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Abstract

Electricity restructuring offers the potential for more efficient production and investment, but may create the opportunity for producers to exercise market power. Oligopolists may cause deadweight loss in wholesale electricity markets, even when demand is perfectly inelastic, by inducing cross-firm production inefficiencies. This study estimates the environmental implications of production inefficiencies attributed to market power in the Pennsylvania, New Jersey, and Maryland electricity market.

Air pollution fell substantially during 1999, the year in which both electricity restructuring and new environmental regulation took effect. I measure production inefficiencies by comparing observed behavior with estimates of production in a competitive market. During the period studied, actual production costs, including abatement costs, exceeded competitive estimates by 8%. Estimates of competitive production, which account for new environmental regulation, explain only 60% of the observed pollution reductions. The remaining 40% can be attributed to firms exercising market power. Given oligopoly behavior in product markets, I discuss the conditions under which environmental policy makers improve welfare with permit systems in comparison to pollution taxes.

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1 Introduction

The world's largest restructured wholesale electricity market–the Pennsylvania, New Jersey, and Maryland Interconnection (PJM)–opened to competition in 1999. Regulators hoped to spur more efficient production and investment than had resulted under rate-of-return regulation. Electricity markets, however, are especially susceptible to the exercise of market power because they lack demand response and storage capability.[1] In an oligopoly market with perfectly inelastic demand, market power leads to production inefficiencies because dominant firms reduce production and more expensive competitive fringe production is therefore required.[2] This substitution of generating units has environmental implications. With perfectly inelastic demand, changes in air pollution emissions resulting from the exercise of market power will depend solely on the technologies that dominant firms use to withhold output in contrast with those that the competitive fringe uses to meet demand.[3]

Concurrent with the recent international movement of electricity restructuring, environmental regulators also unleashed market forces by establishing regional and national pollution permit markets. However, the effectiveness of incentive-based environmental regulation can be distorted by the structure of and competition in a product market.[4] This paper explores whether restructuring the PJM wholesale electricity market resulted in substantial production inefficiencies and changed the costs of complying with environmental regulation. Furthermore, it examines how imperfect competition in product markets should affect regulators decisions regarding policy instruments.

[1]A number of studies find the exercise of market power in England (Wolak and Patrick, 1997; Wolfram, 1998; Wolfram, 1999), California (Borenstein, Bushnell, and Wolak, 2001; Puller, 2001; and Joskow and Kahn, 2001), PJM (Mansur, 2001; MMU, 2001); and New England (Bushnell and Saravia, 2001). Consumers are sensitive to electricity prices (Bushnell and Mansur, 2001). However, the regulatory structure of electricity retail markets has kept the rate that 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.

[2]Each firm produces in a cost-minimizing manner, but dominant firms optimize by producing where marginal costs equal marginal revenue. This leads to cross-firm production inefficiencies.

[3]The structure of the California electricity market suggests, for example, that market power may *increase* pollution while the PJM market is structured such that pollution will likely *decrease*. Section 2.4 elaborates on this point.

[4]I use the term "product market" to distingush markets that produce goods (and pollute in the process) as opposed to a market, like a permit market, where firms trade property rights.

Air pollution from PJM electricity generators fell substantially from 1998 to 1999 when new environmental regulation and electricity restructuring took effect (see Figure 1).[5] While overall electricity production increased slightly to meet growing demand, the set of production technologies also changed. The relative increase in heavy polluters' input costs may explain reduced emissions. Beginning in 1999, the Ozone Transport Commission mandated that Northeastern electricity producers possess tradable permits for summer NO_x emissions, permits that turned out to be quite expensive. Alternatively, restructuring may have led to market imperfections, including the exercise of market power, that caused production inefficiencies and reduced pollution.[6]

In order to separate out these effects, this study measures production inefficiencies by comparing observed behavior with two estimates of production in a competitive market. The EPA provides detailed data on hourly, unit-specific observed production choices. One method of estimating competitive behavior uses a simulation technique common to the literature.[7] This relatively simplified technique assumes that units operate following an on-off strategy based on price exceeding marginal cost. It does not take into account the intertemporal constraints on and the costs of changes in generator output, such as the cost of starting a unit.[8] I propose an alternative approach that measures how competitive firms address intertemporal constraints, using econometric estimation of production choices during the pre-restructuring period.

Section 2 provides background on the PJM electricity market, expected environmental implications of market power, and preliminary evidence of market power. Section 3 explains the methodology of estimating the simplified and intertemporal models of com-

[5] Annual sulfur dioxide (SO_2) and carbon dioxide (CO_2) emissions were reduced by 13 and 12 percent, respectively, the largest reductions in the 1990s. Annual nitrogen oxides (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*. All tables and figures may be found in Section 7.

[6] In addition to market power, inefficiencies could also be caused by non-strategic firm behavior (*e.g.,* misunderstanding marginal costs) or by the market maker, PJM (*e.g.,* flaws in the pricing algorithm). However, section 4.3 provides empirical evidence supporting the hypothesis that these inefficiencies do stem from the strategic behavior of firms. Note that the environmental impacts of restructuring hold regardless of why the production efficiencies occurred.

[7] Wolfram (1999), Borenstein, Bushnell, and Wolak (2001), Joskow and Kahn (2001), Mansur (2001), and Bushnell and Saravia (2001) use this method in measuring market power in electricity markets.

[8] The literature has focused on direct measures of price-cost margins. Years of regulatory hearings have resulted in accurate measures of marginal costs of production. Ignoring intertemporal constraints when measuring competitive prices may lead to partially offsetting biases. Borenstein, Bushnell, and Wolak (2001) use this technique to estimate welfare implications in the California electricity market.

petitive behavior. In section 4, both of these models provide evidence that restructuring resulted in production inefficiencies, which led to tangible welfare losses and emissions reductions in PJM. Tests of firm behavior imply that firms with incentives to exercise market power significantly reduced production in comparison to other firms. Section 4 also discusses the value of pollution reductions and considers the policy implications for environmental regulators facing an imperfect product market. Given oligopoly behavior in product markets, I discuss the conditions under which environmental policy makers improve welfare with permit systems in comparison to pollution taxes. Section 5 offers concluding remarks.

2 Background

Over the past fifteen years, several countries and U.S. regions–such as California, PJM, New York, and New England–have restructured their electricity markets. Historically, in these U.S. markets, many regulated utilities made inefficient investments in generation, particularly in nuclear power plants, and signed expensive long-term contracts with independent power producers. In many cases, these costly decisions resulted in retail electricity rates that were substantially above the national average. Policy makers believed that restructuring would impose market discipline and thus lead to more efficient investment in new generation and lower production costs at existing generating units.

Unfortunately, the promises of restructuring have not been realized in many markets. Thus far, restructured markets in the Eastern U.S. have experienced greater success than the California market. Some argue that the market design of the Eastern markets has reduced price volatility and limited the degree to which firms exercise market power. Nevertheless, these markets also appear to have experienced market imperfections and high prices. For example, in the summer of 1999, PJM's prices exceeded the marginal cost of the most expensive power plant almost three times as often as in the previous summer, when prices were regulated.

This study examines how restructuring changed firms' behavior, focusing on the summers of 1998 and 1999. This section discusses the structure of the PJM market, incentives for vertically integrated utilities, and the issues of measuring of market power in electricity markets. It also examines expected environmental implications of market power, summarizes how the data were constructed, and provides preliminary evidence of firms exercising market power.

2.1 The PJM Electricity Market

By facilitating trading amongst generators and distributors, the wholesale market attempts to lower utilities' costs of providing power to customers.[9] The market consists of 57 gigawatts (GW) of capacity, including nuclear, hydroelectric, coal, natural gas, oil, and renewable energy sources (see Table 1 and Figure 2). Nuclear and coal plants provide baseload generation capable of covering most of the demand.[10] Nuclear power comprises 45% of generation but only 25% of capacity. In contrast, natural gas and oil burning units provide over 33% of the market's capacity, yet they operate only during peak demand times. These differences in production result from heterogeneous cost structures. Baseload units have low marginal costs and significant intertemporal constraints while the relatively flexible peaking units are more expensive to operate. Section 3.1 further discusses the importance of intertemporal constraints.

Utilities must purchase electricity to meet the demand of their customers, which is called "native load". Only 10 to 15% of supply comes from spot market purchases, while the remainder is met by the utilities' own generation (53 to 59%), bilateral contracts (30%), or imports (one to two percent).[11] Market structure did not change substantially between 1998 and the summer of 1999.[12]

In 1998, the PJM wholesale electricity market established a new pricing network to

[9] Regulated utilities and independent producers involved in the generation, transmission, and distribution of electricity comprise the PJM Interconnection, LLC. The whole of New Jersey, Delware and the District of Columbia, the majority of Pennsylvania and Maryland, and part of Virginia comprise the market's regulatory bounds.

[10] These plants have a capacity of 35 GW in a system averaging 30 GW demand.

[11] 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.

[12] Utilities sold only one plant and retired none 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).

facilitate inter-utility trading.[13] PJM required firms to offer non-binding bids to supply electricity from each generating unit into a day-ahead uniform-price auction. In the first year of the market, PJM mandated that bids equal marginal production costs. Years of regulation rate hearings resulted in well understood cost measures. In April 1999, the market operators restructured the market again by allowing for competition in the wholesale electricity spot market. 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 has been vertically integrated. Unlike in other markets, PJM did not require utilities to divest plants as a condition of restructuring. As such, little divestment occurred during the period of this study. Each utility's incentives depend on how much generation it sells versus its native load.[14]

In addition, utilities sign short and long-term bilateral contracts for buying and selling energy with each other and other producers. These contracts affect a utility's net position. The objective function for vertically integrated firm i will be:

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

where, for firm i, $p_i(q_i)$ is the inverse residual demand function the firm faces in the spot market, q_i is its production, q_i^d is its native load, q_i^c is the net supply/demand position from bilateral contracts the firm has signed that are priced independently of the spot market price, r_i^d and r_i^c are the retail and contract prices, and $c_i(q_i)$ is total production costs. The first order condition will be:

$$p_i + p_i' \cdot (q_i - q_i^d - q_i^c) = c_i', \tag{2}$$

[13]PJM accommodates transmission constraints by using what is known as "nodal" pricing (Schweppe, Caramanis, Tabors, and Bohn, 1988). Each of the over 2000 nodes is a point of energy supply, demand, or transmission.

[14]The incentives of publicly-owned utilities may be unclear even for net selling firms. Net buyers can exercise monopsony power by operating units with costs above the market price, reducing net purchases and lowering wholesale prices. However, regulated firms are unlikely to be rewarded by this behavior.

where firms have incentives to increase prices only if they are net sellers ($q_i > q_i^d + q_i^c$).

In 1999, Philadelphia Electric Co. (PECO) and Pennsylvania Power & Light (PPL), for example, had incentives to exercise market power. Table 1 reports PJM's six largest firms' 1999 shares of capacity, generation, generation when demand exceeded 40 GW, and peak demand. PECO and PPL tended to produce more than their native load.[15] PECO's net selling position was even greater during peak demand hours. In addition to often being net sellers, PECO and PPL were active in offering market-based bids into the spot market. Firms opted to change the bidding structure of only a few units during the summer of 1999. PECO and PPL accounted for 84% of these market-based bids.[16]

A model of dominant firms with a competitive fringe characterizes many electricity markets. As will be discussed in section 2.4, when firms with asymmetric costs or strategies exercise market power, they generally cause cross-firm production inefficiencies.[17] In addition, firms face uncertainty in demand and each other's bids in the day-ahead blind auction. A firm will distort production by either intentionally or unintentionally bidding a low-cost unit above the market clearing price, or simply deciding not to operate regardless of the bid.[18]

[15]Pennsylvania Electric (Penelec) has 14% of the generation market and 5% of the demand, suggesting that it had incentives to exercise market power. However, its parent company GPU Inc., which includes Jersey Central, Metropolitan Edison, and GPU nuclear, has 20% shares 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 participate in bidding "market-based" offers.

[16]PJM masks firm and unit identities in the publicly available bidding data. However, the firm level codes are easily deciphered. According to *The Wall Street Journal*, August 4, 1999: "An analysis of trading data from that day shows that (PECO and PPL) 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."

[17]I assume that an individual firm will achieve a given level of output by minimizing its own production costs. However, in aggregate, firms in imperfect markets do not produce the overall output level using the least costly technology. Note firms can potentially exercise market power without causing welfare losses; if all firms uniformly increase bids, the optimal order of production will not be distorted. However, as long as firms have asymmetric costs or strategies, production inefficiencies will occur (Borenstein and Farrell, 2000). Furthermore, an individual oligopolist will not necessarily produce less than it would have in a perfectly competitive market. Levin (1984) notes that, in an oligopoly with asymmetric costs, some producers may increase production relative to competitive levels.

[18]Even in 1998, firms could have exercised market power using this latter technique. However, the ability to move prices was limited since the prices were determined based on marginal cost bids. Enabling firms to use bids and quantity instruments may have facilitated exercising market power to the degree that constraints, such as regulatory surveillance, were circumvented. In addition, these historically regulated utilities may have undergone a learning process about how to exercise market power.

2.3 Market Power in Power Markets

Electricity markets exhibit several major characteristics that make market power more probable than in other markets with similar levels of concentration. These include: nearly perfectly inelastic demand, economically prohibitive storage, and limited generation and transmission capacity. Furthermore, system operators are bound by the necessity to continually balance supply and demand.[19] Market power can arise when both the market demand and a competitive fringe's supply are highly inelastic. This occurs during high demand times that require production from most generating capacity. Under such circumstances, firms with even small market shares can greatly influence prices.

Wolfram (1999) develops a technique of measuring market power in electricity markets. In order to construct a competitive supply curve, she calculates the marginal cost of each generating unit in the England and Wales market. 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' availability. Joskow and Kahn (2001) also use Wolfram's technique in estimating market power in California. They note that environmental permits substantially increased perfectly competitive price estimates, but that observed prices are even greater. Puller (2001) estimates firm-level behavior in the California market using the EPA's Continuous Emissions Monitoring System data. He tests whether production choices were consistent with static or dynamic pricing models and finds evidence supporting the former.

Few studies have tested whether PJM firms exercise market power. Research by PJM's Market Monitoring Unit (MMU) examines firm behavior during the first summer after the market restructured (Bowring *et al.*, 2000; and MMU 2000). These studies center on three high demand days and find that prices may have resulted either from scarcity or firms exercising market power; however, the MMU does not attempt to separate out these effects. A more expansive MMU study (2001) compares units' bids and marginal costs between April 1999 and December 2000. By their measures, firms exercised a modest amount of market power.[20]

[19] Unlike most markets where excess demand sends a signal to raise price, an electricity market's entire system collapses. Operators must resort to tactics, such as rolling blackouts, to prevent this from occurring.

[20] MMU (2001) bases these price-cost margin estimates on the bid and marginal cost of the unit that

Mansur (2001) applies Wolfram's technique to determine whether market imperfections persisted during the initial summer of restructuring when prices spiked more frequently than in other recent summers. From April through August, 1999, the observed price averaged \$40.3 per megawatt-hour (MWh); in comparison, the study estimates average competitive equilibrium price to be \$32.3/MWh. In the previous summer, the observed prices (\$26.5) and competitive prices (\$27.1) were indistinguishable. Mansur (2001) concludes that market imperfections increased the cost of procuring electricity in the spot market by 41% during the summer of 1999.

2.4 Environmental Implications of Market Power

Research on the environmental impacts of restructuring has focused on the intended effects of more efficient production and investment.[21] However, firms exercising market power cause production inefficiencies that result in welfare losses directly in the product market, and can also affect input markets.[22] For example, inefficient production distorts the effectiveness of incentive-based environmental regulation.

The broad theoretical literature on incentive-based environmental regulation includes the theory of taxation under market imperfections.[23] Many papers have simulated the effectiveness of incentive-based environmental regulation, but the scarcity of implemented regulation has resulted in little empirical research on how firms actually respond to these economic incentives. One notable study by Carlson, Burtraw, Cropper, and Palmer (2000)

sets the price in any hour (market rules require the price equal some energy bid). This ignores firms exercising market power by altering the order of production and will understate estimates. In another study of the PJM market, Borenstein, Bushnell, and Knittel (1997) simulate Cournot equilibria. They find substantial price-cost margins above moderate demand levels (approximately 37 GW). Joskow (1997) uses Herfindahl-Hirschman Indices to examine the proposed Baltimore Gas & Electric and PEPCO merger.

[21]Impacts result from improved production efficiency, optimal investment in technologies, increased demand resulting from *lower* prices, and firm responsiveness to incentive-based environmental regulation. Burtraw, Palmer, and Heintzelman (2000) review the state of the literature on environmental impacts of electricity restructuring.

[22]This will clearly be the case for large distortions in demand for inputs. By the envelope theorem, there will be no first order effect on efficient input markets. However, a previously distorted input market, such as 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, may initially be suboptimally set and likely cannot optimally respond to market shocks.

[23]See Cropper and Oates (1992) or Hanley, Shogren, and White (1997) for an overview of this literature. Seminal 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.

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.[24]

Economists have long understood the importance of considering the structure of product markets when determining environmental regulation. The problem of regulating 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).[25] The second-best tax for a monopoly is less than the marginal environmental cost due to additional distortion in the product market (Lee, 1975; and Barnett, 1980).[26]

However, determining second-best taxes becomes more complicated when an imperfect market includes several producers. Levin (1985) demonstrates that 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 and distorts the total quantity produced.[27]

Monopolists distort overall production levels but still produce a given level using the least costly technology. Oligopolies also distort overall production. However, an additional production substitution effect causes cross-firm production inefficiencies. Therefore, the pollution implications of a market's competitiveness depend on total production and the technologies employed, which result from several factors: demand elasticity, the distribution of technologies among firms, and the costs and emissions associated with various technology types. In addition, the exact oligopoly game will determine firm output.

[24]These findings suggest that simulations assuming efficient behavior may be misleading, especially in a regulated market.

[25]Oates and Strassmann (1984) suggest that ignoring market structure will likely lead to small inefficiencies when determining pollution 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.

[26]A related literature directly concerns market imperfections in the permit markets. Hahn (1984) discusses how firms exercise monopolistic or monopsonistic power depending on their net permit positions. 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.

[27]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.

As previously mentioned, many electricity markets consist of dominant firms with a competitive fringe facing perfectly inelastic demand. In this case, only technology substitution yields pollution effects. For example, emissions will fall if dominant firms reduce output from dirty units and a competitive fringe meets demand using cleaner technology. In general, for this market structure, the environmental consequences of exercising market power depend only upon whether marginal production costs are increasing or decreasing in emission rates, assuming this relationship is monotonic. When expensive units pollute more than cheap units, market power increases emissions, and vice versa.[28]

To further elucidate this point, one may compare the differing implications of this model for the California and PJM electricity markets. Recall that a firm choosing to exercise market power will restrict output from its marginal units.[29] While California generators primarily use hydroelectric, nuclear, and natural gas to produce electricity, dominant firms' marginal units almost always burn gas. Therefore, firms opting to exercise market power will do so by restricting output from gas units. As a result, more expensive gas units operate to meet demand in lieu of cheaper ones. High-cost gas units tend to be older, less efficient, and more polluting. Thus, in California, we observe marginal production costs (including pollution permits) increasing in emissions and one should expect the exercise of market power to increase pollution in California. Typically, exercising market power in electricity markets will increase pollution when dominant firms and fringe producers use the same fuel type.

In contrast, dominant firms in PJM reduce output from coal, natural gas, or oil units at different demand levels. When demand ranges from low to average levels, a firm considering exercising market power will have a coal unit on the margin. Coal units tend to be substantially dirtier and cheaper, even including the given permit prices, than natural gas units. Therefore, restricting output with coal leads to less pollution than under perfect competition. Firms exercising market power in California will likely cause more pollution due to within-technology substitution. The effect in PJM will depend on the relative size of the across-technology substitution that reduces pollution and the within-technology substitution that increases it. The appendix more formally demonstrates these points.

[28] The environmental impacts will be exacerbated if the dominant firms are more concentrated in low-cost technology.

[29] For a given demand level, marginal units are the most expensive units a firm would operate under perfect competition.

The next section examines preliminary evidence of firm behavior and the environmental impacts of exercising market power.

2.5 Data and Preliminary Evidence

This study utilizes detailed data about each unit's hourly production, costs, and emissions. The EPA's Continuous Emissions Monitoring System (CEMS) provides hourly production data for fossil-fuel burning units, or "fossil units".[30] During the summers of 1998 and 1999, CEMS monitored 234 units that accounted for over 97% of PJM's fossil fuel capacity.[31] These data were also used to calculate quarterly emissions rates.[32] Marginal cost estimates draw upon various sources.[33] PJM provides information on system-wide hourly prices, demand, and net imports.

Table 2 provides descriptive statistics about demand, fossil unit generation, electricity prices, and input prices during the summers of 1998 and 1999. Demand rose three percent while fossil unit generation increased only one percent, causing a greater dependence on imports. The market price was 46% higher in 1999, in part because of higher input prices for oil, natural gas, and SO_2 permits.[34] The introduction of the Ozone Transport

[30]CEMS records hourly gross production of electricity, heat input, and three pollutants – SO_2, NO_x, and CO_2 – for most fossil units in the country. Net production is approximately 90 to 90% of gross production, which includes electricity generated for the firms own on-site use. Net production is utilization rate times net capacity. This study assumes the utilization rate to equal current gross production divided by the maximum observed gross production in the sample. The sample excludes units not operating in the previous week.

[31]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. CEMS data are highly accurate and comprehensive for most types of fossil units (Joskow and Kahn, 2001).

[32]Quarterly emission rates equal aggregate tons of pollution over aggregate heat input.

[33]Variable operating and maintenance cost, heat rate, ramping rates, and capacity data are from the PROSYM model (Kahn 2000). EIA provides data on various oil spot prices. The daily natural gas spot prices were provided by Natural Gas Intelligence for Transco Zone 6 non-NY. Gas and oil costs include an imputed adder for transportation costs and fees of \$0.29/mmBTU. A trading company called Cantor Fitzgerald provided monthly permit price indices for the NO_x and SO_2 markets.

[34]Title IV of the 1990 Clean Air Act Amendment established a national tradable permits system for SO_2 emissions, which will eventually reduce electric utility emissions to about 50 percent of 1980 levels. A firm can opt to purchase permits, switch to low sulfur coal, or install a scrubber. Excess permits can be traded to other firms or held for future use by 'banking' them. Note that one possible explanation for reduced emissions is improved abatement techology. Firms may have been preparing for the tightening of the national SO_2 permit market in 2000. 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 the scope of regulated firms was accompanied by an increase in permits.

Commission (OTC) NO_x trading program had the largest impact on costs.[35] The marginal production costs and competitive price estimates reflect these input prices.[36]

Firms did not respond to these input costs symmetrically. Table 3 reports on the fraction of total capacity used for generation across firm and fuel type during the summers of 1998 and 1999.[37] The behavior of the dominant firms, PPL and PECO, is compared with that of the fringe by fossil fuel type: "dirty" (high SO_2 emissions rate) coal, "clean" (low SO_2 emissions rate) coal, natural gas, dirty oil, and clean oil.[38] Dominant and fringe firms had similar production rates in 1998 for most fuel types. In 1999, PECO and PPL production dropped for all fuel types in the sample. The fringe also reduced output from dirty units, however to a lesser degree than did PECO and PPL.

Either cost or incentive asymmetries could cause this disproportional reduction in output by PECO and PPL. If the dominant firms owned units with relatively high NO_x emissions rates, one might expect the OTC program to have affected these firms more so than others. Alternatively, one could presume that PECO and PPL produced inefficiently in exercising market power. The following section describes models that account for cost increases in order to separate out these explanations.

Overall, phase II requires more abatement. In 1999, firms installed some scrubbers but not in PJM. PJM firms' SO_2 and NO_x emission rates did not change significantly over this sample period.

[35] Twelve Northeastern states comprising the OTC established a trading and banking program for 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 participated in 1999 (CT, DE, MA, NH, NJ, NY, PA, and RI). The degree to which firms in the PJM wholesale market opted to reduce emissions depended on marginal abatement costs and incentives of all affected firms. At the start of permit market, in May of 1999, the permit price was \$5244/ton. This increased the marginal production costs of some coal units by 50% in comparison to the previous summers' costs. However, the permit prices fell over the summer and reached \$1093/ton by mid-September. In contrast, the price of SO_2 allowances was about \$200 per ton during the summer of 1999. 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.

[36] Section 3.2 explains how these prices, which rose 19% between the summers of 1998 and 1999, were estimated.

[37] This can be thought of as a production rate or a capacity-weighted "utilization rate."

[38] 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.

3 Models of Competitive Behavior

This section employs two methodologies to estimate perfectly competitive behavior. Section 4 measures production inefficiencies by comparing actual production choices with these estimates. The first methodology simulates perfect competition using marginal cost measures, in a manner similar to the models used in the literature.[39] This simplified model ignores intertemporal constraints, such as start-up costs. The second method constructs an econometric model that estimates how firms responded to intertemporal constraints in a period when they probably took prices as given. Both models have relative advantages. 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 treat these constraints; however it depends on the assumption that short-run production choices under regulation were socially optimal. The section begins by defining the optimization problem with which firms facing intertemporal constraints contend.

3.1 Model of Firm Behavior

Several types of intertemporal constraints affect firms' decisions regarding the technology set used in production. After a firm shuts down a unit, additional "start-up" costs are associated with resuming its operation. Even if a unit does not produce, the owner must incur daily costs in preparing for operation, such as certain maintenance costs. These are referred to as "no-load" costs. Ramping constraints limit the speed at which a unit can increase or decrease hourly production. Minimum down times limit how fast a unit can be brought back on line. Finally, minimum and maximum operating levels restrict a unit's range of operation. These intertemporal costs create non-convexities in firms' production cost functions. A firm operating n units will face the following dynamic programming

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

problem:[40]

$$V(\overrightarrow{q}_{t-1},t) = \max_{\{q_{it}\}_{i=1}^{n}} \{\pi(\overrightarrow{q}_{t}) - \sum_{i=1}^{n}[SRT_{it} \cdot \Psi(q_{it}, q_{i,t-1})] + \delta \cdot V(\overrightarrow{q}_{t}, t+1)\}, \qquad (3)$$

$$s.t.\ \forall i \in \{1, ..., n\}:$$

(1) Capacity: $q_{it} \in \{0, [K_{\min}, K_{\max}]\}$

(2) Ramping: $|q_{it} - q_{i,t-1}| \leq RMP$

(3) Minimum Downtime: $q_{it} > 0 \Leftrightarrow \{[q_{i,t-1} > 0] | [q_{i,t-1} = 0, ..., q_{i,t-w(i)} = 0]\}$,

where, $\pi(\overrightarrow{q}_{t}) = p_t(\sum_{i=1}^{n} q_{it}) \cdot [\sum_{i=1}^{n}(q_{it}) - q_t^d - q_t^c] + r_i^d q_t^d + r_i^c q_t^c - \sum_{i=1}^{n} c_{it}(q_{it})$,

$\Psi(q_{it}, q_{i,t-1}) = 1(q_{it} > 0) \cdot 1(q_{i,t-1} = 0)$,

$\overrightarrow{q}_{t}$ is the vector $(q_{1t}, ..., q_{nt})$, SRT_{it} is the start-up and no-load cost, $K_{\min}$ and $K_{\max}$ are the minimum and maximum operating capacity limits, RMP is the ramping rate, $w(i)$ is the minimum down time, and δ is the discount factor.

The value function simplifies for price-taking firms: The spot market price is taken as given $p_t(\sum_{i=1}^{n} q_{it}) = \overline{p}_t$, and firms ignore native load, contract coverage, and aggregate firm production. Therefore, the optimization problem can be written for each unit separately:

$$\begin{aligned} V(q_{i,t-1}, t) &= \max_{q_{it}} \{\overline{p}_t q_{it} - c_{it}(q_{it}) - SRT_{it} \cdot \Psi(.) + \delta \cdot V(q_{it}, t+1)\} \\ & s.t. \quad \text{Constraints 1-3 from equation (3).} \end{aligned} \qquad (4)$$

A heuristic representation of the first order condition is:

$$\overline{p}_t = c_{it}'(q_{it}) + \lambda_{it}(q_{i,0}, ..., q_{i,t-1}, q_{it}, q_{i,t+1}, ..., q_{i,T}), \qquad (5)$$

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. Intertemporal constraints may reduce a unit's true marginal cost if postponing shutting down when the price is low leads to greater overall profits (the firm will therefore avoid restarting the unit a few hours later when the price is high). However, the true marginal cost of a unit may increase if start-up costs prohibit operation when prices exceed marginal production costs since the

[40]Traditionally, economists write state variables as s_t. However, in this case, the state variable simply refers to the initial production level going into period t, $\overrightarrow{q}_{t-1}$; therefore, an extra variable is not introduced.

rents are not substantial enough to justify starting. When intertemporal constraints are inconsequential, the price-taking firms' optimization problem can be simplified further: These firms operate units at full capacity when price equals or exceeds marginal cost.

3.2 Simplified Competitive Model

The simplified model of firm behavior assumes no intertemporal constraints on production choices. This implies that the perfectly competitive price equals the system-wide marginal cost.[41] In equilibrium, the socially optimal price (p_t^*) clears the market:

$$q^f(p_t^*) + q^h + q^n + \widehat{IMP}(p_t^*) = q^d + L(q^d) + Ancillary, \tag{6}$$

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. This analysis ignores effects of restructuring on nuclear supply, as it is extremely expensive to alter production from these otherwise low cost units. Furthermore, this paper ignores the endogeneity of hydroelectric generation, as it comprises only a small fraction of PJM's total capacity.[42] Mansur (2001) estimates the net import supply curve.[43]

Estimating the fossil unit supply requires the construction of a marginal cost curve. A unit's constant marginal cost of production (MC_{it}) is determined be the equation:

$$MC_{it} = VOM + HR_i \cdot (W_{it}^{fuel} + W_{it}^{SO_2} r_i^{SO_2} + W_{it}^{NO_x} r_i^{NO_x}), \tag{7}$$

where VOM is the variable operating and maintenance cost, HR is a measure of efficiency called the heat rate, W_{it}^{fuel} is unit i's relevant fuel price, W_{it}^{x} is the permit price of pollutant

[41] 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.

[42] Mansur 2001 further discusses how to account for hydroelectric generation in measuring competitive prices.

[43] Mansur (2001) assumes that firms selling energy into PJM from other regions behave as price takers because they were under rate-of-return regulation at the time. Net imports depend on prices in PJM and in neighboring regions. Many exporting regions use bilateral contracts that are not publically available. Weather variables for these states and monthly indicators proxy for external prices. Weather variables for PJM states provide instruments for PJM prices in the two-stage least squares analysis. Net import supply is estimated to equal 1094*ln(price), implying an elasticity of 1.47 for average net imports.

x when applicable to unit i, and r_{it}^x is unit i's quarterly emissions rate of pollutant x. The marginal cost estimates must account for the scarcity rents associated with a unit operating at full capacity and opportunity costs, such as exporting electricity to other markets.[44]

A stochastic process affects units' availability. Sometimes a unit cannot operate when a firm wants it to produce. This model accounts for this uncertainty in availability when determining unit i's output (GEN_{it}):

$$GEN_{it} = CAP_i \cdot 1(P_t^* \geq MC_{it}) \cdot 1(\xi_{it} > FOF_i), \tag{8}$$

where CAP_i is capacity, FOF_i is the forced outage factor, and ξ_{it} is an idiosyncratic shock.[45] If $\xi_{it} \leq FOF_i$, a forced outage prohibits the unit from producing. 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. Unbiased estimates of these variables requires a Monte Carlo simulation to account for the uncertainty over outages.[46] For each hour in the sample, outages are simulated 100 times. The model concatenates all available units in a given run and solves for the equilibrium price while accounting for net import response. The mean perfectly competitive price and unit output decisions are computed for each hour. Figure 3 depicts a hypothetical example of how to solve for an equilibrium using a hypothetical offer curve, marginal cost curves, and a residual demand curve (estimated net import supply curve determines its slope). For a given price, PJM firms offer to produce electricity and other firms outside of PJM supply imports. In equilibrium, the price will induce firms to generate exactly enough to cover demand. The model estimates socially optimal prices and output decisions for each generating unit.[47]

Figure 4 plots the relationship between price-cost margins (measured as the Lerner index) and system demand.[48] Markups typically increase with demand because firms

[44] See Mansur (2001) for further discussion.

[45] The forced outage factor is, for a given hour, a generator's probability of being unable to produce any electricity when called upon. In addition to forced outages, units have scheduled outages for annual or semi-annual Spring or Fall maintenance. However, this paper focuses on summer production so scheduled outages are irrelevant. I do not model partial outages, which temporarily reduce a unit's capacity, but assume that the frequency does not change over time. As will be discussed below, I will use actual production before restructuring to control for unobserved factors such as partial outages.

[46] To my knowledge, Borenstein, Bushnell, and Wolak (2001) were the first to apply this technique to electricity markets.

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

[48] The PJM market may consist of thousands of prices that differ spatially in some hours because of

produce larger quantities and, therefore, have larger incentives to restrict output. Residual demand also tends to be less elastic because the fringe's costs increase substantially with high demand. However, many hours display high Lerner indices at low demand levels. Due to a technology gap, firms appear to be exercising market power over an inelastic segment of the residual demand curve. In particular, many coal units are near capacity limits at moderate demand levels (approximately 30 GW) and the next cheapest technology that burns natural gas is notably more expensive (see Figure 2).

Alternatively, given intertemporal constraints, the observed outcome may be consistent with competitive behavior. Coal units have high start-up costs in comparison to natural gas units; thus, the competitive outcome may be that gas units will operate in such a situation. The following model of competitive behavior attempts to separate these effects.

3.3 Intertemporal Competitive Model

Quantity-based measurements of market imperfections, such as pollution and welfare implications, may be sensitive to intertemporal constraints. Knowing exactly *which* units firms use to distort production will likely be important. This section examines whether ignoring intertemporal constraints biases production choice estimates. I determine how firms address intertemporal constraints by using production behavior data before restructuring. This approach assumes that firms behaved competitively prior to restructuring in 1999.[49]

Competitive behavior implies that the shadow price of the intertemporal constraints equals the price-cost margin (price minus the marginal production cost). Inverting equation (5), the price-taking firm will choose output as a function of historic, current, and future prices, marginal production costs, and intertemporal constraints such as start-up

congestion. Price-cost margins are calculated using an hourly demand-weighted average price. The Lerner index equals price minus marginal cost divided by price.

[49]Firms invest inefficiently under regulation. In addition, the marginal cost of production may be distorted by inefficient decisions regarding maintenence, labor and capital allocation, and environment abatement technologies. However, given these costs, operators likely dispatched units in a least-cost manner. Some argue that units did not operate efficiently when prices were regulated. To minimize effort, firms may have let units operate during low demand times instead of stopping and restarting them. This would imply units started more often after restructuring. However, in the summer of 1998, fossil units started 5,894 times relative to only 4,013 in 1999. This measure does not control for other factors affecting starting up such as increased costs or changes in market competitiveness.

costs and ramping rates:

$$q_{it} = f(p_t - c'_{it}, \lambda_{it}). \tag{9}$$

This model accounts for the intertemporal constraints' shadow price (λ_{it}). Firm behavior will depend on price-cost margins, intertemporal constraints, and their interaction. Suppose that in 12 hours a firm expects price to exceed costs substantiality but that current prices are below costs. It might shut down a fast ramping unit now to save money but would keep a unit with high start-up costs running through the lull.

Typical production-cost models estimate the optimal mix of inputs. Unlike these models, I know production costs but must estimate how constraints affect the firm's dynamic optimization problem. Direct calculation of the dynamically optimal solution would require information on the exact methodology the system operators use to "dispatch" units and on the ways firms form expectations about future prices and their choice of start-up and no-load bids.[50]

The dependent variable, "utilization rate" (UR), measures the fraction of a unit's capacity operating in a given hour. The shadow price of intertemporal constraints depend on historic and future behavior: recall from equation (5), $\lambda_{it}(q_{i,0}, ..., q_{i,t-1}, q_{it}, q_{i,t+1}, ..., q_{i,T})$. However, including lagged and lead dependent variables would bias estimates in 1999; a unit that reduces output to exercise market power may be unable to produce at full capacity because of ramping constraints. Firm choices are identified by iteratively substituting in for lagged and lead production, a vector of prices, marginal costs, start-up costs, and unit and market characteristics.[51]

These choices probably differ by time of day and ramping constraints, so the sample is divided by hour of day (24) and ramping rate quartile (4) (data from Kahn, 2000). For each of the sub-samples $j \in \{1, ..., 96\}$, I model production using a flexible functional form estimation technique:

$$\begin{aligned} UR_{ijt} \;=\; & \alpha_j + \beta_{1j} H_{t-1}^{PCM} + \beta_{2j} H_t^{PCM} + \beta_{3j} H_{t+1}^{PCM} + \beta_{4j} D_{t-24}^{PCM} + \beta_{5j} D_t^{PCM} \\ & + \beta_{6j} D_{t+24}^{PCM} + \gamma_{1j} H_{t-1}^{PCM} \cdot SRT_i + \gamma_{2j} H_t^{PCM} \cdot SRT_i + \gamma_{3j} H_{t+1}^{PCM} \cdot SRT_i \\ & + \gamma_{4j} D_{t-24}^{PCM} \cdot SRT_i + \gamma_{5j} D_t^{PCM} \cdot SRT_i + \gamma_{6j} D_{t+24}^{PCM} \cdot SRT_i + \xi_j SRT_i + \varepsilon_{ijt}, \end{aligned} \tag{10}$$

[50] Dispatch refers to the set of units that are operating. For example, least-cost dispatch means that operators meet demand using the units with the lowest costs.

[51] Note that an alternative approach would be to instrument for the lag and lead production variables. However, this ignores the underlying economic variables determining behavior: prices and costs.

where H_t^{PCM} and D_t^{PCM} are the hourly and daily mean price-cost margins and SRT is the start-up cost. To account for non-linear relations, each variable is written as a piece-wise linear function.[52]

The censoring of the utilization rate at zero and one requires Tobit model estimation. The error structure is serially 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 for predicting firm behavior only requires consistent coefficients.[53]

Prices may be endogenous for a regulated price-taking firm; a large unit sustaining a forced outage will likely move the market price. For each endogenous variable constructed from hourly or daily average prices, I create an instrument using competitive price estimates from Mansur (2001).[54] Each endogenous variable is regressed on the set of instruments and the exogenous variables. The technique follows that described in Newey (1987), in which the Tobit model's independent variables include 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 the median observation for each variable in equation (10). The marginal effects are reported for all hours and for one peak hour (6pm). Many units operate near full capacity during peak hours. Therefore, as expected, the average unit's production is less sensitive to hourly price-cost margins. Furthermore, output increases in price in a highly non-linear manner. High start-up cost units are more affected by daily average prices than by movements in hourly prices. Finally, higher marginal and start-up costs reduce output. For 1999, I estimate the fitted competitive production outcomes.

The intertemporal model fits the actual production data better than the simulated estimates from the simplified model in section 3.2.[55] Figure 5 plots a kernel regression of

[52] Three parts, determined by trecile, comprise each spline. An industry formula proxies as an approximation of start-up costs: Two times marginal costs times capacity.

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

[54] For example, for the $D_{t+24}^{PCM} SRT_i$ (daily mean price tomorrow times unit i's start-up costs) variable for quick ramping units at 1pm in the lowest trecile, a similar variable is created using the daily average of the estimated prices.

[55] The correlation of observed utilization rates to simplified utilization rate estimates is 0.53 while the

actual utilization rates based on 1998 price-cost margins. As price-cost margins increase from -\$30 to \$30/MWh, marking the 5th and 95th percentiles, the average utilization rate rises slowly from 0.15 to 0.80. Kernel regressions of estimated utilization rates using the simplified and intertemporal models are shown in comparison. The expected utilization rates for this increase faster than actual utilization rates.[56] The intertemporal model more closely fits observed behavior because it accounts for intertemporal constraints.

The simplified model's average utilization rates tend to be smaller. This results because the model estimates that baseload units will run at 100% capacity most hours; however, the multitude of smaller peaking units rarely operate.[57] As a result of overestimating the use of low cost units, the simplified model will understate production costs.

3.3.1 Calibration

This analysis uses the intertemporal model to estimate total generation, emissions, and production costs. As described in section 3.2, the simplified model imposes that supply and demand equate. However, the intertemporal model does not impose such an equilibrium constraint. Recall that the intertemporal model's estimates are unbiased for the dependent variable, utilization rate. However, this does not imply that the aggregate measure of total production will also be unbiased because the observations are weighted by capacity. If capacity and the predicted errors are correlated in 1998, total production implied by the intertemporal model will not equal the observed production. The simplified model's total annual predicted generation serves as a benchmark.

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 3.3. The new vectors of the endogenous variables and residuals will be $\widetilde{p} = \alpha \cdot p$ and $\widetilde{e} = \alpha \cdot \widehat{e}$, respectively. A revised utilization rate ($\widetilde{UR}$) equals the product of these variables and the Tobit regression coefficients. For a given summer, the α's that equate the simplified

correlation of observed utilization rates to the intertemporal utilization rate estimates is 0.60.

[56]Recall that the simplified model requires that units operate at 100% capacity whenever the *perfectly competitive price* exceeds the estimated marginal cost. However, the simplified model estimates of the utilization rate do not jump from zero to one when the *actual price* exceeds marginal costs in Figure 5. This is because the simplified model and actual prices are not always equal. In fact, for 1998, the simplified model price estimates slightly exceed actual prices on average.

[57]The unweighted average utilization rate for 1998 was 0.45 for the intertemporal model's and observed production. The simplified model predicts a utilization rate of only 0.35.

model's total production with the calibrated level from the intertemporal model are 1.19 in 1998 and 1.28 in 1999.[58]

4 Results and Discussion

4.1 Welfare Losses

As discussed in section 2.4, welfare losses, in general, result from both an overall production effect and a production substitution effect. However, in the special case persistent in electricity markets, perfectly inelastic demand implies that no overall production effect will occur. Calculating the effects of cross-firm production inefficiencies, then, is simply a matter of aggregating total production costs. The welfare loss associated with market power in a market with perfectly inelastic demand equals the extra costs associated with production distortions. For a sample of T hours and N units in PJM, the welfare effect is measured:

$$W^* - \widehat{W} = \sum_{t=1}^{T}\{\sum_{i=1}^{N}[c_{it}(\widehat{q}_{it}) - c_{it}(q^*_{it})] + \int_{\sum_{i=1}^{N} q^*_{it}}^{\sum_{i=1}^{N} \widehat{q}_{it}} p_t(\overline{D}_t - Q)dQ\}, \tag{11}$$

where W^* and $\widehat{W}$ are social welfare under perfect and imperfect competition, q^*_{it} and $\widehat{q}_{it}$ are the respective production levels, $p_t(.)$ is the inverse net import competitive supply function, and $\overline{D}_t$ is demand. I assume constant marginal costs in electricity production: $c_{it}(q_{it}) = c'_{it} \cdot q_{it}$. The EPA CEMS provides data used to determine the actual hourly production of fossil fuel units ($\widehat{q}_{it}$). Net import changes are based upon the estimated supply curve described in section 3.2.

First, I discuss the welfare effects using the simplified cost model to estimate q^*_{it}. This model does not account for intertemporal constraints that, as apparent in Figure 5, may be important and lead the model to underestimate welfare effects. One can account for intertemporal constraints by treating the 1998 simplified model estimates as a control group. Assuming that the 1998 welfare loss estimates resulted *solely* from the bias of ignoring these constraints, the welfare effects from restructuring related market imperfections equal the

[58]Alternative approachs include using weights when estimating the intertemporal model or having the dependent variable be generation.

change in total welfare losses from 1998 to 1999. Note that if the bias is not constant over time, this method will inaccurately measure welfare effects.

Table 5 reports the welfare implications. In the summer of 1998, production costs in PJM were \$218 million greater than those implied by the simplified model's estimates of an efficient market. I assume that all of these losses result from measurement error in costs based upon intertemporal constraints. In the summer of 1999, inefficiencies caused welfare losses that exceeded this benchmark by an additional \$127.5 million. Recall that oligopolists cause *cross-firm*, not within-firm, production inefficiencies. In addition, importers needed to supply additional power to meet demand that cost \$33.1 million. Therefore, the total welfare loss from firms exercising market power after PJM was restructured is \$160.5 million.

The second method of calculating production under perfect competition, q_{it}^*, uses the intertemporal model estimates. Since this model is estimated based on 1998 observations, one might expect the 1998 welfare losses to be zero. However, this does not follow since the welfare effects are weighted aggregations. Recall that the intertemporal model estimates utilization rate so, in expectation, the residual from the estimated model ($\widehat{e}_{it}$) will be zero. However, the expected welfare loss in PJM at hour t equals:

$$E(W_t^* - \widehat{W}_t) = \sum_{i=1}^{N} c'_{it} \cdot [\widehat{q}_{it} - E(q_{it}^*)] \equiv \sum_{i=1}^{N} c'_{it} \cdot CAP_i \cdot \widehat{e}_{it}. \tag{12}$$

Therefore, if capacity (CAP) or marginal costs (c'_{it}) are correlated with the residual $\widehat{e}_{it}$, then the expected welfare effects in 1998 will not be zero. As such, using the intertemporal model to estimate how restructuring affected deadweight loss, I subtract the 1998 welfare estimates from the 1999 welfare estimates.

Before prices were deregulated, the intertemporal model predicts production inefficiencies of \$81 million (see Table 5). This measure increased by \$125.2 million after restructuring. In 1998, the intertemporal model predicts smaller inefficiencies than the simplified model. However, both models estimate similar *changes* in welfare loss. Using the intertemporal model, the overall effect of firms exercising market power on welfare is \$158.3 million.[59]

[59] Recall that the intertemporal model's total production is calibated to equal the competitive production measured from the simplified model. Similarly, the costs of changes in imports are assumed to be the same for both the simplified and intertemporal models.

To put these estimates in some perspective, the total observed electricity production costs were \$1.67 billion in 1998 and \$2.10 billion in 1999. Mansur (2001) measures wealth transfers; during the summer of 1999, the costs of procuring electricity from the PJM spot market exceeded the estimated procurement costs of a perfectly competitive market by \$224 million. If bilateral contracts reflect similar markups, wealth transfers from the exercise of market power total \$827 million.

4.2 Environmental Implications

This section compares observed emissions with emissions from the simplified and intertemporal models of perfectly competitive behavior. The environmental implications of firms exercising market power will depend on: dominant firms' reduced emissions, increased emissions from the fringe, and greater import-related emissions. This can be written for pollutant j, either SO_2 or NO_x:

$$\widehat{E}_j - E_j^* = \sum_{t=1}^{T}\{\sum_{i=1}^{N}[r_{ijt}(\widehat{q}_{it} - q_{it}^*)] + \int_{\sum_{i=1}^{N} q_{it}^*}^{\sum_{i=1}^{N} \widehat{q}_{it}} r_{jt}^{imp}(D_t - Q)dQ\}, \tag{13}$$

where E_j^* and $\widehat{E}_j$ equal total pollution under perfect and imperfect competition, r_{ijt} is the emissions rate, and r_{jt}^{imp} is the net import supply's emissions rate.

Figure 6 displays a kernel regression for 1999 of observed hourly $\mathrm{SO_2}$ emissions on demand. I also regress simplified and intertemporal model predictions for comparison. Regression estimates have been calibrated using the estimated biases from the 1998 regressions.[60] The calibrated competitive estimates exceed the observed emissions for medium-low demand levels.[61] This is consistent with the results from Figure 4, namely that gas units are

[60]For each model and demand level in 1998, the expected bias equals the average of observed minus estimated pollution. For a given demand level, I add this bias to the 1999 estimates.

[61]The difference between observed and estimated emissions can easily be tested if there is no idiosyncratic measurement error from the competitive production estimates. Measurement error probably is important in testing pollution differences; however, to simplify the estimation, this paper assumes these errors are small. I pool actual and an estimate of hourly emissions. Emissions are regressed on indicators of demand decile. I include terms interacting the demand deciles with a 1999 indicator, an indicator for observed emissions, and an indicator for both 1999 and observed emissions. Standard errors are adjusted for serial correlation and heteroskedasticity using a Newey-West correction assuming a 24-hour lag structure. When controlling for the 1998 biases, the 1999 observed emissions were significantly lower than the simplified model's estimated emissions at demand levels between 26.0 and 31.8 GW. With the intertemporal model, I find lower observed emissions for demand levels either below 24.1 GW or in the range of 26.0 to 31.8 GW. Similar tests on overall emissions find observed reductions were significant at the 5% level for both models.

replacing coal units.

Figure 7 plots similarly calibrated kernel regressions for NO_x emissions. In this figure, coal units appear to be replaced by gas. Additionally, the intertemporal model estimates NO_x emissions below the actual and simplified model predictions.[62] One possible source of this discrepancy is that increased permit prices led to high start-up costs for some dirty oil units. The intertemporal model may be predicting that, under perfect competition, the high start-up costs would prevent these units from operating as often as they did the previous year. In contrast, the simplified model would ignore this effect since it does not account for start-up costs. Furthermore, if firms exercise market power in this region of the demand curve, they will reduce output from low emission oil units, thereby requiring production by higher cost, dirtier units. The result would be that the intertemporal model would predict fewer emissions than either the simplified model or an imperfect market.

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 implies that, in 1999, 37% of the observed reduction in SO_2 (and 45% of NO_x reduction) resulted from market imperfections. The intertemporal competitive model suggests that electricity market imperfections attributed 41% of the SO_2 emission reductions but accounted for only 14% of the observed NO_x reductions.

4.2.1 Emissions from Increased Imports

When PJM firms exercise market power, generating units throughout the Eastern grid must produce more to satisfy PJM demand. This section estimates the emissions associated with the import supply curve. I calculate the correlation during the summer of 1999 between PJM net imports and production throughout the East. Production data are available from CEMS. Import firms produce based on prices in PJM and their local areas outside of PJM. I use temperature variables to proxy for local prices in other regions. The

[62] Using a similar analysis as mentioned in the previous footnote, the simplified model finds significantly reduced NO_x emissions when demand is below 30.4 GW. Intertemporal model estimates significantly exceeded observed emissions for demand was below 24.1 GW or in the range of 26.0 to 31.8 GW.. However, observed emissions are greater when demand is above 33.9 GW. Similar tests on overall emissions find observed reductions were significant at the 5% level only for the simplified model.

correlation between a unit's production and total PJM imports is directly examined rather than measuring the impact of PJM price on a unit's production and then imposing that prices affect the aggregate production of firms exactly the same as they affect measured imports. For each unit i not in PJM, the following equation is estimated:

$$Q_{it} = \alpha_i + \beta_i I_t + \gamma_i T_{it} + \delta_i (T_{it})^2 + \varepsilon_t, \tag{14}$$

where Q_{it} is hourly production, I_t is PJM net imports, and T_{it} is the unit i's state daily mean temperature. The estimated $\widehat{\beta}_i$ coefficients are calibrated to sum to one, imposing that the total change in imports equals the total change in production outside of PJM:

$$\widetilde{\beta}_i = \frac{\widehat{\beta}_i}{\sum_{i=1}^{M} \widehat{\beta}_i}, \tag{15}$$

where M is the sample of units in the Eastern grid not in PJM. The implied emissions from imports equal $I_t \cdot (\sum_{i=1}^{M} \widetilde{\beta}_i r_{ij})$, where r_{ij} is the emissions rate for unit i and pollutant j. During the summer of 1999, importing regions' SO_2 emissions increased by 1.25 tons per hour. The effects on permit prices are partially offset if the importing firms were among the few regulated by Phase I of the SO_2 program or were in the Northeast, thereby regulated by the NO_x program.[63] Note that if the imports came from outside of the OTC region, such as from Ohio, then the overall amount of NO_x would increase. The PJM reductions are offset by increases within the OTC region, either across space or time, due to the trading and banking nature of the pollution cap. Thus, importing electricity from Ohio will result in even more emissions.

4.3 Test of Firm Behavior

In this section, I test how firm behavior has changed as a result of restructuring. Some vertically integrated firms were net sellers in many hours and therefore had incentives to exercise market power after restructuring. Other firms were net purchasers most of the

[63] 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 nationally increased emissions that occur as a result of production inefficiencies. The NOx emissions increased by 0.55 tons per hour. This is 1.5% of the 1998 PJM emissions. The 7.2% reduction in emissions in PJM is reduced to 5.7% when accounting for the nationally increased emissions that occur as a result of production inefficiencies. When accounting for national import emissions, the effect of restructuring on emission accounts for only approximatly 30% of the overall reductions. Finally, it is worth noting that the coefficients on imports summed to 20. Therefore, recalibrating the coefficients substantially changed the coefficients.

time in the spot market. These firms likely did not exercise market power either before or after restructuring. Based on evidence discussed in section 2.2, namely that only some firms opted to bid market-based offers and also only some firms had net selling positions on average, PPL and PECO probably exercised market power while the others did not.

A formal test of whether PECO and PPL behaved differently than other firms in 1999 examines the relationship between the price-cost margin and the size of a firm's infra-marginal production. Since strategic production decisions are made at the firm level, I test firm behavior using data on firms' choices of total production by hour. Firms with market power are assumed to optimize according to equation (3). The first order condition for firm i equals:[64]

$$p_t - c'_{it} = -p'_{it} \cdot (Q_{it} - q^d_t - q^c_t) + \lambda_{it}, \tag{16}$$

where Q_{it} is firm i's total production. As shown in equation (16), a firm will determine output as a function of price (p_t), marginal cost (c'_{it}), the shadow price of intertemporal constraints (λ_{it}), the slope of the inverse residual demand facing firm i (p'_{it}), and the net position of production less native load and the net supply/demand contract coverage ($Q_{it} - q^d_t - q^c_t$). In contrast, a firm behaving competitively will have the same first order condition but will behave as if $p'_{it} = 0$. The amount of a firm's generation with marginal costs below price, that is, the infra-marginal production, does not affect a firm's decisions if it is a price taker.

For purpose of estimation, I write the first order condition as:

$$pcm_{it} = \alpha + \beta(Q_{it} - q^d_t) + \varepsilon, \tag{17}$$

where pcm_{it} is the price-cost margin ($p_t - c'_{it}$). The constant captures the average net contract coverage and the average shadow price of the constraints. The coefficient on the net position will account for correlations between net supply and the price-cost margin. If a firm exercises market power, it will have a positive β since residual demand curves are downward sloping. Otherwise, the coefficient will be zero.[65] α equals the mean of $p'_{it} \cdot q^c_t$,

[64] Where the firm's true marginal cost is the marginal cost its most expensive unit $j : c'_{jt} + \lambda_{jt} \geq c'_{it} + \lambda_{it}, \forall i \neq j$.

[65] If the net position of a firm 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 net supply of generation would be biased. As will be described below, difference-in-differences technique controls for this bias.

which will equal zero if the firm does not exercise market power or if the net contact coverage is zero. Otherwise, α can be positive or negative.

The model attempts to separate out common shocks to PJM (like the OTC NO_x program) from behavior unique to the oligopolistic firms using a difference-in-differences technique. I test whether the parameters α and β differ by year (t) and firm (i): $\alpha = \alpha_i + \alpha_t + \alpha_{it}$ and $\beta = \beta_i + \beta_t + \beta_{it}$. Fringe firms produce according to equation (5) before and after restructuring. Before restructuring, the dominant firms optimize based upon this equation as well, but follow equation (16) afterwards. By controlling for common time shocks (α_t and β_t) and common firm shocks (α_i and β_i), I can identify the behavior of each firm after restructuring (α_{it} and β_{it}). If $\beta_{it} > 0$, firm i behavior is consistent with the exercise of market power in period t. The econometric model is:

$$\begin{aligned} pcm_{it} &= \sum_i \alpha_{0i} FIRM_i + \alpha_1 RESTRUCT_t + \sum_i \alpha_{2i} FIRM_i \cdot RESTRUCT_t \\ &+\beta_0 q_{it}^{net} + \beta_1 q_{it}^{net} RESTRUCT_t + \sum_i \beta_{2i} q_{it}^{net} \cdot FIRM_i \\ &+\sum_i \beta_{3i} q_{it}^{net} \cdot FIRM_i \cdot RESTRUCT_t + Z_t' \Pi + \varepsilon_{it}, \end{aligned} \quad (18)$$

where $FIRM_i$ is a dummy variable for firm i ownership, $RESTRUCT_t$ is a dummy variable for restructuring, q_{it}^{net} is production minus native load, and Z_t is a vector of exogenous variables including a ten-piece spline function of demand, hourly indicators, and day of week indicators. ε_{it} is a first-order autoregressive, heteroskedastic error term.[66] I construct a proxy for each firm's native load.[67] The firm's marginal cost of production equals the marginal cost of the most expensive unit observed to be operating.[68] As q_{it}^{net} will be endogenous to the price-cost margin, I instrument it using daily temperatures in states in PJM and nearby. Temperatures are modeled as quadratic functions for current and lagged daily means, with coefficients allowed to vary above and below 65 degrees Fahrenheit. All

[66]Tests of serial correlation and heteroskedaticity were significant for all models in the table 7. For example, for model 1, DW-Stat = 0.24 and Cook-Weisberg test p-value 0.001.

[67]For each large firm, I only know its peak native load. That is, I know how much power a utility's customers demanded on the hottest day of 1999, which was July 6 for all firms. I also have data on system-wide demand for each hour. I calculate the share of the market demand that each utility met during the peak. By assuming that all PJM utilities' demands are perfectly correlated, I can determine the native load for each hour. The product of hourly system demand and share of peak demand proxies for native load.

[68]If the unit's production exceeds 90% of its capacity, the firm's marginal cost is defined as the cost of its next most expensive unit that has operated during the previous week (Puller, 2001).

small firms are aggregated as firm "other" since none of them would be large enough to exercise market power.

I account for serial correlation by quasi-differencing the data using the Prais-Winsten method. Table 7 reports the IV coefficients and robust standard errors for equation (18). Model 1 compares the behavior of PECO, PPL, and other major firms with that of smaller firms. Model 2 tests whether either PECO or PPL behaved differently than all other firms combined. The findings show that, on average, PECO and PPL exhibited behavior consistent with exercising market power after restructuring while the other firms did not change behavior after restructuring.

Next, I test whether all firms behaved strategically during hours in which they had incentives to do so. PECO and PPL were the only firms exercising market power on average. This may result either because PECO and PPL were the only firms that attempted to maximize profits or because the other large firms were usually net buyers, but when they were net sellers they too exercised market power. Models 3 and 4 in table 7 limit the sample to only those hours when q_{it}^{net} is positive, testing whether all firms exercised market power when they had incentives to do so. The findings show that, in addition to PECO and PPL, GPU and Potomac exercised market power during these hours but the other firms in the fringe did not.[69] Model 4 groups firms other than PPL and PECO and predicts that, for these hours, PPL behaved differently than other firms, but that PECO did not.

A second analysis directly tests if, on average, firms behaved differently than under perfect competition after restructuring, using estimates from either the simplified or intertemporal model. A difference-in-differences model accounts for shocks that are common to all firms in the summer of 1999 (ζ_t) and shocks specific to each firm (η_i). In this model, I estimate behavioral changes following restructuring for oligopolists (γ) and the fringe (ψ). As such, firm aggregate observed production (Q_{it}) is modeled as follows:

$$\begin{aligned} \ln(Q_{it}) &= \alpha + \phi \ln(\widehat{Q}_{it}) + \sum_i \eta_i FIRM_i + (\zeta + \psi) RESTRUCT_t \\ &\quad + \gamma RESTRUCT_t \cdot OLIG_i + Z_t'\Pi + u_{it}, \end{aligned} \tag{19}$$

where $\widehat{Q}_{it}$ is estimated production using either the simplified or intertemporal model and

[69] Public Service was always a net buyer.

$OLIG_i$ indicates PECO or PPL. The common time shock ζ and the effect of restructuring on fringe firms ψ cannot be separately identified since they are both identified by the change in behavior between 1998 and 1999. Without a perfect control group, this is a first-differences model that compares the behavior of each type of firm before and after restructuring.

Table 8 reports the OLS coefficients with Newey-West standard errors assuming a 24-hour moving average process.[70] Models 5 and 6 estimate firm behavior using the simplified and intertemporal models, respectively. I find that oligopolists' reduce output by about 10% when compared to the fringe. Given this reduction by the dominant firms and perfectly inelastic demand, either imports or fringe production must increase. In Model 5, which controls for the simplified model's predicted behavior, the fringe did not behave differently after restructuring than it did prior to restructuring. However, model 6, which controls for the intertemporal model's predicted behavior, predicts the fringe produced about 7% more after restructuring. Therefore, importers and the fringe increased production while the dominant firms, PECO and PPL, reduced production after the market restructured. This result again supports the hypothesis that market power was exercised after prices were deregulated in this market.

4.4 Discussion

4.4.1 Value of Pollution Reduction

Recall that under a cap-and-trade system, production distortions cannot affect aggregate emissions.[71] Reducing demand for permits in one part of the system allows for increased pollution elsewhere. Note that the distribution of emissions will be important if the damage function depends on locational and temporal factors.[72] Even if there are no environmental effects, the costs associated with regulation will be affected.

[70] Since observations have been aggregated by firm, a linear model assumption will probably be less biased by the censoring of production.

[71] A cap-and-trade permit system places a systemwide cap on total pollution. Firms can trade permits for the right to pollute, so long as the total cap is not exceeded. Although aggregate emissions will be uneffected, the spatial and temporal distribution of the emissions will change as a result of the exercise of market power.

[72] This is an issue of instrument choice. Debates over the optimal size of a permit system's region should also consider the implications of production distortions in product markets.

Efficient permit markets imply that permit prices accurately reflect the marginal cost to society of abating pollution. Although emissions will increase elsewhere when firms exercise market power in PJM, society forgoes abatement technology expenditures. When permit prices remain unchanged by firms exercising market power, the value of emission reductions equals the permit prices times the reductions. In the summer of 1999, the simplified model estimates that SO_2 decreased 23,552 tons.[73] Multiplying daily SO_2 permit prices and emission reductions yields a value of \$5.6 million. In that summer, NO_x emissions were reduced by 11,637 tons (5% of the mandated reductions), which corresponded to \$21.5 million. Therefore, the total value of reduced pollution in PJM over a single summer is \$27.1 million. Note that the electricity market welfare loss measures take these welfare effects into account since marginal costs include permits.

Ignoring any responsiveness of permit prices to PJM firm behavior will lead to estimates that overstate welfare losses and understate compliance cost savings. PECO and PPL emit 14% of the NO_x emissions in the OTC market (68% of the region's emissions originate from some firm in PJM). The dominant firms may be capable of affecting the NO_x permit price, depending on the price elasticity of abatement.[74] This study does not include a model of the OTC market needed to estimate how NO_x permit prices respond to market power in the PJM electricity market.[75] The next section explores how policy makers should regulate pollution when firms in product markets exercise market power and affect permit prices.

[73] This amount equals less than a percent of the total reductions mandated by the Clean Air Act Amendments.

[74] Even if no single firm exercises market power in the permit market, a shift in the marginal abatement cost function caused by firms exercising market power in the electricity market may affect permit prices.

[75] However, a publicly available model of the SO_2 market can test whether SO_2 permits are sensitive to production distortions (see Burtraw *et al.* (1998) and Burtraw and Mansur (1999) for a discussion of the Tracking and Analysis Framework, TAF, model). The model can be used to estimate the price elasticity of supply of abatement technology. When firms reduce pollution in PJM, less abatement technology needs to be installed. Approximately 10% of the SO_2 market's Phase I units are in PJM, and PECO and PPL account for 3.3% of the emissions. The TAF model estimates a price elasticity of 0.1, implying that a 4% annual reduction in PJM emissions would reduce permit prices proportionally by 4%. If the OTC market has a similar price elasticity of abatement, NO_x prices would have fallen by a third. Observed NOx prices fell from over \$5000/ton to about \$1000/ton over the summer of 1999. However, permit prices likely fell as expectations of installing abatement technology and fuel substitutions rose. The SO_2 price also fell through the summer of 1999. On possible explanation is that the EPA threatened lawsuits to force a number of plants to comply with New Source Review standards that would increase the supply of permits.

4.4.2 Policy Implications

In this section, I discuss how market power in electricity markets, or in product markets in general, can cause welfare losses in the environmental externality market. However, as an application of the theory of the second best, regulators may not want to eliminate all of this deadweight loss since other losses also exist in the product market. I then discuss the conditions under which permit markets are more robust to market power in product markets in comparison to a tax.

The presence of market power in product markets can affect policy makers' optimal choice of incentive-based environmental regulation instruments, such as Pigouvian taxes and pollution permit systems. The preferred regulation would minimize total welfare losses. In addition to the losses in the product market, regulators must consider losses corresponding to the pollution externality. Suppose that a product market is initially competitive and that regulators set either a tax or a permit cap at the socially optimal level. Taxes and permit systems are unlikely to respond optimally to shocks in firms' willingness to pay for pollution rights.[76] Firms exercise market power and distort pollution levels; deadweight loss corresponding to pollution will result when optimal emissions cannot be achieved.

As shown above, the exercise of market power reduces emissions from units in PJM. Figure 8 portrays an example of a pollution permit market. Assume regulators set the permit cap optimally based on perfect competition in the electricity market. By definition, the marginal benefits (MB) and marginal costs (MC_1) of abatement equate. When firms exercise market power and pollution decreases, overall emissions reductions in the region of environmental regulation can be achieved using less abatement technology; therefore, the supply of abatement has increased, or equivalently, permit demand has decreased. I denote the new marginal abatement cost curve MC_2. This curve includes the feedback effect that permits have on the electricity market: firms change their behavior when permit prices fall. PJM firms that exercise market power cause the optimal level of abatement to be where $MB = MC_2$. The new optimum has less pollution and lower permit prices in

[76] This is a matter of the slope of the marginal benefits of abatement. If the marginal benefits are perfectly inelastic, then a permit system will respond optimally. Taxes respond optimally when the marginal benefits are perfectly elastic (Weitzman, 1974).

comparison to the initial one.[77]

At the initially optimal permit cap, $MB > MC_2$, implying too large of a cap. Had regulators established an initially optimal tax instead, restructuring would have resulted in increased abatement supply and firms would continue to abate until marginal abatement costs equaled the initial tax. At that point, the initial tax is too high because $MB < MC_2$. Before lowering taxes, reducing permit caps, or changing the instrument type, policy makers should also consider how permit prices affect welfare in the electricity market.

An illustrative example makes further assumptions to simplify the question of policy instruments. Weitzman (1974) shows that the social planner facing uncertainty in abatement costs will prefer a tax to a quota system when the absolute value of the slope of the marginal benefits of abatement is less than the slope of the marginal costs of abatement. The quota system will be preferred if MB is steeper. In the case of equal absolute elasticities, policy makers should be indifferent between the instruments; both cause the same pollution-related welfare losses (see shaded areas in Figure 8). In this case, the policy instrument choice depends only the welfare implications in the product market. One can think of this question as asking whether taxes improve welfare in product markets.[78]

For the monopoly case, increasing taxes clearly reduces welfare. However, in the case of dominant firms with a competitive fringe, higher taxes may increase welfare if they induce dominant firms to exercise less market power and to increase production (Q_{dom}). These firms will produce more if taxes (t) increase their marginal revenues (MR_{dom}) by more than they increase their marginal costs (MC_{dom}).[79] When demand ($\overline{D}$) is perfectly inelastic, the inverse residual demand function of these dominant firms $P(Q_{dom})$ is simply

[77] Additional welfare losses can result if a permit market's cap initially equals or exceeds the optimal emissions level. In the case of perfectly elastic marginal abatement benefits and a cap set where $MB = MC_1$, welfare losses in the permit market total only \$68,000 in one summer. This calculation is based upon marginal abatement cost estimates from the TAF model. However, if the cap were even 10% above the optimal cap, production inefficiencies would increase deadweight loss by \$1 million. Conversely, if the initial cap were too high, these market distortions could *reduce* welfare losses in the permit market.

[78] Permit prices respond to firm behavior whereas taxes do not. When market imperfections increase pollution, permit prices will be greater than taxes. Taxes will be greater when emissions are reduced by firms exercising market power. Levin (1984) provides intuition into this question in examining the pollution outcomes of taxing oligopolists.

[79] Each dominant firm behaves according to its own reaction function. For simplicity, this discussion treats the dominant firms as a single entity.

a function of fringe's marginal cost MC_f:

$$P(Q_{dom}) = MC_f(\overline{D} - Q_{dom}) \tag{20}$$

Hence, at equilibrium Q^*_{dom}:

$$\frac{\partial MR_{dom}}{\partial t} = \frac{\partial MC_f}{\partial t} - \frac{\partial^2 MC_f}{\partial t \partial Q_f} Q_{dom}, \tag{21}$$

where Q_f is the fringe production. In general, the marginal revenue may be more or less sensitive to taxes than the marginal cost of the dominant firms. However, this does not necessarily lead to ambiguity.

In the case of PJM, the fringe pollutes less than the dominant firms. When firms exercise market power, less pollution occurs and permit prices fall. This will reduce the marginal costs of dominant and fringe firms. However, since dominant firms emit more pollution, their marginal costs will be more affected ($\frac{\partial MC_{dom}}{\partial t} > \frac{\partial MC_f}{\partial t}$). In the case of California, the fringe pollutes more. Firms exercising market power will increase pollution and permit prices. Here, $\frac{\partial MC_{dom}}{\partial t} < \frac{\partial MC_f}{\partial t}$. Higher permit prices increase marginal costs for the dominant firms, but the marginal cost of fringe firms increases even more. Had a subsidy been placed only on Q_{dom}, the effects would be similar.[80]

In both cases, the dominant firms will produce more and welfare will be greater under a permit system than under a tax when $\frac{\partial^2 MC_f}{\partial t \partial Q_f}$ is sufficiently small or negative. Otherwise, a tax will be preferred. In the case when fringe supply is uniform in emissions ($\frac{\partial^2 MC_f}{\partial t \partial Q_f} = 0$), permit systems will necessarily improve welfare in comparison with taxes. This seems a plausible assumption for small deviations from Q^*_{dom}. Note that even when the marginal benefits and marginal costs of abatement have different elasticities, this finding suggests that more consideration should be given to permit markets.

Welfare benefits of a permit system may not be politically feasible when high prices result. For example, consider the Regional Clean Air Incentives Market (RECLAIM) tradable permit system that regulates pollution in the Los Angeles basin. In the summer of 2000, RECLAIM NO_x prices skyrocketed partially because of reduced permit supply. Production inefficiencies may have also increased permit demand. Regulators responded by

[80] As depicted in the cases of PJM and California, an expensive fringe will either be cleaner or dirtier than the dominant firms. If the fringe is cheaper, it will not produce more in an imperfect market; the dominant firms will reduce output from more expensive units.

effectively replacing the permit system with a tax lower than the permit price.[81] This might have increased welfare losses if marginal benefits and marginal costs of abatement had similar elasticities; however, regulators may have been more concerned with substantially reducing wealth transfers.

5 Conclusions

In the summer of 1999, firms in the PJM wholesale electricity industry exercised market power and caused production inefficiencies. I measure the impacts of market power on welfare and pollution emissions by comparing observed behavior with estimates of competitive production choices. At given permit prices, a simplified competitive model yields estimates that production inefficiencies led to welfare losses equal to 8% of optimal production costs. Observed SO_2 emissions fell 10.5% between the summers of 1998 and 1999, while NO_x emissions fell 15.9%. The simplified model accounts for 60% of the emission reductions typically attributed to new environmental regulation. The remaining 40% may be ascribed to market imperfections. In a second approach, I use econometric estimation of production choices to determine how non-strategic firms address intertemporal constraints. This intertemporal competitive model suggests that electricity market imperfections attributed to similar welfare losses and SO_2 emission reductions, but accounted for only 14% of the observed NO_x reductions.

I test firm behavior by comparing the vertically-integrated, net-buying firms with net-selling firms. The latter group had incentives to exercise market power after restructuring. The findings show that net-selling firms reduced production by about 10% in comparison to other firms. These results suggest that firms exercising market power likely contributed substantially to the welfare and environmental implications associated with restructuring related production inefficiencies.

Reduced emissions in PJM caused the compliance costs of incentive-based environmental regulation to fall by $27 million. The corresponding NO_x reductions comprised approximately 5% of the reductions mandated by the OTC. Furthermore, permit prices may have been affected by imperfect competition in the product market.

[81] As of May 2001, electricity generators in the RECLAIM region are guaranteed permits at fixed prices far below the prices for which permits had been selling.

Policy makers developing incentive-based environmental regulation should consider the consequences of firms exercising market power in product markets. When dominant firms pollute more than the fringe, exercising market power reduces pollution from the product market and lowers prices in permit markets. The optimal pollution cap is lower than under perfect competition. However, reducing the cap could increase welfare loss in the electricity market.

Product market conditions influence whether a permit system increases welfare in comparison to a tax. Suppose marginal costs and marginal benefits of abatement have similar elasticities and environment policies initially optimize welfare assuming perfect competition in all markets. When the fringe pollutes less than the dominant firms, permit prices fall as market power is exercised. A permit system will be preferable to a tax if dominant firms' marginal costs decrease by more than their marginal revenues (which depend on the fringe's marginal costs). In the case in which the fringe is dirtier, the optimal cap will be greater when firms exercise market power. As an application of the theory of the second best, permit systems initially set optimally, assuming competitive behavior in the product market, may be preferable to either a tax system or a permit system that only optimizes over the pollution externality.

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6 Appendix

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

6.1 Cournot Model

A simple model demonstrates the ways in which oligopolies distort production, thereby affecting social welfare, emission levels, and optimal taxation choices. Assume that an industry has a small number of previously regulated firms, $m > 1$. Firm i faces the market demand curve $P(X) = P(x_1, ..., x_m)$ and has a cost function of $c_i(x_i)$. Assume that under regulation, all firms behave as price takers and produce 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:

$$P(x_i, X_{-i}) + \alpha P'(X)x_i - c_i'(x_i) = 0, \forall i \in \{1, ..., m\}. \tag{22}$$

A conjectural variation model of firm behavior allows for an examination of the marginal implications of market power on: firm output ($\frac{dx_i}{d\alpha}$), market output ($\frac{dX}{d\alpha}$), and aggregate emissions ($\frac{dE}{d\alpha}$).

6.1.1 Proposition

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

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

$$\frac{dx_i}{d\alpha} = \frac{P'x_i + [P' + \alpha P''x_i]\frac{dX}{d\alpha}}{c_i'' - \alpha P'}. \tag{23}$$

The overall output equals:

$$\frac{dX}{d\alpha} = \frac{P' \sum_{i=1}^{m}[\Pi_{j\neq i}(c_j'' - \alpha P')x_i]}{\Pi_{k=1}^{m}(c_k'' - \alpha P') - \sum_{i=1}^{m}[\Pi_{j\neq i}(c_j'' - \alpha P')(P' + \alpha P''x_i)]}, \tag{24}$$

where the assumptions of Hahn (1964) and Levin (1984) are followed: $c_i''(x_i) > \alpha P'(X)$ and $P' + \alpha P''x_i < 0$. Homogeneous costs imply $c_i''(x_i) = \gamma$ and that $\frac{dX}{d\alpha}$ will be negative:

$$\frac{dX}{d\alpha} = \frac{P'X}{(\gamma - \alpha P') - (mP' + \alpha P''X)} < 0. \tag{25}$$

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

$$P'x_i \lesseqgtr -[P' + \alpha P''x_i]\frac{dX}{d\alpha}. \tag{26}$$

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, individual firm 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 although total output has fallen. In other words, by assuming that the environmental externalities depend on the aggregate emissions and not on the spatial distribution of pollution, one 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:

$$\frac{dE}{d\alpha} = \sum_{i=1}^{m} \frac{de_i(x_i)}{dx_i}\frac{dx_i}{d\alpha} = \sum_{i=1}^{m}[r_i'(x_i)x_i + r_i(x_i)]\frac{dx_i}{d\alpha}, \tag{27}$$

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 emissions rates, the overall effect on emissions will be ambiguous.

6.2 Dominant Firms with Competitive Fringe

When firms use the same technology and some take prices as given, imperfect competition can increase total emissions. 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. A set of dominant firms able to exercise market power do so by choosing a quantity-setting equilibrium, subject to the fringe supply curve and resulting residual demand. Let the subset, $m \subset n$, be dominant firms (where $m > 1$) and the other firms, $n \backslash m$, are the competitive fringe producers. The overall effect of an imperfect market structure on emissions will depend on the marginal implications of market power on dominant firm output ($\frac{dx_i}{d\alpha}$), fringe firm output ($\frac{dq_i}{d\alpha}$), market output ($\frac{dX}{d\alpha}$), and aggregate emissions ($\frac{dE}{d\alpha}$).

6.2.1 Proposition

Dominant 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, note that the marginal implications of market power on firm output for the dominant firms $(\widehat{x}_i)$ will be:

$$\frac{d\widehat{x}_i}{d\alpha} = \frac{P'\widehat{x}_i + [P' + \alpha P''\widehat{x}_i]\frac{dX}{d\alpha}}{c'' - \alpha P'}. \tag{28}$$

For the fringe output $(\widetilde{x}_i)$:

$$\frac{d\widetilde{x}_i}{d\alpha} = \frac{P'\frac{dX}{d\alpha}}{c''}, \tag{29}$$

Hence, aggregating over m dominant and $(n-m)$ fringe firms yields:

$$\frac{dX}{d\alpha} = \sum_{i=1}^{m} \frac{P'\widehat{x}_i + [P' + \alpha P''\widehat{x}_i]\frac{dX}{d\alpha}}{c'' - \alpha P'} + \sum_{i=m+1}^{n} \frac{P'\frac{dX}{d\alpha}}{c''} \Longrightarrow \tag{30}$$

$$\frac{dX}{d\alpha} = \frac{c''P'\widehat{X}}{(c'' - \alpha P')c'' - c''(mP' + \alpha P''\widehat{X}) - (c'' - \alpha P')(n-m)P'} < 0, \tag{31}$$

where $\widehat{X} = \sum_{i=1}^{m} \widehat{x}_i$. This implies the fringe increases output:

$$\frac{d\widetilde{x}_i}{d\alpha} = \frac{P'\frac{dX}{d\alpha}}{c''} > 0, \tag{32}$$

and dominant firms reduce output:

$$\frac{d\widehat{x}}{d\alpha} = \frac{P'\widehat{x}_i + (P' + \alpha P''\widehat{x}_i)(m\frac{d\widehat{x}}{d\alpha} + (n-m)\frac{d\widetilde{x}}{d\alpha})}{c'' - \alpha P'} \Longrightarrow \tag{33}$$

$$\frac{d\widehat{x}}{d\alpha} = \frac{P'\widehat{x}_i + (P' + \alpha P''\widehat{x}_i)(n-m)\frac{d\widetilde{x}}{d\alpha}}{(c'' - \alpha P') - (P' + \alpha P''\widehat{x}_i)m} < 0. \tag{34}$$

Total emissions will be:

$$\frac{dE}{d\alpha} = m[r'(\widehat{x})\widehat{x} + r(\widehat{x})]\frac{d\widehat{x}}{d\alpha} + (n-m)[r'(\widetilde{x})\widetilde{x} + r(\widetilde{x})]\frac{d\widetilde{x}}{d\alpha} \tag{35}$$

$$\frac{dE}{d\alpha} \gtreqless 0 \Leftrightarrow \frac{m}{n-m}\frac{r'(\widehat{x})\widehat{x} + r(\widehat{x})}{r'(\widetilde{x})\widetilde{x} + r(\widetilde{x})} \gtreqless -\frac{d\widetilde{x}/d\alpha}{d\widehat{x}/d\alpha}. \tag{36}$$

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

6.2.2 Corollary: Cournot with Fringe and Perfectly Inelastic Demand

In focusing on perfectly inelastic demand functions, the relationship between a market's degree of imperfection and 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 because of frozen retail rates.

Proposition In a setting of dominant and fringe firms with symmetric sets of heterogeneous technology facing perfectly inelastic demand, the effect of firms exercising market power on emissions will depend entirely on the correlation between emissions 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. The following emissions distortion results from market imperfections:

$$\Delta E = E_{Cour} - E_{PC} = [\sum_{i=1}^{m} r_i(\widehat{x}_i)\widehat{x}_i + \sum_{i=m}^{n} r_i(\widetilde{x}_i)\widetilde{x}_i] - \sum_{i=1}^{n} r_i(x_i^*)x_i^*, \tag{37}$$

where $\widehat{x}_i$ and $\widetilde{x}_i$ are output levels for dominant and fringe firms and x_i^* is the competitive output. When firms have different sets of technology, the net effect on emissions will be ambiguous and will depend upon the type of technology each firms uses.

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 dominant firms becomes:

$$c'(\frac{\overline{D} - m\widehat{x}}{n-m}) - (\frac{m}{n-m})c''(\frac{\overline{D} - m\widehat{x}}{n-m})\widehat{x} = c'(\widehat{x}). \tag{38}$$

Therefore, $\widetilde{x} = \frac{\overline{D} - m\widehat{x}}{n-m}$. From this it follows that when $m = 0$, $x^* = \frac{\overline{D}}{n}$. Provided that cost functions behave typically, $c'(x) \geq 0$ and $c''(x) \geq 0$, output can be ordered: $\widehat{x} \leq x^* \leq \widetilde{x}$. The change in emissions resulting from imperfect competition becomes:

$$\begin{aligned} \Delta E &= mr(\widehat{x})\widehat{x} + (n-m)r(\widetilde{x})\widetilde{x} - nr(x^*)x^* && (39)\\ &= (n-m)[r(\widetilde{x})\widetilde{x} - r(x^*)x^*] - m[r(x^*)x^* - r(\widehat{x})\widehat{x}]. && (40) \end{aligned}$$

Note that if $r_i'(x) = 0$,then $\Delta E = 0$. Alternatively, imposing monotonicity on $r(x)$ and noting the ordering of production:

$$\begin{aligned} \Delta E &\gtrless 0 \Leftrightarrow \frac{r(x^* + \varepsilon)}{r(x^* - \varepsilon)} \gtrless \frac{m(x^* - \widehat{x})}{(n-m)(\widetilde{x} - x^*)} = 1 && (41)\\ \Delta E &\gtrless 0 \Leftrightarrow r'(x) \gtrless 0, && (42) \end{aligned}$$

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 dominant firms with a fringe will emit more (less) if the average emissions rate is increasing (decreasing) in output.

7 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%

Sources: EIA 860 and 759 forms and EPA CEMS.

Table 2: PJM Market Summary Statistics During Summers of 1998 and 1999

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	\$16.3	\$1.3	\$14.0	\$19.2
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	\$20.6	\$2.9	\$16.5	\$26.0
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

Sources: PJM, EIA, Natural Gas Intelligence, and EPA CEMS.

Table 3: Fraction of Capacity Used for Generation by Ownership, Fuel Type, and Emissions Rate

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

* MW Change = average change in MWh per hour.

Source: EPA CEMS. Units have high emissions rates if the rate is above one pound of SO_2 per mmBTU (the sample median for oil and coal units).

Table 4: Intertemporal Competitive Model Estimation

Dependent variable is hourly utilization rate by unit.

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	0.36		0.37	
Sample Size:	562,176		23,424	

IV Tobit coefficients, i.i.d. standard errors not shown. (1) average of marginal effect for all hours; (2) marginal effect at the median observation for all hours; (3) average of marginal effect for 6pm only; (4) marginal effect at the median for 6pm only. PCM is price-cost margin and SRT is start-up cost. PCM is instrumented with variables constructed using competitive price estimates from Mansur (2001). Each independent variable is modeled as a piece-wise linear function with three 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 and Fossil Production in PJM

Pollutant	1998	1999	Change	% Change
SO_2 (tons)				
-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 (tons)				
-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 (GWh)s				
-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: Test of Firm Behavior Based on Price-Cost Margins

Dependent variable is price-cost margin by firm and hour.

Variable	(1)	(2)	(3)	(4)
Net Output in 1999 (100 MWh)	-0.9	-0.3	-59.7	1.1
	(1.6)	(1.2)	(10.3)*	(0.6)
Net Output in 1999: Firm PECO	27.5	29.0	58.3	-4.2
	(5.1)*	(4.8)*	(11.4)*	(4.2)
Net Output in 1999: Firm PPL	21.7	19.0	74.3	15.1
	(2.9)*	(2.6)*	(10.7)*	(2.5)*
Net Output in 1999: Firm GPU	-6.9	-	51.3	-
	(2.3)*		(10.2)*	
Net Output in 1999: Firm Potomac	-10.2	-	72.7	-
	(2.2)*		(10.7)*	
Net Output in 1999: Firm PubServ	-12.4	-	N/A	-
	(3.0)*		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

IV coefficients reported for data that have been quasi-differenced using the Prais-Winsten method. Robust standard errors are given in parentheses. * is significant at 5% level. Models 1 and 2 examine entire sample. Models 3 and 4 are conditioned on positive net output positions. Firm fixed effects, general net output effects, ten-piece demand spline, hour of day indicator, and day of week indicators are not shown. The excluded firm category is "other," which consists of smaller utilities. Net quantity is instrumented with daily temperatures in states in PJM and nearby. 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: Test of Firm Behavior Based upon Hourly Firm-Level Production

Dependent variable is ln(observed production) by firm and hour.

Model	(5)	(6)
Competitive Model	Simplified	Intertemporal
Restructuring	0.004	0.073
	(0.013)	(0.012)*
Oligopolist*Restructuring	-0.109	-0.104
	(0.042)*	(0.041)*
Ln(Estimated Production)	0.427	0.479
	(0.017)*	(0.017)*
Sample Size	62,852	64,670

OLS coefficients with Newey-West standard errors, assuming a 24-hour moving average process, in parentheses. * is significant at 5% level. Firm fixed effects, hourly indicators, day of week indicators, and constant not shown.

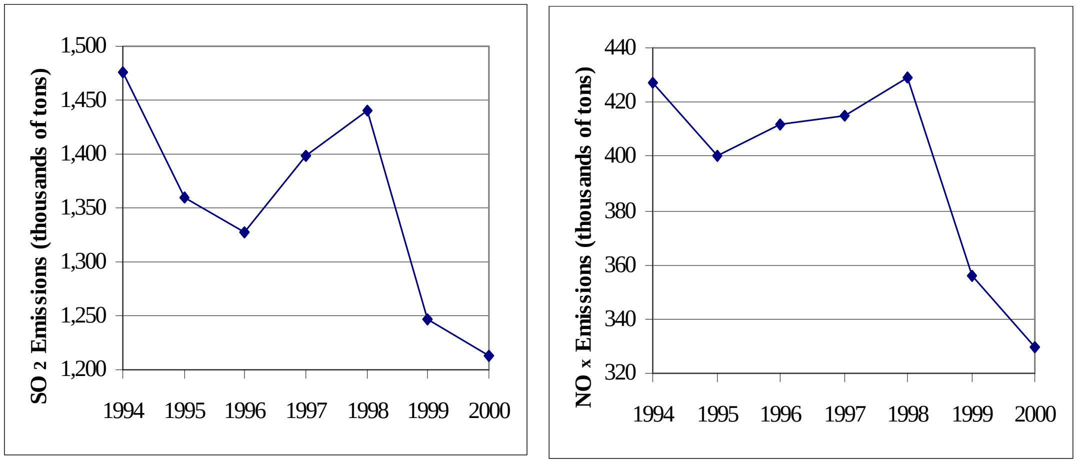

Figure 1: **Annual Electric Utility SO_2 and NO_x Emissions in Pennslyvania, New Jersey, Maryland, and Delaware**

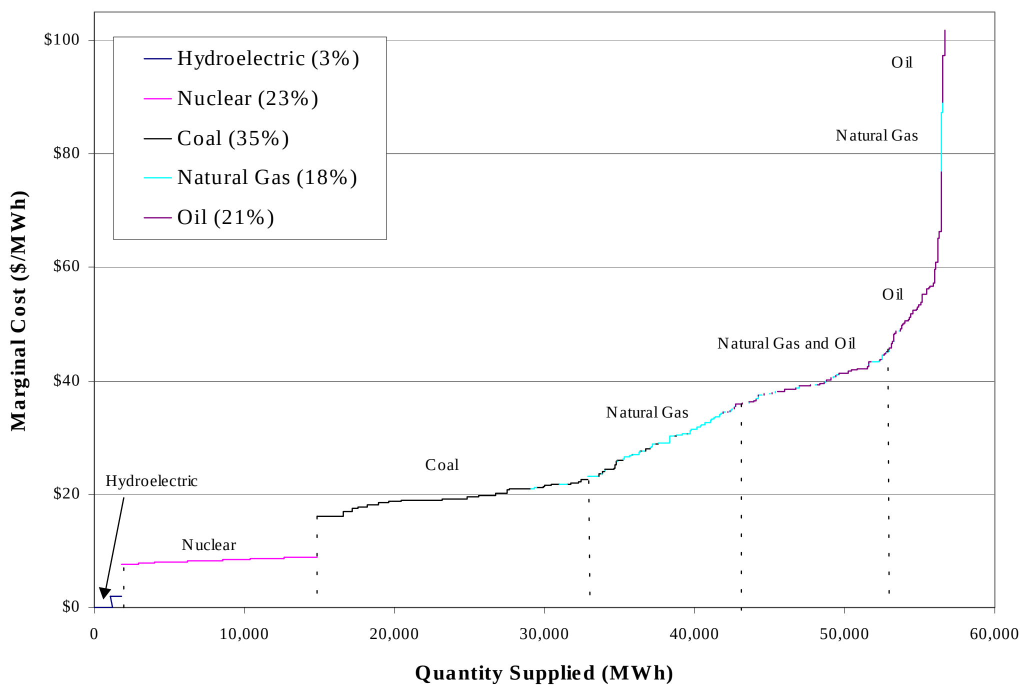

Figure 2: **PJM Market-wide Marginal Cost Curve**

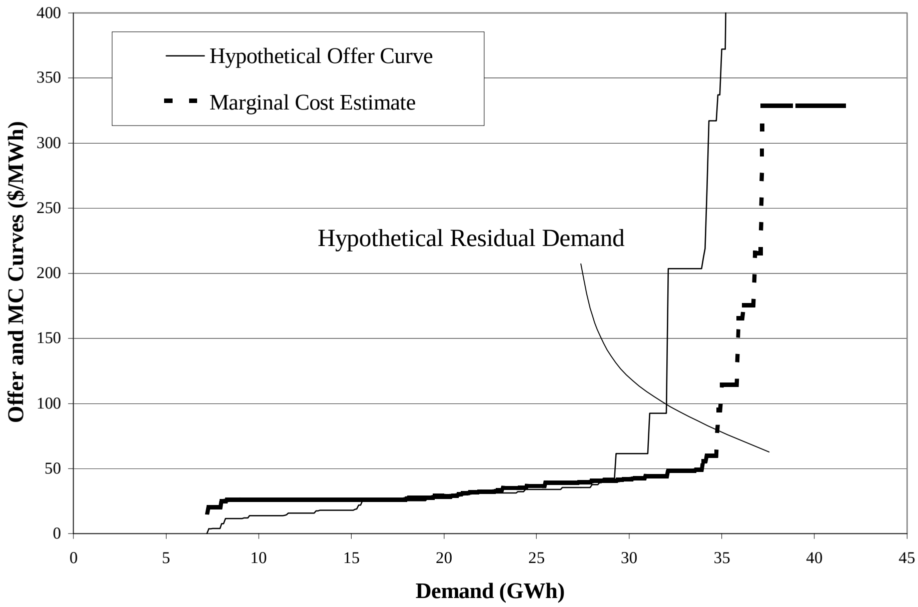

Figure 3: **Determining Perfectly Competitive Equilibria Using Simplified Model**

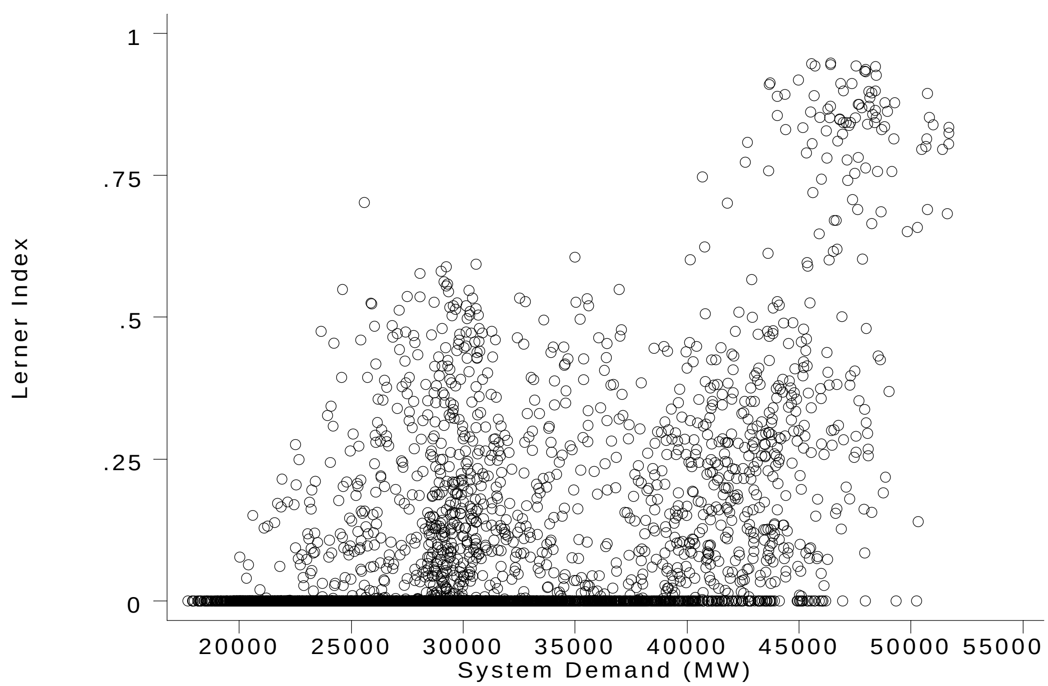

Figure 4: **Relationship Between Lerner Index and System Demand**

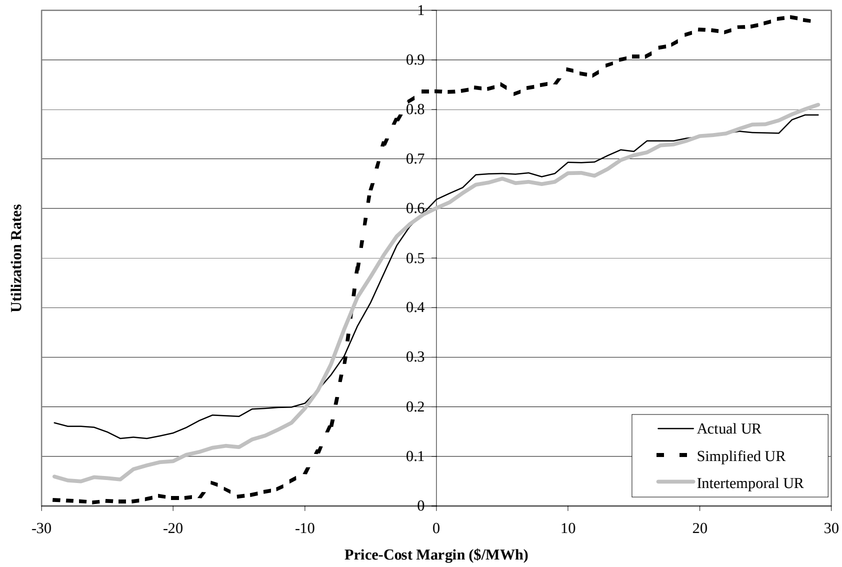

Figure 5: **Comparison of Estimated and Actual Utilization Rates across Price-Cost Margin**

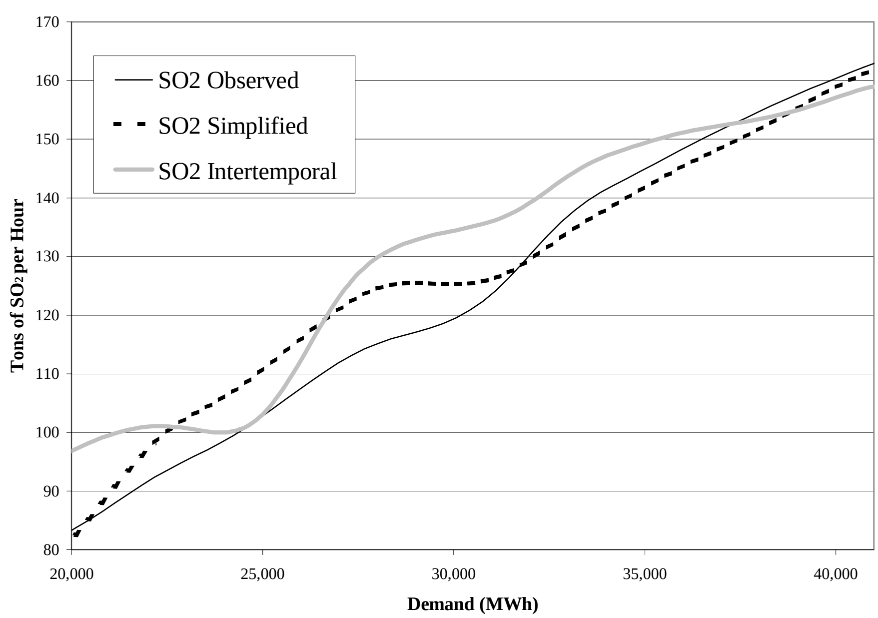

Figure 6: **1999 Actual and Calibrated Estimates of SO_2 Emissions**

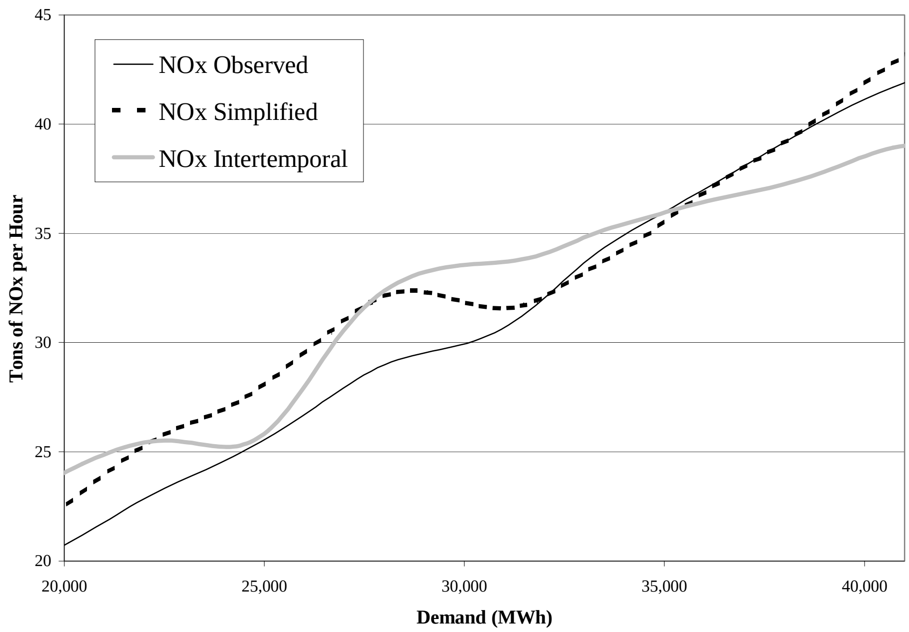

Figure 7: **1999 Actual and Calibrated Estimates of NO_x Emissions**

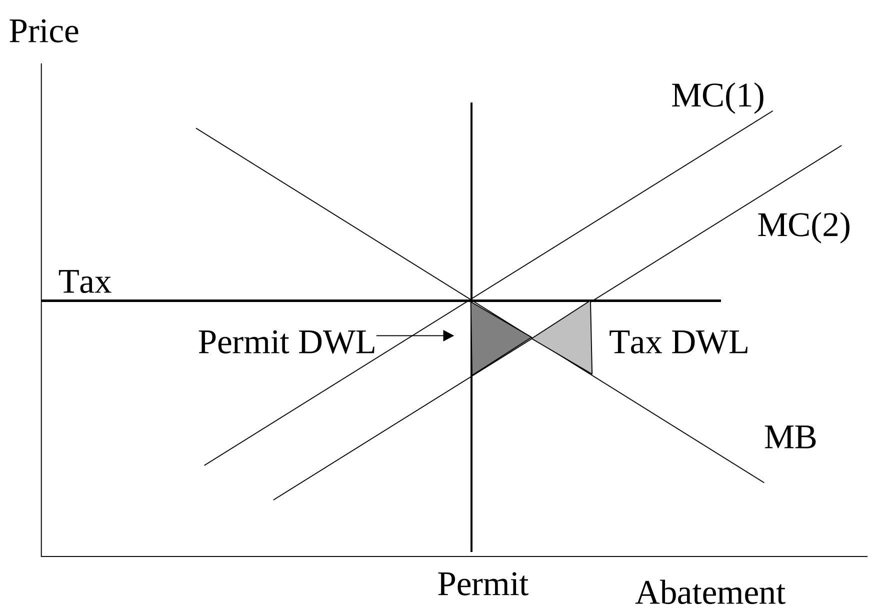

Figure 8: **Welfare Implications in the Pollution Abatement Market**