5. Why Were Prices High This Summer?

The West experienced unusually high electricity prices during the summer of 2000, with large spikes in May and June, and high average prices throughout the summer. As discussed in Section 3, prices in western markets showed a close relationship to prices in the California PX. Prices in the PX reached as high as $750/MWh during individual hours.[1] Average PX prices were high all summer: $47/MWh in May, $120 in June, $106/MWh in July, and $166 in August. Many end-users were insulated from these wholesale price spikes, by rate freezes in most parts of California, or by traditional utility regulation in other western states. However, others were not insulated from high prices. End-users in the San Diego area were not protected by a retail rate freeze and saw their electricity bills increase several-fold. Some industrial users in the Northwest also experienced price volatility. The three IOUs in California have seen their financial position significantly weakened by these increased prices.[2]

There are three possible factors that can contribute to high prices. This section is divided into three subsections to discuss the effect of each factor on western prices in the summer of 2000:

A. *Competitive market forces*. Prices can be driven up by the normal forces of a competitive market, such as increases in costs of fuel or environmental compliance, or by scarcity of supply.

B. *Market design problems*. The rules of market institutions may contribute to prices higher than those that would prevail under competitive forces or with more efficient rules.

C. *Market power exercise*. If sellers possess market power, they have the potential to influence price. If conditions are conducive, the market price can be raised significantly above competitive levels.

In principal, it is important to distinguish among these three factors, because each factor calls for somewhat different regulatory approaches. In the absence of flawed market rules or the exercise of market power, competitive market forces may not call for regulatory action, or may only call for further

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[1] *Price Movements in California Electricity Markets*, California Power Exchange Corporation Compliance Unit (PX September report), September 29, 2000, at 10.

[2] Edison International, SEC 8K Filing, September 25, 2000; "California Utilities' Losses On Electricity Pose Risk, *Wall Street Journal Interactive Edition*, September 27, 2000; Joint Motion for Emergency Relief and Further Proceedings of Pacific Gas and Electric Company, et. al., San Diego Gas & Electric v. Sellers of Energy and Ancillary Services, Docket No. EL00-95-000 *et. al.*, pp. 5-7, October 16, 2000.

monitoring of overall market developments. Market design problems are generally best addressed by changing the market rules. Approaches to dealing with the exercise of market power may vary from compliance actions, to development of new rules, or to broader policy measures.

In practice, one single type of explanation seldom dominates the others, especially under extreme conditions such as those observed in the West over the past summer. Market rule problems with new institutions during a transition period, scarcity or near scarcity supply conditions, and rapid increases in input prices with their associated uncertainty may all be conducive to the exercise of market power. At the same time, these conditions make the detection of the market power exercise more difficult, because they can lead to many of the same results. For example, scarcity can lead to price spikes in competitive markets and rapid increases in input costs can lead to increases in average prices in competitive markets. Policymakers addressing these issues will need to consider all three explanations of high prices.

This staff investigation found that all three factors played some role in the high prices seen in the West in the summer of 2000. The data clearly show that a general scarcity of power in the West and increased costs to produce power were factors causing these high prices. It is also clear that existing market rules exacerbated the situation and contributed to the high prices. The data also indicate some attempted exercise of market power, if the standard of bidding above marginal running cost is used, and some actual market power effects, to the extent that prices, at least in June, were significantly above competitive levels. However, the data do not isolate specific exercises of market power or suggest that the exercise of market power was more important than other explanatory factors.

A. Market Forces: Costs and Scarcity

1. Increased Power Production Costs

As discussed in Section 3, suppliers' costs of generating electricity increased over the summer. The primary causes of the increase were rising prices for natural gas and NOx credits. Natural gas-fired combustion turbine units are usually the marginal units during peak demand periods, so increased natural gas prices can have a substantial impact on the market clearing price. In addition, a combined-cycle gas generator typically emits from 1 to 1.5 pounds of NOx per MWh, so increased prices for emission credits can also affect the market clearing price. Since many of the resources in California are oil and/or natural gas-fired generation, and prices in California closely correlate to prices in the rest of the West, increases in the cost of purchasing natural gas or NOx credits in order to generate power have a significant impact on electricity prices in the West.

Natural gas prices roughly tripled from January 2000 to September 2000 in the West, from less than \$2/MMBtu in January to more than \$6/MMBtu in September (see Figure 3-10). At the same time, the price of NOx credits increased from about \$5 per pound to over \$40 per pound (see Figure 3-11). As a result, the marginal operating cost of generation needed to meet peak load in California rose over the summer. As discussed in Section 3, these input price increases drove up the marginal operating cost of a combustion turbine from about $70/MWh in May to more than $190/MWh in August. As a result, market clearing prices that approached the $250/MWh price cap in August may have reflected the true cost of the resource rather than the exercise of market power.

2. Scarce Resources Throughout the West

It is clear that resources were scarce throughout the West during the summer of 2000. Unusually high temperatures and strong economic growth in California, the Northwest and the Southwest resulted in increased demand for electricity. Lower than expected hydropower output and increased unplanned plant outages in California contributed to the general scarcity of power to meet demand. Circumstances in California were exacerbated by increased exports of power from California to other parts of the West.

This section discusses the factors that contributed to a shortage of power in the West. Even in a well functioning market, prices can be driven up when costs increase or supplies become scarce. The following section discusses whether the exercise of market power could have allowed market participants to push up prices by withholding supplies from the market.

The generation shortage began long before the summer of 2000. Growth in demand over time was not matched by increases in generation capacity. Load outpaced generation capacity additions throughout the West in the 1990s. Load in the WSCC region increased by an average of around 3 percent per year, while capacity grew less than 1 percent. This trend resulted in a scarcity of supplies in the region, with the importing areas vulnerable to shortages. California has relied on imports to meet much of its load.

Reserve Margins

Going into the summer, the WSCC's forecast indicated ample reserve margins for the entire WSCC (Table 2-5). However, reserve margins for the California/Mexico (California) subregion (Table 2-6) were slightly lower than those for the total WSCC. The reserve margin for the neighboring Arizona-New Mexico-Southern Nevada (Arizona) subregion was also tight, with forecasts predicting a reserve margin of 13.5 to 13.8 percent for most of the summer (June-August).[3] While the California PX Compliance Unit noted that these were unrealistically rosy predictions,[4] a close reading of the

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[3] Western Systems Coordinating Council, *Summary of Estimated Loads and Resources*, May 2000, p. 86.

[4] PX September report at 13-25.

WSCC forecasts shows that they contained stipulations. The WSCC concluded that projected regional capacity margins and reliability would be adequate only if normal temperatures prevailed and normal unplanned generator outages occurred. The forecast stated that, if higher than normal unplanned generator outages were to occur, and an area experienced significantly higher than normal temperatures, or the load in multiple areas peaked simultaneously, portions of the region might need to issue public appeals for customers to reduce their electrical consumption or that other measures might be necessary. [5]

In particular, the WSCC concluded that the southwest portion of the WSCC (New Mexico, Arizona, southern Nevada, California, and Baja California, Mexico) might not have adequate resources to accommodate a widespread severe heat wave or higher than normal generating outages. The forecast raised the specific concern that the California subregion was dependent on contracted supplies that might not be available under emergency conditions. Unfortunately, most of the conditions that posed problems for the region were in place during the summer of 2000.

The higher-than-normal planned and unplanned outages during the summer of 2000 illustrate the impact of the stipulations on the WSCC reserve forecast. The WSCC forecasted no unavailable capacity for the California/Mexico subregion in July and August of 2000, with small volumes of unavailable capacity for May and June of 2000. The same assumptions applied to the Arizona subregion. Factoring in the actual planned and unplanned outages that occurred in the California market (see Figure 2-12), and holding the other assumptions equal, the reserve margins in the California subregion dropped from 26.3 to 17.5 percent for June, from 17.7 to 10.2 percent for July and from 17.4 to 8.98 percent for August. Because the reserve margins were already tight in the Arizona subregion, a small generator outage could drive reserve margins in that region below 10 percent and increase the demand for imports.

As the California PX Compliance Unit has indicated,[6] a significant change in spot prices can be expected when reserve margins drop below established reliability standards. Spot prices spike when reserve margins fall below the 15 to 20 percent range. The connection between reserve margins and price spikes was also observed in the Midwest in 1998.[7]

As noted in Section 2, during May through August of 2000, the Cal-ISO declared 24 Stage One and 14 Stage Two alerts (see Table 2-10). The Cal-ISO declares Stage One alerts when operating reserve levels fall below 7 percent and Stage Two alerts when operating reserve levels fall

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[5] Western Systems Coordinating Council, *Assessment of the 2000 Summer Operating Period*, revised May 25, 2000, p. 1.

[6] PX September report at 16.

[7] *Staff Report to the Federal Energy Regulatory Commission on the Causes of Wholesale Electric Pricing Abnormalities in the Midwest During June 1998*, issued September 22, 1998.

below 5 percent. During 1998 and 1999, when prices were significantly lower than the summer of 2000, the Cal-ISO declared only three Stage One and three Stage Two alerts for 1998 and three Stage One alerts for 1999. The Cal PX has noted a strong correlation between spot prices and low reserve margins this past summer.[8]

Unusually High Temperatures

Temperatures throughout the WSCC were higher than normal for the summer of 2000. Temperatures in the Arizona subregion were particularly high, averaging 3 to 5 degrees higher than normal.[9] The summer of 2000 was also significantly warmer than the previous two years for California. As shown above, in Figure 2-5, western temperatures ranked high relative to other periods over the last 106 years, and particularly relative to the last two summers. For example, the California/Nevada region was ranked 99th out of 106 in June of 2000, compared with 59th and 14th in 1999 and 1998, respectively. Some areas, such as the Southwest, were hot all summer. However, in California high temperatures were more of a factor in May and June than they were in July and August (see Figure 2-4).

Increased Demand

Energy consumption and average daily loads during the summer of 2000 grew rapidly compared with the same period in 1999 (see Figure 2-7). Energy consumption in the WSCC states, excluding California (see Table 2-8), increased by 4.7 percent in May 2000 versus May 1999 while energy consumption in California increased by 5.8 percent over the same period. The increase in energy consumption for June 2000 versus June 1999 was even greater—7.3 percent for the WSCC states, excluding California, and 13.7 percent for California. Within the ISO, average daily peak loads grew by 11 percent in May and 13 percent in June compared with those same months of 1999. California residential energy consumption increased by 8.3 percent in May 2000 compared with May 1999 and 23.8 percent in June 2000 compared with June 1999. Arizona, New Mexico and Nevada experienced even larger increases in residential energy consumption with increases of 36.3, 5.0, and 34.8 percent, respectively for May 2000 over the previous year and 22.3, 11.0, and 27.2 percent respectively for June 2000 over the previous year. These are significant increases in energy consumption from the previous year which can be directly tied to the higher temperatures across the region.

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8 PX September report at 15, Figure 3, citing a study by Cambridge Energy Research Associates, *The Summer 2000 Spot Electricity Markets Outlook: Divergent Trends n Price Volatility*, July 2000.

9 PX September report at 19, Figure 5, adapted from information on the NOAA web site.

Forecasts of peak loads made day-ahead were also higher than in 1999 (see Figure 2-8), adding price pressures, even though peak loads ultimately were below peak loads in 1999, primarily as a result of emergency alerts and demand reduction.

Reduced Imports to California

In the past, California has relied upon large amounts of imports from neighboring systems within the WSCC to serve load. However, the amount of imports into California for May through August 2000 were less than the levels for the same period in 1999 (see Figure 2-9). Scheduled net imports to the Cal-ISO fell from an average of 6,294 MW in 1999 to 3,231 MW in 2000; real-time imports from 6,321 MW in 1999 to 4,241 MW in 2000. The trend toward reduced imports was more evident in July and August than it was in May and June; while real-time May 2000 net import levels were 561 MW below 1999 levels. August 2000 real-time net imports were 3,449 MW below 1999.

The amount of imports available into California were reduced because of shortfalls in hydro supply during the summer. Hydro generation from outside California was 8.6 percent below 1999 levels in May 2000, and 23.2 percent below 1999 levels in June 2000 (see Table 2-15).

There appears to be a correlation between the amount of exports and the lowering of the Cal-ISO's buyers cap. When the ISO's buyers cap was lowered from $750/MWh to $500/MWh on July 1, exports rose from 2,995 MW in June to 3,846 MW in July (see Figure 2-10). When the Cal-ISO's buyers cap was further reduced from $500/MWh to $250/MWh on August 7, the amount of exports rose to 4,851 MW in August, an increase of 1,005 MW from the previous month. Thus, the capacity situation in California was tightened by lower supplies entering the state and a large increase in the amount of in-state generation that was sold out-of-state, possibly as a result of the Cal-ISO's buyers cap.

Increased Outages

Another factor that contributed to the supply shortage was the amount of generating capacity that was unavailable because of unplanned outages. In May 2000, outages within the California ISO were only slightly higher than May 1999, but the problem of outages grew worse throughout the summer (see Figure 2-12). By August 2000, 3,391 MW of capacity were unavailable because of unplanned outages compared with 604 in August 1999. California’s steam natural gas plants make up 36 percent of the total capacity and are now quite old: 82 percent of these plants are more than 30 years old.[10] As these units are dispatched more frequently due to the shortage of available generating capacity, they are more susceptible to breakdown.

Future Resource Additions

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[10] RDI Powerdat database, September 2000.

The problem with California's oil and natural gas generating plants will not be alleviated quickly through the addition of new generating resources within the state. According to the California Energy Commission (CEC), five projects totaling 3,643 MW are expected to be online in 2001-02.[11] An additional 14 projects totaling 8,015 MW are under review by the CEC; however, these projects do not have an anticipated in-service date. Capacity additions throughout the WSCC also lag in the near term. Only 1,521 MW of capacity is planned to be on-line during 2000. The capacity situation within WSCC should improve shortly thereafter when around 23,000 MW of capacity should come on-line between 2001-2003 (see Table 2-3).

Since California started its electric restructuring program, the amount of new generating capacity in California has lagged while load has increased. Only 672 MW of net capacity has been added in California between 1996 through 1999. In the meantime peak load has increased by 5,522 MW over the same period.[12] Load growth rapidly outpaced generation additions, reducing important reserve levels within California.

A major factor in the lack of new generation within California is the complexity of siting generation within the state. As noted by the EOB/CPUC in their report to the governor, "state siting procedures in California are complex and create investor risk because of California's commitment to environmental protection and public participation in the permitting process."[13] The California Environmental Quality Act (CEQA) and the federal Clean Air Act are two of the principal laws that determine where power plants are constructed in California. The CEQA requires evaluation and mitigation of potential power plants before the state allows construction and failure to conduct environmental review can result in CEQA litigation by citizens or local government agencies that can delay, change or eliminate a generating project. In addition, Local Air Districts enforce state, federal and local air quality laws for power plants. The changing California regulatory environment throughout much of the 1990s also created regulatory uncertainty for investors who chose to wait until clear rules were established before applying to build new power plants.

The California legislature's attempt to expedite this process through enactment of AB 970 does little to relieve these difficulties. That legislation gives priority to projects that would have the greatest efficiencies and the least impacts. Thus, while AB 970 centralizes in the CEC determinations that would normally be made by numerous state and local agencies, it does not appear to materially change the substantive provisions governing siting decisions in California.

B. Market Rules

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11 www.energy.ca.gov/sitingcases/projects_since_1979.html

12 EOB/CPUC report to the Governor on California's Electricity Options and Challenges at 36.

13 Id. at 38.

The market conditions discussed in the previous section contributed to high prices, but their effects were magnified by the existing market design and some flawed regulatory policies. This section discusses the rules and regulatory policies that appeared to have a significant contributing role in the high prices, as well as some that did not appear to be a factor but that have been commonly assumed to be factors.

Among the factors that appear to have contributed to the recent high electricity prices in western markets, and California in particular, are rules and policies of the PX and the Cal-ISO, and statutory requirements and regulations administered by state and local regulatory bodies. For example, until very recently, SDG&E, SoCal Edison and PG&E were required by CPUC regulations to purchase and sell all of their electricity through the PX. While the three IOUs now have some additional authority to purchase outside the PX, their purchases are subject to an after-the-fact prudence review. These state policies greatly limited the options available to the three IOUs and have created an impediment to their use of forward contracts. Also, state retail rate policies currently prevent consumers from seeing and responding to market prices, and they provide weak incentives for the IOUs to minimize the wholesale cost of electricity once their stranded costs are paid off. In addition, certain ISO and PX rules appear to have contributed to underscheduling of load and generation in forward markets, causing operational problems for the ISO and forcing it to procure energy out-of-market at high prices. These are discussed below.

1. Lack of Forward Contracting

The three IOUs in California were required to purchase their power through the PX with little or no ability to purchase through forward contracts. Requiring the three IOUs to purchase and sell through the PX exposed them to the volatility of the spot market without the ability to mitigate the summer price volatility.

Forward financial contracts for energy potentially can provide IOUs and other load serving entities with a highly effective hedge against high costs in energy spot markets, while providing both buyers and sellers with a greater level of price certainty. Moreover, for generators that are otherwise able to exercise market power in energy spot markets, such contracts can help to mitigate the market power of the generators that hold them. Thus, forward financial contracts offer the potential to reduce both the cost impact of price spikes on consumers' bills, and the incidence and magnitude of the price spikes that occur.[14]

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[14] The Market Surveillance Committee and the ISO's Division of Market Analysis have reached similar conclusions. See, *e.g.*, *An Analysis of the June 2000 Price Spikes in the California ISO's Energy and Ancillary Services Markets*, by Frank A. Wolak, *et al.*, September 6, 2000, pp. 6-11, and *Report on California Energy Market Issues and Performance: May-June 2000,*

Properly structured forward contracts can benefit consumers by providing load serving entities with the ability to lock in a fixed price for a fixed quantity of energy well in advance of the actual consumption of that energy. This means that a load serving entity need only face spot prices to the extent that its actual energy purchases differ from its forward market purchases. Indeed, if a load serving entity's actual purchases match its forward market purchases, it can achieve both a perfect hedge against high spot prices and the benefit of complete price certainty in the face of spot price volatility. Of course, holding forward contracts does not guarantee that consumers will incur lower total energy costs. These costs ultimately will depend on the relative level of prices in the forward and spot energy markets.

Forward financial contracts also help to mitigate generation market power in energy spot markets. For example, consider a generator with market power that holds a contract for differences with a load serving entity. Such a contract requires the generator to compensate the buyer for the difference between the energy spot price and the contract's strike price when the strike price is lower than the spot price, and requires the buyer to compensate the generator when the strike price is higher. Holding this type of contract reduces the incentive of the generator to raise spot prices because any increase in spot prices will cause its payments to the buyer to increase (or its receipts from the buyer to decrease). Thus, to the extent that the majority of its supply portfolio is committed under contracts for differences, the generator's incentive to exercise market power in the spot market will be reduced or even eliminated. Similar results can be shown to hold for generators that hold other forms of financial contracts as well as forward physical contracts. It must be emphasized, however, that forward contracts serve only to mitigate market power in spot markets; the market power that a generator may have in forward markets will be unaffected by the forward contracts that it holds. Nevertheless, market power tends to be found less in forward markets than it is in spot markets, because forward markets provide energy purchasers with more lead time and therefore more options. Indeed, with sufficient lead time, the options available to purchasers in the forward market can include the construction of new generating units.

Until recently, CPUC regulations placed strict limits on the options available to IOUs to enter into forward contracts. Specifically, prior to August, the CPUC limited the forward contracts available to PG&E, SoCal Edison and SDG&E to block forward contracts purchased through the PX that provided for delivery of energy up to 12 months hence. Also, the regulations strictly limited the quantity of energy that each IOU could obtain through forward contracting. However, since August, actions by the CPUC and the state legislature have provided the IOUs with an expanded array of PX energy products and with the authority to enter into long-term bilateral contracts with entities outside the PX. Restrictions on forward contract trading levels remain in place as well as after-the-fact prudence reviews which dampen a purchaser's incentive to buy forward.

California ISO Department of Market Analysis, August 10, 2000, p. 6.

During and prior to the summer of 2000, the IOUs did not fully utilize even the limited authority they had to enter into forward contracts. There are perhaps several reasons for this. First, the standard products available through the PX block forward market may not have met the specific needs of the IOUs. For example, these products are defined only for a limited set of fixed hourly periods (peak, super-peak and shoulder-peak) within a given calendar month. Second, because the standard contracts did not provide a full range of hedging features, they may not have offered the level of insurance against price spikes that the IOUs sought. Third, the prices for the block forward contracts may have appeared high relative to the IOUs' forecasts of spot prices for the summer of 2000. Indeed, by the time the IOUs received authority to increase their forward market trading levels, forward market prices had already increased, probably in response to the early spot market price spikes. Finally, the IOUs may have feared that the CPUC would declare their forward market purchases to be imprudent if spot prices turned out to be lower. In addition, because SDG&E was allowed to easily pass through to retail customers its energy and ancillary services costs, it may not have had a strong incentive to aggressively pursue cost reductions through forward contracting.

The restrictions on the ability of the IOUs to enter into forward contracts have denied the IOUs the opportunity to adequately insure themselves against high energy spot prices. Also, because forward contracts can help to mitigate generation market power in energy spot markets, price spikes during the summer of 2000 have probably been larger and more frequent than they otherwise would have been if the level of forward contracting had been higher.

2. Demand Responsiveness

In well functioning competitive markets, both suppliers and consumers are able to see and respond to market prices. Indeed, this is what allows competitive markets to achieve the efficient outcomes for which they are well noted. However, in electricity markets, such as those of California, consumers often must make their consumption decisions without knowledge of the true market price of electricity. In addition, some utility purchasers of electricity, such as SDG&E, may not always have strong incentives to minimize the wholesale cost of the electricity that they purchase for their retail customers. This lack of demand responsiveness can, at times, lead to excessively high prices.[15] It can also have important implications for the Commission's regulation of wholesale power markets.

To be effective, prices must accurately reflect the cost of supplying electricity at a given time and place, and they must be communicated to consumers in a timely manner. In California, for example, retail customers generally are not provided with accurate and timely price signals. This is due

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[15] See also, *An Analysis of the June 2000 Price Spikes in the California ISO's Energy and Ancillary Services Markets*, by Frank A. Wolak, *et al.*, September 6, 2000, pp. 10-13, and *Report on California Energy Market Issues and Performance: May-June 2000*, California ISO Department of Market Analysis, August 10, 2000, p. 6.

in part to the retail rate freeze that was applied to the IOUs as part of the statewide restructuring. The retail rates of PG&E, SoCal Edison and SDG&E were frozen at the time of restructuring to ensure that retail customers would not pay rates that exceeded the rates paid before deregulation. The rate freeze was designed to operate in conjunction with the recovery of the utilities' stranded costs. Specifically, AB 1890 provided for recovery of stranded costs through a Competition Transition Charge (CTC). The CTC surcharge cannot, in conjunction with PX market prices, exceed the rate freeze levels. This means that, to the extent that PX prices are high, CTC recovery is slower. Consequently, if customers reduce their demands, their rates do not fall; the utilities simply recover their stranded costs at a faster rate. Both the CTC and the rate freeze are limited in duration to the earlier of March 31, 2002, or until stranded costs are fully recovered for each IOU.

SDG&E completed its recovery of stranded costs in 1999 and the CPUC lifted its rate freeze in July 1999. With the end of the rate freeze, SDG&E was allowed to pass on its wholesale costs of power directly to its customers. Consequently, SDG&E customers felt the full impact of the wholesale price increases that were experienced in the summer of 2000, when their electricity bills more than doubled. However, because these customers did not see the rate impacts until they received their bills, they had no practical way to respond in the short term to the high prices. Also, without time-of-use metering, they were unable to reduce their bills by moving consumption to off-peak periods. Furthermore, SDG&E itself may have had little incentive to minimize its purchased power costs given that it could simply pass through the costs to ratepayers, subject only to the possibility of a prudence review by the CPUC.

By contrast, PG&E and SoCal Edison have not completed their stranded cost recovery and therefore remain subject to the retail rate freeze. Consequently, these utilities' customers were fully insulated from the price increases of the summer of 2000, and clearly had no incentive to modify their consumption patterns in response to the increased costs. However, because PG&E and SoCal Edison were unable to pass through the increased wholesale costs to their customers, they likely had a much stronger incentive than SDG&E to minimize these costs, because any cost savings realized can be applied as an offset to their CTC costs. However, neither of these companies had much ability to minimize their costs because they were largely required to buy in the spot market.

It should be noted that available evidence suggests that customers that had direct access to wholesale markets this summer did indeed change their consumption patterns in response to the price increases. Based on discussions during this investigation, there is evidence to suggest that some load reduced purchases during peak periods and increased purchases off peak.

The fundamental problem created by unresponsive demand is that, during periods of tight supply, prices can rise far above competitive levels. The reason is as follows. In a competitive market, if demand is low relative to the available generating capacity (such as during off-peak periods), the market clearing price will approximate the marginal running cost of the most costly generator operating. This is true even when demand is unresponsive to price, as long as the market includes many owners of generation competing to serve the limited demand, and none of these generators has locational market power. However, these same generation owners will discover that they have considerable market power when demand is both unresponsive to price and at such a high level as to require the ISO to place virtually all available generating capacity in operation or on reserve in order to meet demand reliably.

This is not to say that competitive prices should never rise above the marginal running cost of generation. When supply is scarce relative to demand, competitive prices will rise to a level that reflects the value that the marginal consumer places on additional consumption. This additional increment above marginal running cost is referred to as the “scarcity rent.” However, market prices in electricity markets like those in California cannot be expected to settle at this level if retail consumers do not have the ability to see these prices and to make known to the market, through their purchasing decisions, the value that they place on marginal consumption. Indeed, in the absence of demand responsiveness, prices in California and in markets elsewhere frequently rise well above this competitive level at times when demand is high and capacity is scarce.

The only alternative facing a system operator in the absence of demand response may be to ration demand through administrative load reductions. This is exactly what happened in California last summer, when a total of 38 emergency alerts were called. These administrative procedures succeeded in reducing demand without curtailment of firm load, which suggests that load does indeed have the ability to reduce its consumption. But it does appear difficult to convert these reductions from an administrative basis to a market one. Under the reliability rules, interruptible load cannot be required to reduce its consumption except under emergency conditions. Thus, as long as firm load is maintained, load may have only limited incentives for price-based reduction of consumption. It appears difficult to develop a large amount of demand response, but the reasons appear to be institutional more than physical.

3. Underscheduling

At present, the PX has a $2,500/MWh price cap[16] and the Cal-ISO has caps of $250/MWh for energy and ancillary services and $100/MWh for replacement reserves. The PX's higher energy price cap has not limited energy prices in the PX. Instead, as noted in the San Diego order, the ISO's cap has effectively limited the price of generation sales in the PX day-ahead and hour-ahead energy markets.[17] Buyers never offer to pay more in the PX market than the ISO's maximum purchase price, since they may still buy at the ISO's cap in the real-time market if their bids are not accepted in the PX.

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[16] The PX price “cap” is actually a practical limit imposed by the market software requirements, not a regulatory restriction on bidding or pricing.

[17] San Diego Gas & Electric Company, *et. al.*, 92 FERC ¶ 61,172 (2000).

Specifically, the net cost to load to buy in the ISO's real time energy market cannot currently exceed $350/MWh (i.e., $250 for energy and $100 for replacement reserves). Thus, loads will not offer to pay more than $350/MWh for energy in the PX's forward market, and the PX energy price will not exceed that level. These restrictions on price helped create incentives for both buyers and sellers to underschedule load and supply in the day-ahead market.

The amount of underscheduling has tended to increase substantially during high demand periods. A major reason appears to be that the amount of supply offered into the PX markets during high demand periods is often substantially less than forecasted demand. Data presented in Section 2 indicate that the day-ahead schedules in the PX consistently fell below forecast loads whenever loads were above 35,000 MW, and that the load level where this occurred decreased in July and August. Information in Section 3 shows that the proportion of supply below $100 in the PX was reduced through the summer as the price cap was reduced. The total amount of supply offered in the PX does not appear to change much over the summer. The California PX states that little additional supply has been offered into the PX Day-Ahead market at any price above $100/MWh, especially when the ISO's load forecast exceeds 35,000 MWh. For example, on July 31, 2000, in hour 16, total supply offered into the PX day-ahead market at any price was less than 35,000 MWh, while the ISO's load forecast was over 45,000 MWh.[18]

As a result, load and generation underschedule in the PX's forward markets and then appear in the ISO's real-time market. Extensive underscheduling creates operational and reliability problems for the Cal-ISO, and has required it to procure energy out-of-market at high prices.

In an attempt to address the operational problems and reduce the incentives for underscheduling, the ISO modified its practices for procuring replacement reserves in May 1999. Specifically, the ISO now procures a day in advance enough replacement reserves to match its estimate of underscheduled load—that is, the difference between its own forecast of real time load and the amount of energy scheduled in the forward markets. The ISO says that procuring additional replacement reserves increases the likelihood that sufficient generation will be available to reliably meet the load that shows up in real time. As an incentive to discourage underscheduling, the ISO charges the costs of the replacement reserves to unscheduled load that shows up in real time and to scheduled generation that fails to produce in real time.[19]

However, the modified replacement reserves policy has not reduced the amount of underscheduling. Indeed, underscheduling has increased, especially during high demand periods. For

18 PX September report at 44.

19 See, *AES Redondo Beach, L.L.C., et al.,* 87 FERC ¶ 61,208, (May 26, 1999) example, in June as much as 21 percent of real time load was not scheduled in advance.[20] A major reason for this phenomenon is that the policy creates conflicting incentives. On the one hand, the policy does discourage buyers from underscheduling, by charging the costs of replacement reserves to unscheduled load. However, the policy also encourages generators not to offer energy in the forward market (especially during periods of high demand), but instead to sell their capacity as replacement reserves. That is because by doing so, the generator can receive a payment for replacement reserves in addition to a payment for selling energy in real time. (During periods of high demand, generators selected to provide replacement reserves are likely to be called on in real time to produce energy. The policy encourages generators to bid less into the PX as load increases, by increasing the probability that all replacement reserves will be used for energy and hence the expected opportunity cost of not deferring supply until the hour-ahead or real time markets.)

As noted by the MSC, because the ISO requires all forward schedules to be balanced, load and generation are equally underscheduled. Underscheduling arises largely because loads and generators disagree about the appropriate forward price of energy. In effect, underscheduling occurs because loads are trying to protect themselves from higher prices in the forward market, while generators are trying to protect themselves from lower prices in the forward market.

Clearly, substantial underscheduling creates operational and reliability problems for the ISO as the grid operator. The effect of underscheduling on energy prices, however, is less clear. On the one hand, the ISO has incurred costs to procure replacement reserves and to make out-of-market purchases at high prices in response to underscheduling. On the other hand, attempts by load to reduce underscheduling by procuring more energy in the forward markets would likely put upward pressure on forward market prices. In sum, underscheduling had no clear impact on this summer's prices.

4. Exports/Imports

Exports increased through the summer along with reductions in the price cap, but there are many possible reasons why this might have occurred, including prior commitments by generators, increased opportunities in the Southwest where weather remained extremely hot, reductions in the overall WSCC level of hydro generation, and off peak pumping requirements for hydro. These exports have the effect of reducing the supply of in-state generation and limiting the amount of such generation bid into the PX. In the summer of 2000, these increases in exports were not compensated by increases in imports, and the net imports into California were reduced.

Several concerns have been raised about the reduction in net imports. The first concern is one of reliability, because the reduction in scheduled imports contributed significantly to the problem of

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[20] *Report on California Energy Market Issues and Performance: May-June 2000,* California ISO Department of Market Analysis, August 10, 2000, p. 26.

underscheduling. The ISO needed to purchase additional imports for real time, either through replacement reserves or out-of-market purchases at the last minute, contributing to the high incidence of emergency alerts and concerns of maintaining the reliability of the system.

The second concern is that generators exporting power were gaming the system in order to increase prices. By selling to entities outside California, who may be the same entities who supply imported power in real time, the increased exports decrease supply in day ahead and hourly energy markets and increase prices. Supply then becomes available in replacement reserve markets at the ISO, or as out-of-market purchases in emergencies. Out of market purchases were not large (less than 1 percent of energy costs), but replacement reserve purchases were very high on certain days in the summer (see Section 3). In one sense, this is not gaming, since there are no administrative rules on the amount of capacity that must be provided to meet load as there are in the eastern ISOs. Loads are required to bid into the PX, but there is no capacity penalty imposed if corresponding supply does not bid into the PX. The concern seems to be that megawatts are exported to the very same entities who then sell the megawatts back in real time at high prices. Several generators reported contracting a significant proportion of their supply forward outside of California, and the buyers of that power may have exported it back to California at some later date. One marketer, who is reported to have contracted for power from California generators at attractive prices before the summer, exported power back as replacement reserves at high prices during emergency conditions in California.

These exporting practices are permitted under the rules and are not necessarily a market power problem. It may simply be the normal working of a market where sellers are maximizing profits in a competitive market, where sellers or buyers see an opportunity at one time, take an option, and exercise it at a later date. It becomes a problem if it is associated with a pattern of withholding resources from the market in order to drive up prices. For example, if a large seller outside California were able to influence the price of power in the West by acquiring power from California, withholding power from the market at a critical time, and selling the power back to California. As such, it is part of the overall issue of market power and scarcity in the West, discussed in the next section.

5. Auction Rules

Currently, the Cal-ISO and the PX use a single-price rule for establishing real time energy prices. That is, the market-clearing price (which is based on the highest accepted bid) is paid to all accepted sellers, including those who bid less than the price. To prevent future price spikes, some have proposed an alternative pricing rule—paying each accepted seller its bid, rather than the market-clearing price. Buyers would then pay a price reflecting the average of the accepted sellers' bids. Proponents of the pay-as-bid rule argue that consumers would pay less in total during high demand periods, on the grounds that consumers would pay less than the highest accepted bid to suppliers who bid less. However, generators are not likely to bid under a pay-as-bid rule in the same way as under the single-price rule. Sellers bidding below the market-clearing price will receive that price under the single-price rule, but they will receive only their bid under the pay-as-bid rule. So generators will generally submit higher bids under a pay-as-bid rule. In sum, it is not clear whether a pay-as-bid rule would have the effect of lowering consumers' bills.

C. Market Power

The previous sections have discussed the factors that contributed to an electricity shortage this summer and the effects of problems with market rules. This section discusses the issue of market power in the context of scarcity and considers whether the apparent shortage arose because of withholding and hence whether the high prices in the West were the result of the exercise of market power. Market power is the ability of a seller to influence market outcomes, especially the market price for a sustained period. Sellers exercising market power use this ability to raise the market price above competitive levels, either by physically withholding some of their capacity from the market, or by offering their capacity at prices above competitive levels. During periods of supply scarcity, the market price naturally rises and even firms with relatively small market shares may possess significant market power. However, as the supply becomes more scarce, it becomes more difficult to isolate the effects of scarcity and market power on the market price.

Market power, like scarcity, is a matter of degree. It is important to recognize that, in practice, the issue of market power is not a simple, all-or-none question, but turns on the magnitude of the market power impact on price and its consequences. In times of scarcity, this impact is potentially very large, but it may be very difficult to separate from scarcity effects that can also be large and the duration of the impact of market power may be relatively short-lived.

Significant market power abuses that violate market rules need to be dealt with directly, but market power in a newly developing market may be magnified by flaws in market rules. The best approach in these cases may be to change the rules in order to mitigate the impact of market power exercise. Mitigation in the form of rule changes may be appropriate even in the absence of findings of market power exercise by specific sellers or buyers, if there are clear incentives for its exercise, and there are potentially large impacts that cannot be adequately separated from the effects of scarcity.

As discussed below, there is evidence suggesting that sellers had the potential to exercise market power during this past summer. However, the evidence available and analyzed during this investigation, to evaluate whether there were actual exercises of market power, is inconclusive. A considerable amount of data on individual bidding patterns and individual plant performance was obtained and reviewed in the course of this investigation, but was not sufficient to make determinations regarding exercises of market power by individual sellers. Further study of high-priced bidding by individual firms or periods when individual generators were not running would be needed to substantiate any charges of market power abuse.

1. Measuring the Effects of Market Power on Price

During periods of high demand and tight capacity, prices would ordinarily rise as a result of basic competitive market forces and real scarcity. However, conditions of tight capacity can often create market power, especially when demand is insensitive to price. When demand is inelastic and approaches capacity, a seller with a relatively small amount of capacity can often begin to influence the market price. It can sell most (if not all) of its output even if it asks for a price higher than what other sellers are asking. The seller may lose some sales by asking a higher price, but these lost sales revenues are more than made up by the higher prices on the output it produces. Thus, while the combination of high demand and tight capacity would ordinarily cause prices to rise due to competitive market forces, they may also create market power that causes prices to rise even higher. From a public policy perspective, the desirable outcome is a competitive price increase, not the higher price increase caused by the exercise of market power.

When market power is exercised, the market clearing price exceeds the price that would have been set under competitive conditions. It is important to note that a generator's true marginal cost is the generator's opportunity cost of selling into a particular market. That is, the next highest value of the resource. If the running cost of a unit is $40 per MWh, but that unit is physically able to sell into a market in which the price would be $80 per MWh if that generator participated in that market, then the opportunity cost of selling into another market is $80 per MWh. As long as the generator bids its true opportunity cost into a market, it will never receive less than the true value of its output.

In order to estimate the degree to which market power is being exercised, the supply curve for a particular hour would have to be reconstructed replacing the bids received with the marginal cost of each bidding generator. The effect of market power on the price would be the difference between the actual market clearing price and what the market clearing price would have been if all the generators had bid their true marginal cost. The Market Surveillance Committee (MSC) of the California ISO has performed such an analysis. The MSC estimated a significant degree of market power being exercised in California markets for the period October 1, 1999, to June 30, 2000. They estimated that prices for non-must-take energy over the entire period were 36.3 percent higher than they would have been under competitive conditions. For the last month of the sample, June 2000, they estimated that prices were 64.6 percent higher than they would have been under competitive conditions. The highest previous monthly market power index was in June 1998, when prices were estimated to be 39.9 percent higher than they would have been under competitive conditions.[21] These findings certainly suggest that market power was exercised in June by the standard of short run marginal costs. Average prices in August were higher than June. However, as discussed in Section 3, costs were also much higher, so it is unclear whether, or to what extent, market power appears to be a continuing concern. The MSC has not yet completed an analysis for July and August.

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[21] The monthly market power index is the percentage increase in monthly wholesale energy revenues relative to monthly revenues under the perfectly competitive benchmark. *MSC Report on June 2000 Price Spikes*, September 6, 2000, p. 17.

2. Demand Conditions

The degree to which the market price will exceed the marginal cost of production depends not only on the supply-side factors discussed above, but also on the demand responsiveness. For any given concentration level, the less responsive (elastic) the demand the more the market price can be raised above marginal cost.[22] Thus the less elastic the demand, the greater the cost to consumers of an exercise of market power. In California, as in other states, demand changes from hour to hour, but not typically in response to hourly prices. Nevertheless, it is clear that demand can respond to conditions, as the difference between peak forecasts and actual loads (see Section 3) suggests. During emergency periods, interruptible customers have their demand reduced and voluntary reductions do occur in measurable amounts, in response to ISO interruptions of loads and public appeals for conservation. The difficulty is that the demand response is driven by administrative directive, not by market prices.

3. Market Power and Scarcity

In both the PX and ISO, all generators supplying energy receive the market-clearing price, which is the highest accepted bid to supply energy. During periods of scarce supply, the market-clearing price will greatly exceed the marginal running costs of most of the generators supplying energy.[23] Those generators with low running costs will receive a significant profit from the output of their units. The high price then serves as a signal to potential entrants that there are profits to be made. High prices during periods of supply scarcity are a normal feature of a properly-functioning market.[24]

It is difficult to separate scarcity from market power. As stated above, during periods when electricity becomes more scarce, the price naturally increases. However, during those same periods the ability and incentive to exercise market power increases. The ability to exercise market power (raise price) increases because the market is clearing in the steep (inelastic) portion of the supply curve, thus a slight reduction in output will significantly increase the market-clearing price. The incentive to exercise market power increases because the payoff becomes much higher. Any generator whose bid is accepted will receive the higher market-clearing price for all the energy it provides for that hour.

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22 For example, a measure of market power in a monopoly, the price-cost margin or Lerner Index ((Price - Marginal Cost)/Price) is equal to -1/elasticity of demand.

23 In fact, during a period of true scarcity, when demand exceeds supply even the unit setting the market-clearing price will receive a profit, or scarcity rent, since the price will naturally increase in order to equate supply and demand.

24 Especially in a market with little demand elasticity.

For an example of true scarcity, the California ISO DMA reports that during June 2000, there were 27 hours when the available supply within the ISO was less than the system demand.[25] For those hours, the average cost of procuring real-time energy was \$709/MWh.[26] During a period of true scarcity, any firm that can sell energy into the ISO real-time market has market power.

In addition, during June 2000 there were 106 hours when the available supply was between 100 percent and 110 percent of the system demand. For those hours the average cost of procuring real-time energy was \$324 per MWh.[27] Even considering the increase in marginal cost of operating gas-fired generators in Southern California, a price of \$324 per MWh exceeds estimates of the marginal cost of the last unit supplying energy. In June, the highest marginal operating cost was about \$160/MWh.[28] As noted in Section 3 of this report, it was not until August and September that the combination of high natural gas and NOx credit prices pushed the running cost of gas turbine units near that level.

4. Methods of Exercising Market Power

A generator could exercise market power through either economic or physical withholding. In the case of economic withholding, a generator would submit bids in excess of its opportunity cost in order to raise the market clearing price. In the case of physical withholding, the generator would not supply all of its available energy in order to increase the market-clearing price. In that case, by withholding lower cost output, higher cost units whose bids would not otherwise have been accepted would set the market clearing price. All suppliers whose bids were accepted would then receive the inflated market-clearing price. As long as the gain from the higher price exceeded the lost profits from the foregone output, withholding output would be a profitable strategy.

However, as noted earlier, determining physical withholding from real unit outages that occur during periods of high demand is difficult. This determination is made particularly difficult in the western environment by the presence of hydropower, must take contracts, and severe environmental compliance limitations. In each of these categories, it is difficult to determine the relevant capacity,

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[25] Department of Market Analysis, California ISO. *Report on California Energy Market Issues and Performance: May - June, 2000*, p. 51.

[26] The total cost includes both capacity and energy payments, since many of the units that provide energy also provide reserve capacity.

[27] Department of Market Analysis, California ISO. *Report on California Energy Market Issues and Performance: May - June, 2000,* p. 51.

[28] Eric Hildebrandt, *Market Analysis Report*, California ISO Department of Market Analysis, September 2000.

since the amount of energy the facility can produce is limited by various factors, not by the physical capacity of the unit. From conversations with the ISO staff, we have learned that hydro facilities and must take contracts are treated on an "as bid" basis, so that the amount of energy bid is taken as the indicator of the power available from the unit in any given hour. These facilities will often appear underutilized and much of the capacity will appear available when measured against the total physical capability of the unit.

Because of the difficulty in assessing a firm's true opportunity cost of selling into a market, economic withholding is even more difficult to assess than physical withholding. Generators are maximizing the profits from a portfolio of generation units. There are many markets into which they can sell. They face environmental, reliability, technical and regulatory constraints. For example, generation units have different start-up costs and ramp rates. Since the bids the units submit to the PX and ISO (through their scheduling coordinator) are composed of capacity and energy but not other costs such as startup, they cannot bid their full set of cost components, so they may "average" some of the costs associated with ramping their units up or down into their bids. It is not clear what constitutes a reasonable averaging and what does not.

A generator that is producing less than its capability during a period when the price is greater than its opportunity cost would appear to be engaging in physical withholding. It is not always clear, however, what separates withholding output in order to raise price from withholding output due to environmental, reliability, technical or regulatory constraints. For example, for a unit that is slow to ramp down, the optimal running plan may be to begin to reduce output (withhold) earlier in the day than for a unit that can be quickly ramped down. For another example, a unit may only be able to run for a fixed number of hours during the summer due to environmental constraints. What appears to be withholding (not running the unit when the market price exceeds the marginal running cost) may be simply the result of the generator trying to maximize the value of the unit's output for those hours it can run.

5. Evidence from Summer of 2000

One method of withholding output would be to call an unplanned plant outage. An increase in unplanned outages shortly before or during price spikes would be an indicator of physical withholding. As noted in Section 2.3, the amount of capacity unavailable due to unplanned outages was 2,787 MW greater in August 2000 than it had been in August 1999. Given the significant cost increase of the marginal units and their associated bid price increase, the absence of 2,787 MW significantly increased the market-clearing price. Higher prices are to be expected during a period with significant capacity unavailable due to outages; they are the result of an inward shift of the supply curve at the time of the outage. As shown in Table 2-14, however, the strongest correlation was between outages (unplanned and planned) and the next day's price rather than the price in the day of the outages. The outages would then be lower on the day of the high prices, than they were on the previous day. High prices in the periods after a significant amount of capacity becomes unavailable would indicate a market reaction beyond the direct effect on the supply. While the reaction could be a competitive attempt to reduce outages in anticipation of tight conditions, it is also consistent with an attempt to exercise market power by driving up prices for the next day and then making the unit available in time to receive those high prices.[29]

If attention is focused on the thermal units that have the greatest ability to respond to price, data from the control areas in the WSCC seem to show that only 5 to 7 percent of the non-hydro generation resources went unused at peak times. This suggests that the magnitude of any physical withholding of available capacity was not large for these units.

Firms could also exercise market power through the bids they submit to the ISO and PX. As described in Section 3, the bid curves offered in the PX change their shape through the summer as the price cap lowers. The proportion of bids under $100 decreased during the summer, so that firms were changing their bidding behavior and increased the price at which they would offer any given amount of supply. However, the change in behavior was exhibited by all categories of participants, so it is as likely to be a response to increased costs as it is to be intentional behavior by any individual firms or groups of firms to raise the lowest price offered to compensate for reduction in the price cap.

As noted by the above, the price responsiveness (elasticity) of supply significantly influences the effectiveness of either type of withholding. If the market supply is highly responsive to changes in price, then any attempt at economic or physical withholding will not be effective, since there will be significant supply at the margin to respond without causing a significant increase in price. An indicator of an effective economic or physical withholding strategy would be if those units that consistently set the market-clearing price were able to decrease the supply elasticity through their bidding behavior. The PX Compliance Unit estimated that the average supply elasticity of the units clearing the market for those hours in May through July 2000 when the market-clearing price exceeded $100 per MWh was actually 24 times greater than the overall supply elasticity.[30] As a result, the entry of supply at high prices may have increased the elasticity of supply in these ranges, making the exercise of market power more difficult over these load ranges that it otherwise would have been. Staff was able to observe this phenomenon in the individual participant bidding curves. Some bidders bid consistently at high levels, submitting bids that varied even though the average price bid was high. Other bidders submitted bid curves that included a large amount of supply at low prices and only a very small amount at high prices, making the bid curve very steep for a small proportion of their submitted supply. Bidders in the former category will tend to make high-priced supply more elastic. However, they also have the effect of

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29 Specific examples of this practice have been noted in the England and Wales pool by several observers. For example, see David Newbury, *Power Markets and Markets for Power*, and Frank Wolak and Robert Patrick, *England and Wales Electricity Market*, February 1997.

30 California Power Exchange Corporation Compliance Unit. *Price Movements in California Electricity Markets, Analysis of Price Activity: May-July 2000*. September 29, 2000, pp. 59-61.

shifting total supply upward, so they will also tend to raise the price at lower load levels compared to bidders who submit only a small proportion of supply at high prices.

6. Market Power in Context

It is important to evaluate the impact of market power in the context of two conditions discussed in the earlier sections: scarcity and market rules. In the short term, when supply becomes very tight and demand is unable to respond, the price discipline of a normal competitive market is greatly diminished. The effects of scarcity and market power in these circumstances are very similar: high prices, a seller's market with few or no restraints on sellers, and few or no options for buyers. In an ideal world with no market power, these prices would signal scarcity and the market would correct itself. But the past summer in the West was not an ideal world. Buyers had essentially no short-term options and few longer-term, forward ones. Without better forward markets, even true scarcity signals would not get effectively conveyed until close to real time, leaving little room for the development of a more stable overall market.

Market power can compound the effect of scarcity, because it will distort normal market signals. Sellers have the incentive to raise prices to inelastic buyers when supplies are anticipated to be tight, and the result can be prices above competitive levels that appear sooner than they would in a workably competitive market where prices are set by short-term marginal opportunity costs. Frequently, these prices may be the work of a competitive market. However, at least some of the June price spikes appear to be attributable to market power, and high bids observed in PX and replacement reserve markets during this investigation provide further indications that above marginal cost bids can be sustainable.

Market rules can provide some substitute discipline if normal market processes break down, at the risk of distorting genuine market signals. But markets designed with overly complex rules and decision procedures can make matters worse, if they give sellers misplaced incentives and the means to act on them. For example, rules that provide incentives to shift supplies from the day-ahead spot market to even shorter-term hourly or real time markets can adversely affect the ability of the ISO to manage the market reliably in real time. Although the price impact of such shifts is uncertain, the effect is to move supply to a market where demand is even less responsive than in the day-ahead market, restricting buyer options and potentially increases any market power the seller may possess. Without prospects of greater demand response in close to real time, these types of problems may be very difficult to manage through purely market incentives, and non-market rules may be needed.

If higher than competitive prices are sustained for a long enough period of time, price restraints, capacity requirements, rules requiring greater forward contracting, or some other market intervention may be needed. However, policy makers need to factor in increases in input costs, unavoidable limitations on siting generation and transmission costs and other true costs or limitations in crafting workable market rules that assist market development rather than impeding it.

D. Conclusion

As noted at the beginning of this section, competitive forces, flawed market rules and, to some extent, market power contributed to the unusually high prices the past summer. These results seem to suggest that some change in market rules is required. Additionally, some further steps during a "transition" period to 2002, when new capacity will be available, may also be necessary. Options to address these conclusions are provided in the following section.