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Pricing Behavior in the Initial Summer of the Restructured PJM Wholesale Electricity Market

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Abstract

The Pennsylvania - New Jersey - Maryland (PJM) spot market for wholesale electricity was restructured by enabling firms to switch from "cost-based" bidding to unregulated, "market-based" bidding in April of 1999. During the first five months of this phase of restructuring, the market-clearing price exceeded the marginal cost of the most expensive power plant almost three times as often as the previous summer. This paper compares market prices with estimates of the prices that would clear a competitive market, namely the marginal cost of producing electricity. I follow the methodology of measuring market imperfections from the literature while accounting for features unique to the PJM market.

I find evidence of market imperfections leading to an increase in total spot market costs of about 41 percent. I use the markup estimates to compare the PJM experience with that of California during the start of each market. Even though the PJM price cap was four times that of California, markup and total cost estimates using comparable techniques for the first summer of the California market are very similar to my estimates for PJM.

Unlike California, restructuring in PJM did not lead to substantial changes in the ownership of generating assets. The majority of the electricity in PJM comes from self-supplied generation of vertically integrated utilities that face retail price caps. The effect of market power will be diminished since firms' incentives to drive up price depend on the degree to which production exceeds their native loads. I find that the PJM spot market had costs exceeding those of a perfectly competitive market by $224 million during the summer of 1999. If similar markups affected demand met with bilateral contracts, my measure of the total cost of market power increases to $827 million.

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1 Introduction

Over the past fifteen years, there has been a movement towards restructuring wholesale electricity markets in several U.S. states and in other countries. Policy makers believed restructuring would impose market discipline and thus lead to lower cost of production from existing generation units and more efficient investments. Unfortunately, the promises of restructuring have not always been realized. Soaring electricity prices throughout the Western U.S. have lead California to consider returning to a more regulated market and has called into question the entire restructuring movement. So far, restructured eastern U.S. markets appear to have had a relatively successful experience compared to California. It has been argued that the market design of the eastern markets have lead to less price volatility and limited the degree to which firms exercise market power.

In 1998, the Pennsylvania - New Jersey - Maryland (PJM) wholesale electricity market established what is called a "nodal" pricing network, which I describe below. At that time, all firms were required to bid marginal costs of production as determined from years of regulatory oversight. In April 1999, the market operators restructured the market again by enabling firms to switch from "cost-based" bidding to unregulated, "market-based" bidding. This paper examines pricing behavior during the first summer of restructured bidding in PJM in order to determine if prices were consistent with perfect competition or whether market imperfections, such as market power, persisted.

Firms exercising market power cause inefficient production and wealth transfers from consumers to producers in the short-run. Conventional measures of concentration, such as the Herfindahl-Hirschman Index (HHI), suggest a homogeneous good market with several firms of similar sizes is unlikely to exhibit market power.[1] In addition to the general critiques of the HHI, concentration measures are particularly misleading in electricity markets. Several major characteristics of electricity markets make market power more likely:[2] nearly perfectly inelastic demand;[3] economically prohibitive storage; and limited gener-

[1] PJM's largest six firms have between ten and twenty percent of the capacity and the HHI is only 1,114. See Joskow (1997) for more discussion of HHI measures in the PJM market.

[2] See Borenstein, Bushnell, Kahn, and Stoft (1995), Borenstein, Bushnell, and Knittel (1999) and Borenstein and Bushnell (1999) for further discussion on the inappropriateness of HHI measures.

[3] While consumers may respond to prices, the regulatory structure of electricity retail markets has kept the rate consumers pay more or less constant. Furthermore, few consumers observe, or are rewarded for responding to, the real-time price of electricity. As a result of utilities having to provide customers with

ation and transmission capacity.[4] Furthermore, the system operators are bound by the physical constraint that supply and demand must balance continuously. Market power can arise when the price elasticities of demand and competitors' supply are highly inelastic, a case often seen when demand nears generation capacity for the system. A firm with even a small share of the market can greatly influence the price under such circumstances.

This paper focuses on the pricing behavior during the summer of 1999 when prices spiked more often than any other time in the past few years. I follow the methodology of measuring market power discussed in the literature.[5] The market performance measure used is based on the Lerner index.[6] This measure compares the market-clearing price with estimates of the prices that would clear a perfectly competitive market, namely the marginal cost of producing electricity accounting for scarcity rents and opportunity costs.

Section 2 briefly outlines how the PJM wholesale electricity market operates. I review the market structure and examine cursory evidence of market imperfections such as market power. Section 3 discusses a more detailed approach to measuring market power and how to construct a measure of perfectly competitive pricing. Section 4 reports the results of market performance using various price measures. I find evidence of market imperfections leading to an increase in total spot market costs of about 41 percent, totaling $224 million. The total cost of market power increases to $827 million if similar markups permeated the bilateral contracts. I compare markups in PJM and California. Section 5 discusses the relationship between markups and demand, a brief sensitivity analysis, potential biases, and error bounds for these estimates. I report my conclusions in section 6.

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power, the derived demand for wholesale electricity is almost completely inelastic.

[4]Unlike most markets were excess demand will send signals to raise prices, electricity markets respond by the entire system collapsing. Operators must resort to tactics such as rolling blackouts to prevent this from occurring.

[5]Borenstein, Bushnell, and Wolak (2000) carefully consider how to estimate marginal costs in studying the California electricity market. Other important empirical works studying market power in electricity markets include Wolak and Patrick (1996), Wolfram (1998, and 1999), Wolak (1999), Bowring *et al.* (2000), Joskow and Kahn (2000), and Puller (2000). See BBW for a general review of the literature and discussion of the basic issues of market power in electricity markets. Borenstein and Bushnell (2000) provide an overview of issues important to electricity restructuring.

[6]The Lerner index is defined as price minus marginal cost, all divided by price: $\frac{p-mc}{p}$.

2 Background

PJM had only one central market - or "pool" - for energy during the summer of 1999. Financial arrangements are made outside of the centralized market but all power must be run through it. Load Serving Entities (*i.e.*, utilities with end-use customers) meet only 10 to 15 percent of demand in the spot market. The other 85 to 90 percent is met via imports (one to two percent), bilateral contracts (30 percent), and self-supplied (53-59 percent) by vertically integrated utilities with generation and demand.[7] The scheduling and operation of generation units in PJM uses a least cost, security constrained, central dispatch system. Market participants offer bid curves for supply of energy on a day-ahead basis. Ten sets of prices, quantities, and slopes compose the bids for a unit.[8] Other markets allow these bids to differ for each hour, but PJM requires that one set of bids be submitted for the *entire day*. During the time period studied here, bids were not binding financial commitments. The PJM dispatchers post a single price when the system is not constrained by the capacity of the transmission grid (*i.e.*, there is no transmission congestion). The market clears based upon a real-time Walrasian auction where the auctioneer uses the non-binding bids as basis for "calling out" the price.[9] The price is calculated every five minutes. PJM accommodates transmission constraints by using what is known as "nodal" pricing (Schweppe, Caramanis, Tabors, and Bohn; 1988). Each node is a point where energy is supplied, demanded, or transmitted. The PJM energy market can have over 2,000 prices every five minutes when congestion occurs. The transmission system was constrained about 20 percent of the hours in the summer of 1999.

PJM rules limit some ways firms can use their market power. Limiting the number of times bids can change may reduce the degree of market power exerted.[10] Supply will be

[7]The amount of demand met on the spot market is reported in MMU (2000). The 30 percent of demand met by bilateral contracts was an estimate by Joe Bowring of the MMU in a personal communication. The fraction of self-supplied generation was the residual of total demand less spot market, bilateral contracts, and net imports.

[8]The slopes allow firms to bid flat step functions, increasing functions that are continuous between the bids, or any slope in between these extremes.

[9]The system operators post the "call-out" price electronically and firms respond to it. The highest bid of those units willing to sell determines the equilibrium price, given that the bids do not exceed the call-out price or the $1000/MWh cap. The dispatchers raise the call-out price if the supply offered at the call-out price fails to meet demand. This process of reaching the equilibrium continues as long as demand does not approach generation capacity limits. An emergency action will be called if demand nears capacity. All bids must be taken before emergency recalls or purchases can be made.

[10]Wolak (2000) displays how constraining the set of allowed bidding strategies can severely limit the

elastic the majority of hours because many producers have excess capacity. Attempts to move market prices will be limited with such an elastic residual demand curve.[11] Firms want to maximize total profits including those times with elastic residual demand. Firms bid to produce energy using a common bid function for each day, as opposed to hour by hour. The frequencies of other types of bids are even more constrained. Activating a generating unit results in unit commitment costs such as "start up" and "no load" costs.[12] The market bid of each unit consists of an energy component and a unit commitment cost component. Firms that have not opted to bid energy as "market-based" may want to alter the bids by changing their bids for starting up. However, these unit commitment bids can only be altered twice a year. Limiting the number of times a firm can change bids for energy and unit commitment costs may decrease the opportunity for exercising market power.

Another way in which PJM rules limit market power affects bids during congestion. A firm typically can exercise additional market power when transmission constraints bind. A local market becomes more concentrated when it is only served by its own firm or firms. These suppliers become capable of setting much higher prices than when competitors can supply additional power over transmission wires. PJM limits this local market power by regulating the firms' bids when the system is constrained in certain ways. Under certain situations, the PJM operators can cap the offers of generation resources that must be run to maintain system reliability. Bids are reset to marginal production costs plus ten percent (for more detail, see MMU 2000).[13]

Sellers in markets usually have an incentive to drive prices above marginal costs, however, the incentives of many PJM firms are complicated. Historically, the generation, transmission, and distribution of electricity have been vertically integrated. The utilities

ability of firms to achieve their optimal bidding strategies. Klemperer and Meyer (1989) explain the theory of optimal bidding under uncertainty.

[11] Residual demand is the remaining demand that the firms with market power can act upon, accounting for the behavior of other firms.

[12] Start up, no load, and ramp rates pose unit commitment problems. Start up costs are those fuel costs incurred whenever a unit is started in excess of the generation costs. The no load costs are the costs required to keep a plant *ready* to run (ie no net output) on a given day. Ramp rate is how long a unit takes to generate at full capacity.

[13] However, these units can get the local bus LMP (locational marginal price) if it is higher. Withholding capacity when there are local constraints will drive up the bus price and allow some exercise of market power.

in PJM were not required to divest plants and, for the most part, they did not choose to do so (see appendix A for state divestment laws). Furthermore, even some of the divested plants were sold to their own subsidiary companies.[14] The incentives of these vertically integrated firms depend on the amount of generation a firm needs to buy for its customers relative to the amount it can sell on the market. The incentives of subsidiary companies will also depend on the regulatory treatment of their Load Serving Entity (LSE) affiliates. A net seller will be "long on capacity" and will have incentive to increase prices. It can do so either by withholding its most expensive capacity or by offering it at a higher price. The incentives of publicly owned utilities may be unclear even when firms know if they are net buyers or sellers. Net buyers might choose to exercise monopsony power by running their more expensive units with costs above the market price so as to demand less from the market and lower the price paid on their purchased generation. However, it is unclear that firms would be rewarded for this behavior since they will pass costs on to consumers once the rate freeze is lifted. In addition, utilities sign contracts affecting how much supply they are responsible for meeting. This also affects whether a firm is long on capacity.[15]

Suppliers had to make "cost-based" offers when the nodal market opened in 1998 - requiring them to bid their marginal costs of production that had been determined by years of regulation rate hearings. This requirement was relaxed in April 1999 when the Federal Energy Regulatory Commission (FERC) granted firms the right to use "market-based" rates subject to a cap of $1000/MWh. Most utilities obtained the right to bid "market-based" from the FERC. However, few plants were switched over during the first summer. The publicly available bidding data suggest two firms accounted for 84 percent of the "market-based" bids over the summer of 1999, and are likely to have been long on capacity during peak hours.[16] The general organization of the industry is discussed next.

[14] A notable exception concerns a new generating firm, Sithe, that purchased plants in fall 1999, after the period of my study.

[15] In contrast to PJM, California restructuring led to utilities selling more plants to new generation owners and prohibited (or at least discouraged) long-term contracts. This provided incentives for generators to drive up the price.

[16] PJM codes these data so that the identities of the firms and units are unknown. According to *The Wall Street Journal*, August 4, 2000 article by Rebecca Smith and John J. Fialka titled "Electricity Firms Play Many Power Games That Jolt Consumers", 'An analysis of trading data from that day shows that PECO Energy Corp. and PPL Corp., the old Philadelphia Electric Co. and Pennsylvania Power & Light, made the most of steamy conditions .... What PECO and PPL did was offer much of their output at low prices so that the majority of their plants would be called into service. But knowing demand was so high, they offered power from their tiniest plants at vastly higher bids, in a way that often set the peak price

2.1 The Structure of the PJM Market

Nuclear, hydroelectric, and coal are baseload generating plants, capable of covering most of the demand (about 35 of 57 gigawatts (GW) of capacity, see Table 1). Even though over a third of the capacity is natural gas or oil, these expensive units are only used during high demand times of day, especially in hot summers, to meet the peak load. Nuclear power produces about 45 percent of the generation even though it makes up only a quarter of the capacity (EIA Form 759). The difference in utilization of these types of generation units is explained by the high start up costs and low marginal costs of the baseload units compared with the low start up costs and high marginal costs of the peaking units. These unit commitment problems are important in determining which unit should be run to meet demand.

Six firms have between ten and twenty percent of the capacity. The peak demand for each electric utility is given in Table 1. PECO, PPL, and Pennsylvania Electric (PennElec) cover at least 70 percent of their peak demand with their own baseload capacity. These firms are most likely to be long on capacity (to have capacity with marginal costs below price in excess of their native retail load) for a given demand level. PennElec plants were old and inefficient, making them less likely to be long on capacity for given price and demand levels. Furthermore, PennElec was in the process of selling a large portion of their capacity to Sithe during this period. On the other hand, PECO and PPL were active in the spot market and likely had incentive to increase prices (see footnote 15).

Restructuring did not result in a large redistribution of power plants in PJM through the summer of 1999. Only one utility plant was sold and none was retired from 1998 through October 1999.[17] Less than 700 MW of new capacity from utilities and non-utilities came on-line from January of 1998 to October of 1999.[18]

for a number of hours.'

[17]Edison Mission M&T bought Homer City from PennElec in March 1999. Sithe bought 21 in November from PennElec (9), NJ Central (4), and MetEd (8). Sunbury separated from PP&L in November. GPU Nuclear sold Three Mile Island to AmerGen in December.

[18]In August 1999, AES started a 200 MW plant in Cumberland, MD. A utility in the town of Berlin, MD, started a 1.8 MW unit in July 1999 and another of comparable size in December. Non-utility generators in Pennsylvania, New Jersey, Maryland, and Virginia built 481 MW of capacity, about half of which were available by April 1999 (EIA form 860 a,b).

2.2 Preliminary Evidence of Market Power

From 1998 to 1999, the average wholesale price of electricity increased by 36 percent in PJM.[19] During the first five months of market-based bids (April to August of 1999), the market-clearing price exceeded \$130/MWh almost three times as often as the previous summer (this occurred 37 hours in 1998 and 96 hours in 1999). PJM's market monitoring unit (2000) considers this level to be the highest marginal cost of production during this period. Many factors must be considered before one can determine the extent to which this difference resulted from market power or other types of market imperfections as opposed to legitimate increases in marginal costs. The demand for electricity varies greatly by time of day and temperature. The summer of 1999 was hotter than the previous summer. The mean of the daily temperature averages went from 73.3 to 74.3, and the mean of the daily maximum temperature went from 82.5 to 84.8. Structure changes slowly in electricity markets; capacity and average hourly demand grew by about 700 MW. However, the peak demand increased by 2180 MW (or 4.4%) over the previous high in the summer of 1999. Key input prices changed from 1998 to 1999, as well. The price of fuel used in oil-burning generating units (No. 2 heating oil sold at New York Harbor) went from an average of 36.2 cents per gallon in the summer of 1998 to 49.4 a year later. Natural gas prices at Transco Zone 6 non-New York ranged from \$1.8 to \$3.28 per million BTU over the two summers, but the average prices were close (\$2.36 and \$2.57 in 1998 and 1999 summers, respectively). The Ozone Transport Commission (OTC) began a regional trading program for nitrogen oxides (NO_x) emissions in the summer of 1999 affecting some of the states in PJM. The permits fell precipitously over the summer from about \$5000 to \$1000 per ton. The national sulfur dioxide (SO_2) emissions trading program had prices climb from about \$150 to \$200 per ton over the two summers. Increases in peak demand, fuel costs, and environmental costs led to higher prices that must be considered when measuring market power.

[19] These prices are averages over a nine-month period of April to December. Only these months were examined because the market did not start until April.

3 Measuring Market Power

Estimates of market power typically focus on determining marginal cost. However, defining *the* price in a nodal system poses a challenge, as well. This study focuses on the first five months of "market-based" offers from April to August of 1999. The generation and transmission capacity limits bind mostly in summer months, making the residual demand inelastic and market power more likely. PJM reports a load-weighted average of all nodal prices for each hour. This price had an unweighted average of \$41.80 and reached the cap several times between April and August. In contrast, from September 1999 to April 2000, the price averaged \$21.60 and peaked at only \$142.00. The summer of 2000 did not see such high prices, due to a combination of factors.[20] Therefore, the period of my study is likely to have more market power than any other period in since the market began.

I calculate the price-cost markup for each summer hour, and report monthly and time of day aggregate load-weighted Lerner indices of 1999. This section describes how I measure prices, marginal cost, imports, and hydroelectric generation. The process of determining the market equilibrium for each hour is also discussed.

3.1 Prices

The PJM energy market can have thousands of different locational prices at a given time. An accurate model of a nodal price system would account for transmission constraints and loop flow concerns in addition to calculating marginal costs. Such a model would have to recreate the dispatch decisions of the PJM operators, an impossible task given the "black box" nature of the decisions. I look at the marginal costs of a market with no transmission constraints within PJM. This makes this study tractable and enables me to accurately estimate costs at least for a subset of hours rather than trying to replicate the market exactly. The market imperfections measured in this manner therefore do not account for

[20] The summer of 2000 had lower temperatures and 73 percent more hydroelectric production. In June of 2000, PJM started a day-ahead market in addition to the real-time market. Allaz and Vila (1993) show how the presence of a two-settlement system can reduce market power. Changes in ownership resulted in less concentration of firms (though more firms that are net sellers). In addition, this change of ownership increased the likelihood of some firms being net buyers, which could have increased oligopsony power. The costs of production were quite different in the summer of 2000: the average fuel costs of natural gas and oil increased by 58% and 45% while environmental costs of SO_2 and NO_x fell 34% and 85%. Future work will extend this analysis to more recent months.

the entire PJM market, only the spot market for energy when congestion constraints do not bind. As a result, I also must determine the prices of a system without transmission constraints for both a perfectly competitive market and the observed market.[21]

One option for estimating a market-wide unconstrained price is to use bid data to calculate what the price would have been without transmission constraints. However, the bids were not financially binding during my sample period and may misrepresent the market price. For example, market-based bidders have ignored their bids by generating before the price reached their bid price, forgoing the ability to set price. In addition, the lack of financially binding bids complicates how I measure hydroelectric generation (see section 3.4).

Alternative measures of a single price use information from the hourly nodal prices in PJM. PJM reports the load-weighted average of all nodal prices for each hour. This measure may be a biased estimate of the unconstrained price but the bias is indeterminate *ex ante*. While constraints necessarily increase total *costs* in a perfectly competitive market, the average *price* may actually fall (see appendix B discussing Figure 1). The effect of congestion on pricing in a market with market power is further confounded. Congestion reduces the elasticity of residual demand but congestion rules cap some bids near costs.

I use this load-weighted average price measure along with two others to approximate the unconstrained market-clearing price. The minimum of all nodal prices cannot exceed the price for an unconstrained system. I use this minimum price to construct a conservative estimate market power.[22] A second method focuses on the 80.3 percent of the hours without congestion. This will result in market power measures comparable to other markets if congestion and market power are uncorrelated. I test for this correlation in section 4.1.2. I then use the markups from the uncongested hours to predict markups, and therefore prices, for an uncongested system for all hours.

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[21] It is important to note that if the price is being set by perfectly competitive bids, then congestion will not affect *bids* since it does not affect marginal costs of production, however, it will affect *prices*.

[22] The minimum nodal price is calculated based on all of the over 2000 nodal prices from the daily LMP data.

3.2 Marginal Costs

Calculating marginal costs requires careful consideration of the opportunity costs firms face when choosing to generate and sell into PJM. The proper measure of the marginal cost of selling into PJM is the greatest of the marginal cost of production, the opportunity cost of the prices in neighboring markets, and scarcity rents in addition to the marginal production cost. The lack of storability makes inter-temporal opportunity costs mostly irrelevant with the notable exception of pumped storage and hydroelectric power that I will discuss in section 3.4.

PJM firms have the option of selling into the spot market, or making bilateral trades with Load Serving Entities inside or outside of PJM, such as in western Pennsylvania or Ohio (the ECAR region). No trading market exists in ECAR and bilateral trades have reached $7500 and $9000 per MWh in the summers of 1998 and 1999 for some small trades. Net imports flow into PJM the majority of the time. If firms observe prices and sell in the market with the highest price, then positive net imports imply PJM prices are greater than or equal to those of other regions. The marginal cost will *not* be the opportunity to export if the outside price does not exceed that in PJM. The prices outside of PJM must be considered when the net imports are negative, however. If the price in ECAR is higher than the production marginal cost, then the marginal cost in PJM is the price in ECAR. There were only four hours when the unconstrained PJM price exceeded $130 and net imports were negative in 1999. A perfectly competitive market will have more hours with net exports relative to a market with imperfections. The opportunity to export power will also disappear if the transmission out of PJM is completely congested by net exports.

Two markets will have the same price in equilibrium if arbitrage exists and the markets have no transaction costs. If this is the case in the electricity markets, then by accounting for the behavior of imports and exports as in section 3.3, I will be describing the equilibrium condition among markets such that no other opportunity to export exists.[23] Thus, the cost of electricity will typically be the production marginal cost, not the opportunity cost.

The marginal cost curve of this industry is a step-wise function. Scarcity rents arise

[23]Even with transaction costs, accounting for import supply behavior imposes that the price difference will not exceed these costs. Their will still be no opportunity to export since the profits of exporting would be less than selling in PJM.

when the equilibrium price falls between the production marginal costs of two units, or exceeds all marginal costs. Excess demand exists at a price equal to the low cost, and excess supply exists at the high cost. The market clears by recognizing the shadow price of the production constraints of the low cost unit. Demand in this market is perfectly inelastic so scarcity rents will only occur with positive probabilities if demand exceeds the capacity of the entire market.

The marginal costs of production can be calculated using rich sources of data and formulas due to years of regulation rate hearings. Production marginal costs are calculated as the sum of fuel costs, variable operating and maintenance costs (VO&M), and emissions costs. The fuel costs were calculated using heat rates, historic fuel costs for coal, and spot prices of oil and natural gas.[24] Appendix C discusses further details of the cost estimates.

Twenty-two generators in PJM are regulated by Phase I of the 1990 Clean Air Act Amendments' Title IV program. These units are required to purchase or use "grandfathered" tradable permits for each ton of sulfur dioxide (SO_2) emitted. If a firm switches to low sulfur coal or installs an expensive scrubber, then they can sell excess permits.[25] In either case, the price of the permit is the opportunity cost of polluting. During the summer of 1999, the price of these allowances was about \$200 per ton. This corresponds to about one dollar per MWh for a coal plant with a heat rate of 12,000 BTU/kWh and an emissions factor of 1.2 lbs. of SO_2/mmBTU.

A tradable permits market has also been established for emissions of nitrogen oxides (NO_x). The Ozone Transport Commission (OTC) market began in 1999 and only applies to May through September emissions. Twelve states, including Maryland, Pennsylvania, New Jersey, and Delaware, are in the market. However, Maryland did not join until 2000 so plants there are exempt during my sample period. The price for permits varied from \$5244/ton in May of 1999 to \$1093 in mid-September - corresponding to \$13 to \$2.5 per MWh for a unit with a heat rate of 10,000 BTU/kWh and an emissions factor of 0.5 lbs. of NO_x/mmBTU.

[24]While spot markets for coal exist, the heterogenous product trades on more dimensions than simply price and quantity. Factors such as moisture, ash content, sulfur content, and location determine the type of coal being traded. Rather than modeling each plants coal costs, I impose constant prices for delivery of coal.

[25]Two generators at the Conemaugh plant, owned by GPU Service Corporation, installed scrubbers in 1994 and 1995.

3.3 Net Imports

Firms inside and outside of PJM will choose what market to sell to depending on relative prices. The price under perfect competition will lie below the market clearing price of a market in which firms exercise market power. This results in the supply of net imports being lower under perfect competition. To meet the perfectly inelastic demand, more expensive units in PJM will have to run instead. Therefore, ignoring the price responsiveness of net imports would lead to an overestimate of markups.

To estimate an import supply curve, Borenstein, Bushnell, and Wolak (2000) – hereafter BBW – aggregate confidential import bid curves for the day-ahead market in California. I do not follow this method since the PJM bids are not financially binding during my sample. In addition, imports other than those bidding into the day-ahead market respond to real-time prices.[26] Instead, I estimate the net import supply relation during my sample period. Firms selling energy into PJM from other regions are assumed to behave as price takes because of regulatory restrictions in those regions, the PJM pricing rules,[27] and the large number of firms capable of selling into PJM. To the extent this assumption is wrong it will lead to an underestimate of market power.

When transmission constraints do not bind, PJM and surrounding regions are essentially one market. However, the multitude of prices and loop flow concerns make assuming perfect information implausible. The net import supply relation depends on prices in PJM and the surrounding regions. More explicitly, the *sign* of the net imports will depend on the price difference, relative to transaction costs, and the *magnitude* of net imports will depend on the price level and, if transaction costs are heterogeneous, the price difference. In other words, a firm in ECAR will only export to PJM if its unit's marginal costs are not greater than the price in PJM and the price in ECAR is not above that in PJM, accounting for transaction costs. I cannot explicitly model the price difference and the level since some prices are not publicly available. The prices in neighboring regions were solely bilateral contracts at the time of my study. New York opened an energy market in November of

[26] The day-ahead bids are less elastic than the real-time supply. The markups derived using the supply curve based on real-time net import supply curve are smaller since reduced imports will prevent the price from dropping as much. I use these real-time imports to estimate net import supply.

[27] PJM only allows imports to set the price if they bid into the day-ahead market. Obviously this will not prohibit importers from exhibiting market power as they can still withhold or bid high in the day-ahead market. However, it makes them price-takers in the real-time market.

1999. I use the daily mean temperature - measured in degrees Fahrenheit above 65 - as a proxy for outside prices in the bordering states of New York, Ohio, Virginia, and West Virginia. I do not include variables such as costs in PJM and outside areas. However, I do include monthly indicator variables allowing supply curve to shift. This imposes that the underlying supply function was constant, conditional on the weather, throughout a month.

Common functional forms for modeling price responsiveness of net imports include a linear relationship or a constant elasticity assumption. Linear models fail to account for the inelastic nature of the supply curve near the transmission constraints. Transmission constraints of lines entering PJM bind and limit the amount of net imports. One option would be to have a piece-wise linear model. However, movements along the supply curve may be misleading near the kink if the actual supply curve is a smooth function. Choosing the break point would require either determining an arbitrary level or "datamining" to find the optimal cutoff. There are several reasons a constant elasticity assumption would not be preferable. First, this assumption requires the supply curve to pass through the origin. Second, there are many hours when the net imports are less than zero. These data would not be modeled since the log of negative net imports is undefined. I could model the *positive* net imports differently than I model the *negative* net imports, but doing so would require accounting for selection bias and the interdependence of the two supply curves. I opt for an alternative model linear in net imports and logarithmic in PJM prices. The model is smooth, defined for all net imports, and accounts for the inelastic nature of imports near the transmission constraint. This functional relation imposes a constant relationship between percent change price and MWh net imports.

The estimation of the price elasticity of net imports must account for the endogeneity of price. If net imports increase, the equilibrium price will fall, assuming the residual demand net importers face is downward sloping. Ignoring this effect leads to a downward bias. I instrument price with the average daily temperatures in Pennsylvania, New Jersey, Maryland, and Delaware. In addition, the log of hourly PJM load is used as an instrument. This unusual choice of an instrument is valid in this case since demand is perfectly inelastic.

I test the error structure for autocorrelation (Durbin-Watson statistic of 0.137) and heteroskedasticity (Cook-Weisberg test with $\chi^2 = 90.18$). I estimate the IV coefficients assuming the errors are independently and identically distributed in order to calculate an unbiased estimate of ρ, the first-degree autocorrelation parameter. After quasi-differencing the data, I reestimate the IV coefficients while using the White technique to address heteroskedasticity. The model is shown in equation 1.

$$IMP = \alpha + \beta \ln(P) + TEMP'_{PJM}\Gamma + MONTH'\Psi + \varepsilon, \tag{1}$$

where IMP is the real-time system-wide net imports; P is the PJM price; $MONTH$ are monthly indicators; $TEMP_{PJM}$ are the daily mean temperatures for states in PJM; and ε is a first-degree autocorrelated, heteroskedastic error. In the first stage, the log of PJM price is regressed upon a constant, the log of demand, daily mean temperatures for states outside of PJM, and the other independent variables from the above regression ($TEMP_{PJM}$ and $MONTH$).

The first model in Table 2 reports the ordinary least squares coefficients and standard errors where the supply curve is assumed to be constant for all months. Models 2a and 2b report the first and second stages of the instrumental variables (IV) regression. Ignoring the endogeneity leads to less response of net imports to the PJM price. The model 2b estimates a 1278 MW increase in net imports for every one percent increase in prices (with standard errors of 81). In order to interpret the price elasticity from this estimate, divide this coefficient by the level of net imports. For example, the average net imports during this study was 1869, leading to an elasticity of 0.684. Higher temperatures in importing states should lower imports during the summer months of my sample since demand in those states will rise and less generation will be available to export.[28] The temperature variables are highly correlated, leading to large standard errors. An F-test finds the temperature variables outside of PJM weakly significant (p-value of 0.052). Models 3, 4a, and 4b include monthly variables. The F-test of the joint significance of the month variables in model 4b is significant (p-value of 0.002). The price responsiveness is unaffected by the inclusion of monthly dummies with a coefficient of 1299 and s.e. of 79.[29] Figure 2 plots the inverse net import supply curve using model 4b with the average temperature in each state during April.

[28]However, this effect will be offset if temperatures affect the relationship of the importing state with other neighboring states. For example, rising New York temperatures may lead to significant imports from New England. This could make more power available for export to PJM.

[29]A Hausman test fails to reject a difference in this coefficient (the difference of -20.4 has s.e. of 15.8).

Net import supply in PJM is likely to be more elastic than in California. PJM units' costs are similar to those in import regions, whereas California costs tend to be higher that its neighbors. The net imports in California are more likely to be constrained by transmission capacity and, as a result, more inelastic. Finally, there are more marketers in PJM making arbitrage of price differences across regions more likely. Nevertheless, PJM net imports are inelastic and large increases in price are needed to drive up the amount of imports. The price elasticity of the average net import is 0.684, which is substantially higher than the implied elasticity of 0.33 in California.[30]

I use the estimated net import supply curve of model 2b to estimate the change in net imports under perfect competition pricing in comparison to the behavior under the observed prices. Net imports are bounded by capacity limits of transmission out of PJM.[31] The assumed functional form for net imports implies the relationship of imports shown in equation 2.

$$IMP_{mc} = IMP_p + \widehat{\beta} \ln(\frac{mc}{p}), \tag{2}$$

where mc is the perfectly competitive price (equal to marginal cost); p is the observed price; IMP_{mc} is the net imports under perfectly competitive pricing; IMP_p is the observed net imports; and $\widehat{\beta}$ is the estimated price responsiveness of net imports from model 2b.

3.4 Hydroelectric Generation

Unlike other types of generation, hydroelectric generation faces limited reservoirs of how much energy it can produce between periods of precipitation. The costs of producing power are negligible, but the opportunity costs of generating can be quite high. A price-taking firm maximizes profits by producing only in the highest price hours; producing at any other time will forgo the opportunity of receiving a higher price.[32] Units are constrained by minimum flow rates of rivers, capacity constraints of generating power, and these reservoir constraints.

Following the logic outlined in BBW, I assume hydroelectric generation will not vary from the observed levels. This biases down the measure of market power for two reasons.

[30] This estimate is calculated in Joskow and Kahn (2001) based on BBW.

[31] The observed net imports for the summer of 1999 ranged from -3,247 MWh to 8,609 MWh.

[32] A price-setting firm will optimize by producing in the hours with the highest marginal revenue.

Owners of hydroelectric generation who behave competitively will to equalize *price* across all time periods given environmental and capacity constraints. If other firms are exercising market power, the price in a perfectly competitive market will be lower than observed and hydroelectric generators would have produced less in the peak hours. Secondly, if firms using hydroelectric plants to exercise market power, then they will attempt to equalize *marginal revenue* across hours, subject to production constraints. This results in more production off-peak than does a perfectly competitive firm (assuming residual demand is more elastic off-peak). The net of these two effects distorts production and biases down estimates of market power. The effect will likely be small as hydroelectric power produces such a small proportion of PJM electricity.

Hydroelectric generators bid into the market differently than other producers. They cannot bid market-based rates. In fact, they are required to bid a price of zero. However, they are allowed to alter the quantity bid for each hour, unlike the rest of the market that bids for the entire day. Other types of generation also place "zero-priced" bids. All generation must be dispatched in the spot market pool. The supply of bilateral contracts may be "bid" in at a zero-price to ensure that they are called upon. PJM reports all of the "zero-priced" bids for the entire system by hour. Even if only hydroelectric units' bids were reported, these data would not be reliable since the bids were not binding. The monthly total of "zero-priced" bids exceeds the EIA reported monthly hydroelectric generation by as much as twenty-fold in some months. I assume the ratio of hydroelectric generation to total "zero-priced" bids remains constant within a month. Appendix C further discusses this estimation procedure.

3.5 Solving for the Perfectly Competitive Equilibria

Firms are more likely to exercise market power using certain types of generation. Some generation resources have bids reset by PJM to avoid local market power during transmission constraints (see section 2). Hydroelectric units must bid "zero-priced" bids as discussed above. In addition, nuclear generation is not likely to be used to affect prices. Huge start up costs and low marginal costs result in these units running near capacity for long periods of time. When they are shut down for maintenance, the units are typically down for three weeks. The median of the monthly utilization rates for all nuclear units was

98 percent in PJM during the summer of 1999. I assume firms do not use nuclear plants to move price since these plants are expensive to ramp up or ramp down. Nuclear units are assumed to have a constant utilization rate based on monthly averages. The nuclear units bid a common daily bid like the fossil fuel units. Marginal costs average less than \$10/MWh and do not set the market price.

The remaining supply units are fossil fuel units capable of affecting prices. I determine the market-clearing price by finding the price at which the demand and supply equate for these fossil units. Changes in fuel and environmental permit costs affected the marginal production costs over the summer so that each day has a different supply curve. The system-wide demand includes the initial market demand plus line losses and ancillary services of regulation and reserves.[33] The demand the fossil units face equals this total demand less the production from other sources, namely the "fringe" supply. This fringe consists of hydroelectric and nuclear generation, which are assumed to be perfectly competitive and perfectly inelastic for the reasons given above. In addition, I subtract net imports, which do respond to price, from the demand as described in section 3.3. Equation 3 shows the residual demand curve facing the fossil fuel units.

$$q_D^R(P) = q_D + L(q_D) + \operatorname{Re} s + \operatorname{Re} g - q_S^H - q_S^N - \widehat{IMP}(P), \tag{3}$$

where q_D^R is the residual demand of fossil fuel units as a function of price; q_D is total demand; L is line losses that are a function of q_D; Reg and Res are ancillary services of regulation and reserves; q_S^H is hydroelectric supply; q_S^N is nuclear supply; and $\widehat{IMP}(P)$ is the estimated net import from equation 1 as a function of price.

The calculation of a supply curve requires knowledge of the marginal costs of those units generating electricity, but also of *which* units are capable of providing electricity for any given hour when calculating the perfectly competitive price. Generating units cannot run constantly; routine maintenance and unexpected forced outages limit the amount of capacity available. Most routine maintenance occurs in the fall when demand has decreased and there is less need for individual generators to be available. Even under perfect

[33]Line losses need to be included since about 4.5 percent of all generation does not reach the demand. Data are available on line losses from PJM. Regulation and reserves are required to insure against system-wide outages. Regulation is defined as 1.1% of maximum of load during each part of the day: the morning hours (hours 1-5) and the rest of the day (hours 6-24) (see PJM's Pre-Scheduling Operation Manual). Reserves are set at 1700 MW (see PJM's Scheduling Operations Manual).

competition, a forced outage can change the price substantially when supply is close to being exhausted.[34] The convexity of the marginal cost curve implies that the expected costs exceed the costs of the expected supply for a given level of demand. Calculating the supply curve from observed outages would bias results because these outages are endogenous when a firm can set prices (Wolak and Patrick, 1997). A firm can exert market power by bidding high and setting the price directly with the marginal unit, bidding above the equilibrium price thereby removing its unit from the set of generating units, or claim a unit had a forced outage and cannot provide generation. In either of the last two cases, the market price will increase because the demand will be met with a higher cost unit leading to deadweight loss. The outage data will reflect this market distortion so outages will need to be simulated in order to replicate a perfectly competitive market. A Monte Carlo simulation based on historic outage factors accounts for uncertainty over which units are capable of supplying power.

The supply curve is the aggregation of capacity for all operating units. In order to account for outages, a unit is determined to be operating if a draw from a uniform distribution exceeds its forced outage factor.[35] The supply curve is constructed of all operating units and the market equilibrium is determined. This is done for each hour. I repeat the process 100 times. If demand exceeds the supply of the entire market, then I use the net import supply curve to determine the equilibrium price. Any price above the price cap is reset to $1000. I calculate the mean and 95th percentile of these draws to compare with observed prices.

Figure 3 plots the market supply curve for capacity on April 1, 1999. The figure also graphs expected capacity - capacity times one minus the forced outage factor - about four GW less than total capacity over the entire market. The curve includes hydroelectric (the first two GW) and nuclear (the next 13 GW). The fossil fuel supply curve begins when the price jumps from $9 to $16 per MWh. The first 37 GW of the fossil fuel capacity have fairly similar costs (between $16 and $45), and it is not until the last five GW of capacity that the supply curve becomes inelastic (quickly rising to over $100/MWh).

[34] When firms are exercising market power, an outage can make a unit pivotal and enable it to increase prices even more than under perfect competition.

[35] I solve for equilibrium by minimizing excess supply. Residual demand is a function of imports, and therefore, responds to price. As a result, the residual demand can intersect supply between operating units. The price is set by imports in this case.

4 Market Power Estimates

I calculate the mean for each hour using the 100 Monte Carlo equilibrium draws. The mean of the draws is an unbiased estimate of the expected price under perfect competition. Figure 4 displays the daily averages of the price and the expectation of the perfectly competitive price for April, the lowest average demand month of the sample.[36] April prices were approximately equal to the costs on average, however the observed prices varied from about zero to $60/MWh while the average perfectly competitive prices were between $15 and $35. This is likely to be a result of unit commitment issues as will be discussed below. Figure 5 displays the daily maxima of the price and the expectation of the perfectly competitive price for July, the highest average demand month of the sample.[37] Prices were highly volatile. The price exceeded $500/MWh in 47 of the hours in which the transmission system was unconstrained (the load-weighted average price never went this high when there was congestion). My measure of the expected competitive price never exceeded $500 in any hour of my sample. From April through August, 1999, the competitive equilibrium price had an unweighted average of $32.3/MWh. This is $9.5/MWh below the actual average price.

4.1 Market Performance Measures

Plants operate when price falls below estimates of marginal cost since the estimate ignore the shadow price of shutting down. If a firm expects the price to increase in the future and its unit has large start up costs, then it will be less expensive to run in low demand hours than to shut down and start up again. The actual markup will be nonnegative when considering this dynamic aspect of costs. A calculation of the average hourly Lerner index ignoring this would be misleading. In addition, an average Lerner index for any market with large demand swings may not reflect the degree to which firms are exercising market power. Electricity demand ranged from 18,000 to 52,000 MW in the summer of 1999. A markup during a high demand hour will result in higher total costs than one in a low

[36]This paper reports the 95th percentile to provide a heuristic description of the distribution of draws and the proximity of demand to supply capacity. In April, the 95th percentile tracks the competitive mean closely due to the abundance of capacity near the competitive market-clearing price.

[37]The 95th percentile of the competitive draws exceeded $500 for 14 hours in July.

demand hour. A measure of market performance concerned with the overall cost of market power should place more importance on markups when demand is high.

BBW suggest an alternative to the Lerner index to measure markups. The change in total energy costs resulting from market imperfections is denoted ΔTC. The market performance (MP), or demand-weighted Lerner index, is defined in equation 4.

$$MP(S) = \frac{\sum_{t \in S} \Delta TC^t}{\sum_{t \in S} TC^t} = \frac{\sum_{t \in S}(p^t - \overline{C}^t)q^t_{tot}}{\sum_{t \in S} p^t q^t_{tot}}, \tag{4}$$

where S is the set of hours in a sample; p^t is the observed price; $\overline{C}^t$ is the average of the Monte Carlo simulations for the perfectly competitive market price; and q^t_{tot} is the total demand affected by the spot price. This quantity will include the fraction of the demand, including line losses, purchased on the spot market. The majority of demand is met by self-supplied generation and is not included in the total costs of market power. The energy purchased directly from the spot market clearly does apply; this is about 10 to 15 percent of demand (appendix C describes how the fraction of demand met on the spot market is determined by month and time of day).

$$q^t_{tot} = (q_D + L) * SPOT\_FRACT, \tag{5}$$

where q_D is total demand; L is line losses; and $SPOT\_FRACT$ is the fraction of the market that is met by the spot market.

In addition, bilateral contracts meet about 30 percent of demand. If the contracts are indexed to the spot price, then this fraction should also be included. Even if they are not explicitly indexed, efficient markets will imply that the contract price will equal the expected price of the spot market (assuming no risk aversion). The cost of market power from the bilateral contracts will be the difference between the expected prices and the expected costs, multiplied by the volume of contracts. In expectation, this will be the same as if the quantity passed through the spot market. However, this market was just beginning and suppliers may have not foreseen the high prices and may have agreed to low prices. The sellers could not profit by ignoring the contracts and selling their power to the spot market instead.[38] In addition, if any of the output is covered under regulatory side

[38] "An energy sale contract typically includes a liquidated damages provision specifying the amount that

agreements, such as qualifying facilities (QFs), the spot market may not be applicable.[39] Including the fraction of demand for bilateral contracts could overstate the change in total costs (the sum of ΔTC). The MP ratio will be approximately the same in both cases, as will the percent changes in total costs.

I focus on cost increases in the spot market, but note that bilateral contracts probably incurred some cost increases resulting from market power. Table 3 reports hourly averages for demand, price, marginal cost, markups, and daily total ΔTC. I also calculate overall market performance. These measures differ by month and time of day (where peak is defined as 11am to 8pm). Panel A reports the results using the average nodal price during all hours and panel B looks at only the hours without congestion.

The average nodal prices exceeded marginal costs primarily during the hottest months of June and July, while the estimates of marginal costs in other months are within a few dollars of prices. Market imperfections in the spot market, the sum of the ΔTC, during these five months totaled $224 million. The load-weighted Lerner index - or market performance measure (MP) - was 0.293 over the entire summer; this is the ratio of market imperfections to total revenue. Dividing market imperfections by the sum of the variable costs of producing energy (the product of marginal cost and spot market load), I estimate that the total costs in PJM were 41 percent higher than under perfect competition.

My estimates of marginal cost include the NO_x emission permit costs. However, the permit market had only opened in May of 1999. Firms who were bidding "cost-based" bids may not have realized that they would have to pay these environmental costs, that the costs were marginal (historically environmental costs have required fixed investments in technology), or that the regulators were allowing these costs to be entered as marginal costs. When I estimate perfectly competitive prices for May but do not include these NO_x costs, the average cost is $21.1/MWh. These estimates are quite close to the prices that averaged $22.7/MWh. These are similar to the price and cost estimates during April. The price of permits in May was quite high and may have cost some firms an additional

the seller, for example, owes the buyer if the seller does not perform, i.e. does not delivery energy when agreed. A typical liquidated damages provision would require the seller to pay the buyer the price the buyer actually had to pay to obtain replacement energy from the market, if the seller were unable to deliver" (MMU 2000).

[39] However, there is only about 4 GW of QF capacity in PJM. This is about 13 percent of the average summer demand and cannot account for all of the bilateral contracts.

\$13/MWh to produce electricity. When these emission costs are included, the competitive price exceeds the average nodal price by about six dollars. This suggests that NO_x costs were not being accounted for properly.

This analysis has focused only on the purchases made in the spot market. If bilateral contracts are also assumed to be sensitive to the spot price, then an additional 30 percent of the electricity market will also be affected by these markups. The MP measure changes slightly from that for spot markets only because the load weights differ. I measure the weighted Lerner index to be 0.323 when including bilateral contracts. The total costs for the bilateral contracts are \$603 million. The sum of spot market and bilateral contract costs equals \$827 million over the summer. This is a 48 percent increase over competitive costs. Another robustness check looks at the minimum nodal prices instead of the average. This will lead to more conservative measures of market imperfections. The market performance measure is 0.231. Costs are 30 higher than under perfect competition. Spot market costs total \$162 million and bilateral contracts cost an additional \$456 million for a total of \$618 million.

Panel B looks at the price during the unconstrained hours. The overall results support those of the first panel; the costs rose 48 percent and the weighted Lerner index was 0.326. However, the monthly markups are more extreme than estimates based on average prices. May and August cost estimates exceed prices by seven dollars, suggesting these estimates understate markups. Spot market costs total \$195 million for the unconstrained hours. Bilateral contracts increase this to \$724 million.

4.1.1 California Comparison

When comparing markups in PJM with those in other markets, one must be careful to consider the many differences between markets. Each state that has restructured their electricity market has done so imposing different regulations and has different market structures. With this caveat, I compare my findings with those by BBW of California's first summer. BBW find similar monthly results for the market performance measure in the first summer of the California market as I do in PJM. In July, August, and September of 1998, BBW find MP estimates of 0.28, 0.40, and 0.35, respectively. In June, July, and August of 1999, I find MP estimates of 0.28, 0.54, and 0.06, respectively. The point estimate of total costs increases in PJM is either \$224 million (spot markets), \$827 million (spot and contacts), or somewhere in between. In comparison, the increase in costs in California was \$495 million for its first five months, about a 33 percent increase over competitive costs. BBW exclude June 1998 from some calculations. Their estimates of increased costs for July to October total \$571 million, an increase of about 45 percent.

4.1.2 Predicting Unconstrained Prices for Constrained Hours

The markups in the unconstrained hours can be used to create a proxy for what the markups would have been during the constrained hours, if congestion had not occurred. This requires out-of-sample estimation. This will be misleading if the hours when congestion occurs are different than those without congestion in some way that would bias measures of the unconstrained price. Under the null hypothesis of perfect competition, suppliers bid the same whether or not congestion occurs. This implies that measures of unconstrained prices should not differ when congestion actually occurs.

I model markups during the unconstrained hours as a function of demand (cubic), input prices (natural gas, oil, and SO_2 and NO_x permits), and indicators of hour and day of week. The estimated markups for the congested hours are tested against the proxies of markups constructed using the load-weighted average prices. I define the price estimate "errors" as the load-weighted nodal prices minus the estimates of the unconstrained prices. The error has an average of -16.3, with the sample's 90 percent confidence interval being -139 to 33 (see Figure 6 for a histogram). A regression of the errors on a constant finds that the load-weighted nodal prices tend to understate the degree of market power associated with an unconstrained system for the hours *with* constraints (the Newey-West standard errors with 24 hour lags are 5.9). The statistically significant additional costs associated with using these estimates of unconstrained prices for the constrained hours are \$68.2 million for the spot market alone over the summer of 1999.[40]

[40] Prices associated with high demand hours can be given more 'importance' by using a weighting matrix. Doing so, further exacerbates the difference (a mean of -22.8 and standard errors of 7.6).

5 Discussion

The estimates of market power using the minimum nodal prices likely understate markups. The results focusing on just the unconstrained hours probably overstate the percentage increase in costs over competitive market prices. The correct measure of markups should lie between these bounds. Using the load-weighted average nodal prices, I find evidence of market imperfections leading to an increase in total spot market costs of about 41 percent. This percentage increase is similar to estimates for the first summer of restructuring in California even though the PJM price cap was four times higher than that in California. However, the total additional costs in PJM are lower than in California because 85 to 90 percent of the market is met with bilateral contracts and self-supplied by vertically integrated utilities.

5.1 Markup and Demand Relationship

Figure 7 presents the relationship between margins and demand for fossil fuel generation (fossil load) for all hours. The Lerner index for each hour is truncated to lie between zero and one.[41] Markups increase with the inelasticity of residual supply, which typically rises with demand. Table 4 reports the results of regressions of the Lerner indices based on the average prices and unconstrained prices on a constant, fossil load, and fossil load squared. The negative coefficient on fossil load results in the Lerner indices falling with load until 18 GW for both prices.[42] One possibility is that I am interpreting markups at low demand as evidence of firms exercising market power rather when the true marginal cost is much higher as a result of unit commitment problems.[43] However, mapping a quadratic function of load to my estimates of marginal cost *also* results in a negative coefficient on load and a positive coefficient on demand.

[41]Negative markups may be misleading for several reasons, as discussed in Section 5. Margins greater than one occur if the price is negative (which does occur in some nodes when there is congestion, though the average is always positive).

[42]Fossil load exceeded this level about half of the time in the summer of 1999 for all hours and for the unconstrained hours (the range was 9.0 to 38.7 GW).

[43]If a coal unit is the cheapest unit available to meet demand, it still will not start if it cannot cover its start up and no load costs. Instead, a more expensive natural gas unit that can start cheaply will generate in an efficient dispatch. The model will report this as a mark up when coal is marginal, namely during low demand times.

5.2 Sensitivity Analysis

In order to test the robustness of my results, I did a sensitivity analysis of the load-weighted Lerner index measure of market performance. I tested three ways of measuring price along with three ways of measuring costs. All nine combinations are reported in Table 5. The market performance (MP) measure was calculated for the minimum nodal price, the load-weighted average price, and the prices for hours when the system was not congested. These are the columns of Table 5.

The first row of the table looks at the base case, that which was reported in section 4. I compare the base case with two alternative assumptions regarding costs. The second row looks at the importance of import responsiveness to price. I report MP measures when net imports do not respond to price. In the third row, I examine how the market would have behaved with a different price cap.

Under the base case, the MP measure varies slightly by price estimate, ranging from 0.231 to 0.326. If imports did not change with prices, the markups would have been only slightly larger. This is a refection of the inelasticity of my estimated net import supply curve. Imports will not respond by as large of a percentage change as seen in prices. Assuming imports would not change at all simply imposes that the supply curve is perfectly inelastic. A more elastic supply curve would reduce the markup estimates.

I calculate a simplified model of the effects of a lower price cap. I assume PJM generation and imports would have been the same under a $250 cap as under $1000.[44] However, it is reasonable to think that changing from a cap of $1000 to $250 would drop net imports by about half during those hours at the price cap.[45] This would increase the likelihood of not having enough reserves to cover demand and rolling blackouts could have resulted. If the reserves were sufficient, then the resulting market would show little sign of market imperfections.

[44] California had a cap of $250/MWh during the first 18 months of its restructuring

[45] This assumes the average elasticity from section 3.3 (0.684) for net imports and a 75 percent reduction in price (going from 1000 to 250 price cap).

5.3 Addressing Biases of Market Power Estimates

Several simplifying assumptions I make in this paper could potentially bias the results, however, these biases are likely to be small and be in the direction of *understating* market power. The method used here ignores unit commitment problems; start up, no load, and ramping costs impose a dynamic optimization problem while I look at the static profit maximization problem. When demand drops in the evening, a plant may continue to run a unit if these costs are high and there is an expectation that tomorrow's peaking hours will have a price above production marginal costs. Units will run when price is below production marginal costs because shutting down will lead to lower profits. Estimates of marginal cost are biased upwards (and estimates of market power are biased downwards) when one ignores this shadow price on start up costs.

However, start up and no load costs will also delay firms from running when price is above marginal costs of production if the firm expects the price difference to be temporary and insufficient to cover the costs of starting. My estimates of marginal cost are biased downwards by ignoring this shadow price. The net effect of the two biases stemming from ignoring the shadow price is ambiguous in theory.

Congestion is five times as likely to occur from 11:00 AM to 10:00 PM than otherwise (7% of night hours are congested while 35% of day hours are congested). However, the biggest increases in demand occur during the seven to nine AM period so many units have already ramped up by 11:00 AM. Units operating by 11:00 AM are likely to operate through the day but those not operating may turn on only for the peak. Thus, markups are more likely to be biased upwards for the congested hours. In contrast, more base units are going to be running through the night implying that the bias lowering markup measures is likely to be more pronounced during the uncongested hours. In fact, the average markups for April, May, and August for unconstrained prices were negative. Ignoring the unit commitment issues probably understates marginal costs for these hours. The monthly averages of the marginal cost estimates and demand levels are similar for the constrained and uncongested hours for these months. The average of actual prices for all hours (including the uncongested hours) were almost exactly the same as the marginal cost estimates for April and August (May prices were lower than cost estimates as discussed previously). This suggests that the net effect of this bias is small.

Local market power issues are treated differently in PJM than in California. BBW note that when units are called for reliability must run in California, then they should not be considered part of the system. If the estimates of marginal cost model the unit as setting the market-clearing price, then the price will be too high. When a unit is called for local demand, the rest of the market clears at the next cheapest unit. However, in PJM, the firms thought to have local market power resulting from constraints stay in the system-wide market but have their bids reset to production marginal costs plus ten percent. Therefore, this bias of applying the BBW technique does not apply. However, a different bias is introduced. If the unit with bids reset is marginal, then I would report the difference between price and cost as evidence of market power when it may simply be a market imperfection resulting from the PJM rules. Since few bids are reset, this is not likely to be a large bias.

The bias of using minimal nodal pricing should lower measures of markups substantially. The bias resulting from focusing on unconstrained PJM prices will depend on how well instruments aimed at curbing local market power work and how unit commitment problems affect these hours differently. I find that markups for hours with congestion tend to be greater than those for hours without congestion.

5.4 Significance Testing

This section calculates the standard errors on the estimates of total cost and the load-weighted Lerner index using the average nodal price. I follow the basic methodology in BBW using a simplifying assumption regarding autocorrelation (See appendix D). The resulting estimates of σ_ε and ρ are 47.2 and 0.832. The standard error estimate of the total costs over the summer of 1999 is \$22.6 million, resulting in a 95 percent confidence interval of \$180 to \$268 million around the expected total cost of \$224 million for all demand purchased on the spot market.

A simple transformation of this estimate results in standard error estimates for the weighted Lerner index. The sum of total revenue – price times total spot demand including losses – equals \$765 million and is known with certainty. Dividing the standard error estimates for total costs by this amount gives the standard error estimates for the weighted

Lerner index, 0.030. The 95 percent confidence interval around the expected Lerner of 0.293 is 0.235 to 0.351.

6 Conclusions

Evidence suggests that market imperfections existed during the summer of 1999 and that at least one firm in the PJM electricity market likely behaved in a non-competitive manner by setting prices. This paper estimates the prices in a competitive market using techniques similar to BBW, attempting to err on the side of understating markups. I find an increase in costs of $224 million, 41 percent above the costs of a perfectly competitive spot market. If similar markups affected demand met with bilateral contracts, the measure of the total cost of market power increases to $827 million. The demand-weighted Lerner index was 0.293, comparable to that seen in the first summer of California. Finding such evidence in a nodal electricity market - which some hold as the ideal design of restructuring - may suggest more focus should be placed on understanding the reasons for market power rather than on market design.

Future work will extend the time period of this study. I will test how accurate this procedure is for a period without market power in estimating 1998 prices. The market imperfections from September 1999 to the present will also be examined. This will include accounting for the two-settlement system that has been in place since June 2000. I plan to improve estimates of the net import supply functions and provide more sensitivity analysis particularly with regard to estimates of net imports.

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Appendix A: State Divestment Laws

The Energy Information Administration's December 1999 report "The Changing Structure of the Electric Power Industry 1999: Mergers and Other Corporate Combinations" summarizes the laws affecting divestment in Investor-Owned Electric Utilities (IOUs) for each state as of September 1999. Among the top ten utilities having to divest, Potomac Electric Power Company sold 6.0 GW and Duquesne Light sold 4.4 GW. The following is an excerpt from Table 11 on the status of state restructuring provisions on divestiture of power generation assets, as of September 1999.

· Maryland HB 703 passed 4/99. HB 703 forbids mandated divestiture. However, Potomac Electric Power Co. is selling all its generation assets.

· Delaware HB 10 passed 3/99. HB 10 allows the Public Service Commission (PSC) to decide if divestiture is needed to alleviate market power "in extreme situations and as a last resort." Stranded cost recovery is not an issue for the IOU in Delaware. Delaware Cooperative's stranded cost recovery will be addressed by the PSC.

· New Jersey A10 and S5 passed 2/99. Laws A10 and S5 leave divestiture and the issue of stranded cost recovery up to the Board of Public Utilities which may require divestiture.

· Pennsylvania HB 1509 passed 12/96. HB 1509 does not require divestiture. Some Pennsylvania utilities are selling generation assets to reduce stranded costs and/or restructure their companies into "wire" companies by getting out of the generation side of the business. Duquesne Light to divest generation. Allegheny Energy to transfer generation to affiliated generation company or divest.

Appendix B: Example of How Transmission Congestion Can Lower Average Price

In a perfectly competitive market, transmission constraints will necessarily increase total costs of generating electricity. However, the average price may actually *fall*, as seen in Figure 1. There are two scenarios shown. The top scenario depicts the "typical" case where the constrained price exceeds the unconstrained price. In the figure, the x-axis represents the total demand that the two firms (firm A and firm B) must meet. The amount of generation firm A provides is measured from the bottom left corner and the amount firm B generates is the remainder. The dotted line represents the demand each firm faces in a transmission constrained market. In this case, each firm is responsible for about half of the market demand. The solid lines represent the marginal costs. Where the two solid lines cross, the marginal cost of each firm is equal and all demand is met. This will be the market clearing price in a perfectly competitive market. The constrained price is the marginal cost for each firm at the dotted line since the two markets have been separated by congestion. The average of these prices is then calculated, and in this case, lies above the unconstrained price. However, scenario 2 shows how different marginal cost curves can result in the opposite situation arising. Here, the average constrained price is lower than the unconstrained price.

Appendix C: Construction of Marginal Cost Estimates

This appendix explains data sources and the construction of the cost estimates. The primary data source used was the publicly available PROSYM Model output (Kahn 2000). In these data, the PJM region is comprised of 439 units including demand side and non-utility generators (NUGs). Several generating units have been aggregated, including hydroelectric power by utility. Marginal cost equals the sum of variable Operating and Maintenance (O&M), fuel costs, and environmental costs. PROSYM has unit specific data on variable O&M costs, environmental emissions, fuel costs, fuel type, summer capacity, heat rate at maximum capacity, and forced outage factors. The coal costs were assumed constant in the sample. The prices of sulfur dioxide (SO_2), nitrogen oxides (NO_x), oil, and natural gas were allowed to vary over time. EPA reports monthly average trades of SO_2 permits at two brokerage firms (Cantor Fitzgerald and Fieldston). The average of these prices was used to calculate SO_2 environmental costs. Cantor Fitzgerald NO_x costs were used in this study. EIA provides data on the daily spot price of New York Harbor No. 2 heating oil and BTU/gallon conversion rates. The daily natural gas spot prices were provided by Natural Gas Intelligence for Transco Zone 6 non-NY.

I model hydroelectric generation by assuming that the hourly generation was consistent with the scheduled "zero-priced" bids, which are primarily hydroelectric. These bids schedule more generation in peak hours. I scale hourly production so total generation matched the EIA Form 759 total production. I assume a conservative pumped storage efficiency rate of 0.5, meaning for every kW produced during peak hours, two kW were required at off-peak hours. EIA reports net generation by month. The run of river production plus the implied production of the pumped storage compose the monthly production. Table 6 below displays the hourly average MWh of run of river and reservoir (RoR&R), pumped storage, total produced hydroelectric power, total "zero-priced" bids, and the ratio of production hydroelectric to scheduled "zero-priced" bids.

Table 7 summarizes average demand in the spot market by month and time of day available from the Market Monitoring Unit's annual report (2000). Peak is defined as 11am to 8pm. The average market demand was between five and nine times greater than the spot market demand.

Appendix D: Standard Error Calculation

This appendix estimates the standard errors of the total costs of market imperfections. I assume that demand levels and prices are known with certainty and the uncertainty stems from measurement errors in costs. The cost estimates are assumed to be unbiased but noisy measures. The noise originates from measurement errors of heat rates, emission rates, and input prices, from differences between realized outages and those in the Monte Carlo simulation, and unit commitment problems.

I note that for each hour t:

$$p^t - \overline{C}^t = E(p^t - \overline{C}^t) + \varepsilon_t$$

Assuming ε_t has a simple first-degree autocorrelation, homogeneous structure, then a consistent approximation for the variance of the total change in costs will be:

$$Var(\sum_{t \in S} \Delta TC^t) = Var(\sum_{t=1}^{T} (p^t - \overline{C}^t) q_{tot}^t) = Var(\sum_{t=1}^{T} \varepsilon_t q_{tot}^t)$$

Or, in vector notation:

$$Var(q'\varepsilon) = q'\Omega q,$$

$$\text{where } \Omega = \sigma_\varepsilon^2 \begin{bmatrix} 1 & \rho & \rho^2 & \cdots & \rho^{T-1} \\ \rho & 1 & \rho & \cdots & \rho^{T-2} \\ \rho^2 & \rho & 1 & \cdots & \rho^{T-3} \\ \vdots & \vdots & \vdots & \ddots & \vdots \\ \rho^{T-1} & \rho^{T-2} & \rho^{T-3} & \cdots & 1 \end{bmatrix}$$

and ρ is the coefficient for the AR(1) lag.

Hence, the variance is:

$$\sigma_\varepsilon^2 \sum_{i=1}^{T} \sum_{j=1}^{T} q_i q_j \rho^{|i-j|}$$

I estimate ε and ρ to calculate the standard errors of the total costs. This is done following the Prais-Winsten method. As in BBW, I regress the markup on fossil load, fossil load squared, and indicators of hour, month, and day of week.

Tables and Figures

Table 1: PJM Capacity and Peak Demand in megawatts (MW) by Electric Utility.

Utility	Nuclear	Hydro	Coal	Natural Gas	Oil	Total	Peak Demand	Share of Capacity
Public Service	3,261	11	1,242	3,380	1,403	9,297	9,804	16.4%
PECO Energy	4,496	303	725	66	2,173	7,763	7,959	13.7%
PPL	2,184	152	3,511		1,877	7,724	6,711	13.6%
Potomac Elec.		512	2,694	1,069	2,339	6,614	5,927	11.7%
PennElec		56	6,194	41	142	6,433	2,631	11.4%
Baltimore	1,675	416	2,135	894	1,000	6,120	6,383	10.8%
Delmarva			928	746	864	2,538	3,441	4.5%
Jersey Central		133		963	378	1,474	5,300	2.6%
GPU Nuclear	1405					1,405	-	2.5%
Met. Ed.		19	642	239	191	1,091	2,439	1.9%
Atlantic		22	364	221	454	1,061	2,430	1.9%
Other	0	220	1,397	2,587	955	5,158	-	9.1%
Total	13,021	1,844	19,832	10,205	11,775	56,678	53,025	
Share	23.0%	3.3%	35.0%	18.0%	20.8%	100.0%		

Source: Capacity from PROSYM Model (Kahn 2000) and Demand from PJM (2000).

Table 2: Two-Stage Least Squares Estimate of Net Imports.

Model	1	2a	2b	3	4a	4b
LHS	Net Imports (MW)	ln(Price)	Net Imports (MW)	Net Imports (MW)	ln(Price)	Net Imports (MW)
Errors	OLS	IV AR(1) White	IV AR(1) White	OLS	IV AR(1) White	IV AR(1) White
ln(Price)	705.0 (38.3)		1278.1 (80.6)	738.5 (36.5)		1298.5 (79.0)
Delaware Mean Temp		-0.006 (0.013)			-0.007 (0.013)	
Maryland Mean Temp		-0.003 (0.01)			-0.002 (0.009)	
New Jersey Mean Temp		-0.004 (0.013)			-0.001 (0.013)	
Pennsylvania Mean Temp		0.002 (0.012)			0.001 (0.012)	
ln(Demand)		2.306 (0.073)			0.339 (0.155)	
New York Mean Temp	119.8 (8.0)	0.000 (0.012)	44.37 (17.41)	84 (8.5)	0.058 (0.192)	40.6 (19.1)
Ohio Mean Temp	-104.0 (11.1)	0.010 (0.014)	-21.53 (18.6)	-124.4 (10.3)	0.038 (0.216)	-31.1 (18.6)
Virginia Mean Temp	52.6 (9.3)	-0.014 (0.013)	13.92 (15.28)	59.6 (9.2)	0.066 (0.212)	18.5 (15.3)
West Virginia Mean Tmp	-43.5 (14.3)	0.003 (0.019)	-26.32 (26.93)	-8.6 (13.5)	2.307 (0.072)	-26.4 (26.6)
May				1964.8 (102.2)	0 (0.012)	1756.8 (483.3)
June				958.5 (141.3)	0.007 (0.014)	790.2 (511.3)
July				1181 (167.7)	-0.012 (0.012)	980.3 (562.2)
August				582 (151.3)	0.003 (0.019)	536.0 (521.4)
Constant	-283.1 (125.9)	0.059 (0.001)	-2085.6 (280.2)	-1449.9 (168.6)	0.106 (0.003)	-3000.5 (446.3)
Rho	.	0.931	0.931	.	0.906	0.906
Observations	3499	3485	3485	3499	3485	3485
Adjusted R^2	0.265	0.220	.	0.370	0.227	.
DW Stat (post-correction)	0.137	1.732	1.732	0.133	1.708	1.708

Table 3: Monthly, Time of Day (T.O.D.), and Total Price, Marginal Cost, Markup, and Change in Costs Hourly Averages, and Aggregate Market Performance.

Panel A: *Average Nodal Price*

Month/ T.O.D.	Demand	Ave Price	Min Price	Marginal Cost	Change in Daily Costs (000s)	Market Performance
April	25,612	21.4	21.3	21.8	0.2	0.002
May	25,871	22.7	20.8	28.7	-27	-0.242
June	31,542	37.1	34.2	30.7	59	0.284
July	36,957	91.7	86.9	46.5	263	0.538
August	33,941	33.6	27.0	33.8	9.7	0.055
Peak	34,678	70.0	63.0	39.0	181	0.483
Off-Peak	27,835	22.0	21.2	27.5	-20	-0.191
Overall	30,687	41.8	38.6	32.3	64	0.293

Panel B: *No Congestion*

Month/ T.O.D.	Demand	Price	Marginal Cost	Markup	Change in Daily Costs (000s)	Market Performance
April	25,430	21.4	21.6	-0.22	0.8	0.010
May	24,581	21.0	28.2	-7.22	-32	-0.315
June	30,119	38.0	29.9	8.09	73	0.342
July	35,850	98.3	47.3	50.94	297	0.567
August	30,247	21.6	28.9	-7.25	-29	-0.290
Peak	27,114	83.0	40.0	42.97	253	0.566
Off-Peak	33,152	20.5	26.8	-6.22	-24	-0.250
Overall	29,149	41.6	31.2	10.36	70	0.326

Table 4: Prais-Winsten Model of Lerner Indices on a Quadratic Net Demand Curve (Lerner Index Truncated at 0 and 1).

Dependent Variable	Mean Price		No Congestion	
	Coef.	Std. Err.	Coef.	Std. Err.
Net Load (in millions of MW)	-55.33	4.31	-55.31	4.56
Net Load Squared	1514	94.6	1513	101
Constant	0.510	0.046	0.481	0.049
Rho	0.65		0.63	
Sample	3527		2797	
Adjusted R^2	0.13		0.15	

Table 5: Sensitivity Analysis of Market Performance Measure.

Cost Estimates	Minimum Price	Mean Price	No Congestion
Base Costs	0.231	0.293	0.326
No Change in Imports	0.262	0.322	0.363
$250 Cap	-0.065	0.027	0.010

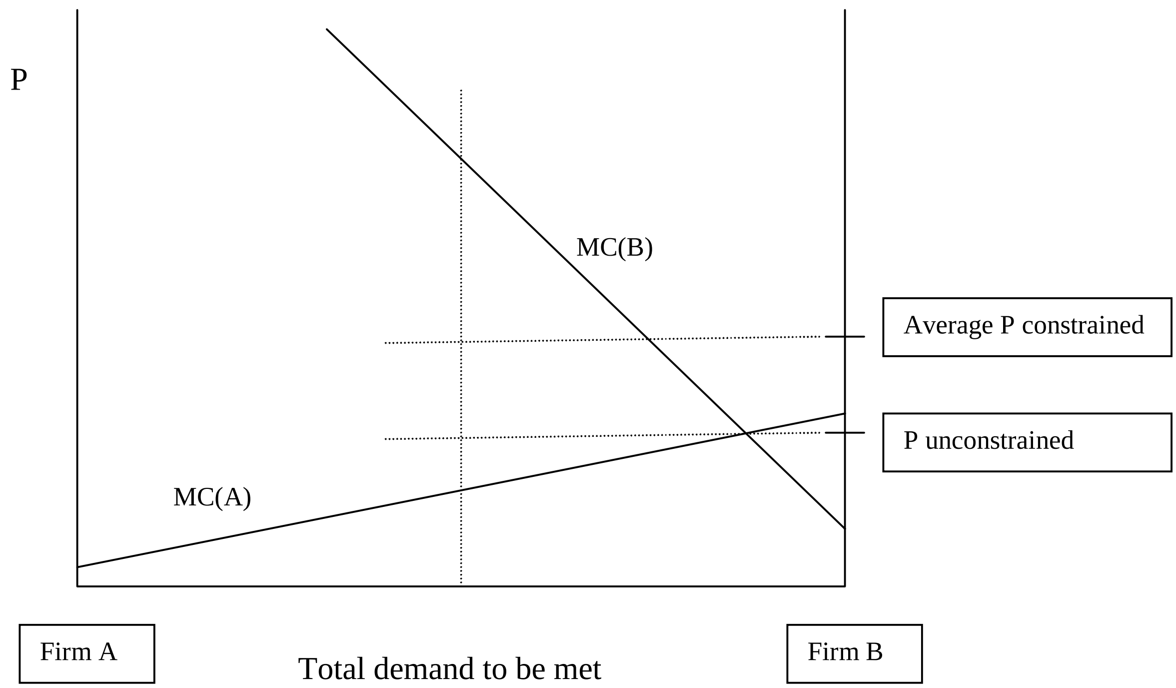
Table 6: Hourly average MWh for RoR&R Generation, Pumped Storage Generation, Total Hydroelectric Generation, Total “Zero-Priced” Bids, and the Percentage of “Zero-Priced” Bids that were Actually Produced as Hydroelectric Power.

Month	RoR&R	Pumped Storage	Hydro Generation	“Zero-Priced” Bids	Percent Hydro
April	739	57	796	2,196	36%
May	295	63	359	2,519	14%
June	100	93	193	2,571	7.5%
July	74	73	148	3,009	4.9%
August	72	91	163	2,692	6.1%

Table 7: Average Spot Market and Total Demand (MW) by Month and Time of Day

Month	Spot Off-Peak	Spot Peak	Total Off-Peak	Total Peak
April	4,000	4,000	24,199	27,587
May	5,000	4,500	23,787	28,788
June	4,500	5,000	28,267	36,126
July	4,000	5,000	32,948	42,568
August	4,500	4,900	30,351	38,968

Scenario 1



Scenario 2

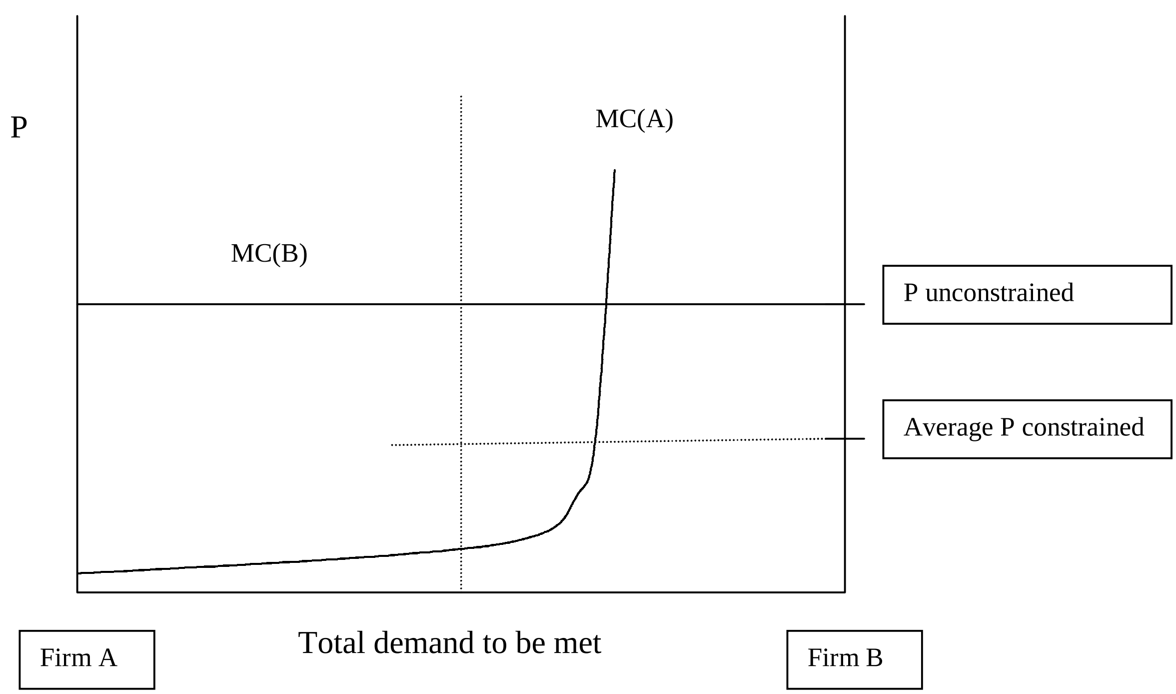


Figure 1: Comparison of Average Constrained Prices and Unconstrained Prices.

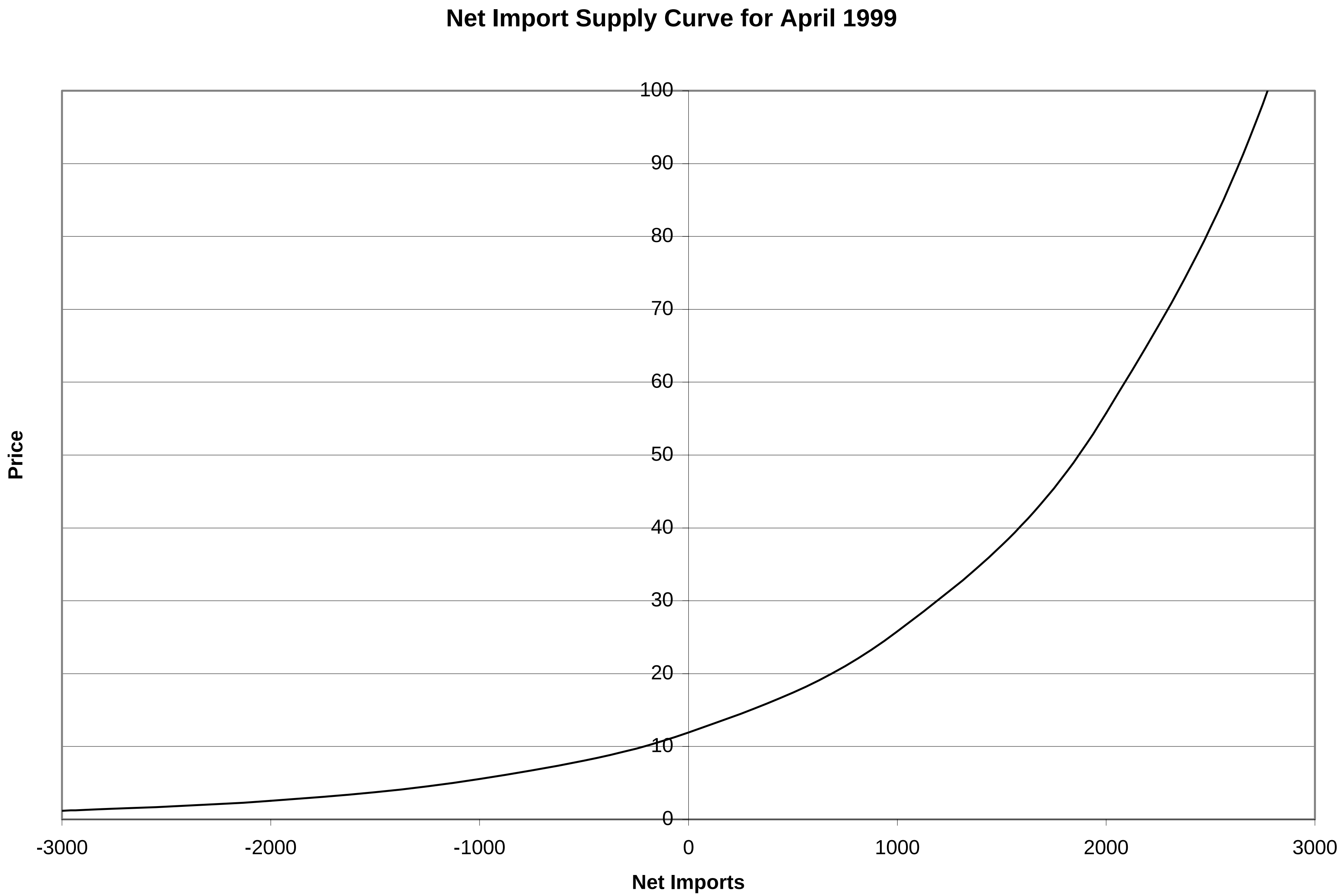


Figure 2: Estimated Net Import Supply Curve for April 1999.

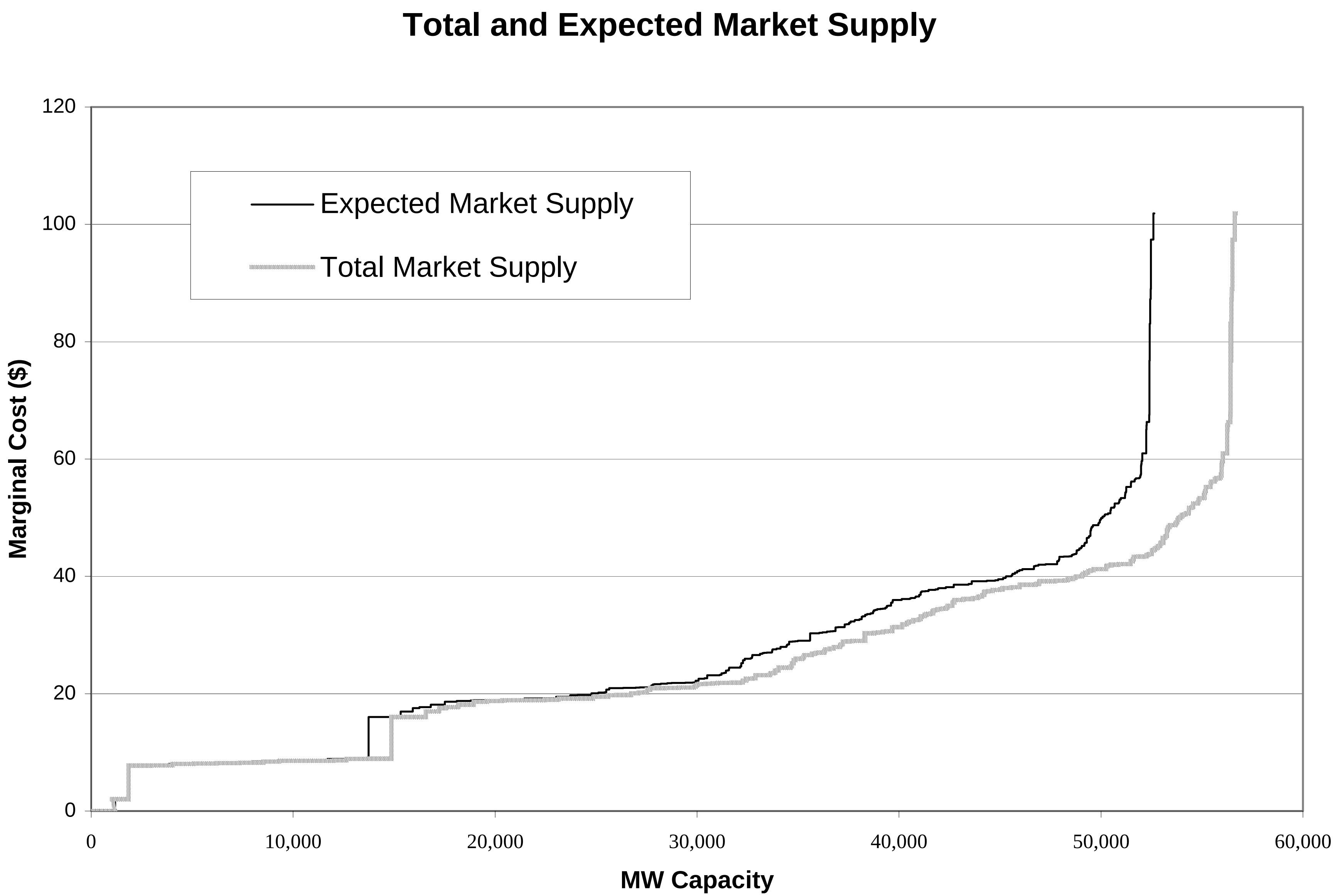


Figure 3: Total and expected market supply curve for April 1, 1999.

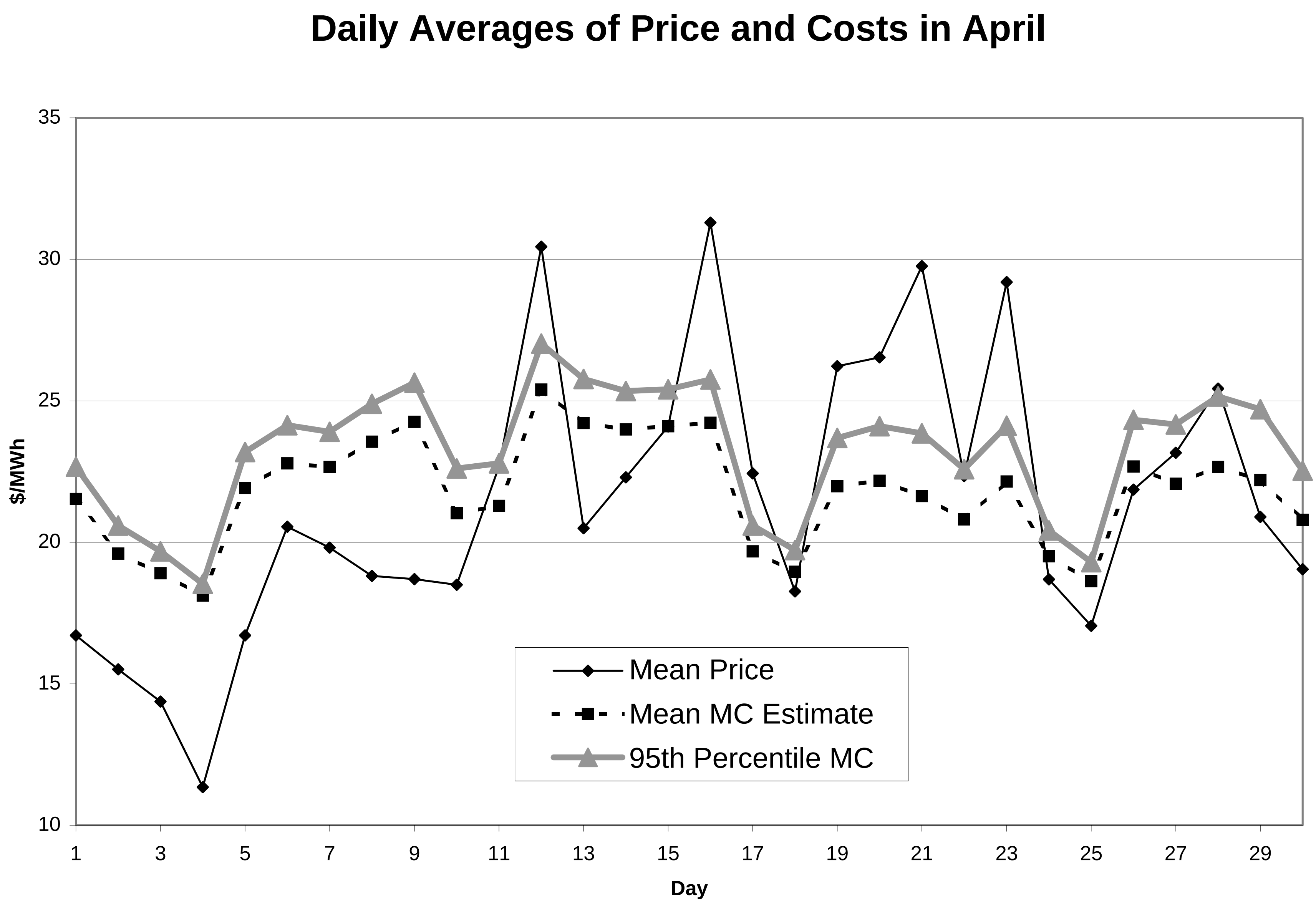


Figure 4: Daily Averages of Price, Expected Marginal Cost, and 95th Percentile Draw for April, 1999.

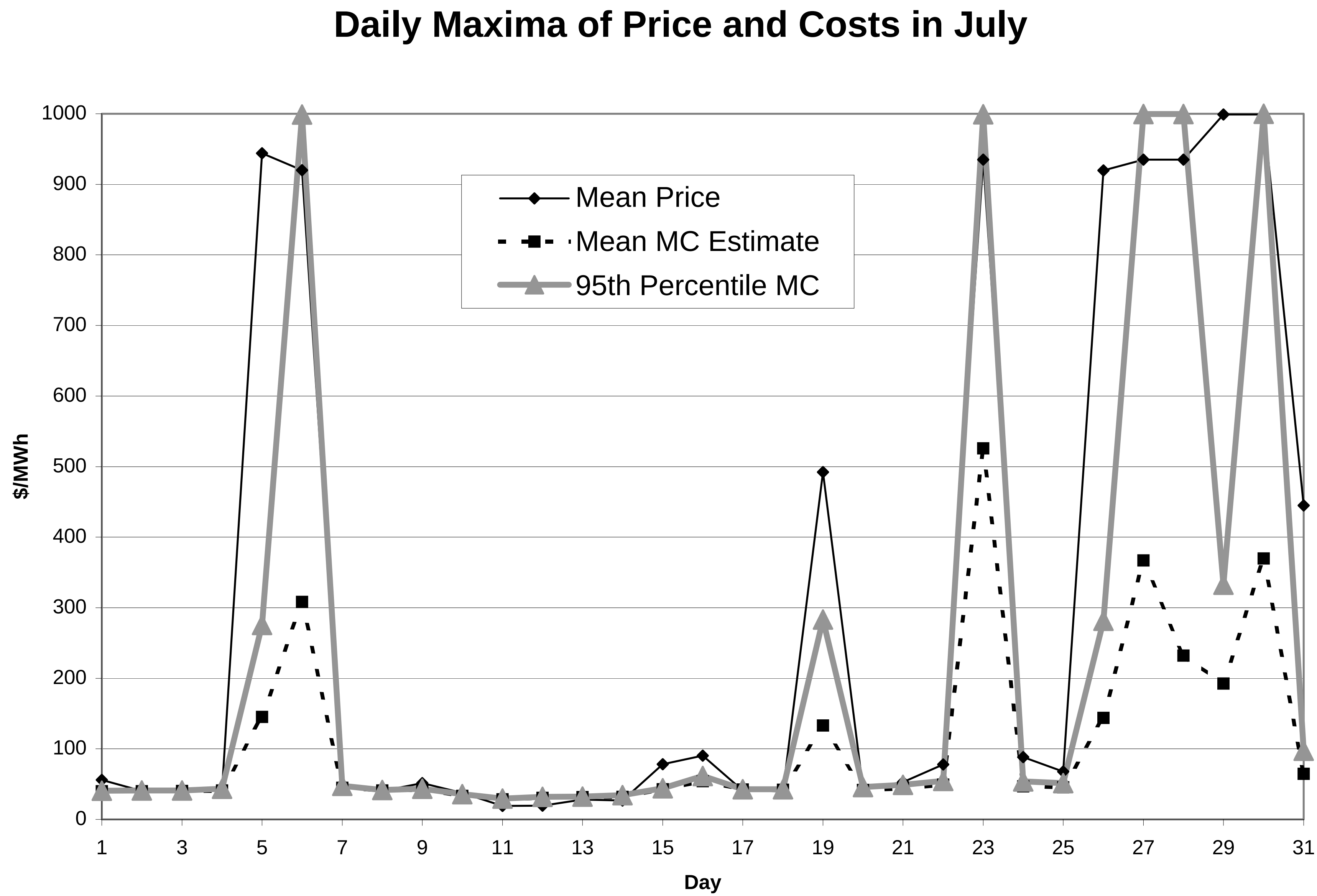


Figure 5: Daily Maxima of Price, Expected Marginal Cost, and 95th Percentile Draw for April, 1999.

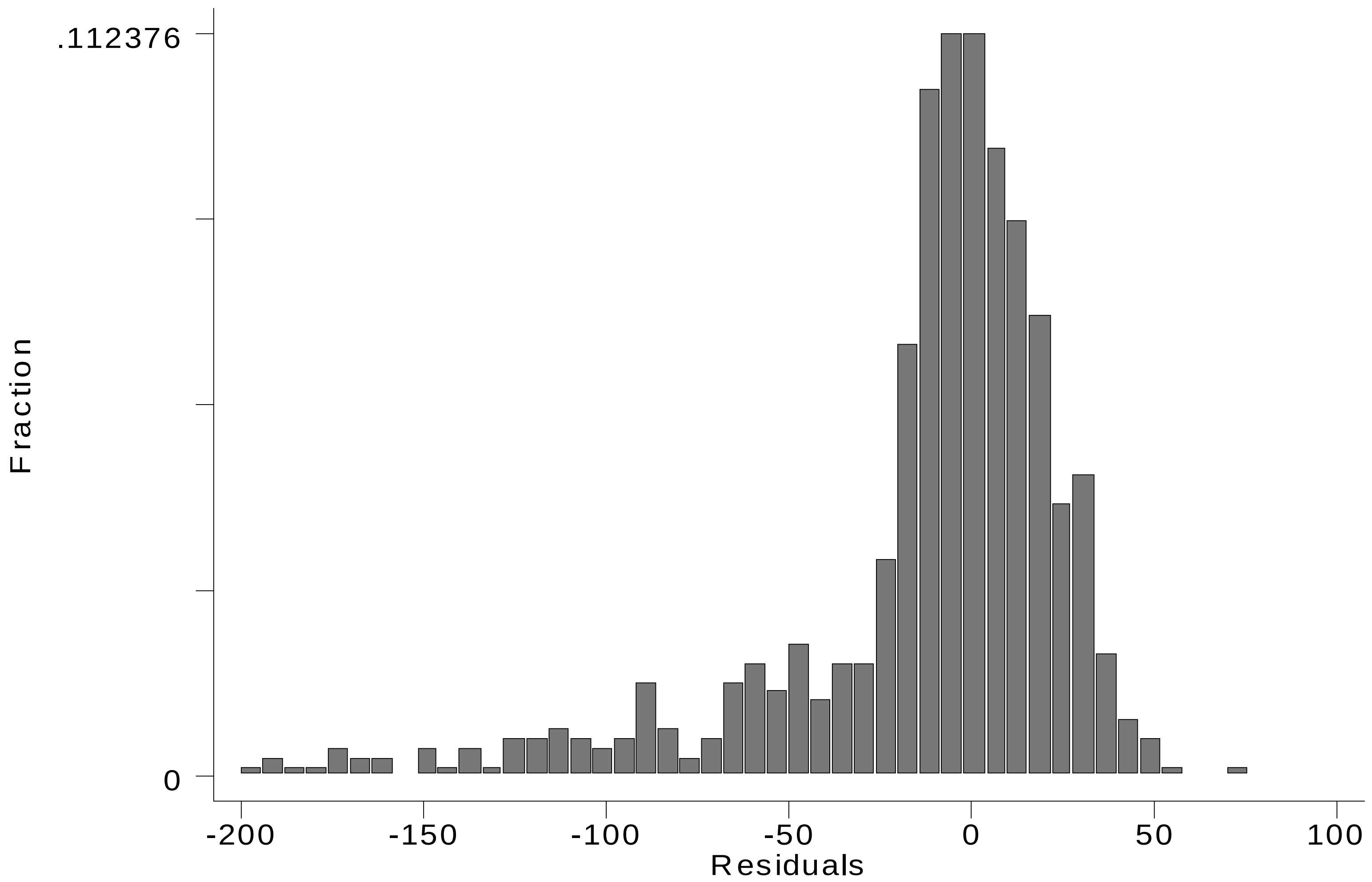


Figure 6: Histogram of Difference Between Load-Weighted Nodal Prices and Unconstrained Price Estimates.

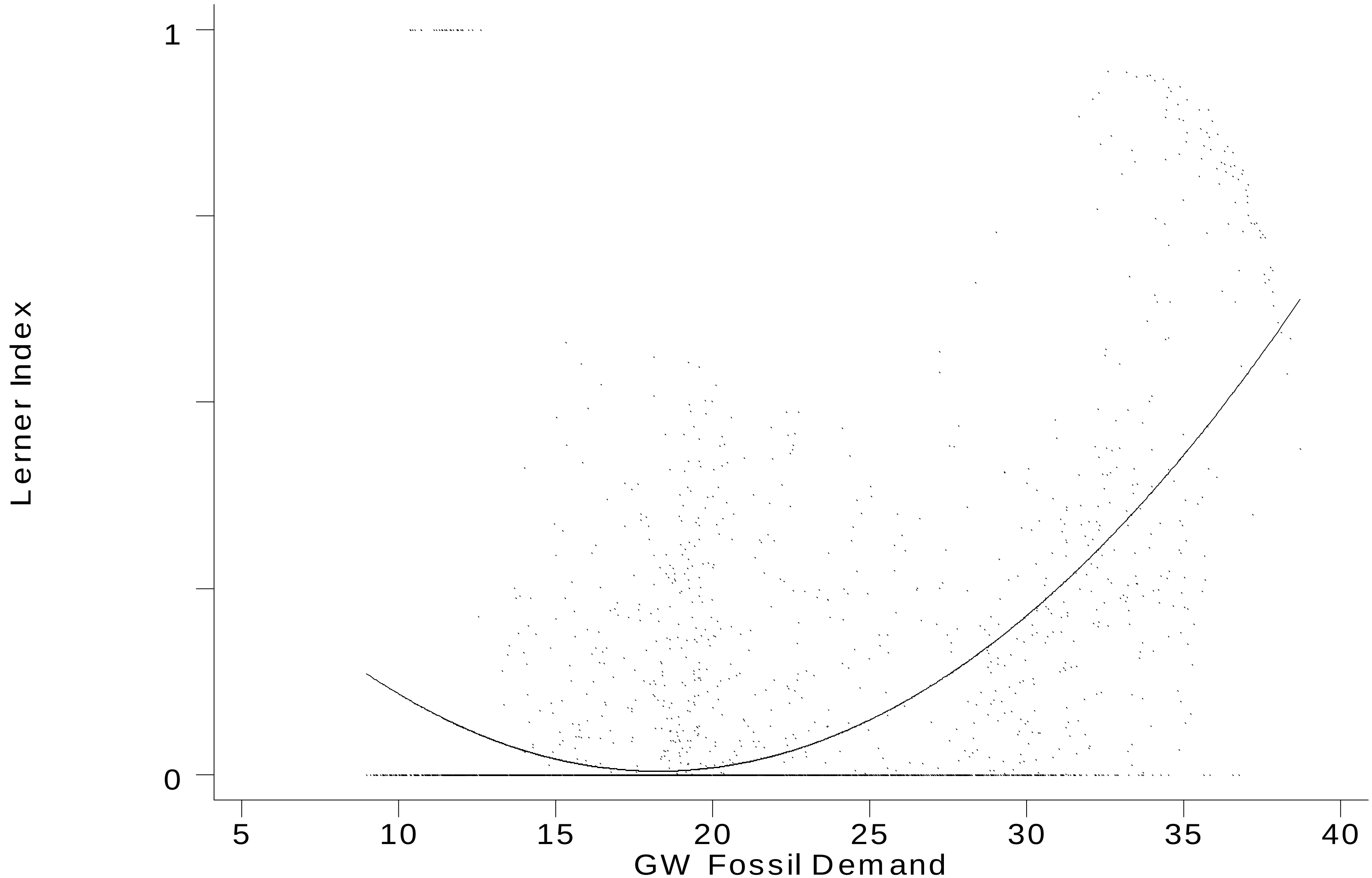


Figure 7: Plot of Lerner Index on Fossil Demand.