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Abstract

Recent environmental regulations have used market incentives to reduce compliance costs and improve efficiency. In most cases, the Environmental Protection Agency (EPA) selects an emissions cap using the predicted costs of reducing pollution. The EPA and other economists have used a "bottom-up" approach to predict the costs of such regulations, which forecast how every affected firm will respond. It is uncertain whether firms rely on the same predictions in making their compliance decisions. This paper uses stock prices to compare the predictions of the bottom-up studies with those of the affected firms.

I focus on a recent tradable permit program, the Nitrogen Oxides Budget Trading Program (NBP). Started in 2004, the NBP requires electric generators in the Midwest and East to reduce their emissions or purchase permits from other firms. I compare utilities' stock prices with the prices that would have occurred in the absence of the new regulation. I make this comparison by exploiting variation in the location of generators owned by utilities; the control group consists of utilities without any generators in the NBP. I estimate that investors expected the program to reduce profits by about $2 billion per year (2000 dollars). Investors expected the NBP to primarily affect coal generators, which have larger baseline emission rates than other fossil fuel generators. These results agree with previous studies that used the bottom-up approach.

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1 Introduction

Following the Acid Rain Program, which reduced sulfur dioxide emissions from power plants, there has been a dramatic increase in market based environmental regulations. These programs place a cap on emissions and allow firms to trade permits to reduce compliance costs. For example, the Clean Air Interstate Rule, recently adopted by the Environmental Protection Agency (EPA), will expand existing sulfur dioxide and nitrogen oxides (NO_x) permit programs. In the past few years, members of Congress and local governments have proposed a variety of tradable permit programs aimed at reducing greenhouse gas emissions.

Cost predictions have played an important role in justifying the permit programs and determining the emissions caps. Previous research (e.g., Ellerman et al., 2000) uses a "bottom-up", or engineering-based approach to forecast costs. These studies simulate a detailed model of electricity supply and demand to predict each firm's response to a given policy. As documented by Carlson et al., 2000, and Ellerman, 2003, most bottom-up estimates significantly over-predict the costs of the Acid Rain Program in the early 1990s.

The EPA has relied on these engineering-based studies to select emissions caps for programs after the Acid Rain Program. It is uncertain whether investors and utilities continue to agree with these predictions after becoming aware of the earlier over-estimates. Disagreement between utilities' and the EPA's expectations could arise either because the bottom-up studies did not incorporate an important aspect of the regulation, or because utilities did not understand the regulation's effects. Firms would not comply as the EPA expected them to, which could limit the cost effectiveness of the market-based policy or lead to an inefficient reduction of emissions.

This paper describes a new approach, using stock prices to estimate investors' and firms' expectations. I focus on a recent program, the NO_x Budget Trading Program (NBP). Assuming that firms are rational and investors are forward looking, I can directly compare firms' predictions with those of the bottom-up studies. The NBP began in 2004, and places a cap on NO_x emissions from electric utilities and manufacturing plants in the Midwest and East Coast. Prior to enactment, several studies (EPA, 1998 and Palmer *et al.*, 2001) made similar estimates of about \$2.2 billion per year.[1] When the EPA proposed the NBP in the late 1990s, firms were aware that earlier studies had overestimated costs of the Acid Rain Program; they may no longer have trusted this method.

[1] These estimates differ slightly because of the choice of baseline emissions and the plants included in the analysis. There are several other estimates, using similar methodologies, for the Ozone Transport Commission program, which covered electric utilities in the Northeast, and for the NBP. See, for example, Farrell, *et al.* (1999) and Krupnick *et al.* (2000). The latter analyses a subset of states in the NBP, and is less comparable to this paper than the Palmer *et al.* study.

In comparison, investors expected the NBP to reduce profits by $2 billion per year.[2] This figure includes the effect of compliance costs and changes in revenue. On the other hand, the engineering-based estimates include only compliance costs. The EPA argues that electricity prices would increase and that the change in profits would be small; on the other hand, Palmer *et al.* predict that utilities would bear nearly all the costs. My results agree with the Palmer *et al.* prediction that profits would fall dramatically, although investors may have expected higher compliance costs as well as a larger increase in revenue. It appears that investors continue to rely on the bottom-up estimates.

The empirical strategy uses changes in stock prices to predict the cost of the NBP, and consists of two stages. First, I estimate the stock prices of utilities in the absence of regulation, which I refer to as the counterfactual stock price. More specifically, from 1990-1995 there was little discussion of regulating NO_x emissions in the Midwest and Southeast. In 1996 the EPA considered implementing a tradable permit program to reduce emissions in these regions, and made a formal proposal in 1998. A number of states and utilities sued the EPA to prevent the program, but on March 3, 2000, the D.C. Court of Appeals ruled in favor of the EPA, allowing it to proceed. I exploit variation in the location of utilities to construct a control group, which consists of utilities located in the western United States; the NBP did not affect their stock prices. I use daily stock price data from the Center for Research in Security Prices (CRSP) to estimate the relationship between the stock prices of the NBP and western utilities in the initial period, 1990-1995. I assume this relationship would have held in the absence of regulation. I use the actual stock prices of the control group from 1996-2000 to estimate the counterfactual stock prices of the NBP firms. After the court decision, investors knew with certainty that the NBP would occur. The difference between the actual and counterfactual stock prices at that time was proportional to the expected cost of the NBP.

In the second stage I characterize how the NBP would affect different types of generators. For a given firm, the effect of the NBP is proportional to the number of generators in the program. I estimate an Ordinary Least Squares (OLS) regression where the dependent variable is the difference between the actual and counterfactual stock prices for each utility. The independent variables are the number of coal, natural gas and oil generators the firm owns in the NBP region, obtained from the Department of Energy (DOE). The coefficients correspond to the changes in expected profits per generator, which I refer to as the expected net cost. I use the estimated coefficients to calculate the total net cost for all firms in the NBP.

[2] This analysis is comparable to the EPA and Palmer *et al.* studies because it measures the effect of the NBP on the same set of generators. The NBP also includes some large manufacturing plants, which are not included in the previous studies or in this paper. The EPA expected that electricity generators would account for about 90 percent of the reduction in emissions, so the analysis probably incorporates most of the effect of the NBP.

This approach allows me to characterize how the NBP would affect different generators. Coal generators, which have higher emission rates than natural gas and oil, would bear nearly all the net costs. The results agree with previous predictions that due to the high fixed costs of the primary control technology (selective catalytic reduction) large coal generators would adopt the technology. These generators would be able to sell excess permits. Small generators would purchase permits or modify their boilers, and would have higher costs per unit of output. The results suggest that investors expected small generators to be more adversely affected.

The change in expected profits for oil and natural gas generators is close to zero. There is evidence that natural gas generators became more valuable, although the estimate is insignificant. These results reflect differences in emission rates across the types of generators, and agree with the EPA's predictions.

The empirical strategy is similar to a traditional event study, which would use a Capital Asset Pricing Model (CAPM) to estimate abnormal returns. The regression in the first stage that yields the counterfactual stock prices is identical to the CAPM. The difference is that the CAPM calculates the cost of the NBP from abnormal returns; I use the difference between the actual and counterfactual stock prices. The drawback of the CAPM is that the model cannot simultaneously allow for a linear relationship between the number of generators and the cost of the NBP, and estimate separate effects for different types of generators. For this reason I prefer the two stage approach, but I obtain similar results with a CAPM.

There are two considerations with estimating the effect of the NBP. Kahn and Knittel (2002) find that the enactment of the Acid Rain Program in 1990 did not affect the stock prices of electric utilities. They argue that state regulators would raise electricity prices to allow utilities to recover the compliance costs, and there would be no effect on profits. In contrast, the NBP was proposed in the late 1990s, as the restructuring of the electricity industry proceeded.[3] Investors did not expect utilities to recover costs (which explains why many utilities sued the EPA), and the program caused stock prices to fall.

Similar to this study, Ellison and Mullin (2001) consider an event in which investors learn about the cost of a policy over a period of several years. They use an isotonic regression to estimate the effect of potential health care reform on the stock prices of pharmaceutical companies in the early 1990s. I obtain similar results using an isotonic regression to those reported in the text.

Two other tradable permit programs demonstrate the need to compare firms' and the EPA's cost estimates. As mentioned above, *ex ante* cost estimates of the Acid Rain Program were too

[3] Recall that the Michigan decision occurred before the California energy crisis, when the majority of states were expected to restructure.

high. More recently, the Illinois Environmental Protection Agency (IEPA) initiated a permit program for volatile organic compounds (a precursor to ground-level ozone), which includes manufacturing plants in the Chicago metropolitan area. It appears that actual compliance costs have been lower than expected, and the IEPA committed to allocating too many permits. The market has not functioned well, with few trades and a permit price close to zero. Kosobud *et al.* (2006) argue that the program has not caused any reductions in emissions.

The paper proceeds as follows. The next section outlines the history of the NBP. Section 3 discusses the empirical strategy for estimating the change in expected profits, and section 4 describes the data. Section 5 presents the results and section 6 concludes.

2 The NO_x Budget Trading Program

I discuss the effect of the NBP and the appellate court decision on stock prices. Had the court ruled against the EPA, utilities in the Midwest and Southeast would have been regulated under the 1990 Clean Air Act Amendments. This is the counterfactual against which I measure costs in the empirical work.

2.1 Historical Background

In the mid 1990s, several northeastern states claimed that because of prevailing winds, NO_x emissions from the Southeast and Midwest were preventing them from complying with the Clean Air Act requirements for ozone (NO_x is an ozone precursor). They argued that the EPA should restrict NO_x emissions from the Midwest and Southeast.

In June, 1995, the Ozone Transport Assessment Group convened, consisting of representatives from 37 states and Washington, D. C. In June, 1997, the Ozone Transport Assessment Group recommended that the EPA establish a NO_x tradable permit system covering the East and Midwest.

Based on this report, in September, 1998, the EPA proposed a program to reduce emissions. The EPA's air pollution modeling had determined that pollution from 14 states contributed significantly to ozone levels in the Northeast. The NBP would include Alabama, Georgia, Illinois, Indiana, Kentucky, Michigan, Missouri, North Carolina, Ohio, South Carolina, Tennessee, West Virginia and Virginia and Wisconsin. Northeastern utilities belonged to a previous NO_x permit program, the Ozone Transport Commission; utilities in that program would join the NBP.[4] With the exception of Florida, the program would cover the entire Midwest and East. In this paper

[4]The Ozone Transport Commission included Connecticut, Delaware, Massachusetts, Maryland, New Jersey, New York, Pennsylvania, Rhode Island and Washington, D.C.

the term NBP region refers to states in the Southeast and Midwest, and NBP utilities include utilities with fossil fuel generators in the NBP region. In other words, this paper examines the effect of expanding the NO_x permit program to the Midwest and Southeast.

In its proposal, each year the EPA would give states a pre-determined number of NO_x permits. The states would allocate the permits to firms, and the EPA would help coordinate a trading program, in which firms could buy and sell permits (cross-state transactions were permitted). All firms owning fossil-fuel fired electric generators or large, NO_x-emitting manufacturing plants would submit permits at the end of each year to cover emissions during the previous summer. The EPA set the total level of permits such that the expected cost would be $2000 per ton of NO_x abated (based on the EPA's predicted compliance costs).

2.2 Michigan v. EPA (March 3, 2000)

Several utilities and states challenged the EPA in court. The primary complaint was that the EPA had not gone through the proper procedure to create the NBP, and could not force utilities to reduce emissions without an act of Congress. The decision by the D.C. Court of Appeals on March 3, 2000, in *Michigan et al. v. EPA et al.*, resolved the dispute, finding mostly in favor of the EPA.

The plaintiffs argued that the EPA had acted improperly in three ways: the original Clean Air Act implied that the EPA could not use compliance costs to include certain states and not others; the EPA's modeling was not sufficiently detailed to trace emissions to sources in specific states, and could not be used to determine which states to include; and the tradable permit system did not allow the states sufficient freedom to reduce their emissions, violating federal law. The court dismissed these claims, although it excluded Wisconsin from the program, and the EPA proceeded with its plan.[5]

There are two distinct periods between 1990 and 2000. From 1990-1995 there was little public discussion about NO_x regulation. The second period spanned 1996-2000, in which there was considerable uncertainty about whether and how the EPA would require a reduction in NO_x emissions. The press first publicized the OTAG meetings in late 1996 and it is unlikely that

[5] Several states had specific claims that they should not be included in the NBP. Thus, it was possible that even if the court permitted the NBP, these states would not participate. For example, Wisconsin and South Carolina argued that they should not be included; the court ruled that there was not enough evidence to include Wisconsin, but dismissed South Carolina's arguments. The court ruled that the EPA had not justified including all of Georgia and Missouri, but at the time of the decision it seemed likely that at least parts of these states would be included. I consider Georgia and Missouri as belonging to the NBP; they will join the program in 2007.

In addition, the court considered several issues regarding the calculation of the state budgets. Although most of these remained unresolved (they were sent back to the EPA for clarification and additional rulemaking), the decision may have affected the expected cost of the NBP, conditional on implementation. For example, the court supported the EPA's inclusion of certain small generating units. I address this issue below.

investors knew that the EPA might compel utilities to reduce NO_x emissions before 1996. Press coverage increased significantly in 1997 and 1998. As I show below, there was little movement of NBP stock prices before 1997, supporting the use of this starting date. The second period ends on March 3, 2000, when investors knew with certainty that the NBP would occur.

2.3 Implications of the Michigan Decision

Broadly speaking, there were two possible outcomes of the litigation: firms would either be regulated by the NBP or by the 1990 Clean Air Act Amendments.[6] I decompose the change in expected profits for an NBP firm at time t, $E_t(TC)$, into three components:

$$E_t(TC) = E_t(P) \cdot G \cdot E_t(C), \tag{1}$$

where $E_t(P)$ is the expected probability at time t that the EPA would create the NBP, G is the number of fossil-fuel generators located in the NBP region, and $E_t(C)$ is the expected net cost per generator. The variable $E_t(C)$ includes the cost of installing abatement technology, purchasing permits, and any other behavior caused by the program.

There are two important features of equation (1). First, the total cost increases linearly with the number of generators, which reflects a central aspect of the NBP. Firms may comply with the regulation in several ways: they may purchase permits, install a control technology (e.g., selective catalytic reduction), or modify their boilers. Consider a firm that complies by purchasing permits and assume that its generators have the same generating capacity and baseline emission rates. The firm's cost is proportional to the number of permits it purchases, which is the difference between its total emissions and its allocated permits. The allocation would be proportional to total baseline emissions and the utility would purchase the same number of permits for each generator. Thus, the total cost of the NBP would be proportional to the number of generators. The argument is similar for generators that install selective catalytic reduction or modify their boilers, because there are constant returns to scale across generators.[7]

Second, the expected cost, $E_t(TC)$, is measured relative to the counterfactual of continuing the 1990 Clean Air Act Amendments. These are the regulations that govern the western utilities,

[6] This assumption is for simplicity. In fact, there were several other possibilities. For example, the court may have granted the EPA the authority to enforce emissions reductions, but not by means of a tradable permit program. More generally, the expected cost of NO_x regulation at time t is equal to the sum of the probability of each mutually exclusive outcome, multiplied by the cost of the outcome. The analysis would be similar to the text, where $E_t(TC)$ would correspond to the effect of any regulation, relative to the 1990 Clean Air Act Amendments. As in the text, after the *Michigan* decision the change in stock price would reflect the cost of the NBP, compared to the continuance of the 1990 Clean Air Act Amendments, because the probability of any other outcome would be zero.

[7] In this discussion I assume that $E_t(P)$ and $E_t(C)$ are the same across all generators. I relax these assumptions in the empirical work and estimate the cost per generator by fuel type and size.

making them the appropriate control group.

Before the Ozone Transport Assessment Group convened, $E_t(TC)$ was equal to zero because both $E_t(P)$ and $E_t(C)$ were zero. Between that point and the *Michigan* decision, the probability was between zero and one, and $E_t(TC)$ was less than the conditional cost, $G \cdot E_t(C)$. There was considerable uncertainty during this period and $E_t(P)$ may have been much less than one; for example, on May 25, 1999 the same court issued a stay, preventing the EPA from proceeding.[8,9] After the *Michigan* decision the change in profits was equal to the conditional cost (i.e., $E_t(TC) = G \cdot E_t(C)$), because the probability was equal to one.

The decision also affected $E_t(C)$. Based on the text of the ruling, the direction of the effect is ambiguous, and the courts and the EPA did not resolve the disputes that affected $E_t(C)$ until 2001. As discussed below, the empirical strategy measures $E_t(C)$, just after the *Michigan* decision.[10]

3 Empirical Strategy

I derive the estimating equation and discuss the identification of expected net costs of the NBP. The empirical strategy is similar to a traditional event study, and I discuss the differences below.

3.1 Effect of the Michigan Decision on the Stock Prices of Firms

I consider a set of electric utilities located in the Midwest and Southeast. They maximize profits and are risk neutral. Time is discrete, denoted by t. Firm i owns a number of generating plants.

[8] The Appeals Court did not lift the stay in the *Michigan* decision. The EPA interpreted this as a formality, and in April of 2000 it sent letters to the NBP states, writing that they must submit their plans for implementing the program.

The Court lifted the stay on June 22, 2000, in a decision by the full panel. It does not appear that this decision addressed any new legal questions, supporting the use of March 3 as the date on which uncertainty was resolved. Below, I show that I obtain similar results if I use June 22 instead of March 3 as the end of the event window. Observers at the time of the June 22 decision did not expect any further appeals, so I do not consider subsequent dates.

[9] Investors probably anticipated the *Michigan* decision. Specifically, in the 1998 proposal, the EPA found that 22 states and Washington D.C. contributed significantly to the non-attainment of counties in the same region. The EPA used the 8-hour ozone standard to evaluate attainment, but the court ruled in May of 1999 that this standard was not appropriate. In late 1999 the EPA published its conclusion that the same states contributed to non-attainment using the 1-hour standard, which had already been established as a legitimate measure. Thus, the EPA had addressed some of the legal issues before the ruling, but the court had not yet ruled that it was satisfied.

[10] Because of certain legal technicalities, after the decision it was still uncertain whether states in the Midwest or Southeast would be included in the program in 2003, as opposed to 2004. This issue was not resolved until June of 2001, in *Appalachian et al. v. EPA*. Following that decision, the EPA decided that the Ozone Transport Commission states would enter the new program in 2003, and other states would enter in 2004. Part of Georgia and Missouri, as well as small generators and industrial boilers, will enter in 2007.

At the time of the *Michigan* decision it is uncertain when investors expected the NBP would begin and whether it would include Georgia and Missouri. In the empirical work, I treat all states in the Midwest and Southeast as being equally likely to be in the NBP in 2004. This should not create a large bias for two reasons: first, the share of generators in Georgia and Missouri in the total number of affected generators is small; second, I use a discount rate of 6 percent, so if investors in 2000 expected the NBP to begin in 2003 instead of 2004, the results would overestimate the expected annual cost by 6 percent.

At date $t = 0$, there are no plans for environmental regulation, and the stock price of firm i at time 0, P_{i0}, is proportional to expected profits. I express the stock price of firm i at time $t = 0$ as:

$$P_{i0} = \pi_{i0} + \omega_{i0},$$

where π_{i0} is the expected discounted profits from the firm's fossil fuel generators (coal, natural gas and oil); and ω_{i0} is the expected discounted profits from non-fossil fuel generators and other businesses owned by the firm.[11] I include non-fossil fuel generators (nuclear and hydroelectric) in the latter category because they do not emit NO_x.

At date $t = 1$, a committee forms to investigate the benefit and cost of reducing NO_x emissions for all fossil fuel fired generators. The time $t = 1$ corresponds to the formation of the Ozone Transport Assessment Group. There is considerable uncertainty as firms do not have any information about the extent of the emission reductions or the type of regulation (i.e., command-and-control versus a tradable permit system).

I decompose a generator's profits into two parts: $\pi_{it} = \widetilde{\pi}_{it} - E_t(TC)$. I define $E_t(TC)$ as the absolute change in expected profits at time t due to NO_x regulation. Thus, $\widetilde{\pi}_{it}$ corresponds to the counterfactual profits, if no regulation were expected.

At time $t = 2$ the EPA announces that it will create a program, the NBP, which will reduce NO_x emissions and allow firms to trade permits. There is some uncertainty about the costs of the program, and whether the EPA will be able to implement it. There are three components of $E_t(TC)$:

$$E_t(TC) = E_t(P) \cdot G_i \cdot E_t(C).$$

The total number of fossil-fuel generators for firm i is G_i. $E_t(P)$ is the expected probability, at time t, that the NBP will take effect. $E_t(C)$ is the conditional expected net cost of the program per generator, and includes the cost of all compliance strategies. The previous section discussed the linear relationship between expected costs and the number of generators.

The stock price of firm i at time $t > 2$ (i.e., after the EPA's announcement) is given by:

$$P_{it} = \widetilde{\pi}_{it} - E_t(P) \cdot G_i \cdot E_t(C) + \omega_{it}. \tag{2}$$

P_{it} is different from P_{i0} for three reasons: expected discounted fossil fuel generating profits, $\widetilde{\pi}_{it}$, may have changed for causes unrelated to the NBP; the firm's expected profits from other operations, ω_{it}, may have changed; and the NBP reduced expected profits.

[11] More precisely, π_{i0} is the expected discounted profits per share of stock, and similarly for ω_{i0}.

I define the variable $\widetilde{P}_{it}$, as the counterfactual stock price. $\widetilde{P}_{it}$ is the value of the firm at time t, had the EPA never announced its plans to create the NBP: $\widetilde{P}_{it} = \widetilde{\pi}_{it} + \omega_{it}$. The difference between the actual and counterfactual stock price is given by:

$$P_{it} - \widetilde{P}_{it} = -E_t(P) \cdot G_i \cdot E_t(C). \tag{3}$$

This quantity is equal to the expected cost of the NBP, at date t.

At time $t = \tau$, the obstacles preventing the implementation of the NBP are removed. At time τ, the expected probability, $E_\tau(P)$, is equal to one; τ corresponds to the day of the *Michigan* decision, March 3, 2000. The difference between the actual and counterfactual stock prices is:

$$P_{i\tau} - \widetilde{P}_{i\tau} = -G_i \cdot E_\tau(C). \tag{4}$$

The left hand side is equal to the expected cost of the NBP, at date τ.

3.2 Identification of Expected Costs

A comparison of equations (3) and (4) reveals one of the main difficulties with measuring the effect of the program. The right hand side of equation (3) contains two unobserved variables: the expected probability that the NBP will occur, and the conditional expected cost. I cannot identify the net cost of the NBP when the probability is less than one. After the *Michigan* decision, the expected probability is equal to one, and there is one unobserved variable on the right hand side of equation (4).

Equation (4) is the basis for the estimating equation. The expected cost of the NBP per generator, $E_\tau(C)$, is the coefficient in a regression of the difference between the actual and counterfactual stock price at time τ on the number of NBP generators. As I discuss below, it is straightforward to measure a firm's stock price ($P_{i\tau}$) and generators (G_i^N). I focus on estimating the counterfactual stock price, $\widetilde{P}_{i\tau}$.

I construct three groups of utilities, according to the locations of their generators. The control group consists of utilities without any generators in the East or Midwest. The NBP did not affect their stock prices after the *Michigan* decision. I refer to these firms with the superscript C. The second group contains fossil fuel generators in the Midwest or Southeast, and has the superscript N. The third group contains all other utilities, most of which were in the Ozone Transport Commission; I denote them with the superscript O.

I assume that before investors learn of the NBP, there is a stable relationship between the stock returns of the control group and the returns of other utilities. The stock return of firm i on date t is: $R_{it} = \ln[(P_{it} + D_{it})/P_{it-1}] - R_t^f$, where P_{it} is the stock price, D_{it} is the firm's dividends, and R_t^f is the risk free interest rate. Let R_{it} be the return of a firm in the NBP region or the Northeast, and let R_{it}^C be the return of a western utility. I define $\overline{R}_t^C$ as the mean return of firms in the control group, and estimate the following equation by OLS:

$$R_{it} = \alpha_i + \beta_i \overline{R}_t^C + \mathbf{X}_t \varphi_i + \eta_{it}, \tag{5}$$

where α_i is a firm-specific intercept, β_i is the correlation between the return of firm i and the average return of firms in the control group, and η_{it} is an error term. The matrix $\mathbf{X}_t$ includes the average return of natural gas utilities and three factors from Fama and French (1993): the difference between the returns of portfolios of small and large stocks; the difference between the returns of portfolios of value and growth stocks; and the excess market return. The vector φ_i is a firm specific vector of coefficients.[12] Observations are daily, and the sample spans January 2, 1990 – December 29, 1995. The endpoints are determined by data availability (see below) and the fact that it is unlikely that investors knew about the potential for regulation in the Midwest and Southeast before 1996. Note that this regression allows for a different relationship between the control variables and the stock return for each firm in the NBP and Northeast.

I compute the estimated counterfactual market returns during the event window, $\widehat{R}_{it}$, according to:

$$\widehat{R}_{it} = \widehat{\alpha}_i + \widehat{\beta}_i \overline{R}_t^C + \mathbf{X}_t \widehat{\varphi}_i.$$

The abnormal return for firm i at time t is $R_{it} - \widehat{R}_{it}$.

An important identifying assumption, as in any event study, is that the parameters α_i, β_i and φ_i do not change during the event window (1996-2000). This assumption is necessary to estimate the counterfactual stock prices. By assumption, there are no shocks, other than the NBP, which differentially affect firms in the treatment and control groups. Below I present several sources of evidence supporting this assumption.

I use the counterfactual return to estimate the cost of the NBP in the second stage. I calculate the counterfactual stock price, $\widehat{P}_{it}$, using the actual stock price on December 29, 1995, and iterating the following equation until March 3, 2000:

$$\widehat{P}_{it} = \exp(\widehat{R}_{it}^C + R^f)\widehat{P}_{it-1} - D_{it}. \tag{6}$$

[12] Among the independent variables the mean stock return of the control group, $\overline{R}_t^C$, explains the largest share of the variance of the dependent variable. Omitting the other variables does not affect the results.

I define the prediction error, ε_i, as the difference between the counterfactual stock price and $\widehat{P}_{i\tau}$. By defining the parameter $\delta = E_\tau(C)$, I can rewrite equation (4) as:

$$P_{i\tau} - \widehat{P}_{i\tau} = -\delta G_i^N - \varepsilon_i. \tag{7}$$

The change in the stock price of firm i, $P_{i\tau} - \widehat{P}_{i\tau}$, depends linearly on the number of generators in the NBP region, G_i^N. The parameter δ is the expected net cost of the NBP per generator at time τ.

The analysis includes several simplifications, which I now relax. First, I have assumed that the expected net costs are the same for different types of generators. I partition firm i's generators into two groups, indexed by the letter j: coal, and natural gas/oil. I estimate δ_j for both types of generators. Below I also consider specifications that separate generators by size and fuel type.

Second, I account for the effect on stock prices of the Ozone Transport Commission, the NO_x tradable permit program in the Northeast. Changes in the expected costs of this program between 1990-2000 would affect stock prices, as would differences between the expected cost of the NBP and Ozone Transport Commission. Consequently I control for the number of Ozone Transport Commission generators in the estimating equation.[13]

It is possible that utilities changed the types of generators they own in response to the NBP. In particular, since coal generators have substantially higher NO_x emissions rates, utilities may have sold or retired coal generators, and constructed natural gas/oil generators. I find some evidence that this occurred, and consequently, the independent variables are counts of generators in 1995, which could not have been affected by the NBP. The parameter δ_j corresponds to the cost of the NBP per generator owned in 1995.

The final consideration is that it may have taken time for investors to understand the implications of the *Michigan* decision. I compare the actual and counterfactual prices seven days after the decision, on March 10, 2000. The results are insensitive to different length windows.

To measure costs as positive numbers, I multiply equation (7) by negative one. The estimating equation is:

$$\widehat{P}_{i\tau+7} - P_{i\tau+7} = \sum_j \delta_j G_{ij}^N + \sum_j \iota_j G_{ij}^O + \varepsilon_i, \tag{8}$$

where ι_j is the coefficient on the number of generators belonging to firm i in the Northeast for generators of type j. The parameters of interest are δ_C and δ_{NO}, which are the cost per generator

[13] Because northeastern utilities already participated in a tradable permit program and the NBP may have affected their stock prices, I do not include them in the control group. However, if I estimate the cost of the NBP using both western and northeastern utilities in the control group I obtain similar, though smaller cost estimates.

of the NBP, for coal and natural gas/oil generators. I use the estimate of δ_j and the total number of generators in the NBP to calculate the total effect of the NBP on expected profits.

This empirical strategy is similar to a CAPM-based event study, which would use equation (5) to estimate abnormal returns during the event period. As in a CAPM approach, I estimate the relationship between the stock prices of NBP firms and a control group during the initial period. I assume that there are no differential shocks to NBP firms between January 2, 1996 and March 3, 2000. The difference is that the CAPM calculates the cost of the NBP from abnormal returns. My approach uses the difference between the actual and counterfactual stock prices.

The shortcoming of the CAPM is that it cannot simultaneously allow for a linear relationship between the number of generators and profits, and allow for the estimation of costs by generator type. It is possible to use the CAPM to estimate abnormal returns separately for each firm, then compute the average effect across firms. However, this specification would not allow me to determine the effect of the NBP on individual generator types. Alternatively, I could estimate equation (5) over the entire period from 1990-2000, and include a dummy variable equal to one during 1996-2000, which would measure the average abnormal return over the second period. By interacting this variable with the share of coal generators, I could estimate the abnormal returns for these generators. However, because the dependent variable is the rate of return, this specification would not allow for a linear relationship between the number of generators and profits. I report the results of both types of CAPM specifications below, and obtain similar results to the baseline cost estimate.

4 Data

To estimate equations (5) and (8) I match generator data from the DOE with stock price data from CRSP. Every year the DOE collects information on all electric generating plants in Form 860. This data is available on the DOE website beginning in 1990; I use date from 1990-2001.[14] For each investor-owned-utility and year, I calculate the number of generators by state and generator type. I distinguish two types of fossil fuel generators, according to the primary fuel: coal and natural gas/oil. Coal generators have much higher NO_x emission rates and are larger, over 280 megawatts (MW) on average; natural gas and oil generators are about 40MW.

I match the DOE utilities to stock prices in CRSP by company name. I use additional information, such as subsidiary names, in cases where the DOE and CRSP names do not match exactly. Utilities in the final data set satisfy several criteria: they are publicly traded, their stocks trade continuously from 1990-2000, and they are not located in Alaska or Hawaii.

[14] I use the 2001 data to compile the names of investor owned utilities. I cannot distinguish investor-owned-utilities from other utility types (e.g., municipal) prior to 2001.

The sample includes 70 firms. There was a wave of mergers and acquisitions in the late 1990s, coinciding with the partial restructuring of the electric power industry. The sample does not include utilities whose stocks discontinued trading as a result of a merger or acquisition.[15] The sample contains most large utilities in the NBP region. The utilities in the balanced panel own 80 percent of the fossil fuel capacity of publicly traded utilities in the NBP, and about 60 percent of the total fossil fuel capacity in the NBP.

Tables 1-3 provide summary information. Table 1 lists the names of the 70 utilities in the sample. The first column contains the control group: utilities that own generators in the West, but not in the Midwest or East during the entire period from 1990-2000. The second column lists the names of utilities with fossil fuel generators in the NBP region, and the third column contains the remaining utilities.

Table 2 provides summary statistics for the firms listed in Table 1. For the three categories of utilities, Panel A shows the mean market capitalization on December 29, 1995, total generating capacity, in MW, and fossil fuel generating capacity, with standard deviations in parentheses. NBP utilities have larger market capitalizations and total generating capacities. Equation (5) can account for these differences because it incorporates the possibility that firms have different expected returns and factor loadings.

Panel B shows the share in total generating capacity for coal and natural gas/oil generators in 1995. The total fossil fuel share is similar for western and NBP utilities, about 0.85, although NBP utilities have a larger share of coal. Eastern utilities have a similar fraction of total fossil fuel capacity, but are weighted more towards natural gas/oil.

Panel C shows the corresponding shares in 2000. Relative to 1995, western utilities have similar portfolios of generators, though there was a slight transition away from coal. NBP utilities show a larger decrease in coal generators and a corresponding increase in natural gas/oil. Northeastern utilities also move away from coal. This pattern suggests that utilities may have adjusted the composition of their generators in response to environmental regulation or for other reasons. I use data from 1995 to construct the independent variables; the NBP could not have affected generators owned in 1995.

Table 3 compares the generators of the NBP firms in the balanced panel with other generators in the NBP region (i.e., generators owned by other utilities or non-utilities). The generators of NBP firms are quite similar in size. This agreement, combined with the fact that the sample includes about 60 percent of the fossil fuel generating capacity in the NBP, implies that firms in

[15] The sample includes some utilities that purchased other utilities, such as American Electric Power, which acquired Central and South West in 2000. Below I show that the results are unaffected by dropping firms involved in mergers.

the sample would experience a similar change in profits to other firms, and that the estimation results should be representative of the entire population of electricity generators.

5 Results

5.1 Estimated Counterfactual Stock Prices

I first discuss the results of estimating the counterfactual stock prices. Figure 1 shows the actual and counterfactual stock prices of NBP utilities from 1990-2000. I estimate equation (5) and use equation (6) to calculate the actual and counterfactual stock prices for each firm. I compute the mean for each day, normalizing prices to one on the last day of the estimation sample, December 29, 1995 (denoted by the first vertical line). The figure shows the 95 percent confidence intervals, computed using the standard error formula in Salinger, 1992 (which accounts for correlation over time and across firms). The second vertical line indicates the date of the *Michigan* decision, March 3, 2000.

During the estimation period and until late 1996 the actual and counterfactual prices follow one another quite closely; the discrepancies are less than a few percent. After 1996, as investors learned about the Ozone Transport Assessment Group, the actual stock price falls below the counterfactual. The actual price continues to decline until late 1998, when the EPA published its proposal to establish the NBP. Between 1998 and 2000, the difference between the two series increases considerably, as the NBP became more likely. The difference stabilizes after the court decision.

Figure 2 provides support for the identification strategy. This figure is constructed using the same control group as in Figure 1, but it plots the average actual and counterfactual stock prices of utilities in the third category. Recall that most of these utilities were in the Ozone Transport Commission and were affected much less by the NBP. The actual and counterfactual prices are nearly identical in 2000.[16] I can reject at the 5 percent level the hypothesis that the difference between the actual and counterfactual prices for these utilities is as large as the difference for the NBP utilities.

5.2 Estimated Annual Costs

I now discuss the estimates of equation (8), shown in Table 4. In each regression, there are 48 observations, one for each utility in the NBP and the Northeast. The dependent variable is the difference between the counterfactual and actual stock prices on March 10, 2000. The

[16] Note that the estimates are less precise, and the two series differ somewhat more than in Figure 1 during the estimation period.

counterfactual is calculated using equations (5) and (6), and is the estimated stock price, had the NBP not been created. In column 1 the independent variables are the total number of fossil fuel generators in the NBP and Ozone Transport Commission regions. The coefficient on the number of NBP generators is 0.11, with standard error 0.03, which is significant at the 1 percent level.[17] Assuming a discount rate of 6 percent (following the analysis of the EPA, 1998), the NBP would cost about $1.3 million per year for the average generator in the sample.

Table 5 reports the estimated annual cost of the NBP from the results in Table 4. I first calculate the net cost to utilities in the sample using the total number of NBP fossil fuel generators and the number of shares of stock of the firms. I scale the sample estimate by the ratio of the total fossil fuel generating capacity in the NBP (obtained from EPA, 1998) to the fossil fuel capacity in the sample.[18] The specification in column 1 of Table 4 implies an annual cost of about $1.95 billion (2000 dollars), with a standard error of $610 million. In comparison, the EPA and Palmer *et al.* estimate compliance costs of about $2.2 billion. The results in Table 5 imply either that investors expected similar costs but did not expect utilities to be able to pass on the costs to consumers, or that investors expected larger compliance costs. The former interpretation agrees with Palmer *et al.*, who predict that the NBP would have a small effect on electricity prices, and that utilities would bear most of the costs.

In column 2 I investigate whether the expected costs of the NBP varied across the two types of generators. Since coal generators generally have much higher NO_x emission rates than natural gas and oil generators, they would be more likely to purchase permits or install capital equipment to reduce emissions. Many natural gas and oil generators would have baseline emissions similar to their allotted permits, and would not be affected by the NBP. I re-estimate equation (8), where the independent variables are the number of generators of each firm, by region and generator type (coal and natural gas/oil). There are considerable differences across the generator types. The estimated change in stock price per coal generator is 0.25 with standard error 0.06, significant at the one percent level. The annual change in profits for a coal generator is $3 million, which is similar to the EPA's estimate of compliance costs.

The point estimate on natural gas and oil generators is close to zero and insignificant. I can reject at the one percent level that the estimate is as large as the coal estimate. This result seems plausible, given the differences in emission rates noted above.

I use the estimates in column 2 to predict the annual cost of the program, similarly to column 1. I obtain an estimated cost of $2.02 billion per year, with standard error $590 million, reported

[17] For clarity of presentation I do not report the other estimated coefficients. In most cases, these estimates are small and insignificant, in agreement with the results shown in Figure 2.

[18] I scale by capacity instead of by the number of generators because I do not have data on the expected number of generators in the NBP.

in column 2 of Table 5. This is close to the estimate in column 1.

As noted above, the estimates in column 2 correspond to the change in expected profits for generators operating in 1995. If firms retired coal generators in the late 1990s, the effect of the NBP on coal generators operating in 2000 might be smaller. In column 3 I use the 2000 generator counts as independent variables. The results are similar to the baseline and suggest that the NBP would cost an operating coal generator about $3 million per year. This similarity suggests that the changes in generator shares reported in Table 2 were not correlated with the independent variables.[19]

Columns 4-6 of Table 4 report several other specifications. The corresponding total cost estimates are reported in columns 4-6 of Table 5. Oil and natural gas generators differ somewhat in size and baseline emission rates (natural gas generators are larger and emit less NO_x). In column 4 I separate these categories. The results provide some evidence that expected profits for natural gas generators increased, presumably because their utilization rates would increase or they would yield excess permits. However, the estimate is insignificant, and I cannot reject the hypothesis that the natural gas and oil estimates are jointly equal to zero.

In columns 5 and 6 I consider whether investors expected the NBP to affect large generators differently from small generators. Most of the costs of installing selective catalytic reduction (the main control technology) are fixed, and many observers expected that only large coal generators would find it profitable to install the technology. The emissions from these generators would decline by as much as 90 percent, allowing their owners to sell excess permits and recover much of the costs of selective catalytic reduction. Smaller generators would purchase permits and would have a larger decline in profits, per unit of generating capacity. Because the independent variables are counts of generators, if large and small generators had similar emission rates and respond similarly to the regulation, the coefficient on large generators would be significantly greater. On the other hand, if the coefficient on small generators is similar in magnitude or larger, this would imply that investors expected small generators to be more adversely affected, after normalizing by output.

In column 5 I separate coal generators into two groups, depending on whether they have a capacity above 280MW (the average capacity for the sample, shown in Table 3). As column 5 shows, the coefficient on large generators is slightly smaller. This result is consistent with the EPA's prediction that large generators would install selective catalytic reduction.[20]

[19] The results are similar to those reported in column 3 if I instrument the 2000 generator counts with the 1995 counts of generators.

[20] Expected costs may also vary for coal generators depending on whether they already have a control technology installed before 1995. I use data from the DOE's Form 767 to identify such generators, where the most common technology is a low-NO_x burner. However, there is not enough variation across firms to identify a different effect

Large natural gas generators have lower baseline emission rates and higher output, and the EPA would allocate more permits to them. In column 6 I separate natural gas/oil generators according to whether their capacity is above 40MW. The estimates suggest that investors expected large natural gas/oil generators to benefit slightly more from the NBP, though the estimate is insignificant.

As Table 5 shows, the annual cost estimates from these specifications are quite similar to the baseline. I conclude from Tables 4 and 5 that the effect of the NBP on electricity generators is consistent with the EPA's expectations about which utilities would be most affected by the program. Coal generators, particularly small generators, would be more adversely affected. The estimates broadly agree with the EPA's and Palmer *et al.*'s predictions of compliance behavior, namely, that large coal generators would be more likely to install selective catalytic reduction, and that their profits would fall by less, per unit of output.

5.3 CAPM Estimate of NBP Cost

For comparison, I use a CAPM to estimate the cost of the NBP. I modify equation (5) to obtain the following equation:

$$R_{it}^{N} = \alpha_i + \beta_i \overline{R}_t^{C} + \mathbf{X}_t \varphi_i + \phi_i N_t + \nu_{it}, \tag{9}$$

where variables and parameters are defined as in equation (5), except that t spans January 2, 1990 to March 10, 2000. The variable N_t is an indicator, equal to one if $t \in [1/2/96, 3/10/00]$; the parameter of interest is ϕ_i, which measures the average abnormal return for each firm.

Equation (9) is a standard CAPM, which allows for firm-specific coefficients on the independent variables, and estimates a separate cumulative abnormal return for each firm.[21] I use the estimates of ϕ_i to compute the total cost of the NBP.

I estimate a similar specification, in which the effect of the NBP is proportional to the number of fossil fuel generators in the program. I define the variable F_i as firm i's share of NBP fossil fuel generators in total generators. I modify equation (9) to obtain:

$$R_{it}^{N} = \alpha_i + \beta_i \overline{R}_t^{C} + \mathbf{X}_t \varphi_i + \lambda F_t + \nu_{it}, \tag{10}$$

where λ is the coefficient on fossil fuel generating share. Multiplying λ by the average fossil fuel share yields the average abnormal return over the event window. Similarly to the baseline

for generators with low-NO_x burners and those without.

[21] It is possible to estimate an equation similar to equation (9), but imposing the restriction that ϕ_i is equal across firms. This specification is not numerically equivalent to the one reported in the text, but the resulting cost estimate is nearly identical.

specification, the effect of the NBP on stock prices is increasing in the number of fossil fuel generators. However, equation (10) does not allow for a linear relationship between the number of generators and the stock price, because the dependent variable is the stock return.

I report the results of estimating equations (9) and (10) in columns 7 and 8 of Table 5. I estimate these equations by a Seemingly Unrelated Regression estimator. The standard errors account for correlation across firms and over time (see Salinger, 1992). These regressions yield estimated average abnormal returns, which I convert to cumulative abnormal returns (CARs) using the number of days in the estimation window. I then use the CARs to calculate the change in market capitalization for firms in the sample, and scale this estimate by the ratio of generating capacity in the NBP to the fossil fuel generating capacity in the sample. The annual cost estimate using equation (9) is \$2.82 billion, and is \$1.67 billion for equation (10). The latter estimate is significant at the 10 percent level, and is similar to the baseline estimate of \$2 billion in column 2. As noted above, I prefer the baseline specification because it allows the number of generators to affect the stock price linearly, and estimates the effect of the NBP by generator type.[22]

5.4 Robustness

5.4.1 Potential Omitted Variables

The main potential source of bias is an omitted variable correlated with the independent variables. I investigate a number of possibilities below, such as the sulfur dioxide regulation, and find that they do not affect the results.

The first two columns in Table 6 focus on demand and productivity shocks. I merge Compustat data with the CRSP/DOE data set to obtain each firm's net earnings in 1995 and 2000. I include the change in this variable from 1995 to 2000, to control for persistent unobserved productivity shocks during this time period. The main estimates in column 1 of Table 6 are similar to the baseline, suggesting that such shocks are not affecting the results. The estimated coefficient on net earnings is insignificant.

A negative demand shock to the NBP region in the late 1990s would cause a decline in revenue, as well as a decline in stock prices. In column 2 I use Compustat data to control for the change in revenue between 1995 and 2000. The main estimates are unaffected and the estimate

[22] As discussed in the introduction, it is also possible to estimate the cost of the program with an isotonic regression (see Ellison and Mullin, 2001). The main assumption in this approach is that the expected cost of the program is monotonically increasing between 1996 and 2000. I obtain a similar estimate, of about \$2.3 billion per year.

on revenue is negative and insignificant (not reported).[23,24]

The Acid Rain Program may have affected the values of generators in the NBP region, biasing the results. This program was created by the 1990 Clean Air Act Amendments, and consisted of two phases: Phase I spanned 1995-2000, and Phase II began in 2000. Phase I included 262 large boilers (mainly coal fired) with especially high sulfur dioxide emission rates. Phase II included a wider range of generators. Many of the generators in both phases are located in the NBP region.

As discussed in the introduction, Kahn and Knittel find that stock prices did not respond to the creation of the program in 1990, arguing that state regulators would allow utilities to recover compliance costs. However, as electricity restructuring began in the mid 1990s, stock prices may have fallen if investors did not expect utilities to be able to recover future costs of the Acid Rain Program. In that case, the baseline estimates of the NBP would include the effect of the Acid Rain Program and would be biased away from zero.

In column 3 I separate Phase I coal generators from other coal generators, using the DOE's Clean Air Act Database. If profit shocks to Phase I generators were driving the results, the coefficient on non-Phase I generators would be smaller than the baseline estimate, and the coefficient on Phase I generators would be larger. This is not the case; the estimate on non-Phase I generators is 0.34, with standard error 0.19. The coefficient on Phase I generators is 0.15, and is insignificant. Thus, I find little evidence that shocks to Phase I generators affected profits.

More generally, restructuring may have reduced expected profits if utilities did not expect to be able to recover the costs of previously made capital investments. In column 4 I separate coal generators according to whether they have a scrubber. This specification differs from column 3 because some firms installed scrubbers to comply with Phase I, and others installed them because of different regulations. Furthermore, many generators in Phase I did not install scrubbers. Utilities' stock prices would decrease during restructuring if they could not recover installation costs, which could be several hundred million dollars. This would have a similar effect as Phase I status; the estimate on coal generators without scrubbers would be smaller than the baseline estimate and the coefficient on coal generators with scrubbers would be larger. The estimate on the non scrubber category is precisely estimated and nearly identical to the baseline, suggesting that this is not a major concern. These results agree with the hypothesis that utilities expected

[23] Other possible measures of productivity or profits, available from Compustat, yield similar results.

[24] A negative demand shock to the NBP region would affect all generators, including non fossil fuel generators. I can test for such a shock by including counts of non fossil fuel generators as independent variables in the baseline regression. If a decline in demand had a large effect on profits, the coefficient on non fossil fuel generators would be positive and significant, and the coefficient on coal generators would be smaller and possibly insignificant. In practice, the coefficient on coal generators is similar to the baseline and precisely estimated, and the coefficient on non fossil fuel generators is small and insignificant. However, there is not enough variation in non fossil fuel generators to reject a large change in profits.

to recover the costs of the Acid Rain Program and other sunk investments during restructuring.

Litigation unrelated to the NBP may have affected stock prices. During the late 1990s, the EPA sued several utilities for not complying with the New Source Review provisions of the Clean Air Act. New Source Review requires that a utility substantially reduce emissions when it modifies an existing power plant. The EPA claimed that some utilities had performed modifications without installing the appropriate technology; the utilities argued that these activities were routine maintenance, and were not covered by New Source Review. Although many of these lawsuits were not resolved before March 3, 2000, stock prices may have fallen in anticipation of expected costs, creating an upward bias.

In column 5 I omit the 5 NBP firms sued by the EPA: American Electric Power, Cinergy, Dominion Resources, Ohio Edison and Southern. The estimate on coal generators would be smaller than the baseline if New Source Review litigation were driving the results; in fact it is larger. The most likely interpretation of this result is not that the litigation had no effect on stock prices, but that the NBP superseded the litigation. That is, the NBP meant that these firms would either have to install the same equipment as required by New Source Review, or that they would incur other costs (e.g., from purchasing permits), which would have similar effects.

Mergers of NBP firms between 1996-2000 may bias the estimates. There are several possible concerns related to mergers, which would imply that the sample is not representative of all firms affected by the NBP. First the sample does not include some merger participants because their stocks discontinued trading. If the compliance costs for these firms were different from firms in the sample, the results would be biased. Second, if a firm is involved in a merger and its stock continues trading, the merger may affect the stock price for reasons related to the NBP (e.g., the compliance costs are lower for the acquired firm) or for other reasons. Using information from the DOE (2000), in column 6 I omit firms involved in mergers between 1995-2000, or involved in proposed mergers, as of April, 2000. The results are nearly identical to the baseline, suggesting that the sample of utilities is representative.

Investors may have viewed the *Michigan* decision as a precedent under which the EPA could impose other regulations on the utility industry. The estimates in Table 4 would include the effects of potential regulations, creating bias. For example, several states were initially included in the Ozone Transport Assessment Group, but were not included in the NBP. Investors may have expected that the *Michigan* decision would enable the EPA to expand regulation to include these states (essentially, this will occur when the Clean Air Interstate Rule begins in 2009). The decision would have had a negative effect on the stock prices of utilities to the west of the NBP, biasing the NBP estimates towards zero. Restricting the control group to the 10 utilities located in the original Ozone Transport Assessment Group states but not in the NBP would lead to smaller estimates. In column 7, the estimates on generator counts are quite similar to the baseline, as is the corresponding total cost estimate, \$1.79 billion (standard error, \$529 million). In column 8 the control group includes utilities located entirely in states that were not part of the Ozone Transport Assessment Group. The estimates confirm the results in column 7. It appears that the baseline estimates do not include the effect of expanding NO_x regulations further West.

Finally, it is possible that restructuring lowered utilities' expected profits. If that were the case, the stock prices of western utilities located in deregulated states would also decline. Restricting the control group to these utilities would lead to smaller abnormal returns for the NBP utilities. In column 9 the estimates are quite similar to column 2 of Table 4, suggesting that the results are not driven by restructuring *per se*, but rather by the combination of restructuring and the NBP (recall that in the absence of restructuring, the NBP would not have affected expected profits).

5.4.2 Additional Results

Table 7 reports the results of several additional specifications. The cost estimates are generally robust to alternative estimation models.

It may have taken more than one week for investors to fully understand the implications of the *Michigan* decision. In that case, a seven day window would not be sufficient. I use a one month window in column 1; the dependent variable is the difference between the counterfactual and the actual stock price on April 3, 2000. The estimates are similar to the baseline.

Although the *Michigan* decision affirmed the EPA's ability to begin the NBP, the court did not lift the stay it had granted on May 25, 1999. As noted above, the EPA considered this issue a formality, but the court did not lift the stay until June 22, 2000.[25] One might interpret June 22 as the date on which the expected probability of the NBP, $E_t(P)$, was equal to one, rather than March 3. In column 2 the dependent variable is the difference between the counterfactual and the actual price on June 29. The estimates are close to the previous results.

An important identifying assumption is that the parameters estimated in equation (5) are constant from 1996-2000. Otherwise, adding observations to the estimation window after March 10, 2000 would likely affect the estimated costs. In column 3 I include stock returns from March 11, 2000 - December 31, 2000 in estimating equation (5). The results are similar, which suggests

[25]It is unclear why the court did not lift the stay on March 3. In the baseline model I assume that it was obvious to observers that after the *Michigan* decision the NBP would go forward as planned, and that the stay was a relatively trivial obstacle. Contemporary articles in the trade press support this assumption.

that the parameters in equation (5) did not change. Note that these results further supports the assumption that there were no differential profit shocks during the event period, which was the focus of Table 6.

Another possibility is that the parameters in equation (5) varied during the estimation period. In that case, changing the endpoints of the estimation window would affect the results. In column 4 the sample used to estimate equation (5) includes observations from January 2, 1990 - May 31, 1995 (which predates the first meeting of the Ozone Transport Assessment Group), and in column 5 the sample includes January 2, 1991 - December 29, 1995. The estimates are similar in both specifications, but I prefer the baseline regression because the results are more robust to other specifications.

It is possible that counts of Ozone Transport Commission generators do not adequately control for shocks to northeastern utilities. The specification in column 6 omits firms in the third column of Table 1. The estimates are similar to the baseline: the coal estimate is smaller, though significant at the one percent level and the natural gas/oil estimate is negative and insignificant.

Given the small number of observations in these regressions, I consider whether the results are sensitive to outliers. In column 7 I drop the 4 firms with extreme values of the dependent variable, which does not affect the estimates. Omitting the four firms with the largest and smallest counts of coal generators (column 8) leads to a larger estimate for coal, though the corresponding total cost estimate is quite similar to the baseline (not reported). In column 9 I report a median regression, where the results are again close to the baseline. Thus, the results are fairly insensitive to outliers.[26]

In the baseline specification I assume that all generators of a given fuel type have the same change in expected profits. Alternatively I could assume that the change in expected profits increases linearly with generating capacity. In column 10 the independent variables are the generating capacity, in gigawatts (GW), by region and fuel type, in place of generator counts. The estimates in column 10 imply similar expected changes in profits. Coal generators have a precisely estimated cost per GW of capacity, which corresponds to an annual cost per generator of \$2.1 million, similar to the baseline figure. The estimate on natural gas/oil generators is insignificant. Note that since these generators are much smaller than coal, the implied cost estimate per generator (\$290,000) is also much smaller. The total cost estimate of the NBP is close to column 2 of Table 5, \$1.7 billion, with standard error \$511 million. I prefer the baseline specification because the results are less sensitive to outliers, i.e., firms with extremely large coal

[26] The results are also insensitive to dropping one firm at a time from the baseline regression.

generators.

6 Conclusions

This paper presents a simple method for predicting the cost of environmental regulation, before the regulation takes effect. I use changes in stock prices to calculate the expected net cost of the NBP. I exploit variation across firms in the location and type of generators they own to construct counterfactual stock prices and to estimate the expected cost of the program by generator type. I estimate an annual cost of about \$2 billion, which is similar to previous estimates that use a bottom-up method to simulate the response of the entire industry to the NBP. I conclude that firms had similar expectations as the EPA and other economists about the effects of the program.

More broadly, the relative simplicity of implementing event studies should make them useful for analyzing other proposed policies, such as greenhouse gas regulation, where employing the bottom-up approach may be more difficult. Event studies have not been widely used for environmental regulation because of a concern that unobserved profit shocks might bias the results, given the long time between a regulation's proposal and its adoption. I have investigated a number of potential demand and supply shocks, and this does not appear to be a serious concern with the NBP. In other contexts the event window may be significantly shorter if it is possible to estimate the total cost of the program before it is adopted.

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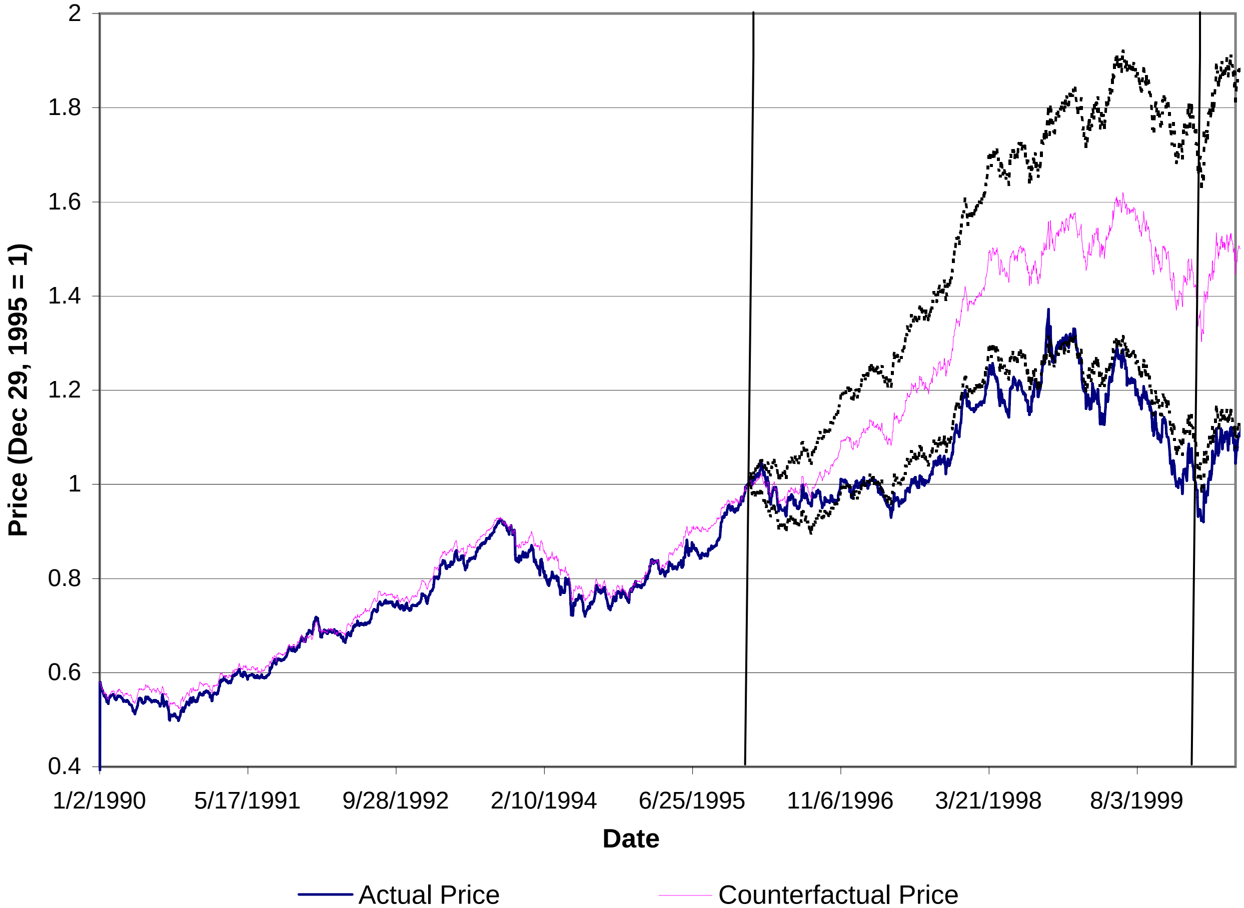
Figure 1

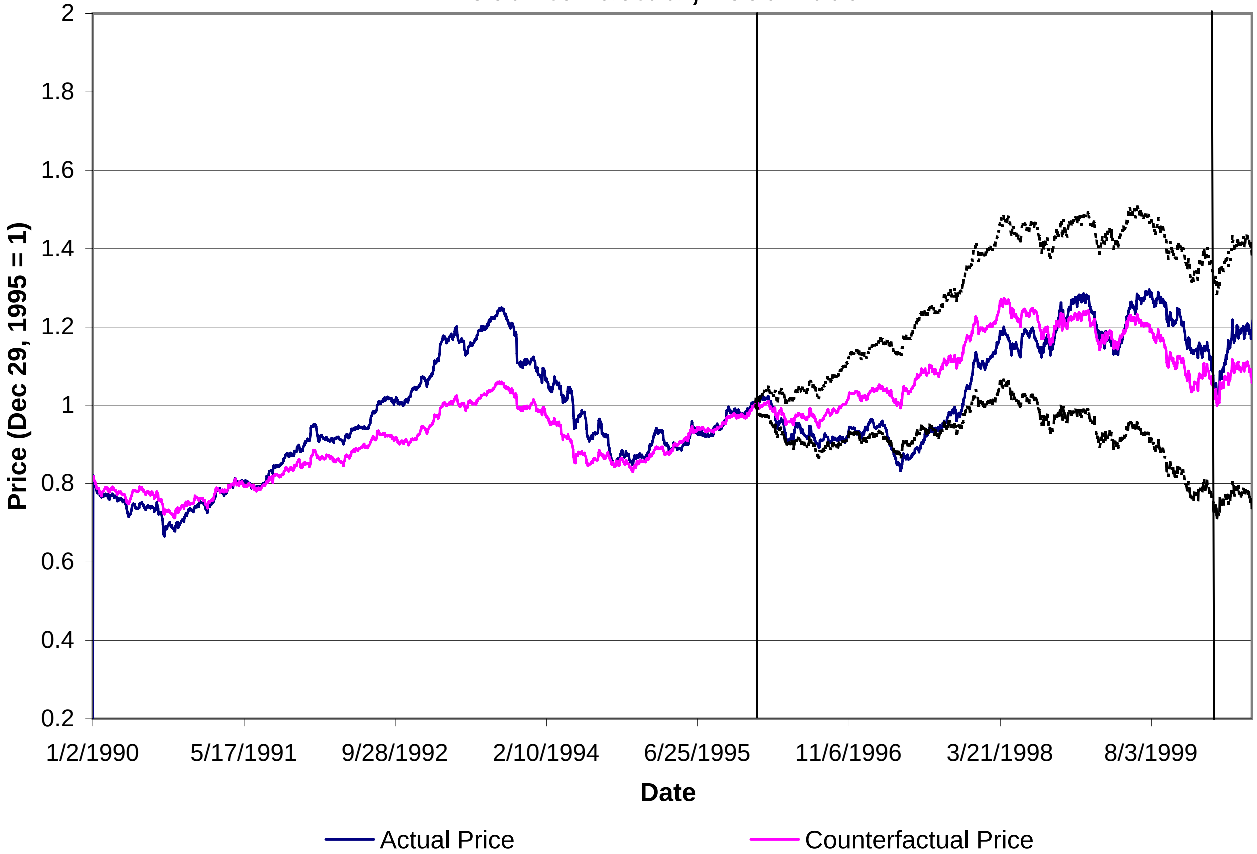
NBP Stock Prices: Actual vs. Counterfactual, 1990-2000



Notes: Counterfactual price is the mean predicted stock price of firms with fossil fuel generators in the NBP region. Counterfactual prices were calculated using the predicted returns from equation (6), with prices normalized to one on December 29, 1995 (see text). Actual price is the average daily stock price of the same firms, normalized to one on the same date. The first vertical line indicates the end of the estimation period, December 29, 1995. The second vertical line denotes the date of the Michigan decision, March 3, 2000. The dashed lines are the 95 percent confidence intervals around the estimated predicted price from 1996-2000.

Figure 2

Ozone Transport Commission Stock Prices: Actual vs. Counterfactual, 1990-2000



Notes: Actual prices, counterfactual prices and standard errors are computed as in Figure 1. The sample includes all utilities in column 3 of Table 1 (see text).

Table 1

Investor Owned Utilities in Balanced Panel

	Western Utilities	NBP Utilities	Eastern Utilities not in NBP
1	Black Hills	Allegheny Energy	Baltimore Gas and Electric
2	Central Louisiana Electric	American Electric Power	Bangor Hydro Electric
3	Idaho Power	C M S Energy	Central Hudson Energy
4	Montana-Dakota Utilities	Carolina Power and Light	Central Vermont Public Service
5	Madison Gas and Electric	Cinergy	Citizens Utilities
6	Minnesota Power and Light	Dayton Power and Light	Consolidated Edison
7	Montana Power	Duquesne Light	Entergy
8	Nevada Power	Delmarva Power and Light	FPL
9	Northwestern Public Service	Detroit Edison	G P U
10	Oklahoma Gas and Electric	Dominion Resources	Green Mountain Power
11	Otter Tail Power	Duke Power	Houston Industries
12	Pacific Gas and Electric	Empire District	Long Island Lighting
13	Pinnacle West	Indianapolis Power and Light	Maine Public Service
14	Public Service Company of NM	Kansas City Power and Light	New York State Electric and Gas
15	Puget Sound Power and Light	NIPSCO	Niagara Mohawk
16	SCE	Ohio Edison	Northeast Utilities
17	TECO	Potomac Electric Power	Northern States Power CO MN
18	Texas Utilities	SCANA	PECO
19	Tucson Electric Power	Southern	Pennsylvania Power and Light
20	W P L	St Joseph Light and Power	Public Service Enterprise Group
21	Washington Water Power	Union Electric	Rochester Gas and Electric
22	Western Resources	Utilicorp	UGI
23		Wisconsin Energy	United Illuminated
24			Unitil
25			WPS

Notes: The table lists the names of all publicly traded investor owned electric utilities, whose stock prices appear in the CRSP database from January 1, 1990 - December 31, 2000 (see text). Each utility was matched to the Department of Energy Form 860, to obtain the locations and types of its generators. Western Utilities include all firms whose generators are located west of the NBP region, and which do not own generators in the NBP region or the Northeast. NBP Utilities include firms with fossil fuel generators in the NBP region in 1995. Eastern Utilities Not in NBP include all other utilities.

Table 2

Firm Summary Statistics

	Western Utilities	NBP Utilities	Eastern Utilities not in NBP
	Panel A: Market Capitalization and Generating Capacity in 1995		
Number of Firms	22	23	25
Market Capitalization	2,234 (3,172)	3,771 (2,704)	2,834 (2,769)
Generating Capacity (MW)	4,256 (5,684)	8,800 (9,003)	5,539 (5,781)
Fossil Fuel Generating Capacity (MW)	3,359 (4,594)	7,109 (7,558)	4,097 (4,705)
	Panel B: Share of Generating Capacity in Total in 1995		
Coal Generating Capacity	0.54 (0.26)	0.64 (0.16)	0.26 (0.29)
Natural Gas/Oil Generating Capacity	0.30 (0.23)	0.21 (0.16)	0.47 (0.31)
	Panel C: Share of Generating Capacity in Total in 2000		
Coal Generating Capacity	0.48 (0.26)	0.56 (0.22)	0.15 (0.20)
Natural Gas/Oil Generating Capacity	0.32 (0.21)	0.30 (0.18)	0.39 (0.29)

Notes: Each cell reports the mean across firms in the corresponding sample, with the standard deviation in parentheses. Data is from CRSP, Compustat and DOE Form 860 (see text for details). Firms are assigned categories as in Table 1. Market capitalization is the stock price on December 29, 1995, multiplied by the number of shares of stock. Generating capacity is the total capacity, in MW, in 1995. Fossil fuel generating capacity is the total generating capacity, in MW, of coal, natural gas and oil generators in 1995. Share of generating capacity is the ratio of the capacity of the indicated generator type to the total generating capacity in the corresponding year.

Table 3

Capacity of Generators in NBP Region

	Generators Owned by Utilities in Sample	All Generators in NBP
All Generators	111.15 (202.61) {24.15}	92.42 (188.89) {19.00}
Coal Generators	278.61 (243.55) {185.28}	240.30 (234.20) {165.00}
Natural Gas/Oil Generators	40.31 (74.81) {20.00}	24.28 (59.50) {5.10}

Notes: Each cell contains the mean capacity of the indicated generators, in MW, from the 1995 Form 860. Standard deviations are in parentheses and medians are in brackets. Generators Owned by Utilities in Sample include all generators owned by the firms in column 2 of Table 1. All Generators in NBP include all generators in Form 860 in the NBP region.

Table 4

Effect of the NBP on Expected Generator Profits

	All Generators	Number of Generators by Fuel Type	2000 Generator Counts	Include Oil and Natural Gas Generators Separately	Include Large and Small Coal Generators Separately	Include Large and Small Natural Gas Generators Separately
	Dependent Variable: Difference Between Counterfactual And Actual Stock Prices					
	(1)	(2)	(3)	(4)	(5)	(6)
All	0.11 (0.03)					
Coal		0.25 (0.06)	0.27 (0.06)	0.26 (0.06)	0.23 (0.34)	0.26 (0.06)
Natural Gas/Oil		0.00 (0.05)	-0.02 (0.04)		0.00 (0.05)	-0.04 (0.15)
Natural Gas				-0.13 (0.15)		
Oil				0.02 (0.07)		
Small Coal					0.25 (0.20)	
Small Natural Gas/Oil						0.00 (0.06)
Number of Observations	48	48	48	48	48	48
R^2	0.23	0.27	0.35	0.29	0.27	0.27

Notes: Huber-White standard errors in parentheses. The sample includes utilities in the second and third columns of Table 1. To construct the dependent variable, equation (5) is estimated by Ordinary Least Squares (OLS), using observations from January 1, 1990 to December 29, 1995. The dependent variable in equation (5) is the daily return for each firm with at least one generator in the Midwest or East. The independent variables are the average return for firms located entirely in the West, the three Fama-French factors and the average stock return of natural gas utilities. Counterfactual stock price is calculated using the estimated coefficients from equation (5) (see text). Table 4 shows the results of estimating equation (8). The dependent variable in all regressions is the difference between the counterfactual and actual price on March 10, 2000. All regressions are estimated by Ordinary Least Squares (OLS). The independent variables in columns 1,2 and 4-6 are counts of generators in 1995, by region (the NBP region and the Northeast); column 3 uses counts of generators in 2000. Table 4 reports only the coefficients on the NBP variables. The independent variables are the total number of fossil fuel-fired generators, by region in column 1. Columns 2 and 3 include the number of coal and natural gas/oil generators by region. Column 4 separates natural gas and oil. Coal generators in column 5 includes coal generators with a capacity of at least 280MW and small coal generators include all other coal generators; similarly for column 6, where small natural gas/oil generators have capacities less than 40MW.

Table 5

Annual Net Cost of the NBP (Billion 2000 Dollars)

	All Generators	Number of Generators by Fuel Type	2000 Generator Counts	Include Oil and Natural Gas Generators Separately	Include Large and Small Coal Generators Separately	Include Large and Small Natural Gas Generators Separately	CAPM using Equation (9)	CAPM using Equation (10)
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
Annual Net Cost	1.95	2.02	1.97	1.94	2.06	2.08	2.82	1.67
	(0.61)	(0.59)	(0.46)	(0.54)	(0.61)	(0.58)	(1.32)	(1.03)

Notes: Huber-White Standard errors in parentheses. Columns 1-6 report the estimated total annual net cost for NBP generators, using the corresponding estimates from columns 1-6 in Table 4. The total cost for firms in the sample is obtained by multiplying the number of generators in the sample by the corresponding estimate in Table 4, and by the total number of shares of stock. The total cost for NBP generators is the product of the sample cost and the ratio of total NBP fossil fuel generating capacity to the fossil fuel capacity in the sample. The annual cost estimate applies a six percent discount rate to the total cost estimate and assumes that the NBP would begin in 2004. Columns 7 and 8 report the annual cost calculated from the estimated abnormal returns in equations (9) and (10) (see text).

Table 6

Potential Omitted Variables

	Control for change in profits	Control for change in revenues	Include Phase I Coal Separately	Include Coal with Scrubbers Separately	Drop New Source Review Firms	Drop Firms Involved in Mergers	Control Grp Incl Utilities in OTAG, not in NBP	Control Grp Incl Western Utilities	Control Grp Incl Utilities in Dereg States
	Dependent Variable: Difference Between Counterfactual And Actual Stock Prices								
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
Coal	0.26 (0.05)	0.23 (0.05)	0.35 (0.18)	0.24 (0.11)	0.46 (0.15)	0.29 (0.12)	0.22 (0.05)	0.29 (0.07)	0.26 (0.06)
Natural Gas/Oil	0.01 (0.05)	-0.01 (0.05)	-0.03 (0.06)	0.00 (0.06)	-0.04 (0.08)	0.02 (0.06)	-0.01 (0.05)	0.01 (0.05)	0.00 (0.05)
Phase I Coal			0.13 (0.22)						
Coal With Scrubbers				0.28 (0.33)					
Number of Observations	46	46	48	48	43	34	48	48	48
R^2	0.27	0.28	0.27	0.27	0.23	0.28	0.25	0.28	0.27

Notes: Huber-White standard errors in parentheses. The dependent variable is the difference between counterfactual and actual stock prices, constructed as in Table 4, except in columns 7-9. Columns 7-9 report the same specification, using different utilities to construct the control group in equation (5). Column 7 includes utilities located in states participating in the Ozone Transport Assessment Group, but not included in the NBP. Column 8 includes utilities located in states that were not in the Ozone Transport Assessment Group. Column 9 uses utilities located in western states that had begun electricity restructuring in 2000 (see text). The independent variables are counts of generators in 1995, by type and region. All regressions are estimated by OLS. Column 1 includes the firm's change in profits between 1995 and 2000, and column 2 includes the change in revenues, obtained from Compustat. Counts of generators in Phase I of the Acid Rain Program and counts of coal generators with scrubbers were obtained from the DOE Acid Rain Program database (see text). Coal generators in column 3 include all coal generators not in Phase I of the Acid Rain Program. Coal generators in column 4 include all coal generators without scrubbers. Column 5 omits the five NBP firms affected by the EPA's New Source Review litigation: AEP, Dominion, Cinergy, Ohio Edison and Southern. Column 6 omits firms involved in mergers between 1995 and 2000 (see text).

Table 7

Additional Robustness Results

	One Month Window	Estimate Equation (8) on 6/22/00	Include Post-3/10/00 Obs in Estimation Period	End Estimation Period 5/31/95	Begin Estimation Period 1/2/91	Omit Firms With Generators in OTC	Omit Obs With Extreme Values of Dep Var	Omit Obs With Extreme Coal Generator Counts	Median Regression	Generator Capacity by Fuel Type
	Dependent Variable: Difference Between Counterfactual And Actual Stock Prices									
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
Coal	0.27 (0.05)	0.29 (0.05)	0.25 (0.07)	0.25 (0.09)	0.35 (0.06)	0.19 (0.06)	0.25 (0.05)	0.43 (0.10)	0.19 (0.09)	0.63 (0.15)
Natural Gas/Oil	0.05 (0.05)	0.04 (0.06)	-0.05 (0.06)	-0.01 (0.08)	-0.07 (0.04)	-0.07 (0.05)	-0.01 (0.04)	-0.06 (0.06)	-0.04 (0.06)	0.61 (1.10)
Number of Observations	48	48	48	48	48	23	44	44	48	48
R^2	0.31	0.29	0.18	0.23	0.28	0.37	0.31	0.25		0.26

Notes: Huber-White standard errors in parentheses. The dependent variable is the difference between the counterfactual and actual stock price, constructed similarly to Table 4. In column 1 the actual stock price on April 3 is subtracted from the counterfactual price. In column 2 the actual stock price on June 29 is subtracted from the counterfactual price. In column 3 equation (5) is estimated using observations from January 2, 1990 - December 29, 1995 and from March 11, 2000 - December 31, 2000. Column 4 uses observations from January 2, 1990 - May 31, 1995 and column 5 uses observations from January 2, 1991 - December 29, 1995. The independent variables in columns 1-9 are counts of generators, by type and region. Column 10 uses generator capacity, in GW, by type and region. Columns 1-8 and 10 are estimated by OLS; column 9 is a median regression. Column 6 includes utilities with fossil fuel generators in the NBP region. Column 7 omits utilities with the two largest and two smallest values of the dependent variable on March 10, 2000. Column 8 omits the four utilities with the largest and smallest numbers of coal generators in the NBP region.