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 the summer of 1998 by comparing the market prices with estimates of the prices that would have resulted if no firms exercised market power. We find that there was significant market power and that it was most pronounced during the highest demand periods. Overall, prices averaged about 17% 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 and ancillary services markets. These debates have raised the question of whether the high prices that have been observed at times are a natural result of peak demand periods in a competitive market or whether they have been exacerbated by strategic behavior by some firms attempting to manipulate those prices. 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 market is currently able to operate efficiently without intervention from the PX, ISO, or government regulatory institutions.

In this paper we attempt to shed some light on these questions by estimating the degree and extent of market power experienced in the California markets for electrical energy from the months of June through September, 1998. Using data provided to us by the California Independent System Operator (ISO) 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 equilibria concept to the electricity market in United Kingdom, 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) and Wolak and Patrick (1996) are, to our knowledge, the only studies that estimate the incidence, 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 some firms profited considerably from declaring the output of some units unavailable at certain times. This lack of availability was correlated with the occurence of market conditions that would make such a strategy particularly profitable.

In this paper, we analyze prices, generator 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. Our goal is to stimulate a discussion on how to diagnose market power in electricity markets and to elicit useful comments that will help to further refine this analysis. 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 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 high prices that are then transmitted across markets by the response of competitive suppliers.

It is important to understand, however, that a price-taking firm does not sell its output at a price equal to the marginal cost of all units it produces. It sells its output at the market price, which is set by the interaction of demand and *all* supply in the market. The price-taking firm is *willing to sell* at that market price any output that it can produce at a marginal cost less than that market price.

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. This is illustrated in figure 1 for a single price-taking firm: the area above the firm's marginal cost curve and below the price line is revenue that contributes to covering 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 (see figure 2). 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, the result is still likely to be an improvement over traditional regulation. 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.

A more extreme view than the inevitability of market power is the view that market power is *necessary* to allow firms to cover their total costs of operation. In the absence of market power, the argument goes, marginal cost pricing will leave nothing to cover fixed costs and firms will not be profitable enough to survive. This view represents an unfortunate confusion about the economics of competitive markets. Price-taking behavior, the manifestation of competitive markets, means simply that every unit of output that can be produced at a marginal cost below the market price is being produced and every unit of output that can be produced at a marginal cost above the market price is not being produced. Thus, most, and in some cases all, output produced is produced at a marginal cost below the market price, and the difference between price and the marginal cost of each unit of output makes a contribution towards fixed costs. During very high demand times, for instance, price spikes will occur even in competitive markets as price rises to ration demand to the available supply. In a competitive market, however, all output that can be produced at a marginal cost less than the market price will be produced, and no generator will inflate its offer bid in an attempt to raise the market price.

B. The Behavior of a Firm with Market Power

In contrast to price-taking firms, a firm with market power influences 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.

The central idea behind market power is that in a market where all output is sold at the same price, a firm that can influence price in the market will do so in order to raise the price for *all* the production it sells. Consider, for instance, a firm that is selling 10 units of output and the market price is $15. If that firm could influence price by reducing its output to 9 units – causing price to rise either to the point that total demand is reduced by one unit or some other seller is induced to increase its production by one unit to compensate, or some combination of these two effects – then it would compare the profit from selling 10 units at $15 with selling 9 units at some higher price.

The same effect occurs if the firm doesn't reduce its output, but instead offers to sell its 10th unit of output for some price above $15. If the firm offers that unit for $17, for instance, then either that offer is accepted and the market price is increased to $17, or that offer is not accepted. If that offer is not accepted, it is because either demand adjusts by demanding less total output or the supply of other producers adjusts by offering to supply more at some price less than $17, or some combination of these effect. In any case, the market price must still rise to some extent in order to equalize supply and demand after this firm has raised the offer price of its 10th output unit to $17.

Two factors are critical in determining the extent to which such behavior 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 demand is very 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 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.[1] 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 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.

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

When a firm does exercise market power, all firms in the market benefit. In fact, other firms may benefit proportionally more than the company that is exercising market power. This is because the company that is exercising market power reduces its sales quantity, or risks doing so, in order to raise the market price. Other firms do not have to reduce their output – in fact they may even increase output – but still benefit from receiving the higher market price. Thus, even a price-taking firm in a market might have 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. In some cases, firms may try to collude to jointly exercise market power. The idea behind collusion is for each firm to recognize that when it expands its output, it may raise its own profits, but it pushes down the market price and reduces the profits of other producers. Conversely, when a firm reduces its output (or raises its offer prices), it may harm its own profits, but it raises the market price and the profits of other producers. Recognizing this interdependence, firms may try to reach an agreement to restrict their output or raise their offer prices in order to jointly raise profits. OPEC tries to do exactly this. But OPEC faces the problem that any set of colluding firms face: each firm would individually like to raise its output while its collusive partners reduce theirs. Attempts by companies in the U.S. to reach such agreements to jointly raise price or lower output are illegal under section 1 of the Sherman Antitrust Act.

C. The Consequences of Market Power

The most visible, and publicly objectionable, impact of market power is high prices. By raising prices above competitive levels, suppliers with market power can enjoy a transfer of wealth from consumers. There are also potentially serious consequences of market power with regards to economic efficiency. By elevating prices above the marginal cost of production, a supplier is ensuring that some transactions that would, in isolation, benefit both buyer an seller do not get made. The gains from such trades therefore are not realized by anyone. The resulting decrease in social welfare is known as the *deadweight loss* from market power.

An important fact to consider when discussing market power in the California electricity market is that, in the short run, 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 energy prices 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 suppliers.[2] However, because of the way the CTC has been designed, higher energy prices can have the effect of delaying its expiration, and thereby delaying a significant drop in the rates of end-users. It now appears that this is certainly the case for SDG&E customers 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 consumers to non-utility generators.

Even if we ignore the issue of transfers between utilities, consumers, and producers, market power can still yield some very 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 are providing baseload power that should be supplied by coal-fired plant 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.[3] 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

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[2] 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 the they buy from other generators.

[3] See Borenstein, Bushnell and Stoft (1998), and Cardell, Hitt and Hogan (1997).

ways that decrease overall economic efficiency.[4]

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 to *not* 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.

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) and Wolfram (1998). In applying this approach, one must be careful to examine systematic rather than isolated behaviors. To observe, for example, that a specific

[4] See Bushnell (1998).

inexpensive generation unit was not operating during a particular high price hour, does not, as one observation, provide strong evidence of market power. If such behavior can be shown to be consistently associated with the particular market conditions that make such behavior profitable, a much stronger case can be made that market power is present.

The second indicator yields implications that we test 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.

III. The California Electricity Market

The market for electrical energy in California is characterized by the repeated interaction of several firms and institutions, each of which perform some type of "market-making" function. 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.[5] 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 in effect 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.[6] In addition to the PX, other institutions, collectively 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.[7]

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[5] A 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.

[6] 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.

[7] 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.

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 a supply shortfall, and generators are relieved of their obligation to provide power in the event of an excess of supply. 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.[8] At this time, 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 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 2.

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[8] 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)
Summer 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

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 the rates of end-users and the effects of the Competition Transition Charge (CTC), the incentives of the incumbent utilities to raise prices have been considerably muted, because lower PX prices result in a greater share of total retail revenues going to the incumbent utilities as opposed to all of the remaining generators.

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.

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

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

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

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.

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 understanding 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 larger buyers of electricity, the large utility distribution companies (UDCs). It is well understood that in a single market, a buyer with completely inelastic demand cannot exercise monopsony power, regardless of the quantity it is purchasing. The UDCs have a demand that is virtually completely price inelastic: they must provide the amount of power that their customers demand and those customers do not see the PX or ISO power prices as costs to themselves. Particularly now, during the rate freeze transition period, the customers have no reason to respond to prices, so the UDCs have virtually no flexibility in the total power they must purchase. Moreover, the vast majority of the interruptible power supply contracts held by the incumbent utilities do not allow curtailment of power for economic reasons such as high PX or real-time prices.

Yet, an analysis of a single market, 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 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.[9] 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.

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[9] 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.

Thus, in equilibrium, a 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.[10] 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.[11]

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.[12] 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

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[10] One might 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. On net, such behavior seems as likely to increase as decrease the buyer's total cost.

[11] Interestingly, a buyer with inelastic demand that also has production capability may be able to exercise monopsony power by reducing its *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.

[12] 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.

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 exceed $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.[13]

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[13] See Wolak, Nordhaus, and Shapiro (1998)

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 June, where, as outlined below, little market power was detected. Even in June, the maximum net quantity of energy exported out of the ISO control area in any hour was a modest 407 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 in all of these markets would converge in expectation.[14]

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.

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.[15] Thus, the real-time energy price is still set by the interaction

[14] One might be concerned that this arbitrage would not hold in light of the requirement, established in 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, the wording of AB 1890 has not prevented the IOUs (and others) from arbitraging energy prices across the PX and ISO energy markets.

[15] Due to reliability concerns, the ISO at times has not utilized spinning and non-spinning reserves for

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 is at most 11% of load, to the market clearing quantity for the purposes of finding the overall marginal cost of supply.[16]

B. Thermal Marginal Cost

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 3 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 3 does not include any adjustments for "forced outages." Generation unit 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.

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.

[16] 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.

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.[17] We therefore simulate the marginal cost curve that accounts for forced outages using Monte Carlo simulation methods. If the generation units $i = 1, ..., N$ 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

$$k = \arg\min x | \sum_{i=1}^{x} I(i) * cap_i \geq q. \tag{1}$$

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 500 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.

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. We therefore feel that it is inappropriate to treat such decisions as random events. Our study period covers only June through September, which are the high demand periods in California. The California IOUs had historically avoided scheduled maintenance on most generation units during these peak demand months. Scheduled maintenance on must-take resources, such as nuclear plants, and reservoir energy sources are 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. 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.

[17] For any convex function $C(q)$, of a random variable q, we have, by Jenson's inequality, $\mathrm{E}(C(q)) \geq C(\mathrm{E}(q))$.

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.[18] For the time being, we do not attempt to capture the impacts of these constraints on our cost estimates, although we do discuss some sensitivities with regards to start-up costs in section V.

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 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.[19]

Several observers have argued that, to the extent that some of these must-take re-

[18] 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.

[19] 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.

sources have marginal costs that are *above* the market-clearing PX price, the PX price is being artifically 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.

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 strategic firm that controlled reservoir resources would apply those resources 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.[20]

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 understate the level of market power, for two reasons. First, the observed output levels will differ from those that minimize costs if the output of these resources has 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.

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[20] See Bushnell, 1998, for a more detailed analysis of the strategic use of hydro resources.

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 4 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 true level of imports is adjusted for.[21]

There are several ways in which we can try to examine the magnitude of this effect. Figure 5 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

[21] 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: 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

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.

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 25% reduction in imports is a conservative upper bound on the reduction in imports likely to result from competitive production within California.

We are continuing to refine our estimates of a plausible level of energy that would be imported at competitive prices. One way we can examine the impact of these assumptions is to calculate the price-cost margin under the assumption that some assumed fraction of current imports would still be realized if the California firms behaved as price-takers. Therefore, in addition to calculating the price-cost margin under an assumption of full imports, we calculated this margin assuming imports are reduced to by 1/4 and 1/2 of the actual observed level of imports for each hour. We view the no-reduction and 50%-reduction on imports as outer bounds of reasonable estimates. In examining the results below, we give the most emphasis to the 25%-reduction analysis.

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 of 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 December, 1998. The residual market demand q_r, to be met by thermal units within the ISO system, was estimated to be

$$q_r^t = q_{tot}^t + q_{reg}^t - q_{mt}^t - q_{rsv}^t - (1-\alpha) * q_{imp}^t. \qquad [2]$$

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. The level of imported energy, q_{imp}^t was adjusted by a scaler α for which we used values of 0, .25 and .5.

As described above, there were 500 cost estimates, each reflecting a combination of independent Monte Carlo 'draws' for the outage of a generation unit, made for each hour. For the residual market quantity in that hour, q_r, the expected marginal cost of supplying that quantity was therefore

$$\bar{C}(q_r^t) = \frac{\sum_{j=1}^{500} C_j(q_r^t)}{500}. \qquad [3]$$

where $C_j(q_r^t)$ represents the marginal cost of producing quantity q_r^t given the unit outages realized in Monte Carlo simulation j. The estimated price-cost margin, or Lerner index, for hour t, therefore, is

$$L^t = \max[\frac{P_{px}^t - \bar{C}(q_r^t)}{P_{px}^t}, 0]. \qquad [4]$$

Note that this calculation of the Lerner index does not permit it to be negative. We set negative margins that obtain in the simulation to zero under a revealed preference assumption that firms would not be willing to sell power at prices below their true economic short-run marginal costs. During some hours, particularly in the spring, PX prices were below our estimates of the marginal cost of the least expensive generation unit in the ISO system. At least two 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 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 can create opportunity costs that raise the true marginal cost as well. We discuss some sensitivity analyses that attempt to account for this in Section V.

Second, 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. Due to the high level of RMR calls by the ISO during the time period we study, it is possible that no other thermal generation was economic during some time periods. However, these periods are likely to occur when the PX price is extremely low, not extremely high. In such cases, import energy with costs below those of in-state thermal generation (such as out-of-state hydro) could be the marginal generation, and the actual PX price could be lower than the marginal costs of any of the thermal units we have examined. Because we don't account for the RMR units, we could still estimate that a thermal unit is marginal and its cost in the system marginal cost, so our estimated system marginal cost would be above the actual PX price due to unaccounted-for RMR calls.[22]

Finally, it is worth noting that cost information for generators are not exact data on which all parties agree. It is possible that the instances of price below our estimated marginal costs is indicative of our marginal cost data being biased upward. If that were the case, our results would understate the degree of market power present.

V. Results

We calculated a Lerner index for each hour for the months of June through September. The marginal cost of supplying demand after accounting for must-take, hydro, geothermal, and imported energy was estimated for import level reductions of 0%, 25%, and 50% of the actual imported energy for that hour. As described above, the marginal cost estimate for each hour is the mean of 500 Monte Carlo draws for the outage status of each unit.

We focus our discussion on the results in which an import reduction of 25% is assumed when the price is reduced from the observed to the competitive level.[23] For the reasons discussed above, we think this is probably closest to the actual import reduction that would occur, though probably still higher than would occur. Figures 6 through 9 show the hourly PX price and estimated marginal cost for June through September, respectively. Table 4 reports the PX price, estimated marginal cost, Lerner index, 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, ΔTC, 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.[24] That is, for hour t,

$$\Delta TC^t = [p^t_{px} - C(q^t_r)] * [q^t_{tot} - q^t_{mt}]. \quad [5]$$

[22] This might imply that neglecting RMR calls could underestimate market power, but 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).

[23] The same calculations for zero import reduction and 50% import reduction are in the appendix.

[24] By taking the observed quantity as the market quantity, 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.

Table 4: Actual Price and Estimated Marginal Cost ($/MWh)
(25% Import Reduction Assumed ($\alpha = 0.25$))

Month	Time Block	mean of actual demand per hour	mean of PX price	mean of marginal cost	mean of Lerner Index	mean of ΔTC per hour
June	mid-6am	19275	2.63	2.63	0.000	0
June	6am-noon	26049	12.04	12.00	0.001	676
June	noon-6pm	28561	20.13	19.30	0.024	14695
June	6pm-mid	25529	13.56	13.52	0.001	615
July	mid-6am	22199	17.64	17.46	0.006	2268
July	6am-noon	28473	26.15	23.21	0.080	57856
July	noon-6pm	34987	51.72	28.40	0.351	562930
July	6pm-mid	30906	34.14	26.36	0.160	165734
August	mid-6am	22795	22.50	22.46	0.001	571
August	6am-noon	30104	31.76	26.82	0.096	117278
August	noon-6pm	37595	67.17	31.97	0.385	985053
August	6pm-mid	32270	36.67	29.01	0.140	189336
September	mid-6am	21224	22.72	22.68	0.001	627
September	6am-noon	28210	30.18	26.57	0.058	90681
September	noon-6pm	32259	49.22	30.14	0.180	523967
September	6pm-mid	28395	33.91	27.70	0.075	159967

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 arbitraged away. Higher prices for PX power therefore imply higher prices for power from other SCs, as well as the imbalance energy market.

Note that the Lerner index, and therefore the price-cost margin, 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, the Lerner index was 0.351 and 0.385 during the months of July and August, respectively. By contrast, very low mark-ups were observed during any 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 (1998).

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 Lerner index we report indicates price increases *above* the levels that would occur in the course of competitive price responses to peak demands.

It is interesting to compare these figures to those from the only other comparable study that has been done to date, Wolfram's (1999) analysis of the U.K. electricity market. Wolfram estimates the price-cost markups for the system marginal price (SMP) of the U.K. pool during a period covering 1993-94. She estimates Lerner indexes to be approximately in the range of 0.20 to 0.25. Wolfram's estimates of marginal cost include only fuel costs and, like ours, do not account for unit commitment constraints. The U.K. market during the time she studies was essentially a duopoly, considerably more concentrated than is the current California market. By contrast, in the California market, which features seven firms with significant generation assets, as well as a large amount of QF and import capacity, the weighted average Lerner index we estimate to be about 0.15.

In our estimates of marginal costs, we did not include the costs of unit start-ups. Nor did we include emissions costs from plants in the Southern California region, where emission permitting places a measurable marginal cost on the byproduct pollution generated. 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. Though the number of startups could change with different market structures and competitive interactions, it is clear that even if one takes all startup costs to be part of the firms' marginal cost calculation, they account for only a tiny fraction of the payments we calculate to be above the competitive level.[25] Likewise, emission costs 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.

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

The results indicate that market power in California's wholesale market was a significant factor during the summer of 1998. Of course, the market was still very new at that time and changes are occuring 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, though they are preliminary, 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 profitibility 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

[25] The ΔTC estimates in Table 4 imply total payments in excess of competitive levels equal to about $500 million during June-September 1998.

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.[26]

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.

[26] 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.

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Appendix: Data Sources

Thermal Generation Data

The unit-specific data used in this analysis can be downloaded from the Energy Institute's website at http://www.ucei.berkeley.edu/ucei/PDFDown/pmdata.pdf .

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.

Fuel prices were aggregated over the four months and across the ISO control area. The price of natural gas was assumed to be $2.83/Mbtu and 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.

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)
(No Import Reduction Assumed ($\alpha = 0$))

Month	Time Block	mean of actual demand per hour	mean of PX price	mean of marginal cost	mean of Lerner Index	mean of ΔTC per hour
June	mid-6am	19275	2.63	2.63	0.000	0
June	6am-noon	26049	12.04	12.00	0.001	702
June	noon-6pm	28561	20.13	19.25	0.026	15528
June	6pm-mid	25529	13.56	13.51	0.001	681
July	mid-6am	22199	17.64	17.45	0.006	2439
July	6am-noon	28473	26.15	23.03	0.085	61551
July	noon-6pm	34987	51.72	27.32	0.367	591650
July	6pm-mid	30906	34.14	25.97	0.169	174340
August	mid-6am	22795	22.50	22.45	0.002	694
August	6am-noon	30104	31.76	26.46	0.104	125402
August	noon-6pm	37595	67.17	29.43	0.414	1058788
August	6pm-mid	32270	36.67	28.29	0.156	206809
September	mid-6am	21224	22.72	22.67	0.002	779
September	6am-noon	28210	30.18	26.35	0.063	95583
September	noon-6pm	32259	49.22	27.99	0.198	588462
September	6pm-mid	28395	33.91	27.18	0.084	172829

Table A2: Actual Price and Estimated Marginal Cost (\$/MWh)
(50% Import Reduction Assumed ($\alpha = 0.5$))

Month	Time Block	mean of actual demand per hour	mean of PX price	mean of marginal cost	mean of Lerner Index	mean of ΔTC per hour
June	mid-6am	19275	2.63	2.63	0.000	0
June	6am-noon	26049	12.04	12.01	0.001	631
June	noon-6pm	28561	20.13	19.35	0.023	13871
June	6pm-mid	25529	13.56	13.52	0.001	549
July	mid-6am	22199	17.64	17.48	0.005	2078
July	6am-noon	28473	26.15	23.48	0.072	52280
July	noon-6pm	34987	51.72	31.34	0.311	482865
July	6pm-mid	30906	34.14	27.07	0.144	149022
August	mid-6am	22795	22.50	22.46	0.001	487
August	6am-noon	30104	31.76	27.54	0.080	99770
August	noon-6pm	37595	67.17	45.12	0.269	591151
August	6pm-mid	32270	36.67	30.88	0.106	141163
September	mid-6am	21224	22.72	22.69	0.001	441
September	6am-noon	28210	30.18	26.94	0.051	81917
September	noon-6pm	32259	49.22	37.88	0.126	290905
September	6pm-mid	28395	33.91	29.61	0.053	108752

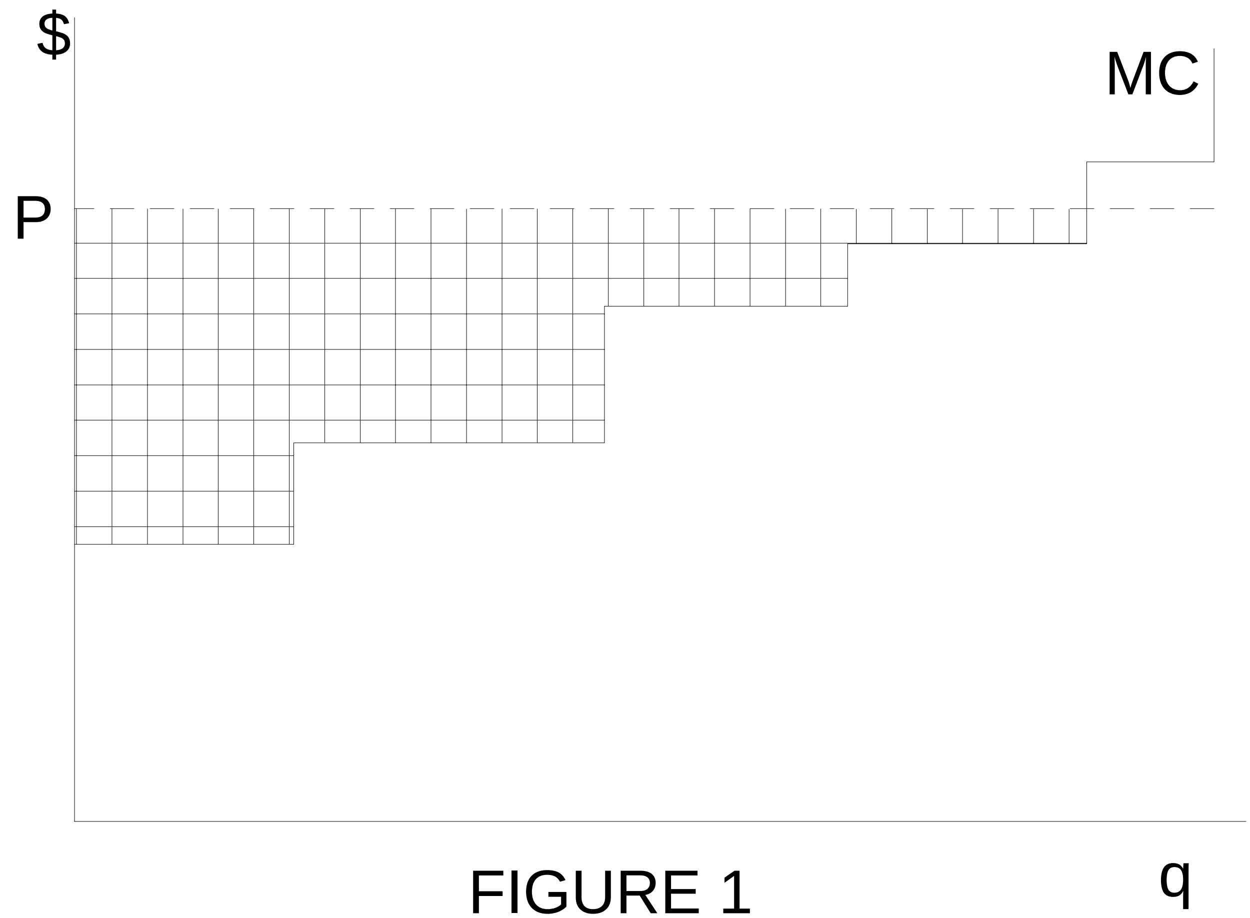


FIGURE 1

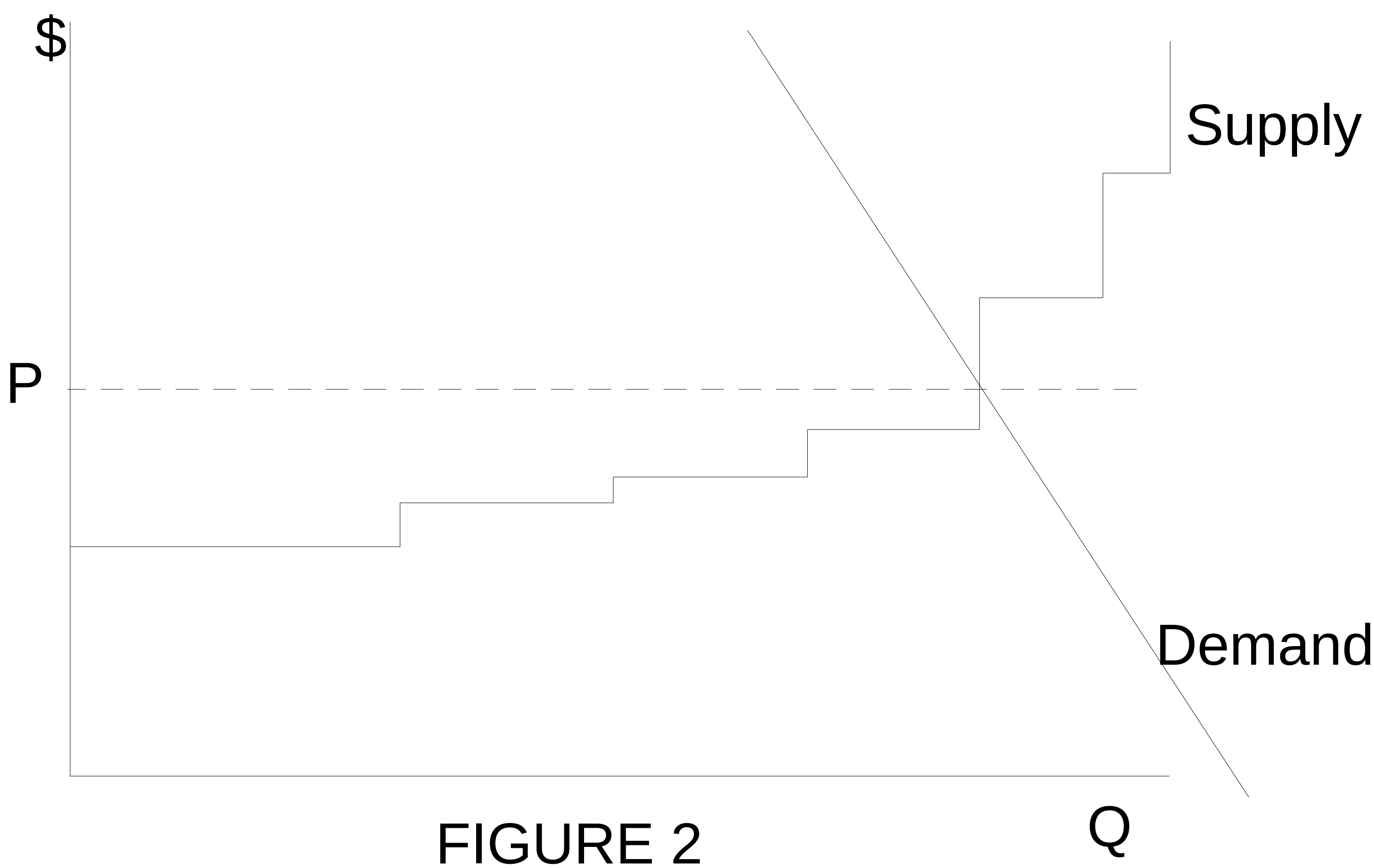
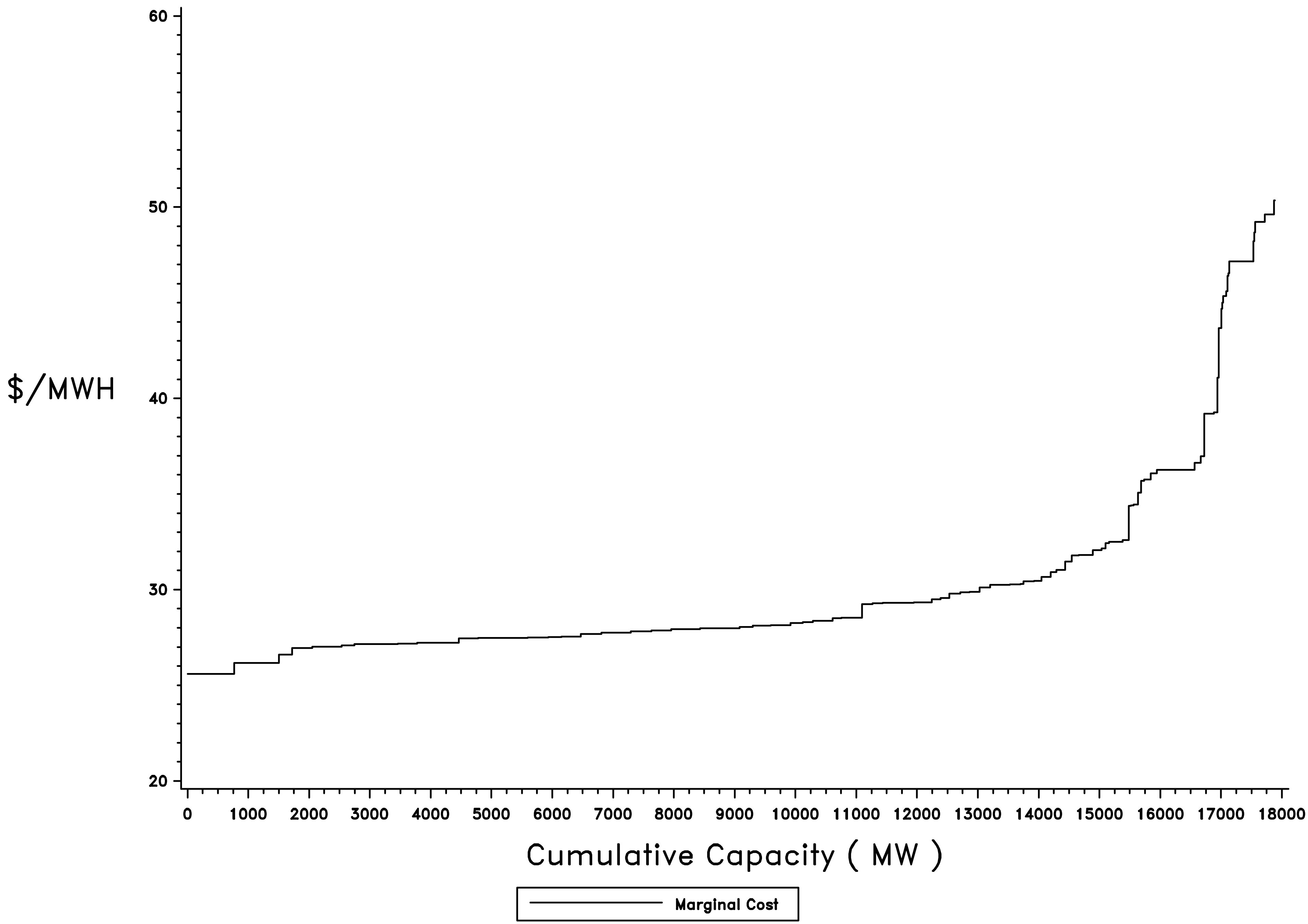


FIGURE 2

Marginal Cost Curve of Instate Fossil Units



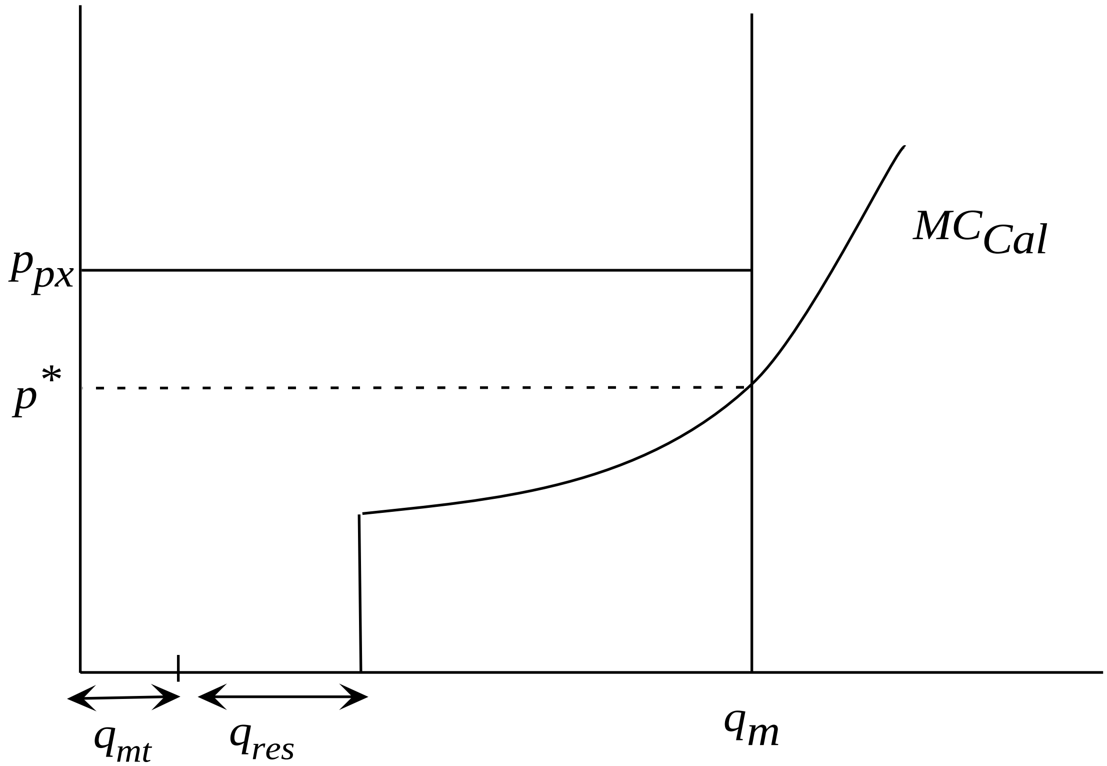


Figure 4: Treatment of must-take and reservoir energy sources

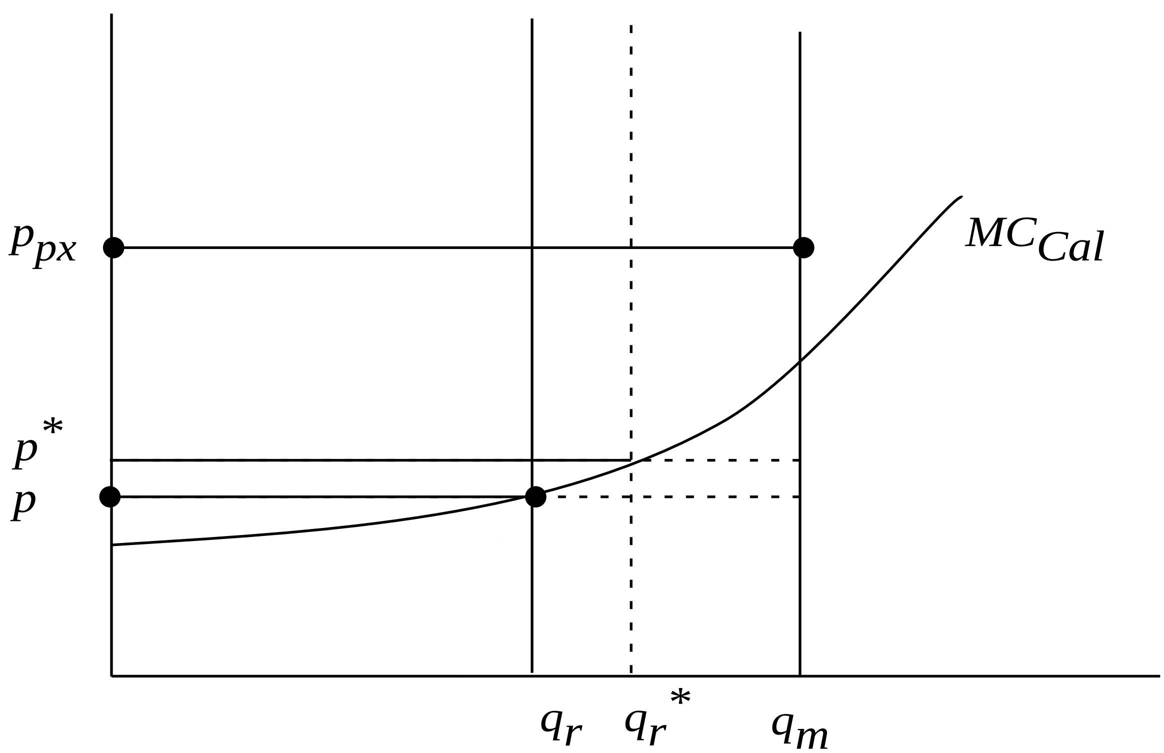
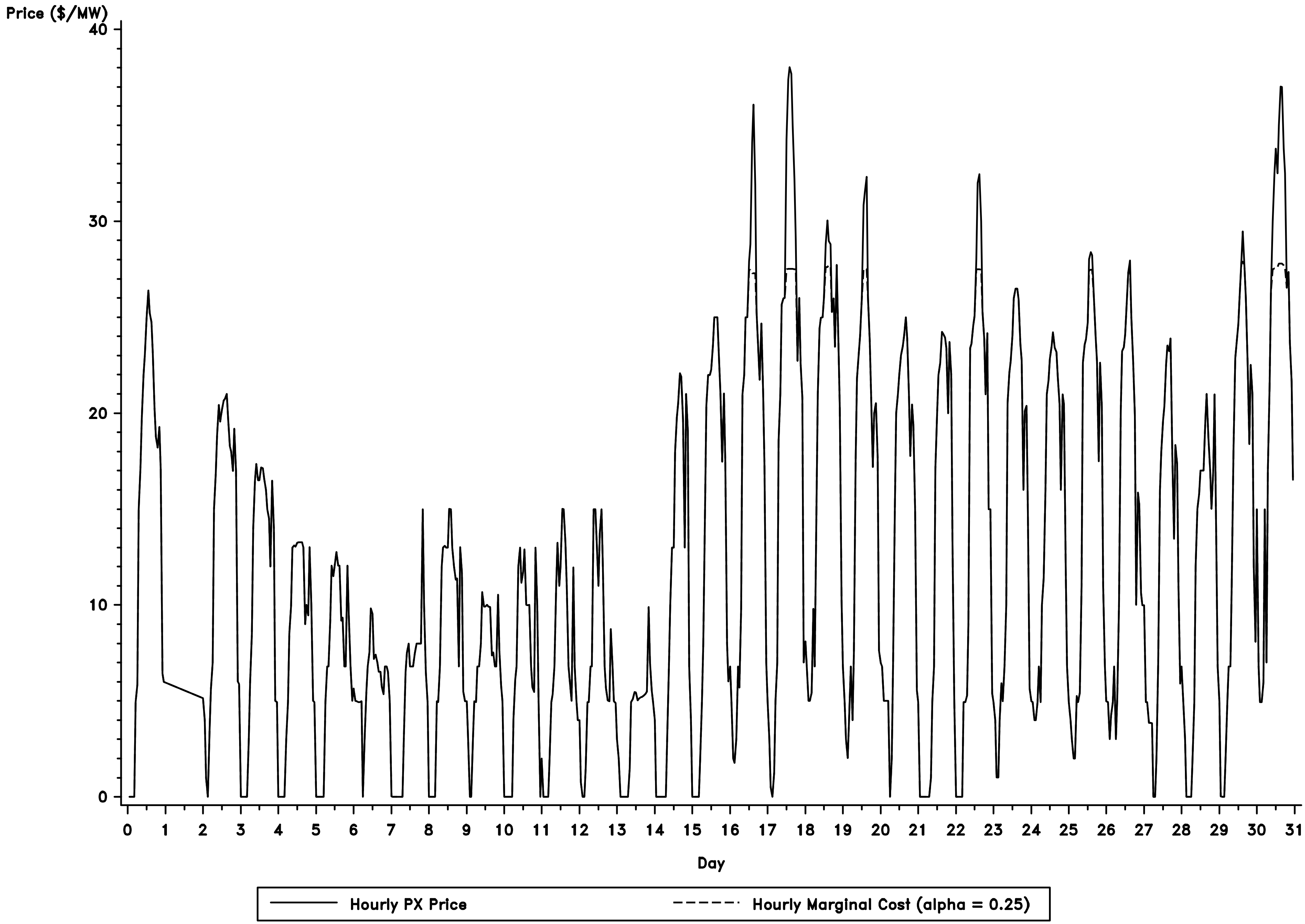
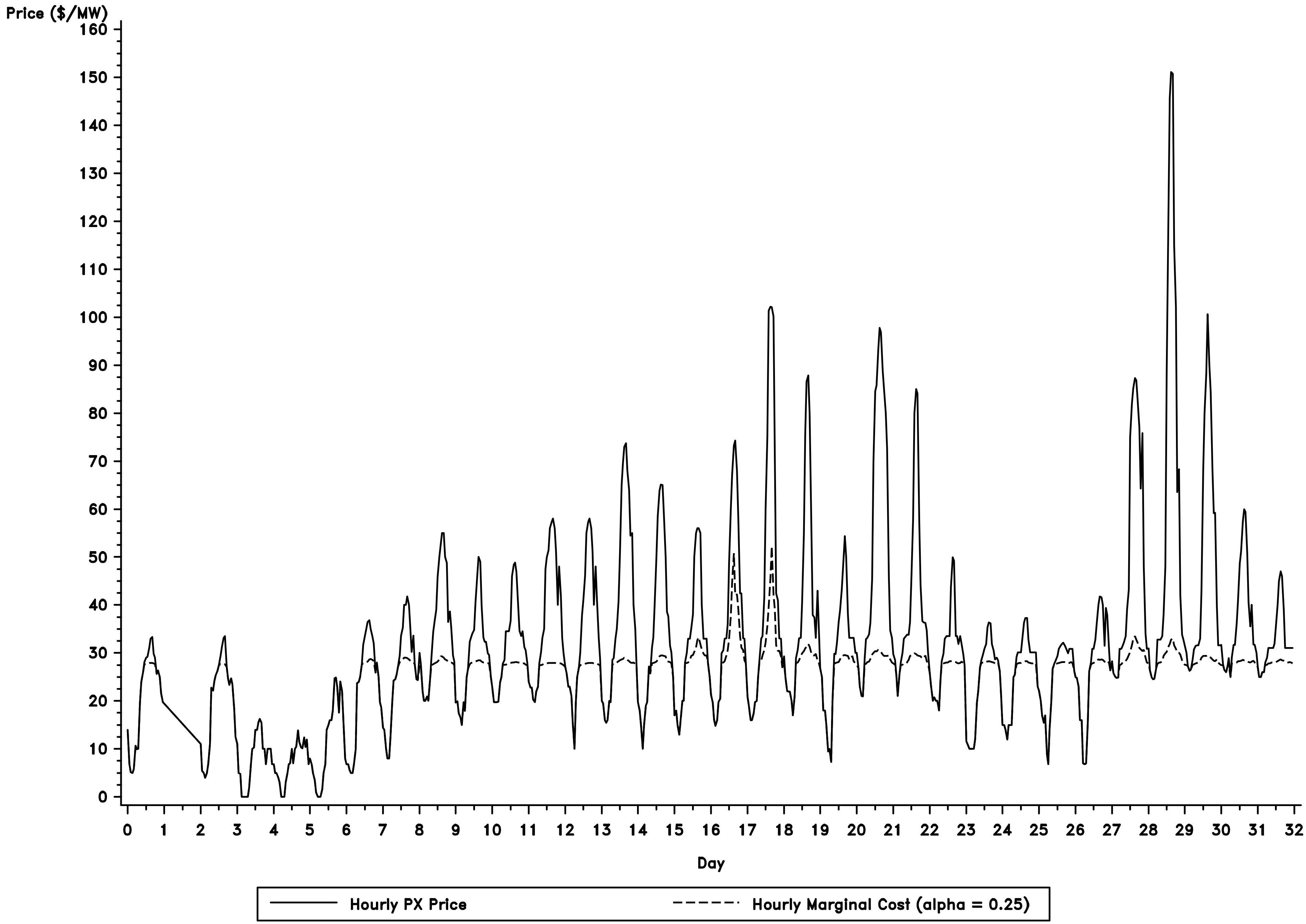


Figure 5: Bounding the impact of imports on marginal cost

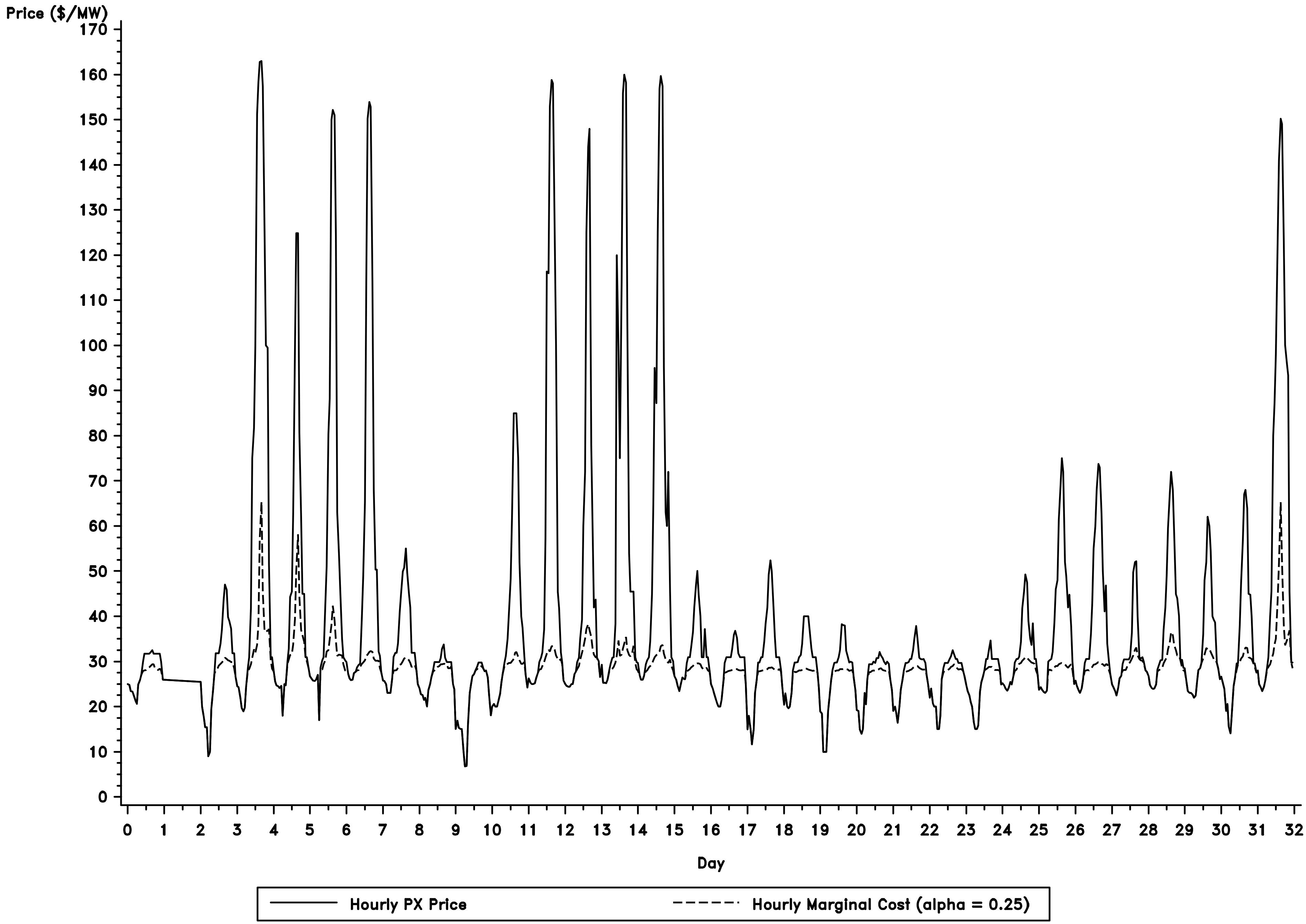
PX Price and Marginal Cost: June 1998

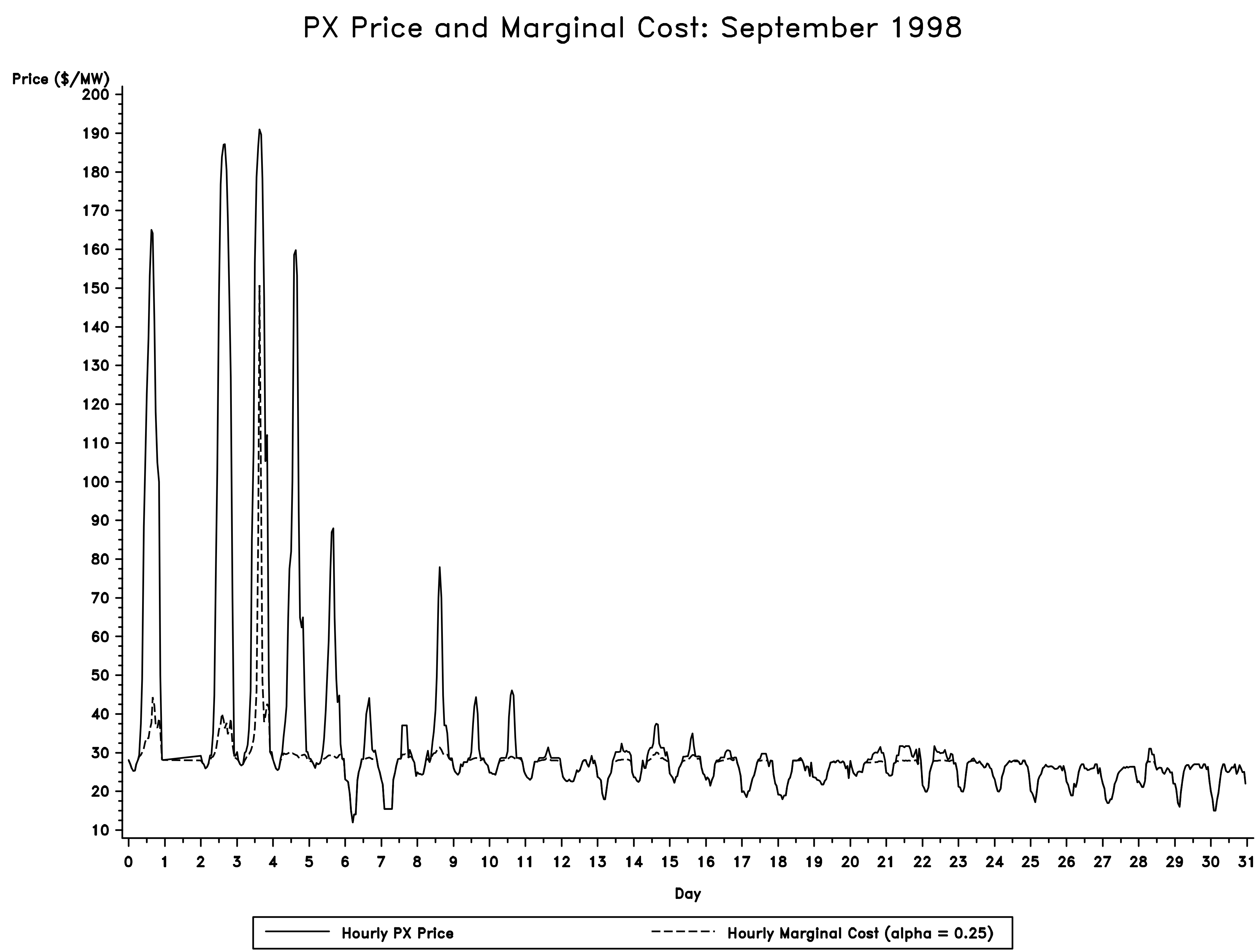


PX Price and Marginal Cost: July 1998



PX Price and Marginal Cost: August 1998




PX Price and Marginal Cost: September 1998
Price ($/MW)
200
190
180
170
160
150
140
130
120
110
100
90
80
70
60
50
40
30
20
10
0 1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24 25 26 27 28 29 30 31
Day
Hourly PX Price
Hourly Marginal Cost (alpha = 0.25)