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## **Diagnosing Market Power in California's Deregulated Wholesale Electricity Market**

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Abstract:

Effective competition in wholesale electricity markets is the cornerstone of the deregulation of the electricity generation industry. We examine the degree of competition in the California wholesale electricity market during June-November 1998 by comparing the market prices with estimates of the prices that would have resulted if all firms were price takers. We find that there were significant departures from competitive pricing and that it was most pronounced during the highest demand periods. Overall, this raised the cost of power purchases by about 22% above the competitive level. We also explain why the prices observed cannot be attributed to competitive peak-load pricing.

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## I. Introduction

In the first year of the deregulated California electricity market a number of issues have arisen that relate to the competitiveness of the wholesale electricity market in the state. There have been lively debates over the need for price caps in the California Power Exchange (PX) day-ahead market and the California Independent System Operator's (ISO) real-time energy and ancillary services markets. These debates have raised the question of whether the high prices that have been observed at times are a result of scarcity of generating capacity during peak demand periods in a competitive market or are the outcome of the attempts of some market participants to exercise market power. The debate about the appropriate treatment of Reliability Must-Run (RMR) plants has likewise focused attention on the possibility that some producers may attempt to supply power from these units in ways designed to influence market prices. The questions raised in these discussions are central to judgments about the degree to which the California wholesale electricity market is currently able to operate efficiently without intervention from the PX, ISO, or government regulatory institutions.

We attempt to shed some light on these questions by estimating the degree and extent to which price in the California markets for electrical energy deviated from competitive levels during June-November, 1998. Using data on the operation of the California electricity supply industry and other sources, we estimate, on an hourly basis, the extent to which prices have exceeded the levels that would obtain in a market in which all generators were behaving as non-strategic, price-taking firms.

Because of the electricity industry's long history of regulation, there is very little existing work that attempts to estimate the competitiveness of an electricity market based upon actual observed outcomes. Most of the work to date has instead relied upon market simulations that are based upon some form of oligopoly equilibrium. Green and Newbery (1992) apply the supply function equilibrium concept to the electricity market in England and Wales, while Schmalensee and Golub (1984) and Borenstein and Bushnell (1999) utilize the Cournot equilibrium assumption to simulate market outcomes for the continental U.S. and California markets, respectively. Borenstein, Bushnell, and Stoft (1998), Oren (1997), and Cardell, Hitt, and Hogan (1997) all utilize the Cournot assumption to analyze the impact of binding transmission constraints on strategic competition in the electricity industry.

Wolfram (1998 and 1999), Wolak and Patrick (1996), and Wolak (1999) are, to our knowledge, the only studies that estimate the actual levels of, rather than potential for, market power in the electricity industry. Wolfram (1999), using an approach similar to

that applied here, estimates the extent to which one component of price paid to generators for energy – the system marginal price (SMP) – exceeds the marginal cost of the most expensive unit dispatched in the U.K. electricity market. She does this by reconstructing the cost curve of producers and comparing the resulting intersection of this marginal cost curve with demand to the actual SMP. Wolak and Patrick examine the impact of plant availability decisions by firms on the price paid to generators, which in the U.K. includes a payment for making capacity available and an uplift charge in addition to the SMP. They find evidence that the two largest generating firms profited considerably from declaring the output of some units unavailable at certain times. This lack of availability was correlated with the occurrence of market conditions that would make such a strategy particularly profitable.

In this paper, we analyze prices, generator variable costs, and supply quantities to measure the degree to which California wholesale electricity prices may have exceeded competitive levels. We begin in section II by discussing the concept of market power in industries with limited production capacity, inelastic demand, and very costly storage. In particular, we point out the possible confusion of competitive, peak-load pricing with the exercise of market power. We explain how these outcomes can be distinguished from one another and the importance of doing so.

In section III, we describe the most relevant details of the California electricity market and describe a general technique for estimating market power, given the institutional details of this market. In section IV, we describe our estimation technique in detail, addressing each component of the market and outlining the assumptions made in implementing the analysis. We try to take a conservative approach, interpreting the data in a way that would be likely to understate the degree of market power exercised. In section V, we present our results and discuss their significance in light of the assumptions made. We conclude in section VI.

## II. Market Power Analysis

### *A. The Behavior of Price-Taking Firms and Competitive Markets*

A firm exercises market power when it reduces its output or raises the minimum price at which it is willing to sell output (its offer price) *in order to change the market price*. A firm that is unable to exercise market power – a price taker – is willing to sell output so long as the market price is above the firm’s marginal cost of producing and selling the output, properly calculated. In the electricity industry, the marginal cost of production will include

both the variable costs due to fuel and the other variable operating and maintenance costs, *i.e.*, all costs that actually vary with the quantity of power that the plant produces.

Still, the cost of selling a unit of electricity can be greater than the simple production costs if the firm has an *opportunity cost* that is greater than its production cost, such as the revenue the firm would get from selling power or reserve capacity in a different location or market. For instance, a power producer in the northwest U.S. can sell power into California or can sell power in its own location or some other location in the Western Systems Coordinating Council (WSCC). Generators also have the option to sell capacity in any of the ISO's ancillary services markets where their capacity can meet the technical requirements to provide that service. If the producer expects that it can earn \$21/MWh selling the power in another location, and if transmission were available and no more costly than transmission into California, then it would not be willing to offer power in California for any price less than \$21/MWh. This would not indicate that the firm is exercising market power: the firm is not raising its offer price in California in order to raise the California market price. It is simply choosing to sell its power where price is highest. Of course, a high price in an alternative market can reflect market power in that market, resulting in the transmittal of high prices across markets by the response of competitive suppliers.

Because a price-taking firm sells its output at the market price, and that market price is usually strictly above the marginal production cost of almost all the output it produces, price-taking firms can still cover their full costs of production, including their going-forward fixed costs of operation. If the industry marginal cost (*i.e.* supply) function, which is the aggregation of all firms' supply functions, exhibits distinct steps – as is often thought to be the case in the electricity industry – then a competitive market equilibrium may be reached at which the price exceeds the marginal cost of even the last unit of output produced, but is still less than the marginal cost of producing one more unit of output. Similarly, if all units of production are in use, then the intersection of supply and demand can occur at a price above the marginal production cost of any unit. That is, *in the absence of market power by any seller in the market, price may still exceed the marginal production costs of all facilities producing output in the market at that time.* Price above marginal production cost of all operating plants is not in itself proof of market power abuse. However, offering power at a price above marginal production (or opportunity) cost, or failing to generate power that has a production cost below the market price, is an indication of market power abuse.

Some analysts of the electricity industry have raised the concern that price-taking

behavior on the part of every firm is simply too strict of a standard to be used as a benchmark. They argue that it is unrealistic to think that no market power will exist, because market power exists in most markets. We recognize this fact and that even with some market power present in the electricity industry there may be lower retail prices than under the historical vertically integrated regulated utility regime. Nonetheless, we must also point out that there are many markets in which virtually no market power exists: most agricultural and natural resource markets, for instance. These industries are notable for producing virtually homogenous products and selling them over a large geographical area, characteristics that bear an important similarity to the electricity industry. Thus, while the presence of some market power should not be grounds for declaring deregulation of electricity generation a failure, neither should it be accepted as inevitable based on observations from other industries.

### *B. The Behavior of a Firm with Market Power*

In contrast to price-taking firms, a firm with market power can unilaterally influence the market price by withholding output at the margin or raising the price at which it is willing to sell this marginal output. By taking such actions, the firm risks selling less, but it raises the price it will get for all output that it does sell.

Two factors are critical in determining the extent to which such unilateral exercise of market power is likely to be profitable for the firm: the sensitivity of market demand to price changes and the sensitivity of the supply of other producers to price changes. If the market demand is very price elastic, then reducing output (or raising the offer price on marginal units), will have very little impact on price as consumers will react to even a very small price increase by reducing consumption enough to match the reduced output. If demand is very inelastic, then only a large price increase would cause enough demand reduction, in which case it is more likely to be profitable for a producer to reduce its supply.

Likewise, if the supply of other producers is very elastic, then one firm reducing output (or raising the offer price on marginal units), will have very little impact on price as other suppliers will react to even a very small price increase by increasing their output enough to match the first firm's reduced output. Inelastic supply of other producers, in contrast, implies that it is more likely to be profitable for a producer to reduce its supply.

Economists generally believe that the ability to exercise market power unilaterally is correlated, albeit imperfectly, with a producer's market share. If, for instance, a firm supplies 1% of the total output in a market, then if it were to reduce output in order to raise its profits, it would run into two problems. First, demand would not have to adjust

very much to absorb the loss of part of the firm's production so price would not have to rise very much. Second, with 99% of the output produced by other companies, they probably could expand their output by the small amount necessary to replace the firm's reduced production without driving up their own costs appreciably. So, even a slight increase in price would probably bring forth a replacement of the reduced supply, undermining the firm's intent when it reduced its supply. In other words, a firm with a very small market share is more likely to see demand as relatively price elastic, and the supply of other firms as relatively price elastic, over the range of output that it might contemplate removing from the market or offering to sell only at a high price.

In contrast, a firm with a large share of the market is more likely to be able to lower its output, or raise the offer price on part of its output, in a way that is difficult for demand to adjust to because the firm's action constitutes a significant share of the entire market production. Likewise, other companies may find it much more difficult to replace the output reduction of a large firm without themselves running into production constraints that would drive up their own costs.

The connection between market share and market power, however, can be overstated.<sup>1</sup> In some situations, a firm with even a relatively small market share might find it profitable to restrict its output or raise its offer price on marginal output. Think about a situation in which demand is not at all price elastic, in the extreme a situation in which buyers don't even know the price at the time they are buying. Then add to that a situation in which other factors, such as a very hot day, have driven up the quantity of electricity that buyers want to consume to the extent that virtually every company is operating at its absolute production limit. That is, the price elasticity of supply from other producers is very low because they are at or near their capacity constraints. In that case, a firm with even a small share of the market might be able profitably to reduce output or raise its offer price.

This situation is particularly relevant to markets in which demand is highly variable – so that there are times when virtually all production capacity is necessary to meet contemporaneous demand – and the output cannot be stored – so that inventories are not available as an alternative supply source if a firm tries to exercise market power. For this reason, electricity markets are more vulnerable to the exercise of market power than are, for instance, gasoline markets.

When a firm does exercise market power, all firms in the market benefit. In fact, other

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<sup>1</sup> See Borenstein, Bushnell, and Knittel (1998), for a more detailed discussion of the applicability of concentration measures to market power analysis in electricity markets.

firms may benefit proportionally more than the company that is exercising market power. Thus, even a price-taking firm in a market has a strong incentive to resist any attempts to detect or undermine the exercise of market power.

Thus far, we have discussed only situations in which a firm unilaterally exercises market power. Antitrust law is more often concerned with collusive attempts to exercise market power. Unfortunately, many of the attributes that facilitate collusion are present in electricity markets: In most markets, firms play repeatedly, interacting on a daily basis, so there is opportunity to develop subtle communication and collusive strategies. The payoff from cheating on a collusive agreement may be limited due to capacity constraints on production, though for the same reason, the ability to punish defectors may be limited. Finally, the industry has fairly standardized production facilities, so homogeneous costs may make it easier for firms to reach tacit or explicit collusive behavior. All that said, we have not explored the question of tacit or explicit collusion among firms in the California market. Rather, in this paper we focus on market outcomes.

### *C. The Consequences of Market Power*

An important fact to consider when discussing market power in the California electricity market is that, during the 1998-2001 transition period, end-use consumers are insulated from energy price fluctuations by the Competition Transition Charge (CTC). The CTC is a mechanism that was implemented along with the restructuring of the industry in order to allow the incumbent utilities to recover their stranded generation costs. The vast majority of end-use consumers currently face fixed rate schedules that were also imposed along with the CTC. Even “direct access” consumers, who buy energy from some source other than their incumbent utility, are insulated from wholesale energy price fluctuations in the short-run by the CTC. This is because the stranded cost component paid by all consumers is calculated in a way that moves inversely to the energy price. The higher the energy price, the lower the CTC payment for that hour. Thus, the CTC greatly lessens the elasticity of final consumer demand with respect to the price of energy.

When the CTC is considered, the exercise of market power by suppliers results, *in the short run*, in a transfer of wealth from the incumbent utilities, rather than end-use consumers, to other suppliers.<sup>2</sup> However, because of the way the CTC has been designed, higher energy prices are likely to delay its expiration, and thereby delay a significant drop in the rates of end-users. It now appears that this is certainly the case for SDG&E customers

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<sup>2</sup> It is also worth noting that the incumbent utilities still sell a significant share of the energy produced in California, so the transfer occurs only on the power they buy from other generators.



and very likely to be the case for customers of PG&E and SCE. In that case, by delaying the end of the CTC, the effect of market power exercised today in the California market is to transfer wealth from end users to non-utility generators.

Even if we ignore the issue of transfers between utilities, consumers, and producers, market power can still yield negative consequences. In a market with a diverse set of firms, the exercise of market power by some firms will decrease the productive efficiency of the industry. While each firm will want to produce whatever quantity it decides to sell in the most efficient way possible, a firm exercising market power will restrict its output so that its marginal cost is below price (and equal to its marginal revenue), while other firms that are price-taking will produce units of output for which its marginal cost is virtually equal to price. Thus, there will be inefficient production on a market-wide basis as more expensive, competitive, production has been substituted for less expensive production owned by firms with market power. This is precisely what Wolak and Patrick (1996) describe as occurring in the U.K. market, where higher cost combined-cycle gas turbine generators owned by new entrants provide baseload power that could be supplied by coal-fired plants which are being withheld by the two large generators exercising market power.

In addition, several recent analyses have demonstrated that the exercise of market power in an electricity network can greatly increase the level of congestion on that network.<sup>3</sup> This increased congestion creates negative impacts on both the efficiency and the reliability of the system. Market power can also lead firms to utilize their hydro-electric resources in ways that decrease overall economic efficiency.<sup>4</sup>

Lastly, it is important to remember that current electricity prices influence long-term decision-making in a way that can seriously impact the economy. While it has been pointed out that high prices should spur new investment and entry in electricity production, these investments may not be efficient if motivated by high prices caused by market power, which indicates a need not for new capacity, but for the efficient use of existing capacity. Conversely artificially high prices can lead some firms *not* to invest in productive enterprises that require the use of electricity. The deregulation of the electricity industry was largely motivated by the hope that a competitive market would lead to more prudent investment decisions than those produced under regulation. For this hope to be realized, market prices must reflect the underlying economic conditions of the industry.

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<sup>3</sup> See Borenstein, Bushnell and Stoft (1998), and Cardell, Hitt and Hogan (1997), Bushnell (1999), and Joskow and Tirole (1999a and 1999b).

<sup>4</sup> See Bushnell (1998).

#### *D. Distinguishing Competition from Market Power*

The previous subsections have explained how prices are determined in competitive markets and in markets in which some firms exercise market power. In both cases, prices can end up being higher than the marginal costs of all generating units producing power at a point in time. In analyzing the electricity market in California, it is critical to be able to distinguish between competitive market pricing and pricing that results from the exercise of market power. Two indicators clearly distinguish these possible market results and each leads to a distinct estimation technique.

1. In a competitive market, a firm is unable to take any action, including output decisions or offer prices, that will significantly affect the price in a market.
2. In a competitive market, a firm is always willing to sell a unit of output so long as its cost of selling that unit is less than the price it receives for that unit. Its offer price will always be its marginal cost, which will be the greater of its marginal production cost or its opportunity cost of selling the power elsewhere.

While these two indicators can be stated clearly, it is more difficult to apply them using the available data. The first indicator suggests a method of estimation that involves studying the specific actions of the various firms in the markets. In particular, one can examine, the bidding and output decisions of each unit or firm in the market to detect successful attempts to manipulate prices. This is the general approach used by Wolak and Patrick (1996), Wolfram (1998), Wolak (1999), and Bushnell and Wolak (1999).

The second indicator yields implications that can be tested by studying market-wide, rather than unit-specific behavior. As such, these tests are less vulnerable to the arguments of coincidence, bad luck, or ignorance that can be applied to the actions of a specific generator. In general, we test whether market prices are consistent with the hypothesis that the market as a whole is acting in a competitive manner. This approach is less informative about the specific manifestations of market power, but is effective for estimating its scope and severity. This is the approach used in Wolfram (1999), and the one that we adopt in this paper.

A potential drawback of this approach is that it captures all inefficiencies in the market, some of which may not be due to market power. If, for instance, the ISO systematically held low-cost generators out of production simply due to a faulty dispatch algorithm, that would impact the estimate of market power. The California market clearly still has a number of design flaws that contribute to inefficient dispatch and market pricing. For the great majority of these, however, the flaw would be fairly benign if firms acted as pure

price takers, rather than exploiting these design flaws to affect the market price. Still, the estimates must be taken with the caveat that they include failures to achieve competitive market prices for reasons other than market power, including bad judgment and confusion on the part of some generators or market-making institutions.

### III. The California Electricity Market

The market for electrical energy in California is characterized by the repeated interaction of several firms and institutions. The two primary institutions are the California Power Exchange (PX) and the California Independent System Operator (ISO). The PX runs a day-ahead and hour-ahead market for energy utilizing a double auction format.<sup>5</sup> Firms can and do submit both demand and supply bids. In the day-ahead market, which is by far the largest market run by the PX, firms may bid into the PX offers to supply or consume power the following day for any or all of the 24 hourly markets. Although they were not originally envisioned as such, the PX markets are effectively financial, rather than physical, markets. As explained below, this is because firms can purchase or sell electricity in real time to change their day-ahead PX positions in what is essentially an energy spot market run by the ISO.<sup>6</sup> In addition to the PX, other institutions, known as “scheduling coordinators,” (SCs) can submit the results of completed wholesale energy transactions to the ISO. Each SC, including the PX, is formally required to submit a “balanced” schedule, *i.e.* one in which supply equals demand.<sup>7</sup>

The ISO is responsible for coordinating the usage of the transmission grid and ensuring that the cumulative transactions, or schedules, do not constitute a reliability risk. As the institution responsible for the real-time operation of the electric system, the ISO must also ensure that aggregate supply is continuously matched with aggregate demand. In doing so, the ISO operates an “imbalance energy” market, which is also commonly called the real-time energy market. In this market, additional generation is procured in the event of

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<sup>5</sup> The PX double auction takes bids from both suppliers and consumers and sets a market clearing quantity at the intersection of the resulting supply and demand curves implied by those bids. Since the time of our sample, the PX has changed its “hour-ahead” market (which actually closed three hours ahead of the operation hour) to a “day-of” market, which operates three times daily, each time for different designated hours of the day.

<sup>6</sup> The transaction costs of trading in the PX relative to the ISO, or other institutions is a source of considerable confusion. For the purposes of this discussion we consider these differences to be negligible relative to the costs of the underlying commodity, electrical energy.

<sup>7</sup> In reality, schedules are seldom truly balanced due to the impact of transmission line losses. The protocols also allow for “inter-SC” trades, which permit an additional fudge factor on the balancing requirement.

a supply shortfall, and generators are relieved of their obligation to provide power in the event that there is excess generation being supplied to grid. Like the PX, this market is run through a double auction process, although of slightly different format. Firms that deviate from their formal schedules are required to purchase (or sell) the amount of their shortfall (or surplus) on the imbalance energy market.<sup>8</sup> To date, no further penalties are assessed for deviating from an advance schedule. The imbalance energy market therefore serves as the *de facto* spot market for energy in California.

The ISO also operates markets for the acquisition of reserves and for the relief of constrained transmission interfaces. These reserves are purchased through a series of auctions that determine a uniform price for the *capacity* of each reserve purchased. Most of this reserve, or stand-by, capacity is also available to provide imbalance energy, and therefore will impact the spot price. A reserve unit would therefore earn a capacity payment for being available and, if called upon in real-time, an energy payment for actually providing energy.

Regulation, the most short-term reserve, is provided by generation that is equipped to respond automatically to voltage fluctuations. Due to the nature of this reserve service, and to metering limitations, generation capacity providing regulation reserves cannot set, or earn, the imbalance energy price. As we describe below, we therefore consider units providing regulation services to be “held-out” of the market.

#### A. Market Structure

The California electricity market at first glance appears remarkably unconcentrated. The former dominant firms, Pacific Gas & Electric (PG&E) and Southern California Edison (SCE) divested the bulk of their gas-fired capacity in the first half of 1998. SCE retained only a small proportion of its capacity not already covered under regulatory side agreements. The divestitures before the summer of 1998 left the gas-fired generation assets in California more or less evenly distributed between seven firms. The generation capacity of these firms is listed in Table 1.

As can be seen from Table 1, PG&E was the largest generation company during the summer of 1998. The seemingly dominant position of PG&E is offset somewhat by outside regulatory agreements. All of the nuclear generation in California is treated under rate settlements separate from the PX market. Also the incumbent utilities in California were the largest buyers of electricity during this time period. Because of a freeze on

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<sup>8</sup> The purchasing and selling is in fact done by the ISO itself, and accounts are settled through an ex-post adjustment.

**Table 1: California Generation Companies (MW)  
1998 Nameplate Capacity**

Firm	Fossil	Hydro	Nuclear
PG&E	3700	5728	2160
SCE	1990	1002	2327
SDG&E	1951	0	430
Duke	2650	0	0
AES/Williams	3756	0	0
Houston Industries	3770	0	0
Dynegy	1584	0	0
Thermo Ecotek	256	0	0

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the rates of end-users and the effects of the Competition Transition Charge (CTC), the incentives of the incumbent utilities are difficult to interpret. If a utility distribution company (UDC) were concerned that it may not recover all of its stranded costs within the 4-year transition period during which the CTC were in force, then higher energy prices would further jeopardize that utility's chances of recovering those costs. On the other hand, if the UDC were confident that it would recover all of its stranded costs within the 4 year transition period, then that company would be largely indifferent to energy prices on the buy side. The generation side of these firms would clearly benefit from higher prices. The net impact on these firms of higher electricity prices therefore depends upon the firms' prospects for stranded asset recovery as well as the extent to which these firms were net buyers or sellers.

#### *B. Analyzing Market Power in California's Electricity Market*

Critical to studying market power in California is an understanding of the economic interactions between the multiple electricity markets in the state. Simply put, participants will move between markets in order to take advantage of higher (for sellers) or lower (for buyers) prices. For instance, if the ISO's real-time imbalance energy price were usually higher than the PX day-ahead price, then sellers who saw this would reduce the amount of power they sell in the PX and sell more in the ISO imbalance energy market. They would do this either by reducing the amount of power they bid into the PX or by raising the offer price on that power. At the same time, buyers would be moving in the opposite direction, trying to buy more in the PX and less in real time. Both of these attempts to arbitrage the PX/ISO price difference would have the effect of raising the PX price and lowering the ISO real-time price, thereby eliminating the price differential.

**Table 2: Average Zonal Energy Prices (\$/MWh)  
North of Path 15 (NP15)**

Month	PX	ISO	Mean PX-ISO	Std Dev PX-ISO
June	12.25	8.38	3.86	9.68
July	32.51	26.08	6.43	29.57
August	38.80	45.39	-6.59	36.92
September	33.97	40.77	-6.80	30.26
October	27.85	35.24	-7.39	9.96
November	27.24	30.57	-3.34	6.68
December	30.42	29.58	0.84	20.37

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**South of Path 15 (SP15)**

Month	PX	ISO	Mean PX-ISO	Std Dev PX-ISO
June	12.34	8.38	3.95	9.42
July	33.14	25.98	7.16	30.25
August	39.96	43.53	-3.56	36.96
September	33.24	35.13	-1.88	29.68
October	23.92	27.78	-3.85	11.28
November	22.91	24.08	-1.16	7.84
December	26.73	26.13	0.60	17.96

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For this reason, it is not useful to study the PX market, or any other of the California markets, in isolation. The strong forces of financial arbitrage mean that any change in one market that affects that market price will spill over into the other markets. For instance, if a generator selling power in the PX market were to suffer an outage that prevented it from offering power in the PX market, this would raise the price in the PX, but it would also attract sellers from other markets and encourage PX buyers to buy elsewhere until the PX price was once again in line with the price in other California electricity markets.

Table 2 contains sample means of the monthly zonal PX price and real time energy price for the North of Path 15 (NP15) and South of Path 15 (SP15) zones. To investigate the arbitrage relationship between the ISO and PX, we also compute the sample mean of the hourly difference between the day-ahead zonal PX price and ISO imbalance zonal price for these two congestion zones. We find that for all months and both congestion zones, the sample standard deviation of this difference is significantly larger than its sample mean,

in some months by an order of magnitude.<sup>9</sup>

This interaction of the different California electricity markets means that we must study the entire California energy market in order to analyze market power in the state. For this reason, in the analysis below we look at the entire generation in the ISO/PX service area regardless of whether the power from a generating plant is being sold through the ISO, the PX, or some other SC. This recognition of the California power market as being effectively an integrated market due to strong arbitrage forces yields two other important insights.

*Monoposony Power:* The California market has a few very large buyers of electricity, the large utility distribution companies (UDCs). This has led to concern that buyers may be able to exercise monoposony buying power in the energy market, thereby depressing the price of electricity. When California is viewed as a series of closely integrated electricity markets, however, it appears much less likely that monoposony power will be a significant issue.

It is well understood that in a single market, a buyer with completely inelastic demand cannot exercise monoposony power, regardless of the quantity it is purchasing. The UDCs have a demand that is virtually price inelastic: they are required to provide the amount of power that their customers demand and those customers do not see the hourly PX or ISO energy prices, only a fixed retail price per KWh that does not vary with either the PX or ISO price for that hour. Particularly prior to 2001, during the retail rate freeze transition period when this price is fixed at 10% of its 1997 level, the customers have no reason to respond to hourly prices, so the UDCs have virtually no flexibility in the total energy they must purchase. Moreover, the vast majority of the interruptible power supply contracts held by the incumbent utilities during the summer of 1998 did not allow curtailment of power for economic reasons such as high PX or real-time prices.

Yet, an analysis of a single market within California, such as the PX day-ahead market, might lead one to think that a buyer could, by reducing its purchases in the PX, consistently lower the PX price and reduce its power purchase costs. But this is a fallacy based on a failure to recognize the interactions of the markets. If a large buyer reduced its power purchases in the PX day-ahead market, it would have to make up the difference in the PX day-of or ISO supplemental energy market (or by buying through some other SC if

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<sup>9</sup> Borenstein, Bushnell, Knittel, and Wolfram (1999) test for price convergence between the ISO and PX markets. They find that the market prices have gradually converged and have been statistically indistinguishable in most months since December 1998.

that were allowed), since the buyer's total purchases are insensitive to price. If the buyer purchased more power in the supplemental energy market and less in the PX day-ahead market – and no other participants changed their behavior – then the supplemental energy price would rise above the PX day ahead price. This would set up a profitable opportunity for sellers in the PX to switch to selling in the ISO's supplemental energy market and buyers in the supplemental energy market to buy more in the PX day-ahead market. Such movement would occur until the prices in the two markets were once again equalized.<sup>10</sup> This would occur where the aggregate of the supply curves in the day-ahead and supplemental markets intersects the aggregate of the demand curves in the two markets. The result would be no change in the market price in either market and no change in the power purchasing cost to the UDC.

Thus, in equilibrium, a pure buyer with an inelastic total demand for power cannot exercise market power in the California electricity market by moving its purchases between the various available venues for trading power.<sup>11</sup> To the extent that a UDC owns its own generation, however, it may be able to exercise monopsony power by reducing *net* purchases. If an IOU in California had some production capacity that has cost above the market clearing price, it could drive down the market price by bidding in that capacity at below its true marginal cost. It is possible that the reduced price on the energy the IOU does buy could produce greater savings than the loss it would take from running a unit when price is below its MC. If this did occur during the time frame we study in California, it would tend to reduce our estimates of market power. Note, however, that this would require the UDC to have generation with costs near the market-clearing price. Because of the divestiture of the majority of gas-fired units owned by SCE and SDG&E before the summer of 1998, PG&E is the only UDC with any significant ability to do this.

In addition, it is not at all clear that the UDCs would have the financial incentive to exercise monopsony power in this way. As explained earlier, if the firm believes that it

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<sup>10</sup> In actuality, they would have to be equal *in expectation*. A seller in the PX would have to expect that it would earn the same price, on average, by waiting and selling in the supplemental energy market.

<sup>11</sup> One could argue that this could still happen as the buyer surprises the market occasionally by moving its purchases from one market to another. It is not clear that such behavior would be expected to lower the buyer's total energy cost. The reason is that once sellers realized the buyer was doing this they would attempt to figure out when it would happen and move their supply in accordance with the expected demand shifts. Sometimes they would be wrong and would move supply out of the PX when no demand shift was occurring, thereby *raising* the UDC's total energy cost. Due to the convexity of the aggregate supply bid curves – increasing at an increasing rate bid prices as a function of aggregate bid quantity – in both the PX and ISO markets, such a strategy by demanders of electricity is more likely to increase expected electricity purchase costs relative to a more certain demand scenario.



will recover all of its stranded investment before the cutoff date in 2001, then its marginal payments for power are born in large part, or completely, by end users. If the price of wholesale power is passed through to customers on the buy side, but the revenues are partially kept by owners of the UDC on the sell side (since they still own some market-rate generation), then the UDC will have an incentive to push the price of wholesale power *up* not down.

The important point here, besides the direct analysis of monopsony, is that understanding the electricity industry in California requires an integrated view of all available markets and an appreciation the powerful forces of arbitrage among the markets.

*Price Caps:* The integrated view of these markets also helps to understand how price caps affect the market. In analyzing price caps, however, the order in which the markets clear becomes important. This is because a buyer or seller who doesn't transact in one market can always transact in a later market, but not vice versa. Put differently, a player in these markets can credibly commit to transact in the last market, but has a much more difficult time credibly committing to transact in any market that clears earlier.

The effect of this is easily illustrated in a slightly simplified version of the California market. Assume that the only markets available are the day-ahead PX market and the ISO's imbalance energy market. Consider a case in which, absent any price caps, both markets would clear at a price of \$300/MWh. This high price could result under competition because supply available to the market is unusually low due to unforeseen outages or demand is unusually high due to weather or other factors. It could also occur as the result of market power being exercised.<sup>12</sup> Now assume that a price cap of \$250 is imposed in the PX market. Clearly no supplier would be interested in selling its power in the PX, seeing that they expect to earn a price of \$300 in the imbalance market. Consumers really have no choice in the matter, because suppliers know that whatever power is not purchased in the PX must be bought in the imbalance market. Therefore, a price cap in the PX would be completely ineffective absent a similar cap in the imbalance market. The only effect of a price cap in the PX would be to move transactions out of the PX and into the ISO's imbalance energy market.

Contrast this with the current situation, in which there is a price cap of \$250/MWh on imbalance energy prices, but a much higher cap of \$2500/MWh on PX prices. Now it is buyers who prefer the imbalance energy market whenever prices are expected to exceed

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<sup>12</sup> It should be clear by now that the supply and demand we are speaking of are the aggregates across all markets, since arbitrage would determine how much is actually transacted in each of the markets.

\$250 in the PX. As such, we would expect to never see prices above \$250 in either market. To prevent prices of \$250 in the PX, buyers simply bid demand curves into the PX that have zero demand at \$250, because they know that is the maximum price at which they can purchase all of their load at in the imbalance energy market. Sellers would prefer to sell at the higher PX price, but given the bidding behavior of demanders, the price that clears the PX will never be greater than \$250. In fact, during the period June 1, 1998 to December 31, 1998 the highest unrestricted PX price has never exceeded \$200/MWh. This discussion demonstrates that, because of the sequential nature of the markets, the only price cap that will significantly affect the price actually paid for power is the one on the last market to clear.

*Opportunity Costs and Market Power:* When analyzing the extent of market power in the energy market, we must consider the effect of prices in other markets in which the same suppliers compete. Those generators that are eligible can earn capacity payments for providing ancillary services, as well as energy payments for generating in real time, if they bid successfully into one of the ancillary services markets, excluding regulation. Ancillary services therefore represent an alternative use of much of the generation capacity in California. It is therefore necessary to consider the interaction between the energy and ancillary services markets.

It is important to recognize that the pool of suppliers available to ancillary services markets is very similar to that available to the energy markets. The main difference is that some generators are physically unable to provide certain ancillary services. Thus there are fewer potential suppliers for some ancillary services than there are for energy. We therefore would expect that the energy market would be at least as competitive as the ancillary services markets, and probably more so. It follows that price-cost margins would be at least as great if not greater in ancillary services markets than in energy markets. In fact the ancillary services markets, for a variety of reasons, appear to have been significantly less competitive than the energy market during the time period of our study.<sup>13</sup>

The other prominent opportunity for the usage of California generation is the supply of power to neighboring regions. Higher prices for energy outside of California could produce a result in which all generators within California were able to earn prices above their marginal cost, even if they behaved as price takers. For this to be the case, the California ISO region would have to be a net exporter of power. During our sample period, such conditions arose only in a total of five hours, four in June and one in October. Even in

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<sup>13</sup> See Wolak, Nordhaus, and Shapiro (1998)

these hours, the maximum net quantity of energy exported out of the ISO control area in any hour was a modest 540 MWh. Therefore, export opportunities outside of the ISO are unlikely to explain the price-cost margins detailed below.

#### **IV. Measuring Market Power in California’s Electricity Market**

The fundamental measure of market power is the margin between price and the marginal cost of production. As discussed above, if no firm were exercising market power, then all units with marginal costs that are below the market price would be operating. Even in a market in which some firms exercise considerable market power, the *marginal* unit that is operating could have a marginal cost that is equal to the price. When a firm with market power reduces output from its plants or, equivalently, raises its offer price for its output, its production is usually replaced by other, more expensive generation that may be owned by non-strategic firms. Thus, although the marginal cost of the most expensive unit operating at a given time may indeed equal the market price, market power would still be present if there were other generators with costs below that price that are choosing not to supply power.

In estimating a price-cost margin in this paper, we therefore must estimate what the marginal cost of serving a given level of demand would be if all firms were behaving as price takers. Unlike most industries, there is enough information available about the costs of the generators to directly estimate the price-cost margin. That is not to say that this measurement is without difficulty. There are many factors that add complexity to the task of estimating the marginal cost of electricity production at a given output level. In addition, one must be careful in defining the market clearing quantity upon which these marginal cost estimates will be based. In the following subsections we describe the assumptions and data used for generating estimates of the marginal cost of supplying electrical energy in California.

##### *A. Market Clearing Prices and Quantities*

As described above, the California electricity market in fact consists of several parallel and overlapping markets. Fortunately, our assessment of the overall degree of market power is simplified by the fact that most sellers and buyers are free to participate in any of these markets. With this fluidity of market participants across markets, we would expect that the market clearing prices from each of these markets to be equal in expectation.<sup>14</sup>

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<sup>14</sup> One might be concerned that this arbitrage would not hold in light of the requirement, established in

Given that generation and distribution firms, as well as other power traders, can arbitrage the expected price of energy across these commodity markets, the price of energy in one market should be an accurate signal of its price in the other markets. In the calculations presented below, we rely upon the unconstrained PX day-ahead energy price as our estimate of energy prices in any given hour. We chose to rely upon the PX unconstrained price because it represents the market conditions most closely replicated in our estimates of marginal costs. In particular, we do not consider the costs of transmission congestion or local reliability constraints in our estimates of the marginal cost of serving a given load. The PX unconstrained price is also derived by matching aggregate supply with aggregate demand without considering these constraints. The resulting market clearing price therefore reflects an outcome that would occur in the absence of transmission constraints, just as our cost calculations reflect the outcome in a market in which all producers are price takers and there are no transmission constraints.<sup>15</sup>

The interaction of these energy markets also permits us, indeed requires us, to use the *systemwide aggregate demand* as the market clearing quantity upon which we base our marginal cost estimates. This level therefore includes consumption from the PX, other SCs, and any ‘imbalance energy’ demand that is provided through the ISO real-time market. Consumption from all of these markets is in fact metered by the ISO, which in turn allocates charges amongst SCs during an ex-post settlement process. We are therefore able to obtain these aggregate market clearing quantities from the ISO settlement data.

The acquisition of reserves by the ISO also requires discussion here. Since the ISO is effectively purchasing considerable extra capacity for the provision of reserves, it might seem appropriate to consider these reserve quantities as part of the market clearing demand level. However, with the exception of regulation, as described below, all other reserves are normally available to meet real-time energy needs if scheduled generation is not sufficient to supply market demand.<sup>16</sup> Thus, the real-time energy price is still set by the interaction

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the legislation facilitating the deregulation of the electricity industry in California (AB 1890), that the three investor-owned utilities buy all of their energy from the PX. Given the financial nature of the PX market, the full meaning of this requirement is somewhat ambiguous. More importantly, it appears that the wording of AB 1890 has not prevented the IOUs (and others) from arbitraging energy prices across the PX and ISO energy markets.

<sup>15</sup> We would like to emphasize again that we use the PX price as representative of the prices in *all* California electricity markets. This is not a study of the PX market and the market power we find is not limited to the PX market. It is present in all California electricity markets.

<sup>16</sup> Due to reliability concerns, the ISO at times has not utilized spinning and non-spinning reserves for the provision of imbalance energy (see Wolak, Nordhaus, and Shapiro, 1998). The conditions under which this occurs are somewhat irregular and difficult to predict. For the purposes of this analysis we have assumed that these forms of reserve are utilized for the provision of imbalance energy.

of real-time energy demand – including quantities supplied by reserve capacity – and all of the generators that can provide real-time supply. Therefore, we consider the real-time energy demand in each hour to be the quantity that must be supplied and capacity selected for reserve services to be part of the capacity that can meet that demand and, as such, to be part of our aggregate marginal cost curve.

The most responsive form of reserve is regulation. Units providing regulation services are required to automatically adjust their output levels in a way that allows the ISO to continuously balance supply and demand. Unlike the other forms of reserve, regulation capacity, is, in a way, held out of the imbalance energy market and its capacity could therefore be considered to be unavailable for additional supply. For this reason we add the *upward* regulation reserve requirement, which at times reaches 11% of load, to the market clearing quantity for the purposes of finding the overall marginal cost of supply.<sup>17</sup>

### *B. Marginal Cost of Thermal Generating Units*

In estimating the marginal cost of production for an efficient market, we use the fuel costs of each thermal generating unit as well as the variable operating and maintenance (O&M) cost of each thermal unit. The marginal cost of each thermal unit is calculated by using its average heat-rate multiplied by fuel cost and adding an estimate of variable O&M to that product. These cost estimates are detailed in the appendix. Figure 1 illustrates the aggregate marginal cost curve for thermal generation resources located in the ISO control area that are not considered to be “must-take” resources (see below).

The supply curve illustrated in Figure 1 does not include any adjustments for “forced outages.” Generation unit forced (as opposed to scheduled) outages have traditionally been treated as random, independent events that, at any given moment, may occur according to a probability specified by that unit’s forced outage factor. In our analysis, each generation unit,  $i$ , is assigned a constant marginal cost  $mc_i$  – reflecting that unit’s average heat rate, fuel price, and its variable O&M cost – as well as a maximum output capacity,  $cap_i$ . Each unit also has a forced outage factor,  $fof_i$ , which represents the probability of an unplanned outage in any given hour. Because of concern that fuel costs for in-state fossil units might

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<sup>17</sup> Regulation reserve is procured for both an upward (increasing) and downward (decreasing) range of capacity. The ISO needs to be able to continuously increase and decrease the output levels of certain units in order to balance the system. Since the generation units that are providing *downward* regulation are, by definition, producing energy, the capacity providing downward regulation should not be considered to be held out of the energy market. Note also that by adding regulation needs to the market demand, we are implicitly assuming that all regulation requirements are met by generation units with costs below the market clearing price. To the extent that some units providing regulation would not be economic at the market price, this assumption will tend to bias downward an estimate of market power.

differ depending on access to fuel sources and changing market conditions during the period we study, we used weekly average prices of natural gas at a number of different locations in the state (see appendix).

Because the aggregate marginal cost curve is convex, estimating aggregate marginal cost using the expected capacity of each unit,  $cap_i * fof_i$ , would understate the actual expected cost at any given output level.<sup>18</sup> We therefore simulate the marginal cost curve that accounts for forced outages using Monte Carlo simulation methods. If the generation units  $i = 1, \dots, N$  are ordered according to increasing marginal cost, the aggregate marginal cost curve produced by the  $j_{th}$  iteration of this simulation,  $C_j(q)$ , is the marginal cost of the  $k_{th}$  cheapest generating unit, where  $k$  is determined by

$$k = \arg \min x \mid \sum_{i=1}^x I(i) * cap_i \geq q. \quad [1]$$

where  $I(i)$  is an indicator variable that takes the value of 1 with probability of  $1 - fof_i$ , and 0 otherwise. For each hour, the Monte Carlo simulation of each unit's outage probability is repeated 100 times. In other words, for each iteration, the availability of each unit is based upon a random draw that is performed independently for each unit according to that unit's forced outage factor. The marginal cost at a given quantity for that iteration is then the marginal cost of the last available unit necessary to meet that quantity given the unavailability of those units that have randomly suffered forced outages in that iteration of the simulation.<sup>19</sup>

We did not adjust the output of generation units for scheduled outages. This is because the scheduling, and duration of planned outages for maintenance and other activities is itself a strategic decision. Wolak and Patrick (1996) present evidence that the timing of such outages was extremely profitable for certain firms in the U.K. electricity market. It would therefore be inappropriate to treat such decisions as random events. Since we find market power in the July-October period – high demand periods in California in which the utilities have historically avoided scheduled maintenance on most generation – it is unlikely that scheduled maintenance could explain these results in any case.<sup>20</sup>

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<sup>18</sup> For any convex function  $C(q)$ , of a random variable  $q$ , we have, by Jensen's inequality,  $E(C(q)) \geq C(E(q))$ .

<sup>19</sup> If, during a given iteration, the residual demand exceeded available capacity, the price was set to \$250/MWh, the maximum allowed under the ISO imbalance energy price cap.

<sup>20</sup> Scheduled maintenance on must-take resources, such as nuclear plants, and reservoir energy sources was accounted for under the procedures outlined in the following sections.

The operation of generation units of course entails other costs in addition to the fuel and short-run operating expenses.<sup>21</sup> It is clear that sunk costs, such as capital costs, and periodic fixed maintenance expenses should not be included in any estimate of short-run marginal cost. More difficult are the impacts of various unit-commitment costs and constraints, such as start-up costs, ramping rates, and minimum up and down times. These constraints create non-convexities in the production cost functions of firms. For a generating unit that is not operating, these costs are clearly not sunk. On the other hand, it is not at all obvious that it is optimal for a price-taking profit-maximizing firm to pro-rate such costs into its supply bids. In fact, it is relatively easy to construct examples where it would clearly *not* be optimal to do so.<sup>22</sup> For the time being, we do not attempt to capture directly the impacts of these constraints on our cost estimates, although we do discuss interpretations in light of these non-convexities.

### C. Hydro, Geothermal and ‘Must-take’ Generation

Conventional thermal generation units, most of them located in California and fueled by natural gas, constitute most of the potential supply that, at any given time, is “in play” in the energy commodity markets. This is not to say that these units constitute the bulk of the energy, or even capacity available to the California electricity market. Due to pre-existing regulatory, environmental, and economic commitments, a large percentage of the electrical energy consumed in California comes from generation sources that are effectively taken before any of the conventional thermal units described above. For our purposes, these generation sources can be divided into two categories: *reservoir energy* sources such as hydro and geothermal, and generators whose output has been pre-committed under *regulatory must-take* agreements.

*Must-take Generation:* Accounting for the impact of the must-take generation is the most straightforward. Must-take generation is composed primarily of the nuclear generation owned by the three incumbent California investor-owned utilities and independent generation providing power under a series of PURPA-based long-term contracts. Since all

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<sup>21</sup> We do not account explicitly for emission costs from these thermal generators, but they are not a significant factor: based upon an assumption of \$382/ton of emission, they were about \$1 million dollars for the period we study.

<sup>22</sup> For example, consider a generator who estimates that it will be ‘in’ the market for six hours on a given day and bids into the market in each hour at a level equal to its fuel costs plus 1/6 of its start-up cost. Now imagine a market outcome where the price in one hour rises well above this bid level, but in subsequent hours remains at a level above the unit’s fuel costs, but below the sum of its fuel cost and pro-rated start-up. This unit thereby has committed to operate in one hour, but is ‘out’ of the market in subsequent hours, even though it could have cleared an operating profit at market clearing prices.

of the output of these generation units is covered under regulatory side agreements, the energy commodity markets in California are effectively setting market clearing prices for the residual demand that is left over after accounting for the output of these units.<sup>23</sup>

Several observers have argued that, to the extent that some of these must-take resources have marginal costs that are *above* the market-clearing PX price, the PX price is being artificially depressed. However, the role of the PX, and the other energy commodity markets, is to arrange transactions between sellers and buyers that are as yet uncommitted. To do this efficiently, such a market must bring together all suppliers that are willing to sell power at a price less than or equal to the price with those consumers that are willing to pay that price. Therefore, if there is an available supplier that is willing to sell power at price  $x$ , then the price in a competitive market would be no higher than  $x$ , even if that supplier is available only because someone signed an outside agreement with a more expensive supplier.

In this paper we focus on the severity of market power in the energy commodity markets. Therefore, we must consider the marginal cost of supplying the *residual* demand that remains after the supply from must-take units, and the market-clearing price of meeting that demand. We do this by removing the must-take energy that is produced in each hour from the market-clearing quantity and removing the must-take generators from the set of units available to meet that quantity. Fortunately, the output of must-take generation is separately identified in the ISO settlement data and can therefore be accounted for relatively easily.

*Hydro and Geothermal Generation:* Hydroelectric and geothermal generation compose another major source of energy production in California's electricity market. For the purposes of market-analysis, these generation sources pose a more difficult problem than must-take generation. These resources, which produce energy from a reservoir of potential energy, have variable production costs that are negligible. Since the amount of potential energy in the reservoir is usually limited, however, the production of energy from such a resource entails a foregone opportunity to produce that energy at some other time. Therefore, while the physical production costs from these resources is very low, the opportunity costs of such production can be significant. Operating constraints, such as minimum and maximum limits on the instantaneous output of these units, also impact the opportunity costs of production.

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<sup>23</sup> In practice, this is accomplished by a requirement that all must-take generation bid its output into the PX at a zero price. This produces the same result as shifting leftward the demand that is bid into the PX by an equivalent amount.



Because of their flexibility, hydro resources are extremely valuable assets for a number of reasons. Their ability to quickly adjust output levels make hydro resources very useful “load following” and reserve resources. For the moment, we will focus on the primary advantage of a reservoir energy resource: the ability to store energy over time. A price-taking firm with hydro resources would try to allocate as much output to the highest price period as is possible, given the hydro units’ operating constraints. If enough hydro energy and capacity is available, price-taking firms would be able to shave price peaks, leaving the price of power constant across all time periods. To see this, consider what would happen if the price in one period were higher than the price in another period. If operating constraints, such as minimum and maximum flow limits were not binding, a price taking firm would shift its hydro production from the lower price hour to the higher price hour until, eventually, either the prices in the two periods equilibrated, or the constraints became binding.

A firm with market power that controlled reservoir resources would apply them in a different way. Instead of equalizing *prices* across time periods, a strategic firm would attempt to equalize its *marginal revenue* across those time periods. Operating constraints would most likely limit a firm’s ability to fully equalize its marginal revenue across all periods, but to the extent possible it would move hydro production from hours in which it has low marginal revenue to hours in which it has high marginal revenue. In a market with a significant, but capacity constrained, price-taking fringe, a strategic firm can find it profitable to allocate relatively more hydro production to *off-peak* periods than to higher demand *peak* periods than would a price-taking firm.<sup>24</sup>

Unfortunately, detecting such a strategic use of reservoir energy sources is much more difficult than estimating the market power exercised by thermal resources whose marginal costs are more easily understood. The hydro and geothermal resources in the state of California are all currently owned by the incumbent investor-owned utilities. Because of various factors, including the fact that these utilities are large buyers of power, the incentives of these firms to exercise market power are somewhat muted relative to those of the new generation owners who have no final customers to serve.

For these reasons, in this study *we assume that there is no strategic use of hydro or geothermal resources*. In other words, we take the actual, observed output of these resources as the level that would be produced by a price-taking firm acting in a perfectly competitive market. This is a conservative assumption, one that will produce downward

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<sup>24</sup> See Bushnell, 1998, for a more detailed analysis of the strategic use of hydro resources.

biased estimates of market power, for two reasons. First, the observed output levels will differ from those that minimize costs if the output of these resources had actually been used in a strategic fashion. Second, the output of these resources may differ from their least-cost usage due to the fact that the actual output reflects the response of hydro firms to the exercise of market power *by other firms*. If the actual hydro and geothermal output schedules differ from the cost-minimizing schedules for either of these reasons, our estimates of the marginal cost of serving load under a competitive dispatch will be biased upward overall and our estimates of market power will be biased downward.

In practice, this assumption means that, in constructing our estimate of the marginal cost of meeting load in any given hour, we apply the observed production of hydro and geothermal resources for each hour and then calculate the marginal cost of satisfying the remaining demand with the state's thermal resources. Figure 2 illustrates this calculation. The thermal cost curve in this calculation is static. The point at which this curve intercepts demand in each hour is adjusted according to the amount of must-take and reservoir energy production in that given hour.

#### *D. Imports and Exports*

One of the most difficult aspects of estimating the marginal cost of meeting ISO load is accounting for imports and exports between the ISO control area and other control areas. Unlike must-take generation, many imports and exports are not a result of pre-existing contractual arrangements. Unlike hydro generation, we cannot automatically assume that imports and exports would always be infra-marginal. Although we can observe the net amount of power entering or leaving the ISO system at each interface point, we do not have data on the value (or opportunity cost) of that power outside California, nor on the cost of transmitting power to the interface point.

If the power market *outside* of California were perfectly competitive, then the marginal generator that is importing into California would, absent transmission constraints, have a marginal cost about equal to the market price in California. When market-power is exercised within California, this would mean that, in an effort to drive up price, some in-state generators are withdrawing (or raising the offer price on) their less expensive generation and allowing more-expensive imported power to be substituted for it. In other words, in the absence of market power, we would see less imports. This means that the cost of serving the demand that remains after the competitive level of imports is netted out would be somewhat higher than the cost of serving the demand that remains after the

**Table 3: Imports in the ISO Control Area (Average MW)**

Month	Dependable	Forecast	
		Non-Firm	Actual
June	3251	7426	3590
July	3251	5231	4718
August	3251	2999	4868
September	3251	3260	5279

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true level of imports is adjusted for.<sup>25</sup>

There are several ways in which we can try to examine the magnitude of this effect. Figure 3 illustrates a hypothetical marginal cost curve of the in-state generation, excluding must-take and reservoir energy resources. The market demand is  $q_{tot}$ , and the observed price is  $p_{px}$ . At a price of  $p_{px}$ , we see imports of  $q_{imp}$  ( $= q_{tot} - q_r$ ) that shift the remaining demand to the left to a quantity  $q_r$ . If the price were instead set at the competitive price of  $p^*$ , we would see imports at some level less than or equal to those seen at  $p_{px}$ . This would shift the residual in-state demand curve to a quantity  $q_r^*$ .

We therefore can derive bounds on the effect of imports on our estimate of the price mark-up by assuming various levels of import reduction as the price in California declines to a competitive level. We first assume that  $q_r^* = q_r$ , that all imports that occur at  $p = p_{px}$  have marginal costs *below* the competitive price of  $p^*$ .

We could then assume that all imports have marginal costs that are *greater* than  $p^*$ , *i.e.*, that  $q_{imp} = 0$  and  $q_r^* = q_{tot}$ . In other words, this assumes that, when the California energy price is  $p^*$ , there are *no* imports into the ISO control area from other regions. This assumption is clearly too extreme. California has always benefited from a significant amount of imported energy, even when wholesale prices were rather modest relative to those experienced during 1998. Furthermore, a significant portion of this energy is imported under firm contractual and energy exchange agreements that predate the opening of the energy commodity markets in California. Lastly, production from plants owned SCE, but located outside of California, also shows up in our dataset as imported energy. This capacity amounts to around 1200MW.

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<sup>25</sup> Capacity constraints on both the transmission interfaces into California and the production capacity of non-Californian producers complicate this intuition somewhat. If such a capacity constraint were binding at the observed California market clearing price, then the marginal *production* cost of imports would most likely be below this market clearing price. In such a circumstance, one cannot say with certainty that a perfectly competitive price within California would yield less imports.

Table 3 helps to illustrate the magnitudes of these various factors. The second column of Table 3 lists the dependable, or firm, import capacity for the three California IOUs given by the California Energy Commission's (CEC) 1994 Electricity Report (CEC, 1995). The third column lists the monthly non-firm imports, in average MW, estimated by the CEC to be available to the three California IOUs for the year 1998. The last column in Table 3 shows the actual average hourly MW imports into the ISO by month for 1998. A comparison of columns 3 and 4 shows that imports were less than anticipated in June and July, but greater than anticipated in August and September. In no month were the forecast non-firm imports less than 60% of the actual imports. When both firm imports and the non-California generation owned by the southern Californian IOUs is added to this total, it seems that a 10% reduction in imports is a conservative upper bound on the reduction in imports likely to result from competitive production within California. We use this as an upper bound for the reduction in imports that would arise if prices were set at competitive levels. This is an average bound, however, one that may be exceeded in some hours. Fortunately, there are means to directly estimate the elasticity of import supply on an hourly basis using data from the day-ahead transmission congestion management process.

#### *Estimating the Elasticity of Import Supply*

One of the primary responsibilities of the California ISO is to ensure the reliable usage of the system's transmission network. This requires that the ISO sometimes operate a market for rationing transmission capacity when its use is oversubscribed. This market is implemented through the use of schedule 'adjustment' bids, which are submitted by scheduling coordinators to the ISO along with their preferred day-ahead schedules.

During low usage periods, scheduling coordinators submit their preferred import quantities and the ISO verifies that these imports do not exceed transmission capacity limits. If these proposed imports are feasible, no further adjustments are required. In the event that the net of proposed import and export schedules does exceed transmission capacity on some interface, the ISO initiates a process of congestion relief by adjusting schedules according to their adjustment bids.<sup>26</sup> Adjustment bids establish, for each schedule coordinator, a willingness-to-pay for transmission usage. Schedules are adjusted according to these values of transmission usage, starting at the lowest value, until the congestion along

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<sup>26</sup> Before turning to adjustment bids, there is a iterative round in which schedule coordinators are allowed to modify their preferred schedules voluntarily, possibly through agreements with other schedule coordinators. If a transmission interface is still constrained after this iteration, the ISO relieves it directly through the use of adjustment bids.

the interface is relieved. A uniform price for transmission usage, paid by all SCs using the interface, is set at the last, or highest value of transmission usage bid by an SC whose usage was curtailed.<sup>27</sup>

The adjustment bid process is intended to allocate scarce transmission capacity to its most valued uses, and to price that capacity based upon those values. Adjustment bids take the form of supply and demand curves located on either side of a congested transmission interface. An SC that is importing power into California, for example, would submit as adjustment bids its cost of imported power on one side of the interface, and its resale value of that power on the other side. The difference between the import cost and resale value is the schedule coordinator’s value of using the transmission interface. If this value is less than the transmission usage charge, the SC would want its schedule to be curtailed. If the transaction value is still greater than the transmission usage charge, then the SC would want the scheduled import to proceed. Figure 4 illustrates the adjustment bid process for the PX at an import zone. If the quantity of imports at the unconstrained PX price, when combined with imports from other SCs, exceeds the import capacity, then import quantities from this zone are adjusted downward according to their adjustment bids. This adjustment continues until the import quantity is feasible. At this point, only the imports that are profitable, even with the transmission charge, remain.

As described above, we use the unconstrained PX price as our estimate of energy prices throughout the State. This is because our estimates of marginal cost also assume that there is no transmission congestion. The adjustment bids, while not accounted for directly in our measurement of price, do provide import information about the elasticity of imports. Adjustment bids provide us with the willingness-to-supply of imported energy at each interface over a wide range of import quantities, not just at the observed import quantity. By aggregating the import adjustment bids over all transmission interfaces and over all schedule coordinators, we can establish an upper bound on the elasticity of import supply. Let the import supply curve of schedule coordinator  $sc$  at import zone  $z$  be the net of its preferred import quantity and all of its incremental and decremental adjustment bids *into California* from  $z$ .

$$q_z^{sc}(p) = q_z^{sc,init} + \sum_{\hat{p} < p} q_z^{sc,inc}(\hat{p}) - \sum_{\hat{p} > p} q_z^{sc,dec}(\hat{p}). \quad [2]$$

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<sup>27</sup> For a more detailed description of the transmission congestion relief process, see Bushnell and Oren (1997).

In other words, the ideal level of imports from  $sc$  at  $z$  and a price of  $p$ , would be the sum of its scheduled imports, which are independent of price, and the amount of extra supply it is willing to provide at a price at or below  $p$  less the amount of supply it does not want to produce at price  $p$ . The aggregate import curve into the California ISO system for any hour can be estimated as by summing the value of  $q_z^{sc}(p)$  over all interfaces and SCs:

$$q_{imp}(p) = \sum_{sc} \sum_z q_z^{sc}(p). \quad [3]$$

This aggregation constitutes an upper bound because the ISO is in practice prevented from substituting import adjustments across individual schedule coordinators or across transmission interfaces, so that the actual import supply curve will yield significantly steeper function of price than the curve constructed as described above. The ISO will only act in the event that the initial schedules indicate that congestion will arise, even though the adjustment bids may indicate a potential Pareto improving import adjustment. Thus while our aggregate import supply curve assumes that all imports from all locations are perfect substitutes, and that these imports are priced at marginal cost, reality falls short of this level of import efficiency. Our aggregate import adjustment supply curve therefore will overstate the responsiveness of imports to a change in the California energy price. Thus, this understates the level of imports that would result from price-taking behavior within California, and will overstate the marginal cost of meeting California demand, and therefore lower our estimates of the extent of market power.

Exports are a much less important factor than imports during the time period that we study. In most of the time periods we study, the ISO control area exported zero or negligible amounts of power to neighboring areas. To the extent that power is exported out of the state, our approach of analyzing a residual demand accounts for the level of exports: a positive level of exports would manifest as an increase in the ISO systemwide quantity that generators must supply. This approach, however, does not account for *increases* in exports that could occur as the in-state price declines. To the extent that export supply from the ISO control region increases significantly as the in-state price decreases, this could understate competitive prices and overstate the level of market power inferred.

### *E. Calculating the Price-cost Margin*

Utilizing the assumptions outlined in the previous sections, we estimated the price-cost margin in the California energy markets for each hour of market operation from June through November, 1998. The residual market demand  $q_r$ , to be met by thermal units within the ISO system, was estimated to be

$$q_r^t(p) = q_{tot}^t + q_{reg}^t - q_{mt}^t - q_{rsv}^t - q_{imp}^t(p). \quad [4]$$

where,  $q_{tot}^t$  is the actual ISO metered generation and imports for hour  $t$ . This number therefore includes generation scheduled through all energy markets associated with the ISO control area, including the PX, ISO imbalance energy market, and other SCs.  $q_{reg}^t$  represents the addition to demand due to the need for capacity dedicated to regulation. The quantities  $q_{mt}^t$  and  $q_{rsv}^t$  represent the amount of energy produced by must take generation and by hydro and geothermal generation, respectively. These quantities are all price inelastic. The level of imported energy,  $q_{imp}^t(p)$  is adjusted by the market clearing price, as described above.

There were 100 thermal generation cost estimates, each reflecting a combination of independent Monte Carlo ‘draws’ for the outage of a generation unit, made for each hour. For each of these draws from the system-wide marginal cost curves we compute the intersection of this marginal cost curve with the residual market demand curve  $q_r^t(p)$ . This yields an estimated marginal cost and an instate market-clearing quantity  $q_{rj}^t$ . We denote the marginal cost associated with this quantity as  $C_j^t$ . Note that for each of the 100 draws from the aggregate marginal cost curve, we obtain different values of marginal cost and the market-clearing quantity. Consequently, we index each of these values by  $j$ , to denote the number of the draw. We can then compute an estimate of the expected value of the marginal cost of meeting the instate demand that results from price-taking behavior by instate generators as:

$$\bar{C}^t = \frac{\sum_{j=1}^{100} (C_j^t)}{100}. \quad [5]$$

Note that there are cases in which  $P_{px}^t - \bar{C}^t$  is negative in our simulations. Absent an attempt at predatory pricing, firms will not actually be willing to sell power at prices below their *true* economic short-run marginal costs. In other words, prices will not be below the perfectly competitive price.

Nonetheless, during some hours, particularly in the spring, PX prices were below our estimates of the marginal cost of the system under perfect competition. At least three factors contribute to these outcomes.

First, our cost estimates can exceed the actual marginal cost because we do not consider the dynamic effects of unit commitment constraints, such as start-up costs, ramping rates and minimum down times. These constraints can create opportunity costs of shutting

down units that, in essence, lower the true marginal cost of operating that plant. Of course these same constraints also can create opportunity costs that, at other times, raise the true marginal cost. This is one reason why we include the negative mark-ups in our results; we did not want to exclude the off-peak impact of these constraints on our cost-estimates, since there is an opposite effect on our estimates during peak-hours.

Second, cost information for generating unit are not exact data on which all parties agree. In some cases, our estimates of a unit’s marginal cost could be slightly too high and in others slightly too low. Therefore we include negative price-cost differences in order to prevent truncating the effect of data uncertainty on our cost-estimates.

Third, as explained earlier, our calculations do not control separately for the output levels of *reliability must-run* (RMR) generation, since we focus on the PX unconstrained price. RMR units are not dispatched as part of the system. Because they are held out and paid a different price, the resulting price in the PX can be below the marginal cost to the system if the power provided by RMR units were instead provided as part of the full dispatch of the system. In fact, due to the high level of RMR calls by the ISO during the time period we study, particularly the spring, it is possible that no other thermal generation was economic during some time periods. In those cases, the highest cost units selling in the PX could be hydro or out-of-state coal plants, either of which have lower marginal cost than any of the thermal plants we examine. Because we don’t account for the RMR units, our estimates could still indicate that a thermal unit is marginal and its cost is the system marginal cost, so our estimated system marginal cost would be above the actual PX price due to unaccounted-for RMR calls.<sup>28</sup>

If the estimated MC above the PX price for either of the first two reasons, then it seems that the most accurate estimate of market power would come from including the “negative market power” outcomes in our calculations. However, the total *annual* startup costs for the thermal units in California is probably less than \$20 million, at least an order of magnitude smaller than the effects we find.<sup>29</sup> Likewise, it is unlikely that much of the negative market power outcomes could be the result of cost data errors. Many PX prices in June, for instance, were well below the costs that anyone has claimed for operation of

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<sup>28</sup> This might imply that neglecting RMR calls could underestimate market power. In addition, it appears from preliminary evidence that the implementation of RMR agreements has exacerbated some of the *local* market power problems that they were designed to mitigate. See Wolak, Nordhaus, and Shapiro (1998).

<sup>29</sup> For most of the units in our thermal cost curve, these costs had been estimated for inclusion in the contract payments for RMR performance. Total annual costs for start-ups of RMR units were about \$17 million.



thermal generating units.<sup>30</sup> Thus, it is most likely that the cost estimates that exceed the PX price occur because there were no thermal generating units that were economic to run at the time. Only thermal units running under RMR contracts were active. In that case, the marginal cost of the system, and thus the market price, is being set by much cheaper out-of-state coal, by nuclear plants, or by hydro or geothermal plants. If this is the case, then the proper treatment would be to truncate the results, resetting any finding of “negative market power” to set marginal cost equal to price. Still, in order to avoid biasing the results in favor of finding market power, we don’t truncate the negative outcomes in the primary results we report.

## V. Results

We calculated the price-cost difference for each hour for the months of June through November using the algorithm described above for computing the expected marginal cost for each hour.

Based upon the import adjustment bids, the import supply curve is quite inelastic. The average hourly reduction in imports from the observed level at the PX price versus the level at our estimate of marginal cost was 0.87%, with a standard deviation of 1.64%. The maximum hourly predicted reduction due to price-taking behavior was 18.2%. Imports were not significantly more price elastic during peak periods. During hours in which the PX price was above \$70/MWH the average import reduction that would arise from price-taking behavior in California was estimated to be 0.54%. These results illustrate a very price inelastic import supply response over a wide range of prices below observed PX prices.

Figures 5 through 10 show the hourly PX price and estimated marginal cost for June through November, respectively. Table 4 reports the PX price, estimated marginal cost, and the added cost of power due to prices that exceeded marginal cost. These figures are aggregated into four blocks of 6 contiguous hours and averaged over each month.

The added cost of energy due to departures from a competitive market,  $\Delta TC$ , is calculated by taking the difference between the PX price and our estimate of marginal cost and multiplying it by the total ISO metered generation less the must take energy for that hour.<sup>31</sup> That is, for hour  $t$ ,

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<sup>30</sup> If we were to ignore any “negative market power” outcomes for prices below, say, \$18/MWh, virtually all of the “negative market power” effects would be eliminated.

<sup>31</sup> By taking the observed quantity as the market demand, we are implicitly assuming that demand is price inelastic. This is a reasonable assumption given that, under the terms of the CTC, almost all end-use customers are considerably, if not completely, insulated from energy price fluctuations.

$$\Delta TC^t = [p_{px}^t - C(q_r^t)] * [q_{tot}^t - q_{mt}^t]. \quad [5]$$

Must take energy is subtracted from the total load because this power is paid for under pre-existing contractual or regulatory agreements. In the future, energy payments to Qualifying Facilities (QFs) may be based upon the PX price, but this was not the case during the period covered by our analysis. Power sold by SCs other than the PX is included in this calculation since, as explained above, it is assumed that price differences across SCs would be arbitrated away. Higher prices for PX power therefore imply higher prices for power from other SCs, as well as the imbalance energy market. In fact, many bilateral power contracts are indexed to the PX price. We also divide this number by total cost of total ISO load less must take energy purchased at the PX price, which is

$$TC^t = [p_{px}^t] * [q_{tot}^t - q_{mt}^t] \quad [6]$$

to get an indication of the magnitude of  $\Delta TC^t$  relative to the full market. The ratio  $\frac{\Delta TC}{TC}$  actually just a quantity-weighted Lerner index.<sup>32</sup>

Note that  $\frac{\Delta TC}{TC}$  is significantly larger during the higher demand months of July and August and during the higher demand hours. During the peak demand period covering hours 13-18, this ratio was 0.48 and 0.58 during the months of July and August, respectively. By contrast, very low (negative) mark-ups were observed during many hours in the month of June or during the off-peak hours, 1-6, in the later months. This fluctuation in the incidence of market power, to coincide with higher demand (and price) hours, is entirely consistent with the nature of competition in the electricity industry. During lower demand hours and months, as well as months such as June in which significant hydro energy is available, no single firm can affect prices significantly. This is because if a firm tries to raise prices by reducing output or increasing its offer price, there are ready supply substitutes available. During higher demand hours, however, these competitive sources of energy begin to reach their capacity limits and the pool of potential competitors for additional supply dwindles. Because of the lack of significant storage capacity and the inelasticity of demand, firms can take advantage of the capacity limits of their competitors during these high demand hours. This is consistent with the effects detected from the oligopoly equilibrium simulations in Borenstein and Bushnell (1999). For the entire

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<sup>32</sup>  $\frac{\Delta TC}{TC} = \frac{(P-MC) \cdot Q}{P \cdot Q}$ . If  $Q$  were equal in all periods, this would be exactly the same as the (unweighted) average Lerner index. As with the Lerner index, prices below marginal cost will yield negative measures that can be greater in absolute value than 1.

**Table 4: Actual Price and Estimated Marginal Cost (\$/MWh)  
(using estimate of import supply curve)**

Month	Time Block	mean of actual demand per hour	mean of PX price	mean of marginal cost	mean of $\Delta TC$	aggregate $\frac{\Delta TC}{TC}$
June	mid-6am	19275	2.63	22.22	-141810	-7.114
June	6am-noon	26049	12.04	23.16	-132553	-0.806
June	noon-6pm	28561	20.13	23.35	-35614	-0.130
June	6pm-mid	25529	13.56	23.22	-106573	-0.644
July	mid-6am	22199	17.64	26.10	-76678	-0.445
July	6am-noon	28473	26.15	26.63	25843	0.027
July	noon-6pm	34987	51.72	27.90	585765	0.478
July	6pm-mid	30906	34.14	27.12	163106	0.232
August	mid-6am	22795	22.50	26.08	-35704	-0.150
August	6am-noon	30104	31.76	26.82	127796	0.191
August	noon-6pm	37595	67.17	29.25	1058298	0.583
August	6pm-mid	32270	36.67	27.65	218362	0.270
September	mid-6am	21224	22.72	24.91	-19128	-0.086
September	6am-noon	28210	30.18	25.43	116062	0.194
September	noon-6pm	32259	49.22	26.36	619530	0.511
September	6pm-mid	28395	33.91	25.85	196844	0.284
October	mid-6am	19158	19.80	25.69	-45536	-0.285
October	6am-noon	25611	28.85	25.94	50222	0.112
October	noon-6pm	27064	29.24	26.00	54956	0.118
October	6pm-mid	25051	28.70	26.07	45258	0.105
November	mid-6am	18694	19.76	26.73	-51207	-0.335
November	6am-noon	24774	27.26	27.18	12327	0.021
November	noon-6pm	26148	28.52	27.24	28375	0.059
November	6pm-mid	24376	27.44	27.31	14571	0.025

6-month period that we study, the aggregate  $\frac{\Delta TC}{TC}$  is 22.4%, amounting to total payments in excess of competitive levels equal to \$494 million.<sup>33</sup>

We also carried out an alternative approach to incorporating the effect of imports and changes in import supply on the estimation of market power. To be conservative, we

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<sup>33</sup> Excluding June, which had many hours with estimated negative markups, this figure increases to \$569 million. If we had truncated the hours where we found PX price below our estimate of marginal cost, so that these hours had a zero, rather than negative, effect on the aggregate estimates, the aggregate  $\frac{\Delta TC}{TC}$  would be 29.6% or total payments in excess of competitive levels equal to \$652 million.

assumed that imports under competition would be a constant 10% lower than the actual imports that occurred, which is a much bigger decline than we found using adjustment bids to estimate an import supply curve. The results of this exercise are in Table A1 in the appendix. The estimates of market power are quite close to those that obtained using estimates of the import supply curve.<sup>34</sup>

It is important to recognize, however, that the effects we have identified here are not the result of competitive peak-load pricing, under which the price *should* rise during peak demand times to reflect the higher marginal cost of production during those times. Competitive peak-load pricing is manifested in the increased marginal costs we estimate as the ISO load rises. Those marginal costs reflect the actual level of consumption in each hour and in each hour there is significant additional capacity available at a cost equal to or only slightly higher than the level we calculate. The ratios we report indicate price increases *above* the levels that would occur in the course of competitive price responses to peak demands.

## VI. Conclusions

Deregulation of electricity generation markets has been predicated on the belief that competitive wholesale electricity markets can be attained. The debate over whether that assumption is correct and what must be done to ensure competition in electricity generation is ongoing. We have attempted here to make a reliable first estimate of whether and the degree to which California’s wholesale electricity market has deviated from the competitive ideal.

Though a great deal of cost data are available for electricity generation units, we still had to make a number of assumptions in order to reach an estimate of the extent of market power in California. We have tried to make these assumptions reasonable, to state them clearly, and to explain how they are likely to affect the calculation. In most, though not all,

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<sup>34</sup> In addition, we examined the sensitivity of the results to our treatment of spin and non-spin reserves. As mentioned above, we have treated all spin and non-spin reserves as being available to meet real-time demand, taking only regulation reserve as an additional demand on the system. We recognize that at times the ISO has held out some capacity for local reliability reasons. To take a very conservative approach, we looked at the proportion of spin and non-spin capacity that was “skipped” in the dispatch, *i.e.*, held out of production even though their bids were below the market price. This proportion is never greater than 2.5% of the system load during peak hours, and many of these skips were due to generator, not ISO, decisions. Nonetheless, when we increased the load by 2.5% to account for all possible skips (by moving an extra 2.5% up the system cost curve), the the aggregate  $\frac{\Delta TC}{TC}$  was still 19.6%. This is an extreme lower bound since in nearly all hours it greatly overstates the proportion of capacity skipped by the ISO.

cases, we have made assumptions that, if anything, are likely to produce results indicating less market power than actually exists.

The results indicate that market power in California's wholesale market was a significant factor during July through November of 1998. Of course, the market was still very new at that time and changes are occurring in both the production and regulatory arenas that may increase or decrease the ability of firms to exercise market power in the future. Nonetheless, these estimates should serve as a reminder that the problem that was addressed in a purely regulatory framework for the past many decades has not completely disappeared with the recent restructuring.

These estimates demonstrate the degree to which prices exceed system marginal costs, the price level that would occur if all firms behaved as competitive price takers. We have not attempted to assess the profitability of any generation firms selling in California, since such profits are not necessarily an indication of market power, just as the absence of profits is not an indicator of competitive behavior. Under very favorable conditions for electric power supply, such as the high hydro conditions experienced over at least the first half of 1998, firms may have difficulty earning profits whether or not they are able to exercise market power. In all markets with durable assets, such as is the case in this industry, there are likely to be periods of high and low (or negative) profits regardless of the competitiveness of the market. Thus, the profits of generating companies in California during the time period we study provide little or no information about the competitiveness of this market.<sup>35</sup>

Finally, we want to emphasize again that these results can certainly be refined further. We think such refinements should be a top priority. Years of electricity regulation confirmed the belief that government intervention can be costly and can result in tremendously inefficient production. The balancing of the costs and benefits of such intervention will require a great deal more study in this industry as the restructuring proceeds.

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<sup>35</sup> It is also worth noting that we have analyzed only the energy markets in California. Most generation units are eligible to earn additional revenues under reliability must-run contracts and from the sale of ancillary services. During the summer of 1998 RMR costs and ancillary services costs were significantly higher than were expected at the time the California market began.

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## Appendix: Data Sources

### Thermal Generation Data

Heat rates for thermal generation units that were not must-take and were located within the ISO control area are primarily taken from the California Energy Commission's dataset on WSCC generation for use with General Electric's MAPS multi-area production cost model. This is the dataset used in Borenstein and Bushnell (1999). Some unit heat rates were taken from the data set used by Southern California Gas Company in its 1995 performance-based ratemaking simulation studies (Pando, 1995). This dataset was also used by Kahn, et. al (1996) in their simulation analysis of the WSCC.

An overwhelming share of California thermal generation is fueled by natural gas. For the time period studied, we used weekly average natural gas spot prices reported by Natural Gas Intelligence at PG&E citygate and the California-Arizona border. The former were used for generation units north of path 15 while the latter were used for generation units in the south. Both sets of prices were adjusted by the distribution rates of the gas utility serving each generator.

A small number of California generators use either fuel oil or Jet fuel as their primary or secondary fuel. Jet fuel and fuel oil prices were aggregated over the four months and across the ISO control area. The price of number 2 fuel oil was assumed to be \$2.98/Mbtu during the time period of this study. These figures are the year-to-date average costs of each fuel delivered to California electricity producers, taken from the Energy Information Administration's December 1998 *Electric Power Monthly*, which includes data through September 1998. The price of jet fuel was taken from the MAPS dataset and assumed to be \$3.29/Mbtu.

Unit forced outage factors are taken from the National Electricity Reliability Council's (NERC) 1993-1997 Generating Unit Statistical Brochure, which reports aggregate generation unit performance data by fuel type and nameplate capacity. The forced outage factor that we used for our monte-carlo simulations were derived from the NERC reported unit Equivalent Availability Factors (EAF) and unit Scheduled Outage Factors (SOF). The former gives the fraction of total hours in which a generation unit was available, including an adjustment for partial outages, while the latter gives the fraction of hours in which each unit was unavailable due to scheduled maintenance procedures. Our derived forced outage factor, which reflects the fraction of time a unit was not available for production for unplanned reasons, was



$$FOF = 1 - \frac{EAF}{1 - SOF}$$

## **Demand and Generation Output Data**

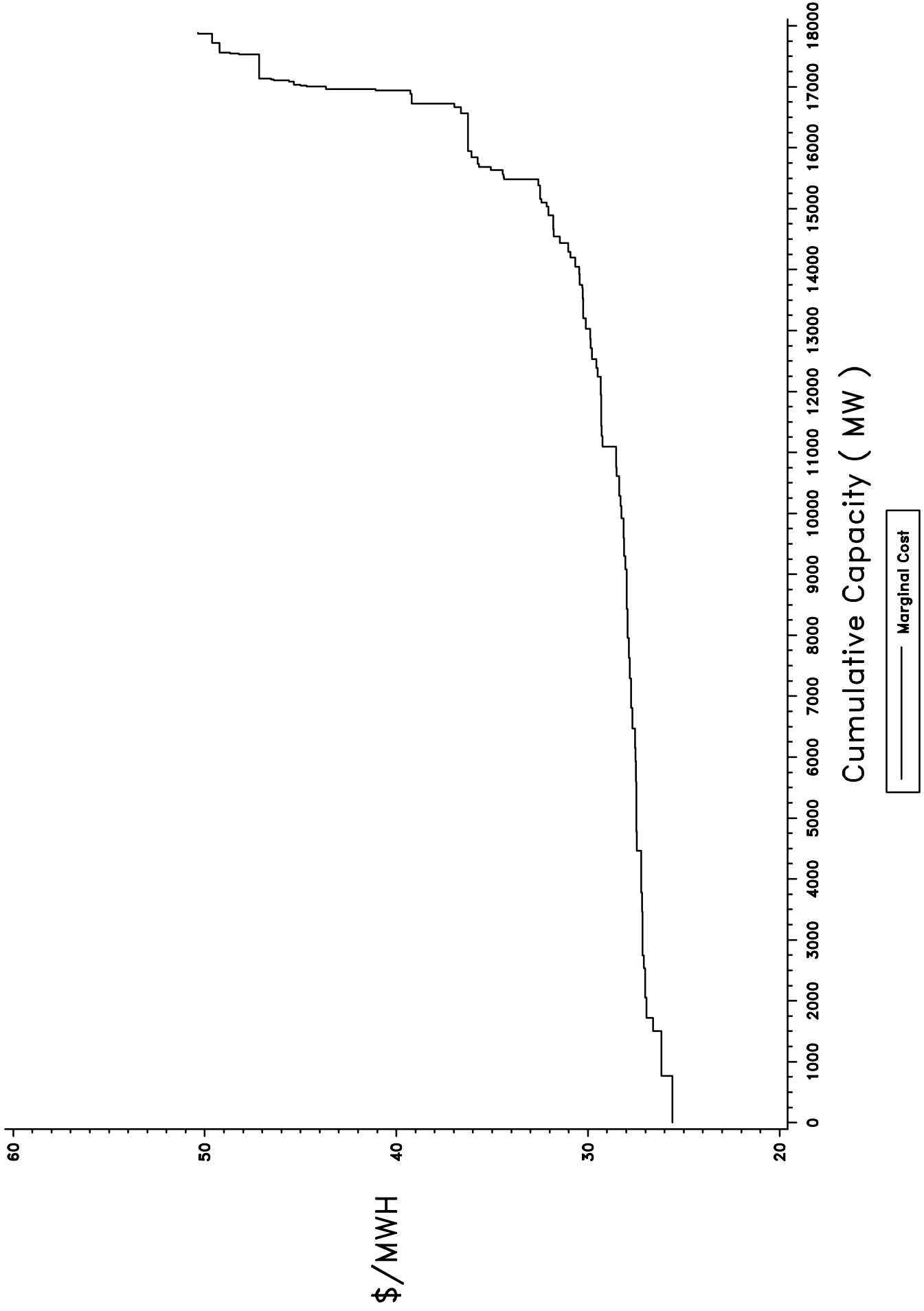
Total ISO quantity for every hour is based upon the ISO's real-time metered generation and is taken from ISO settlement data. The output of must-take, hydro, and geothermal generation for each hour is also taken from these data. Imports are calculated from the net of real-time metered imports and exports aggregated over all transmission interties connecting the ISO's control area with neighboring control areas. The Mohave generation plant, although located outside of California, appears in metered data as must-take generating facility and not as an import. Production from all other generation units owned by SCE, but located outside of California, appear as imports in the settlement data.

**Table A1: Actual Price and Estimated Marginal Cost (\$/MWh)  
(10% Import Reduction Assumed ( $\alpha = 0.1$ ))**

Month	Time Block	mean of actual demand per hour	mean of PX price	mean of marginal cost	mean of $\Delta TC$	aggregate $\frac{\Delta TC}{TC}$
June	mid-6am	19275	2.63	22.31	-142527	-7.149
June	6am-noon	26049	12.04	23.27	-134086	-0.814
June	noon-6pm	28561	20.13	23.45	-37027	-0.134
June	6pm-mid	25529	13.56	23.35	-108202	-0.653
July	mid-6am	22199	17.64	26.17	-76346	-0.449
July	6am-noon	28473	26.15	26.69	24961	0.025
July	noon-6pm	34987	51.72	28.19	577632	0.472
July	6pm-mid	30906	34.14	27.19	161633	0.229
August	mid-6am	22795	22.50	26.12	-36145	-0.152
August	6am-noon	30104	31.76	26.84	127420	0.191
August	noon-6pm	37595	67.17	29.28	1056918	0.583
August	6pm-mid	32270	36.67	27.70	217517	0.269
September	mid-6am	21224	22.72	24.96	-19605	-0.088
September	6am-noon	28210	30.18	25.45	115823	0.193
September	noon-6pm	32259	49.22	26.76	606908	0.501
September	6pm-mid	28395	33.91	25.97	193774	0.280
October	mid-6am	19158	19.80	25.75	-45991	-0.288
October	6am-noon	25611	28.85	25.97	49843	0.111
October	noon-6pm	27064	29.24	26.02	54587	0.117
October	6pm-mid	25051	28.70	26.09	44916	0.104
November	mid-6am	18694	19.76	26.89	-52430	-0.342
November	6am-noon	24774	27.26	27.22	11866	0.020
November	noon-6pm	26148	28.52	27.27	27991	0.058
November	6pm-mid	24376	27.44	27.34	14191	0.024

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# Marginal Cost Curve of Instate Fossil Units



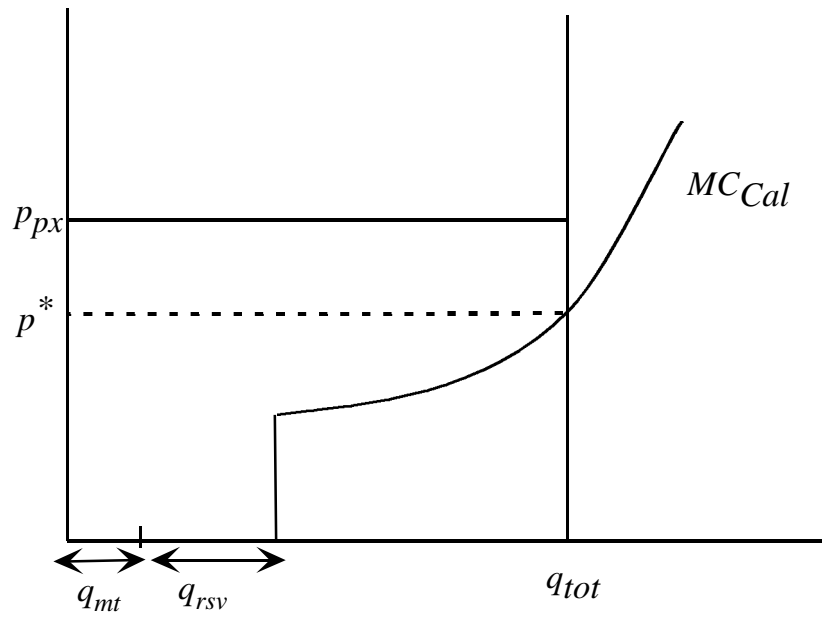


Figure 2: Treatment of must-take and reservoir energy sources

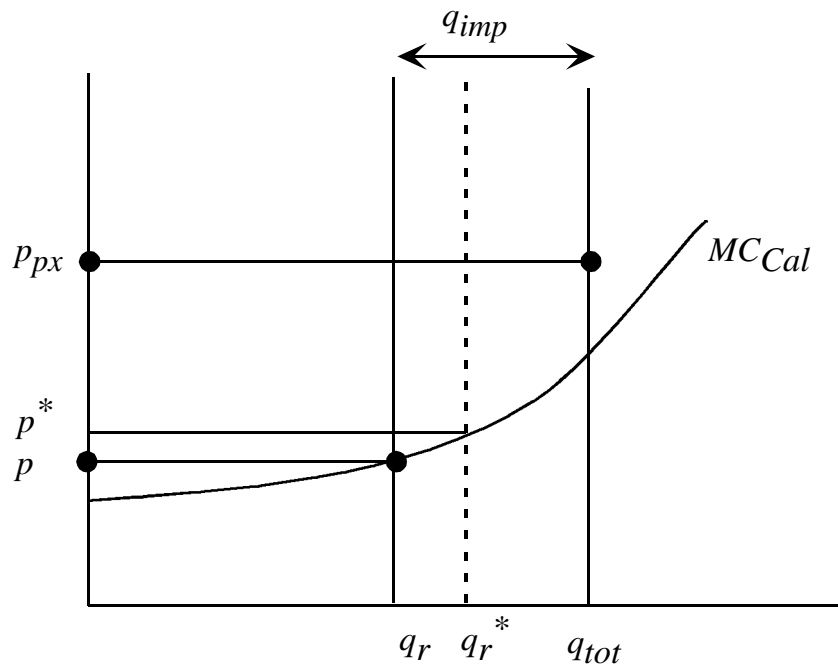


Figure 3: Bounding the impact of imports on marginal cost

Figure 4: Hourly PX Price and Predicted Marginal Cost for June

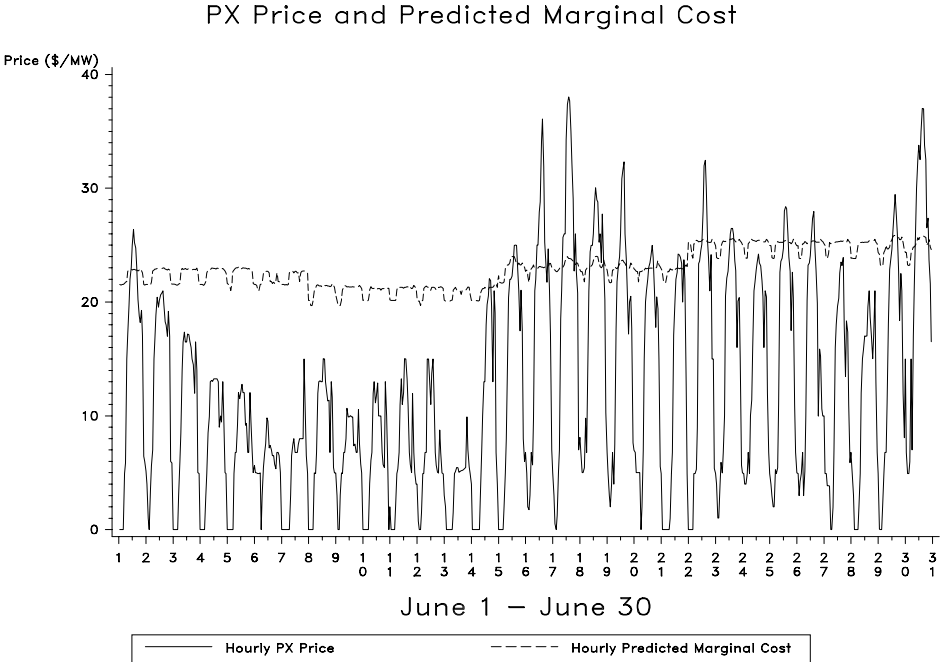


Figure 5: Hourly PX Price and Predicted Marginal Cost for July

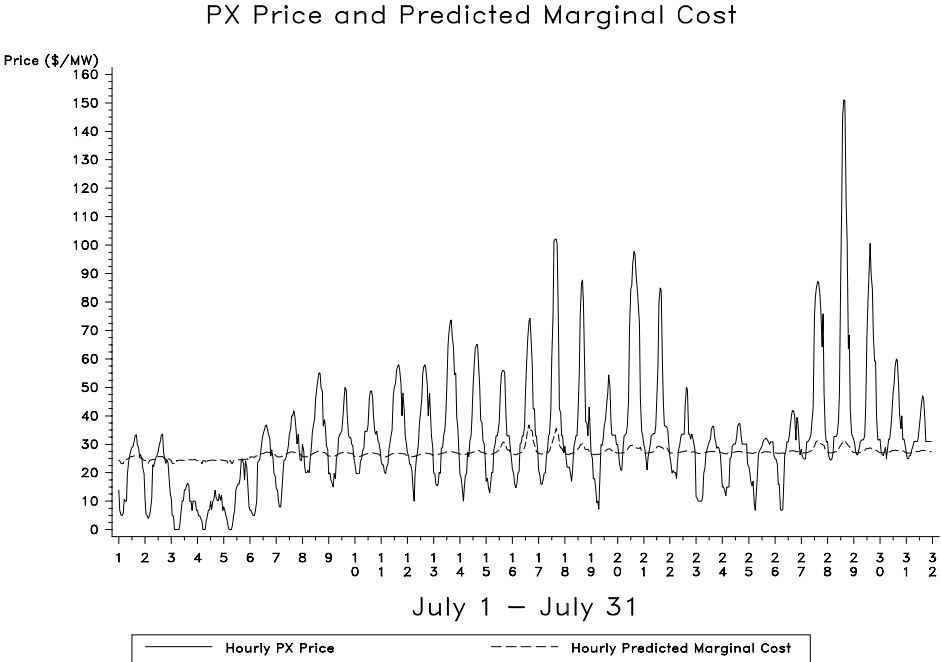


Figure 6: Hourly PX Price and Predicted Marginal Cost for August

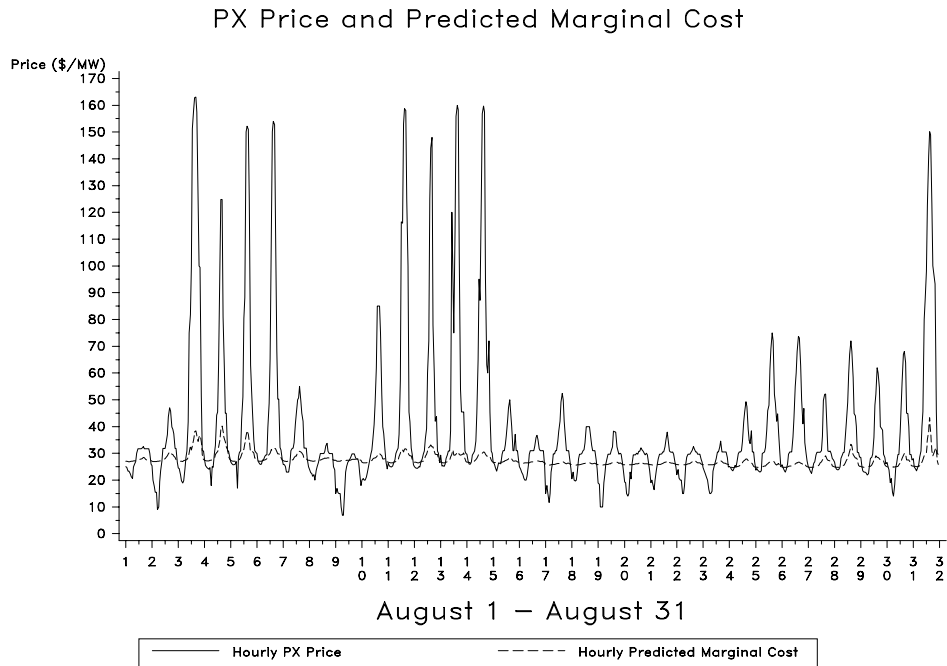


Figure 7: Hourly PX Price and Predicted Marginal Cost for September

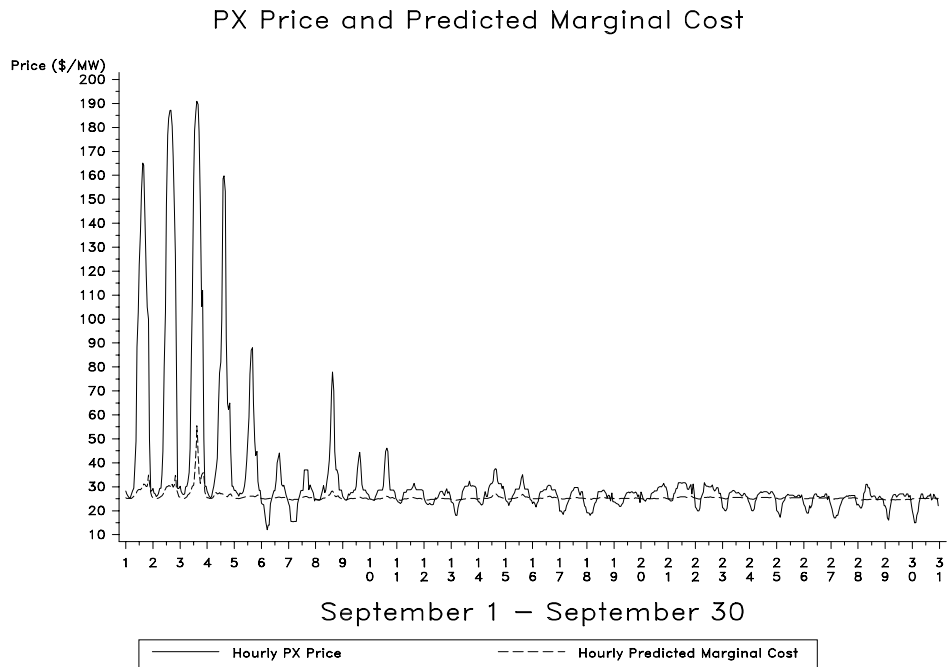


Figure 8: Hourly PX Price and Predicted Marginal Cost for October

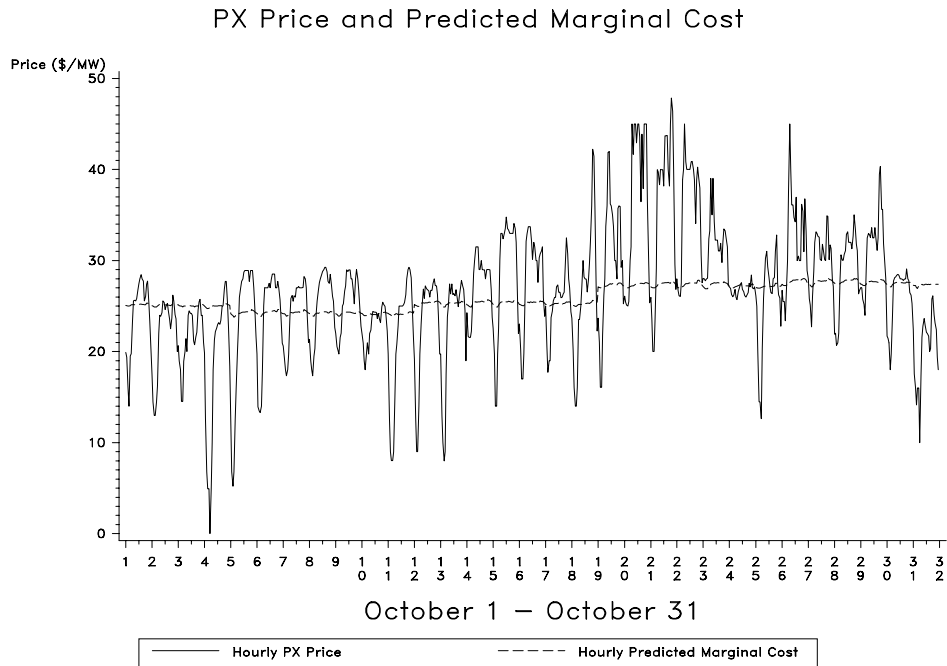


Figure 9: Hourly PX Price and Predicted Marginal Cost for November

