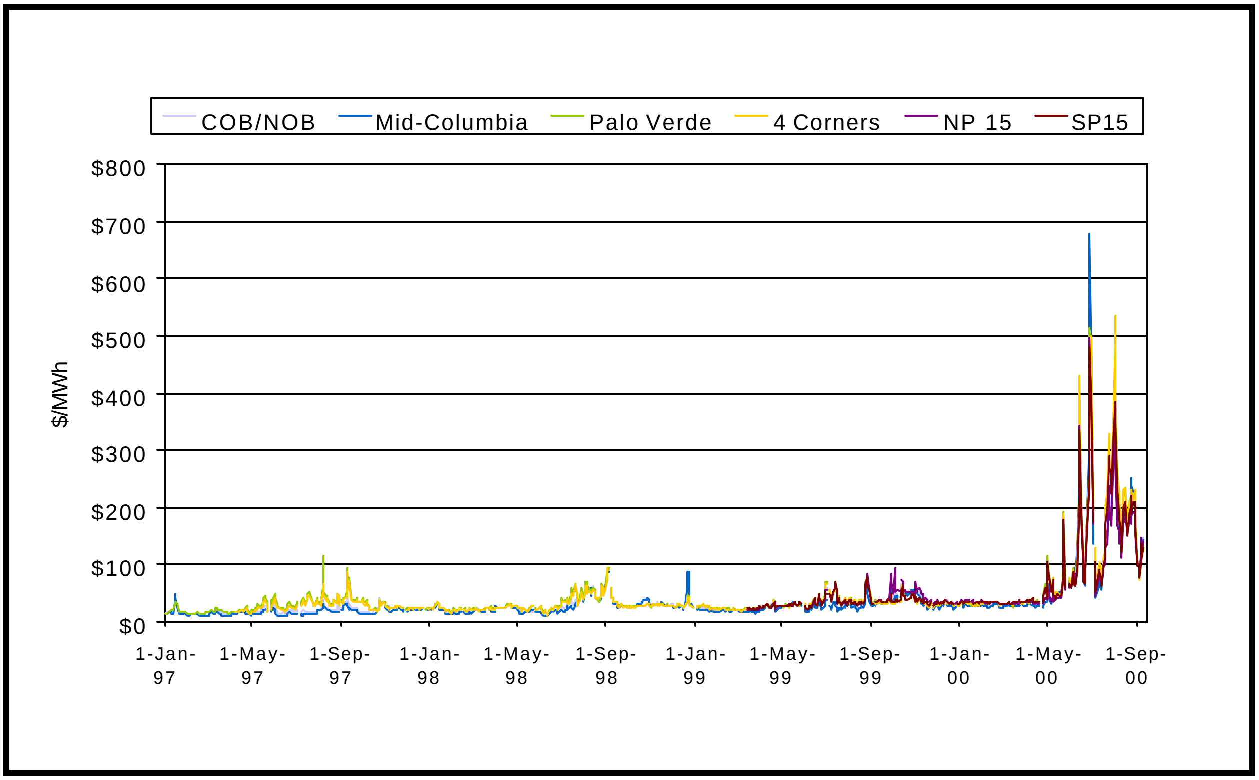
[3]The Cal-ISO Department of Market Analysis reports “..only a nominal amount of ancillary service capacity traded in the Cal PX BFM,” as of July 28, 2000. Cal-ISO Department of Market Analysis, Request to Extend Price Caps, filed with FERC August 14, 2000, ER00-3673, Attachment C, p. 8.

Figure 3-1. Daily Price Indices for Western Market Hubs, 1997-2000



May price spikes. The first spike of the season was in early May. Prices at Palo Verde prices rose well over $100 per MWh in response to hot weather and diminished supplies, with several generation units down for maintenance. The Northwest could not send supplies south because of its own demands and a large number of coal units were offline with unplanned outages. Daily index prices at Mid-Columbia reached over $65/MWh, but did not exceed prices at the typically higher-priced COB and Palo Verde.

In late May, a heat wave caused western prices to spike again, almost doubling the spike that occurred two weeks earlier. Hot weather, combined with 6,000 MW of off-line generation drove day ahead prices at all the western hubs over $200 per MWh. The Cal-ISO implemented State 2 emergency measures as reserves fell below 5 percent. Some non-firm loads were cut and the ISO bought supplemental power to prevent rolling blackouts. Real-time prices in the California PX rose to the ISO's $750 cap on ancillary services for several hours. The California PX average, onpeak day-ahead price topped $316/MWh, an all-time high.

June price spikes. In mid-June, western markets experienced another price spike, with prices reaching an unprecedented level for western markets. Daily index prices at

Palo Verde reached $450, with prices at COB reaching $430 and prices at Mid-Columbia reaching $400. Real-time prices in California hit the ISO's $750/MWh cap on ancillary services for three days straight. Hot weather, the shortage of hydro generation, and plant outages were cited in trade press reports of the spikes. Temperatures in San Francisco reached 105 degrees, breaking a 34-year record. The Cal-ISO ordered rolling blackouts, curtailed interruptible loads, and cut a small amount of firm power to customers in the San Francisco Bay area.

In the final week of June, bilateral prices rose to their highest levels to date as Bonneville Power Administration and the Northwest utilities outbid California and the Southwest, reportedly paying as much as $1,400/MWh to buy power in hourly bilateral markets.[4] Market players noted that, with caps in place in California markets, adjacent regions were able to outbid California, buying power out of the state. Hot weather, unit outages and hydro shortages were again cited by market participants as reasons for the spike. Daily index prices rose to $677 per MWh at Mid-Columbia, $648 per MWh at COB, $497 at NP-15 and $513 at Palo Verde.

July price spikes. Daily prices reached over $100 per MWh several times in July, mostly at the southwestern hubs. Prices showed a large spike near the end of the month, during a period of hot weather in the Southwest, with index prices at Four Corners and Palo Verde reaching over $320 per MWh, with prices $246 at COB and $233 at Mid-Columbia. Loads in Arizona set record highs, with the two utilities in Phoenix setting new highs on five days in July.[5] High loads in the Southwest left little power to import to California. Hot weather, combined with supply shortages sent up prices throughout the West.

August price spikes. Western hub prices remained at a significantly higher level for the month of August. Starting around mid-July, prices at the western hubs never fell below $110. The average index price for August was $211.33 at SP15, and $188.73 at NP15.

In early August, prices at Palo Verde reached $1,500 per MWh in hourly markets, with Palo Verde index prices escalating to $523 per MWh. Index prices at COB and Mid-Columbia reached almost $500 per MWh, hitting $481 and $472, respectively. High temperatures in the Southwest and in parts of California were partially responsible, but wildfires threatened transmission facilities and increased the pressure on prices.

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4 "Traders See Northwest More Easily Outbidding California Under New ISO Cap," *Power Markets Week*, July 3, 2000, pp. 1, 12.

5"West Prepares for High Temps, Loads; Traders Brace for Vote on Price Caps," *Power Markets Week*, July 31, 2000.

Prices generally remained over $200 per MWh at the southwestern hubs for the duration of August. For the remaining hubs, prices fell below $200 for several days. But in late August, prices surged in the Northwest when hydro generation was restricted. Hydro supplies came to an abrupt halt as dam operators were forced to fill reservoirs so they could continue to provide power through the rest of the year.[6] Day-ahead prices at Mid-Columbia and COB increased to $260 per MWh.

Increase in overall price levels. The summer 2000 price levels greatly surpassed the price levels of prior years. Figures 3-2 to 3-4 compare prices at COB, Palo Verde and Mid-Columbia for the past three summers. The summer 2000 prices show a dramatically different pattern from the previous 2 years, with large spikes in May and June. In mid-July through August 2000, lower price caps limited the prices in hourly markets, but the general level of prices was significantly higher, hovering around $200. A similar trend can be seen at Palo Verde and Mid-Columbia, with extreme price spikes or high overall prices occurring throughout the summer in 2000, compared with much lower price levels for the previous two summers.

Prices in western markets show a close relationship to the prices in the California PX from which 80 percent of load, served by IOUs in California, must purchase energy. The California PX noted this relationship on an average basis for the May and June period.[7]

Figure 3-5 shows daily onpeak prices for NP15 and SP15 for bilateral markets and the California PX. While the prices track very closely, the PX prices show much larger spikes than the bilateral prices. The California PX products are not identical to the bilateral market products. The bilateral market prices are index prices for 16-hour blocks

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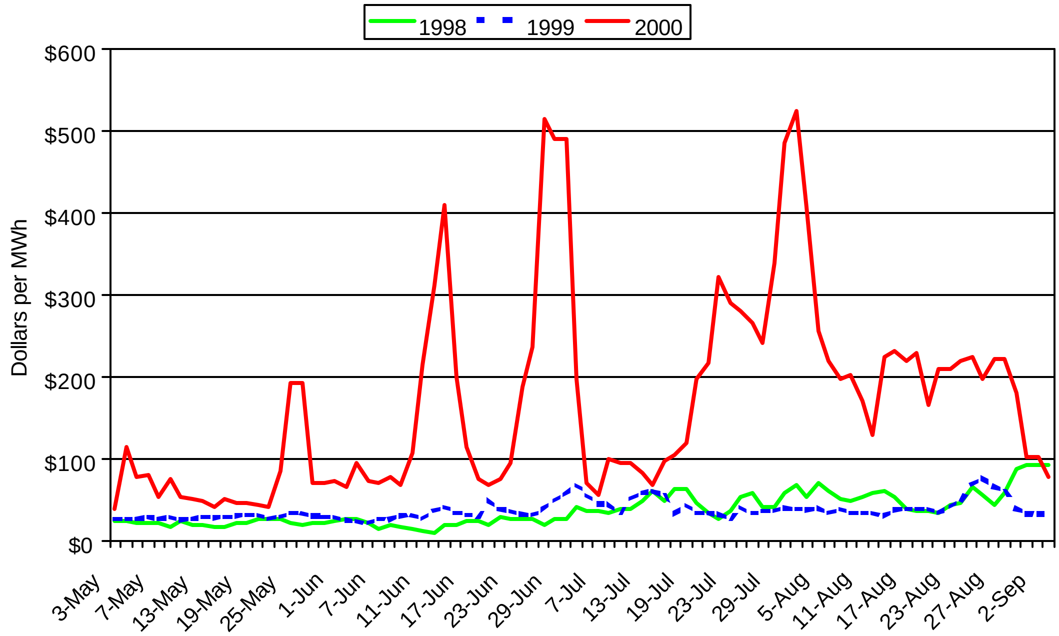
[6] "N.W. Prices Escalate as Hydro Dwindles; Dams Store Water, Runoff Disappears," *Power Markets Week*, August 28, 2000.

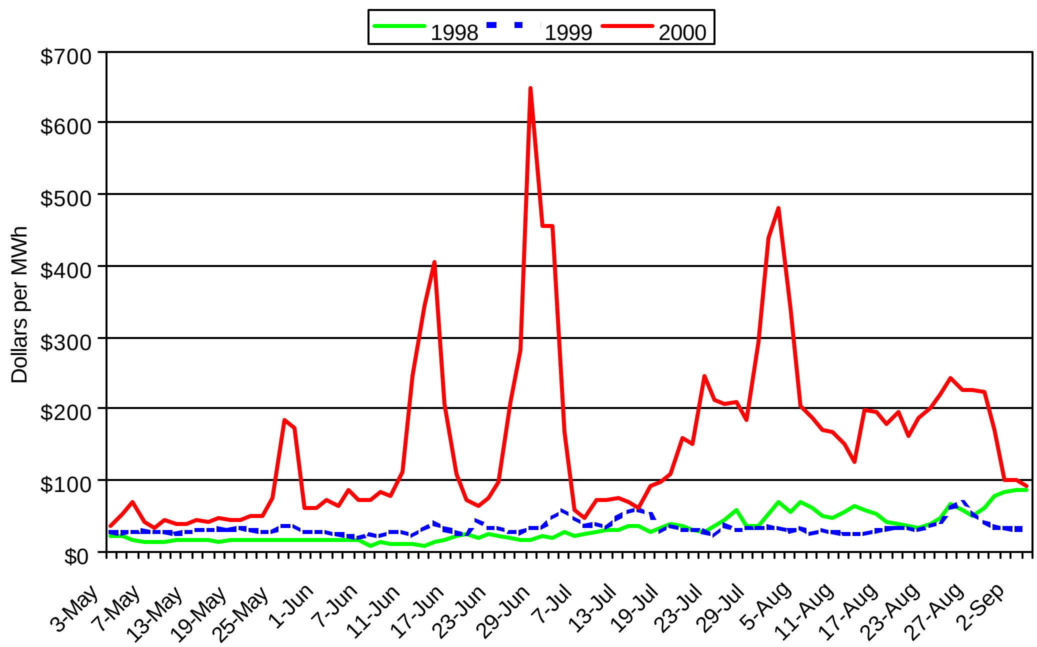
[7] California PX Report on June 29, 2000, "Price Behavior in the CalPX Markets, May-June 2000."

Figure 3-2. Bilateral Index Prices at Palo Verde



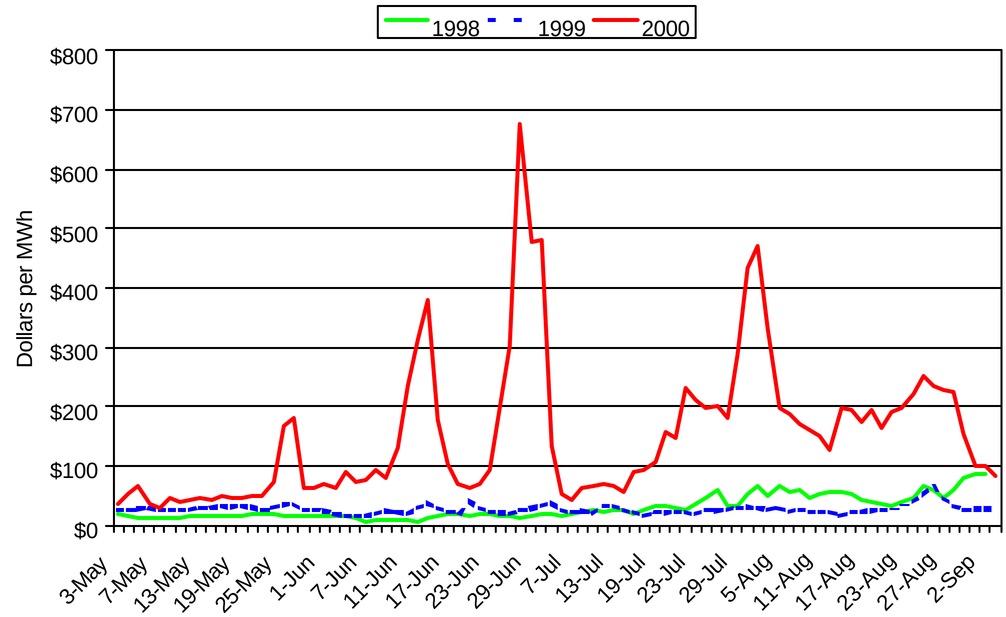
Source: *Power Markets Week*.

Figure 3-3. Bilateral Index Prices at COB



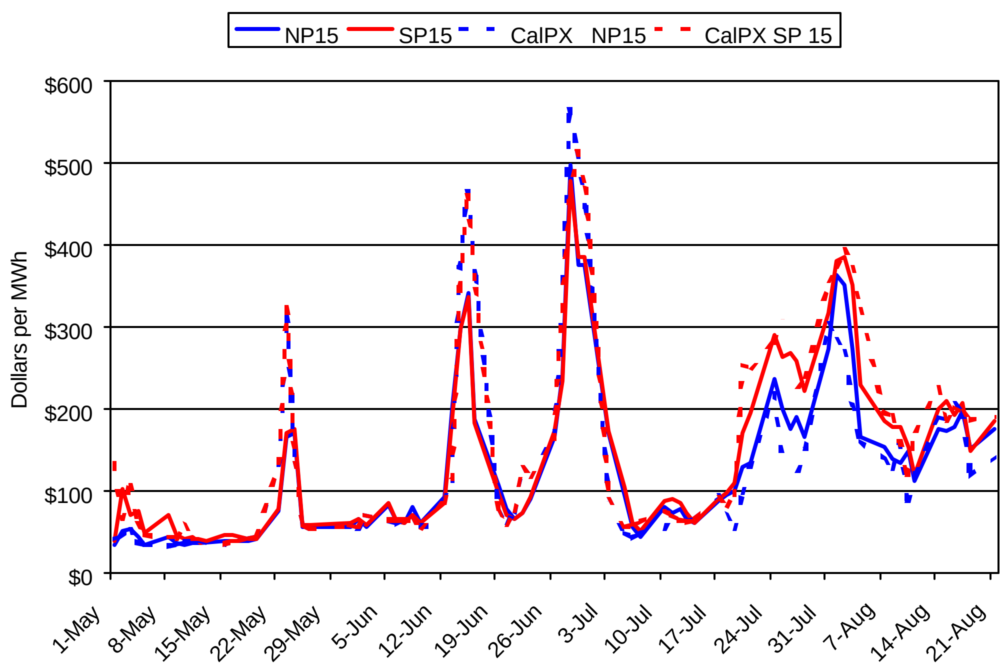
Source: *Power Markets Week*.

Figure 3-4. Bilateral Index Prices at Mid-Columbia



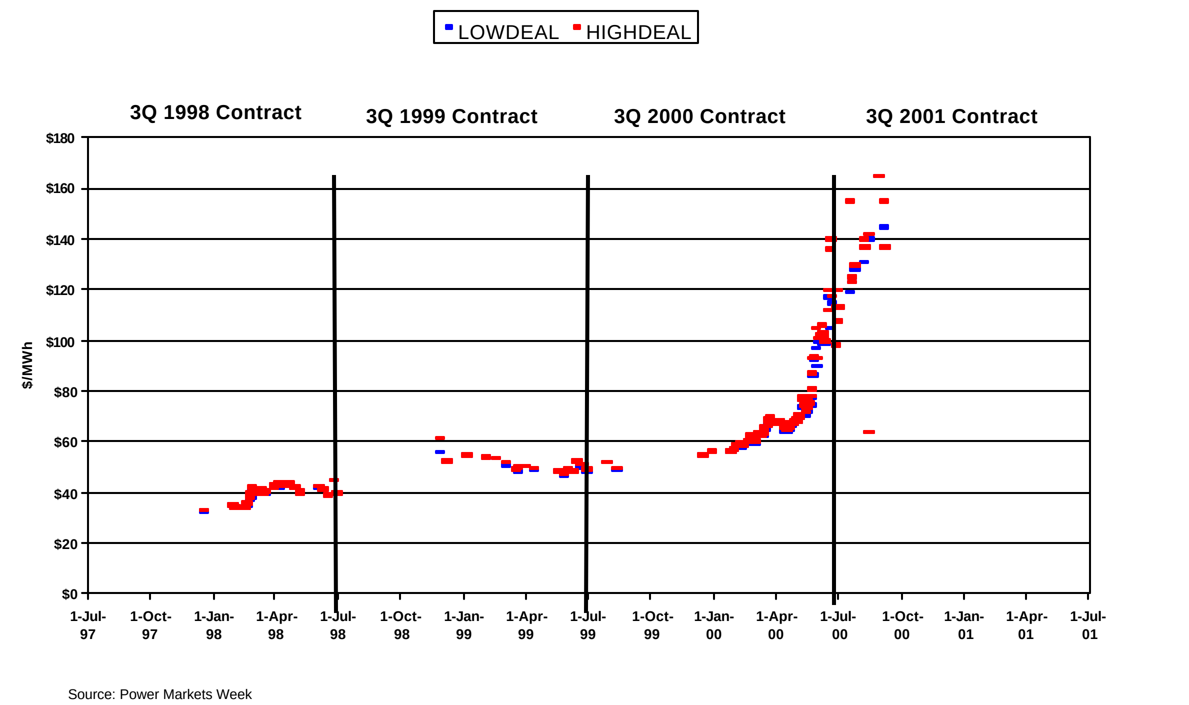
Source: *Power Markets Week* .

Figure 3-5. Western Market Prices for Summer 2000: Bilateral Markets vs. California PX



Source: RDI PowerDat. Bilateral prices are Power Markets Week 16-hour on-peak prices.

Figure 3-6. Palo Verde Forwards: 3rd Quarter Contracts



Source: Power Markets Week

of power. The PX prices and sells power on an hourly basis.[8] It is possible that, because these products are slightly different, they are valued differently at peak times.

The pattern of prices was different in July and August. The PX and bilateral market prices tracked more closely, with bilateral market prices often higher than PX prices at NP15 and PX prices remaining higher at SP15.

Forward market prices were much lower earlier in the year and were used by some market participants to hedge potentially high prices over the summer. Figure 3-6 shows

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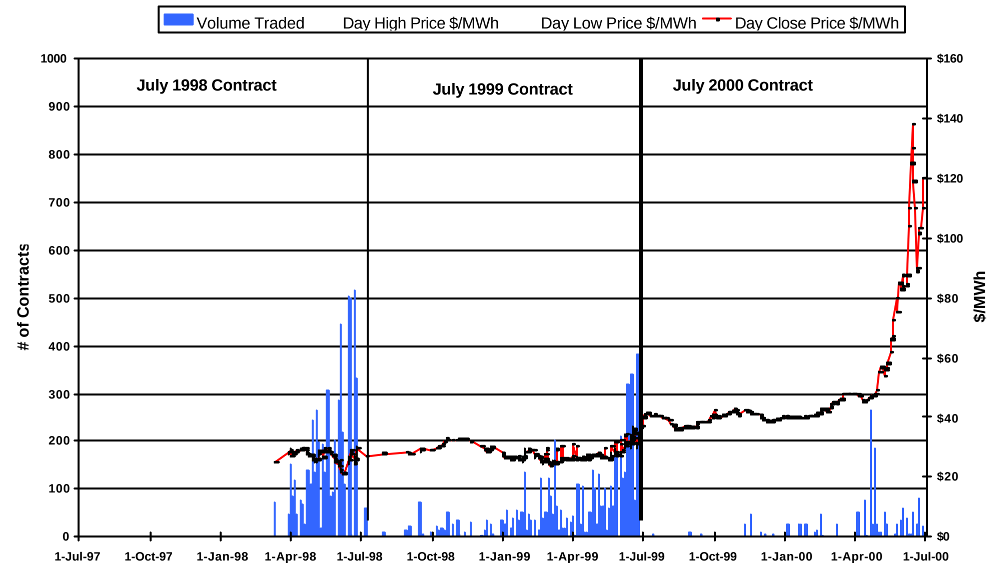
[8] The PX prices have been averaged for a 16-hour block period to correspond to the 16-hour block traded in bilateral markets, but the products are not the same because buyers and sellers in the PX set individual hourly prices whereas bilateral buyers and sellers trade at a single price for the entire block. Buying a block at a single price does not permit the buyer to tailor hourly prices to expected hourly levels, and is consequently less flexible, particularly if the buyer plans to resell in hourly markets.

forward contracts for the third quarter for the last 3 years (1998 through 2001) at Palo Verde, COB and Mid-Columbia. Forward prices have risen in each of the past 3 years. A substantial number of forward contracts were made in early 2000 at prices between $60 and $80 per MWh. Market participants who purchased forward contracts for the summer of 2000 received prices well below spot market prices. COB and Mid-Columbia had similar patterns, with somewhat lower prices for those hubs.

Figure 3-7 shows the July futures contract at COB for 1998 through 2001. While no July 1998 contracts were traded prior to March 1998, trading for both the 1999 and 2000 contracts began as early as one year earlier, as market players recognized the need to prepare for summer price spikes. Prices for July 2000 were as low as $50 per MWh up until April 2000. After April, the July contract escalated, reaching almost $140 per MWh prior to expiration. Futures prices that seemed high earlier in the year resulted in significant savings to those who used futures contracts to hedge their positions in the market. A similar pattern occurred for the August contracts at COB and Palo Verde.

The number of futures contracts traded declined substantially in 1999 and 2000. Market participants have noted in discussions that they find the futures contracts less flexible than individually tailored forward contracts, preferring to use over the counter forwards instead. A contract structured around a monthly market may not be sufficiently flexible to attract a large number of buyers in a market given to a high level of daily and hourly volatility, where both buyers and sellers may have different supply and demand profiles. Over-the-counter products customized to buyer and seller needs, while more expensive to arrange than current futures market products, may be the best alternative in the absence of greater ability to develop attractive standardized products.

Figure 3-7. COB Futures: July Contracts



Source: RDI POWERdat

4. Correlation of Prices in Western Markets

Bilateral and PX Markets

Table 3-2 shows the correlations of western market onpeak prices for the summer 2000 period. The correlations between California PX prices and western market bilateral prices are quite strong. As one would expect, the correlations between the California PX prices and bilateral prices at NP15 and SP15 are high. By the same token, CalPX NP15 and Mid-Columbia are highly correlated, as are CalPX SP15 and Palo Verde because of the geographic proximity of the points and the general absence of transmission limits into California. Correlations between all of the western onpeak prices show correlations of 0.858 or above.

Table 3-2. Correlations of Western Market Prices: Onpeak Prices from Megawatt Daily and California Power Exchange
(May 1-August 21, 2000)

	COB/ NOB	Mid- Columbia	Palo Verde	4 Corners	NP15	SP15	Cal PX NP15	Cal PX SP15
COB/NOB	1.000							
Mid-Columbia	0.997	1.000						
Palo Verde	0.971	0.963	1.000					
4 Corners	0.961	0.953	0.995	1.000				
NP 15	0.992	0.987	0.974	0.966	1.000			
SP 15	0.969	0.960	0.992	0.983	0.977	1.000		
CalPX NP15	0.912	0.908	0.865	0.858	0.919	0.876	1.000	
CalPX SP15	0.915	0.906	0.932	0.932	0.922	0.937	0.930	1.000

Table 3-3 shows the correlations of offpeak western market prices. The correlations of offpeak prices show strong relationships between prices in bilateral markets, but the relationships between prices in the CalPX and bilateral markets are weaker. The CalPX SP15 price shows a higher correlation to all the bilateral prices than does the NP15 price. One would expect the CalPX NP15 to more closely correlate to the COB/NOB price because it is closer in proximity.

During summer 2000, power flowed into the Northwest from California especially during offpeak hours to allow hydro generators to store water for more costly onpeak hours.[9] It is possible that the demand for exports of offpeak power from California to the Northwest created a different pattern of prices for markets in northern California.

[9] "N.W. Prices Escalate as Hydro Dwindles; Dams Store Water, Runoff Disappears," *Power Markets Week*, p. 11.

Table 3-3. Correlations of Western Market Prices: Offpeak Prices from Megawatt Daily and California Power Exchange
(May 1-August 21, 2000)

	COB/NOB	Mid-Columbia	Palo Verde	4 Corners	CalPX NP15	CalPX SP15
COB/NOB	1.000					
Mid-Columbia	0.963	1.000				
Palo Verde	0.946	0.942	1.000			
4 Corners	0.848	0.881	0.946	1.000		
CalPX NP15	0.499	0.568	0.422	0.596	1.000	
CalPX SP15	0.742	0.699	0.700	0.554	0.702	1.000

ISO Energy and Ancillary Services Markets

Ancillary Services prices showed a similar pattern to that of energy prices in the PX and ISO during the summer of 2000. As shown in Figure 3-8, spinning, non-spinning and replacement reserves reached the level of the price cap ($750 per MW in May and June, $500 per MW in July and $250 per MW in August) for periods throughout the summer. These patterns track with the energy market price and reflect the opportunity cost of generators' providing ancillary services. That is, if generators are holding a portion of their units in reserve, they are foregoing the revenue they could have earned by providing energy in the day-ahead, hour-ahead, or real-time markets.

The ISO instituted an additional purchase price cap for replacement reserves at $100 per MW as part of a strategy to reduce out-of-market calls associated with under-scheduling. As shown in Figure 3-9, the ISO increased the amount of replacement reserves it purchased in July and August relative to the level it had purchased in May and early June.

The Cal-ISO reports that the strategy to reduce the reliance on out-of-market calls may have increased generators' incentive to withhold capacity from the day-ahead PX energy market and shift capacity into replacement reserve and real-time energy markets during the high load periods.[10] Suppliers could benefit by not scheduling capacity in the day-ahead markets, and instead bidding into the replacement reserve market so that they have a high probability of receiving both the capacity payment for replacement reserves and

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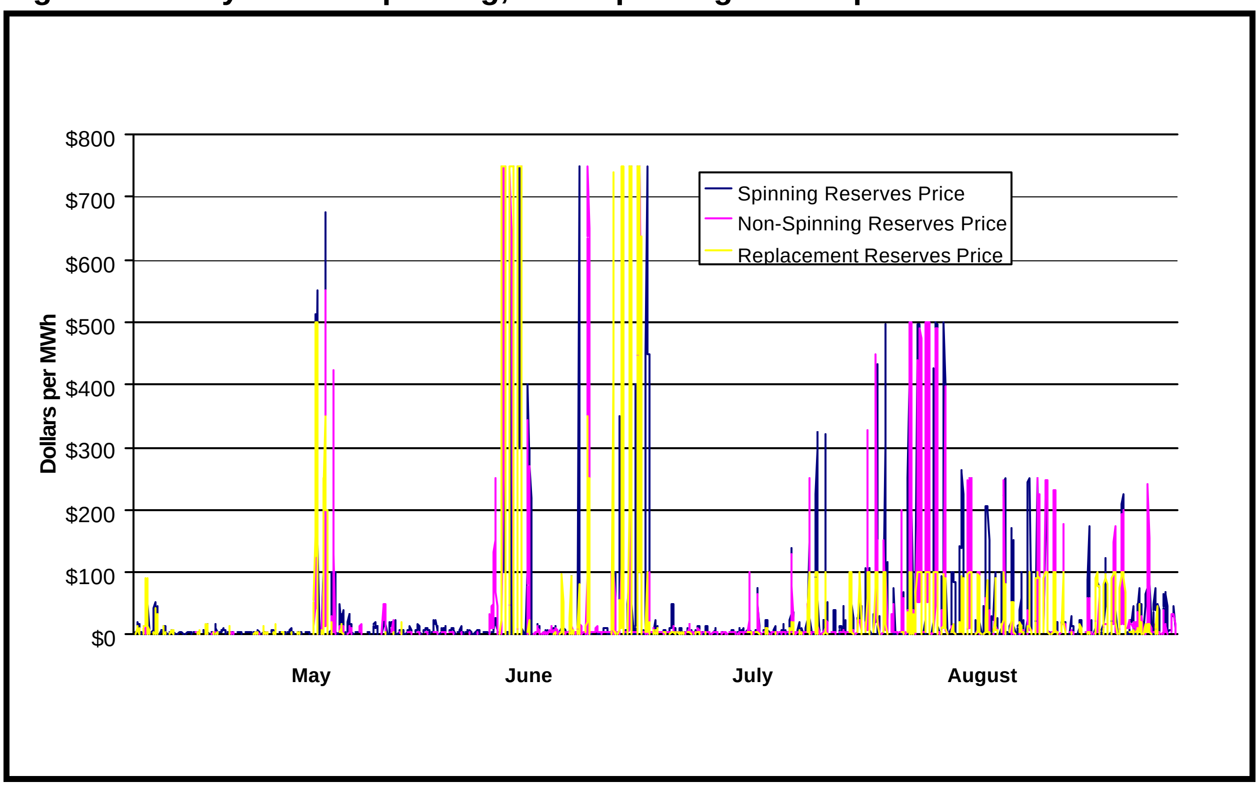
[10] *Report on the California Energy Market Issues and Performance: May-June 2000*, prepared by the Department of Market Analysis, California Independent System Operator, August 10, 2000.

also the real time energy price. During high load periods, the replacement reserve price can be high and a high proportion of all available energy is likely to be taken by the Cal-ISO, so this can be a profitable strategy. In July, the Cal-ISO lowered the price cap on replacement reserves in an attempt to limit the attractiveness of this strategy.[11]

Real-time energy prices in the Cal-ISO closely follow the PX prices for the same period. As described above, these two markets are linked since one is effectively a substitute for the other from both the supply and demand perspectives. It is also clear that the real-time energy and PX prices experienced longer periods of prices at or near the price cap than the ancillary service price.

Figure 3-8. Day-Ahead Spinning, Non-Spinning and Replacement Reserves



[11]California ISO, "Minutes of Special Board of Governors Meeting," June 28, 2000.

Figure 3-9. Day-Ahead and Hour-Ahead Replacement Reserve MWh, NP15

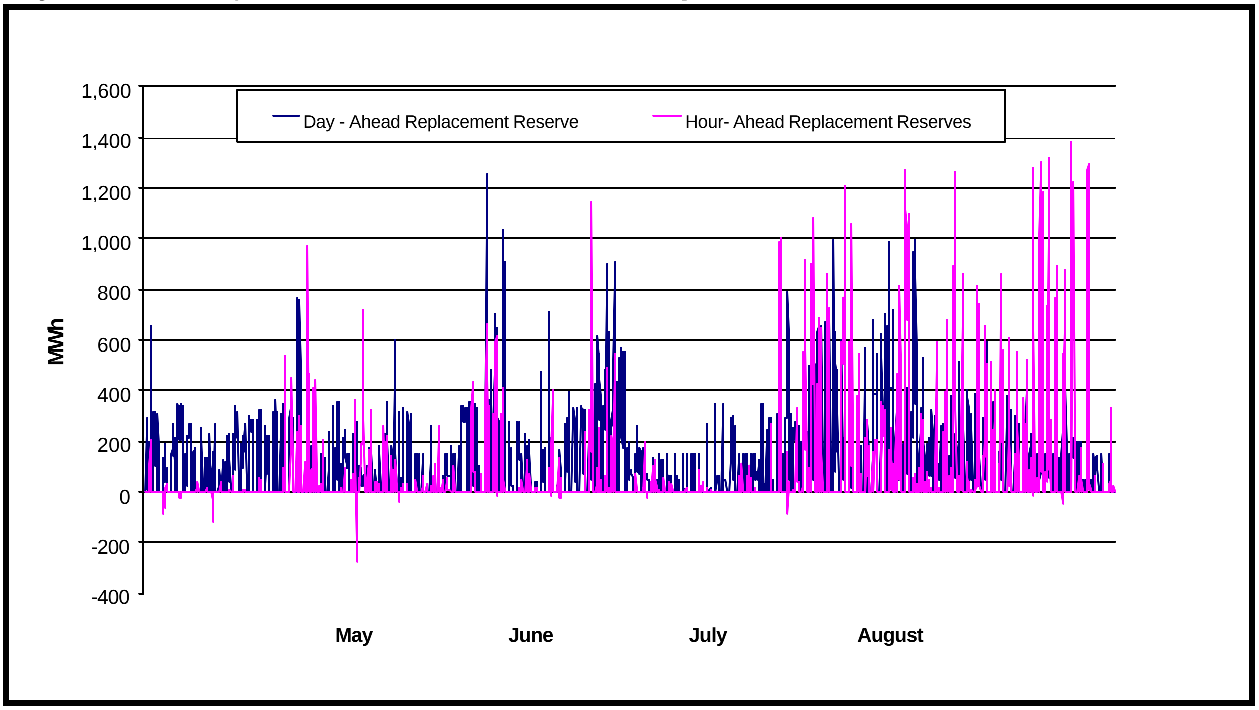
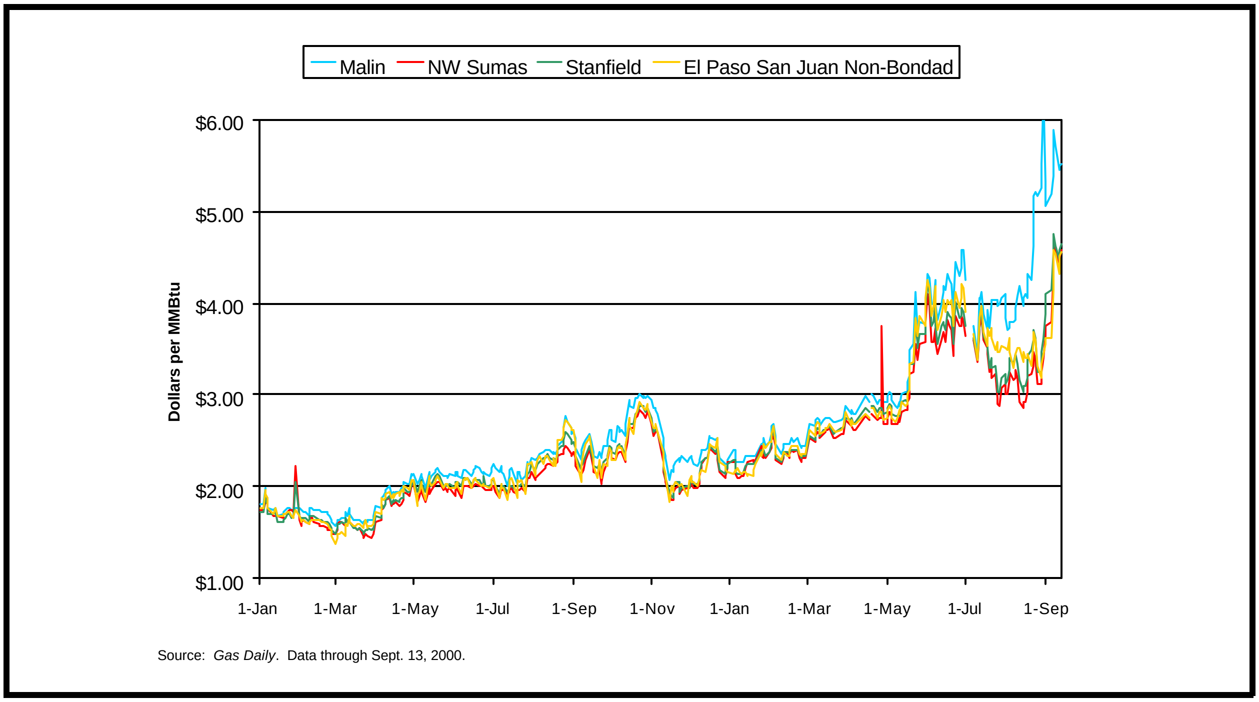
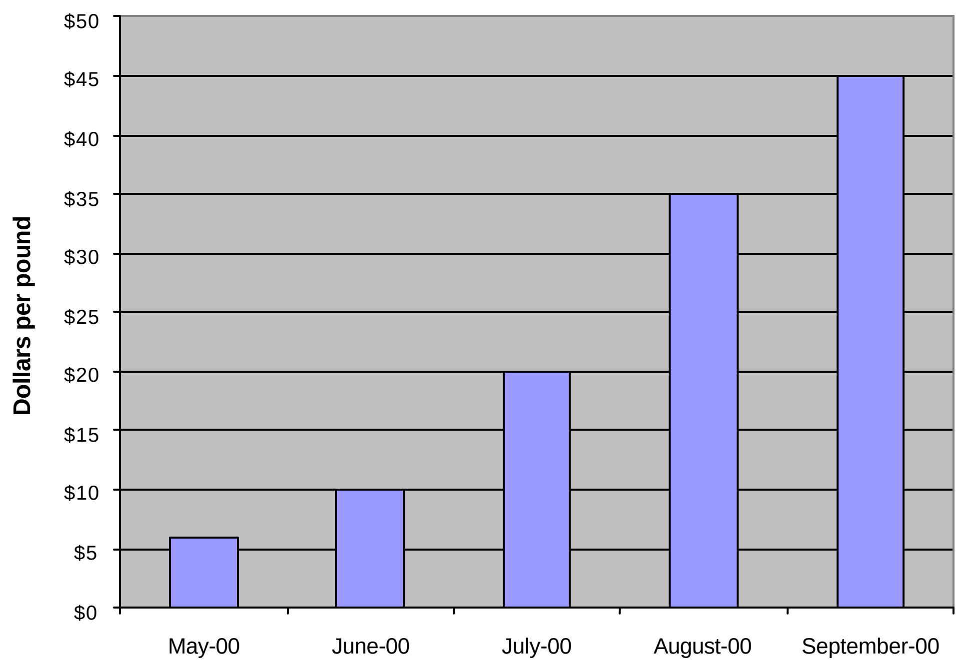


Figure 3-10. Daily Spot Prices for Western Natural Gas Markets in 2000



Source: *Gas Daily*. Data through Sept. 13, 2000.

Figure 3-11. NOx RECLAIM Prices for SCAQMD, May to September, 2000



B. Cost Factors in Prices and Price Increases

1. Input Price Increases

One of the reasons for the higher prices in the West during the summer of 2000 was the increase in input prices, specifically increases in natural gas prices and NOx compliance costs. As shown in Figure 3-10, natural gas prices roughly tripled from January 2000 to September 2000 in the West.

Since natural gas-fired units are usually the marginal units during peak demand periods, input price increases can have a significant impact on the market clearing price. For example, for a gas-fired unit with a heat rate of 10,000 Btu/kWh, if the natural gas price goes from $2.00/MMBtu to $5.00/MMBtu, the fuel cost rises from $20.00/MWh to $50.00/MWh.

In addition, the price of the NOx credits necessary to run gas units also increased significantly. As shown in Figure 3-11, the price of NOx RECLAIM credits rose from approximately \$6.00/lb to over \$40/lb at the end of August.[12] A combined-cycle gas generator typically emits around 1 pound of NOx per MWh. A combustion turbine gas peaking unit can emit more than 2 pounds of NOx per MWh. At a price of \$40/lb, the emission reduction cost of a gas peaking unit would be approximately \$80/MWh as opposed to \$12.00/MWh when the NOx credit price is only \$6.00/lb. Taken together, the increases in natural gas and NOx credit prices raised the marginal running cost of a combined cycle generation unit with a heat rate of 10,000 Btu/kWh and a NOx emission rate of 1 lb/MWh by approximately \$64.00 per MWh (from \$26.00 to \$90.00 per MWh).

Most critically, in times of peak demand when internal and external transmission constraints limit transfers, the least-efficient plants are called on to provide energy and thus set the market-clearing price. These plants have the highest heat rates and some of the highest NOx per MWh emission rates. In these cases, the marginal running cost of the plant is significantly above \$100/MWh. For example, for a combustion turbine gas-fired peaking plant with a heat rate of 16,000 Btu/kWh with a NOx emission rate of 2 lbs/MWh, marginal running cost would have risen from \$44/MWh to \$160/MWh.[13] Therefore, market clearing prices that approach the \$250/MWh price cap may simply reflect the true cost of the resource and be solely the result of tight supply, not the exercise of market power. Figure 3-12 shows the effect of rising natural gas prices and NOx emission permit

12 The prices in Figure 3-11 are averages based on sales reported by Cantor Fitzgerald Environmental Brokerage Services, www.cantor.com/ebs. The May, June and July and August figures reflect both vintage 1999 and 2000 RECLAIM allowances. The September figure is for vintage 2000. June 1999 RECLAIM allowances expired at the end of August 2000.

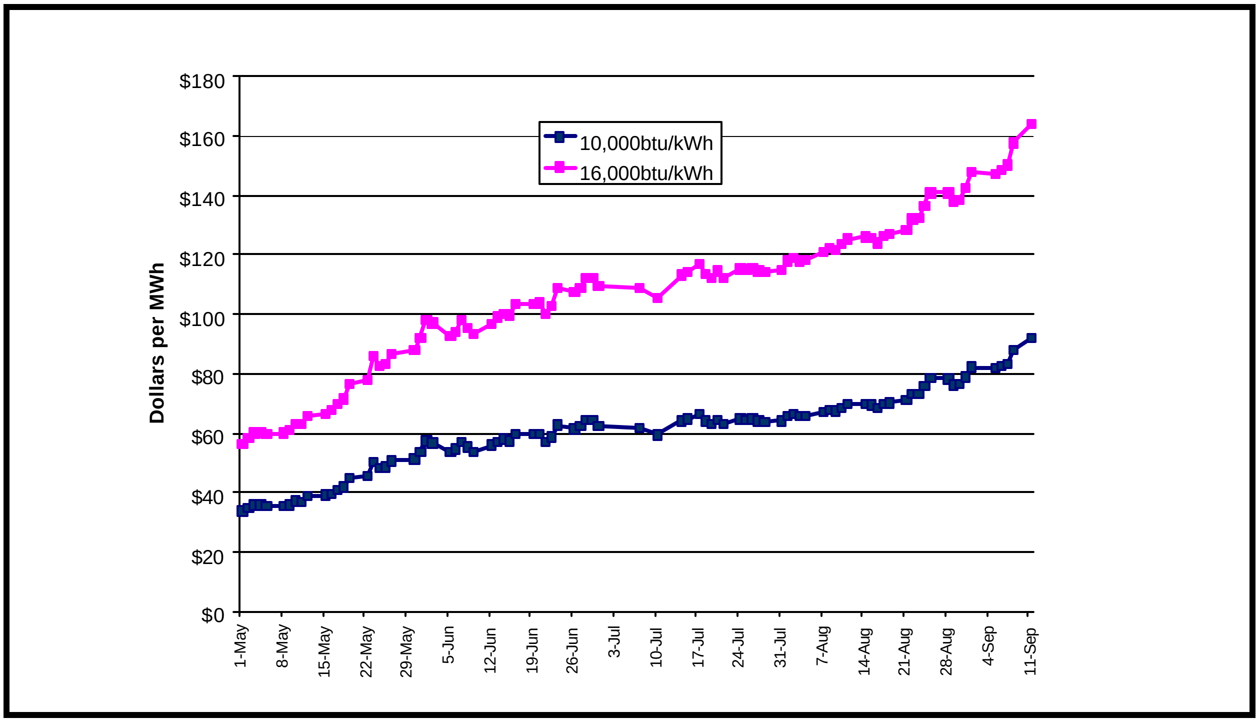
13 Both examples assume an increase in the natural gas price from \$2 per MMBtu to \$5 per MMBtu and an increase in the NOx emissions credit price from \$6.00/lb to \$40/lb. Under extreme conditions gas-fired units with heat rates exceeding 16,000 Btu/kWh may be called on to produce energy in the PX or real-time energy markets. The ISO DMA uses somewhat more extreme emissions and heat rate assumptions in Market Analysis Report, September 2000, basing costs on a NOx rate of 4 lb/MWh and at heat rate of 20,000 for a combustion turbine. These extremes can be reached, but only in the most extreme emergencies. However, they use \$35 for NOx costs, the approximate August average, rather than the end of August price. They estimate a price of just under \$250 rather than the lower number we provide here. Given the uncertainties in the information, either estimate is consistent with high prices close to \$250 in August.

rates on the running cost of gas-fired generation from a combustion turbine emitting 2 lbs NOx per MWh over the summer of 2000.[14]

C. Bidding in the CalPX and Selected Cal-ISO Markets

This section discusses bidding patterns in the PX and the ISO replacement reserve market, and the role of out-of-market purchases by the ISO. These discussions provide information on the patterns that appear to have driven the high prices encountered in the summer of 2000. The PX bidding is discussed first, followed by bidding in the ISO replacement reserves and out of market purchases.

Figure 3-12. Estimated Running Cost for Gas-Fired Generation in Southern California



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14 Cost estimates based on stated heat rates, average western hub gas prices from the four hubs shown in Figure 3-10, assumed NOx emission rates of 1 and 2 lb per MWh, for the 10,000 and 16,000 Btu/kWh heat rates respectively, and a linear estimate of NOx reclaim prices ranging from $6.00/lb. on May 1 to $40.00/lb on August 31. Note, the NOx emission rate is not simply of function of the heat rate, it also depends on the unit-specific NOx burn rate. That is, two different combustion turbines with the same heat rates could have different NOx emission rates.

1. Bidding in the CalPX

In the last section, the decrease in the amount of power scheduled through the PX on a day-ahead basis was described. Given the requirement for balanced schedules in the California design, the reduction in the proportion of power scheduled day-ahead is the joint result of bidding by both supply and demand. However, much of the change has been driven by suppliers migrating to other markets, such as the real-time market or the export market. As a result, there is a clear reduction in the total supply available in 2000 compared with 1999. This result has been documented by the recent analysis provided by the PX.[15] This section further examines bidding patterns over the last summer to determine how the pattern changed as the Cal-ISO price cap changed over the summer. Although the PX has no price cap, the Cal-ISO cap provides a *de facto* cap, since the Cal-ISO markets provide an alternative for both loads and supply. Loads will have an incentive to move their purchases to the Cal-ISO rather than bid to raise prices in the PX above the Cal-ISO price cap. And suppliers have incentives to shift sales to Cal-ISO markets at peak times in hopes of gaining a capacity payment for replacement reserves and also being paid at the price cap for real-time energy.[16]

For these reasons, one would expect the level of the price cap to have some detectable impact on bidding behavior. This impact is examined from two primary perspectives. First, differences in the total amount of supply offered into the day-ahead PX market are examined. Second, changes in the shape of bid curves are examined by studying the proportion of supply offered at selected price levels.

Quantities of Supply Bid into the PX

To examine how supply quantities bid into the PX changed over periods with different Cal-ISO price caps, the quantity of supply made available under the price cap was calculated from bidding data by participants. Participants were classified by the following categories used by the PX. The three largest participants are the California IOUs, the new generation owners (NGOs) who have acquired the divested units previously owned by the California IOUs, and the power marketers. These entities account for over 90 percent of

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15 California Power Exchange Corporation Compliance Unit, Price Movements in California Electricity Markets, September 29, 2000.

16 For further discussion of incentives for shifting supply away from the day-ahead PX market, see California PX Report, September 29, 2000, ISO Market Surveillance Committee Report, September 6, 2000, and report from the ISO Department of Market Analysis, August 10, 2000.

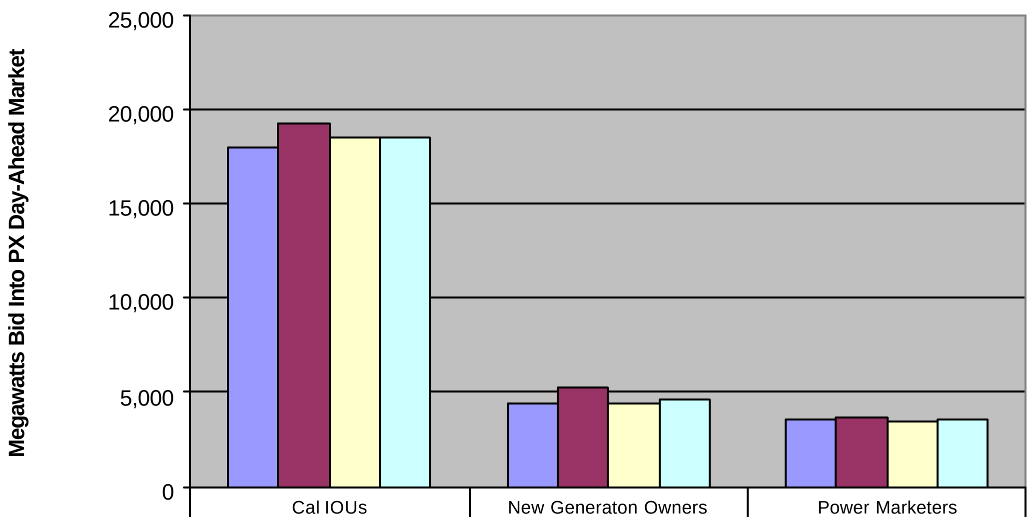
the quantities bid into the PX market. Other participants with smaller shares include municipal and other governmental participants and IOUs outside California.

Figure 3-13 shows the quantity bid into the PX under the Cal-ISO price cap for three time periods defined by the level of the Cal-ISO price cap[17] and the three major participant categories. The quantities represent the average total quantity bid hourly during onpeak hours over the period. There appears to be little or no change in the total quantity bid for any of the participant categories. Figure 3-13 includes all supplies bid, and includes the quantities bid in at zero prices, which make up around two-thirds of the total and may not change appreciably when the price cap changes. However, it is interesting to note that the price cap seemed to have a relatively small impact on the total quantity bid.

In each participant category, slightly more supply is bid into the PX in July, when the price cap was at $500, than in the other two periods when the cap was lower or higher. This period corresponds to the time when the supply/demand picture was less tight than it was before, in June, or afterwards, in August. Under these conditions, there may be fewer opportunities to sell outside of California because supplies in the West were generally more abundant.

17 The $750 period extends from May 1 to June 30, the $500 period from July 1 to August 6, and the $250 period from August 7 to September 20. Although the $250 period extends past the end of August, used as the end date for other statistics in the report, it was used here to make use of the additional information gained by the extension.

Figure 3-13. Comparison of PX Onpeak Supply Bid Under ISO Cap for Selected Participant Types



	Cal IOUs	New Generaton Owners	Power Marketers
ISO Cap=$250	18,018	4,445	3,506
ISO Cap=$500	19,270	5,277	3,615
ISO Cap=$750	18,514	4,441	3,483
Onpeak Total	18,544	4,647	3,523

Changes in Bid Shape

August prices were higher than June prices on average in both the PX and the ISO, even though the ISO cap was reduced from $750 to $250 over the period. The higher price in the PX is a result of upward shift in the supply offered in the PX. This upward shift can be seen by calculating the percentage of supply offered at any given price level. Table 3-4 shows the percentage of supply offered at $100, $150 and $200. Figure 3-14 depicts the percentages offered at $100. These percentages clearly show that all participant categories changed the supply they offered as the price cap was reduced, particularly when the price cap fell to $250. However, it may be incorrect to attribute the change in bidding patterns solely, or even primarily, to the price cap reduction. As

Figure 3-14. Percentage of Non-Zero Supply Bid at $100 or Below

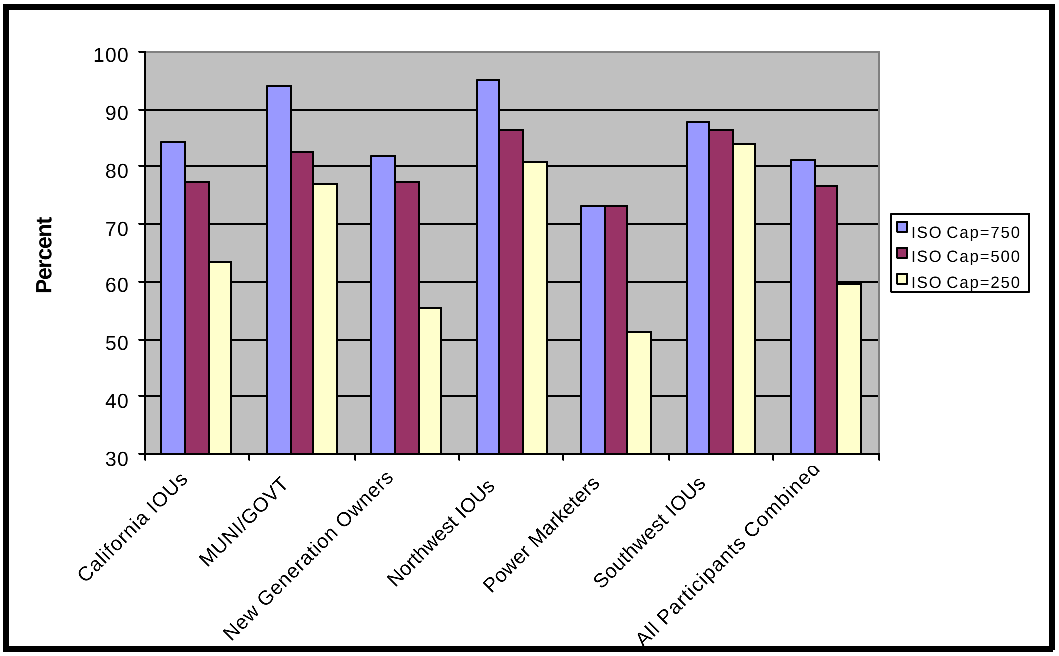


Table 3-4. Bidding in the CalPX by Participant and Cal-ISO Price Cap, May to September 2000

ISO Price Cap	California IOUs	Municipal/ Government	New Generation Owners	Northwest IOUs	Power Marketers	Southwest IOUs	All Participants
Percent of Non-Zero Supply Offered at $100							
250	63.4	76.9	55.5	81.0	51.1	84.0	59.6
500	77.2	82.5	77.5	86.3	73.2	86.5	76.8
750	84.4	94.1	82.0	95.2	73.1	87.7	81.3
Percent of Non-Zero Supply Offered at $150							
250	83.3	81.6	72.9	86.9	66.6	91.7	74.9
500	88.1	85.3	82.6	92.8	79.9	90.9	83.7
750	88.7	96.7	88.0	97.7	75.6	90.7	85.4
Percent of Non-zero Supply offered at $200							
250	89.6	87.4	84.3	91.7	76.6	94.9	83.2
500	91.4	90.0	86.5	96.3	83.0	93.0	87.2
750	91.1	97.2	91.2	98.8	77.8	92.2	87.8

discussed in the last section, costs rose over the same period, shifting costs upward and changing the underlying cost structure. Since all participant categories exhibit the same pattern, the changed bid shapes are unlikely to be the result of individual participants or classes of participants changing their bidding behavior in an attempt to manipulate prices.

2. Cal-ISO Replacement Reserve Markets and Out-of-Market Purchases

Both replacement reserve markets and out of market purchases by the Cal-ISO were closely related to the problem of underscheduling in the Summer of 2000. When underscheduling in the day-ahead and hour-ahead markets occurred, the ISO turned to replacement reserve markets or out-of-market (OOM) purchases to procure capacity needed to provide energy for meeting the difference between the forecasted load and the scheduled supply. The policy of purchasing replacement reserves for this purpose was motivated in part by the desire to limit the use of out of market calls, which take place outside the structure of the normal market during emergencies and are not subject to the price cap. As a result of these policies, OOM purchases were only a small portion of total energy costs in May through August. OOM purchases totaled $93 million dollars, less than 1 percent of the total energy costs of $11.6 billion. Around half of the cost and quantity of OOM purchases were for power from public entities or scheduled through public entities as scheduling coordinators.

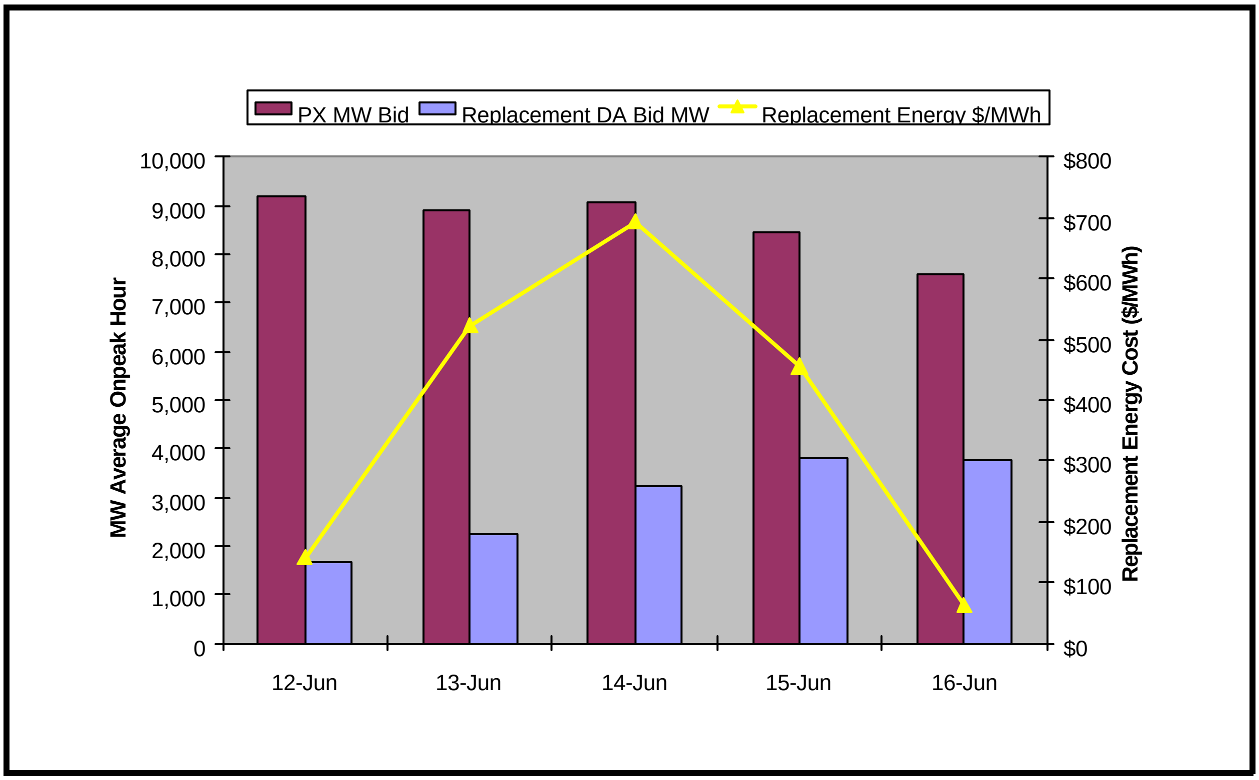
Replacement reserve total costs were much greater than OOM purchase costs, totaling $217 million dollars in June alone, almost half the total ancillary service costs of $436 million dollars for the month. Examining bids and bid patterns for two high-costs weeks in June showed a pattern of increased bidding into the replacement reserve market as the week progressed. The quantities bid into the replacement reserve markets are shown in Figure 3-15, where these quantities are compared with quantities bid into the PX for the week of June 12 to 16. Replacement reserve costs for Tuesday to Thursday of this week were over $120 million. It appears that more offers are placed in the replacement reserve markets this week as the hotter weather sets in, while the quantity bid into the PX falls or remains level. This information confirms that bidders are following their incentives to place supplies in the replacement reserve market, where they can obtain payment for both reserve capacity and for replacement energy when called. Given these incentives, bidders would shift additional supplies to the day-ahead or hour-ahead replacement reserve market, rather than the day-ahead PX energy market, in order to obtain additional payment for reserve capacity. While there are a range of bidding patterns in the replacement market, no one participant or class appears to dominate others in setting the overall pattern. It is also interesting to note that the higher level of bidding into replacement markets continues even on Friday, June 16, when replacement reserve costs and purchases by the ISO have fallen to low levels.

3. Transmission Congestion Costs and Prices

Transmission was not a major issue in 2000 in most discussions with market participants. However, as noted in Section 2.B.6, transmission congestion patterns shifted in 2000 compared to earlier years, but congestion remained significant. Transmission congestion on paths into California generally lessened, but congestion on major paths within California, Path 15 and Path 26, worsened during some periods. Overall, day-ahead, interzonal congestion costs were $141 million in May to August 2000 compared with $27 million in 1999. However, $81 million of the cost was for congestion on Path 26, which not counted as interzonal congestion cost prior to the start of zone ZP26 in February, 2000. If these charges are removed, year 2000 costs are $60 million in 2000. This indicates that comparably-compared congestion costs about doubled from 1999, a somewhat smaller increase than overall energy costs.

Table 3-5 shows the congestion charges on the major transmission paths in 1999 and 2000. In general, the total cost impact of imports was less in 2000, particularly during peak periods. Costs for imports were much lower in 2000 on COI, during both peak and offpeak periods. As shown earlier in Table 2-18, import flows on NOB and Eldorado were

Figure 3-15. CalPX Bids, Replacement Reserves and Real-Time Payments to Replacement Units, June 12 to June 16



much lower in 1999, so the higher charges in 2000 for these paths, shown in Table 3-5 did not have as much impact. However, internal California paths, that affected the price difference between NP15 and SP15, Path 15 and Path 26, were both congested more often in 2000 than in 1999 and had cost per MWh of congestion. Exports flowing north offpeak were also more frequent and more costly per MWh, as show in Table 2-18 and in Table 3-5.

Table 3-5. Transmission Congestion Price During Congested Hours on Major Congested Paths, May through August, 1999 and 2000

Transmission Path	1999	2000	Difference (2000 minus 1999)
Onpeak Congestion			
Imports over Cal-Oregon Intertie (COI)	$13.96	$0.50	-$13.46
Imports from Oregon over DC Tie (NOB)	$5.15	$16.47	$11.32
North to South flow on Path 15	$12.18	$34.78	$22.60
North to South flow on Path 26	$0.00	$61.21	$61.21
Offpeak Congestion			
Imports over Cal-Oregon Intertie (COI)	$9.19	$0.00	-$9.19
Imports from Southwest over Eldorado Path	$4.83	$7.86	$3.03
Exports Oregon over DC Tie (NOB)	$4.83	$27.25	$22.42
South to North flow on Path 15	$5.91	$24.99	$19.08