Oligopoly-Induced Production Inefficiencies and Incentive-Based Environmental Regulation: An Empirical Study of the Mid-Atlantic Electricity Market

Erin T. Mansur*

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Abstract

The structure and competitiveness of a product market can distort the effectiveness and costs associated with incentive-based environmental regulation. Recently restructured electricity markets provide a unique forum to study the environmental effects of market imperfections. In particular, this paper examines how firms in the Mid-Atlantic (PJM) wholesale electricity industry exercised market power in the summer of 1999, causing production inefficiencies and reducing emissions. The resulting welfare losses and reduced costs of complying with environmental regulation are measured by comparing observed behavior with two estimates of the social optimum. Electric utilities in Pennsylvania, New Jersey, Maryland, and Delaware reduced SO_2 and NO_x emissions by over 12 percent in 1999. A simulation of a competitive market accounts for only 60% of these emission reductions that are typically attributed to new environmental regulation. Given the observed permit prices, welfare losses from production inefficiencies are estimated to be $161 million, an 8% increase over optimal production costs. I test the robustness of these results using an econometric estimation of a competitive market accounting for constraints on and costs of increasing and decreasing generator output. The environmental and welfare implications are consistent with the first model. The implications of different regulatory instruments are discussed.

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*Ph.D. Candidate, Department of Economics, U.C. Berkeley. Email: mansur@econ.berkeley.edu. I would like to thank Alan Auerbach, Peter Berck, Severin Borenstein, Jim Bushnell, Stephen Holland, Aviv Nevo, Steve Puller, Celeste Saravia, and Catherine Wolfram. I am grateful for funding from the California Public Utilities Commission and the University of California Energy Institute.

1 Introduction

In the last decade, economic and environmental regulation have converged in providing firms with incentives to minimize production and pollution abatement costs. The structure and competitiveness of a product market distort the effectiveness and costs associated with incentive-based environmental regulation. Firms exercising market power cause production inefficiencies that result in welfare losses in the product market directly, but can also affect input markets.[1] Many electricity markets throughout the world have recently restructured in order to improve on production costs and investment decisions. A number of studies, primarily focusing on the California and England wholesale electricity markets, have found evidence of firms exercising market power.[2] Determining oligopoly-induced distortions in wholesale electricity markets is more tractable than in other industries because of the relative feasibility of measuring marginal costs and the lack of demand response. This paper examines the degree to which production inefficiencies in the Mid-Atlantic or Pennsylvania-New Jersey-Maryland (PJM) wholesale market reduce welfare, lower emissions, and ease compliance costs of incentive-based environmental regulation.

Electric utilities in Pennsylvania, New Jersey, Maryland, and Delaware reduced emissions by over 12 percent from 1998 to 1999 (see Figure 1).[3] During this time, overall electricity production in these states increased slightly to meet growing demand. However, the manner in which demand was met changed from the previous year. One reason was that the Ozone Transport Commission (OTC) mandated that electricity firms throughout the Northeast possess expensive tradable permits for summer NO_x emissions.[4] Furthermore,

[1] This will clearly be the case for large distortions in demand for inputs. The envelope theorem states that there will be no first-order effect on efficient input markets. However, a previously distorted input market, like a taxed labor market, will increase the amount of deadweight loss associated with market power in a product market (Browning, 1997). Similarly, markets that are regulatory constructs, such as permit markets, are not capable of responding to - and are therefore susceptible to - market shocks.

[2] For example, see Borenstein, Bushnell and Wolak (2001); Puller (2001); and Joskow and Kahn (2001) for evidence of market power in California. Wolak and Patrick (1997) and Wolfram (1998, 1999) find evidence of market power in England.

[3] Annual SO_2 and CO_2 emissions were reduced by 13 and 12 percent, respectively, the largest reductions in the 1990s. Annual NO_x emissions were reduced by 17 percent, second only to a 22 percent reduction in 1993. Annual emissions for PA, NJ, MD, and DE were aggregated from the Energy Information Agency's *Electric Power Annual*.

[4] Twelve Northeastern states comprising the OTC established a trading and banking program of nitrogen oxides (NO_x) emissions. An allowance enables utilities to emit a ton of NO_x from May through September. Sources may be constrained by other federal and state environmental regulations. The reductions call for a greater than 50 percent reduction from 1990 emission levels of 490,000 tons. Eight states

firms may have been preparing for the tightening of the national SO_2 permit market in 2000.[5] These trading programs mandated substantial overall reductions. The degree to which firms in the PJM wholesale market opted to reduce emissions depended on marginal abatement costs and incentives of all effected firms.[6] Concurrent with these environmental regulations, PJM restructured in 1999 thereby enabling some firms to exercise market power.[7]

The theoretical literature has explored how market structure affects externalities. The implication of the theory of the second best for a polluting monopolist - namely that a smaller tax should be assessed than under perfect competition - does not necessarily carry over to oligopolistic models. Oligopolists with asymmetric costs produce less in aggregate than a competitive market, but could potentially pollute more due to cross-firm production inefficiencies. Oligopoly-induced distortions can be categorized into an aggregate production effect, like the monopolist case, and a production substitution effect resulting from technology not being used in a least-cost manner.[8] A model typifying many electricity markets is composed of a few price-setting firms, a competitive fringe, and perfectly inelastic demand.[9] Production inefficiencies result solely in a production substitution effect whereby environmental implications depend on the technologies that some price-setting firms use to reduce output and that others use in meeting demand.[10]

participated in 1999 (CT, DE, MA, NH, NJ, NY, PA, and RI). The price for permits fell from \$5244/ton in May of 1999 to \$1093 in mid-September. Some plants marginal costs increased by 50%.

[5]Title IV of the 1990 Clean Air Act Amendments established a tradable permits system for sulfur dioxide (SO_2) emissions. Annual nationwide electric utility pollution is capped at about 50 percent of 1980 levels. A firm can opt to purchase permits, switch to low sulfur coal or install scrubbers. Excess permits are banked or traded. The first phase began in 1995, regulating the dirtiest 398 units, including 22 units in PJM. Phase II began in 2000, and brought over 2,300 fossil fuel units into compliance. The increase in scope of regulated firms was accompanied by an increase in permits. Overall, phase II requires more abatement. Some firms installed scrubbers in 1999 but none in PJM. 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.

[6]PJM is comprised of firms involved in the generation, transmission, and distribution of electricity in all of New Jersey, Delware, and the District of Columbia. The majority of Pennsylvania and Maryland, and part of Virginia are also included.

[7]In Mansur (2001), I find market imperfections increased the cost of procurring electricity in the spot market by 41 percent during the summer of 1999.

[8]Each firm produces in a cost-minimizing manner, but oligopolists optimize by producing where marginal costs equal marginal revenue, not price, thereby leading to distortions.

[9]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. The derived demand for wholesale electricity is almost completely inelastic because utilities are mandated to provide customers with power at any cost.

[10]For example, the structure of the California electricity market suggests that market power may *increase*

In order to determine the oligopoly-induced production inefficiencies, I construct two models of perfectly competitive behavior and compare estimates from these models with observed production choices. I simulate a 'simplified' competitive model using a technique common to the literature on measuring market power in electricity markets.[11] This technique does not take into account intertemporal constraints on and costs of increasing and decreasing generator output, such as the cost of starting up a generating unit.[12] In the second approach, I econometrically estimate production choices in the pre-restructuring period to determine how firms address intertemporal constraints.[13] I compute the optimal production for each model and compare these measures with observed production choices.

The EPA's Continuous Emissions Monitoring System (CEMS) reports hourly, unit-specific generation and emissions data for most fossil-fuel burning units in the U.S. electricity industry. Observed SO_2 emissions from CEMS units in PJM fell 10.5% from the summer of 1998 to the summer of 1999. NO_x emissions fell 15.9%. The simplified competitive model accounts for 60% of the emission reductions typically attributed to new environment regulation. Furthermore, this model suggests that production inefficiencies in the electricity market lead to welfare losses from of these four states on the order of $161 million for the one summer given permit prices, about 8% of total costs. With the intertemporal competitive model, I find evidence that electricity market imperfections attributed to SO_2 emission reductions and welfare losses similar to the simplified model, but account for only 14% of the observed NO_x reductions. Aggregate emissions will be unaffected by production distortions when pollution is regulated by a cap-and-trade permit system.[14] Nonetheless, firms exercising market power in product markets can affect the

pollution while the PJM market is structured such that pollution will likely *decrease*. Section 3 elaborates on this point.

[11]For example, see Wolfram (1999), Borenstein, Bushnell, and Wolak (2001), Joskow and Kahn (2001), and Mansur (2001).

[12]This literature has focused on aggregate measures of price distortions, namely, comparing observed prices with those prices associated with a perfectly competitive market. Not accounting for intertemporal constraints when measuring competitive prices probably leads to offsetting biases. Borenstein, Bushnell, and Wolak (2001) also use this technique to estimate welfare implications in the California electricity market.

[13]While ignoring intertemporal constraints in price estimates may lead to insignificant biases, they potentially pose more of a problem for quantity-based measurements like pollution and welfare implications. Knowing the characteristics of exactly *which* units are affected by imperfect competition are likely to be important.

[14]A cap-and-trade permit system places a system-wide cap on total pollution. Firms can trade permits for the right to pollute so long as the total cap is no exceeded. Even though aggregate emissions will be uneffected, the spatial and temporal distribution of the emissions will change as a result of market power

cost of complying with such regulation.

Some vertically integrated firms were net sellers in the market and therefore had incentives to act as price-setters after restructuring. Other firms purchased in the spot market and had similar incentives under regulation as in the restructured market. I test whether firms changed production behavior relative to cost model estimates. I find that firms with incentives to exercise market power reduced production by 18% relative to other firms, while the fringe firms increased production by 8%. These results suggest that the welfare and environmental implications from production inefficiencies are attributable to firms exercising market power.

Section 2 provides an overview of the PJM electricity market. I review the incentives of vertically integrated utilities and issues of measuring of market power in electricity markets. In Section 3, I discuss the environmental implications of market power in product markets. Section 4 reviews the data and discusses cursory evidence. In Section 5, I explain the methodology of estimating the simplified and the intertemporal models of competitive behavior. Section 6 presents the environmental and welfare results of production inefficiencies. I discuss policy implications of market power in product markets on environmental regulation, such as tax and permit trade-offs. Section 7 examines whether the production inefficiencies resulted from firm behavior manner consistent with exercising market power. Section 8 concludes.

2 The PJM Electricity Market

Over the past fifteen years, there has been a movement towards restructuring electricity markets in several U.S. states – such as California, PJM, New York, and New England – and in other countries. Regulated utilities in these states were under scrutiny because of high electricity prices stemming from investment choices and expensive long-term contracts with independent power producers. Policy makers believed restructuring would impose market discipline and thus lead to lower costs of production from existing generation units and more efficient investments. This section discusses the structure of the PJM market, understanding incentives of vertically integrated firms, and evidence of market power in

being exercised.

electricity markets in general and in PJM.

2.1 PJM Market Structure

PJM Interconnection, LLC, operates the largest wholesale electricity market in the world. The market consists of 57 gigawatts (GW) of capacity, using a diversity of nuclear, hydroelectric, coal, natural gas, oil, and renewable energy sources (see Table 1). The nuclear, hydroelectric, and coal are baseload generating plants capable of covering most of the demand (˜35 GW). Nuclear power comprises 45% generation but only 25% capacity. In contrast, over a third of the capacity uses natural gas or oil but these expensive units only operate during high demand times of day, especially during the hottest or coldest times of year, to meet the peak load. The difference in utilization of these types of generating units results from high start-up costs, long ramping times, and low marginal costs of base units compared with low start-up costs, quick ramping times, and high marginal costs of peaking units. The importance of these intertemporal problems will be discussed in section 5.3.

PJM had only one central market - or "pool" - for energy during the summers of 1998 and 1999. Commercial arrangements were made outside of the market but all power had to be run through it. Utilities purchasing electricity for customer demand (also known as "native load") meet only 10 to 15 percent of demand in the spot market, while the remainder is supplied by the utilities' own generation (53-59 percent), bilateral contracts (30 percent), or imports (one to two percent).[15] The structure of the market did not change substantially from 1998 to the summer of 1999.[16]

The PJM wholesale electricity market established a new pricing network to facilitate inter-utility trading in 1998.[17] PJM required firms to bid into a day-ahead market non-binding offers to supply electricity from each generating unit. The market clears based

[15] 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.

[16] Only one utility plant was sold and none was retired from 1998 through October 1999. Edison Mission M&T bought Homer City from PenElec in March 1999. Sithe bought 21 plants in November of 1999 from PenElec (9), NJ Central (4), and MetEd (8). Sunbury separated from PPL also in November. GPU Nuclear sold Three Mile Island to AmerGen in December. Less than 700 MW were built at this time by utilities and non-utilities. In August 1999, AES started a 200 MW plant in Cumberland, MD. 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).

[17] PJM accommodates transmission constraints by using what is known as "nodal" pricing (Schweppe,

upon a real-time Walrasian auction where the auctioneer uses the non-binding bids as basis for "calling out" the price.[18]

In the first year of the market, the bids were mandated to equal marginal production costs, which were well understood as a result of years of regulation rate hearings. In April 1999, the market operators restructured the market again by allowing for competition in the spot market for wholesale electricity. The Federal Energy Regulatory Commission granted most firms the right to switch from "cost-based" bidding to unregulated, "market-based" bidding, subject to a $1000/MWh cap.

2.2 Incentives of Vertically Integrated Firms

Historically, the generation, transmission, and distribution of electricity have been vertically integrated. The utilities in PJM were not required to divest plants and, for the most part, they did not choose to do so through the summer of 1999. The incentives of these vertically integrated firms depend on the amount of generation a firm needs to buy for native load relative to the amount it can sell on the market.[19] In addition, utilities sign bilateral contracts that affect their net positions. A net seller will have incentive to increase prices. The objective function for firm i will be:

$$\max_{q_i} p_i(q_i)(q_i - q_i^d - q_i^c) + r_i^d q_i^d + r_i^c q_i^c - c_i(q_i), \tag{1}$$

where $p_i(q_i)$ is the inverse residual demand function that firm i faces in the spot market; q_i is the production of firm i; q_i^d is the amount of native load; q_i^c is the net supply of

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.

[18] 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.

[19] 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 by regulators as it requires inefficient production choices. Firms could not ignore purchase obligations because the retail rate was frozen. Without a cap, the firms could increase the market price and pass the rate increase on to customers.

bilateral contracts priced independently of the spot market price; r_i^d is the retail rate for native load; r_i^c is the fixed rate for contracted production; and $c_i(q_i)$ is the total costs of production for firm i.

Evidence suggests that Philadelphia Electric Co. (PECO) and Pennsylvania Power & Light (PPL) behaved as price-setters in 1999. Table 1 reports the share of capacity, generation, generation when demand exceeds 40 GW, and demand in 1999 for the six largest firms in PJM. PECO and PPL tended to produce more than their native load.[20] PECO's net selling position was even greater during peak demand hours. In addition to being net sellers many hours, PECO and PPL were active in bidding market-based bids into the spot market. Only a few firms opted to change the bidding structure of their units during the summer of 1999. Of these, PECO and PPL accounted for 84 percent of the market-based bids.[21]

Firms can exercise market power without causing welfare losses. Firms can increase bids uniformly without distorting the optimal "dispatch." Dispatch refers to meeting demand with the lowest cost units so that low-cost (low-bid) units are called upon to produce prior to turning towards higher-cost (higher-bid) ones. However, it is likely that firms exercising market power did cause cross-firm production inefficiencies. One reason is that firms face uncertainty; they do not see each other's bids in the day-ahead blind auction and demand is uncertain. A firm might set the bid of a unit with marginal cost below the market clearing price so high that it is not called upon in the real-time market. Alternatively, a firm may have bid low for a unit but decide in real-time that it would be better off not generating at any price.

Firms could have exercised market power in 1998 using this latter technique. However,

[20]Pennsylvania Electric (Penelec) has 14% of the generation market and 5% of the peak demand, suggesting that they too would act as price-setters. However, the parent company GPU Inc., which is comprised of Jersey Central Power & Light Company, Metropolitan Edison Company, Pennsylvania Electric Company, and GPU nuclear, has 20% of both generation and demand. Furthermore, PenElec was in the process of selling a large portion of its capacity to Sithe during this period and did not actively partake in bidding "market-based" bids.

[21]PJM codes the publicly available bidding data so that the identities of the firms and units are unknown. According to *The Wall Street Journal*, August 4, 1999: "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 for a number of hours."

a firm was less likely to be able to move the price substantially. Recall that the price was determined by the marginal cost curve in 1998. In contrast, the marginal bid curve set the price in 1999. If firms exhibited imperfect bidding behavior in 1999, then the residual demand a firm faced in 1998 was probably relatively elastic. This will limit firms' abilities to increase prices.

2.3 Market Power in Power Markets

Unfortunately, the promises of restructuring have not been realized in many markets. So far, restructured Eastern U.S. markets appear to have had a relatively successful experience compared to California. Some argue that the market design of the Eastern markets has reduced price volatility and limited the degree to which firms exercise market power. However, from April through August, 1999, the market-clearing price in PJM exceeded the marginal cost of the most expensive power plant almost three times as often as in the previous summer.

Several major characteristics of electricity markets make market power more likely to occur than in other markets with similar levels of concentration: nearly perfectly inelastic demand; economically prohibitive storage; and limited generation and transmission capacity. Furthermore, the system operators are bound by the physical constraint that supply and demand must balance continuously.[22] Market power can arise when demand and fringe supply are highly inelastic, a case often seen when most generating capacity is required to meet system demand. A firm with even a small share of the market can greatly influence the price under such circumstances.

Wolfram (1999) develops a technique of measuring market power in electricity markets. She calculates the marginal cost of each generating unit in the England and Wales market in order to construct a competitive supply curve. The price-cost margins provide evidence of market power, but below levels consistent with Cournot behavior. Borenstein, Bushnell, and Wolak (BBW, 2001) apply this technique to the California electricity market. They use a Monte Carlo simulation to account for uncertainty over units being able to operate.

[22] 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.

Joskow and Kahn (2001) also use Wolfram's technique in estimating market power in California. They note that environmental permits substantially increased the perfectly competitive price estimates, but observed prices were substantially greater yet. Puller (2001) estimates firm-level behavior in the California market using the CEMS data. He tests whether production choices were consistent with static or dynamic pricing models and finds evidences supporting the former.

Few studies have tested for evidence of firms exercising market power in the PJM market. The PJM market monitoring unit examined firm behavior in the first summer after the market restructured (Bowring *et al.*, 2000; and MMU 2000). They examine three high demand days and find that the high prices may have resulted either from scarcity or firms exercising market power, but that they cannot separate these effects.[23]

In Mansur (2001), I apply Wolfram's technique to determine whether market imperfections persisted during the initial summer of restructuring when prices spiked more often than other recent summers. From April through August, 1999, the observed price averaged $40.3 per megawatt-hour (MWh) while I estimate the average competitive equilibrium price to be $32.3/MWh. In the previous summer, the observed prices ($26.5) and competitive prices ($27.1) were much closer. Market imperfections led to an increase in total spot market costs of about 41 percent in the first summer of the market.

3 Discussion of Environmental Implications of Market Power in Product Markets

A broad theoretical literature exists on incentive-based environmental regulation, including the theory of taxation under market imperfections.[24] Many papers have simulated the effectiveness of regulation, but the scarcity of implemented environmental incentive-based regulation has resulted in little empirical research on how firms respond to such economic

[23] Borenstein, Bushnell, and Knittel (1997) simulate Cournot equilibria for the PJM market. They find substantial price-cost margins above moderate demand levels (~37 GW). Joskow (1997) analyzes the PJM market using HHI measures to examine the proposed Baltimore Gas & Electric and PEPCO merger.

[24] See Cropper and Oates (1992) or Hanley, Shogren, and White (1997) for an overview of this literature. Semial works include Pigou (1938) on obtaining the first-best by taxing the externality and Crocker (1966) on establishing a tradable emission permit market to obtain the optimal outcome.

incentives.[25] One notable study by Carlson, Burtraw, Cropper, and Palmer (2000) evaluates the performance of regulated utilities in the SO_2 allowance market and finds that most trading gains were not achieved in the first two years of the program.[26]

Economists have long understood the importance of considering the structure of product markets when determining environmental regulation. How to regulate a polluting monopoly is a common example of the theory of the second best. Placing a tax equal to the marginal external cost on a monopoly could result in larger welfare losses than ignoring the externality in a perfectly competitive market (Buchanan, 1969; Oates and Strassmann, 1984).[27] The second-best tax for a monopoly will lie below the marginal environmental cost because of the additional distortion in the product market (Lee, 1975; and Barnett, 1980).[28]

However, determining second-best taxes becomes more complicated when an imperfect market has several producers. Levin (1985) demonstrates how taxes may increase pollution from an oligopolistic industry with asymmetric cost functions, *even* when the taxes are proportional to producers' pollution per unit of output. Shaffer (1995), Simpson (1995), and Carlsson (2000) have shown that the second-best tax may exceed the marginal environmental cost, since the market structure leads to production inefficiencies in addition to distorting the total quantity produced.[29]

Monopolists distort overall production levels but use the most efficient technology

[25]Two related areas of empirical research concern productivity and environmental regulation (for example, see Gollop and Roberts, 1983; Gray and Shadbergian, 2001), and taxation of imperfect markets focusing on the cigarette industry (for example, see Delipalla and O'Donnell 2001).

[26]This suggests that simulations assuming efficient behavior may be misleading, especially in a regulated market. Electricity restructuring was intended to lead to more efficient production and investment. As such, research on the environmental impacts of restructuring has focused on how competition leads to production efficiency gains, fuel switching particularly by new investments, demand response to lower prices, and firm responsiveness to incentive-based approaches to environmental regulation. Burtraw, Palmer, and Heintzelman (2000) review the state of the literature on environmental impacts of restructuring.

[27]Oates and Strassmann (1984) suggest that ignoring market structure will likely lead to small inefficiencies when determining the emissions regulation. Cropper and Oates (1992) note that in an economically regulated market this will not necessarily be the case. Furthermore, if small changes in production lead to discrete environmental implications, market structure will matter.

[28]A related literature concerns market imperfections in the permit markets directly. Hahn (1984) discusses how firms exercise monopolistic or monopsonistic power depending on their net positions of permits. Misiolek and Elder (1989) and Sartzetakis (1997a) discuss how firms may want to distort the permit market in order to raise rivals' costs. Stavins (1995) discusses how transaction costs distort permit markets.

[29]Sartzetakis (1997b) constructs a model of oligopolistic competition in a product market and discusses the trade off of command-and-control versus market incentive regulation under imperfect information.

in the production set to obtain that level of production. Oligopoly distortions result from an overall production effect, like the monopolist. In addition, cross-firm production inefficiencies cause a production substitution effect whereby individually firms minimize their own costs, but collectively, they fail to use the least-costly technology to achieve a given level of output. In general, pollution implications of market competitiveness will depend on the change in total output, and changes in the technologies used to meet production. Demand elasticity, firm incentives, the distribution of technologies among firms, and the costs and emissions associated with various technology types are key market characteristics determining these effects. In the cases of the monopoly and oligopolists with symmetric technologies, no cross-firm production inefficiencies will occur under symmetric equilibria. However, if either firms' incentives (ability to set prices) or technology sets (reflecting production costs and emissions) differ, a substitution effect will further distort the level of pollution.

When some firms behave as oligopolists and others as a competitive fringe, pollution may be greater than under perfect competition. In the case of perfectly inelastic demand, changes in pollution will result solely from the technology substitution effect. In this case, the pollution effect will depend simply on the relative emission rates of the technology being withheld and the technology used to meet demand. For example, if oligopolists reduce output from plants using a dirty technology and the fringe uses cleaner technology in its place, overall emissions will fall. Note that if industry supply is monotonic in emission rates, the direction of the change in pollution resulting from market power will depend entirely upon the correlation of emission rates and market output.

The model of a few dominant firms with a competitive fringe facing perfectly inelastic demand has practical importance as it is a plausible characterization of many electricity markets. Demand in wholesale markets is perfectly inelastic because of frozen retail caps. This model has different implications in California and PJM electricity markets. A firm choosing to exercise market power will restrict output from its marginal unit, which is the most expensive unit that would be operating in a competitive environment. California generators primarily use hydroelectric, nuclear, and natural gas to produce electricity. Of these, natural gas is almost always the marginal fuel. That is, if firms reduce production to exercise market power, they will do so by restricting output from a gas unit. The result will be that a more expensive unit will operate to meet demand in lieu of the cheaper unit. More expensive gas units tend to be older, less efficient, and more polluting. In general, pollution will tend to increase as firms behave anti-competitively as long as the type of technology firms use to set prices is the same as the fringe uses to meet demand.

In contrast, the marginal fuel in PJM is either coal, natural gas, or oil, depending on the level of demand. In many hours, a price-setting firm that is considering reducing output will have a coal unit on the margin. Coal units are substantially dirtier than the and cheaper than natural gas units. Therefore, restricting output with coal will lead to less pollution than under perfect competition.

Firms exercising market power in California will necessarily result in more pollution due to the substitution of technology. The effect in PJM will depend on the relative size of across-technology substitution reducing pollution and within-technology substitution increasing it. The magnitude of environmental impacts will be exacerbated by the degree to which the marginal emissions rate is correlated with oligopoly ownership of low cost technology when firms have asymmetric costs. Appendix A demonstrates these points more formally.

4 Data and Cursory Evidence

The EPA's Continuous Emissions Monitoring System (CEMS) records hourly gross production of electricity, heat input, and three types of emissions – SO_2, NO_x, and CO_2 – for most fossil-fuel burning units (hereafter referred to as fossil units) in the country.[30] The data have been found to be highly accurate and comprehensive for most types of fossil units (Joskow and Kahn, 2001). CEMS monitored 234 units in PJM that produced during the summers of 1998 and 1999. The EPA data account for over 97 percent of overall fossil fuel capacity (99 percent of coal capacity) in PJM.

[30]Gross production includes electricity generated for the firms own on-site use. The net generation is approximately 90 to 95 percent of gross. I calculate net production by using the utilization rate implied from the CEMS data and net capacity from the Prosym model (Kahn, 2000). I define the utilization rate as being current gross production divided by the maximum observed gross production in my sample. All units over 25 megawatts and new units under 25 megawatts that use fuel with a sulfur content greater than 0.05 percent by weight are required to measure and report emissions under the Acid Rain Program. The data are reported quarterly so if a unit did not operate in that quarter, then it will not be in the sample. I restrict observations to only those units that operated in the past week. Puller (2001) uses these data in estimating firm behavior in the California electricity market.

The marginal cost data were constructed using variable operating and maintenance (VOM), heat rate, and capacity data from the PROSYM model (Kahn 2000) along with daily natural gas and oil prices.[31] The marginal environmental costs were calculated using monthly price data from Cantor Fitzgerald and quarterly emission rates from the CEMS data.[32]

Table 2 provides descriptive statistics on the demand, fossil unit generation, and prices of electricity for the summers of 1998 and 1999. Hourly average demand rose by about 800 MW while fossil unit generation increased by about 150 MW. The unweighted average utilization rate increased by 11%, reflecting that smaller units were running more often or at higher output levels than before, relative to larger units.[33] In addition, the input prices for oil, natural gas, and SO_2 and NO_x permits are reported. All four input prices increased, with the largest change being seen in the NO_x market. These input prices are reflected in the marginal cost of production for each fuel type.

Table 3 reports the ratio of total generation to total capacity for the summers of 1998 and 1999 across firm and fuel type. PPL and PECO, the two firms likely to behave as price-setters, are compared with the other firms, which I call the fringe. I calculate the ratio for each type of fossil fuel: "dirty" (high SO_2 emission rate) coal; "clean" (low SO_2 emission rate) coal; natural gas; dirty oil; and clean oil.[34] In the summer of 1998, firms had similar generation-capacity ratios by fuel type with the exception of PPL's clean coal. In 1999, PECO and PPL ratios fell for all fuel types. The ratios fell for dirty coal and dirty oil fringe units, but not by as much as for PECO and PPL. A possible explanation for the drop production is the introduction of the Ozone Transport Commission (OTC) regional trading program for NO_x emissions in the summer of 1999 described in footnote 4. If PECO and PPL had dirtier plants than other firms, this could explain the difference in changes in the ratios. Alternatively, this may have been the result of market power being exercised. I account for the cost increases in the production models described in the

[31]See Mansur (2001) for further discussion on determining marginal production costs.

[32]Cantor Fitzgerald is a trading company that constructs monthly permit price indices for the NO_x and SO_2 markets. The emission rates are calculated for every three months (Jan-Mar, Apr-Jul, etc.) based on aggregate tons of pollution and aggregate heat input. The emission rates do not change significantly over the time period of my sample.

[33]The utilization rate is the fraction of capacity used to produce generation in a given hour.

[34]High emission rates are defined as those with rates above a pound of SO_2 per mmBTU using emission rates from the EPA. This level was the median emission rate for oil and coal units in the sample. Similar findings result from using NO_x emission rates to stratify unit types.

following sections.

5 Models of Competitive Behavior

In this section, I construct estimates of perfectly competitive behavior in order to measure production inefficiencies by comparing actual production choices with these estimates. I use two methodologies to estimate the social optimum. The first is a simulation of perfect competition using marginal cost measures, similar to models used in the previous literature.[35] This 'simplified' model ignores intertemporal constraints like start-up costs. I then construct an econometric model that estimates how firms did respond to intertemporal constraints in a period when price-taking behavior was likely. Both models have relative advantages to each other. The simplified model simulates optimal behavior without relying on an observed baseline, but ignores intertemporal constraints. In contrast, the intertemporal model uses information from the pre-restructuring period to capture how firms do treat these constraints, but is dependent on assuming regulated short-run production choices were equivalent to the social optimum. I begin be defining the optimization problem firms face, including the intertemporal constraints. Then I explain the simplified and intertemporal models.

5.1 Model of Firm Behavior

Several types of intertemporal constraints affect firms' decisions regarding the level and technology set used in production. Whenever a plant prepares for operating on a given day, costs are incurred even without production. These are referred to as "no-load" costs. After a unit is shutdown, it must incur additional "start-up" costs when to operator wants to start producing. Ramping constraints limit the speed at which a unit can increase or decrease its amount of hourly production. Minimum down times limit how fast a unit can be brought back on-line. Finally, minimum operating levels restrict the unit from producing below a certain level while still operating. These intertemporal costs create non-convexities in firms' production cost functions.

[35]See Wolfram (1999) on the UK; Borenstein, Bushnell, and Wolak (2001), and Joskow and Kahn (2001) on California; and Mansur (2001) on PJM.

A firm operating n units will face the following dynamic programming problem:

$$
\begin{aligned}
V(\overrightarrow{q}_{t-1}, t) &= \max_{\{q_t\}_{i=1}^{n}} \{\pi(\overrightarrow{q}_t) - \sum_{i=1}^{n} [\kappa_{it} * \Psi(q_{it}, q_{i,t-1})] + \delta * V(\overrightarrow{q}_t, t+1)\} && (2) \\
s.t. \quad q_{it} &\in \{0, [K_{\min}, K_{\max}]\}, \forall i \in \{1, ..., n\} && \text{(1) Capacity} \\
|q_{it} - q_{i,t-1}| &\leq R, \forall i \in \{1, ..., n\} && \text{(2) Ramping} \\
q_{it} &> 0 \Leftrightarrow \{[q_{i,t-1} > 0] | [q_{i,t-1} = 0, ..., q_{i,t-w(i)} = 0]\}, \forall i \in \{1, ..., n\} \\
& && \text{(3) Minimum Downtime} \\
\text{where } \pi(\overrightarrow{q}_t) &= p_t(\sum_{i=1}^{n} q_{it})[\sum_{i=1}^{n}(q_{it}) - q_t^d - q_t^c] + r_i^d q_t^d + r_i^c q_t^c - \sum_{i=1}^{n} c_{it}(q_{it}), \\
\Psi(q_{it}, q_{i,t-1}) &= 1(q_{it} > 0) * 1(q_{i,t-1} = 0),
\end{aligned}
$$

q_{it} is the production of unit i at time t; $\overrightarrow{q}_t$ is the vector $(q_{1t}, ..., q_{nt})$; $p_t(\sum_{i=1}^{n} q_{it})$ is the inverse residual demand function that the firm faces in the spot market; q_t^d is the amount of native load for the firm; q_t^c is the amount of net supply of contracts independent of the spot price; r_i^d is the frozen retail rate; r_i^c is the contract coverage price; c_{it} is the cost of production ignoring intertemporal constraints; κ_{it} is the start-up and no-load cost; $K_{\min}$ is the minimum operating level; $K_{\max}$ is the maximum capacity; R is the ramping rate; $w(i)$ is the minimum down time; δ is the discount factor.

Price-setting firms have the same value function but with a few simplifications. The price, $p_t(\sum_{i=1}^{n} q_{it}) = \overline{p}_t$, is the given spot market price. Furthermore, the amount of native load and contract coverage are irrelevant to a price-taking firm. When firms are price-takers, aggregate firm production does not affect optimal unit production choices. Therefore, the units can be optimized separately. I account for these simplifications and rewrite the optimization problem for unit i:

$$
\begin{aligned}
V(t) &= \max_{q_{it}} \{\overline{p}_t q_{it} - c_{it}(q_{it}) - \kappa_{it} * \Psi(.) + \delta * V(t+1)\} && (3) \\
& \quad s.t. \quad \text{Constraints 1-3 from equation 2,}
\end{aligned}
$$

I simplify the first-order condition for heuristic purposes only:

$$
\overline{p}_t = c_{it}'(q_{it}) + \lambda_{it}(q_{i,0}, ..., q_{i,t-1}, q_{it}, q_{i,t+1}, ..., q_{i,T}) \qquad (4)
$$

where λ_{it} is a general function accounting for all of the intertemporal constraints, which can have a positive or negative effect on the marginal cost. The intertemporal constraints may reduce the true marginal cost if postponing shutting down a unit at low-price times leads to greater overall profits (since the unit will not need to start the next day). However, the true marginal cost of a unit may increase if start-up costs prohibit operation when prices exceed marginal costs of production (since the rents are not substantial enough to justify starting). When the shadow price of the intertemporal constraints is small, the problem can be simplified further. Under that assumption, price-taking firms produce at levels where price equals marginal cost. The next section simulates a model assuming no intertemporal constraints.

5.2 Simplified Competitive Model

The simplified model of firm behavior assumes no intertemporal constraints on production choices. Industry-wide, this implies that the price should be set at the system-wide marginal cost.[36] An equilibrium condition is imposed such that the socially optimal price (p_t^*) clears the market:

$$q^f(p_t^*) + q^h + q^n + \widehat{IMP}(p_t^*) = q^d + L(q^d) + Ancillary, \tag{5}$$

where q^f is supply from fossil units; q^h is hydroelectric supply; q^n is nuclear supply; $\widehat{IMP}(p_t^*)$ is the estimated net import supply; q^d is the perfectly inelastic demand; L is line losses that depend on q^d; and *Ancillary* is ancillary services of regulation and reserves needed to insure against blackouts. I assume the supply of hydroelectric and nuclear units are unaffected by restructuring. It is extremely expensive to alter production of nuclear units. Furthermore, nuclear units have low marginal costs so when they are marginal, there is little inframarginal capacity; this implies there is little incentive to increase prices. Hydroelectric generation is endogenous but comprises a small fraction of the total capacity in PJM. I estimate the net import supply curve controlling for weather variables likely to influence the prices in neighboring regions.

I construct a marginal cost curve for fossil fuel generators, while accounting for scarcity rents and opportunity costs. A unit's marginal cost of production equals:

$$MC_{it} = VOM + HR_i(W_t^{fuel} + W_{it}^{SO_2} r_i^{SO_2} + W_{it}^{NO_x} r_i^{NO_x}), \tag{6}$$

[36]The system-wide marginal cost is the marginal cost of generating an additional unit of electricity, given that the least costly technologies are already producing to meet demand.

where MC_{it} is the constant marginal cost of production; VOM is the variable operating and maintenance costs; HR is the heat rate - a measure of inefficiency; W^{fuel} is the relevant fuel price for unit i; W^{SO_2} and W^{NO_x} are the permit prices *when applicable* to firm i; and r^{SO_2} and r^{NO_x} are the emission rates of unit i. Note the lack of uncertainty regarding this measure of marginal cost.

However, uncertainty does enter in the ability of a unit to operate when a firm attempts to produce. I model the output of a unit as:

$$GEN_{it} = CAP_i * 1(P_t^* \geq MC_{it}) * 1(\xi_{it} > FOF_i), \tag{7}$$

where GEN_{it} is generation; CAP_i is capacity; FOF_i is the forced-outage factor; and ξ_{it} is the shock to unit i at time t. If $\xi_{it} \leq FOF_i$, then the unit cannot produce in that hour; this is an important limitation in a market without storage capability. A common technique to account for these outages is to "derate" the capacity of a unit. However, the market's supply curve is convex in price and emissions. I run a Monte Carlo simulation accounting for uncertainty of outages in order to accurately measure expectations of these variables. For each run, I construct the competitive supply curve of all available units and solve for the equilibrium price, accounting for net import response. The mean perfectly competitive price and unit output decisions are computed for each hour.

Figure 2 depicts a hypothetical example of how I solve for an equilibrium using observed prices, marginal cost curves, and a residual demand curve where the slope is determined from the estimated net import supply curve. The model estimates socially optimum prices and output decisions for each generating unit.[37]

Figure 3 plots the relationship between price-cost margins (measured as the Lerner index) and system demand.[38] Markups typically increase with demand because a larger share of a firm's capacity is operating (*i.e.,* there is a larger inframargin) and fringe competitors tend to have to use more expensive generation (so the residual demand is less elastic). However, there were a number of hours with high margins at low levels of demand. One possibility is that firms are facing a segment of the residual demand curve

[37]See Mansur (2001) for more detail on the construction of the perfectly competitive equilibrium.

[38]The PJM market may consist of thousands of prices that differ spatially in some hours because of congestion. In order to calculate a price-cost margin, I use the demand-weighted average price for each hour.

that is inelastic because of a technology gap. Namely, coal units are near capacity when demand is at 30,000 MW and natural gas units are notably more expensive. Alternatively, I may be misinterpreting firms behaving as price-takers that have binding intertemporal constraints. In that case, a coal unit may be unable to cover start-up costs so a gas unit will be called upon to operate.

5.3 Intertemporal Competitive Model

While not explicitly modeling intertemporal constraints in price estimates may lead to offsetting biases, ignoring the constraints potentially poses more of an issue for quantity-based measurements like pollution and welfare implications. Knowing the characteristics of exactly *which* units are affected by imperfect competition is likely to be important. I examine whether ignoring intertemporal constraints biases estimates of production inefficiencies.

I use data on the production behavior in the pre-restructuring period to determine how firms address intertemporal constraints. Firms are assumed to behave competitively in the regulated market, implying that the difference between price and marginal cost of production will equal the shadow price of the intertemporal constraints. Inverting equation 4, the price-taking firm will choose output as a function of historic, current, and future prices, marginal production costs, and intertemporal constraints like the start-up costs and ramping rates:

$$q_{it} = f(p_t - c'_{it}, \lambda_{it}) \tag{8}$$

Contrary to the previous section, I now account for λ_{it}, the shadow price of the intertemporal constraints. Furthermore, the interaction of price-cost margins and intertemporal constraints will matter. For example, if price is expected to exceed costs substantiality in 12 hours, I might shut down a fast ramping unit now to save money in a low demand time but I would keep a unit with high start-up costs running through the lull.

Note that this is not a typical production-cost model estimation used to determine the optimal mix of inputs; I know production costs but not how constraints affect dynamic optimization. Furthermore, I do not calculate the dynamically optimal solution directly. I do not know the exact methodology the regulators use to dispatch units, nor do I know how firms form expectations about future prices and their choice of start-up and no-load bids.

I model output by observing unit-level data on the fraction of capacity being used for generation in a given hour. This ratio is the "utilization rate" (UR), and is bound by zero and one. Firm choices are likely to differ by time of day and ramping constraints. As such, I separate the sample by hour and ramping rate quartile. For each of the samples $j \in \{1, ..., 96\}$, I model production using a flexible functional form estimation technique:

$$\begin{aligned} UR_{ijt} \;=\; & \alpha_j + \beta_{1j} H_{t-1}^{PCM} + \beta_{2j} H_t^{PCM} + \beta_{3j} H_{t+1}^{PCM} + \beta_{4j} D_{t-24}^{PCM} + \beta_{5j} D_t^{PCM} \\ & + \beta_{6j} D_{t+24}^{PCM} + \gamma_{1j} H_{t-1}^{PCM} SRT_i + \gamma_{2j} H_t^{PCM} SRT_i + \gamma_{3j} H_{t+1}^{PCM} SRT_i \\ & + \gamma_{4j} D_{t-24}^{PCM} SRT_i + \gamma_{5j} D_t^{PCM} SRT_i + \gamma_{6j} D_{t+24}^{PCM} SRT_i + \xi_j SRT_i + \varepsilon_{ijt}, \end{aligned} \tag{9}$$

where H_t^{PCM} is the hourly price-cost margin at time t; D_t^{PCM} is the daily mean price-cost margin at time t; SRT is the start-up cost. Each variable is represented as a piece-wise linear function to account for the non-linearity relations.[39]

I estimate the model using a Tobit model since the utilization rate is censored at zero and one. The error structure is likely to be highly correlated, however estimating standard errors can be quite computer-intensive in maximum likelihood estimation especially for a model with many independent variables. Constructing a model in order to predict firm behavior only requires that the coefficients be estimated in a consistent manner, even if the standard errors are modeled incorrectly.[40]

Furthermore, the price variables may still be endogenous even for a regulated price-taking firm; a large unit sustaining a forced outage will likely move the market price. For each endogeous variable constructed from hourly or daily average prices, I create an instrument using competitive price estimates from Mansur (2001). For example, for the third trecile $D_{t+24}^{PCM} SRT_i$ (daily mean price tomorrow times the start-up costs of unit i) variable for quick ramping units at 1pm, I create a similar variable using the daily average of the estimated prices. Each endogenous variable is regressed on the set of instruments and the exogenous variables. Following the technique described in Newey (1987), I use a

[39]Each spline is composed of three parts that are determined by trecile. Start-up costs are approximated using the formula: $STR = 2 * CAP * MC$, where CAP is capacity and MC is marginal cost.

[40]Robinson (1982) demonstrates that Tobit model estimation will be consistent when serial correlation is ignored.

Tobit model where the independent variables are the fitted variables from the first-stage regressions, the exogenous variables, and the residuals from the first-stage regressions.

Table 4 reports the average of the marginal effects and the marginal effect at for the median observation for each variable in equation 9. The marginal effects are reported for all hours and for 6pm only. I predict the competitive production outcome for 1999 using these coefficient estimates.

While the goodness of fit measure is not substantial, the fit is better than from the simplified model.[41] Figure 4 plots a cubic spline function fit of expected utilization rates for 1998 using both the simplified and intertemporal production models. The 45 degree line is shown for comparison. The simplified model is quite jumpy reflecting the fact that units do not change from off to 100% whenever the price goes above costs. Prices tend to fluctuate around firms marginal costs but firms respond by smoothing production choices to account for intertemporal constraints. The intertemporal model has a greater fit than the simplified model because it accounts for these constraints.

The unweighted average utilization rate for 1998 was 0.45 for observed production and the intertemporal model. The simplified model predicts a utilization rate of only 0.35. The rate is smaller because baseload units are running at 100% capacity most of the time and peak units are only on when price is above the marginal cost. This suggest cost estimates maybe understated using the simplified model.

5.3.1 Calibration

I use the intertemporal model to estimate total generation, emissions, and costs. The simplified model imposes an equilibrium constraint as described in section 5.2. However, the intertemporal model does not impose an equilibrium constraint. While the regression estimates will be unbiased for the dependent variable, utilization rate, they will not necessarily be unbiased for the aggregate measure of total production. If the errors are correlated with capacity, or if the model was misspecified, then the total amount of production implied by the intertemporal model will not equal the observed production in 1998. I use total annual predicted generation from the simplified model as a benchmark.

[41] The correlation of observed utilization rates to simplified utilization rate estimates is 0.54 while the correlation of observed utilization rates to the intertemporal utilization rate estimates is 0.72.

I calibrate the model by uniformly altering the coefficients on the endogenous variables (p) and the residuals ($\widehat{e}$) from the first-stage of the regression described in section 5.3. The new vectors of endogenous variables and residuals will be $\widetilde{p} = \alpha * p$ and $\widetilde{e} = \alpha * \widehat{e}$, respectively. I multiply these variables by the coefficients from the Tobit regression to predict utilization rate $\widetilde{UR}$. I iterate over this process until the estimated total production for a given summer equals the amount predicted by the simplified model; α equals 1.19 in 1998 and 1.28 in 1999.

6 Results

6.1 Welfare Losses

Welfare losses result from both an overall production effect and a production substitution effect as discussed in section 3. No overall production effect will occur when demand is perfectly inelastic. Calculating the effects of cross-firm production inefficiencies is simply a matter of aggregation. The welfare loss associated with market power in a market with perfectly inelastic demand is the extra costs associated with production distortions:

$$W^* - \widehat{W} = \sum_{t=1}^{T} \{ \sum_{i=1}^{N} [c_{it}(\widehat{q}_{it}) - c_{it}(q^*_{it})] + \int_{\sum_{i=1}^{N} q^*_{it}}^{\sum_{i=1}^{N} \widehat{q}_{it}} p_t(D_t - Q) dQ \},$$

where W^* is the social welfare under perfect competition; $\widehat{W}$ is the social welfare under imperfect competition; T is the number of hours in the sample; N is the number of units in PJM; $c_{it}(q_{it})$ is the cost of unit i producing a MWh at hour t; $\widehat{q}_{it}$ is the level of production for unit i at hour t under imperfect competition; q^*_{it} is the socially optimal level of production for unit i at hour t determined using the simplified cost model; $p_t(x)$ is the inverse net import supply function that is assumed to be perfectly competitive; and D_t is the level of demand at hour t. I assume that marginal costs are constant: $c_{it}(q_{it}) = c'_{it} * q_{it}$.

The EPA CEMS data are used to determine the observed hourly production of fossil fuel units ($\widehat{q}_{it}$). I use both the simplified and the intertemporal cost model estimates of perfectly competitive behavior to determine q^*_{it}. The change in net imports is calculated based on estimates from Mansur (2001).

The estimates of welfare losses may be biased by ignoring intertemporal constraints. Recall the imprecision of the simplified model seen in Figure 4. The price varies throughout the day while the marginal cost remains constant. The simple model predicts that whenever the price exceeds a units costs, the unit should immediately increase output to 100% capacity. The intertemporal constraints will limit the rate of changing production as well as the decision of whether to produce at all. Whenever the simplified competitive model errs in estimating production, this results in additional welfare losses, regardless of whether the error was in over or under predicting behavior.

I control for the bias from ignoring intertemporal constraints by using 1998 estimates as a control. I assume that the 1998 measured welfare losses resulted solely from the bias. Therefore, the reported welfare effects are the change in welfare losses from 1998 to 1999. As in the simplified model, I use the 1998 estimates of welfare losses to control for any intertemporal constraints I am not capturing in the model. Table 5 reports the welfare implications.

The simplified model estimates that welfare was reduced by $160.5 million in the summer of 1999 because of production inefficiencies. Of this, $127.5 million were from production inefficiency directly in PJM resulting from the wrong generators producing. That is, there are *cross-firm* production inefficiencies but not *within-firm* production inefficiencies. The remaining $33.1 million resulted from the increased need of imports because of too little overall production in PJM.

The intertemporal model better accounts for firm decisions in 1998; the welfare loss is $81 million where as the simplified model estimates costs of $218 million. The intertemporal model finds similar amounts of welfare losses directly in PJM as the simplified model ($125 million), but only when controlling for the welfare losses in 1998. The absolute measures of welfare losses in 1999 were $346 million for the simplified model and $206 million for the intertemporal model. I assume that total import welfare implications under the intertemporal model are the same as under the simplified model I calibrate total production in the intertemporal model to equal total production in the simplified model. Therefore, total import welfare implications will be equal for the two models. This leads to a total of $127.7 million in welfare losses using the intertemporal model.

In comparison, the observed total costs associated with electricity production were

\$1.67 billion in 1998 and increased to \$2.10 billion in 1999. I measure wealth transfers in Mansur (2001). I find that the PJM spot market revenues exceeded those of a perfectly competitive market by \$224 million during the summer of 1999. If similar markups affected demand met with bilateral contracts, the total wealth transfer from market power was \$827 million.

6.2 Environmental Implications

6.2.1 Measuring Emission Changes

I compare the emissions from actual behavior with emissions from both the simplified and the intertemporal cost models of perfectly competitive behavior. The environmental implications will depend on two effects: (1) the relative difference between the emissions from units oligopolists use to reduce and the emissions of the units the fringe uses to meet demand; and (2) the overall increase in pollution from importers. This can be categorized into cross-firm production inefficiency effects and aggregate output reduction effects, respectively:

$$\widehat{E}_j - E_j^* = \sum_{t=1}^{T}\{\sum_{i=1}^{N}[r_{ijt}(\widehat{q}_{it} - q_{it}^*)] + \int_{\sum_{i=1}^{N} q_{it}^*}^{\sum_{i=1}^{N} \widehat{q}_{it}} r_{jt}^{imp}(D_t - Q)dQ\},$$

where E_j^* is the sum of emissions of pollutant j (where j is SO_2 or NO_x) under perfect competition; $\widehat{E}_j$ is the sum of emissions of pollutant j under imperfect competition; r_{ijt} is the emissions rate of unit i, pollutant j, and at time t; and r_{jt}^{imp} is the emissions rate of pollutant j corresponding to the net import supply at time t.

Figure 5 displays kernel regressions of observed and predicted hourly emissions using the simplified model across demand levels.[42] In 1998, the competitive estimates and the observed emissions are similar for many demand levels. However, the Demand levels below 25 GW. The estimated emissions exceeded the observed emissions for most demand levels above 23 GW in 1999, especially at medium demand periods. This is consistent with the results from Figure 1, namely that gas units are replacing coal units. Observed emissions are less than predicted at the high demand levels in 1999. These results suggest that the

[42] I used a kernel regression analysis of hourly emissions on demand for each time series using a Gaussian weighting over 100 grid points.

model fails to explain emissions precisely at those demand levels when market power is being exercised.[43]

Table 6 reports the hourly average emissions in PJM using observed and predicted data for both competitive models. The simplified model of perfect competition finds that the implied percent change in emissions explained by cost and demand shocks was -6.6% for SO_2 and -8.7% for NO_x. This suggests that 37% of the observed reduction in SO_2 (and 45% of NO_x) resulted from market imperfections in 1999. With the intertemporal competitive model, I find evidence that electricity market imperfections attributed to SO_2 emission reductions similar to the simplified model (41%), but account for only 14% of the observed NO_x reductions.

6.2.2 Economic Implications of Reductions

There are several ways to interpret the economic importance of emission reductions. Recall that under a cap-and-trade system, aggregate emissions will be unaffected by production distortions since a reduction in one area lowers the permit price and allows more pollution elsewhere. Note that the distribution of emissions will matter if the damage function depends on locational and temporal factors. However, this is an issue of instrument choice rather than an implication of production distortions. On the other hand, the costs associated with regulation will be affected.

One measure of the value of environmental impacts is to argue that the permit price accurately reflects the value society places on clean air. The total reduction in SO_2 for the summer of 1999 was 23,552 tons. Multiplying the daily price of SO_2 permits by the daily emission reductions and aggregating over the summer, I estimate a value of \$5.6 million from SO_2 reductions. NO_x emissions were reduced by 11,637 tons corresponding to \$21.5 million in the summer of 1999. Therefore, the total value of reduced pollution in PJM is \$27.1 million for one summer.

[43] I test the significance of the difference between observed and estimated emissions by regressing the difference on a piece-wise linear function of demand (in GWh) by decile with terms interacting with an indicator for 1999. I account for serial correlation using the Prais-Winsten method. The model finds that the only signifiant coefficients for 1999 were for demand in the first, fourth, and fifth decile, which were significant at the 1% level (the corresponding coefficients and standard errors were: -0.246 (0.080); -0.902 (0.311); and -1.117 (0.423). These results correspond to demand below 21.9 GW, and between 26.0 and 29.4.

A broader view of the permit market recognizes that under a cap-and-trade system, emissions will be increased in other parts of the system as long as the permit price is positive. The overall welfare implications in the permit market will depend on the elasticity of abatement supply. I use the Tracking and Analysis Framework model of the SO_2 market under Title IV of the Clean Air Act to simulate how production inefficiencies would affect permit market prices.[44] I estimate a price elasticity of abatement (emission reductions) of approximately 0.1. PJM is about 10% of the permit market. This implies that if PJM reduced emissions by 4% annually, the price of SO_2 permits would fall by 4%. This in turn, would lead to a reduction in national SO_2 compliance costs of $35 million annually.

Additional welfare losses can result if the initial cap was equal to or above the optimal level of emissions because the permit market does not adjust to reduced abatement costs by reducing the total permit quantity. Figure 6 portrays an example of a permit market. The optimal cap is shown, whereby the marginal benefits (B') and marginal costs (A'_1) of abatement equate. However, market power reduces the cost of abatement to A'_2, thereby reducing the optimal price in the permit market.

I estimate that in the case of perfectly elastic marginal benefits of abatement and an initially optimum cap, welfare losses in the permit market will total only $68,000 in one summer. However, if the initial cap level were even 10% above the optimal cap, then deadweight loss would be increased by about $1 million in a summer because of production inefficiencies. Conversely, if the initial cap were too high, these market distortions could *reduce* welfare losses in the permit market.

6.2.3 Policy Implications

Firms exercising market power in product markets can affect the cost of complying with such regulation. Restructuring the PJM wholesale market enabled firms to exercise market power that would have reduced pollution levels without environmental regulation. The welfare effects of production inefficiencies also include the losses in the 'market' for the externality. If a tax or permit cap does not adjust to changes in demand for polluting rights, or equivalently supply of abatement, deadweight loss will increase or occur. In the

[44] See Burtraw *et al.* (1998) and Burtraw and Mansur (1999).

case of environmental taxes and market power lowering abatement costs, welfare losses in both markets will be reduced by lower taxes.

Ignoring the implications of market imperfections could lead to more inefficiencies under an *a priori* optimal tax than in a permit market when abatement costs are reduced by firms exercising market power because of the feedback effect of the permit. In other words, suppose a market is more or less indifferent between a tax and quota.[45] In this case, a tax or a quota will result in similar distortions to the permit market when the marginal abatement cost curve is reduced by firms exercising market power in the electricity market (recall Figure 6). However, the permit leads to smaller losses in the product market since the price of permits responds to a reduction in permit demand, lessening the amount of deadweight loss. In contrast, the tax does not have a feedback mechanism.

Ignoring market imperfections under a cap-and-trade system when market power reduces abatement costs will result in potentially minor losses; lowering the cap reduces welfare losses in the permit market, while increasing the permit cap reduces welfare losses in the product market. In the case of market inefficiencies increasing abatement costs, a tax system would likely lead to less inefficiencies by the opposite reasoning.

6.2.4 Emissions from Increased Imports

I approximate which firms produce more as a result of firms in PJM exercising market power by determining the correlation of net imports into PJM over the summer of 1999 with production at all units in the Eastern grid, controlling for local weather phenomenon likely to affect this distribution. For each unit i not in PJM, I estimate the following equation:

$$Q_{it} = \alpha_i + \beta_i I_t + \gamma_i T_{it} + \delta_i (T_{it})^2 + \varepsilon_t, \tag{10}$$

where Q_{it} is the production of unit i at time t; I_t is the net imports into PJM at time t; and T_{it} is the mean daily temperature in the state of unit i. For each hour in the summer of 1999, the $\widehat{\beta}$ coefficient estimates are calibrated such that:

$$\widetilde{\beta}_i = \frac{\widehat{\beta}_i}{\sum_{i=1}^{M} \widehat{\beta}_i}, \tag{11}$$

[45]If the absolute values of the slopes of the marginal benefits and marginal costs of abatement are equal, then the social planner will be indifferent between a tax and quota system (Weitzman, 1974).

where M is the sample of units in the Eastern grid not in PJM. The implied emissions from imports equal $I_t * (\sum_{i=1}^{M} \widetilde{\beta}_i r_{ij})$ where r_{ij} is the emissions rate for unit i and pollutant j. Using the CEMS data, I estimate an increase in SO_2 emissions from importing regions averaging 1.2 tons per hour in the summer of 1999. The effects on permit prices will be partially offset if the importing firms were some of the few regulated by Phase I of the SO_2 program or were in the Northeast thereby regulated by the NO_x program.[46]

7 Natural Experiment Estimation of Firm Behavior

In this section, I treat restructuring as a natural experiment in order to test firm behavior. Some vertically integrated firms were net sellers in the market and therefore had incentives to set prices after restructuring. Other firms were net purchasers in the spot market. They had incentives to be price-takers both under regulation and after restructuring. I test the assumption about which firms exercise market power. PPL and PECO are identified as the most likely firms to behave as price-setters based on evidence from bidding behavior, average net positions, and a more formal examination of production behavior discussed in Appendix B. I test the accuracy of the competitive model estimates using unit-level data in Appendix C.

The strategic decisions of production are made at the firm level. As such, I test firm behavior using data on firms' choices of total production by hour. First I test simply whether firms behave differently after restructuring using indicator variables. I use a difference-in-differences model to account for shocks that are common to all firms in the summer of 1999 (ζ_t), and shocks specific to the oligopolists relative to the fringe (η_i). I test change in the behavior following restructuring for both the oligopolists (γ) and the fringe (β). By aggregating generation, I can estimate the equation:

$$\ln(gen) = \phi \ln(\widehat{gen}) + \alpha + \eta O_{lig} + (\zeta + \beta) Y_{99} + \gamma Y_{99} O_{lig} + Z'\Pi + u_{it}, \qquad (12)$$

where gen is the observed total hourly firm generation; $\widehat{gen}$ is the estimate of total hourly firm generation (using either the simplified or the intertemporal model); and Z is a vector

[46] This amount equals 0.9% of the 1998 PJM emissions. The 3.9% reduction in emissions in PJM is reduced to 3.0% when accounting for the increased emissions nationally that occur directly from production inefficiencies.

of exogenous variables including a 10-piece spline function of demand, hourly indicators, and day of week indicators. The common time shock and the effect of restructuring on fringe firms cannot be separately identified. Therefore, this is more of a first-differences model where the behavior of each firm is compared to historic behavior.

Table 7 reports the results for the hourly firm-level analysis. The standard errors of these models accounting for serial correlation and heteroskedasity are more straightforward to calculate since aggregating over many censored observations results in a variable capable of being modeled using linear techniques. In model 1, I control for simplified model estimates and find an increase in fringe output of 3% while oligopolists' reduced output by 18% relative to the fringe. Controlling for the intertemporal model estimates leads fringe and oligopolist firms reducing output (by 2% and 14%, respectively). Only the oligopolist coefficients are significant.

The second pair of models in Table 7 more closely examines the relationship between price and quantity. The first-order condition for a price-setting firm will be:

$$gen = \frac{pcm}{p'} + q^d + q^c, \tag{13}$$

where pcm is the price-cost margin; p' is the slope of the inverse residual demand for the firm; q^d is native load; and q^c is the net supply contract coverage independent of price. The correlation between pcm and generation should be greater for a price-taking firm since those firms behave as if the slope of their inverse residual demand was zero. I estimate this equation using the following econometric model:

$$\ln(gen) = \phi \ln(\widehat{gen}) + \alpha + \beta_1 pcm + \beta_2 pcmO_{lig} + \beta_3 pcmY_{99} + \beta_4 pcmY_{99}O_{lig} + Z'\Pi + u_{it}, \tag{14}$$

The price-cost margin variables are endogenous. I instrument using quadratic functions of daily mean and lag daily mean temperatures for states in and around PJM. Table 7 reports the oligopolists reduce output at higher prices relative to other firms in 1999 and relative to their historic behavior.

8 Conclusions

Firms in the PJM wholesale electricity industry exercised market power in the summer of 1999, thereby causing production inefficiencies. The resulting welfare losses and effects on incentive-based environmental regulation are measured by calculating the perfectly competitive equilibria. I find increased permit costs fail to explain all of the observed reduction in pollution, implying that changes in market structure account for 40 percent of the reduction. Furthermore, welfare losses are approximately \$161 million in the electricity market for one summer in these four states. With the intertemporal competitive model, I find evidence that electricity market imperfections attributed to SO_2 emission reductions and welfare losses similar to the simplified model, but account for only 14% of the observed NO_x reductions. A test of firm behavior finds that firms with net-selling positions reduced output relative to other firms. Imperfect markets in which firms reduce emissions relative to perfect competition may be better regulated by permit markets than taxes because of the feedback effect; less emissions lower permit prices that reduce the amount of market power being exercised.

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9 Appendices

9.1 Appendix A

This appendix discusses the theoretical environmental implications of firms exercising market power relative to perfect competition. The overall effects on output and emissions are examined for several market structures: Cournot equilibrium; Cournot with fringe; and Cournot with fringe and perfectly inelastic demand.

9.1.1 Cournot Model

I begin with a simple model to demonstrate how oligopolistic behavior distorts production, thereby affecting social welfare, emission levels, and optimal taxation choices. Assume that an industry has a small number of previously-regulated firms, $m > 1$. They face a market demand curve $P(X) = P(x_1, ..., x_m)$. Each firm has a cost function of $c_i(x_i)$. Assume that under regulation, the firms behaved as price-takers and produced where $P(x_i, X_{-i}) = c_i'(x_i)$. Let α be the degree to which deregulated firms are able to unilaterally exercise market power under a quantity-setting equilibrium. The resulting profit maximization is therefore:

$$P(x_i, X_{-i}) + \alpha P'(X)x_i - c_i'(x_i) = 0, \forall i \in \{1, ..., m\} \tag{15}$$

Using a congectural variation model of firm behavior enables me to examine the marginal implications of market power on firm output ($\frac{dx_i}{d\alpha}$), market output ($\frac{dX}{d\alpha}$), and aggregate emissions ($\frac{dE}{d\alpha}$).

Proposition Firms with asymmetric sets of technology (differing in costs or emission rates) may pollute more in a Cournot equilibrium than a perfectly competitive one.

Proof Marginal implications of market power on firm output will equal:

$$\frac{dx_i}{d\alpha} = \frac{P'x_i + [P' + \alpha P''x_i]\frac{dX}{d\alpha}}{c_i'' - \alpha P'} \tag{16}$$

Summing over all i, the overall output equals:

$$\frac{dX}{d\alpha} = \frac{P' \sum_{i=1}^{m}[\Pi_{j \neq i}(c_j'' - \alpha P')x_i]}{\Pi_{k=1}^{m}(c_k'' - \alpha P') - \sum_{i=1}^{m}[\Pi_{j \neq i}(c_j'' - \alpha P')(P' + \alpha P''x_i)]} \tag{17}$$

I assume $c_i''(x_i) > \alpha P'(X)$ and $P' + \alpha P''x_i < 0$ (similar to Hahn 1962 and Levin 1984). If costs are homogeneous ($c_i''(x_i) = \gamma$), then $\frac{dX}{d\alpha}$ will be negative:

$$\frac{dX}{d\alpha} = \frac{P'X}{(\gamma - \alpha P') - (mP' + \alpha P''X)} < 0 \tag{18}$$

Furthermore, these assumptions ensure $\frac{dX}{d\alpha}$ will be negative even with heterogeneous costs. This implies $\frac{dx_i}{d\alpha} \lesseqgtr 0$ if and only if:

$$P'x_i \lesseqgtr -[P' + \alpha P'' x_i]\frac{dX}{d\alpha} \tag{19}$$

For the homogeneous cost case, $\frac{dx_i}{d\alpha} = \frac{dX}{d\alpha}\frac{1}{m} < 0$, and therefore, emissions will unambiguously decrease as a result of market power. However, when costs are heterogeneous, then the individual firms' output is ambiguous.

If the firms that produce more in a Cournot equilibrium than in a perfectly competitive equilibrium have large emissions associated with that extra production, then emissions can increase even though total output has fallen. To elaborate, by assuming that the environmental externalities depend on the aggregate emissions and not on the spatial distribution of pollution, we can measure the environmental impacts by looking at the sum of the change in emissions resulting from the introduction of imperfect competition. The distortion in emissions from imperfect competition is:

$$\frac{dE}{d\alpha} = \sum_{i=1}^{m} \frac{de_i(x_i)}{dx_i}\frac{dx_i}{d\alpha} = \sum_{i=1}^{m} [r_i'(x_i)x_i + r_i(x_i)]\frac{dx_i}{d\alpha},$$

where $E(X)$ is the aggregate emissions; $e_i(x_i)$ is the emissions from firm i; and $r_i(x_i)$ is the average emissions rate of firm i. The covariance of the marginal emissions of production and the marginal implications of market power on firm output determines the sign of $\frac{dE}{d\alpha}$. When firms use technology with asymmetric costs or emission rates, the overall effect on emissions will be ambiguous.

9.1.2 Cournot Dominant Firms with Fringe

Emissions can be greater under imperfect competition when all firms use the same technology, but some firms are price-takers. Begin with an industry with $n > 2$ firms. Some firms behave as price-takers, either because they are limited by economic regulation or are profit maximizing subject to a perfectly elastic firm-specific demand function. However, a set of dominant firms are able to exercise market power and do so by choosing a quantity-setting equilibrium, subject to the fringe supply curve and resulting residual demand. I refer to this game as Cournot dominant firms with fringe. Let the subset, $m \subset n$, be price-setting firms (where $m > 1$) while the other firms, $n \backslash m$, be the fringe price-taking producers. The overall effect of imperfect market structure on emissions will depend on the marginal implications of market power on Cournot firm output ($\frac{dx_i}{d\alpha}$), fringe firm output ($\frac{dq_i}{d\alpha}$), market output ($\frac{dX}{d\alpha}$), and aggregate emissions ($\frac{dE}{d\alpha}$).

Proposition Cournot and fringe firms with symmetric sets of heterogeneous technology (symmetric marginal cost curves) may pollute more than under perfect competition.

Proof The assumption of symmetric sets of heterogeneous technology implies that $c_i(x_i) = c(x_i)$ and $r_i(x_i) = r(x_i)$ for all firms. By symmetry, I note that the marginal implications of market power on firm output for the price-setting firms will be:

$$\frac{d\widehat{x}_i}{d\alpha} = \frac{P'\widehat{x}_i + [P' + \alpha P''\widehat{x}_i]\frac{dX}{d\alpha}}{c'' - \alpha P'}, \tag{20}$$

where $\widehat{x}_i$ is the output for the price-setting firm i. For the price-taking firms:

$$\frac{d\widetilde{x}_i}{d\alpha} = \frac{P'\frac{dX}{d\alpha}}{c''}, \tag{21}$$

where $\widetilde{x}_i$ is the output for the price-taking firm i. Hence, aggregating over m price-setting and $(n-m)$ price-taking firms yields:

$$\frac{dX}{d\alpha} = \sum_{i=1}^{m}\frac{P'\widehat{x}_i + [P' + \alpha P''\widehat{x}_i]\frac{dX}{d\alpha}}{c'' - \alpha P'} + \sum_{i=m+1}^{n}\frac{P'\frac{dX}{d\alpha}}{c''} \Longrightarrow \tag{22}$$

$$\frac{dX}{d\alpha} = \frac{c''P'\widehat{X}}{(c'' - \alpha P')c'' - c''(mP' + \alpha P''\widehat{X}) - (c'' - \alpha P')(n-m)P'} < 0, \tag{23}$$

where $\widehat{X} = \sum_{i=1}^{m}\widehat{x}_i$. This implies the price-taking firms will increase output:

$$\frac{d\widetilde{x}_i}{d\alpha} = \frac{P'\frac{dX}{d\alpha}}{c''} > 0 \tag{24}$$

And price-setting firms will reduce output:

$$\frac{d\widehat{x}}{d\alpha} = \frac{P'\widehat{x}_i + (P' + \alpha P''\widehat{x}_i)(m\frac{d\widehat{x}}{d\alpha} + (n-m)\frac{d\widetilde{x}}{d\alpha})}{c'' - \alpha P'} \Longrightarrow \tag{25}$$

$$\frac{d\widehat{x}}{d\alpha} = \frac{P'\widehat{x}_i + (P' + \alpha P''\widehat{x}_i)(n-m)\frac{d\widetilde{x}}{d\alpha}}{(c'' - \alpha P') - (P' + \alpha P''\widehat{x}_i)m} < 0 \tag{26}$$

Total emissions will be:

$$\frac{dE}{d\alpha} = m[r'(\widehat{x})\widehat{x} + r(\widehat{x})]\frac{d\widehat{x}}{d\alpha} + (n-m)[r'(\widetilde{x})\widetilde{x} + r(\widetilde{x})]\frac{d\widetilde{x}}{d\alpha}$$

$$\frac{dE}{d\alpha} \gtrless 0 \Leftrightarrow \frac{m}{n-m}\frac{r'(\widehat{x})\widehat{x} + r(\widehat{x})}{r'(\widetilde{x})\widetilde{x} + r(\widetilde{x})} \gtrless -\frac{d\widetilde{x}/d\alpha}{d\widehat{x}/d\alpha}$$

If the emissions rate is sufficiently increasing in output, then emissions will be greater when some firms behave anti-competitively.

Corollary: Cournot with Fringe and Perfectly Inelastic Demand When I focus on perfectly inelastic demand functions, the relationship between the degree of imperfection of a market and the emissions becomes even more transparent. This model is applicable to wholesale electricity markets where consumers do not observe or respond to the real-time price. The change in emissions associated with the degree of market imperfection in a setting of Cournot and fringe firms with symmetric sets of heterogeneous technology facing perfectly inelastic demand will depend entirely on the correlation between emission rates and aggregate production.

Proof When $P(X)$ is perfectly inelastic, the aggregate production X will equal demand, $\overline{D}$, under perfect and imperfect competition. This results in the distortion in emissions from the imperfect competition being as follows.

$$\Delta E = E_{Cour} - E_{PC} = [\sum_{i=1}^{m} r_i(\widehat{x}_i)\widehat{x}_i + \sum_{i=m}^{n} r_i(\widetilde{x}_i)\widetilde{x}_i] - \sum_{i=1}^{n} r_i(x_i^*)x_i^*$$

Where $\widehat{x}_i$ is the output for price-setting firm i under the Cournot dominant firms with fringe; $\widetilde{x}_i$ is the output for price-taking firm i under this Cournot game; and x_i^* is the output for firm i under perfect competition. When firms have different sets of technology, the net effect on emissions will be ambiguous and depend on which firms use what type of technology.

Even when firms have symmetric sets of technology, imperfect competition can lead to different emissions outcomes. Let $r_i(x_i) = r(x)$ and $c_i(x_i) = c(x)$ for all n firms. The first-order condition for the price-setting firm becomes:

$$c'(\frac{\overline{D} - m\widehat{x}}{n-m}) - (\frac{m}{n-m})c''(\frac{\overline{D} - m\widehat{x}}{n-m})\widehat{x} = c'(\widehat{x}) \tag{27}$$

Therefore, $\widetilde{x} = \frac{\overline{D}-m\widehat{x}}{n-m}$. From this it follows that when $m = 0$, $x^* = \frac{\overline{D}}{n}$. Assuming the cost function behaves as typical cost functions, $c'(x) \geq 0$ and $c''(x) \geq 0$, it follows that $\widehat{x} \leq x^* \leq \widetilde{x}$. The change in emissions resulting from imperfect competition becomes:

$$\begin{aligned} \Delta E &= mr(\widehat{x})\widehat{x} + (n-m)r(\widetilde{x})\widetilde{x} - nr(x^*)x^* && (28) \\ &= (n-m)[r(\widetilde{x})\widetilde{x} - r(x^*)x^*] - m[r(x^*)x^* - r(\widehat{x})\widehat{x}] && (29) \end{aligned}$$

Note that if $r_i'(x) = 0$,then $\Delta E = 0$. Otherwise, imposing monotonicity on $r(x)$ and noting $\widehat{x} \leq x^* \leq \widetilde{x}$:

$$\begin{aligned} \Delta E &\gtrless 0 \Leftrightarrow \frac{r(x^*+\varepsilon)}{r(x^*-\varepsilon)} \gtrless \frac{m(x^* - \widehat{x})}{(n-m)(\widetilde{x} - x^*)} = 1 && (30) \\ \Delta E &\gtrless 0 \Leftrightarrow r'(x) \gtrless 0, && (31) \end{aligned}$$

where $\varepsilon > 0$ is a minute deviation from the perfectly competitive output level. Since the amount withheld, $m(x^* - \widehat{x})$, equals the additional amount the fringe must supply, $(n-m)(\widetilde{x} - x^*)$, the change in emissions will depend only on the marginal emissions rate. Therefore, the Cournot dominant firms with a fringe will emit more (less) if the average emissions rate is increasing (decreasing) in output.

9.2 Appendix B

I test whether PECO and PPL behaved differently than other firms in 1999 by looking at the relationship between the price-cost margin and a firm's inframarginal capacity. If a firm is behaving competitively, then the first-order condition will not depend on the inframargin. However, if the inframargin is correlated with the shadow price of the intertemporal constraints, then a measure of the relationship between the price-cost margin and a firm's inframarginal capacity would be biased. I use a difference-in-differences technique to control for this bias. Explicitly, I assume that a price-setting firm will optimize:

$$\max_{q_i, s_t} p(Q_f)(Q_f - q^d - q^c) + \overline{r}q^d + \overline{w}q^c - \sum_{i=1}^{M} c_i(q_i) - \sum_{i=1}^{M} k(s_{t-1,i}, s_{t,i}), \tag{32}$$

where $Q_f = \sum_{i=1}^{M} q_i$ is total firm production; $p(\sum_{i=1}^{M} q_i)$ is the residual demand function for the firm accounting for all other firms' equilibrium behavior; M is the number of units the firm owns; q_i is the production of unit i; q^d is the amount of native load a firm must provide its customers; q^c is the net supply of bilateral contracts that are priced independently of the spot market price; $\overline{r}$ and $\overline{w}$ are the fixed rates for native load and contracted production, respectively; and $c_i(q_i)$ is the total costs of production for unit i. The resulting first-order condition for unit j (the most expensive operating unit for the firm):[47]

$$p - c'_j = -p'(Q_f)(Q_f - d - q^c) + \lambda_j \tag{33}$$

As shown in equation 33, a firm will determine the output of a unit based on a function of price (P), marginal cost (c'), the shadow price of intertemporal constraints (λ), and the inframargin ($Q_f - q^d - q^c$). I rewrite the first-order condition as:

$$PCM_{it} = \alpha + \beta(Q_f - q^d) + \varepsilon,$$

where PCM is the price-cost margin. The constant will capture the average net contract coverage and shadow price of the constraints. The coefficient on the net supply quantity will pick up correlations between net supply and the shadow price. The model attempts to separate out common shocks to PJM (like the OTC NO_x program) from behavior unique to the oligopolistic firms. I assume that the parameters α and β differ only by year (y) and firm type (j) so that $\alpha = \alpha_j + \alpha_y + \alpha_{jy}$ and $\beta = \beta_j + \beta_y + \beta_{jy}$. I assume that fringe firms make decisions based on equation 4 in both the pre- and post-restructuring eras. The oligopolists also use this equation in the pre-restructuring period, but follow equation 33 in the post-restructuring period. By differencing across time for the fringe firms, I capture common time shocks (α_y and β_y), and firm-type shocks (α_j and β_j). I identify the behavior of price-setting firms is compared to the behavior of other firms in the post-restructuring period by parameters α_{jy} and β_{jy}. The econometric model is:

$$\begin{aligned} PCM \quad = \quad & \alpha_0 + \alpha_1 Y_{99} + \sum_j \alpha_{2j} F_j + \sum_j \alpha_{3j} F_j Y_{99} + \beta_0 q^{net} + \beta_1 q^{net} Y_{99} \\ & + \sum_j \beta_{2j} q^{net} F_j + \sum_j \beta_{3j} q^{net} F_j Y_{99} + \varepsilon, \end{aligned} \tag{34}$$

[47]Namely, $c'_j + \lambda_j \geq c'_i + \lambda_i, \forall i \neq j$. Therefore, $c'_j + \lambda_j$ defines the true marginal cost of the firm.

where Y_{99} is an indicator for the year 1999 (post-restructuring); F_j is a firm indicator; q^{net} is the firm's inframarginal capacity less native load. ε is a first-order autoregressive, heteroskedastic error term.[48]

I proxy measures of native load with system-wide demand times the fraction of peak-load demand (which occured on July 6, 1999) that each firm faced. The price is the demand-weighted average price across PJM. The firm marginal cost equals the marginal cost of the most expensive unit observed to be operating (c_j'). If the production exceeds 90 percent of capacity, I define the firm marginal cost as the cost of the firm's next most expensive unit that has run in the past week. Table 8 reports the results of equation 34. Model 1 compares PECO and PPL with the other major firms relative to PENELEC. Model 2 explicitly tests whether these firms behaved differently than the others. I find that PECO and PPL exhibited behavior consistent with price-setters while the other firms did not.

9.3 Appendix C

In this appendix, I test the accuracy of the competitive model estimates using unit-level data. The dependent variable measuring production choices is the observed utilization rate for each unit and hour (UR_{it}). I compare the observed behavior with the estimates of competitive firm production, from either the simplified or intertemporal model, also using utilization rates ($\widehat{UR}_{it}$).The econometric model is therefore:

$$UR_{it} = \phi \widehat{UR}_{it} + \alpha + \eta O_{lig} + (\zeta + \beta) Y_{99} + \gamma Y_{99} O_{lig} + u_{it} \tag{35}$$

where Y_{99} is an indicator of restructuring and O_{lig} is an indictor of ownership by PPL or PECO. A limited dependent variable Tobit model is used to account for left and right censoring (a unit cannot produce negative amounts nor can it produce more than its capacity). The errors, u_{it}, are likely to be highly correlated hourly and unit-level errors are likely to be clustered since decisions are made at the firm-level. However, addressing serial correlation in maximum-likelihood is difficult.

Table 9 reports results for the unit-level approach where the dependent variable is the hourly utilization rate for each unit. Model 1 ignores any controls for changes in costs or demand and finds that oligopolists reduced output by 0.16 utilization points relative to other firms while the fringe increased production by 0.10 utilization points. These results are diminished once I control for either the simplified model's estimates of unit production (-0.10 and 0.08, respectively) or the intertemporal model's estimates (-0.05 and 0.03, respectively). All coefficients are significant assuming iid standard errors. The coefficients on the simplified and intertemporal model estimates of utilization rate are 0.58 and 0.97 respectively. The intertemporal model estimates are more highly correlated with observed behavior.

[48]Tests of serial correlation and heteroskedaticity were significant for all models in the table 9 (for example, for Model B1, DW-Stat = 0.24; Cook-Weisberg test p-value 0.0001).

10 Tables and Figures

Table 1: Market Characteristics.

Panel A: Capacity by Fuel Type and Firm (MW).

Firm	Nuclear	Hydro	Coal	Gas	Oil	Total
GPU, Inc.	1,405	208	6,836	1,243	711	10,403
Public Service Electric	3,261	11	1,242	3,380	1,403	9,297
PECO	4,496	303	725	66	2,173	7,763
PPL	2,184	152	3,511	0	1,877	7,724
Potomac Electric Power	0	512	2,694	1,069	2,339	6,614
Baltimore Gas & Electric	1,675	416	2,135	894	1,000	6,120
Other	0	242	2,689	3,554	2,273	8,757
Total	13,021	1,844	19,832	10,205	11,775	56,678
Share	23.0%	3.3%	35.0%	18.0%	20.8%	100%

Panel B: Market Shares of Capacity, Generation, and Demand by Firm.

Firm	Capacity	Generation	Peak Gen	Demand Served
GPU, Inc.	18%	20%	16%	20%
Public Service Electric	16%	14%	18%	19%
PECO	14%	19%	21%	15%
PPL	14%	18%	15%	13%
Potomac Electric Power	12%	10%	11%	11%
Baltimore Gas & Electric	11%	13%	11%	12%
Other	15%	6%	8%	10%

Table 2: Summary Statistics of PJM market for Summers of 1998 and 1999 (April through September)

Panel A: Summer of 1998

Variable	Units	Mean	Std. Dev.	Min	Max
Hourly Demand	MWh	29,646	6,481	17,461	48,469
Hourly Fossil Generation	MWh	17,444	4,934	7,927	30,569
Utilization Rate	.	0.449	0.407	0	1
Price of Electricity	\$/MWh	\$26.04	\$43.33	\$0.00	\$999.00
Competitive Price Estimate	\$/MWh	\$26.63	\$4.95	\$13.87	\$115.96
Price of Natural Gas	\$/mmBTU	\$2.33	\$0.25	\$1.80	\$2.81
Price of Oil	\$/Barrel	\$38.8	\$3.2	\$33.3	\$45.7
Price of SO_2 Permit	\$/Ton	\$172.5	\$24.4	\$136.5	\$198.5
Price of NO_x Permit	\$/Ton	N/A	N/A	N/A	N/A
MC of Coal Units	\$/MWh	\$18.70	\$2.37	\$13.19	\$26.92
MC of Natural Gas Units	\$/MWh	\$33.03	\$8.92	\$16.09	\$98.91
MC of Oil Units	\$/MWh	\$36.46	\$9.63	\$20.04	\$73.07

Panel B: Summer of 1999

Variable	Units	Mean	Std. Dev.	Min	Max
Hourly Demand	MWh	30,453	7,156	17,700	51,714
Hourly Fossil Generation	MWh	17,598	5,086	7,818	30,620
Utilization Rate	.	0.495	0.390	0	1
Price of Electricity	\$/MWh	\$37.97	\$100.95	\$0.00	\$999.00
Competitive Price Estimate	\$/MWh	\$31.69	\$19.45	\$15.08	\$457.02
Price of Natural Gas	\$/mmBTU	\$2.60	\$0.27	\$2.08	\$3.28
Price of Oil	\$/Barrel	\$49.0	\$6.9	\$39.4	\$62.0
Price of SO_2 Permit	\$/Ton	\$203	\$9.3	\$188	\$211
Price of NO_x Permit	\$/Ton	\$2,858	\$1,922	\$0	\$5244
MC of Coal Units	\$/MWh	\$24.15	\$7.45	\$13.22	\$62.29
MC of Natural Gas Units	\$/MWh	\$38.44	\$13.29	\$18.37	\$127.91
MC of Oil Units	\$/MWh	\$46.09	\$13.93	\$21.65	\$93.27

Table 3: Ratio of Total Generation to Total Capacity in Summers of 1998 and 1999.

Panel A: Fringe Producers

Fuel Type	1998	1999	% Change	MW Change
Coal (High Emis Rate)	0.746	0.730	-2.1%	-193
Coal (Low Emis Rate)	0.766	0.850	11.0%	337
Gas	0.228	0.203	-11.0%	-138
Oil (High Emis Rate)	0.535	0.524	-2.1%	-22
Oil (Low Emis Rate)	0.275	0.274	0.4%	-3
Total	0.555	0.554	-0.2%	-18

Panel B: PECO

Fuel Type	1998	1999	% Change	MW Change
Coal (High Emis Rate)	0.688	0.554	-19.5%	-21
Coal (Low Emis Rate)	0.573	0.552	-3.7%	-13
Gas	N/A	N/A	N/A	N/A
Oil (High Emis Rate)	N/A	N/A	N/A	N/A
Oil (Low Emis Rate)	0.165	0.115	-30.3%	-195
Total	0.236	0.187	-20.8%	-230

Panel C: PPL

Fuel Type	1998	1999	% Change	MW Change
Coal (High Emis Rate)	0.708	0.668	-5.6%	-126
Coal (Low Emis Rate)	0.221	0.165	-25.3%	-40
Gas	N/A	N/A	N/A	N/A
Oil (High Emis Rate)	0.679	0.556	-18.1%	-136
Oil (Low Emis Rate)	0.192	0.136	-29.2%	-164
Total	0.468	0.409	-12.6%	-466

Table 4: Intertemporal production cost estimate with dependent variable of hourly utilization rate by unit. Tobit model assuming iid errors. (1) is average of marginal effect for all hours; (2) marginal effect at the median observation for all hours; (3) is average of marginal effect for 6pm only; (4) marginal effect at the median for 6pm only.

Variable	(1)	(2)	(3)	(4)
Hourly PCM (hr-1)	-7.8	-4.7	-0.5	-0.8
Hourly PCM ($100)	38.4	85.2	3.5	6.8
Hourly PCM (hr+1)	-22.5	-49.8	-4.2	0.7
Daily PCM (day-1)	-3.5	-5.6	2.8	7.1
Daily PCM ($100)	-3.9	-14.0	5.1	4.3
Daily PCM (day+1)	-5.2	-16.8	2.0	0.7
Hourly PCM (hr-1) * SRT	34.9	193.0	-14.0	-47.0
Hourly PCM * SRT	-363.3	-914.8	-11.8	-19.7
Hourly PCM (hr+1) * SRT	380.3	374.8	133.8	320.4
Daily PCM * SRT (day-1)	15.5	-50.4	-90.2	-262.6
Daily PCM * SRT	64.9	241.0	-98.1	-241.7
Daily PCM * SRT (day+1)	65.0	200.9	-86.6	-199.0
SRT ($ million)	-110.1	-1152.6	-400.9	-742.2
Constant	-0.22	-0.22	0.51	0.51
Average R-Squared	0.53		0.58	
Sample Size:	562,176		23,424	

Standard errors not shown. PCM is price-cost margin and SRT is start-up cost. Each independent variable is modeled as a piece-wise linear function with 3 segments by trecile. Each hour and technology type defined by the ramping rate is modeled separately.

Table 5: Welfare Implications of Production Inefficiencies ($ millions).

	1998	1999	Change	% Change
Observed Total Costs	$1,668.0	$2,100.8	$432.8	26%
Welfare Losses in PJM				
Simplified Model	$218.2	$345.6	$127.5	58%
Intertemporal Model	$81.2	$206.4	$125.2	154%
Additional Import Costs	$8.6	$41.7	$33.1	385%
Total Losses				
Simplified Model	$226.8	$387.3	$160.5	71%
Intertemporal Model	$89.8	$248.1	$158.3	176%

Table 6: Hourly Average Emissions (tons) and Fossil Production (GWh) in PJM.

Pollutant	1998	1999	Change	% Change
SO_2				
-Observed	137.5	123.0	-14.5	-10.5%
-Simplified Competitive Model	140.0	130.6	-9.4	-6.6%
-Intertemporal Competitive Model	135.8	127.5	-8.4	-6.2%
NO_x				
-Observed	36.8	30.9	-5.9	-15.9%
-Simplified Competitive Model	49.2	44.9	-4.3	-8.7%
-Intertemporal Competitive Model	35.4	30.6	-4.9	-13.7%
Fossil Generation in PJM				
-Observed	17.4	17.6	0.2	0.8%
-Simplified Competitive Model	17.4	17.9	0.5	2.7%
-Intertemporal Competitive Model*	17.4	17.9	0.5	2.7%

* The intertemporal model is calibrated so that total generation in each year equals the total generation estimated using the simplified competitive model.

Table 7: Natural experiment of firm behavior using hourly firm-level production data. Dependent variable is log of observed production (GEN) by firm and hour. Models 1 and 2 report OLS coefficients for data that have been quasi-differenced using the Prais-Winsten method. Models 3 and 4 report IV coefficients for data that have been quasi-differenced similarly.

Model	1	2	3	4
	OLS	OLS	IV	IV
Competitive Model	Simplified	Intertemporal	Simplified	Intertemporal
Oligopolist (Olig)	-0.289	-0.340		
	(0.058)	(0.039)		
Restructuring (Rest)	0.025	-0.021		
	(0.027)	(0.027)		
Olig*Rest	-0.176	-0.136		
	(0.068)	(0.051)		
PCM			-0.006	-0.004
			(0.002)	(0.001)
PCM*Olig			0.037	0.027
			(0.005)	(0.005)
PCM*Rest			0.008	0.007
			(0.002)	(0.002)
PCM*Olig*Rest			-0.042	-0.035
			(0.007)	(0.007)
Log Predicted GEN	0.116	0.164	0.770	0.763
	(0.004)	(0.006)	(0.004)	(0.005)
Sample Size	62,461	64,724	62,142	64,399
R-Squared	0.59	0.42	0.31	0.49
Rho	0.92	0.90	0.87	0.87

Robust standard errors are in parentheses. PCM is price-cost margin. Ten-piece spline function of demand, hourly indicators, day of week indicators, and constant not shown. In Models 3 and 4, I instrument price-cost margins using daily temperatures in states in PJM and nearby. The temperatures are modeled as quadratic functions for current and lagged daily means, with coefficients allowed to vary above and below 65 degrees Fahrenheit.

Table 8: Price-cost margin Difference-in-Differences Models. Two-stage least squares with robust errors. OLS coefficients reported for data that have been quasi-differenced using the Prais-Winsten method. Models B1 and B2 examine entire sample. Models B3 and B4 condition on positive net output positions.

Variable	B1	B2	B3	B4
Net Output in 1999	-0.009	-0.003	-0.597	0.011
	(0.016)	(0.012)	(0.103)	(0.006)
Net Output in 1999: Firm PECO	0.275	0.290	0.583	-0.042
	(0.051)	(0.048)	(0.114)	(0.042)
Net Output in 1999: Firm PPL	0.217	0.190	0.743	0.151
	(0.029)	(0.026)	(0.107)	(0.025)
Net Output in 1999: Firm GPU	-0.069		0.513	
	(0.023)		(0.102)	
Net Output in 1999: Firm Potomac	-0.102		0.727	
	(0.022)		(0.107)	
Net Output in 1999: Firm PubServ	-0.124		N/A	
	(0.030)		N/A	
1999 Indicator	-30.1	-19.6	207.2	33.0
	(37.7)	(4.8)	(38.9)	(11.9)
1999 Indicator: Firm PECO	-55.7	-73.1	-192.5	-13.9
	(37.5)	(12.1)	(44.8)	(24.3)
1999 Indicator: Firm PPL	-162.4	-170.9	-353.0	-205.2
	(49.2)	(23.8)	(48.0)	(27.5)
1999 Indicator: Firm GPU	363.6		141.7	
	(104.4)		(65.7)	
1999 Indicator: Firm Potomac	28.8		-413.1	
	(43.4)		(45.4)	
1999 Indicator: Firm PubServ	-263.9		N/A	
	(65.7)		N/A	
Sample Size	64,951	64,951	49,420	49,420
Rho	0.88	0.93	0.86	0.91

Firm fixed effects, general net inframargin effects, 10-piece demand spline, hour of day indicator, day of week indicators, and constants are not shown. The excluded firms are the smaller utilities. Robust standard errors in parentheses. Instrument net quantity with temperature variables (see description in Table 7).

Table 9: Natural experiment of firm behavior using hourly unit-level production data. Dependent variable is hourly utilization rate (UR) for a unit. Tobit model estimation.

Model	C1	C2	C3	C4
Oligopolist	0.030	0.010	-0.027	-0.022
	(0.002)	(0.002)	(0.002)	(0.002)
Restructuring	0.110	0.083	0.030	0.037
	(0.001)	(0.001)	(0.001)	(0.001)
Oligopolist*Restructuring	-0.161	-0.102	-0.054	-0.054
	(0.003)	(0.003)	(0.002)	(0.002)
Predicted UR		0.584		0.213
(simplified model)		(0.001)		(0.001)
Predicted UR			0.968	0.766
(intertemporal model)			(0.001)	(0.002)
Constant	0.306	0.020	-0.051	-0.080
	(0.001)	(0.001)	(0.001)	(0.001)
Sample Size	1,024,080	1,024,080	1,024,080	1,024,080
Pseudo R-Squared	0.004	0.17	0.25	0.27

Independently and identically distributed standard errors in parentheses.

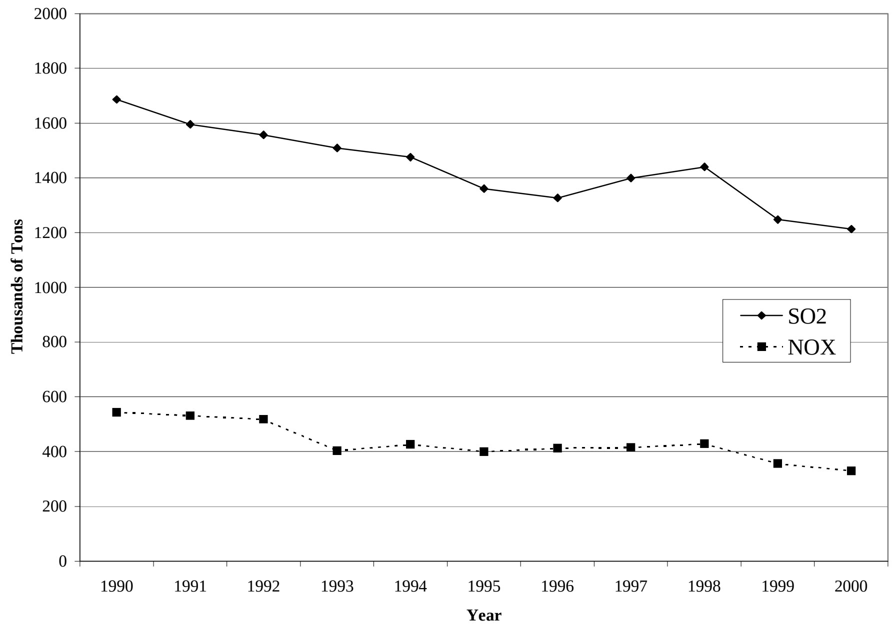

Figure 1: Annual Electric Utility SO_2 and NO_x Emissions in Pennslyvania, New Jersey, Maryland, and Delaware.

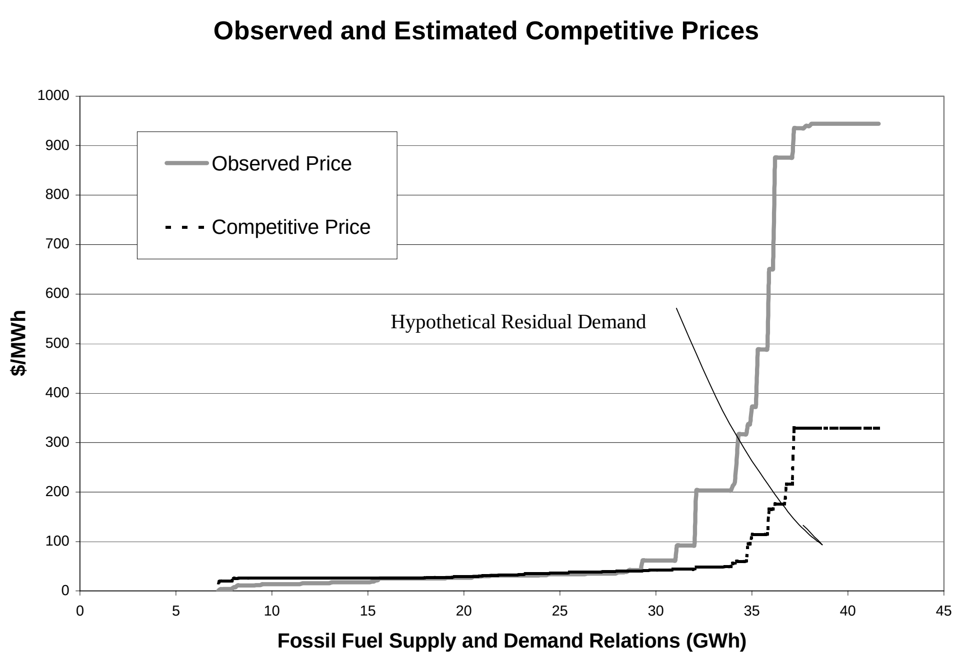

Figure 2: Determining Perfectly Competitive Equilibria

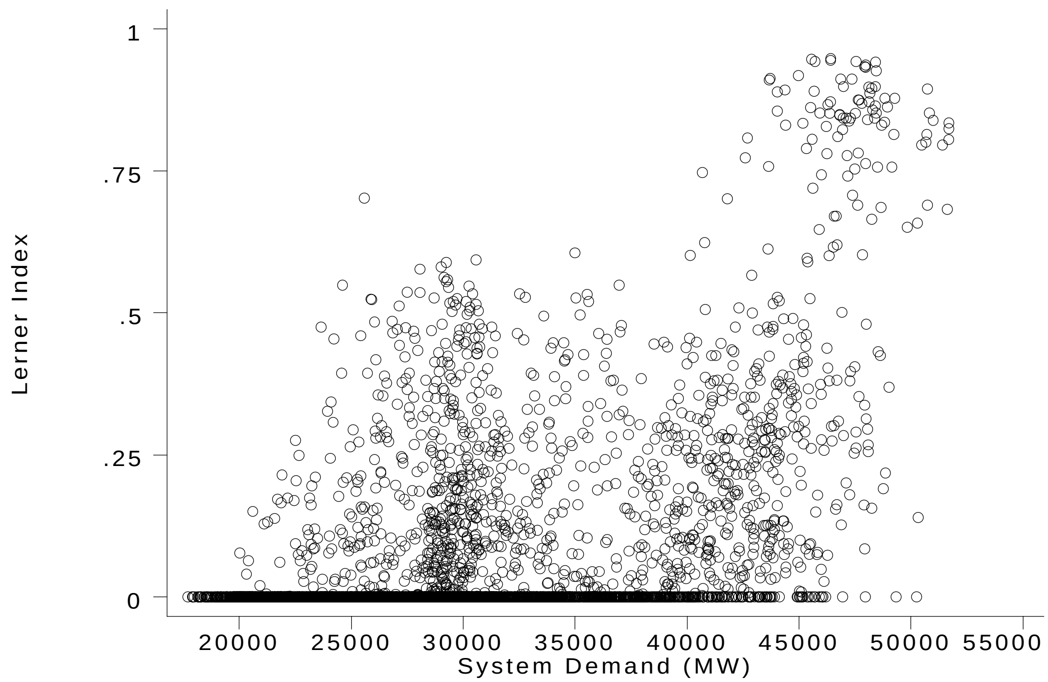

Figure 3: Relationship between Lerner Index and System Demand.

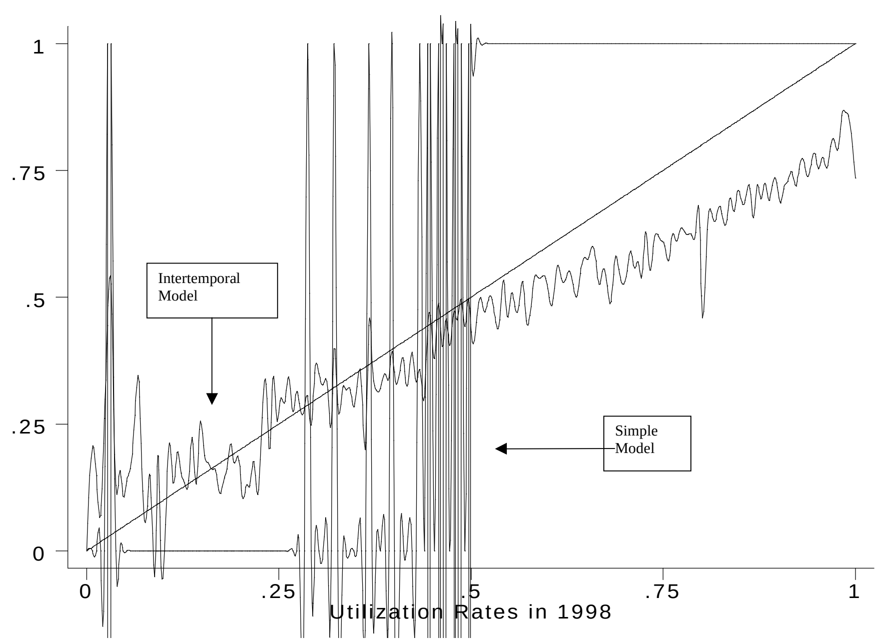

Figure 4: Comparison of Observed and Estimated Utilization Rates in 1998.

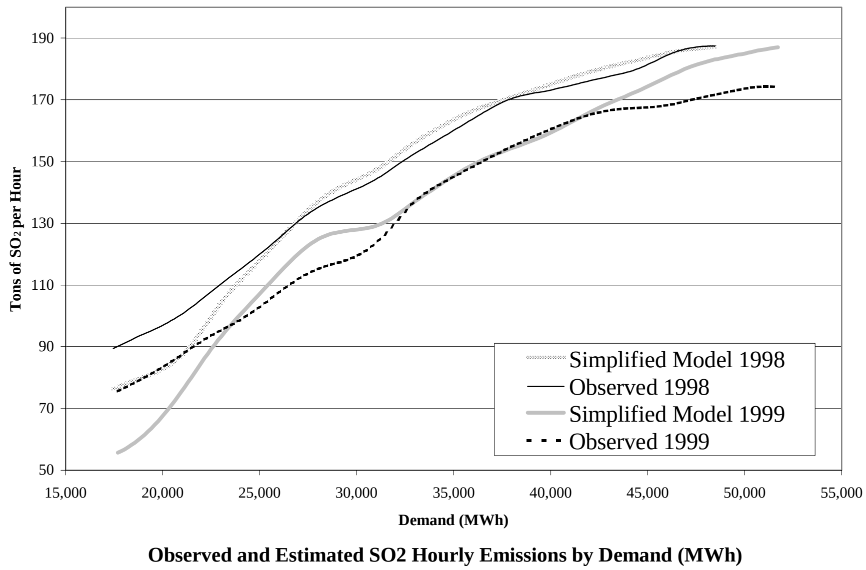

Figure 5: Observed and Estimated Hourly Average SO_2 Emissions for Summers of 1998 and 1999.

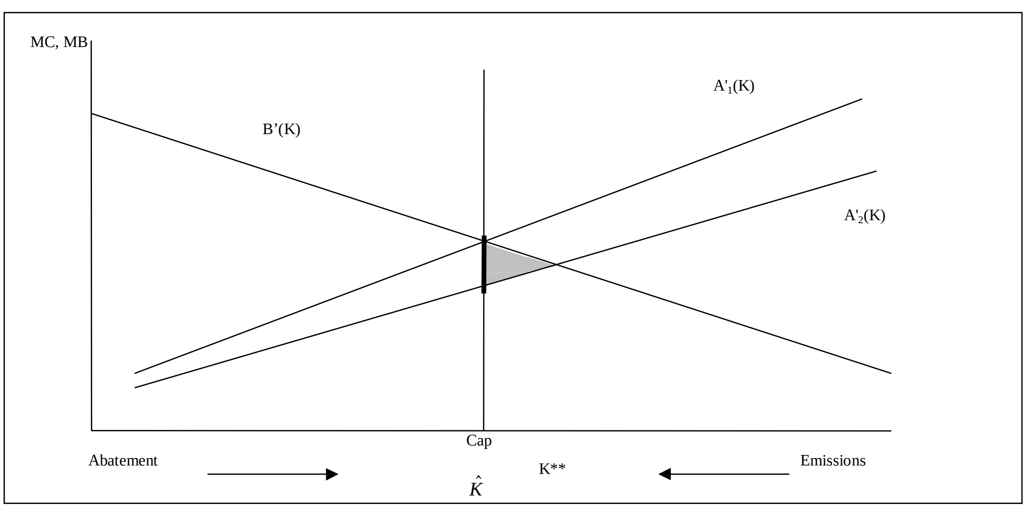

Figure 6: Welfare Implications in the Pollution Abatement Market