Emissions Trading, Electricity Industry Restructuring, and Investment in Pollution Abatement

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The NOx State Implementation Plan Call was designed to facilitate cost effective reductions of nitrogen oxides emissions from large stationary sources (primarily electricity generators) through the introduction of an emissions trading program. I investigate the relationship between economic regulation and firms' long-run response to the incentives created by this emissions trading program. I estimate a discrete choice model of the firm's compliance decision, controlling for unit-level variation in compliance costs and using exogenous variation in state-level electricity industry restructuring activity to identify an effect of electricity market regulation on generators' environmental compliance strategy choices. I present evidence that differences in economic regulation across states have resulted in a disproportionate amount of the mandated emissions reductions occurring in more regulated electricity markets. Unfortunately, these are the areas least in need of pollution control.

Emissions trading programs have become the preferred alternative to more traditional, prescriptive approaches to regulating point source emissions in the United States. Currently, all of the major emissions markets are "emissions based": a permit can be used to offset a unit of pollution, regardless of where the unit is emitted. This presumes that the health and environmental damages resulting from the permitted emissions are independent of where in the regulated region the emissions occur. A growing body of scientific evidence indicates that this assumption is inappropriate in the case of nitrogen oxides and mercury, two pollutants that have recently been regulated under "cap and trade" (CAT) programs (Hubbard Brook Research Foundation, Mauzerall et al..).

The vast majority of the emissions currently regulated under CAT programs come from electricity generators.[2] Asymmetries in state electricity industry regulations have the potential to interfere with permit markets' ability to allocate emissions reductions efficiently. This research addresses two questions: did economic regulation in electricity markets affect how coal plant managers chose to comply with a regional NOx emissions trading program, and did inter-state variation in electricity industry regulation exacerbate the inefficiencies associated with an emissions based permit market design that fails to reflect spatial variation in marginal damages from pollution.[3]

The NOx State Implementation Plan (SIP) Call was designed to facilitate cost effective emissions reductions of nitrogen oxides (NOx) from large stationary sources through the introduction of an emissions trading program. In the period between when the SIP Call was upheld by the US Court of Appeals (March 2000) and the deadline for full compliance (May 2004), firms had to make costly decisions about how to comply with this new environmental regulation.

NOx emissions contribute to the formation of ozone.[4] High ambient ozone concentrations have been linked to increased mortality, increased hospitalization for respiratory ailments, irreversible changes in lung capacity, reductions in agricultural yields and increased susceptibility of plants to disease and pests. The NOx SIP Call was designed to help northeastern states come into attainment with the Federal 1-hour and 8-hour federal ozone standards of 120 ppb and 80 ppb respectively.

Ground-level ozone in the eastern United States has a lifetime of about 2 days (Fiore et al..). Surface ozone concentrations are a function of both in situ ozone production and pollutant transport; both are significantly affected by prevailing meteorological conditions. Figure 1 illustrates how, during high ozone episodes, significant portions of the northeast can fail to attain the Federal standard(OTAG). The dashed line outlines the 19 state region regulated under the NOx SIP Call. The arrows represent transport wind vectors. Many states that are in attainment with Federal ozone standards were included in the SIP Call program because their NOx emissions contribute to the non-attainment problems of downwind states. Although some states contribute significantly more than others to the non-attainment problem, the NOx SIP Call applies uniform stringency across all 19 states. The states that have been identified as relatively "high damage" in terms of ozone exposure (Krupnick, Mauzerall) are also states that have restructured (and thus reduced the degree of economic regulation in) their electricity industries.

The NOx SIP Call mandated a dramatic reduction in average NOx emissions rates. Major changes have been underway to make sure that coal plants regulated under the program achieved compliance by the deadline.[5] To comply with the regulation, firms can do one or more of the following: purchase permits to offset emissions exceeding their allocation, install NOx controls to reduce emissions or reduce production at dirtier plants during ozone season.

There are several reasons why coal plants operating in regulated electricity markets might have been more likely to adopt more capital intensive compliance strategies (such as major pollution control technology retrofits), as compared to similar plants operating in restructured electricity markets.[6] Regulators in unrestructured markets have authorized rate increases and cost recovery clauses to allow utilities to recover their investments in NOx control technology retrofits (Business Wire, Charleston Gazette, Megawatt Daily, PR Newswire, Southeast Power Report, Platts Utility and Environment Report 1999, Platts Utility and Environment Report 2000, Platts Utility and Environment Report 2002, Platts Utility and Environment Report 2003). In restructured markets, plant owners must recover their environmental compliance costs in the wholesale spot market, or in long term supply contracts that are based on expected spot prices. Consequently, firms cannot be certain that they will be able to recover large capital investments in abatement technology retrofits, nor can they appeal to public interest arguments (such as cleaner air or construction job creation) to justify receiving higher prices for their electricity. Merchant plants and other generators that rely heavily on the wholesale electricity market to recoup their pollution control investments will be particularly reluctant to adopt a compliance strategy that involves large investments in abatement equipment. Unlike utilities, many merchant plants had low credit ratings in the years leading up to the SIP Call (Senate Committee on Energy and Natural Resources). Highly leveraged plants would have more difficulties securing financing for major pollution control retrofits, which can cost over $50M per unit.

The objective of this paper is to estimate a discrete choice model of firms' compliance decision in order to test the hypothesis that the type of electricity market in which a coal plant is operating has significantly affected the environmental compliance strategy choice. Using unique data on unit-level compliance costs, a conditional logit model and a random parameter logit model of the compliance choice are estimated. Results indicate that electricity market regulation significantly affected how coal plants made their environmental compliance choices.

For decades, economists have studied the relationship between economic regulation and the investment decisions of regulated firms. In their seminal paper, Averch and Johnson demonstrate how rate of return regulation[7] provides firms with an incentive to overintensively substitute capital for other production factors. A large share of the regulation literature has been devoted to extending and testing Averch and Johnson's work. Empirical verification of this effect in the context of the electricity industry has been attempted several times with mixed results: Courville, Spann, and Hayashi and Trapani all find support for the Averch-Johnson effect in the U.S. electricity industry, whereas Boyes does not.

With the creation of the Acid Rain Program (ARP) in 1990, researchers became interested in the effect of economic regulation on electricity generators' compliance choice between SO_2 pollution permits, fuel switching and a more capital intensive compliance alternative- installing scrubbers. Using single agent models of the compliance decision, Bohi and Burtraw conclude that the compliance choice will be distorted if variable and compliance costs are treated asymmetrically in rate base calculations, while Fullerton et al. show how state Public Utility Commission (PUC) rules that distort investment incentives could more than double the cost of compliance. Other researchers have used partial equilibrium models of the permit market to analyze the effect of PUC regulation on permit market outcomes (Coggins and Smith, Cronshaw and Kruse, Winebrake et al.). These studies predict that the performance of permit markets will depend importantly on how rate of return regulation treats compliance costs, and that rate of return regulation that favors capital intensive compliance options will limit permit market efficiency.

Once the Acid Rain Program came into effect in 1995, economists could empirically analyze how generators respond to the incentives created by this emissions trading program. In general, results have been mixed. Some studies find little or no evidence that PUC regulations biased generators in favor of installing scrubbers (Bailey, Keohane). Other researchers do find that cost recovery regulations significantly discouraged participation in the permit market (Arimura, Rose); this effect is found to be particularly strong in states where there was uncertainty about the extent to which generators would pe permitted to recover costs of purchasing permits, and in states with deposits of high sulfur coal.

This paper differs from previous studies of the relationship between economic regulation and environmental compliance decision in two important ways. First, to my knowledge, this is the first paper to use inter-state variation in electricity industry restructuring activity to identify an effect of electricity market regulation on generators' choice of compliance strategy. Because the ARP began before electricity restructuring got underway, all firms made their compliance choices in a regulated electricity industry environment; variation in economic regulation across electricity markets was limited to differences in PUC cost recovery rules and coal protection measures.[8]

The piecemeal, state-by-state approach to electricity industry restructuring in the US has since resulted in considerable inter-state variation in electricity market structure which I can exploit in the interest of identifying an effect of electricity market regulation on firms' choice of compliance strategy. Uncertainty with regards to the status of restructuring in the states affected by the SIP Call had been largely resolved by March of 2000 when the courts upheld the NOx SIP Call and the terms of compliance were finally established. Between 1994 and 1998, all 19 states that were ultimately included in the NOx SIP Call held hearings to consider restructuring their respective electricity industries. By 1999, restructuring bills had been passed in 12 of these states and D.C. By 2000, the remaining 7 states had all resolved not to move forward with electricity restructuring (EIA).[9]

The second factor that distinguishes this work from earlier papers looking at compliance decisions under the ARP has to do with the regional nature of the ozone non-attainment problem. Whereas the documented inefficiencies resulting from the regulation of compliance cost recovery under the ARP were limited to regulated firms' overinvestment in pollution control (i.e. the aggregate emissions reduction target is not achieved at least cost), in the case of the SIP Call NOx market, additional allocative inefficiencies arise if the firms who are biased towards investing in capital intensive pollution controls are located in areas where the marginal health benefits from pollution reduction are relatively low.

Health and environmental consequences could be significant if asymmetries in regulatory incentives across electricity markets have resulted in a disproportionate amount of the mandated NOx emissions reductions occurring in regulated electricity markets where ozone non-attainment is less of a problem. A recent study finds that shifting 11 tons of NOx emissions per day from a relatively "low damage" location (North Carolina, a state that has not restructured its electricity market) to a "high damage" area (Maryland, a state that restructured its electricity industry) over a ten day period could result in the loss of approximately one human life (Mauzerall et al.). An average unit in the sample emitted 15 tons of NOx per day in 1999; retrofitting a *single unit* with the most capital intensive NOx control option results in daily reductions of 12 tons on average.

In the next section, I present a simple theoretical model of the compliance decision. I then describe the data and the empirical framework for assessing the relationship between economic regulation in the electricity market and firms' environmental compliance decisions. Section 5 summarizes the results. Section 6 concludes.

The firm's compliance choice

This section describes a simple model of a plant manager's choice between J mutually exclusive approaches to complying with the NOx SIP Call. The purpose of specifying the model is to provide a framework to test the hypothesis that the structure of the electricity market in which a unit is operating significantly affects a firm's choice of compliance strategy.

Two factors that are likely to figure significantly into a plant manager's compliance decision are the up-front capital costs associated with retrofitting a plant with a particular NOx control technology, and the anticipated variable compliance costs (i.e. the costs of operating the control technology plus the cost of purchasing required permits per kWh of electricity generated). The capital costs, variable operating costs and emissions reduction efficiencies associated with different compliance alternatives vary significantly, both across control technologies and across generating units with different technical characteristics.

Let J_n represent the compliance strategy choice set for the nth firm. Using detailed unit-level data, estimates of capital costs and variable compliance costs can be generated for each of the $\{1..J_n\}$ compliance alternatives, for all N firms.[10] Figure 2 is a graphical representation of the compliance choice faced by a unit drawn randomly from the sample. Each of the nine points plotted in fixed cost ($/kW)/variable cost (cents/kWh) space corresponds to a different compliance technology or "strategy". Variable costs include the costs of operating the control technology, plus the costs of purchasing permits to offset emissions.[11]

A compliance-cost minimizing plant manager will want to choose a compliance strategy corresponding to one of the points lying along the lower "compliance frontier" that is approximated by the broken line in figure 2. Points lying to the right of this line are not cost minimizing.[12] Points to the left would result in non-compliance (the plant would not be purchasing enough permits to offset its emissions). Larger emissions reductions are associated with more capital intensive compliance strategies along the steeper portion of the compliance frontier. Retrofitting a unit with Selective Catalytic Reduction (SCR) technology can reduce emissions by up to 90%. NOx emissions rates can be reduced by as much as 35% through the adoption of Selective Non-Catalytic Reduction Technology (SNCR) (EPA, 2003). Pre-combustion control technologies such as low NOx burners or combustion modifications can result in emissions rate reductions ranging from 15-50%, depending on the boiler (EPA, 1998, EPA, 1999, EPRI).

Let the fixed capital investment associated with retrofitting unit n with NOx control technology i be K_{ni}; let v_{ni} represent the variable operating costs, (including the costs of purchasing permits to offset emissions) that the manager of the nth unit expects to incur having retrofitted his unit with technology i. I define a compliance frontier function $K_n(v_{ni})$. I assume: $K_n'(v_{ni}) < 0, K_n''(v_{ni}) \geq 0$ because the compliance frontiers of all the units in the sample are negatively sloped and convex to the origin.

The location of each point on a generator's compliance cost frontier is determined by pre-retrofit characteristics of the unit (such as nameplate capacity, firing type, furnace dimensions, etc.), the expected permit price and expected future production levels. For the purpose of modeling the compliance decision, I assume that the plant manager can choose any point on its continuous, convex compliance frontier $K_n(v_{ni})$. In the empirical model, the decision is represented more realistically as a choice among discrete points that define the frontier

I assume that plant managers minimize the present value of expected compliance costs subject to the constraint that the chosen compliance strategy must lie on the least-cost compliance frontier $K_n(v_{ni})$. Let C_{ni} represent the compliance costs that the manager of the nth unit expects to incur, having adopted compliance strategy i. I assume that the variable and capital compliance cost components enter additively into the compliance cost function of each firm:

$$\min_{v_{ni}} C_{ni} = \beta_n^v \left(\int_{t=0}^{T_n} \{V_{nit} q_{nt} + \tau_t (m_{ni} q_{nt} - A_{nt})\} e^{-r_i t} dt \right) + \beta_n^K s_n K_n(v_{ni}), \quad (1)$$

where $v_{ni} = V_{ni} + \tau m_{ni}$. The manager expects to produce q_{nt} kWh of electricity in time t.[13] V_{nit} represents the anticipated variable costs of producing electricity while operating control technology i, net of permit purchases. I assume that all firms are price takers in the permit market; the permit price τ is assumed to be exogenous to the firm's compliance decision. The unit's permit allocation is A_{nt}; the post-retrofit emissions rate is m_{ni}. The total capital cost is equal to the installation cost

K_{ni}, multiplied by the interest cost of holding capital s_n. The coefficients β^v and β^K indicate how the firm weights capital costs and variable operating costs respectively in the compliance decision.

When comparing the costs and benefits across compliance alternatives, any terms that do not differ across alternatives will not come to bear on the compliance decision. I assume that the manager chooses v_{ni} to minimize the following levelized annual compliance cost function (substituting for the constraint):

$$\min_{v_{ni}} lac_{ni} = \beta_n^v v_{ni} Q_n + \beta_n^K s_n l_n K_n(v_{ni}), \tag{2}$$

where

$$l_n = \frac{r_n(1+r_n)^{T_n}}{(1+r_n)^{T_n}-1}. \tag{3}$$

The Q_n denotes the quantity of electricity (in kWh) that the manager expects the nth unit to produce in an average ozone season.[13] The levelized annual cost factor l_n is a function of the firm's discount rate (r_n) and investment time horizon T_n.

Minimization of the above constrained optimization problem implies :

$$K_n'(v_{ni}) = -\frac{\beta_n^v Q_n}{\beta_n^K s_n l_n} \tag{4}$$

The manager will want to choose the point on the compliance curve where the (negative) slope is equal to the ratio of the cost of an incremental change in variable compliance costs and the cost of an incremental change in fixed compliance costs. A relative increase in $\theta_n^v(\theta_n^K)$ will cause the firm to choose a point on the compliance frontier where the slope is more (less) steep. Similarly, an increase in the cost of capital or levelized cost factor will, ceteris paribus, be associated with a less capital intensive compliance choice.

To the extent that regulation in the electricity market significantly affects the capital and variable compliance cost coefficients, plants with identical compliance choice frontiers will make different compliance choices in different electricity market environments.

Compliance Choices in Unrestructured Markets

In unrestructured electricity markets, the cost coefficients used by regulated firms could have been significantly influenced by PUC regulations governing capital and variable cost recovery. There are a variety of ways in which regulated utilities can seek to recover their fixed and variable environmental compliance costs. Rate base adjustments have been requested in order to recover the costs of capital required to make investments in NOx control technology, to recover compliance related increases in operating expenses, and to reasonably compensate shareholders for exposure to risk by allowing them to earn a return on equity. Companies have also sought approval for various kinds of rate adjustment "trackers" to allow them to recover costs associated with purchasing NOx permits and construction work in progress.[14]

A review of the industry press indicates that regulators have authorized rate increases and various cost recovery trackers to allow utilities to recover investments in NOx control technologies in the seven states that are regulated under the SIP Call and that have not enacted electricity industry restructuring (Business Wire, Charleston Gazette, Megawatt Daily, PR Newswire, Southeast Power Report, Platts Utility and Environment Report 1999, Platts Utility and Environment Report 2000, Platts Utility and Environment Report 2002, Platts Utility and Environment Report 2003). Anecdotal evidence suggests that regulated utilities have been permitted to earn a positive rate of return on their investments in abatement equipment and have typically been permitted to recover a significant portion of variable compliance costs.

In some states, legislation has been passed to make it easier for regulated utilities to recover their environmental compliance costs. [15]

One approach to modeling the compliance decision in regulated markets assumes that managers of regulated plants maximize shareholder profits subject to the constraint that they remain in compliance with environmental regulations (Fullerton et al.). In this model, β_n^V represents the portion of variable compliance costs (not including the opportunity costs of using the permits it has been allocated) that the utility is *not* permitted to pass on to its ratepayers through rate increases; [16] β_n^K represents the portion of capital investments in NOx control technology that is not included in the rate base. If the regulated rate of return on capital exceeds the cost of capital, the regulated firm will be biased towards capital intensive compliance options. Alternatively, the compliance choice in regulated market can be modeled as a risk (versus cost) minimizing choice (Rose). In this model, uncertainties regarding how PUCs will treat future permit purchases could bias firms towards cleaner, more capital intensive options (i.e. $\beta^K < \beta^v$)(Bailey, Burtraw). Finally, several researchers found that state environmental regulations and coal protection policies were an important factor in ARP compliance decisions (Arimura, Coggins and Swinton, Keohane). If local environmental quality or construction job creation concerns were a factor in PUCs' rulings regarding cost recovery, costs associated with SCR technology (the compliance alternative that delivers the most significant emissions reductions and requires more substantial retrofits) may be treated more favorably in rate base calculations.

The Compliance Decision in Restructured Markets

Restructured electricity markets consist of buyers and sellers whose bids determine a wholesale market price. Because the costs of storing electricity are prohibitively high, supply and demand for electricity are balanced in real time. Trading occurs via bilateral contracts, in day ahead markets and through spot markets or "real time" transactions. Generators submit bids (prices and quantities) that they are willing to produce; Independent system Operators (ISOs) combine these bids into an aggregate supply curves and intersect this curve with demand. Energy and reserve markets clear intermittently throughout the day. Units are dispatched so as to meet load at least cost, subject to system security, stability and transmission constraints.

Three ISOs operate centralized power markets in the region regulated by the SIP Call[17], all operate as uniform price auctions. For generators operating in these regions, the extent to which the electricity price they receive will increase to reflect or track their environmental compliance costs is determined not by a regulator, but by the wholesale electricity market. The effect of the manager's choice of v_{ni} on the average wholesale price she receives per kWh $\bar{P}_n$ will depend on how the increase in marginal operating costs affects the position of the nth unit in the order of dispatch.

Whereas firms in more regulated markets can pass a significant portion of variable and capital compliance costs through to electricity customers, firms in restructured electricity markets must recover capital and variable compliance costs in the wholesale spot market or in long term supply contracts that are based on expected spot prices. This suggests that firms in restructured markets will be more cost sensitive when making their compliance decision (i.e. the β^K and β^v coefficients will be larger in absolute value), as compared to firms facing similar compliance frontiers who are subject to rate of return regulation.

In the years leading up to the NOx SIP Call, credit rating changes in the energy sector were overwhelmingly negative.[18] This trend has affected generators operating in restructured industries disproportionately. While the credit ratings of merchant energy companies and some companies with a significant degree of non-core activities have fallen drastically, most regulated utilities have been affected to a far lesser extent

(Business Wire, 2001; Business Wire, 2004a; Business Wire, 2004b;Platts Utility Environment Report, 2002, Business Wire 2003). This has likely made securing financing for a large capital investment in NOx control technology more costly for firms in restructured electricity markets. Concerns about maintaining shareholder value could also bias management against compliance alternatives that require large, up-front capital investments.[19]

Data and Preliminary Evidence

Data description

Information about which compliance strategies were chosen by coal plant managers was obtained from the Environmental Protection Agency, the Energy Information Administration, the Institute for Clean Air Companies and M.J. Bradley and Associates. The data set includes the 702 coal fired generating units that are regulated under the NOx SIP Call. Of these, 326 are classified as "regulated" for the purpose of this analysis. "Regulated" plants include those subject to PUC regulation in states that have chosen not to restructured their electricity industries, and a state owned and operated facility operating in a restructured market. The results presented here are generated using data from 588 units. I am awaiting data on 46 units. Compliance costs for the remaining 68 generating units cannot be generated due to data limitations.

I do not directly observe the variable compliance costs v_{ij} and fixed capital costs K_{ij} or the post-retrofit emissions rates m_{ij} that plant managers anticipated when making their decisions. I can, however, generate unit-specific engineering estimates of these variables using detailed unit-level and plant-level data. In the late 1990's, to help generators prepare to comply with market-based NOx regulations, the Electric Power Research Institute[20] developed software to generate cost estimates for all major NOx control options, conditional on unit and plant level characteristics.[21] I use this software to generate variable costs and fixed cost estimates for each unit, for each viable compliance option. Cost estimation requires detailed data on over 60 operating characteristics, fuel inputs, boiler specifications, plant operating costs, etc. Post-retrofit emissions rates are estimated using the EPRI software, together with EPA's Integrated Planning Model (EPA 2003). A more detailed data appendix is available upon request from the author.

It is impossible to directly observe plant managers' expectations regarding ozone season production levels Q_n under different compliance strategy scenarios. Because coal generation tends to serve load on an around-the-clock basis, the production levels of the plants in this sample are less likely to be significantly affected by changes in variable operating costs (as compared to intermediate and peak load units). Anecdotal evidence suggests that managers used past summer capacity factors to estimate future production levels, independent of the compliance choice being evaluated (EPRI, 1999). I observe unit-level hourly production over the period 1997-2005. I assume that managers used past summer production levels to proxy for expected ozone season production. This assumption is discussed in more detail in the Appendix.

Summary Statistics

Figures 3 and 4 summarize the observed choices for units in restructured and unrestructured markets in terms of MW of installed capacity (87, 828 MW in regulated markets and 88,370 MW in restructured markets).[22] A significantly larger proportion of the coal capacity in unrestructured markets has been retrofit with SCR (the control option that delivers the most significant emissions reductions). Conversely, in restructured markets, a greater proportion of capacity has either not been retrofitted, or has been retrofitted with controls that can achieve only moderate emissions reductions (such as combustion modifications or SNCR). These preliminary results are consistent with the predictions of the model.

There are several reasons why we might observe asymmetries in compliance strategy choices across states. It could be that the costs of installing SCR were lower for units in unrestructured electricity markets. These differences could also be explained by differences in generating unit characteristics (for example, older plants might be less likely to make large capital investments in pollution controls).

Table 1 presents summary statistics for unit level operating characteristics that significantly affect compliance costs: nameplate capacity, plant vintage, pre-retrofit emissions rates, pre-retrofit heat rates and pre-retrofit summer capacity factor. Units in restructured markets had lower pre-retrofit emissions rates on average. Because of persistent air quality problems in the northeast, plants in this region have historically been subject to more stringent pollution regulation prior to the SIP Call. With respect to other important determinants of compliance costs such as capacity, age and technology type(not summarized here), the two subpopulations of coal units look very similar.

Table 2 presents estimated capital and variable costs for the most commonly adopted NOx control technologies. Average costs are very similar across the two electricity market types, but are slightly higher for units in more regulated electricity markets. This is likely due to the fact that plants with higher pre-retrofit emissions rates tend to have higher retrofit costs.

Empirical Framework

Summary statistics suggest that it is unlikely that the differences in compliance strategy choices that we observe across electricity market types can be explained entirely by differences in unit characteristics and compliance costs. In this section, I develop an empirical framework for testing whether regulation in the electricity market significantly affected the environmental compliance choice.

There is arguably a dynamic component to the compliance strategy choice; managers could purchase permits to offset their emissions in the early years of the program and defer the decision to make major capital investments in emissions controls until they had more information about permit market conditions and pollution control technologies. This analysis focuses exclusively on the compliance choices that were made in the years leading up to the compliance deadline (i.e.2000-2004). These decisions will likely determine regional emissions patterns to a significant extent for the foreseeable future. Because these choices were ineluctably made in a very short time frame, they can be modelled as static decisions.

Each plant manager (indexed by n) faces a choice among J_n compliance strategy alternatives. With the obvious exception of the "no retrofit" option, all of the observed compliance strategies chosen by plant managers involve some combination of 8 different NOx control technologies. Although there are 15 compliance "strategies" represented in the data set, the most alternatives available to any one unit is 10. Some control technologies are only applicable to certain types of boilers.[23] Other technology combinations were excluded from the choice set if the unit had already installed the technologies prior to 2000.

The compliance cost that the nth manager associates with a given strategy i is comprised of two components: a non-stochastic component that depends on observable characteristics and a stochastic component:

$$C_{ni} = \alpha_i + \beta_n^v Q_n v_{ni} + \beta_n^K K_{ni} + \varepsilon_{ni}, \tag{5}$$

The estimated variable cost (per kWh) of operating the control technology is V_{ni}. The estimated variable costs associated with offsetting per kWh emissions with permits is equal to the permit price τ multiplied by the post-retrofit emissions rate m_{ni};

$v_{ni} = V_{ni} + \tau m_{ni}$. The estimated capital costs of installing the technology is K_{ni}. I assume that the manager chooses the compliance strategy that minimizes expected compliance costs. As it is likely that the compliance choice characteristics that are relevant to the compliance decision are not limited to the attributes we observe, technology specific constants α_i are included to improve the fit of the model. These fixed effects capture unobserved, intrinsic technology preferences or biases, such as widely held perceptions regarding the reliability of a particular NOx control technology. Because this decision depends in part on unobserved factors, it is impossible to say with certainty which compliance strategy a firm will choose. An extreme value stochastic component ε_{ni} is included in the model to capture the idiosyncratic effect of the unobserved factors.

I first estimate a conditional logit (CL) model of the compliance choice. Let $\beta' x_{ni}$ represent the deterministic component of C_{ni}. Let Y_n denote the nth firm's chosen alternative. The ε_{ni} are assumed to be iid extreme value and independent of β and x_{ni}. The probability (conditional on β) that the nth firm chooses compliance strategy i is the standard logit probability (McFadden) :

$$P(Y_n = i) \equiv P_{ni}^{CL} = \frac{e^{\beta' x_{ni}}}{\sum_{j=1}^{J_n} e^{\beta' x_{nj}}} \tag{6}$$

The most restrictive specification of this CL model imposes homogeneity in responses to changes in capital and variable compliance costs; the β coefficients are not allowed to vary across plants. A second specification captures systematic variation in the β parameters by interacting observed plant characteristics with compliance choice attributes. To facilitate a test of the hypothesis that firms in different types of electricity markets weigh cost components differently in their compliance decisions, capital cost and variable compliance costs are interacted with a restructured electricity market dummy. Because older plants can be expected to use shorter investment time horizons (and thus weigh capital costs more heavily), the capital cost variable is also interacted with plant age. Conditional on observed unit characteristics, coefficients are not permitted to vary across plants.

The advantage of the CL model is its simplicity, which facilitates hypothesis testing and the estimation of confidence intervals. However, to the extent that there is unobserved heterogeneity in how plant managers respond to choice attributes, errors will be correlated and CL coefficient estimates may be significantly biased. The random parameter logit (RPL) model does a better job of accommodating unobserved response heterogeneity. The presence of a standard deviation of β allows coefficients to vary across plants and facilitates a test of whether managers value cost components uniformly versus differentially.[24] In the RPL model, the coefficient vector β_n is unobserved for each n and varies in the population with density $f(\beta|\theta)$. I maintain the assumption that the unobserved stochastic term ε_{ni} is iid extreme value and independent of β_n and x_{ni}.

The data used to estimate the model has an unbalanced panel structure. While I only observe one compliance choice for each coal-fired boiler, an electricity generating facility or "coal plant" can consist of several, independently operating generating "units", each comprised of a boiler (or boilers) and a generator. Some facilities only have one boiler, but there can be as many as ten boilers at a given plant. I assume that the same manager made compliance decisions for all boilers at a given facility. The β coefficients are allowed to vary across managers, but are assumed to be constant over the choices made by a manager. This does not imply that the errors corresponding to all choices faced by a single manager are perfectly correlated; the independent extreme value term still enters for each choice.

Conditional on β_n, the probability that a manager of a facility with T_n regulated units makes the observed T_n compliance choices is:

$$P(Y_n = i) \equiv P_{n\mathbf{i}}^{RPL}(\beta) = \prod_{t=1}^{T_n} \frac{e^{\beta_n{}' x_{nit}}}{\sum_{j=1}^{J_{nt}} e^{\beta_n{}' x_{njt}}}, \tag{7}$$

where $\mathbf{i}$ is a $T_n * 1$ dimensional vector denoting the sequence of observed choices. Unconditional choice probabilities are derived by integrating conditional choice probabilities over the distribution of unobserved random parameters (Train, 2003). The θ vector of unknown parameters describes the distribution of β. The parameter estimates are those that maximize the following log likelihood function:

$$LL(\theta) = \sum_{n=1}^{N} \ln \int_{-\infty}^{\infty} \prod_{t=1}^{T_n} \frac{e^{\beta' x_{nit}}}{\sum_{j=1}^{J_{nt}} e^{\beta' x_{njt}}} f(\beta|\theta) d\beta, \tag{8}$$

J_{nt} is the number of viable compliance alternatives available to unit t operated by manager n. Because this integral does not have a closed form solution, the unconditional probabilities are approximated numerically through simulation. For each decision maker, R draws of β are taken from the density $f(\beta|\theta)$;one for each decision maker. For each draw, the value of [7] is calculated for each decision maker. The results are averaged across draws. Simulated maximum likelihood estimates of the parameters maximize the following:.

$$SLL(\theta) = \sum_{n=1}^{N} \ln \frac{1}{R} \sum_{r=1}^{R} \prod_{t=1}^{T_n} \frac{e^{\beta_n^{r\prime} x_{nit}}}{\sum_{j=1}^{J_{nt}} e^{\beta_n^{r\prime} x_{njt}}} \tag{9}$$

To increase the accuracy of the simulation, 1000 pseudo-random Halton draws are used (Train, 1999). The program that estimates the RPL model is based on GAUSS code developed by Train, Revelt and Ruud (1999).

Estimation

Conditional logit model results

Results for three models are presented in Table 3. To estimate standard errors, the robust asymptotic covariance matrix estimator is used (Mc Fadden and Train). The first column corresponds to the most restrictive, benchmark CL model in which coefficient values are not permitted to vary across plant managers. All of the technology specific fixed effects are negative, all but the low NOx burner (LNB) fixed effect are significant at the 1% level. This suggests that, relative to the baseline option of no control technology retrofit, the average manager was biased against adopting these technologies (controlling for costs).

The variable operating cost and capital cost coefficients are also significant at the 1% level and have the expected negative sign, suggesting that an increase in either capital or operating costs significantly reduces the probability that a given compliance alternative will be chosen. The ratio of the variable cost and fixed cost coefficients is 3.75, suggesting that plant managers are, on average, willing to pay an additional $1 in capital costs so as to reduce annual ozone season operating costs by $3.75.

The second column of Table 4 presents the results from a nested likelihood ratio test of this benchmark specification. The test statistic is larger than the χ^2 statistic with 2 degrees of freedom and a p-value of 0.001. This indicates that variable operating cost and capital cost variables significantly improve the fit of the model (as compared to a model that includes only technology fixed effects).

The second CL model (CLII) accounts for systematic differences in responsiveness to variation in capital and variable compliance costs. The second column of Table 3 reports results for the second CL model. To account for the possibility that firms in different types of electricity markets might weigh choice attributes differently, variable and capital cost variables are interacted with an electricity market structure dummy that equals one if the plant is operating in a restructured electricity market and is not state owned and operated, zero otherwise. Because older plants can be expected to use shorter investment time horizons, the theoretical model predicts that older plants will weigh capital costs more heavily in their compliance decisions ($\frac{\partial l_n}{\partial T_n} < 0$). To allow the capital cost coefficient to vary with plant age, I include an interaction term in both models. The youngest plant in the sample was built in 1996; plant age is defined as vintage year-1996.[25]

The age-capital cost interaction terms are both significant and have the expected negative sign. The older the plant, the shorter the investment time horizon, the more significant the effect of an increase in capital costs on choice probabilities. The age-capital cost coefficient is found to be significantly more negative among units operating in restructured markets. Somewhat surprisingly, the coefficient on the un-interacted capital cost variable is not significant, implying that an incremental change in capital costs does not significantly affect the probability that a control technology will be adopted at a very young plant. This "baseline" capital cost coefficient, (i.e. the average value of the coefficient for very young plants) does not differ significantly between restructured and regulated markets. These results imply that among units of similar age, larger negative capital cost coefficients are associated with units in restructured markets. Although both the variable cost and the variable cost/market structure interaction term coefficients are negative, the coefficient on the interaction term is not statistically significant. All technology specific fixed effects are negative and statistically significant.

The two CL models (I and II) are compared using a nested likelihood ratio test. A test statistic of 75.74 is highly significant (see Table 4). This implies that accounting for systematic heterogeneity in response to changes in compliance costs improves the fit of the model.[26]

Random parameter logit results

Several different specifications of the RPL model were tested. The best results were obtained when all cost coefficients are allows to vary randomly. In the RPL model presented in Table 3, the estimated standard deviations of all but one of the random coefficients are all highly significant, indicating that these parameters do vary across managers, even after allowing for observed, systematic variation across electricity market types and plant vintages. The results of a nested likelihood ratio test imply that allowing for response heterogeneity dramatically improves the fit of the model. These RPL estimation results are robust to various optimization routines and initial starting values.

In the RPL model, unobserved variation is decomposed into an extreme value stochastic term and variance of the random parameters. In the CL models, all unobserved variation in anticipated costs is captured by the extreme value stochastic term. Consequently, normalizing coefficients by the variance of the extreme value component of the disturbance term will make RPL parameters larger in absolute value. The significant increase in the magnitude of the cost coefficient estimates suggests that the variation in random parameters constitutes a significant portion of the variance in (unobserved) perceived compliance costs. Conversely, the technology specific fixed effects get smaller in absolute value, and some cease to be significant. This suggests that the statistical significance of these fixed effects in the CL specifications was partly due to random response heterogeneity to variations in costs.

All of the cost coefficients are assumed to be normally distributed.[27] The means of both the variable cost coefficient and the variable cost/restructured market interaction term are negative and significant at the 1% level. The estimated standard deviations are also large in absolute value and statistically significant. This indicates that there is random variation in response to changes in variable operating costs, even after accounting for differences in response across units of different vintages and across electricity market types. In an effort to attribute some of this variation to observable plant characteristics, other interactions were also tested, but none improved the fit of the model.

The negative and significant coefficient values on the two capital cost/age interaction terms indicate first that more capital intensive strategies are less likely to be adopted at older plants, and that when age is held constant, this coefficient is larger in absolute value among plant managers in restructured electricity markets. Neither of the coefficients on the capital cost constants are significant, although these coefficients vary significantly in both sub-populations.

Because these models are non-linear, the coefficients on the interaction terms involving the restructured electricity industry indicator variable and the capital (variable) cost variable (in both the CL and the RPL models) are not equal to the marginal effect of electricity industry regulation on the responsiveness to changes in capital (variable) cost. To assess the effect of electricity industry regulation on managers' response to changes in costs, I compare the marginal effects implied by the RPL model in the two different electricity market types. [28] These marginal effects are calculated for each unit.

Table 5 presents average interaction effects for the most frequently chosen NOx control technologies. These estimates indicate that plant managers in restructured markets are relatively more responsive to incremental changes in compliance costs. For example, if the expected capital costs of SCR increase incrementally by $100,000, the probability that this compliance alternative will be chosen decreases by approximately 0.008% in regulated markets and 0.014% in restructured markets. The marginal effect of an incremental increase in the variable compliance costs of SCR on the probability that SCR will be chosen is only 13% larger in restructured markets. In percentage terms, the effect of electricity restructuring on the marginal effect of a change in capital costs is greater than the corresponding effect of a change in variable operating costs. A more formal statistical test of whether firms in restructured markets are relatively more biased against incurring higher capital costs is a work in progress.

Elasticity calculations provide a more intuitive characterization of the responsiveness of compliance decisions to changes in compliance costs. Table 6 presents the elasticities of choice probabilities with respect to both capital and variable compliance costs for the most common compliance choices. Elasticities are calculated using both the CL and RPL coefficient estimates. The RPL model yields larger (in absolute value) elasticity estimates for all compliance strategies, suggesting that the CL model underestimates the responsiveness of compliance decisions to changes in compliance costs. For example, if the expected capital cost of an SCR retrofit increases by 1%, the RPL model predicts that the probability that a manager will choose to retrofit his unit with SCR decreases by approximately 6% in regulated markets, and approximately 11% in restructured electricity markets. The CL model predicts more moderate decreases of 0.7% and 1.5% respectively. If anticipated variable costs increase by 1%, the RPL model predicts that the probability of an SCR retrofit would decrease by 2% and 4% in regulated and restructured markets respectively. The CL model predicts decreases of only -0.80% and -1%.

Summary and Next Steps

This paper presents evidence that economic regulation in electricity markets has significantly affected how electricity generators have chosen to comply with the NOx

SIP Call. Unit level compliance cost estimates are generated using detailed data on units' technology and operating characteristics, operating costs, fuel inputs, etc. Two types of discrete choice models of the compliance strategy choice are estimated: a conditional logit model, and a random parameter logit model that allows the cost coefficients in the model to vary across units.

Results from both models suggest that compliance choices do differ significantly across restructured and more regulated electricity markets. Managers of generators operating in restructured electricity markets are significantly more responsive to variation in compliance costs as compared to managers in regulated electricity markets who are able to pass a significant portion of these costs through to electricity customers.

With coefficient estimates from the random parameter logit models in hand, a logical next step involves deriving conditional distributions for unit specific coefficients and simulating the compliance decisions that coal plant managers would have made had the NOx emissions market been designed to reflect spatial heterogeneity in marginal damages from pollution. A more complicated "exposure based" approach to designing the permit market would have involved estimating the variability in marginal damages resulting from increased ozone exposure in different regions of the regulated area. In order to set "trading ratios" to determine the terms of interregional permit trading, estimated damages in each region are normalized by the damages in a designated baseline region (Krupnick et al.). Because pollution permits carry more currency in low damage areas, the introduction of trading ratios offers additional incentives to install pollution controls in relatively high damage areas. The magnitude of this effect will depend on how responsive firms compliance choices are to changes in variable compliance costs

My approach will differ from prior work[29] on exposure based trading in two important respects. First, previous studies have used very blunt measures of compliance costs; conditional on boiler firing type, capacity and capacity factor, all units are assumed to face identical compliance costs. I use a much more detailed approach to cost estimation in order to capture a larger proportion of the inter-unit variation in expected compliance costs. Second, rather than using a deterministic, economic model of the compliance choice that assumes that managers will choose the compliance choice that minimizes estimated compliance costs, I use an econometric model of the compliance choice. The economic models used in earlier studies do not allow for asymmetric investment incentives across electricity markets, heterogeneity in the responsiveness of plant managers to variation in compliance costs, intrinsic biases for or against particular types of NOx controls or idiosyncratic errors on the part of decision makers.

I have presented evidence here that all of these factors have played a significant role in the compliance decisions made by firms. Equipped with more precise cost estimates, and a more realistic model of how plant managers in different electricity markets respond to variation in compliance costs, I will revisit the question of whether an exposure based market design would have significantly affected the spatial distribution of permitted emissions. These simulations are a work in progress.

Appendix : Testing the Independence of Future Electricity Production Levels and the Compliance Decision

I cannot directly observe plant managers' expectations regarding ozone season production levels Q_n under different compliance strategy scenarios. In the paper, I assume that managers used past summer production levels to proxy for expected ozone season production. This assumption is supported by production costing models of electricity dispatch under NOx regulation (Leppitsch and Hobbs) and anecdotal evidence that managers used past summer capacity factors to estimate future production levels when choosing how to comply with the SIP Call, independent of the compliance choice being evaluated (EPRI,1999).

Let $\bar{Q}_n$ represent the nth unit's average production in past ozone seasons. I now assume:

$$Q_{ni} = \bar{Q}_n + \Delta_{ni}, \tag{10}$$

where Δ_{ni} is the difference between the unit's historic average ozone season production and its the quantity of electricity that the nth unit expects to produce in an average ozone season, conditional on adopting compliance strategy i (Q_{ni}). For a baseload unit with relatively low operating costs serving either a restructured or more regulated electricity market, we can assume that $\Delta_{ni} = 0 \ \forall \ i$. For units with higher operating costs, however, future electricity production levels could be affected by the compliance choice, and it is conceivable that managers took this into account in their compliance decisions.

In the analysis presented in the paper, I assume $\Delta_{ni} = 0$ for all firms, for all compliance choices. One way to empirically test the validity of this assumption is to test whether firms' production levels changed significantly once the NOx SIP Call began, and whether the magnitude and the direction of these changes are significantly correlated with firms' compliance strategy choices. I estimate the following regression equation using monthly, unit-level ozone season production data from 1997-2004:

$$\tilde{Q}_{nt} = \alpha_n + D_{nt}^{SIP} + D_{nt}^{SIP} \cdot \delta_{nj} + D_{nt}^{SIP} \cdot \delta_{nj} \cdot D_n^{NBL} + \varepsilon_{nt} \tag{11}$$

The quantity produced in month t by unit n is $\tilde{Q}_{nt}$.α_n is a unit specific fixed effect. D_{nt}^{SIP} is a dummy indicating that the NOx SIP Call market is "on"; this indicator variable has an n subscript because the program came into effect in different years for different subsets of plants. The SIP Call indicator variable is interacted with a series of technology dummies indicating compliance strategy choices; $\delta_{nj} = 1$ if the nth firm chose compliance strategy j, 0 otherwise. A second set of interaction terms are included that interact the SIP Call indicator and the compliance strategy indicators with a dummy variable that indicates whether the unit is a non-baseload unit. A superior specification would include a measure of market area load. Estimation of this preferred model will be carried out when the load data become available.

This regression equation is estimated separately for restructured and regulated markets. A significant amount of the variation in the dependent variable is explained by the unit fixed effects and the SIP Call dummy. The coefficient on the SIP Call indicator variable is positive in both models, although imprecisely estimated. Both SCR interaction terms are significant in both models. These results indicate that, on average, units adopting SCR technology experienced a larger increase their production on average, once the SIP Call took effect.

There is no way of knowing whether plant managers adjusted their production expectations upwards when estimating the costs of an SCR retrofit. If they did, the estimate of variable operating cost I use will be an underestimate, and the added revenues associated with producing more electricity will be absorbed by the SCR technology constant. I add an interaction between variable compliance cost and the SCR indicator variable to see if this model fits the data better. Adding this interaction terms allows the coefficient on variable compliance costs to be more negative in strategies that incorporate an SCR retrofit, to reflect the fact that Δ_{ni} might exceed 0 in these cases.

Estimation of the coefficient on the newly included interaction term is confounded by the significant correlation between this interaction term and the SCR fixed effect. Whereas we would expect that the coefficient on the SCR indicator variable should become more positive (to reflect additional profits associated with higher production levels) and a negative coefficient on the SCR/variable cost interaction, I find the opposite. The SCR fixed effect coefficient gets significantly more negative (-1.51) whereas the interaction term coefficient is significant and positive (0.59). Including this interaction term does not improve the fit of the model.

These results favor a rejection of this more restrictive specification. Empirical evidence suggests that the effect of a unit's choice of compliance strategy on ozone season production levels is significant for those choices involving SCR retrofits. Anecdotal evidence suggests that managers did not take this relationship into account when making their compliance decisions. Attempts to account for the possibility that managers might have anticipated higher future production levels conditional on adopting SCR to not improve the fit of the model.

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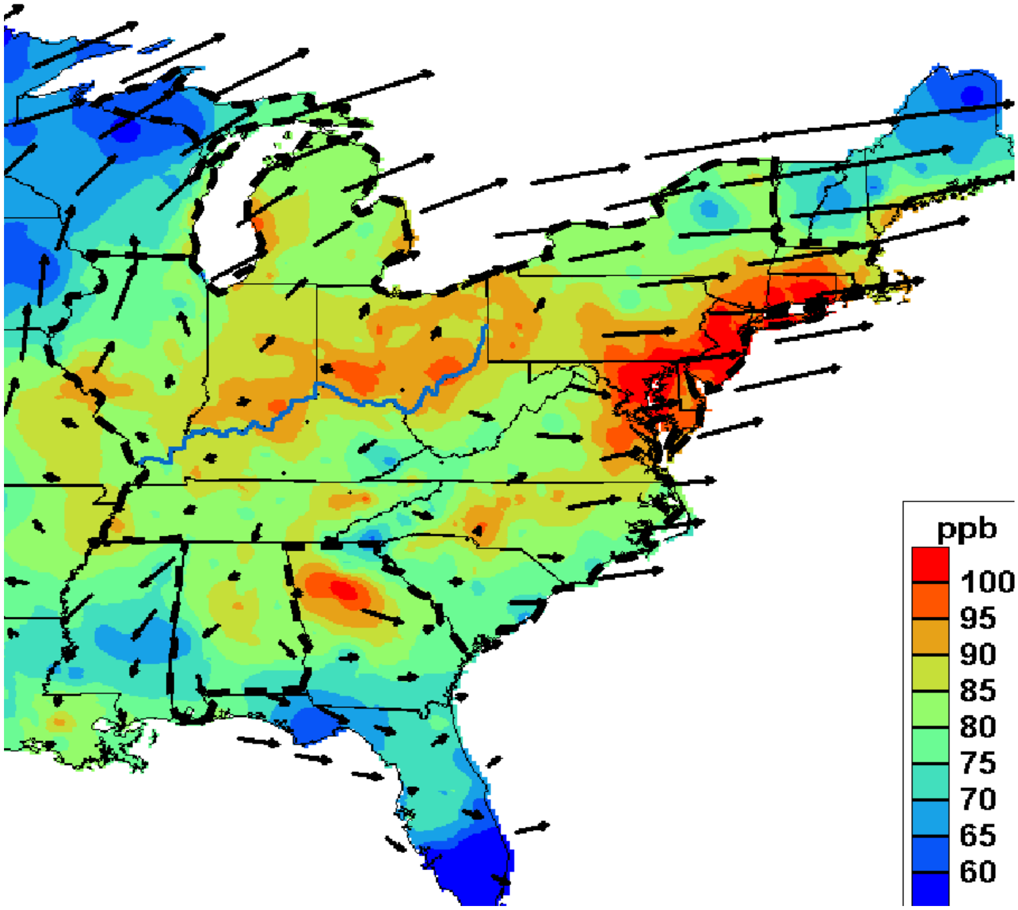

Figure 1: **Ozone Transport and Non-Attainment**

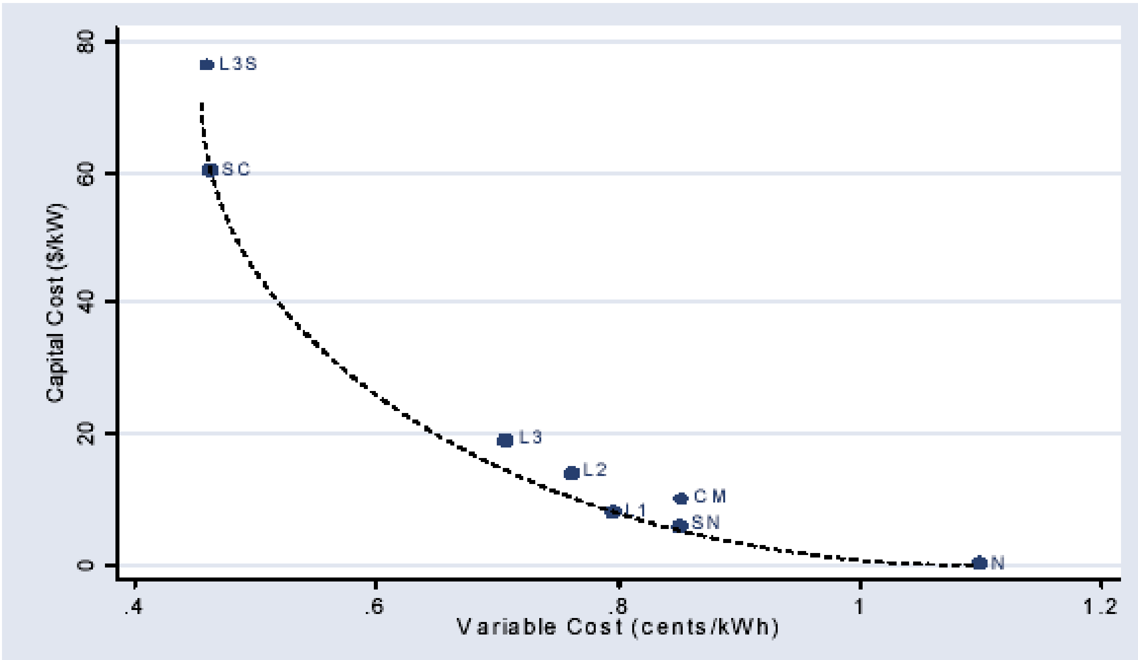

Figure 2 : Estimated Compliance Costs for a 500 MW Boiler

Strategy	Technology	lbs NOx/mmBtu
N	No Retrofit	0.42
SN	Selective Non-Catalytic Reduction (SNCR)	0.34
CM	Combustion Modification	0.33
L1	Low NOx Burners with overfire air option 1	0.31
L2	Low NOx Burners with overfire air option 2	0.28
L3	Low NOx Burners with overfire air options 1&2	0.26
SC	Selective Catalytic Reduction (SCR)	0.13
L3S	L3 + SCR	0.11

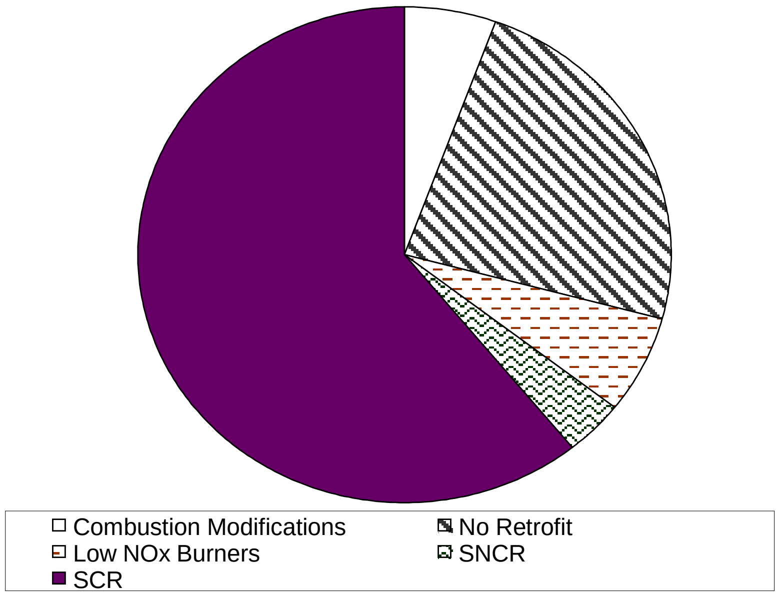

Figure 3: Compliance Choices of Units in Regulated Markets

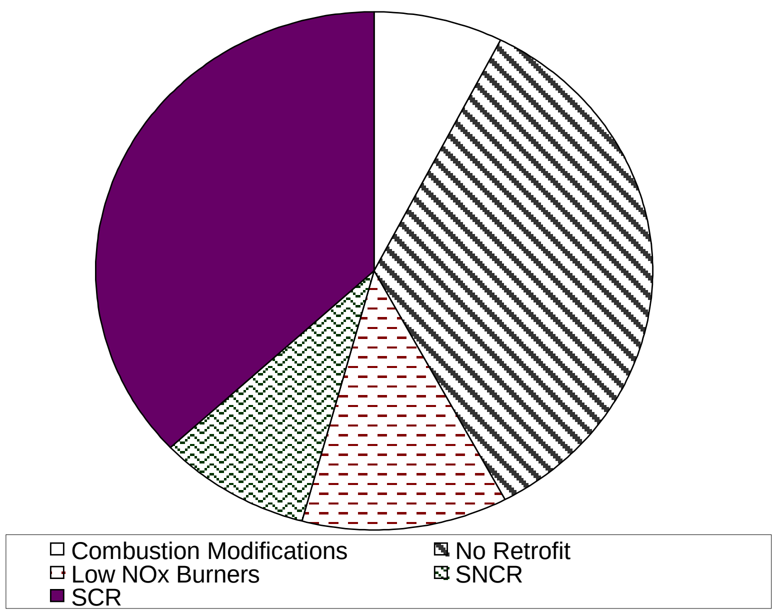

Figure 4: Compliance Choices of Units in Restructured Markets

Table 1. Summary Statistics by Electricity Market Type[1]

Variable	Restructured	Regulated
# Units	302	286
# Facilities	109	99
Capacity (MW)	277	273
	(245)	(266)
Pre-retrofit NOx emissions (lbs/mmBtu)	0.51	0.55
	(0.20)	(0.23)
Pre-retrofit summer capacity factor (%)	64	67
	(16)	(14)
Pre-retrofit heat rate (kWh/btu)	11,378	11,536
	(2176)	(1739)
Unit Age (years)	43	42
	(11)	(11)

[1]Summary statistics generated using the data from the 588 units used to estimate the model.

Table 2: Compliance Cost Summary Statistics for Commonly Selected Control Technologies

Technology	Capital Cost ($/kW)		Per kWh operating costs (cents/kWh)	
	Restructured	Regulated	Restructured	Regulated
Combustion Modification	12.71	12.38	0.94	1.05
	(4.89)	(4.17)	(0.38)	(0.38)
Low NOx Burners	25.01	27.16	0.72	0.74
	(12.73)	(19.11)	(0.26)	(0.22)
SNCR	16.16	19.21	0.97	1.02
	(14.57)	(22.82)	(0.41)	(0.38)
SCR	70.55	73.40	0.51	0.54
	(21.10)	(26.04)	(0.31)	(0.20)

Table 3. Conditional and Random Parameters Logit Results

	CLI	CLII	RPL
	Technology Fixed Effects		
α_{SNCR}	-1.91**	-1.86**	-0.94*
	(0.30)	(0.30)	(0.40)
α_{SCR}	-0.97**	-0.55**	0.82**
	(0.19)	(0.20)	(0.38)
α_{CM}	-1.77**	-1.77**	-1.18
	(0.29)	(0.28)	(0.38)
α_{OFA}	-1.70**	-1.64**	-1.45**
	(0.35)	(0.33)	(0.42)
α_{LNC1}	-1.59**	-1.41**	-0.13
	(0.33)	(0.53)	(0.51)
α_{LNC2}	-2.27**	-2.15**	-0.67
	(0.42)	(0.44)	(0.56)
α_{LNC3}	-2.31**	-2.36**	-1.84**
	(0.53)	(0.53)	(0.57)
α_{LNB}	-0.40	-0.44**	-0.27
	(0.39)	(0.43)	(0.50)
	Cost Variables		
Annual operating cost (V)	-0.30**	-0.33**	-0.80**
($100,000)	(0.06)	(0.06)	(0.15)
σ_V	–		-0.90**
			(0.16)
V*Restructured	–	-0.01	-0.51**
		(0.07)	(0.16)
σ_{VR}	–		0.69**
			(0.13)
Capital cost (K)	-0.08**	0.01	0.21
($100,000)	(0.01)	(0.04	(0.14)
σ_K	–	–	0.15**
			(0.05)
K*Restructured	–	0.04	0.16
		(0.04)	(0.23)
σ_{KR}	–	–	0.48**
			(0.10)
K*Age	–	-0.04**	-0.20**
		(0.02)	(0.07)
σ_{KA}		–	0.06**
			(0.02)
K*Age*Restructured	–	-0.02*	-0.13*
		(0.01)	(0.06)
σ_{KAR}			0.02
			(0.01)
Log-likelihood	-955.04	-917.16	-783.61

Robust standard errors are in brackets. The age interaction variables are scaled by 0.1.
*Indicates significance at 5%. **Indicates significance at 1%.

Table 4: Measures of Data Fit

	Technology fixed effects only	CLI	CLII	RPL
Log-likelihood value at convergence	-1008.10	955.04	917.17	783.61
Number of parameters	8	10	14	20
LR test statistic	–	106.12	75.74	267.12
p-value		<0.001	<0.001	<0.001

Table 5: Average Capital Cost and Variable Compliance Cost Marginal Effects for Commonly Selected Technologies(RPL)

Technology	Capital cost marginal effects		Variable cost marginal effects	
	Regulated	Restructured	Regulated	Restructured
CM	-0.051	-0.090	-0.072	-0.109
LNB	-0.125	-0.204	-0.147	-0.246
SCR	-0.008	-0.013	-0.043	-0.049
SNCR	-0.045	-0.075	-0.081	-0.119

Table 6: Elasticities of Choice Probabilities with Respect to Capital Cost for Commonly Selected Technologies

Technology	CLI		RPL	
	Regulated	Restructured	Regulated	Restructured
CM	-0.12	-0.55	-0.99	-1.70
LNB	-0.18	-0.32	-1.40	-2.29
SCR	-0.67	-1.46	-6.22	-10.76
SNCR	-0.14	-0.22	-1.05	-1.76

Table 7: Elasticities of Choice Probabilities with Respect to Variable Compliance Costs for Commonly Selected Technologies

Technology	CLI		RPL	
	Regulated	Restructured	Regulated	Restructured
CM	-1.33	-1.43	-3.17	-5.22
LNB	-1.11	-1.23	-2.53	-4.02
SCR	-0.79	-1.14	-2.20	-3.76
SNCR	-2.13	-2.19	-4.65	-7.40

Notes

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[2]All of the emissions regulated under the Acid Rain Program and over 90% of the emissions regulated under the NOx SIP Call come from electricity generators. The mercury cap and trade program laid out in the EPA's mercury rule, published in May 2005, applies exclusively to the electricity sector.

[3]The paper focuses exclusively on the compliance decisions of coal-fired electricity generators. Although only 31% of the units regulated under the SIP Call are coal plants, the majority of the point source NOx emissions in the region comes from coal plants. Over 80% of permits were allocated to coal plants in 2004.

[4]NOx reacts with carbon monoxide and volatile organic compounds (such as hydrocarbons and methane) in the presence of sunlight to form ozone in the lower atmosphere.

[5]Coal plants in 9 Northeastern states had to achieve compliance by May 2003; plants in the southeastern states had to comply by May 2004.

[6]For want of a better term, I use the word "regulated" to refer to those electricity markets that have not been restructured. This is misleading in the sense that wholesale electricity markets are arguably subject to more regulation once restructuring takes hold.

[7]In many of the states that have chosen not to restructure their electricity industries, "incentive" or "performance based" regulation (PBR) has replaced more traditional "rate of return" regulation. PBR is a broadly defined concept that includes any regulatory mechanism that attempts to link profits to desired performance objectives (such as improved operating efficiency, improved environmental performance and rational procurement decisions). Under most forms of PBR, Regulators continue to set baseline revenue requirements as a function of prudently incurred costs. See Knittel for an assessment of how incentive based regulation has affected generator efficiency.

[8]See Lile and Burtraw for a compilation of PUC cost recovery rules and actions that were in place during the years when utilities were making ARP compliance investment decisions (1990-1995).

[9]Of the 19 states that are affected by the NOx SIP Call, 12 have restructured their electricity industries: CT, DE, IL, MA, MD, MI, NJ, NY, OH, PA, RI and VA. The remaining 7 chose not to go forwards with restructuring: AL, IN, KY, NC, SC, TN, WV.

[10]A discussion of how these cost estimates are generated is included in the following section.

[11]These calculations assume perfect compliance and a permit cost of $2.25/lb NOx. This was the average futures permit price (per lb NOx) in the years leading up to the SIP Call. Permits started trading in early 2001 in anticipation of the SIP Call Rule.

[12]For example, for this particular plant, a manager will not want to adopt "L3"; while this choice would incur roughly the same capital costs as "CL1", expected variable compliance costs would be significantly higher.

[13]I assume that anticipated electricity production is independent of the compliance strategy choice. Production cost modeling has indicated that the effects of NOx regulation on electricity generation dispatch are small (Farrell et al.). Anecdotal evidence suggestt that plant managers have used past ozone season production to proxy for expected production, regardless of the compliance strategy being evaluated (EPRI). This assumption is discussed in more detail in the Appendix.

[14]Trackers are mechanisms that allow the utility to recover its "tracked" expenses by adjusting its rates accordingly. These trackers reduce the frequency of general rate cases and significantly reduce

the likelihood of failing to recover costs associated with volatile inputs, such as fuel, emissions permits or environmental construction work.

[15]Kentucky's environmental surcharge law gives utilities the assurance that they will fully recover the capital and operating costs associated with environmental compliance, and North Carolina's "Clean Smokestacks" bill allowed two utilities that serve North and South Carolina to freeze their retail rates for five years in order to cover the costs of reducing NOx emissions.

[16]It is worth noting that firms will not be compensated for the opportunity cost of using the permits they have been allocated to offset their emissions; they can only recover some portion $(1-\theta^v)$ of their net permit purchase through higher rates.

[17]These are the New York ISO, the New England ISO and the "PJM" (Pennsylvania Jersey Maryland) ISO.

[18]Downgrades outnumbered upgrades 65 to 20 in 2000; that ratio was up to 182 to 15 in 2002. In 2003, 18 percent of firms were non-investment grade (Senate Committee on Energy and Natural Resources).

[19]There has been at least one case of an independent power producer cancelling plans to install SCR and choosing instead to rely on less capital intensice compliance options in order to improve cash flows in the near term (2003-2005) (Platts Utility Environment Report 2002).

[20]The Electric Power Research Institute (EPRI) is an organization that was created and is funded by public and private electric utilities to conduct electricity related R&D.

[21]Anecdotal evidence suggests that this software has been used not only by plant managers, but also by regulators to evaluate proposed compliance costs for the utilities they regulate(Himes, Musatti, Srivastra).

[22]Units in these two different groups were equipped with very similar NOx controls when the SIP Call was promulgated. Over 80% of capacity in both types of markets had some type of low NOx burners. Over 5% of capacity in restructured markets and over 7% of capacity in regulated markets had installed some type of combution modification or overfire air ports. Only 1% of capacity in restructured markets had been retrofit with SCR as of 2000, no SCR retrofits had taken place in regulated markets.

[23]For example, the :"LNC1", "LNC2" and "LNC3" options are only appropriate for tangentially fired boilers.

[24]Another advantage of the RPL model is that it relaxes the assumption that the unobserved component of C_{ni} is iid; unobserved components of anticipated compliance costs are represented in the model as a combination of the standard iid extreme value term and the random component of the coefficients. This induces correlations in the unobserved components across compliance alternatives, which in turn allows for flexible substitution patterns between compliance choices.

[25]Other specifications were also examined, but provided worse results than the specification presented here.

[26]Interaction terms were added sequentially to the model and individual nested LR tests were carried out. In each case, test statistics indicated that each of the four interaction terms belong in the model.

[27]It is common in the literature to assume that cost coefficients are lognormally distributed, so as to ensure the a priori expected negative domain for the distribution (costs enter the model as negative numbers). Hensher and Greene(2002) discuss some of the drawbacks of assuming a lognormal distribution. Log-normal specifications for the variable compliance cost coefficients were tested, but resulted in a failure to reach convergence.

[28]For example, the effect of an incremental change in capital costs on choice probabilities in a restructured and a regulated electricity market environment are calculated as follows:

$$\mu_{niK}^{1} = \left.\left[\frac{\partial C_{ni}}{\partial K_{ni}}[P_{ni}(1-P_{ni})]\right]\right|_{D^{RES}=1}, \quad (12)$$

$$\mu_{niK}^{0} = \left.\left[\frac{\partial C_{ni}}{\partial K_{ni}}[P_{ni}(1-P_{ni})]\right]\right|_{D^{RES}=0}, \quad (13)$$

The same approach is used to calculate the marginal affects of changes in variable compliance costs.

[29] Research that considers the merits of ozone-exposure based permit trading is limited. Farrell et al. develop a dynamic, linear programming model of the NOx Budget Program, a smaller NOx emissions trading program that predated the SIP Call. They address a variety of permit market design issues, including whether to impose geographic constraints on permit trading so as to prevent undesirable spatial patterns of permitted emissions between pre-determined zones. They conclude that the benefits associated with geographically constrained permit trading (1-2% change in the spatial pattern of emissions) do not justify the costs. In a more recent paper, Krupnick et al. use a regional atmospheric model of the eastern United States to estimate point source trading ratios. They compare an emissions based NOx trading program with an exposure based scenario and conclude that there is no clear benefit to a spatially differentiated trading policy.