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Environmental Regulation in Oligopoly Markets: A Study of Electricity Restructuring

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Abstract

This paper studies the implications of strategic behavior in product markets on pollution decisions and environmental regulation. Given oligopoly behavior, I discuss the conditions under which welfare loss will be reduced if policy makers opt for tradeable permits in comparison to pollution taxes. I then examine the environmental implications of exercising market power in the context of restructured wholesale electricity markets. While electricity restructuring offers the potential for more efficient production and investment, it may create the opportunity for producers to exercise market power. Oligopolists may cause deadweight loss in wholesale electricity markets, even though demand is extremely 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 restructured wholesale electricity market. Air pollution fell substantially during 1999, the year in which both electricity restructuring and new environmental regulation took effect. I measure the environmental implications of these production inefficiencies by comparing observed behavior with estimates of production in a competitive market. Estimates of competitive production, which account for new environmental regulation, explain approximately 70% of the observed sulfur dioxide reductions. The remaining 30% can be attributed to firms exercising market power. The share attributed to market imperfections is even larger for nitrogen oxides and carbon dioxide emissions. From a policy perspective, these emission reductions have both environmental and cost implications. Since CO_2 remains unregulated, these findings imply lower environmental and health damages. As pollution markets exist for SO_2 and NO_X, these findings imply lower costs of abatement for firms overall.

(*JEL*: H23, L11, L94)

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1 Introduction

Market-based instruments, such as tradeable pollution permit markets, have become powerful tools for environmental regulators. However, the structure of and competition in a product market may limit the effectiveness of these incentive-based regulations.[1] In particular, firms in imperfect markets may produce inefficiently and emit less (or possibly more) pollution overall than would occur in a competitive market. A substantial literature has studied how market based environmental regulations affect pollution; other research has examined the welfare implications of oligopoly behavior in product markets. This paper examines the interactions of these markets by asking: what are the environmental implications of firms setting prices in product markets; and what impacts do environmental regulations have on welfare in imperfect product markets? I first develop a theoretical model of the implications of imperfect product markets on both pollution decisions and on policy makers' regulatory choices in a second best setting. In the context of restructured wholesale electricity markets, this paper then measures the implications of strategic behavior on pollution decisions.

While regulators had hoped to spur more efficient production and investment than had resulted under rate-of-return regulation, electricity markets have proven to be especially susceptible to the exercise of market power.[2] Prices are so amenable to firms because derived demand is completely inelastic.[3] Without demand response, oligopoly behavior leads to production inefficiencies: strategic firms produce less, requiring fringe firms to operate more expensive power plants.[4] This substitution among power plants may have environmental implications. In particular, in the short run, 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.[5]

The first contribution of this paper is a theoretical examination of incentive-based instrument choice in the context of imperfect product markets. Subject to uncertainty in abatement costs, Weitzman (1974) discusses the general case of when regulators will improve welfare by opting to use price or quantity regulations. Relative to these findings, I examine whether imperfect competition also impacts the optimal incentive-based instrument choice of environmental policy makers. Given market power in product markets, I discuss the conditions under which regulators improve welfare with permit systems in comparison to pollution taxes.

The reason why permits may be less distortionary is that, unlike taxes, tradeable permit prices may be endogenous to firm behavior. To elucidate this point, consider a polluting firm regulated by a permit system. Assume the firm once took prices as given, but now has a monopoly over its product. Relative to

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[1] To be consistent with the literature on pollution regulation, I use the term "product market" to distinguish markets that produce goods (and pollute in the process) as opposed to a market, like a permit market, where firms trade property rights.

[2] Numerous studies find price-cost markups in England (Wolak and Patrick, 1997; Wolfram, 1998; Wolfram, 1999), California (Borenstein, Bushnell, and Wolak, 2002; Puller, 2000; and Joskow and Kahn, 2002), New England (Bushnell and Saravia, 2002), and PJM (Mansur, 2003).

[3] There are two reasons for this. First, consumers have no incentive to reduce quantity demanded at higher prices because the regulatory structure of electricity retail markets has kept consumers' rates constant. A few customers have "interruptible" contracts that are exercised when the quantity demanded approaches the capacity of supply, causing customers to curtail electricity demanded. As this does not depend on price, demand shifts but remains completely inelastic. Second, the firms that procure customers' electricity in the wholesale market are mandated to provide the power at any cost.

[4] 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.

[5] In the short run, I assume consumers' retail prices and producers' abatement technology are fixed. 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 elaborates on this point.

the competitive outcome, the firm will reduce production, emissions, and demand for permits. In contrast to a tax, the reduced demand for permits results in a lower permit price. With lower a lower permit price, the monopolist's marginal cost of producing will fall. Relative to a tax, the monopolist will opt to increase production, which in turn, reduces welfare loss in the product market. As discussed in the paper, the welfare implications in the permit market need to be considered as well.

The paper then explores why air pollution from generating electricity in the Mid-Atlantic states–Delaware, Maryland, New Jersey, and Pennsylvania–fell substantially from 1998 to 1999 (see figure 1).[6] Reductions occurred, despite an increase in the quantity of electricity demanded over this period, because clean plants operated more and dirty ones produced less. This resulted, in part, from the introduction of environmental regulation. The Ozone Transport Commission (OTC) mandated that Northeastern electricity producers possess tradeable permits for summer nitrogen oxides (NO_x) emissions. These permits, which were quite expensive that summer, dramatically increased production costs at some power plants. Not all regulated states saw the same incidence of pollution reduction: for example, NO_x emissions in Massachusetts increased from 1998 to 1999 (see figure 2). An alternative explanation for why emissions fell in the mid-Atlantic is that its electricity market, PJM, was restructured. This may have led to market imperfections, including oligopoly behavior, that caused production inefficiencies and reduced pollution.[7] This paper explores whether restructuring the PJM wholesale electricity market resulted in pollution changes associated with production inefficiencies, which in turn, changed the costs of complying with environmental regulation.

To do this, I compare production estimates of a competitive market with actual hourly behavior, which the EPA provides for most fossil-fuel burning power plants. As in Mansur (2003), I model competitive behavior accounting for production complexities.[8] Using data prior to restructuring (i.e., during 1998), I estimate how firms produced and use the coefficient estimates to predict how the firms *would have* generated if restructuring had not occurred. This method contrasts with the simulation technique that is common to the literature on measuring competitive behavior in electricity markets that assumes power plants operate following an on-off strategy based on price exceeding marginal cost.[9] Using my estimates of competitive production, which account for the new environmental regulation, I explain approximately 70% of actual SO_2 pollution reductions. The remaining 30% can be attributed to firms exercising market power. Forty-two percent of NO_x emission reductions can be attributed to market imperfections. While carbon dioxide emissions fell only seven percent, I attribute 59% of the reductions to strategic behavior.

From a policy perspective, these emission reductions have both environmental and cost implications. In the case of CO_2, which does not have a cap limiting total emissions, these findings imply lower environmental and health damages. When pollution markets exist, these findings imply lower costs of abatement for firms overall. Since less NO_X pollution occurred in PJM, to clear the market the extra permits from PJM will

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[6] Specifically, annual sulfur dioxide (SO_2) and carbon dioxide (CO_2) emissions were reduced by 13 and 12%, respectively, the largest reductions in the 1990s for these states. Annual nitrogen oxides (NO_x) emissions were reduced by 17%, second only to a 22% reduction in 1993. Annual emissions for PA, NJ, MD, and DE were aggregated from the Energy Information Agency's *Electric Power Annual* on electric utilities.

[7] 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, Mansur (2003) 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.

[8] For example, one intertemporal constraint that I take into account is the cost of starting up a power plant. These "start-up" costs cause cost non-convexities that make solving the optimal dispatch a dynamic programming problem.

[9] For example, see Borenstein, Bushnell, and Wolak (2002).

be sold at a lower price to firms elsewhere in the OTC tradeable permit market. The total pollution level will be the same in equilibrium, however, now firms in New England and New York no longer need to install as much of the expensive abatement technology as they would have done without the excess permits from PJM. For SO_2, Phase I of the 1990 Clean Air Act Amendments' Title IV capped total pollution only for some power plants. Therefore, market power will reduce pollution and reduce permit prices in this case.

The paper proceeds as follows. In section 2, after discussing the literature on environmental regulation in imperfect markets, I construct a theoretical model of the environmental implications of firms exercising market power and discuss the policy choice over market-based regulation. Section 3 describes the environmental regulation and electricity restructuring in the Mid-Atlantic states. I review the methodology and data used to estimate competitive behavior in section 4. Section 5 displays evidence that restructuring resulted in production inefficiencies leading to emissions reductions in PJM and discusses the economic consequences of these pollution reductions. Section 6 offers concluding remarks.

2 Environmental Regulation of Imperfect Markets

2.1 Related Literature

Since Pigou (1938) argued for setting pollution taxes equal to the marginal external cost, many economists have examined the theory of environmental regulation in imperfect markets. As an example of the theory of the second best, Buchanan (1969) examines the issue of regulating a polluting monopoly. He argues that a monopolist facing a Pigouvian tax may cause more welfare loss than an unregulated competitive market.[10] In practice, however, Oates and Strassmann (1984) argue that ignoring market structure will probably lead to small inefficiencies when determining pollution regulation given these concerns are second order. On the other hand, Browning (1997) explains that second order implications *do* matter in a general equilibrium setting because of distortions in other markets, like labor markets.[11]

Monopolies distort overall production but produce using the least costly technology. In contrast, in addition to distorting overall production, oligopolies also cause production inefficiencies by substituting production across firms. In these markets, the pollution implications of market power depend on total production and the technologies employed. Key factors include demand elasticity, the costs and emissions associated with various technology types, the distribution of technologies among firms, and the exact oligopoly game. Therefore, determining second-best taxes becomes more complicated when an imperfect market includes several producers. Levin (1985) demonstrates that taxes, even when proportional to emission rates, may increase pollution from an oligopolistic industry with asymmetric cost functions.[12] I now model how exerting market power affects firms' production and abatement decisions and thus has policy implications for market-based instruments.

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[10] Due to additional distortion in the product market, Lee (1975) and Barnett (1980) note that the second-best tax for a monopolist is less than the marginal external cost.

[11] In general, environmental policy makers may improve welfare by considering: when the product market is economically regulated (Cropper and Oates; 1992); when markets are regulatory constructs (such as permit markets) that may be either set sub-optimally initially or cannot respond optimally to market shocks; and when product market regulations or structure have large environmental impacts.

[12] Since market structure leads to production inefficiencies and distorts the total quantity produced, the second-best tax may exceed the marginal environmental cost (Shaffer, 1995; Simpson, 1995; and Carlsson, 2000).

2.2 Model of Environmental Regulation

Suppose that there are several independent, competitive product markets with a total of N firms that emit pollution into a common airshed. For firm $i \in \{1, ..., N\}$, emissions (e_i) equal the firm's output (q_i) times its emissions rate (r_i):

$$e_i = q_i r_i. \tag{1}$$

In the short run, I assume firms cannot change abatement technology nor consider entering or exiting the product markets: r_i and N are fixed. Pollution results in environmental and health damages. Assume a convex damage function that depends only on aggregate emissions and not on their spatial distribution:

$$D = D(\sum_{i=1}^{N} q_i r_i). \tag{2}$$

Regulators can set a tradeable permits cap or an environmental tax to limit pollution in an effort to correct for the externality. In the case of a permit system, firm i is allocated permits of amount $\overline{e}_i$. If the product markets and the permit market are competitive, firm i will take as given its product market's price (P_i) and the permit price (τ). Firm i has convex production costs $c_i(q_i)$ and will choose its production level (q_i) in order to maximize profits (π_i). Profits equal total revenue less total production costs, but also less the environmental regulation costs of any additional pollution beyond the firm's allocated permits. Dropping the subscripts, in a competitive market, firm i will solve:

$$\max_q \{Pq - c(q) - \tau \cdot (qr - \overline{e})\}. \tag{3}$$

Therefore, in the case of a price taking firm, the first order condition of (3) implies:

$$P - c'(q) = \tau r.^{13} \tag{4}$$

Efficiency is defined by the set of output decisions $\{q_1^*, ..., q_N^*\}$ that solve the vector of equations where, for each firm, the marginal net benefits of production equal the marginal damages from that production:

$$P_i - c_i'(q_i^*) = D'(\sum_{i=1}^{N} q_i^* r_i) \cdot r_i, \forall i \in \{1, .., N\}. \tag{5}$$

Note that the source of emissions is not relevant to the marginal damage function. Therefore, the social optimum will be achieved under a tradeable permit system when the permit price τ equals the marginal damages from emissions $D'(\sum_{i=1}^{N} q_i^* r_i)$ where firms produce $\{q_1^*, ..., q_N^*\}$. The regulator allocates permits in aggregate equal to the optimal level of emissions:

$$\sum_{i=1}^{N} \overline{e}_i = \sum_{i=1}^{N} q_i^* r_i. \tag{6}$$

Assume that firm i is allocated permits equal to its optimal level of emissions: $\overline{e}_i = q_i^* r_i$.[14] In the case of an environmental tax, τ_0, the regulator levies the tax equal to the marginal damages from emissions at q^* for all firms: $\tau_0 = D'(\sum_{i=1}^{N} q_i^* r_i)$.

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[13] This assumes an interior solution, an assumption made throughout this paper. Note that the second order conditon for profit maximization is met: $-c''(q) < 0$.

[14] If there are any transaction costs associated with trading permits, then under competitive markets, the regulator will minimize these costs with this allocation rule.

2.3 Pollution Implications of Imperfect Product Markets

The first question I examine is whether introducing strategic behavior into a product market affects the total pollution emitted by firms in that product market: I call these emissions "local" pollution. Even though under a permit system, total emissions are fixed, the share of emissions from any one product market may change. Under a permit system, a strategic firm recognizes that its output affects prices: $P(q)$ and $\tau(q)$. The firm will solve:

$$\max_q \{P(q) \cdot q - c(q) - \tau(q) \cdot (qr - \overline{e})\}. \tag{7}$$

The first order condition then implies:

$$P(q) + P'(q) \cdot q - c'(q) = \tau(q) \cdot r + \tau'(q) \cdot (qr - \overline{e}).^{15} \tag{8}$$

Let $\widetilde{q}$ solve (8). I assume that a firm acting strategically will produce less than it would have in a competitive market, $\widetilde{q} < q^*$. This will be the case provided that the firm's incentive to increase the price in the product market either does not conflict with, or otherwise dominates, the incentive to distort the permit price.[16]

Under a tax, the firm cannot affect the regulation price ($\tau_0' = 0$) and therefore will have the first order condition:

$$P(q) + P'(q) \cdot q - c'(q) = \tau_0 \cdot r.^{17} \tag{9}$$

Let $\widehat{q}$ solve (9). In the face of a tax, given $P'(q) < 0$, the strategic firm will always produces less than it would have in a competitive market: $\widehat{q} < q^*$.

Figure 3 presents the local pollution effects of introducing market power. Under competition, the marginal abatement cost equals forgone profits. Rearranging (4), the marginal abatement cost of a firm in a competitive market ($mca^{comp}(q)$) will be:

$$mca^{comp}(q) = \frac{P - c'(q)}{r}, \tag{10}$$

which is decreasing in production (and therefore in emissions). As consistent with the literature, I model marginal damages from pollution as increasing in emissions. For both types of regulation, namely the the permit cap and tax, the figure displays the optimal policy under the assumption of competitive product markets. When the dominant firm can set the product price, its marginal abatement costs (mca^{mkt_pwr}) again equal the forgone profits:

$$mca^{mkt\_pwr} = \frac{P(q) + P'(q) \cdot q - c'(q)}{r}. \tag{11}$$

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[15] Here, the second order condition for profit maximization is $2P'(q) + P''(q) \cdot q - c''(q) - 2\tau'(q) \cdot r - \tau''(q) \cdot (qr - \overline{e}) < 0$. Note that $P'(q) < 0$ and that $c''(q) > 0$. However, I have not imposed restrictions on $\tau(q)$ as the point of this section is to determine the sign of $\tau'(q)$, as discussed below.

[16] As in Hahn (1984), firms may have incentives to affect permit prices in order to minimize regulation costs. Hahn shows that a firm will exercise monopoly or monopsony power depending on whether its sells or buys permits, on net. The firm will produce less when acting strategically than it would have in a competitive market as long as: $P'(q) \cdot q < \tau'(q) \cdot (qr - \overline{e})$. This holds when permits are allocated $\overline{e} = q^* r$. However, this will not always be the case. As will be discussed below, increasing output may increase the permit price in some cases, but will decrease it in others. In the case of a positive $\tau'(q)$, had the firm been allocated a substantial amount of permits, it would want to produce more in order to drive up the permit price and this inequality would fail. Similarly, in the case of a negative $\tau'(q)$, if the firm had been given very few permits, then the firm would increase production and reduce the permit price (as explained below, by reducing demand for other, dirtier firms' production). This would also result in the failure of the inequality. Another reason firms would have incentives to affect the market price is in order to raise their rivals' costs (Misiolek and Elder, 1989; and Sartzetakis, 1997).

[17] Here, the second order conditon for profit maximization is the typical condition for strategic firms and is assumed to hold: $2P'(q) + P''(q) \cdot q - c''(q) < 0$.

As price exceeds marginal revenue, the dominant firm will emit less for a given permit price. However, fringe firms produce more in an imperfect market, which may potentially offset this shift in the market's marginal abatement costs. As with wholesale electricity markets, I model demand as perfectly inelastic ($\overline{q}$). Assume that the imperfect product market consists only of a dominant firm (which produces q_m) and a competitive fringe (q_f). In equilibrium, the quantity supplied and demanded equal: $q_m + q_f = \overline{q}$.

With fixed abatement technology, the local pollution implications of introducing strategic behavior will depend solely upon the relative emission rates of the dominant firm and of the competitive fringe. Note that under a permit system, the reduction in output resulting from the exercise of market power from the dominant firm ($q_m^* - \widetilde{q}_m$) exactly equals the increase in output from the fringe ($\widetilde{q}_f - q_f^*$). Therefore, for a given permit price, the dominant firm reduces emissions by $(q_m^* - \widetilde{q}_m) \cdot r_m$ while the fringe emits more: $(\widetilde{q}_f - q_f^*) \cdot r_f$.

In figure 3, the dominant firm has a higher emission rate ($r_m > r_f$) so that the same level of emissions can be achieved with less abatement from firms in other product markets. The aggregate marginal abatement cost function lies below that of the competitive market.[18] For the permit market to be in equilibrium, the reduced demand for permits will result in permit prices falling. Figure 4 presents the converse case when the dominant firm has a lower emission rate than the fringe. At a given permit price, more local pollution occurs when the dominant firm exercises market power. In equilibrium, this increase in demand for permits will result in permit prices rising.

2.4 Implications for Policy Choice

Assuming that regulation is set optimally given competitive product markets, almost any deviation in marginal damages or marginal abatement costs will result in welfare loss.[19] One such shock to costs, as shown above, is enabling strategic behavior in product markets. As an application of the theory of the second best, regulators may not want to eliminate this deadweight loss since additional welfare losses also exist in the imperfect product market. In this subsection, I examine the conditions under which permit markets are more robust to market power in product markets in comparison to a tax.

When the dominant firm is dirtier than the fringe, as in figure 3, exercising market power will reduce local emissions so, at the initial permit cap, the marginal damages exceed the new marginal abatement costs, implying that firms emit more than the new optimal level. This new optimum has less pollution and lower permit prices in comparison to the initial one.[20] Alternatively, had regulators established an initially optimal tax instead, strategic behavior would result in less pollution as firms abate to the point were marginal abatement costs equal the tax. At that point, the tax exceeds marginal damages, implying emissions are less than socially optimal. The converse arguments can be made when the fringe is relatively dirty, as shown in figure 4.

However, before policy makers either alter the level of taxes or permit caps or change the type of incentive-based instrument, they may improve welfare by considering how permit prices affect welfare in the economy

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[18] This curve includes the feedback effect that permits have on the product market: firms will alter production decisions when marginal costs change, including permit prices.

[19] In the extreme cases, regulatory mechanisms can mimic society's demand for clean air: if the marginal damages are perfectly inelastic, then a permit system will respond optimally. Alternatively, taxes respond optimally when the marginal damages are perfectly elastic.

[20] If a permit market's cap is initially equal to or greater than the optimal emissions level, then the introduction of anticompetitive behavior results in even greater welfare losses in comparison to an initially optimized cap.

as a whole. Here, I examine the welfare implications of setting a tax or a tradeable permit system under the first best given that environmental regulators either may not consider the welfare implications in the product market, or simply do not know whether there will be more or less pollution after a dominant firm exercises market power in the product market. As with Weitzman (1974), the uncertainty of the marginal abatement costs imply that taxes and tradeable permits are not equivalent but rather depend on the elasticities of marginal abatement costs and marginal damages. The social planner will prefer a tax to a quota system when the slope of marginal damages is less, in absolute terms, than that of marginal abatement costs. In contrast, the quota system will be preferred if marginal damages are steeper. In the special case of equal absolute elasticities, policy makers should be indifferent between the instruments; both cause the same pollution-related welfare losses given a shock to marginal abatement costs, like the introduction of strategic behavior.

Assume that, under perfect competition, regulators are indifferent between a tax and tradeable permits that are set such that the tax equals the expected permit price where marginal damages and marginal abatement costs equal. This implies that the slope of the marginal damages equals the absolute value of the slope of the marginal cost of abatement. Thus, any shock to costs will result in welfare loss in the market for abatement that will have the same expectation regardless of instrument choice. This is shown in both figures 3 and 4 by the shaded areas; the gray area is the welfare loss associated with a permit cap while the black area is the welfare loss associated with a tax.

The additional welfare implication that I want to address is: how does instrument choice affect welfare in the product market? Relative to a tax, permit prices respond to production decisions. The implications on production, and therefore welfare, can be seen by looking at how profits change when the permit price falls.

In the case of perfectly inelastic demand, the dominant firm's residual demand ($P(q_m)$) is defined by the marginal cost of the fringe:

$$P(q_m) = c_f'(q_f) + \tau(q_m) \cdot r_f = c_f'(\overline{q} - q_m) + \tau(q_m) \cdot r_f. \tag{12}$$

Under a permit system, this implies that the slope of the residual demand function will be:

$$P'(q_m) = -c_f''(\overline{q} - q_m) + \tau'(q_m) \cdot r_f \tag{13}$$

The first order condition (8) is modified for the dominant firm as:

$$\begin{aligned} \frac{d\pi(\tau(q_m))}{dq_m} &= [c_f'(\overline{q} - q_m) + \tau(q_m) \cdot r_f] + [-c_f''(\overline{q} - q_m) + \tau'(q_m) \cdot r_f] \cdot q_m \\ &\quad -c_m'(q_m) - \tau(q_m) \cdot r_m - \tau'(q_m) \cdot (q_m r_m - \overline{e}_m) = 0. \end{aligned} \tag{14}$$

Under a tax, the condition (9) is rewritten as:

$$\frac{d\pi(\tau_0)}{dq_m} = [c_f'(\overline{q} - q_m) + \tau_0 \cdot r_f] + [-c_f''(\overline{q} - q_m)] \cdot q_m - c_m'(q_m) - \tau_0 \cdot r_m = 0. \tag{15}$$

At the dominant firm's profit maximizing level of production under a tax ($\widehat{q}_m$), I examine the difference between the first order condition under a permit (14), ($\frac{d\pi(\tau)}{dq}|_{\widehat{q}_m}$), and that condition under a tax (15), ($\frac{d\pi(\tau_0)}{dq_m}|_{\widehat{q}_m}$). (Note that $\frac{d\pi(\tau_0)}{dq_m}|_{\widehat{q}_m} = 0$.)

$$\frac{d\pi(\tau(q_m))}{dq_m}|_{\widehat{q}_m} - \frac{d\pi(\tau_0)}{dq_m}|_{\widehat{q}_m} = [\tau_0 - \tau(\widehat{q}_m)] \cdot (r_m - r_f) + \tau'(\widehat{q}_m) \cdot (\overline{e}_m + \widehat{q}_m r_f - \widehat{q}_m r_m). \tag{16}$$

2.4.1 Relatively Dirty Dominant Firm

If the dominant firm is relatively dirty ($r_m > r_f$) and exercises market power, then permit prices will fall below the level of the tax ($\tau(\widehat{q}_m) < \tau_0$). In this case, $\tau'(q_m) > 0$ and (by assumption) $\overline{e}_m > \widehat{q}_m r_m$. Therefore, at $\widehat{q}_m$, profits are increasing in q_m under a permit and the firm produces more.

As a case in point, consider $r_m = 1$ and $r_f = 0$. Now (16) equals:

$$\tau_0 - \tau(\widehat{q}_m) + \tau'(\widehat{q}_m) \cdot (\overline{e}_m - \widehat{q}_m). \tag{17}$$

Figure 5 depicts the welfare implications of this example by plotting residual demand (a function of the fringe's production costs), the marginal revenue of that function, and four cost curves: marginal private costs ($c'_m(q_m)$), marginal social costs ($c'_m(q_m) + D'(q_m) \cdot r_m$), marginal private costs plus the tax ($c'_m(q_m) + \tau_0 r_m$), and marginal private costs plus the permit price ($c'_m(q_m) + \tau(q_m) \cdot r_m$).

As permit prices fall relative to the tax, the strategic firm produces more. This will reduce the dominant firm's production costs relative to a tax, and production for the strategic firm is greater than it would have been under a tax: $\widetilde{q}_m > \widehat{q}_m$. The welfare loss from a dominant firm facing a tradeable permit is the area between the residual demand curve and the marginal social costs from the point where the dominant firm opts to produce ($\widetilde{q}_m$) to the optimal point where the lines intersect q_m^* (the hashed area). A tax would result in addition welfare loss (the gray area), as the dominant firm would produce even less ($\widehat{q}_m$).

2.4.2 Relatively Clean Dominant Firm

If the dominant firm is relatively clean ($r_m < r_f$) and exercises market power, then the dirty fringe produces more and permit prices rise relative to a tax ($\tau(\widehat{q}_m) > \tau_0$). Greater permit prices will result in an increase of production costs for all firms; however, the fringe's production costs increase even more so than those of the relatively clean dominant firm. Returning to (16), this has two potentially offsetting effects on marginal revenue. On the one hand, as the permit price is above the tax and the dominant firm is relatively clean, increasing output improves profits under a permit relative to a tax: $(\tau_0 - \tau(\widehat{q}_m)) \cdot (r_m - r_f) > 0$. On the other hand, the more the dominant firm produces, the less the permit price increases above the tax: $\tau'(q_m) < 0$. When q_m is near zero, the first effect is likely to dominate: the marginal revenue under a permit system will exceed that under a tax (as long as $\tau'(q_m) \cdot \overline{e}_m$ is not substantial). Conversely, at the competitive output level q_m^*, the permit price equals the tax ($\tau = \tau_0$) so the second effect dominates. At this point, marginal profits are greater under a tax. There will be some $q_m \in (0, q_m^*)$ where the two effects offset and the marginal revenue under the tax is equal to the marginal revenue under the permit system. Permits will result in more production by the dominant firm than a tax ($\widetilde{q}_m > \widehat{q}_m$) and less welfare loss *only if* the permit price does not respond substantially to changes in q_m around $\widehat{q}_m$, meaning:

$$\frac{[\tau_0 - \tau(\widehat{q}_m)] \cdot (r_m - r_f)}{\overline{e}_m + \widehat{q}_m r_f - \widehat{q}_m r_m} > -\tau'(\widehat{q}_m). \tag{18}$$

I examine the implications of this condition using a simplifying assumption: $r_m = 0$ and $r_f = 1$. Also, I assume that the clean dominant firm will not be allocated permits: $\overline{e}_m = 0$. Now the condition (18) is:

$$\frac{\tau(\widehat{q}_m) - \tau_0}{\widehat{q}_m} > -\tau'(\widehat{q}_m). \tag{19}$$

If the average increase in the permit price is greater than the marginal increase from further reducing output, then permits are welfare improving. In other words, this constraint will hold if $\tau(q_m)$ is concave.

Figure 6 provides an example of the welfare implications. As in the previous case, the strategic firm produces where marginal revenue equals marginal cost. This figure has four residual demand curves based on the fringe's costs in these cases: marginal private costs ($c'_f(\overline{q} - q_m)$), marginal social costs ($c'_f(\overline{q} - q_m) + D'(q_m) \cdot r_f$), marginal private costs plus the tax ($c'_f(\overline{q} - q_m) + \tau_0 r_f$), and marginal private costs plus the permit price ($c'_f(\overline{q} - q_m) + \tau(q_m) \cdot r_f$). I have drawn the marginal revenue curves for the two policy instruments. I have shown the case when the residual demand with the permit price lies above that with the tax at $\widehat{q}_m$. Therefore, for a given fringe emissions rate, the marginal revenue for the residual demand with permits is greater than that with taxes, implying more welfare loss under the tax (the same area shading is used as in the previous figure).

In both cases, the dominant firm produces more and, therefore, reduces welfare loss. Note that even when the marginal damages and marginal abatement costs have different absolute elasticities, this finding suggests that more consideration should be given to permit markets. Another important consideration is that transaction costs imply improved welfare from using a tax instead of a tradeable permits system (Stavins, 1995). All else equal, I find that given the presence of strategic firms in product markets, welfare losses will be reduced if environmental policy makers opt for tradeable permit systems in comparison to pollution taxes.

2.5 Application to Restructured Electricity Markets

Many electricity markets consist of a few strategic firms and a competitive fringe facing perfectly inelastic demand. If plants' abatement rates are fixed, only technology substitution yields pollution effects. For example, emissions will fall if strategic firms reduce output from dirty power plants and a competitive fringe meets demand using cleaner technology. Further, if marginal production costs are monotonically increasing or decreasing in emission rates, then direction of the pollution effects of imperfect markets depend only upon the sign of this correlation. When expensive plants pollute more than cheap plants, market power increases local emissions. Conversely, when cheap plants pollute more, strategic behavior results in less local pollution. These environmental impacts will be exacerbated if strategic firms are more concentrated in low-cost technology.

To further elucidate this point, I compare the different implications of this model for the California and PJM electricity markets. A firm choosing to exercise market power will opt to restrict output from its most expensive power plants. While California generators primarily use hydroelectric, nuclear, and natural gas to produce electricity, strategic firms' plants on the margin almost always burn gas. Therefore, firms opting to exercise market power will do so by restricting output from gas-fired plants. As a result, more expensive gas-fired plants owned by the fringe must operate in order to meet demand (in lieu of cheaper ones owned by the strategic firms). High-cost gas plants tend to be older, less efficient, and more polluting. Thus, in California, we observe marginal production costs (including pollution permits) increasing in emissions. Therefore, exercising market power in California will likely increase local emissions (or the permit price if emissions are capped). Typically, exercising market power in electricity markets will increase pollution when strategic firms and fringe producers use the same fuel type; variation in "heat rates" (a measure of efficiency) leads to a positive correlation between marginal production costs and emission rates.

In contrast, strategic firms in PJM will reduce output from coal, natural gas, or oil plants, depending upon the level of demand. When demand ranges from low to medium levels, a firm considering exercising market power will have coal-fired power plants on the margin. Coal plants tend to be substantially dirtier and cheaper, even including permit prices, than natural gas plants. Therefore, restricting output with coal leads to more production by gas plants. On net, there will be less local pollution than under perfect competition. Hence, firms exercising market power in California will likely cause pollution to *increase* 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 remaining sections of this paper will examine the environmental impacts of strategic behavior in PJM.)

With regard to the policy implications, when firms exercise market power in PJM, less pollution occurs locally and permit prices fall. This will reduce the marginal costs of strategic and fringe firms. However, since strategic firms emit more pollution, their marginal costs will be more affected. In the case of California, the marginal production costs and emission rates tend to be positively correlated. Firms exercising market power will increase local pollution and permit prices. Here, the marginal costs of the strategic firms are less affected: higher permit prices increase marginal costs for the strategic firms, but the marginal cost of fringe firms increases even more. Had a subsidy been placed only on the strategic firms' output, the effects would be similar.[21] In both cases, the strategic firms will produce more under a permit system than under a tax.[22]

3 Environmental and Economic Regulation in the PJM Market

Given these general theoretical findings, I now examine the case of PJM and ask whether restructuring the electricity market had environmental implications. Over the past fifteen years, several countries and U.S. regions – such as California, New England, New York, PJM, and Texas – 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

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[21] 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.

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

the most expensive power plant almost three times as often as in the previous summer, when prices were regulated.

Mansur (2003) finds evidence of firms exercising market power in PJM during 1999, the first year the market restructured. Furthermore, that paper provides evidence that when firms set prices, they do so, in part, by distorting production decisions. Given the variation in emission rates of these firms, the cross-firm production inefficiencies may have impacted local pollution levels, and therefore, the permit prices of the regulating markets. To test for these impacts in PJM, I begin by discussing the incentive-based environmental regulations and electricity regulation during 1998 and 1999. Electricity generation in the PJM region was subject to two incentive-based environmental regulations in the summer of 1999. One had just been introduced that summer, the OTC NO_x tradeable permit regulation. In contrast, the CAAA SO_2 tradeable permit regulation had been in effect for a number of years but affected a smaller number of power plants, at least at that time period.

3.1 OTC Nitrogen Oxides Tradeable Permit Regulation

Twelve Northeastern states comprising the OTC established a tradeable permits program for summer NO_x emissions. For each ton of NO_x emitted from May through September, power plant owners must procure an allowance. If the permits are not used, they may be 'banked' (in a limited manner) for use in future years. In 1999, Phase II of this program called for substantial reductions: greater than 50% reduction from 1990 emission levels of 490,000 tons. Eight states participated in 1999 (CT, DE, MA, NH, NJ, NY, PA, and RI). Sources may be constrained by other federal and state environmental regulations.

The permit market had a substantial impact on the marginal cost of production for many power plants in the Northeast. When the permit market started, in May of 1999, the permit price was \$5244/ton. This increased the marginal production costs of some coal plants by 50% in comparison to the previous summers' costs. Many in the industry were concerned about firms 'hoarding' permits and the lack of announced equipment retrofits. However, the permit prices fell over the summer and reached \$1093/ton by mid-September.[23]

3.2 CAAA Sulfur Dioxide Tradeable Permit Regulation

Title IV of the 1990 Clean Air Act Amendments (CAAA) established a national tradeable permits system for annual SO_2 emissions. As a result, power plant emissions have been reduced to approximately 50% 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. Phase I began in 1995, regulating the 398 dirtiest "generating units" in the U.S. In 2000, Phase II brought over 2,300 fossil fuel units into compliance. The increase in the scope of regulated firms was accompanied by an increase in permits, while overall, Phase II requires more abatement.

Twenty-three units at ten plants in PJM were regulated by Phase I. Two generators at the Conemaugh plant, owned by GPU, installed scrubbers in 1994 and 1995. The others either switched to low sulfur coal or purchased permits from the market. Regardless of how these units complied with the regulation, the price

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[23] The price remained around \$1000 since that first summer. For more information on the OTC, see http://www.epa.gov/airmarkets/otc/.

of the permit is the opportunity cost of polluting. During the summer of 1999, the price of these allowances was about \$200 per ton. For the median coal unit regulated by Title IV, this corresponds to about three dollars per MWh. The average Phase II unit is cleaner with an expected marginal cost of approximately one dollar per MWh at these prices.[24]

Note that one possible explanation for the reduction in emissions from 1998 to 1999 is that some of the firms may have invested in improved abatement technology. Firms may have been preparing for the tightening of the national SO_2 permit market in 2000. I account for this by using actual emission factors instead of historic ones when determining counterfactual production decisions. Of course, this assumes that the investments in abatement technology would have resulted regardless of electricity restructuring (using the previous section's notation, r is fixed). However, no power plant in PJM installed a scrubber in 1999. In general, PJM firms' SO_2 and NO_x emission rates did not change substantially from 1998 to 1999.

3.3 The PJM Electricity Market

In 1998 and 1999, the whole of New Jersey, Delaware and the District of Columbia, the majority of Pennsylvania and Maryland, and part of Virginia comprised the PJM Interconnection market's regulatory bounds. PJM facilitates trade among regulated utilities and independent producers involved in the generation, transmission, and distribution of electricity. In so doing, the wholesale market attempts to lower utilities' costs of providing power to customers. The market consists of 57,000 megawatts (MW) of capacity, including nuclear, hydroelectric, coal, natural gas, oil, and renewable energy sources (see table 1 and figure 7). Nuclear and coal plants provide baseload generation capable of covering most of the demand. 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.[25] The corresponding SO_2 emission rates for these generating units are shown in figure 8. Coal units tend to emit more SO_2 than oil units while natural gas only has trace amounts of SO_2. Table 2 provides the summary statistics by fuel type for SO_2, NO_x, and CO_2 emission rates for the summer of 1998.

In 1998, the PJM wholesale electricity market established a new pricing network to facilitate inter-utility trading.[26] 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.

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[24] In Phase I, the median "heat rate" was 10,179 BTU/kWh (a measure of how efficient the unit is in converting fuel into electricity) and the median emissions factor was 2.93 lbs. of SO_2/mmBTU. In Phase II, I assume a heat rate of 12,000 BTU/kWh and an emissions factor of 1.2 lbs. of SO_2/mmBTU.

[25] See Mansur (2003) for more on these intertemporal constraints and greater discussion on the PJM market.

[26] 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.

4 Methodology and Data

This section defines the optimization problem of competitive firms while accounting for intertemporal constraints. I then explain the econometric estimation technique of this intertemporal model that requires observing a baseline of competitive behavior. While regulated, I argue that the short run operation of power plants prior to restructuring, in 1998, was consistent with such behavior. Surely this regulated market did not exemplify *perfect* competition; firms invested inefficiently and probably distorted marginal production costs by making inefficient decisions regarding maintenance, labor, and capital allocation including environment abatement technologies. However, *given these costs*, operators likely dispatched units in a least-cost manner. Using the coefficient estimates from the pre-restructuring period, I predict a competitive counterfactual for production decisions for the post-restructuring period.

4.1 Intertemporal Model of Competitive Production

Several technologically-induced intertemporal constraints limit firms' ability to produce electricity. As previously mentioned, after unit i shuts down, in order to resume operation at hour t, the firm pays "start up" costs ($START_i$). In addition to marginal production costs, firms incur some "no load" costs ($NOLOAD_i$), such as running conveyor belts and fans, regardless of the amount produced. Ramping rates (RMP_i) limit the speed at which units increase or decrease hourly production. After being shut down, minimum down times ($DOWN_i$) limit how quickly units can restart. Finally, minimum ($K_i^{\min}$) and maximum ($K_i^{\max}$) operating capacity levels restrict a unit's range of operation.

These intertemporal constraints create non-convexities in firms' production cost functions. Price-taking firms obtain profit maximization by optimizing units' production separately. Neither a firm's production at other plants nor its contractual agreements (including native load) affect optimization. Given price (P_t) and variable production costs ($C_{it}(q_{it})$) at unit i and hour t, a competitive firm chooses production (q_{it}) to solve the dynamic program:

$$\begin{aligned} V(q_{i,t-1},t) \quad &= \quad \max_{q_{it}}\{P_t q_{it} - C_{it}(q_{it}) - START_i q_{it}^{+} q_{i,t-1}^{0} \\ &\qquad -NOLOAD_i q_{it}^{+} + \delta E_t[V(q_{it},t+1)]\} \ s.t.: \end{aligned} \tag{20}$$

(i) Capacity: $q_{it} \in \{0, [K_i^{\min}, K_i^{\max}]\}$,
(ii) Ramping: $\frac{|q_{it}-q_{i,t-1}|}{K_i^{\max}} \leq RMP_i$,
(iii) Min. Down: $q_{it} > 0 \Rightarrow (q_{i,t-1} > 0 \text{ or } q_{i,t-s} = 0, \forall s \in \{1,...,DOWN_i\})$,
where, $V(q_{i,t-1},t)$ is the value function this hour,[27] q_{it}^{+} indicates operation this period, (while $q_{i,t-1}^{0}$ indicates no production last hour), and $\delta E[V(q_{it},t+1)]$ is the discounted expectation of the value function next hour.

I assume $C_{it}(q_{it})$ to be a linear function: $c_{it}q_{it}$. Noting that competitive firms take P_t as given, a heuristic representation of the first order condition of (20) is:

$$PCM_{it} \equiv P_t - c_{it} = \lambda_{it}(\overrightarrow{q}_{it}), \tag{21}$$

where $\overrightarrow{q}_{it} = (q_{i,0}...q_{i,T})$, T equals total hours, PCM_{it} is the price-cost markup (ignoring intertemporal constraints), and λ_{it} is a general function accounting for intertemporal constraints that can have a positive

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[27] Bellman equations typically have an additional state variables 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, I avoid introducing an extra variable.

or negative effect on the true marginal cost: $c_{it} + \lambda_{it}(\overrightarrow{q}_{it})$. Intertemporal constraints may reduce a unit's marginal cost; for example, postponing shutting down at low prices may improve overall profits since the firm avoids restarting the unit later on when prices rise. Intertemporal constraints may also increase marginal costs. Again, using the case of start up costs, a firm will not operate even when prices exceed marginal production costs if rents are not substantial enough to cover the cost of 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 exceeds (or equals) marginal cost of production (c_{it}). Given this description of competitive firms' optimization problem and estimates of c_{it} from Mansur (2003), the following section explains the methodology used to account for intertemporal constraints in order to determine a competitive counterfactual market outcome.

4.2 Methodology of Intertemporal Model

For the pre-restructuring period, when I assume competitive behavior, I estimate the policy function: q^*_{it} equals the *argmax* of (20). Effectively inverting (21), the price-taking firm will choose output as a function of historic, current, and future price-cost markups and intertemporal constraints. Unlike production models that estimate the optimal mix of inputs, I know production costs but must estimate how constraints affect the firm's dynamic optimization problem. An alternative approach would be to make a direct calculation of the dynamically optimal solution. However, this would require information on the exact methodology the system operators use to dispatch units and on the ways firms form expectations about future prices. Rather, I opt for a reduced-form approach relating output decisions to price-cost markups and constraints using in a flexible format.

The dependent variable, "utilization rate" (UR_{it}), measures the fraction of a unit's capacity operating in a given hour. I model $UR_{it} = X'\beta$ so that the predictions of $\widehat{UR}_{it}$ for 1999 are consistent with competitive behavior. To do this, I need consistent measures of the β parameters but also X variables unlikely to be subject to strategic behavior. For example, while the shadow price of intertemporal constraints depends on historic and future behavior (see (21)), including lagged and lead dependent variables could potentially bias competitive estimates in 1999 (e.g., a unit that reduces output to exercise market power may be unable to produce at full capacity because of ramping constraints). Instead, I identify firm choices by substituting in a vector of past, current, and future price-cost markups ($\overrightarrow{PCM}_{it}$) and unit characteristics: RMP_i, $K_i^{\max}$ and $START_i$. I set $\overrightarrow{PCM}_{it}$ to consist of six variables: markups during the previous, current, and following hour as well as the daily average markup for yesterday, today, and tomorrow. I write utilization rate as a function of these variables and an idiosyncratic shock (ε_{it}):

$$UR_{it} = f(\overrightarrow{PCM}_{it}, RMP_i, K_i^{\max}, START_i) + \varepsilon_{it}. \tag{22}$$

In the estimation procedure described below, each of the six markup variables are interacted with each of the three unit characteristic variables. To further account for non-linear relations, I estimate each of these 27 variables (6+3+6*3) as a piece-wise linear, or spline, function that is separated by quintile. Finally, I allow these choices to differ by time of day by estimating 24 sets of hourly coefficients.

Using data described in Mansur (2003), I estimate firm production choices in three steps of an instrumental variables-Heckman selection model. First, as prices may be endogenous, I predict fitted values of price-cost markups ($\widehat{PCM}_{it}$) that are orthogonal to production. Even before restructuring, a large unit sustaining a forced outage will likely move the market price. Furthermore, if firms behave strategically after restructuring, markups will be inconsistent with that of a competitive equilibrium. I instrument the actual markups using the predicted competitive markups from Mansur (2003): $\overrightarrow{PCM}^*_{it} \equiv \overline{P}^*_t - c_{it}$. These instruments include predicted competitive markups of six types: the previous, current, and following hour and the daily average markup for yesterday, today, and tomorrow. Like all other variables, I allow these instruments to enter as piece-wise linear functions separated by quintile and to differ by hour of day. For markup measure j in $\overrightarrow{PCM}_{it}$–which varies by type, quintile, and hour–I run an OLS regression:

$$PCM_{jit} = f_1(\overrightarrow{PCM}^*_{it}, RMP_i, K_i^{\max}, START_i) + \varepsilon_{1,it}. \tag{23}$$

In the second stage, I estimate the binary choice of whether a unit operates or not. Using a probit model, I estimate ON_{it}, an indicator that $UR_{it} > 0$, as a function of fitted markups and intertemporal constraints:

$$ON_{it} = f_2(\widehat{PCM}_{it}, RMP_i, K_i^{\max}, START_i) + \varepsilon_{2,it}. \tag{24}$$

I estimate the probability of operating ($\Pr(\widehat{ON}_{it})$) and the inverse Mill's ratio ($\widehat{MILLS}_{it}$). Finally, conditional on operation, I estimate utilization rates as a function of fitted markups, ramping rates, capacity, and their interactions. Conditional on operation, I assume start up costs do not affect production:

$$UR_{it}|_{ON_{it}} = f_3(\widehat{PCM}_{it}, RMP_i, K_i^{\max}, \widehat{MILLS}_{it}) + \varepsilon_{3,it}, \tag{25}$$

where I use weighted least squares, with $K_i^{\max}$ as the weight, so that predicted system-wide production–namely the sum over all units of $(\widehat{UR}_{it}|_{ON_{it}} * \Pr(\widehat{ON}_{it}) * K_i^{\max})$–is consistent with actual system-wide production in 1998.

Given the high degree of periodicity of a unit's hourly utilization rate, serial correlation must be taken into account. Maximum likelihood estimation of (23), (24), and (25) that accounts for serial correlation would require imposing a specific functional form on the error structure and would be quite cumbersome to estimate. Rather, I determine the models' coefficients and standard errors using a bootstrapping method. I account for serial correlation by grouping observations in seven-day increments: For a given bootstrap draw, I pick an observation (with replacement) as well as the following six days' observations. I repeat the estimation procedure using the new sample, which has the same number of observations as in the initial regression.[28] I repeat the process 200 times to determine the sample mean and standard deviation of these draws in order to estimate firm competitive decisions, as well as their aggregate production costs. See Mansur (2003) for a discussion of the results.

4.3 Data

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." 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.[29] During the summers of 1998 and 1999, CEMS

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[28] Robinson (1982) demonstrates that estimation of limited dependent variable models will be consistent when serial correlation is not modeled explicitly in the likelihood function.

[29] Net production is approximately 90 to 95% 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.

monitored 234 units that accounted for over 97% of PJM's fossil fuel capacity.[30] These data were also used to calculate quarterly emissions rates.[31] Marginal cost estimates draw upon various sources.[32] PJM provides information on system-wide hourly prices, demand, and net imports.

Table 3 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. The introduction of the Ozone Transport Commission (OTC) NO_x trading program had the largest impact on costs. The marginal production costs reflect these input prices, primarily for the dirtier fuel types. In addition, the competitive price estimates from Mansur (2003) rose 19% between the summers of 1998 and 1999.[33]

Firms did not respond to these input costs symmetrically. Table 4 reports on the fraction of total capacity used for generation across firm and fuel type during the summers of 1998 and 1999.[34] Two firms, PECO and PPL, are likely to have exercised market power while the others did not (see Mansur, 2003). The behavior of these strategic firms 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.[35] 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.

5 Results of Environmental Implications

5.1 Changes in PJM Emissions

This section compares observed emissions with emissions from my model 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

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[30] All units over 25 megawatts and new units under 25 megawatts that use fuel with a sulfur content greater than .05% 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, 2002).

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

[32] 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 $.29/mmBTU. A trading company called Cantor Fitzgerald provided monthly permit price indices for the NO_x and SO_2 markets.

[33] Mansur (2003) explains how these prices were estimated.

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

[35] 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.

for pollutant j, either SO_2 or NO_x:

$$\widehat{E}_j - E_j^* = \sum_{t=1}^{T}\{\sum_{i=1}^{N}[r_{ijt}(\widehat{q}_{it} - q_{it}^*)] + \int_{\sum_{i=1}^{N} q_{it}^*}^{\sum_{i=1}^{N} \widehat{q}_{it}} r_{jt}^{imp}(D_t - Q)dQ\}, \tag{26}$$

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.

Table 5 reports the hourly average emissions in PJM using actual and predicted data from my competitive model. Actual emissions fell 13.9% for SO_2, 20.8% for NO_x, and 6.8% for CO_2. With the competitive model, I find that the implied percent reduction in emissions explained by cost and demand shocks was 9.9% for SO_2, 12.3% for NO_x, and 2.8% for CO_2. I attribute the difference between these percentages (4.0%, 8.5%, and 4.0%, respectively) as the result of market imperfections such as firms setting prices. I estimate standard errors for the competitive model estimates using a bootstrapping method as in Mansur (2003).[36] All changes in emissions are significant at the 1% level. This suggests that, in 1999, 31% of the observed reduction in SO_2 resulted from market imperfections. For NO_x and CO_2, the fraction of the actual reductions attributed to market imperfections are even larger: 42% and 59%, respectively.[37]

5.2 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 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:

$$Q_{it} = \alpha_i + \beta_i I_t + \gamma_i T_{it} + \delta_i (T_{it})^2 + \varepsilon_t, \tag{27}$$

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:

$$\widetilde{\beta}_i = \frac{\widehat{\beta}_i}{\sum_{i=1}^{M} \widehat{\beta}_i}, \tag{28}$$

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. Estimates of imports in the competitive scenario are modeled in Mansur (2003). 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

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[36] The model of production behavior from Mansur (2003) predicts output decisions. Mansur uses the measures to determine the cost of production inefficiencies. In this paper, the production decisions are used to determine the pollution implications. As with Mansur, I measure the estimates' standard errors by reporting the standard deviation of 200 bootstrap draws' pollution implications.

[37] These environmental effects will be overstated if permits are endogenous (a possibility discussed in section 2).

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.[38] 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.

5.3 Discussion

In this section, I discuss the environmental implications of restructuring. In particular, I determine the value of the pollution reductions that resulted from firms exercising market power in PJM. Under tradeable permit systems, production distortions *cannot* affect aggregate emissions. These systems place system-wide caps on the total amount of pollution emitted. The firms can trade permits for the right to pollute, so long as the total cap is not exceeded. Reducing demand for permits in one part of the system allows for increased pollution elsewhere. Although aggregate emissions will be unaffected, the distribution of pollution may change as a result of firms exercising market power. This emission distribution could be of potential importance, if environmental and health damages depend on spatial and temporal factors.[39]

Even if no health or environmental effects resulted from restructuring the PJM electricity market, the reduction in local pollution still had *real* economic effects. Since less pollution occurred in PJM, there are temporarily more unused permits available. Firms elsewhere in the OTC tradeable permit market, like in New York, can now purchase these permits. The total pollution level will be the same in equilibrium, however, now the firm in New York no longer needs to install expensive abatement technology as it would have done without the excess permits from PJM. In other words, society forgoes expenditures on abatement technology, reducing the overall cost associated with complying with environmental regulation.

In order to measure these cost savings, I make the following assumptions. I assume that the SO_2 and NO_x markets are efficient permit markets, implying that the permit prices accurately reflect the marginal cost to society of abating pollution. Furthermore, for the moment, I assume that permit prices are exogenous to firm behavior. If permit prices remain unchanged by firms exercising market power, then the value of emission reductions equals the permit prices times the amount of pollution that is reduced.

These assumptions lead to the following welfare implications. In the summer of 1999, I estimate that actual SO_2 emissions were 24,442 tons below my competitive estimates. This amount equals less than one percent of the total reductions mandated by the Clean Air Act Amendments. Multiplying daily SO_2 permit prices and emission reductions, and aggregating over days, yields a value of \$6.2 million. In that summer, NO_x emissions were reduced by 3637 tons, which is five percent of the system's mandated reductions and corresponds to \$6.7 million. Therefore, over a single summer, the total value of reduced pollution in PJM is \$12.9 million. Note that total welfare measures of restructuring this electricity market, as discussed and enumerated in Mansur (2003), take these welfare effects into account since marginal costs include permit prices.

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[38] This amount equals 0.9% of the 1998 PJM emissions. The 4.0% reduction in emissions in PJM is reduced to 3.1% when accounting for the nationally increased emissions that occur as a result of production inefficiencies. The NO_x emissions increased by 0.6 tons per hour. This is 1.5% of the 1998 PJM emissions. The 8.5% reduction in emissions in PJM is reduced to 7.9% 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 approximately 22% of the overall reductions.

[39] However, the issue of distributional effects is one of the optimal size of a permit system's region.

Ignoring any responsiveness of permit prices to PJM firm behavior will lead to estimates that overstate welfare losses and understate compliance cost savings. To influence permit prices, firms need to be relatively large in comparison to the permit market. PJM firms have historically emitted a substantial 68% of the NO_x emissions in the OTC market. The two firms that likely exercised market power, PECO and PPL, alone account for 14% of the OTC region's emissions. These dominant firms may be capable of affecting the NO_x permit price, depending on the price elasticity of abatement.[40] This study does not explicitly model the OTC market, as would be needed to estimate how NO_x permit prices respond to market power in the PJM electricity market.[41]

6 Conclusions

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 damages and marginal abatement costs 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.

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 pollution emissions by comparing observed behavior with estimates of competitive production choices. Between the summers of 1998 and

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[40] 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.

[41] A simple calculation may help determine the likely magnitude of these effects. A publicly available model of the SO_2 market can test whether SO_2 permits are sensitive to production distortions. The Tracking and Analysis Framework, TAF, model can be used to estimate the price elasticity of supply of abatement technology (see Burtraw *et al.,* 1998). 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. Using the TAF model, I estimate a price elasticity of supply of 0.1. This implies that a four percent annual reduction in PJM emissions would reduce permit prices proportionally by four percent (since PJM is only 10% of the market). 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.

If the OTC market has a similar price elasticity of abatement, NO_x prices would have fallen by a *third*. However, over the summer of 1999, the observed NO_x prices fell by even more: from over \$5000/ton to approximately \$1000/ton. A confounding explanation for the permit price reduction is that market expectations of the amounts of installed abatement technology and fuel substitution rose.

In the case of perfectly elastic marginal damages and a cap set optimally assuming a competitive product market, 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 ten percent 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.

1999, actual SO_2 emissions fell 13.9%, NO_x emissions fell 20.8%, and CO_2 fell 6.8%. Using a model of competitive behavior, I account for approximately 70% of the SO_2 emission reductions typically attributed to new environmental regulation. The remaining 30% may be ascribed to market imperfections. For the other pollutants, this competitive model suggests that electricity market imperfections accounted for even more of the actual reductions (42% for NO_x and 59% for CO_2). Reduced emissions in PJM caused the compliance costs of incentive-based environmental regulation to fall by $13 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.

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Figures and Tables

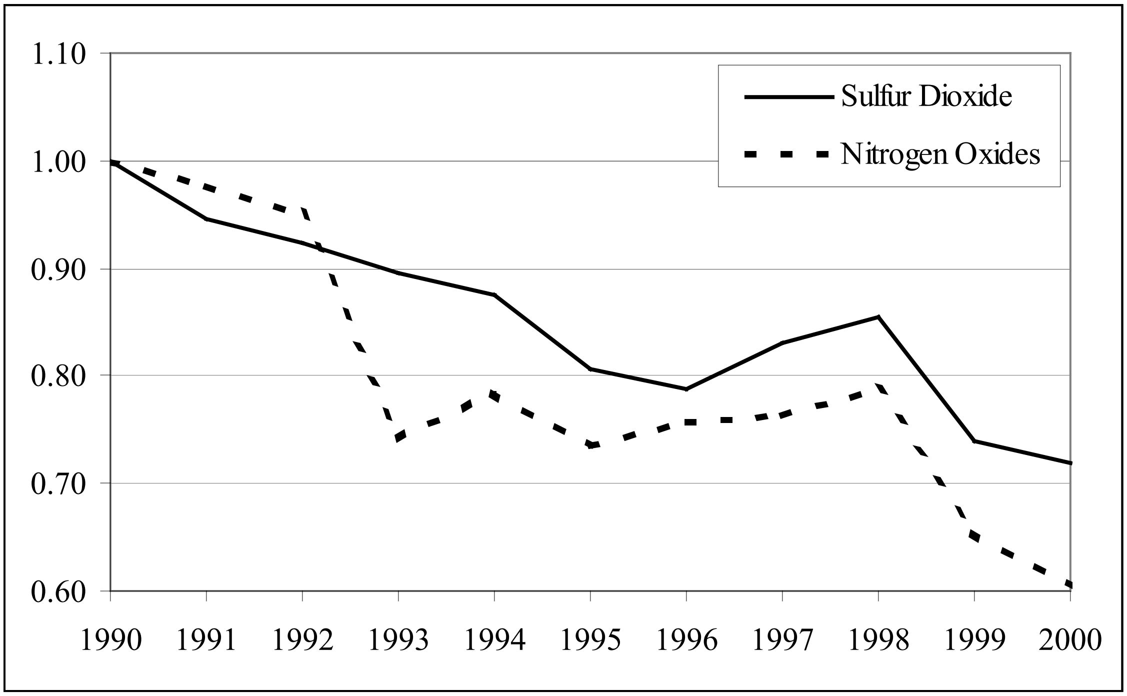

Figure 1: Annual SO_2 and NO_x Emissions from Electricity Generation in the Mid-Atlantic (Pennsylvania, New Jersey, Maryland, and Delaware). Emissions are normalized to 1990 levels: 1,686,000 SO_2 tons and 544,000 NO_x tons.

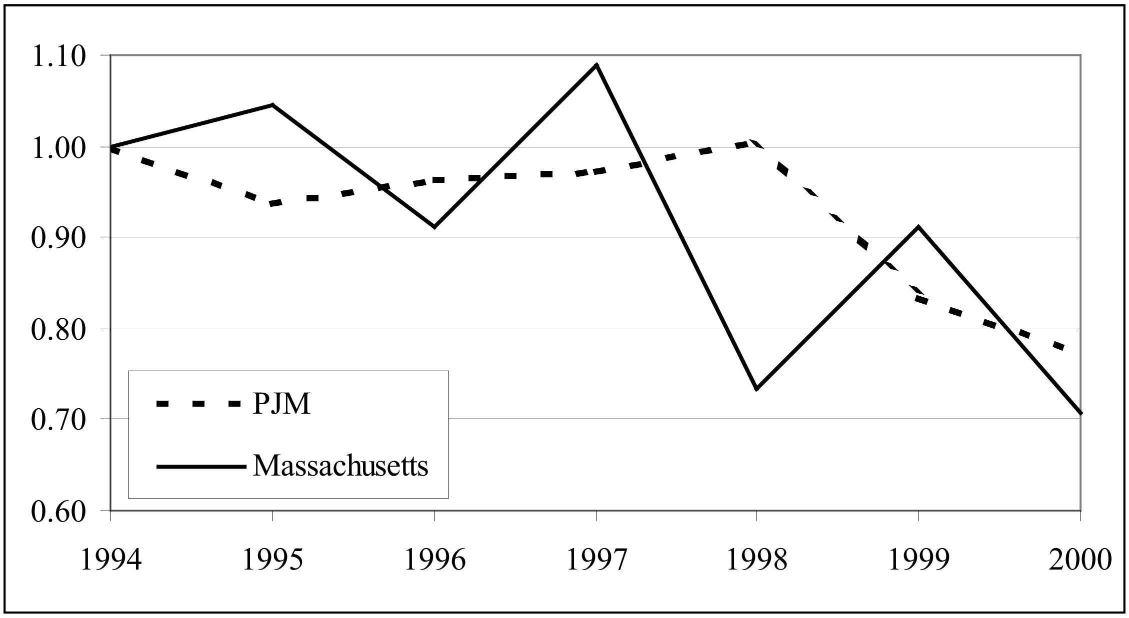

Figure 2: Annual NO_x Emissions from Electricity Generation in Massachusetts and in the Mid-Atlantic. Emissions are normalized to 1994 levels: 45,000 tons in Massachusetts and 427,000 tons in the Mid-Atlantic.

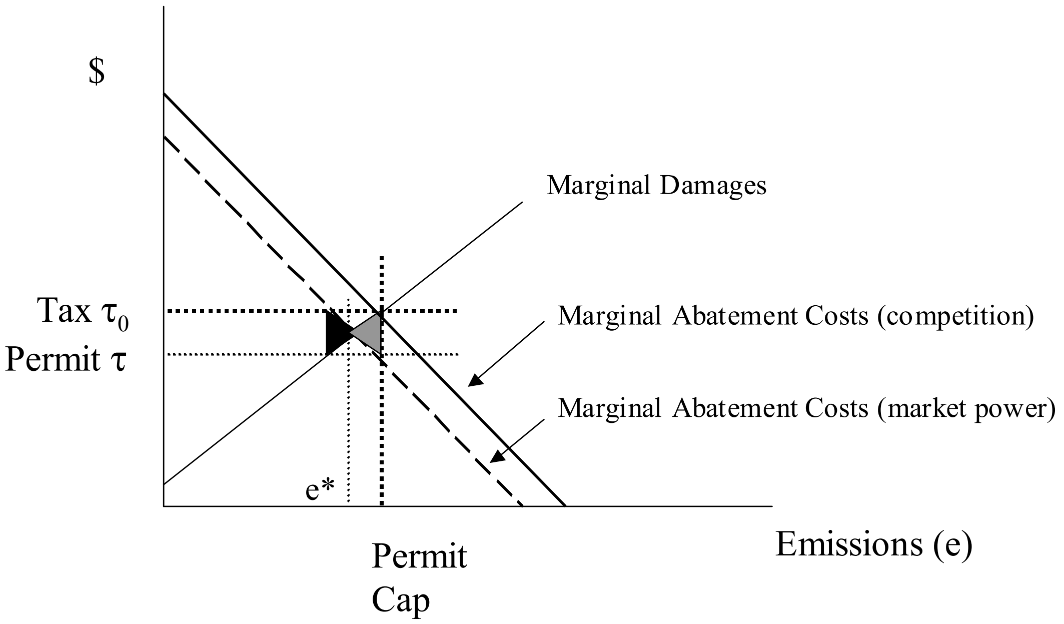

Figure 3: Emissions Implications of Imperfect Product Market Under Pollution Tax versus Tradeable Permit System: Case A of a polluting dominant firm.

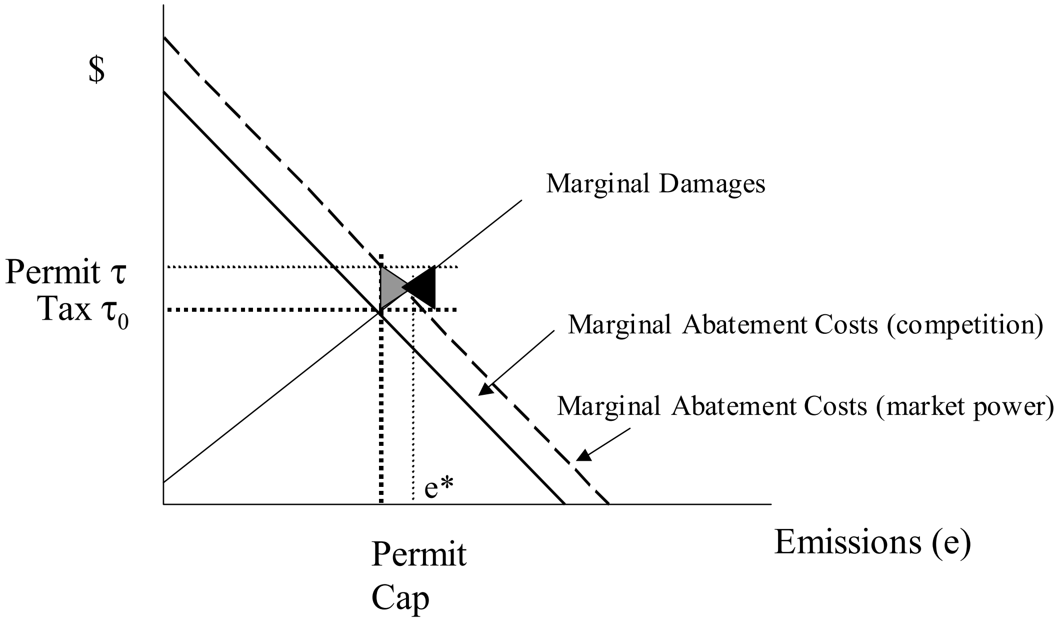

Figure 4: Emissions Implications of Imperfect Product Market Under Pollution Tax versus Tradeable Permit System: Case B of a polluting competitive fringe.

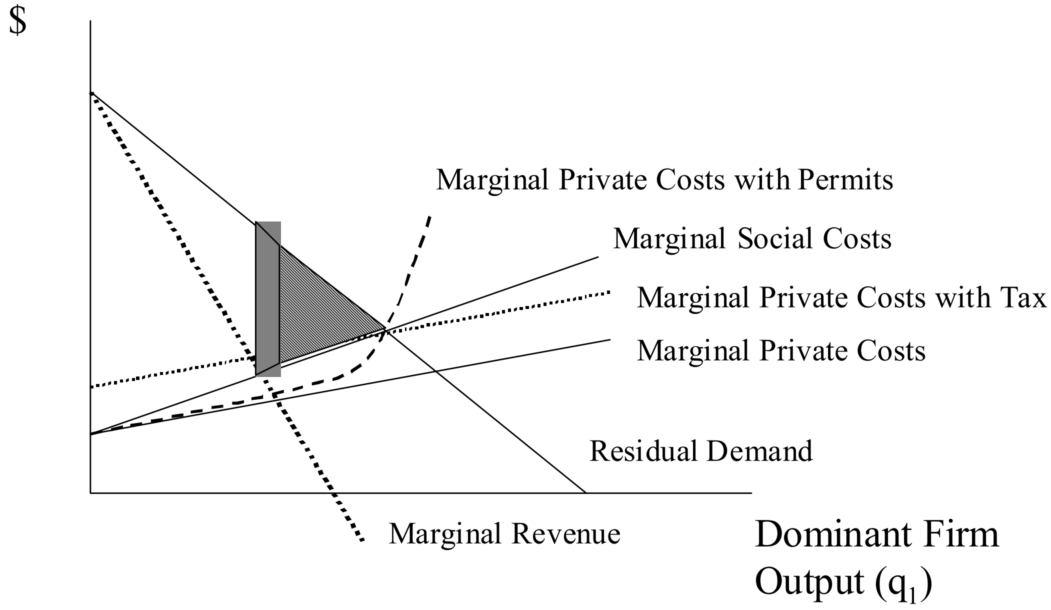

Figure 5: Production Implications of Imperfect Product Market Under Pollution Tax versus Tradeable Permit System: Case A of a polluting dominant firm.

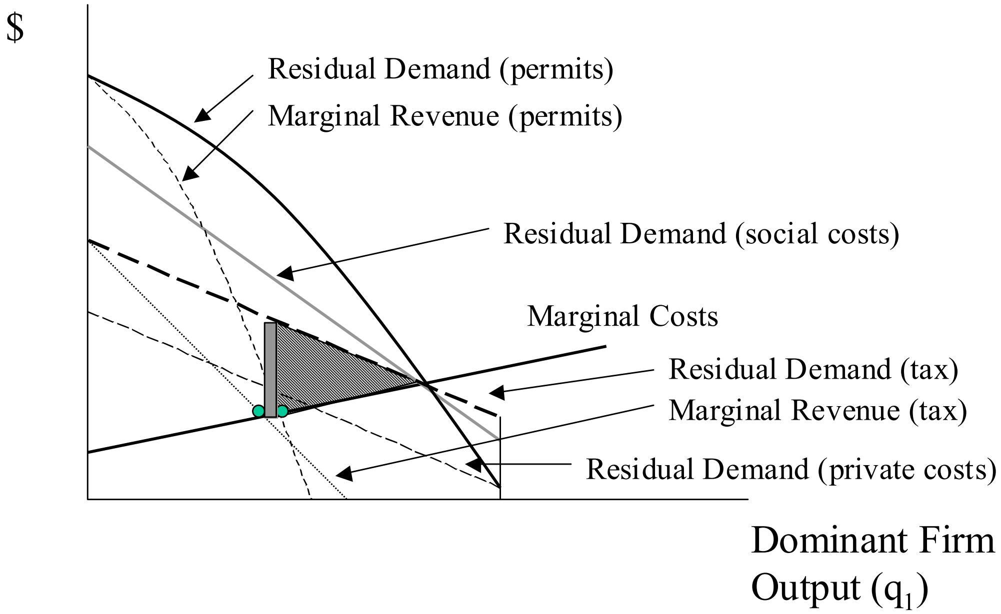

Figure 6: Production Implications of Imperfect Product Market Under Pollution Tax versus Tradeable Permit System: Case B of a polluting competitive fringe.

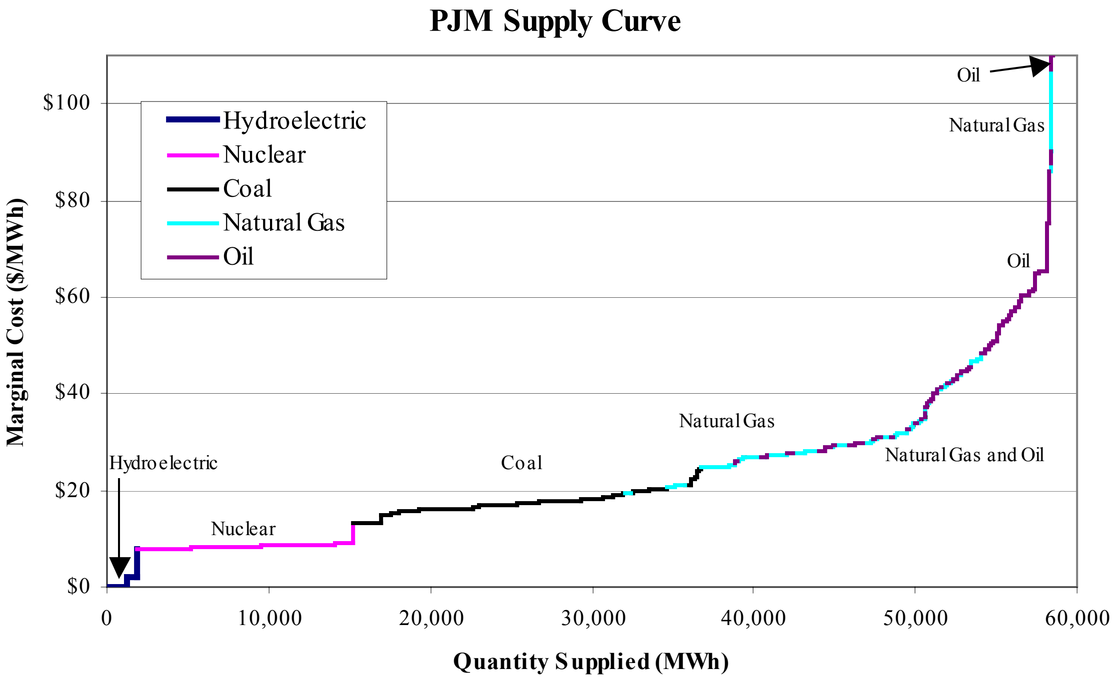

Figure 7: PJM Supply Curve.

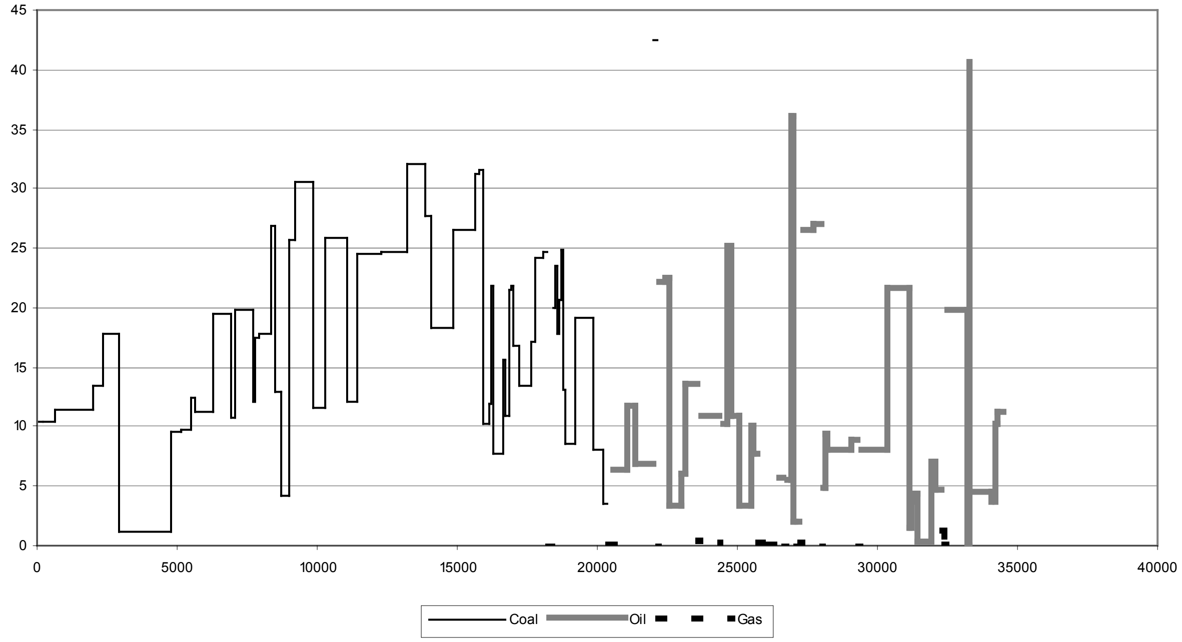

Figure 8: SO_2 Emission Rates (lbs/MWh) Along Fossil-Fuel Supply Curve (coal, oil and gas only).

Table 1

PJM Firm Characteristics

Panel A: Generation Capacity by Firm and Fuel Type in 1999[a]

Firm	Coal	Oil	Gas	Water	Nuclear	Total
Public Service Electric[b]	1,607	1,842	3,311	-	3,510	10,269
PECO	895	2,476	311	1,274	4,534	9,490
GPU, Inc.	5,459	1,816	203	454	1,513	9,445
PP&L Inc.	3,923	478	1,701	148	2,304	8,554
Potomac Electric Power	3,082	2,549	876	-	-	6,507
Baltimore Gas & Electric	2,265	925	755	-	1,829	5,773
Delmarva Power & Light	1,259	888	311	-	-	2,458
Atlantic City Electric	391	436	482	-	-	1,309
Other[c]	2,087	353	-	439	-	2,880
Total	20,967	11,762	7,949	2,316	13,690	56,685
Market Share	37%	21%	14%	4%	24%	

Panel B: Market Shares of Capacity, Generation, and Demand by Firm in Summer of 1999[d]

Firm	Capacity	Generation[e]	Peak Generation[f]	Demand Served[g]
Public Service Electric	18.1%	14.0%	16.8%	17.3%
PECO	16.7%	17.8%	19.9%	8.8%
GPU, Inc.	16.7%	19.8%	16.4%	14.7%
PP&L Inc.	15.1%	15.9%	16.1%	9.9%
Potomac Electric Power	11.5%	10.1%	10.2%	10.4%
Baltimore Gas & Electric	10.2%	12.5%	11.3%	11.2%
Delmarva Power & Light	4.3%	3.2%	3.3%	6.0%
Atlantic City Electric	2.3%	1.1%	1.3%	4.3%
Other	5.1%	5.6%	4.7%	17.4%

Notes:

a) Capacity, in megawatts (MW), is listed by primary fuel type used in each generating unit at a power plant, as determined by the EIA. Coal includes anthracite, bituminous coal, and petroleum coke. Oil includes No. 2, 4, and 6 fuel oil and kerosene. The other categories are natural gas, hydroelectric, and nuclear. Source: Energy Information Administration (EIA), Form 860 (1999).

b) In 1999, the GPU parent company owned Jersey Central, GPU Nuclear, Metropolitan Edison and Pennsylvania Electric.

c) "Other" includes the following utilities: Safe Harbor Water Power, Easton Utilities, UGI Development, Allegheny Electric Coop, A&N Electric Coop, and cities of Berlin, Dover, Lewes, Seaford, and Vineland. Also I include Edison, which purchased Homer City from GPU in March 1999.

d) Summer is defined as April 1 to September 30.

e) Source: EIA Form 759, 1999. I aggregate monthly generation for April through September.

f) Source: EPA Continuous Emissions Monitoring System, 1999. Peak generation share is share during hours with demand above 40,000 MW.

g) Source: www.oca.state.pa.us. Demand served is share summer peak demand less direct access customers. On July 6, 1999, the system-wide demand reached a peak of 51,700 MW. Source: EIA Form 861, 1999. In 1999, many Pennsylvania customers switched to alternative providers, leaving GPU (3.4 percent of total market demand), PECO (5.6 percent), and PP&L (2.5 percent). "Other" demand includes direct access customers.

Table 2

Summary Statistics on Emission Rates (lbs. per MWh) by Fuel

Fuel Type	Emission	Obs.	Mean	Std. Dev.	Min	Max
Coal	SO_2	60	20.3	9.2	1.2	44.6
	NO_x	60	5.8	2.9	2.6	18.9
	CO_2	60	2197.9	307.7	1797.9	3382.6
Gas	SO_2	16	0.0	0.0	0.0	0.0
	NO_x	16	0.9	0.8	0.2	3.1
	CO_2	16	1423.3	216.1	1137.0	1902.7
Oil	SO_2	48	7.0	9.5	0.0	47.8
	NO_x	48	3.5	2.7	0.2	16.3
	CO_2	48	1789.5	468.2	383.8	2990.1
All	SO_2	124	12.5	11.7	0.0	47.8
	NO_x	124	4.3	3.1	0.2	18.9
	CO_2	124	1939.9	459.2	383.8	3382.6

Notes: Data source is EPA CEMS for the summer of 1998.

Table 3

PJM Market Summary Statistics During Summers of 1998 and 1999

Panel A: Summer of 1998

Variable	Units	Mean	Std. Dev.	Min	Max
Quantity demanded hourly[a]	MWh	29,650	6,482	17,461	48,469
Price of:					
Electricity[a]	\$/MWh	\$26.04	\$43.46	\$0.00	\$999.00
Electricity (Q weighted)	\$/MWh	\$29.82	\$53.45	\$0.00	\$999.00
Natural Gas[b]	\$/mmbtu	\$2.33	\$0.25	\$1.80	\$2.81
Oil[c]	\$/Barrel	\$16.30	\$1.36	\$13.99	\$19.17
SO_2 Permit[d]	\$/Ton	\$172.44	\$24.40	\$136.50	\$198.50
NO_x Permit[e]	\$/Ton	N/A	N/A	N/A	N/A
Marginal costs: [f]					
Coal Units	\$/MWh	\$19.70	\$5.17	\$13.15	\$37.51
Natural Gas Units	\$/MWh	\$36.75	\$11.73	\$17.23	\$115.81
Oil Units	\$/MWh	\$46.94	\$11.54	\$22.79	\$113.49

Panel B: Summer of 1999

Variable	Units	Mean	Std. Dev.	Min	Max
Quantity demanded (hourly)	MWh	30,459	7,156	17,700	51,714
Price of:					
Electricity	\$/MWh	\$37.97	\$100.99	\$.00	\$999.00
Electricity (Q weighted)	\$/MWh	\$47.92	\$47.92	\$.00	\$999.00
Natural Gas	\$/mmbtu	\$2.60	\$0.27	\$2.08	\$3.28
Oil	\$/Barrel	\$20.56	\$2.91	\$16.55	\$26.04
SO_2 Permit	\$/Ton	\$202.71	\$9.23	\$188.00	\$211.50
NO_x Permit	\$/Ton	\$2,406	\$1,756	\$0	\$5,244
Marginal cost of:					
Coal Units	\$/MWh	\$24.16	\$6.58	\$13.18	\$50.92
Natural Gas Units	\$/MWh	\$42.08	\$14.24	\$19.44	\$138.01
Oil Units	\$/MWh	\$59.56	\$15.68	\$25.25	\$158.58

Notes:

a) Electricity price and quantity data from PJM Interconnection: www.pjm.com
b) Natural gas prices at Transco Zone 6 non-New York from Natural Gas Intelligence.
c) No. 2 heating oil sold at New York Harbor from the U.S. Energy Information Agency.
d) EPA reports monthly average trades of SO_2 permits at two brokerage firms (Cantor Fitzgerald and Fieldston).
e) NO_x costs are from Cantor Fitzgerald's monthly price index.
f) In addition to the above input costs, data from the PROSYM model (Kahn 2000) are used to determine marginal costs.

Table 4

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

Panel A: Fringe Producers

Fuel Type	Summer of 1998	Summer of 1999	Change
Coal (High Emis Rate)	0.588	0.493	-0.095
Coal (Low Emis Rate)	0.803	0.831	0.028
Gas	0.380	0.592	0.212
Oil (High Emis Rate)	0.099	0.100	0.001
Oil (Low Emis Rate)	0.276	0.570	0.294
Total	0.441	0.442	0.001

Panel B: PECO

Fuel Type	Summer of 1998	Summer of 1999	Change
Coal (High Emis Rate)	0.003	0.002	-0.001
Coal (Low Emis Rate)	0.745	0.658	-0.086
Gas	0.000	0.170	0.170
Oil (High Emis Rate)	0.116	0.067	-0.049
Oil (Low Emis Rate)	0.062	0.625	0.564
Total	0.230	0.211	-0.019

Panel C: PPL

Fuel Type	Summer of 1998	Summer of 1999	Change
Coal (High Emis Rate)	0.657	0.402	-0.255
Coal (Low Emis Rate)	0.395	0.721	0.326
Gas	0.017	0.138	0.122
Oil (High Emis Rate)	0.259	0.139	-0.119
Oil (Low Emis Rate)	0.092	0.474	0.382
Total	0.546	0.442	-0.104

* MW Change = average change in MWh per hour.
Source: EPA CEMS. Units have “high” emissions rates if the rate is above the median of SO2 pounds per MWh by fuel type in the summer of 1998: 21.8 for coal and 4.4 for oil.

Table 5

Summer Hourly Average Emissions in PJM

	Summer of 1998	Summer of 1999	Change	Percent Change
SO_2 Emissions				
Actual in PJM	139.0	119.8	-19.3	-13.9%
Estimates in PJM	134.8	121.5	-13.3	-9.9%
Difference in PJM	4.3	-1.7	-6.0	
	(0.6)	(0.3)	(0.7)	
Percent difference	3.1%	-1.4%	30.9%	
NO_x Emissions				
Actual in PJM	38.6	30.6	-8.0	-20.8%
Estimates in PJM	37.7	33.0	-4.6	-12.3%
Difference in PJM	0.9	-2.4	-3.4	
	(0.2)	(0.1)	(0.2)	
Percent difference	2.4%	-8.0%	42.1%	
CO_2 Emissions				
Actual in PJM	16,401.7	15,279.1	-1122.6	-6.8%
Estimates in PJM	16,488.9	16,022.6	-466.3	-2.8%
Difference in PJM	-87.1	-743.5	-656.4	
	(75.5)	(42.8)	(86.8)	
Percent difference	-0.5%	-4.9%	58.5%	

* Standard errors in parentheses. I assume actual emissions are measured without error and I determine the standard errors for my competitive model estimates bootstrap draws. In calculating the standard errors on the changes in costs over time, I assume that the errors are uncorrelated across years.