Minimizing Costs, Maximizing Sustainability

Finance Working Paper N° 702/2020
March 2021

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ECGI Working Paper Series in Finance

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Abstract

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Keywords: Product Market Competition, Environment, ESG

JEL Classifications: G30, D22, Q52, Q53

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Minimizing Costs, Maximizing Sustainability

Abstract

Do strong incentives to cut costs lead firms to neglect negative externalities? We find that cost-cutting incentives can be environmentally friendly. To arrive at this conclusion, we examine uniquely detailed plant-level data of private and public firms in the most polluting industry in the US - electric utilities. To establish causality, we exploit the staggered passage of restructuring legislation, which opened the market to competition and incentivized utilities to cut costs. Following the restructuring, plants moved to cheaper but less polluting production processes. In addition, competition forces have improved allocation of operation across competing plants, contributing further to pollution reduction.

Introduction

In the last several years, investors have increased demand for sustainable investment and even started to pressure firms to become more sustainable (Hartzmark and Sussman, 2019, Bialkowski and Starks, 2016, Bolton and Kacperczyk 2020, Krueger, Sautner, and Starks 2019, Gloßner 2019, Dimson, Karakas, and Li 2015). Despite the growing demand from investors and the rise of environmental activism, not all firms respond equally to these calls. Some firms make massive investments to reduce their environmental impact, while others resist the pressure, deeming sustainability too costly to afford.

Do cost considerations impede adoption of sustainable policy in corporations? Would firms that do not derive significant benefits from adopting sustainable processes still choose to become sustainable? Existing literature typically assumes that adopting sustainable production is costly. Therefore, sustainability is value enhancing because its benefits (such as reduced legal risk, investor and customer preferences, and employee motivation) surpasses its costs. However, it is not clear that this assumption is indeed correct. It is possible that cost-minimization incentives, even absent benefits, can enhance sustainability and even substitute for other mechanisms such as investor pressure or regulatory intervention. Our goal is to examine whether, for a given level of benefits, cost-minimization incentives enhance sustainability.

Analyzing the effect of cost-cutting incentives on sustainability is empirically challenging for several reasons. First, we need to identify the space of potential actions that firms can take to become more sustainable. Second, we need to be able to quantify the costs and benefits that each action entails. Third, we need to disentangle cost-minimization incentives from other economic forces that affect corporate sustainability.

We address the empirical challenges by focusing on the US utilities industry – the nation's largest polluter. This industry set-up provides numerous advantages, allowing us to overcome each of the empirical challenges above. First, electric generation process is homogeneous across fossil-fuel plants. As a result, the space of all possible production and investment decisions that, in turn, affect the environment is well-understood. Second, data regarding corporate decisions in this industry are rich and detailed, allowing us to quantify the benefits and costs of each action. Specifically, we are able to obtain plant-level data of public and private plants, including quantities and prices of inputs and outputs, as well as pollution levels and pollution abatement expenses. Lastly, we take advantage of the staggered passage of restructuring across US utilities during the 1990s which has increased incentives to cut costs by opening the market to competition. This setup mitigates endogeneity concerns and allows us to identify cause and effect between cost-cutting incentives and pollution.

Our main finding is that in states that underwent restructuring, subsequent plant-level declines in pollution occurred as compared with plants in nonrestructured states. Using a difference-in-differences approach, we find that, following restructuring, the average plant in a restructured state showed an 18% decrease in pollution levels compared to the average plant in a nonrestructured state. Further, the decrease was concentrated in larger plants, thereby resulting in even greater average emissions reduction.

We then examine potential sources of the reduction in pollution. The technology of electricity generation permits plant managers to undertake three types of actions to alter emissions levels: (i) enhanced pollution abatement; (ii) change in fuel mix towards less polluting fuel; and (iii) increased production efficiency (i.e., higher electricity generation for a given energy input).

Our first finding is that there is no enhanced pollution abatement in restructured states compared with non-restructured states. In fact, plants in restructured states have actually reduced their abatement activity compared with plants in non-restructured states. For the average plant in the restructured states, investment in pollution-reducing equipment decreased by 55% following the restructuring, as compared with plants in nonrestructured states. Additionally, plants in restructured states decreased their overall abatement expenses by 35% as compared with plants in nonrestructured states.

In contrast, we find strong evidence that plants in restructured states have reduced their environmental impact by changing their fuel mix. Specifically, the affected plants shifted from a heavily polluting fuel, oil, towards the least polluting fuel, natural gas. In restructured states, the reliance on gas within the affected plants increased on average by 9%, whereas the reliance on oil decreased on average by 8% after the restructuring, as compared with plants in nonrestructured states. Although coal use overall remained relatively stable, we find that plants increased their reliance on more polluting types of coal. Finally, we find that plant efficiency in restructured states increased in comparison to plants in nonrestructured states, as measured by the ratio between electricity output and heat input.

After establishing our main findings, we gauge the role of cost-minimization incentives of plants in restructured states. To pinpoint the cost-cutting mechanism, we explore the sensitivity of the affected plants' fuel choice to pre-restructuring costs. We find that the tendency of plants in restructured states to adopt cost-efficient fuels increased among affected plants whose cost structure was particularly high prior to restructuring. The cost-cutting channel is also consistent with the finding that coal-based plants moved towards lower-quality coal.[1]

We also find that the comparatively more efficient allocation of production across plants in restructured states was another channel at work. Prior to restructuring, utilities operated as regulated monopolies, and the price of electricity was determined on a cost-plus basis. Namely, whenever demand peaked and plants had to rely on less efficient peaking units, the price of electricity rose. Following restructuring, underutilized competing plants had the opportunity to offer their electricity at a cheaper price whenever local plants went into overcapacity, thereby enabling a more efficient production allocation across competing plants. Consistent with this argument, we find an improvement in efficiency among affected plants following restructuring. Further, the capacity factor (i.e., actual production relative to capacity) declined in affected plants, which is consistent with the argument that local plants had to yield whenever they went into overcapacity. We also find that the decrease in the capacity factor following restructuring explains the improvement in the efficiency gap between restructured plants and regulated plants.

We also ensure that our results are not driven by omitted variables correlated with both the restructuring and the drop in pollution. To that end, we examine parallel trends around the restructuring year and show that the reduction in pollution was statistically significant only after the restructuring. We also explore differences between Independently Owned Utilities (IOUs) and Municipal Utilities (*Munis*) within states; primarily, the latter were largely exempt from restructuring. We find that *Munis* did not change their production or emissions behavior following

[1] A move from one type of fuel to another can entail setup costs. In general, the switch to/from coal from/to other types of fuel is costly, while the switch from/to gas to/from petroleum is comparatively cheap. We therefore do not expect petroleum or gas plants to switch to coal.

restructuring. Third, we perform additional cross-sectional tests to further alleviate concerns regarding alternative causes for the change in pollution in utilities in restructured states.

We discuss the extent to which firms' environmental strategies following restructuring can be explained by alternative channels. One argument is that consumers favor environmentally friendly producers and are willing to put a premium on their products. With enhanced competition following restructuring, utilities may have begun to differentiate themselves by going green. To evaluate this argument, we take advantage of the fact that restructuring involved two stages, namely wholesale restructuring and retail access restructuring. Although all restructured states have allowed electricity generators to compete in the wholesale market, only a portion have opened their markets to retail sales access, which would enable end-users to choose their electricity providers. If the consumer channel is in play, then the impact of the reform on emissions production should be pronounced in those states that have implemented retail competition. However, we find that this is not the case.

Another possibly instrumental economic channel is the legal channel. Restructuring legislation requires major changes in rulings, therefore its passage may potentially open the industry to litigations, some of which could be established on the grounds of environmental concerns. To the extent that restructuring exposes utilities to new legal threats, affected utilities may try to mitigate the legal risks by becoming more environmentally friendly. [2] However, an additional set of tests shows the greatest decreases in pollution among cleaner plants relying on gas as primary fuels, whereas plants that rely primarily on coal, and should therefore be more susceptible to litigation risk, show increased emissions levels.

[2] In addition, regulators may act favorably towards firms if they observe that they are environmentally friendly. For example, Hong et al. (2019) find that regulators favor socially responsible firms and view them as more reputable.

Finally, we consider the role of the investor channel. If restructuring has attracted more environmentally-friendly investor clientele, then that clientele may demand pollution reduction. We note that this channel, while consistent with our findings' overall trend in emissions, cannot explain the cross-sectional variations found in our study. For example, we find that coal-based plants have increased their emissions levels, while gas-based plants have decreased emissions. Moreover, long-term investors who place the highest value on environmentally friendly policies (Starks et al., 2017), are shown to be attracted to regulated utilities (e.g., Brochet et al., 2012).

Our study contributes to emerging finance research that studies the drivers of corporate environmental policy. Past contributions include the effect of limited liability (Akey and Appel, 2020a), legal risk (Ben-David et al., 2020); shareholder preferences (Naaraayanan et al., 2020; Akey and Appel, 2020b; Shive and Forster, 2019); and financial constraints (Bartram et al., 2019; Xu and Kim, 2020; Goetz, 2019).

This paper augments the above literature by examining the role of cost-cutting incentives and product market competition on corporate environmental policy. The effect of product market competition on corporate environmental decisions is of particular relevance due to the tendency of competition to motivate cost cutting and increase the focus on profitability, which may be implemented at the expense of environmental protection (Friedman, 1970). We highlight the claim that cost-cutting incentives can bring about lower negative externalities. In our setting, regulated utilities had fewer incentives to adopt new, more cost-efficient production; higher pollution was the byproduct of this inefficiency. We also show a potentially important side effect of competition largely overlooked in the literature: Product market competition can lead to more efficient allocation of resources across competing plants which, in turn, further reduces the negative impact of corporate production activity on the environment.

Our work also belongs to a growing strand of finance literature whose methodology entails placing a single industry at the core of its empirical design to provide precise inferences regarding the forces that shape corporate policies (e.g., Benmelech, 2009; Benmelech and Bergman, 2011; Gilje et al., 2020; Decaire et al., 2020). Detailed and precise empirical setting is critical for a study of corporate environmental activity, because a change to environmental policy may be attributed to different economic channels. The detailed production-level data allow us to distinguish among those channels. In particular, observing the costs and benefits of different production processes for each plant is crucial for concluding that the observed environmental policies are a by-product of cost-efficient production processes.

Finally, a number of finance papers have recently pointed out a trend in the form of an increase in product market concentration and a decline in competition in the US (Grullon et al., 2019; Gutierrez and Philippon, 2019), which, in turn, has implications for investment (Barkai 2019), labor markets (Benmelech et al., 2018), and entrepreneurship (Decker et al., 2014, 2016)). Our work contributes to this strand of research by exploring environmental implications of changes in a competitive landscape. We thereby offer another channel through which industry consolidation may affect stakeholders.

The rest of the study continues as follows. Section 2 provides a summary of the electric utility industry and its restructuring. Section 3 presents the data and Section 4 reports the results. Section 5 examines the findings in light of the different hypotheses and Section 6 concludes.

2. The Electric Utility Industry in the US

This section provides a brief summary of the US electric utility industry. It consists of an explanation of how electricity is generated (Section 2.1) and how the electricity generation process affects the environment (Section 2.2). Section 2.3 describes the restructuring process of electric utilities in the US.

2.1 Electric Generation

The focus of our study is steam turbine electric plants that are powered by fossil fuel. This type of plant was responsible for generating approximately 70% of all US electricity during our sample period.

The basic process of electricity generation starts with burning fossil fuels to heat a boiler and create steam to rotate a turbine. The turbine is connected to a generator that rotates through opposing magnetic fields. The rotation induces the flow of electricity, which then travels to its final destination through a network of power grids. The steam that leaves the turbine is cooled and fed into the boiler again.

Plants differ in their modes of operation. Base load power plants usually provide a continuous supply of electricity throughout the year with minimum power generation requirement. These plants are often larger and tend to be cheaper to operate. Peaking power plants are often smaller and run only during peak hours of electricity demand.

Three main types of fossil fuels are used to generate heat in steam turbine electric plants: coal, petroleum, and gas. These fossil fuels differ in their heat content as measured by the amount of fossil fuel required to generate one unit of heat. Fossil fuels also differ in cost and environmental impact.

2.2 Environmental Concerns and Environmental Regulation

The main environmental concern associated with steam generating plants is the hazardous byproducts emitted when burning fossil fuels.[3] A chief byproduct is sulfur dioxide (SO_2), which causes acid rain proven harmful to plants and to animals that live in water. SO_2 also worsens respiratory illnesses and heart diseases in humans. Another hazardous byproduct is nitrogen oxides (NOx), which contribute to ground-level ozone and irritate and damage human lungs. Third, burning fossil fuels emits the poisonous gas carbon monoxide (CO), as well as particulate matter (PM), which results in hazy conditions in cities and scenic areas. Coupled with ozone, PM contributes to asthma and chronic bronchitis, especially in children and the elderly. In addition, burning fossil fuels emits small amounts of heavy metals such as mercury, which are hazardous to human and animal health. Finally, electric plants emit large quantities of carbon dioxide (CO_2). While not as toxic as other byproducts, CO_2 contributes to the greenhouse effect responsible for global warming.

Among the three fuels used for steam power-plants operation, coal has the most damaging emissions content, followed by petroleum and natural gas. For example, burning coal to generate one billion British Thermal Units (BBTU) of heat is associated with approximately 2,600 pounds of SO_2. A typical power plant uses 22,000 BBTU per year, resulting in approximately 57 million pounds of SO_2. In contrast, generation of the one BBTU of heat by burning petroleum is associated with 1,122 pounds of $SO_{2.}$ Finally, burning natural gas is associated with one pound of SO_2 for one BBTU.

[3] Other environmental concerns include (i) the use of water resources to produce steam, provide cooling, and serve other functions; (ii) discharges of pollution into water bodies, including thermal pollution (water that is hotter than the original temperature of the water body); (iii) generation of solid waste, which may include hazardous waste;(iv) land use for fuel production, power generation, and transmission and distribution lines; and (v) harmful effects on plants, animals, and ecosystems that result from the air, water, waste, and land impacts above.

To mitigate the environmental effects of burning fuel, electric plants can employ three main strategies. First, they can adopt less polluting fossil fuel: rely on natural gas or less pollutive coal, or pretreat the coal. Second, plants can capture the flue gas during the fuel burning process. Capturing the pollutants can be done in several ways, but the most efficient one requires an apparatus called a flue-gas desulfurization unit (FGD), or scrubber. Scrubbers remove about 90% of the pollution in the flue gas, but are expensive (Baasel, 1988). Third, plants can increase efficiency, resulting in less fuel required to produce the same amount of electricity. Efficiency can be increased, for example, by replacing older equipment with newer boilers, turbines, and generators.

Electric utilities are required to abide by the emissions standards of the Clean Air Act, which the US introduced in 1970 and significantly amended in 1990. The most relevant amendment for electric utilities was Title IV, which was specifically directed at SO_2 and NOx emissions from utility power plants. The amendment was implemented in two phases: Phase I, which became effective January 1, 1995, required 110 listed power plants of greater than 100 MW electrical capacity and with high emissions levels to considerably reduce their emissions ("Table 1 Units").[4] Phase II, implemented in 2000, targeted all units with capacity of at least 75 MW. Phase II has affected the majority of US electric plants.

2.3 Restructuring of the Electric Utility Industry

This subsection briefly summarizes the restructuring process of the electric utility industry in the US. For more detailed explanations see, e.g., Warwick (2002) and Joskow (1997).

[4] Those units were referred to as "Table 1 units" because they were listed in Table 1 of the allowance allocation regulation, 40 CFR 73.10. Additional 182 units were allowed to substitute for "Table 1 Units" in reducing overall utility emissions levels.

Historically, electric utilities operated mostly as vertically-integrated regulated monopolies, owning generation, transmission, and distribution of electricity within their localized geographic market. The majority of plants in the US are owned by private investors and denoted as investor-owned utilities (*IOU's*). A minority of the plants are owned by the public government or local municipalities, as well as member-owned cooperatives across municipalities (*Munis*).

State regulators set the price of electricity based on utility costs in a process called a rate case, a lengthy and complex procedure for determining both the electricity price level and the price design. A rate case can be initiated by either the local public utility commission (PUC) or by the utility itself. A utility generally initiates a rate case only when it needs to increase revenues or believes that it needs a higher rate of return to attract investment capital. The PUC will initiate a rate case if it believes rates are in excess of their cost of service or cost of capital. Rate cases are examined by the regulator on a periodic basis, usually every several years.

By the early 1990s it became apparent that electric industry regulatory approaches were not working. The demand for electricity increased, attempts to build new plants faced regulatory constraints, and the regulatory process was time-consuming and expensive. As a result, states began adopting different versions of industry restructuring in the early 1990s. The restructuring involved opening the electricity utilities to competition both within the state and outside the state. In the restructured supply system, generation and distribution became unbundled and power plants were free to compete with each other through a market mechanism to sell electricity to distributors or customers. Purchasing of power is done via market mechanisms like the power exchange, and transmission scheduling is conducted by an independent body known as the Independent System Operator (ISO).

Between 1990 and 1999, a total of 23 states plus the District of Columbia restructured their electric utility industry. The regulation affected primarily the IOUs. Munis were not compelled to restructure and were permitted to rely on their own production and distribution systems in their own localized markets.

Numerous studies have shown a positive effect of the restructuring on cost-cutting actions and improved efficiency of utility plants. For example, Fabrizio et al. (2007) show that plants have decreased non-fuel costs after the restructuring, whereas Bushnell and Wolfram (2005) and Davis and Wolfram (2012) show that plants have increased their output-to-input efficiency.

In addition, the economics literature analyzing the competitiveness of the electricity industry after restructuring has established that electricity price levels have generally become competitive (see, e.g., the Federal Energy Regulatory Commission (FERC) report to Congress, 2011). Davis and Bushnell et al. (2017) conclude that "despite the notable isolated failures of competition, U.S. electricity markets are now found to be reasonably competitive overall…" (page 2).

3. Data

The main dataset for the analysis consists of annual plant-level data of fossil-fuel generated electric utilities in the US. The dataset combines three different sources: EPA, EIA, and Utility Data Institute (UDI), as described below.

Emissions data are obtained from the Environmental Protection Agency (EPA). Electric utilities are required by law to monitor and disclose their emission levels. Within the EPA platform, our emission data comes from two sources. First, we rely on data from the Emissions & Generation Resource Integrated Database (eGRID). The eGRID database is based on plant-specific data for all US electricity generating plants that provide power to the electric grid and report data to the US government. The information on emissions starts from 1996 and, according to the EPA, is a comprehensive source of data on the environmental characteristics of almost all electric power generated in the US. Data reported include mass emissions of carbon dioxide (CO_2), nitrogen oxides (NO_x), sulfur dioxide (SO_2), and other chemicals. The eGRID database reports this information on an annual basis and at different levels of aggregation, namely plant, state, and grid regions of the country.[5]

Although eGRID provides detailed information with respect to plant emissions, it does not cover the pre-restructuring years for most states. Therefore, the concern arises that the resulting time-series is too short to capture emission patterns of utility plants prior to the restructuring to a meaningful degree. To extend the time-series, we supplement the eGRID information with historical information on emissions from a different platform, Air Markets Program Data (AMPD), which is also managed by the EPA.[6] Because SO_2 is one of the principal byproducts of fossil fuel burning and is considered a major threat to human health and to the environment, the US government began gathering SO_2 emissions data as early as the 1980s. AMPD provides information on emission levels of SO_2 for the years 1980, 1985, 1990, and annually from 1995. We therefore combine our eGrid data with information on SO_2 emissions for the years 1985, 1990, and 1995.[7] The only complete available data are for SO_2 emissions, therefore we focus on this pollutant in our analysis. However, as we will elaborate in the analysis section, our findings extend also to other chemicals involved in the production of electricity.

[5] https://www.epa.gov/energy/emissions-generation-resource-integrated-database-egrid.
[6] https://ampd.epa.gov/ampd/.
[7] Air Markets Program Data also reports statistics on NO_x, but these data start in 1995. We therefore focus our analysis on SO_2 pollution.

We further augment our dataset with information from the US Energy Information Administration (EIA). EIA is a statistical and analytical agency within the US Department of Energy, which collects comprehensive data covering a full spectrum of elements related to the energy generation process, including sources, uses, technologies, and distribution. The information is usually available at a plant level.[8]

The majority of the EIA information in our project comes from Form EIA-767. Specifically, the data on capital investment in pollution abatement as well as expenditures associated with the collection and disposal of byproducts during the generation process, are obtained from Form EIA-767 files. Information on boilers (installation date and primary fuels type), as well as the information on the use of flue-gas desulfurization (FGD) equipment (including its installation date), are also collected from this form. Next, we include data on quantities of fuel by fuel type (coal, natural gas, or petroleum). This information is collected in Form EIA-423 and is available at monthly frequency (we sum up monthly fuel use by each fuel type within each calendar year). Finally, we rely on Form EIA-861 to obtain information on electricity sales and prices, which we also convert into annual frequency. Because plant production and plant emissions datasets both rely on the same type of plant identifier, namely the Office of Regulatory Information Systems Plant Location (ORISPL), merging the EPA and EIA databases is straightforward.

The third dataset is collected from the Utility Data Institute (UDI) Operations and Maintenance (O&M) Production Cost Database, which combines data from the following publicly available resources: The Federal Energy Regulatory Commission (FERC); the US Energy Information Administration (EIA); and the Rural Utilities Service (RUS). The dataset contains

[8] Some reports provide more granular information (e.g., at a unit, boiler, or generator level). In these cases, we aggregate information at a plant level; the data are available online at www.eia.gov and are categorized into topics (each topic corresponds to a specific form the plant needs to fill out).

basic plant characteristics such as plant ownership, age, location, and capacity. The dataset additionally contains additional production-related factors, including (i) energy output measured in net Megawatt hours (MWh); (ii) energy input measured in British thermal units (BTUs) of fuel consumption; (iii) number of employees; (iv) fuel; and (v) nonfuel expenses. Nonfuel expenses primarily consist of operation and maintenance expenses, as well as wage and salary expenses. Fabrizio et al. (2007) have combined these variables into one dataset and have made it available for researchers. Their data spans the period 1981–1999 and contains all large fossil-fuel steam and combined-cycle gas turbine generating plants with a capacity of 100 megawatt hours (MWh) and higher[10] Overall, for the 599 facilities that appear in the Fabrizio et al. (2007) dataset in all the years that overlap with EPA data we were able to find data on 572 facilities with nonmissing SO_2 information in the eGRID or Air Markets Program datasets.

Table 1 summarizes key variables in our sample. An average plant generates approximately 3.4 terawatt-hours of electricity a year, so that the combined production of our sample plants accounts for close to 60% of the total electricity generated in the United States during that time. Consistent with the fact that only a small fraction of municipal utilities has a capacity of 100 MW and higher, 80% of our plants are investor-owned. Regarding emissions, plants allocate on average around $2 million a year on pollution abatement activities; however, significant variation occurs across plants. Finally, our plants also differ substantially in the types of input they use. An average plant uses coal as the primary fuel in two-thirds of its operating boilers, compared to 27% and 11% reliance on gas and petroleum, respectively.[11]

3.1 Restructuring

The restructuring reform affected 23 states plus the District of Columbia. The reform in each state began with several rounds of formal hearings prior to establishing the laws in question. The process took between two and three years; therefore, identifying the specific year that captures the economic impact of the reform is challenging. To address this issue, we follow the assignment method proposed by Fabrizio et al. (2007), and for the reform implementation year, we use the year of the formal hearing initiation in those states that passed restructuring legislation by the end of our sample period. As will be described in further detail in Section 4.1, our parallel-trends test results confirm that plants began to alter their emissions activity as early as the hearings stage.

Figure 1 shows the states that restructured their utility industry and the restructuring year. New York was the first state to begin the restructuring process in 1993, followed by eight additional states in 1994 and a further nine states in 1995. Two states and the District of Columbia restructured their utilities industries in 1996, and three additional states followed suit in 1997.

The economics literature points to high electricity prices as the main driver of a given state's decision to restructure its electric utility industry (Joskow 1997, White 1996, Fabrizio et al., 2007; Sharabaroff et al. 2009). To test the validity of this argument within our sample, in Table 2 we examine the determinants of states' choice to restructure. To that end, we run a logit regression where the dependent variable is a dummy variable that equals one if the state restructured its utility industry between 1993–1999, and zero otherwise. The independent variables are electricity prices during the three-year period prior to the first restructuring initiation, as well as additional controls.[12]

The specification in Table 2 Column 1 confirms the conjecture that electricity prices are an important driver of restructuring in a state. To evaluate the extent to which electricity prices explain the restructuring decision, we re-estimate the regression using OLS and find the adjusted R-squared of 20% (unreported for the sake of brevity). In Table 2 Column 2 we also control for the fuel mix. Variations in endowments of fossil reserves across states may be related to a number of state-level economic factors, including the prices of fuel types and electricity, as well as employment in mining, oil refinery, transportation industries, etc. These factors, in turn, may play an additional role in the state's restructuring decision. Empirically, we augment our estimation with the quantities of each of the fuel types used (measured in logs of their physical quantities). Because the total quantity of fuel used is significantly affected by state electricity consumption, we scale each fuel quantity variable by total electricity produced by all of our sample plants in a given state-year (measured in net MWh). The results indicate that the inclusion of fuel quantities improves the overall explanatory power of the regression, as measured by pseudo R-squared. However, neither of the fuel variables is statistically significant. Importantly, the negative coal quantity coefficient and the positive coefficient on gas indicate that the decision to restructure is unlikely to be driven by high state-level pollution. In Table 2 Columns 3 and 4, we explore the potential role of pollution in a more direct way and include the state-level amount of emissions as another independent variable. Similar to the fuel quantities, we scale the emissions by MWh.[13] We find that the level of SO_2 has no significant explanatory power, and the price of electricity remains the only statistically significant variable. To summarize, our analysis of the restructuring determinants indicates that the reforms were driven primarily by high electricity prices and are unlikely to be triggered by the emissions levels in a given state.

We do not expand our database beyond 1999 because several events occurred in the early 2000s that complicated the restructuring process in certain states. Specifically, electricity prices in California skyrocketed in 2000–2001, due to market manipulation and the shortage of electricity.

As a result, the state of California suspended its restructuring. Other states began debating whether to continue with the restructuring process, and five additional states (Oklahoma, Arkansas, New Mexico, Nevada, and Montana) postponed restructuring. Those developments contaminate our difference-in-differences setting in the post-1999 period. For example, it is not clear whether a state that began and then postponed restructuring following the California crisis should be assigned into a treated or control group. Also, a significant delay implementing already initiated restructuring processes undermines our assumption that the impact of the reform starts at the hearings stage; a delay further prevents identifying the true year of the reform for the treated states. Finally, it is not clear whether the states that did not initiate the restructuring process did so because they had originally decided against this policy or because they were waiting to see the resolution of the energy crisis for other states. Consequently, to ensure that we accurately capture the causal effect of competition on the outcomes of interest, we restrict our data to the years before 2000.

4. Results

In the first set of tests, we ask whether the level of SO_2 emissions changed following restructuring. Specifically, we take advantage of the reforms in the electric utility sector to form a difference-in-difference test of the effect of restructuring on firms' pollution levels.

Our baseline OLS regression tests the impact of a competition shock on SO_2 output of utility plants using difference-in-differences (DiD) framework. Our specification takes the following form:

$$(1) \qquad Ln(SO_{2i,s,t}) = \beta_1 * Restructure_{s,t} + \beta_2 Scrubber_{i,s,t} + \beta_3 PhaseI_{i,s,t} + \alpha_i + \delta_t + \varepsilon_{i,s,t}$$

where the dependent variable is the natural logarithm of the level of toxic emissions of SO_2 (in tons) by plant *i* under the jurisdiction of state *s*, in year *t*.[14] $Restructure_{s,t}$ is a dummy variable that equals one for every plant in a state that eventually passed the restructuring law, starting from the year of the first restructuring hearing and onward, and zero otherwise. We also include a set of control variables to capture technological and regulatory differences across plants that can subsequently have an effect on emissions levels. The first variable, $Scrubber_{i,s,t}$, is an indicator variable that takes on a value of one if the plant has at least one FGD unit in operation (operating status "OP") in a given year, and zero otherwise. The second variable, $PhaseI_{i,s,t}$, is a dummy variable for whether the plant had at least one unit that was specifically required to participate in the Acid Rain program (i.e., belongs to "Table 1 Units"). As discussed in greater detail in Section 2, beginning in 1995, the Acid Rain program imposed stringent requirements on a subset of the most polluting plants. About 6% of the plants in our sample were identified under the Act.[15]

In designing our empirical specifications, we assume that the variation in control variables and the technological differences are unlikely to be driven by the restructuring. The Clean Air Act of 1990, which flagged the facilities that would become subject to Phase I of the Acid Rain program, was passed several years prior to the first talks of deregulation. Similarly, we find that most of the variation in the *Scrubber* variable is driven by the years prior to restructuring hearings (unreported for the sake of brevity). Specifically, approximately 84% of the scrubbers in our sample were installed prior to 1993, which is the year the first state, New York, began formal restructuring hearings. Restructuring may have affected certain plants' decisions to install scrubbers. We address this argument in the later part of our analysis.

In a variant of Specification 1, we also control for the overall level of production, as measured by net electricity generation in MWh, converted into logs.[16] Because SO_2 is significantly affected by the amount of output produced, a change in output following the restructuring could have been the driver of the results.

Lastly, we include plant-epoch fixed effects and year fixed effects. Including plant fixed-effect absorbs unique production characteristics of the plant as well as regional characteristics, such as demand for electricity, weather conditions, proximity to input factors, etc. We follow Fabrizio et al. (2007) and use plant-epoch, rather than just plant fixed effects as a more refined way to capture key production characteristics of a facility, as well as to neutralize the effect of deregulation on plant-level capacity. Specifically, if the capacity of a plant changes by more than 15%, we consider it a new entity epoch. We also include time fixed effects to account for common industry factors such as production shocks driven by economic conditions, country-wide weather profile that could affect demand, etc. Standard errors are double clustered by year and plant-epoch.[17]

4.1 Effect of Restructuring on Pollution Levels

The results on the impact of restructuring on emissions are presented in Table 3. In our baseline specification, summarized in Table 3 Column 1, we find that the restructuring has a negative and statistically significant impact on emissions levels. The impact of the reform is also sizeable: Following the restructuring, the average reduction in log SO_2 emissions was -33% compared to changes in pollution in nonaffected plants. The comparison of this result to that in Table 3 Column 2, where we control for the level of production, demonstrates that some of the decline in pollution could be attributed to changes in total production. However, the impact of restructuring remains high: After controlling for the level of production, the restructuring leads to roughly 20% reduction in log SO_2 emissions. Our control variables are also statistically significant and show the expected sign. A plant that installs a scrubber, or flue-gas desulfurization (FGD) technology, reduces its log emission by 85% on average. The impact of being included in the Phase I program is also considerable, in terms of reducing the emissions of affected plants by close to 40%.

Although the results in the first two columns show an average percentage decrease in emissions across plants, whether this decrease translates into a meaningful economy-wide emissions decrease depends on plant size. Larger plants tend to be base load plants, which produce larger amounts of electricity overall. We therefore separate our estimation into the groups of large and small plants to examine which plant types are the drivers of our main results. To measure plant size, we rely on the information about net megawatt (MW) capacity. We use the cutoff point of 575 MW, which divides the sample at roughly the median plant size. Table 3 Columns 3 and 4 show that the decrease in pollution came from larger plants and indicate that the aggregate effect across all the deregulated utilities is likely sizeable.

Next, we ask whether the change in pollution levels differed across other plant characteristics. First, we split our sample into two groups based on plant age. New plants are in general more flexible at changing fuel sources and production procedures, while old plants, with less advanced technology, are often less flexible. Smaller and older plants often do not operate full-time but instead provide operating reserves (Warwick 2002). We measure plant age based on the year in which the oldest plant unit was installed. In addition, we define new plants as those built after 1960, which is roughly the median age in our sample. Consistent with our conjecture, in Table 3 Columns 5 and 6, we show that old plants have reduced their SO_2 emissions by approximately 15% and the effect is not statistically different from zero. In contrast, new plants have reduced emissions by approximately 21%, and the effect is statistically significant.

Finally, we separate plants by ownership type. In the US, certain utilities are investor owned (IOUs), while others are publicly owned, including utilities owned by the government or local municipality, as well as member-owned cooperatives. For simplicity, we refer to all non-IOU plants as Muni plants. State legislation has generally either exempted Muni utilities from complying with restructuring or has left the decision to participate in the restructuring program to the Munis themselves. Thus, we expect the effect of restructuring to be stronger among IOUs. Consistent with our conjecture, we find that IOUs and Munis were both affected by the restructuring; however, the effect is twice as large and statistically significant among IOUs, although we cannot reject the hypothesis that the coefficients across the two groups are similar.

One concern regarding our results is that changes in SO_2 emissions may not be related to the restructuring, but to other possible shocks affecting both the competitive landscape and the pollution policy of the electricity generating industry. For example, a push towards newer electricity generation technologies in some states may have initiated both the restructuring process and the decline in emissions. To address this concern, we run our original specification in Table 3 Column 1 and replace the restructuring variable with a vector of time dummies for years $t-3$ to $t+3$ relative to the first year of restructuring. If pollution levels in restructured states were affected by the restructuring, then we should expect to see significantly negative coefficients only from year t onward. Moreover, we should see the effect occurring primarily among IOUs and not Munis, which were free to choose whether to comply with the restructuring or not, and among larger plants. Table 4 confirms the validity of these predictions. The impact of time dummies on emissions increases in magnitude and becomes statistically significant only after the restructuring (Table 4 Column 2). Although the restructuring effect attenuates after controlling for total output (Table 4 Column 2), large IOUs see a significant reduction in SO_2 emissions in year t (the regulation year), but not before, consistent with Table 3. At the same time, we observe no significant change in emissions among Muni plants (Table 4 Columns 4–6) further confirming the differential impact of the restructuring on plants of different ownership type. While our setting cannot rule out all alternative explanations, we believe these findings alleviate omitted variables concerns.[18]

4.2 Emissions Reduction Mechanisms

After establishing the impact of restructuring on plant-level emissions output, we turn to exploring mechanisms that could alter emissions levels at the affected plants following restructuring. Electricity generation technology dictates the viable range of activities directed at reducing SO_2 emissions at the plant level. First, plants can allocate more resources to the air cleaning process, both in terms of ongoing labor and material expenses, and in terms of investment in pollution-reducing equipment. Second, the composition of the fuel used to generate a certain heat level has a significant effect on pollution levels (Ellerman and Montero 1998; Kaminski 2003). Third and finally, increasing plant operation efficiency and optimizing existing controls can also achieve a reduction in emissions rate by reducing the overall amount of heat input needed for electricity generation. In the remainder of the section, we analyze the impact of each mechanism on the level of SO_2 at the plant level.

4.2.1 Expenditure on air cleaning

We start by analyzing the effect of restructuring on investment in equipment to reduce pollution, as well as on expenses towards material and labor. A plant can substantially reduce emissions by increased spending on emissions abatement. Specifically, plants may invest in control technology, such as scrubbers or fluidized bed combustion (FBC) boilers, or they can increase expenses on collection and disposal of byproducts.

We first focus on capital expenditures. For the given reporting year, EIA requires plants to report all pollution abatement capital expenditures for new structures and/or equipment. We collect this information and examine the effect of restructuring on the level of investment in pollution abatement. The results reported in Table 5 Column 1 demonstrate that the level of capital expenditure among restructured utilities dropped measurably following restructuring: the average affected facility reduced its log investment in emissions 82%. In Table 5 Column 2 we refine the definition of investment by focusing on scrubbers. We estimate an OLS regression because our estimation includes plant-epoch fixed effects, and the logit estimation is not feasible in this type of setting. The results demonstrate that plants have not increased reliance on scrubbers following the reform. The only significant variable in this specification is the Phase I dummy, indicating that installing scrubbers was one emissions reduction method employed by facilities subject to the first stage of the acid rain program.

Next, we look at pollution abatement expenses measured by expenditures on material and labor costs, as well as equipment operation and maintenance. In Table 5 Column 3 we consider abatement costs across all categories of chemicals, including ash, flue gas, and other potentially hazardous chemicals. In Table 5 Column 4 we consider only expenses associated with the collection and disposal of the sulfur byproducts. In both cases, we find that restructured plants cut their costs in these categories.

The decline in emissions collection expenditures may have been driven by a diminishing reliance on coal following restructuring. Although we explore the effect of restructuring on fuel mix in greater detail below, we conclude this subsection by expanding the analysis of pollution abatement expenses to control for the amount of coal used in the electricity generation process. Table 5 Panel B shows that the reduction of air cleaning expenses is not attributed to the move from coal to cleaner fuel sources, and the impact of restructuring on abatement expenses remains negative and statistically significant.

4.2.2 Fuel mix

We next examine whether, subsequent to restructuring, plants switched to an environmentally friendly fuel. Overall, substantial heterogeneity obtains in the amount of SO_2 pollution across fuel types. Coal burning generates the largest emissions of SO_2 per unit of heat generated (about 2,600 lb/ BBtu), followed by petroleum (about 1,100 lb/BBtu), whereas natural gas-fired units generate the least emissions with only about 1lb/BBTU. Further, a large heterogeneity obtains across coal types, and the main types available in the US vary dramatically by their sulfur content. For example, bituminous coal, the most prevalent type in the US, contains 0.7%–4% of sulfur per mass unit, whereas higher-quality anthracite coal contains only 0.6–0.8%, and is almost as high as bituminous in its heat content.[19] As a result, a plant can reduce SO_2 emissions by switching to a less polluting coal.

To examine whether plants have changed their fuel mix following the restructuring, we first estimate regressions where the dependent variable is the fraction of all the plant's operating boilers (status "OP") that rely on coal, gas, or petroleum as their primary fuel in a given year, as weighted by the number of hours under load of each boiler in that year. We present the results in Table 6 Panel A. We find the fraction of coal-fired boilers increased on average by 0.7% compared to nonaffected plants (Table 6 Column 1), and the fraction of gas-fired boilers increased on average by 3.4% (Table 6 Column 2). In contrast, the fraction of oil-fired units decreased by 4.3% (Table

6 Column 3). We find similar results when we measure the use of coal, gas, and petroleum by the log of (one plus) the physical quantity of each fuel (Table 6 Columns 4–6).[20]

Although affected plants may have not changed the overall amount of coal used, they could have switched to less polluting coal types. To analyze this possibility, in Table 6 Panel B we look at the sulfur and ash content of the coal used as measured by the percentage amount of sulfur or ash reported times the amount of coal reported (in tons). We add the value of one before converting each variable into logs. We find that plants switched to coal with higher sulfur content (Column 1), and the results remain similar when we directly control for the amount of coal used. In Columns 3 and 4 we also analyze the ash content of coal. Higher ash content indicates more residue after the coal is burned, which can be released to the atmosphere as particulate matter. We find that following the reform, affected plants saw an increase in ash content in coal, although the effect is not statistically different from zero.

In summary, the overall impact of fuel change on pollution is mixed. The shift from petroleum towards higher reliance on natural gas is consistent with pollution reduction findings. However, although plants on average have increased their reliance on natural gas, they have also begun using coal with higher sulfur levels. These two findings conflict with one another if the plant's goal is pollution reduction.

4.2.3 Efficiency of operations

Finally, we test whether the change in emissions rates may be driven by a more efficient production process. Plants may have improved fuel efficiency by generating the same amount of electricity with a smaller energy input. Plant production efficiency varies with the amount of electricity produced. Plants are often designed to generate base load electricity continuously at relatively high efficiency levels, and then cover peak load intermittently with less efficient units (Warwick, 2002). Higher efficiency can be achieved by avoiding peak load operation, as well as by running a plant continuously. Smaller improvements, such as changes to equipment maintenance practices, may also play a role.

We start the analysis of efficiency by examining whether the heat input, measured in log units of heat (BTU), declined following the restructuring. Table 7 Column 1 demonstrates that, by controlling for the amount of generated electricity, an affected plant reduces its BTU input by approximately 1.2%. This finding implies an increase in electricity generating efficiency following restructuring.

A primary reason for restructuring across states was the inability to meet peak electricity demands (Warwick, 2002). We should therefore expect plants prior to restructuring to have been subject to high loads and lower efficiency. Following restructuring many utilities started to compete for electricity across states, and several states initiated third-party power exchanges, in which electricity generators submitted bids to sell electricity. Electric utilities operating at close to maximum capacity sustain higher costs and cannot compete with utilities that operate below full capacity. Because peak demands are not fully correlated with one another, electricity restructuring has the potential to improve production and efficiency. In addition, the entry of nonutility electricity suppliers further increases the supply of electricity and potentially reduces loads across existing utilities.

To test whether utilities reduced their production after the restructuring, we examine plant-level capacity factor in affected plants. To measure capacity factor, we scale total annual generation, *Net MWh*, by overall plant capacity (Gross MWh multiplied by 8,760 annual number of hours). We then estimate capacity factor as a function of deregulation and control variables.

Consistent with the argument above, we find a decrease following restructuring of about 2.4% in the capacity factor of plants in the restructured states (Table 7 Column 2). In Table 7 Column 3 we use an alternative way to capture capacity and examine whether overall plant-level production has declined following restructuring. We find that the decline in the capacity factor translates into a decrease of about 16.6% in the log amount of electricity produced over time by the utilities (Table 7 Column 3).

To examine if the change in capacity led to the increase in efficiency, we add the capacity factor variable as an additional explanatory variable in Specification 1. After controlling for total production, we find a positive relation between capacity factor and BTU use, which indicates that a higher load is indeed associated with less efficient production. [21] Moreover, once we introduce the capacity factor, the effect of restructuring on efficiency decreases by about 25% (from 1.2% to 0.9%). This result means that the change in production output explains a substantial portion of the increase in efficiency.[22]

5. Why Did Firms Change Their Emissions Policy After Restructuring?

After exploring possible changes in the electricity production process, which affected pollution following the restructuring, we now address the underlying economic channels through which these patterns may have been established.

5.1 Cost-Cutting Channel

Our main hypothesis is that the restructuring led to more efficient production decisions, which is also likely to impact pollution outcomes. Specifically, we ask whether the decrease in pollution following restructuring could be driven by plants' aiming to reduce overall costs. Past studies, such as Fabrizio et al. (2007), have concluded that restructuring improved some aspects of production efficiency. In this section we examine the extent to which the observed reduction in pollution is the byproduct of efficient production. The economics literature tends to view pollution as a negative externality that is costly to reduce. Therefore, cost-minimizing production policy is often associated with a more polluting production process. Our findings that plants' expenses on pollution reduction have decreased are consistent with this idea. However, if restructuring increased plants' sensitivity to production costs, a switch to cheaper but greener inputs may also give rise to less polluting processes.

We have noted that fossil-fuel plants employ three main inputs: coal, gas, and petroleum. We averaged the price paid by plants in our sample for each fuel in each of the years 1985–1999 and plot the average price for each fuel over the years in Figure 2. The figure shows that coal is the cheapest fuel throughout our sample period (145 cents/mmBTU), followed by natural gas (262 cents/mmBTU), whereas petroleum, at 404 cents/mmBTU on average, is the most expensive. Reduction in pollution may therefore be the outcome of a higher sensitivity to input prices in particular, and the shift to a less costly production process. Consistent with this idea, Table 6 Panel A shows that plants in restructured states began to rely more heavily on natural gas and reduced their reliance on petroleum.

To test more directly the extent to which pollution-reducing actions may be driven by cost-cutting considerations, we exploit a cross-sectional variation in plants' incentives to become cost-efficient. We hypothesize that the motive for switching to cheaper fuel will be stronger among those plants that, prior to restructuring, had especially high production costs. The opening of a state to competition would make these plants more vulnerable to losing their market share to out-of-state producers of cheaper electricity, as well as to the potential entry of new incumbents. In response to the threat of entry, existing plants in areas with high operating costs should therefore have greater incentives to reduce production costs by switching to gas from petroleum.

We look at state-level electricity prices to empirically determine which states had especially high production costs prior to restructuring. Absent restructuring, utility rates are established through a rate of return scheme: Electricity prices are set by regulators in a way that allows utilities to recover their return on investment and operating costs. The higher the cost of production, the higher the electricity cost of MWH set by the regulator. We therefore rank all states by electricity prices every year; states with the highest prices receive high ranks, and vice versa. We obtain annual state-level electricity prices from the EIA.[23] We then identify states with notably high production costs in a year prior to restructuring initiation. For each state, we compare its average electricity price levels a year before restructuring to the distribution of electricity prices in the rest of the states at the same time. The average ranking among states that were subject to restructuring throughout our sample period is 33.5 (where 50 is the highest and 1 is the lowest). This finding is consistent with our Section 2 findings showing that the key motive for restructuring was the high prices of electricity in a given state. For every state *s*, we then define a new time-invariant variable, *High Electricity Price*$_s$, which equals the difference between the state rank and 33.5 whenever the state rank is higher than 33.5 one year before the restructuring, and zero otherwise. The intuition behind the variable construction is as follows: When electricity prices in a given state are above those of other restructured states, plants will have incentives to reduce costs, and the incentives will increase with the deviation of the state's prices from the average in restructured states. However, when electricity prices in a given state are lower than average, we expect that plants operating in this state will keep their production function unchanged rather than increase costs.[24] We interact our proxy of production costs, *High Electricity Price*, with restructuring indicator, and reestimate the equations of input use. The higher the interaction term, the higher the production costs in a restructured state prior to the initiation of deregulation and the stronger the plants' response through the cost-cutting channel. [25]

Table 8 Column 1 shows that overall fuel costs in plants were reduced in only those restructured states where production costs were high. The coefficient of −0.006 implies that an increase of 10 positions in state ranking relative to the median ranking of 33.5 is associated with a 6% reduction in log fuel costs. This finding confirms the validity of the cost-cutting channel among the restructured plants. Next, in Table 8 Columns 2-4 we examine whether changes in fuel mix were the underlying mechanism. The results show that, among restructured plants, there was an increase in the fraction of gas-fired boilers and a decrease in the percentage of oil-fired boilers. In both cases the change was statistically pronounced only in those states where production costs were high before the restructuring. The coefficients of 0.008 and −0.009 indicate that an increase in state ranking of 10 positions is associated with an 8% increase in the fraction of boilers operating primarily on gas and a 9% decrease in boilers operating primarily on petroleum. We obtain similar results when we examine the annual physical amount of coal, gas, and petroleum used across plants (Table 8 Columns 5-7). The coefficient of 0.09 for gas use (Table 8 Column 6) indicates that an increase in state ranking of 10 positions is associated with 90% increase in the log amount of gas and the coefficient of −0.047 in Table 8 Column 7 indicates a decrease of 47% for petroleum use. We also find a marginally significant increase in the use of coal after the restructuring (coefficient of 0.011). To summarize, our findings confirm the existence of a cost-cutting channel: Affected plants with higher cost-cutting incentives substituted the cheaper fuel type for the more expensive fuel type.

5.1.1 The trade-off among different fuel types

In this subsection we discuss the fuel-switching decisions of plants in more depth. Overall, the shift from petroleum is rational: Petroleum is inferior to gas as it is both costlier and more polluting. When we compare gas and coal, gas is less polluting but coal is less costly, and the choice between coal and gas is less trivial. Of note is the finding that output prices had a higher impact on the quantities of gas than quantities of coal. Although we cannot precisely determine the reason behind this pattern, we offer several potential explanations.

Despite our inability to precisely determine the driver of this pattern, we offer boiler modification costs as one potential reason. Existing literature shows that adding fuel switching capabilities is costly. Adding switching capabilities to petroleum and gas boilers to coal requires extensive reconstruction that is also expensive to implement (Mallory III, 1978). Although allowing switching capabilities from oil to natural gas is somewhat cheaper, it remains costly and requires up to two years of downtime (IEA 1988). In the short run, fuel switching can occur either by relying on existing generators with switching capabilities or by reallocating production across different generators in a given plant. The majority of generators in our sample with switching capabilities can switch between gas and oil, and only a small fraction of generators can switch between coal and oil or between coal and gas. [26] Because our parallel trend analysis indicates the impact of restructuring on emissions and fuel mix starting from the first year of restructuring, the switch may have been made within boilers that had preexisting switching capacity or between boilers of different types. If this is the case, then the largest reduction in pollution should be observed among those plants able to operate on gas and petroleum but not on coal. When installing a new coal-based boiler is expensive, a cheaper alternative for this type of plant is to substitute gas for petroleum. At the same time, restructured plants with coal-firing generators will shift from petroleum/gas towards coal, which is the cheapest input possible. We therefore expect that emissions among the latter group of plants have changed less or even increased after the restructuring.

In Table 9 we test this conjecture empirically. In Table 9 Column 1 we reestimate the main equation for the subset of plants with no gas-firing capacity (that is, plants that have reported zero quantity of natural gas used throughout our entire sample period). In Table 9 Column 2 we limit our analysis to a subset of plants that have never used coal (that is, plants that reported zero quantity of coal used), whereas in Table 9 Column 3 we examine the impact of restructuring on emissions among plants with the capacity to operate on both gas and coal (that is, the cumulative physical amounts of both coal and gas used throughout our sample period are strictly positive). We find that restructuring has reduced emissions only among plants with the ability to use gas but without coal-firing technological capacity. In contrast, plants that use coal but lack gas-firing capacity increased their emissions. The coefficient on the restructuring dummy is positive and statistically significant in Table 9 Column 1. Plants that operate on both coal and gas have also increased emission (Table 9 Column 3) although the results are statistically insignificant.[27] Taken together, the results of Table 9 further support the cost-cutting channel. Given boiler modification constraints, plants have responded to cost-cutting pressure by minimizing fuel expenses within the space of available fuel-firing options.

To summarize, this section demonstrates that stronger incentives to minimize fuel costs have encouraged affected plants to move from more expensive and polluting petroleum to cheaper and more environmentally friendly gas. At the same time, the impact on coal use was modest. Together, these findings demonstrate that efficiency and cost-cutting incentives responding to a more competitive product market environment can lead to cleaner production.

5.2 Exploring Other Channels

Although our evidence suggests that the change in pollution is driven by cost-cutting considerations, it is possible that other economic forces helped shape this decision. In this section we explore additional potential channels for the reduction in pollution. These channels were offered by finance literature to explain a given firm's choice to enhance their corporate social responsibility (CSR). We discuss the extent to which these channels could drive our findings.

5.2.1 Customer channel

Existing literature argues that responding to customers' needs is one reason to increase corporate social responsibility (e.g., Albuquerque et al., 2019; and Servaes and Tamayo, 2013). If restructuring has given customers the freedom to choose their electricity provider by comparing different utilities, and consumers prefer energy that is less environmentally harmful, customers have plausibly shifted their consumption towards less polluting utilities. This argument is consistent with our general findings of SO_2 emissions reduction, as well as the findings that firms have increased the use of natural gas at the expense of more polluting petroleum.

To better understand the importance of the customer channel in a plant's decision to emit, we perform an additional test. We take advantage of the fact that restructuring occurred at both the wholesale level and the retail level at different points in time, and only a fraction of the states had implemented retail access by the end of our sample period. At the wholesale level, the restructuring allowed all utilities in the state to compete for sales to wholesale distributors. Retail access allowed retail providers to compete for end users by either buying electricity through the exchange or by buying electricity directly from providers. To the extent that end users prefer providers that rely on less polluting energy, we expect retail access to have an impact on the environmental policy of utilities. Under wholesale deregulation, however, end users have no choice which electricity provider to choose. Consequently, we should not expect the wholesale deregulation to have an impact on customer choice.

To examine the above hypothesis, we re-estimate our regressions of SO_2 pollution after augmenting our specification with an indicator variable for retail-level restructuring. This variable, obtained from the Fabrizio et al. (2007) dataset, takes a value of one starting from the year in which a state has implemented retail access, and zero otherwise. If retail access led to the use of less polluting fuels, we should expect the variable to be negative. The first column of Table 10 shows that the coefficient of *Retail* is positive and statistically insignificant. Moreover, its inclusion does not weaken the explanatory power of our main measure of restructuring. The coefficient on the *Restructured* variable has the same magnitude as in the baseline case (see Table 3 Column 2 for comparison).

The insignificant effect of retail access on emissions may be due to utilities' sorting themselves into a separating equilibrium. Plants that found pollution reduction easier to accomplish have decreased their emissions further, whereas plants that found pollution reduction more difficult have either not changed the level of emissions or have increased it. Therefore, the customer channel argument can be refined to a separating equilibrium, in which plants with lower costs for adopting less-polluting operations would separate themselves from plants with higher costs (Flammer 2015). To the extent that product differentiation exists, pollution reduction actions will less likely be taken by those plants relying solely on coal, because it is harder for them to switch to less-polluting fuels. To test this conjecture, we separate the plants in our sample into coal operating and gas operating ones. Table 10 Columns 2 and 3 show the results. Consistent with the differentiation argument, we find that plants relying on coal increased pollution, while plants relying on gas decreased pollution. However, in both cases, the retail variable is not significant. This finding indicates that product differentiation is unlikely to be the reason for the different patterns in SO_2 pollution across plants.

5.2.2 Investor channel

The pollution reduction we found may be driven by investors of public utilities interested in protecting the environment. Shareholder activism has increased in recent decades, and Dimson et al. (2015) and Naaraayanan et al. (2020) demonstrate that, aside from traditional activism, active owners engage target firms in socially responsible practices. Therefore, investors may have responded to restructuring by pushing firms to reduce pollution. We note that this channel, while consistent with our trend in emissions overall, cannot explain the cross-sectional variations found in our study. For example, we find that coal-based plants have increased their emissions levels, while gas-based plants have reduced emissions. Moreover, this argument relies on the assumption that investors would have had a hard time engaging firms in pollution-reduction activities before restructuring. Because restructuring has changed the electricity price setting mechanism by abandoning the cost-of-sale process through which utilities were essentially guaranteed a certain level of profits, the new system has created more risk. Therefore, we cannot conclusively posit why investors choose to compel the utility to increase expenses during the more vulnerable post-restructuring period, but did not do so when the utility was regulated and less risk would have been involved.

The investor channel can also be manifested through clientele effect, in which some investors prefer firms to be more protective of the environment than others. However, the clientele effect, if present, should generate the opposite pattern for the following reason. Regulated utilities attract long-term, dividend-loving investors (e.g., Brochet et al., 2012), who also tend to focus more heavily on environmental impact (Starks et al., 2017; Nguyen et al., 2020). We should therefore expect a stronger push towards environmentally friendly policies before—rather than after—restructuring. We conclude that the investor channel is unlikely to drive our results.

5.2.3 Managerial entrenchment channel

Past studies have shown that managers may attempt to become environmentally friendly because of nonpecuniary motives, and these actions are a manifestation of agency conflicts. For example, Chen et al. (2019) show that, consistent with the agency channel, the passage of shareholder-rights proposals leads to less environmentally friendly policies. Similarly, Masulis and Resa (2015) show that corporate philanthropy is a manifestation of agency conflicts that reduce firm value. If this is the case, then we should expect to find regulated plants more susceptible to agency conflicts. However, to the extent that product market competition spurs alignment of incentives (e.g., Hart, 1983; Schmidt, 1997; Chhaochharia et al., 2017), managers of less competitive industries are more likely to be involved in environmentally friendly policies. Therefore, our findings stand in contrast to the managerial entrenchment argument, as we find that managers of restructured utilities have decreased pollution. Our findings are instead consistent with the agency view that well-governed firms could engage more actively in CSR (Ferrell et al., 2016).

5.2.4 Legal channel

Finally, we address the possibility that industry restructuring has led to greater legal uncertainty. Restructuring essentially involves changes in rulings that are yet to be challenged in a court of law. Moreover, other types of legislation, such as possible amendments to the Clean Air Act, could potentially interact with restructuring rules in ways not predicted by utilities. As a result, reducing environmental risk may be a value-enhancing strategy in such a setting. Consistent with this rationale, Sharfman and Fernando (2008) find that low environmental risk reduces firms' cost of capital, and Fernando et al. (2017) and Koh et al. (2013) find that a decrease in environmental risk enhances firm value. In addition, from a legal standpoint, behavioral benefits may accrue to environmentally friendly policy. For example, Hong et al. (2019) demonstrate that regulators act favorably towards environmentally friendly firms.

If legal risk considerations are the effective channel, then we should expect an increase in environmentally friendly behavior in a restructured environment. Our results are consistent with this argument, because we find that utilities have as a whole decreased pollution upon deregulation. However, the legal channel cannot explain the variation in our findings between plants that rely on coal, and plants that rely on natural gas. Tables 9 and 10 demonstrate that coal-reliant plants have increased their pollution levels. Coal plants are likely to be subject to higher scrutiny by regulators because they are the most polluting agents across all categories of toxic emissions. Consistent with this notion, Phase I of the Acid Rain Program has deliberately targeted the largest polluters—old coal-operating plants—and required them to reduce pollution. We therefore conclude that the legal channel cannot be the driver of our findings.

6. Conclusion

In this paper we examine the impact of cost-cutting incentives on corporate environmental policy by focusing on the effect of electric utility restructuring on SO_2 emissions – one of the most harmful byproducts of electricity generation. Our empirical strategy takes advantage of a staggered passage of restructuring legislation in the electric utilities industry across the US during the 1990s. We find that plants in restructured states have decreased pollution relative to plants in nonrestructured states.

We explore possible drivers of pollution reduction and find that plants in restructured states have changed their fuel mix and begun to rely more heavily on clean gas as a source of energy. We find that the move to gas was driven by cost-cutting considerations. In addition, operation efficiency has increased, allowing plants to burn less fuel overall. We also find that despite the decline in pollution, affected plants have reduced abatement-related capital investment, as well as operations and management expenditures on pollution-reduction activities. These changes are also consistent with cost-cutting considerations.

We rule out a number of other potential economic channels for these results, such as the role of customer preferences and product differentiation; investor clientele and activism; managerial entrenchment incentives; and legal motives. We find little evidence in support of any of these channels.

Although the study examines the relation between pollution and cost-cutting incentives in the 1990s, its implications are also relevant today. Sulfur dioxide and nitrogen oxide have decreased substantially since the 1990's, yet electric utilities still remain the number one source of carbon dioxide pollution, responsible for global warming and climate change. Our findings show that cost-cutting incentives and efficient allocation of resources within plants and across plants can mitigate the environmental impact across all types of toxic pollutants.

Our findings that cost-cutting incentives could lead to higher sustainability could be expanded to other industries and production processes. For example, cost-cutting considerations in industries where supply chain structure involve transportation of raw materials and final goods could lead to the establishments of distribution centers which reduce both transportation costs and emission. Similarly, smarter utilization of raw material in the production of final goods would enhance the bottom line while leading to less landfill waste.

Our findings show also the potential benefits of product market competition on the environment. To the extent that product market consolidation in the US has increased in the last two decades, our findings may offer another channel through which industry consolidation affects the environment. Consequently, we believe the findings of this project would interest both environmental and antitrust regulators.

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Figure 1:

Restructured States

The figure depicts the U.S. map where restructured states are shaded. Each color corresponds to a specific restructuring year (see legend).

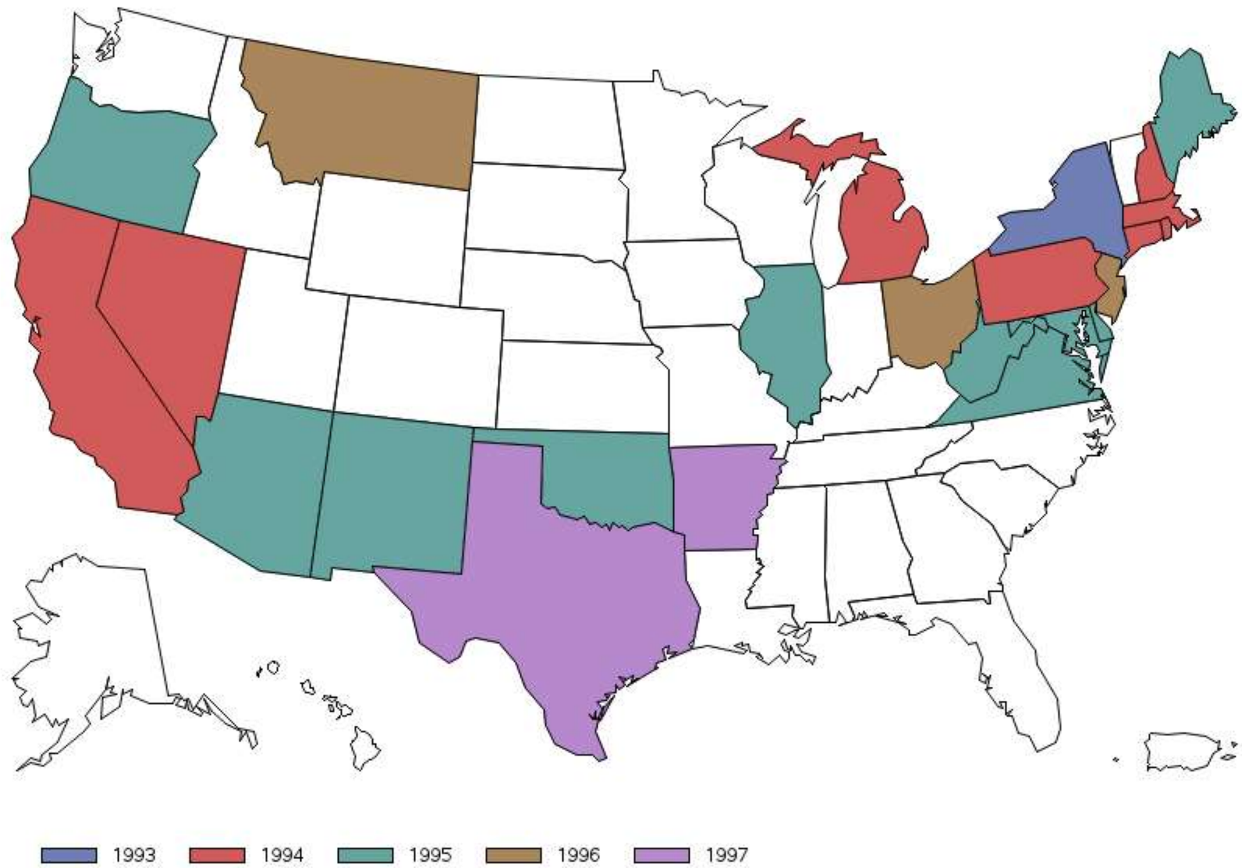

Figure 2:

Average Fuel Prices Over Time

The figure depicts average prices of coal, petroleum and gas, all in cents per million BTU, based on information reported in Form EIA-861 for plants in our sample. To aggregate the data across plants, for every fuel type and year we calculate the average of fuel prices, weighted by total MWh generated by each plant. To mitigate the impact of outliers, prices of each fuel type at the plant-year level are winsorized at 1% and 99% of their empirical distribution prior to averaging.

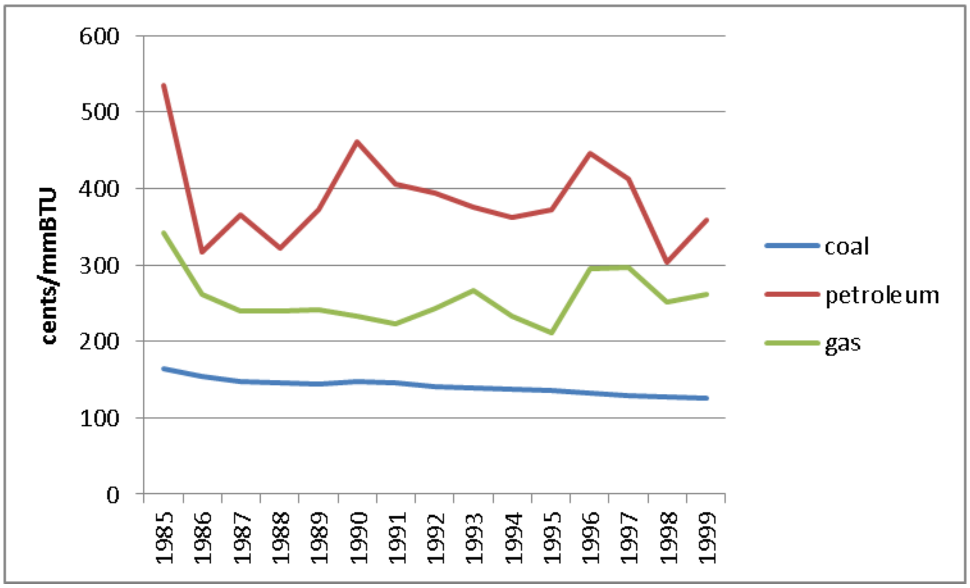

Table 1
Descriptive Statistics

The table presents descriptive statistics for the merged EPA-EIA- Fabrizio et al. (2007) plant-year sample for the period of 1985–1999. *Restructured* is an indicator variable that takes on a value of one for every plant in a state that passed the restructuring legislation starting from the year of the first restructuring hearings and onward. Net annual MWh measures the amount of electric energy produced, in Megawatt hour. *Gross MW Capacity* is the maximum electric power a plant can produce, in Megawatt. *Installation year* is the year when the oldest unit in the plant was installed. *Heat input* is the amount of heating energy used as an input in the generation of electricity and is measured in billions of British thermal units (BBTUs); *Capacity factor* is the ratio of total net energy produced by the plant to its maximal capacity (defined as Gross *MW* Capacity, multiplied by number of hours per year). *IOU* is an indicator variable which equals one if the plant belongs to an investor-owned utility firm. SO_2 is the annual emission of sulfur dioxide, in tons. *Scrubber* is an indicator variable that equals 1 if the plant has at least one flue-gas desulfurization (FGD) system in operating status, and zero otherwise. *Phase I* is an indicator variable for whether the plant was subject to Phase I of the Acid Rain program. The indicator takes on the value of 1 for all affected plants starting from 1995 and onward, and zero otherwise. *Abate. Capex* measures all pollution abatement capital expenditures for new structures and/or equipment made during the reporting year, in thousand dollars. *Abate. Costs* cover all material and labor costs including equipment operation and maintenance costs (such as particulate collectors, conveyers, hoppers, etc.) associated with the collection and disposal of the byproducts, including fly and bottom ash collection, FGD collection, and other pollution collection. *SO_2 Costs* variable covers all material and labor costs associated with SO_2 collection. Fuel quantities (Coal, Gas, and Petroleum) are total annual amount of each input used, measured in its respective units. %boilers with primary fuel – coal [gas, petroleum] measures the fraction of boilers in a given plant-year that use coal [gas, petroleum] as their primary fuel, weighted by each boiler’s total hours under load.

Table 1 (cont.)

Variable	Obs	Mean	Std. Dev.	Min	p25	Median	p75	Max
Dummy (Restructured=1)	7,940	0.15	0.36	0	0	0	0	1
Plant Characteristics								
Total output (Net annual MWh)	7,940	3,447,705	3,726,115	886	819,218	2,167,528	4,691,988	22,000,000
Gross Capacity (MW)	7,940	807	665	100	304.00	588.96	1,137.60	3,969
Installation year	7,940	1962	12	1918	1953	1960	1972	1997
Heat input (BBTU)	7,940	35,441	37,254	15	9,068	22,706	48,042	229,489
Capacity factor	7,940	0.44	0.22	0.00	0.26	0.45	0.62	0.98
Dummy (IOU=1)	7,940	0.80	0.40	0	1	1	1	1
Pollution and Abatement								
SO_2 emission, ton	3,467	24,345	39,024	0	497	10,847	28,112	374,920
Dummy (Phase I=1)	7,940	0.06	0.24	0	0	0	0	1
Dummy (Scrubber=1)	7,940	0.16	0.37	0	0	0	0	1
Abate. Capex, ($1,000)	7,810	731	6,139	0	0	0	117	304,014
Abate. Costs, total ($1,000)	7,810	1,369	4,163	0	0	17	979	95,656
SO_2 Costs ($1,000)	7,810	643	2,810	0	0	0	149	56,236
Fuel Inputs								
Coal quant. ('000 short tons)	7,788	1,457	2,024	0	0	628	2,116	14,108
Gas quant. ('000 cubic ft.)	7,788	4,509,418	11,000,000	0	0	8,300	2,780,975	107,000,000
Petroleum quant. ('000 barrels)	7,788	282	1,009	0	1	9	44	13,617
% boilers with primary fuel - coal	7,598	0.62	0.46	0.00	0.00	1.00	1.00	1.00
% boilers with primary fuel - gas	7,598	0.27	0.43	0.00	0.00	0.00	0.67	1.00
% boilers with primary fuel - petroleum	7,598	0.11	0.29	0.00	0.00	0.00	0.00	1.00

Table 2
Determinants of Restructuring

This table reports estimates of logit regressions where the dependent variable is an indicator variable that takes on a value of one if the state has passed restructuring legislation at any point between 1993 and 1999. The sample in Specifications 1 and 2 consists of all plants in the EIA- Fabrizio et al. (2007) sample over the period of 1990-1992. The sample of the independent variables in specifications (3) and (4) consists of all plants in the EIA-EPA- Fabrizio et al. (2007) sample in 1990. *Cents/KWh* is annual state-level electricity prices. Net annual MWh measures the aggregate amount of electric energy produced by all the plants in our sample at a given state-year, measured in Megawatt hour. SO_2 is the annual emission of sulfur dioxide, in tons, aggregated across all plants in a given state-year. Fuel quantities (Coal, Gas, and Petroleum) are the total annual amount of each input used, measured in its respective units, aggregated across all plants in a given state-year. Robust standard errors are reported in parentheses below coefficient estimates and are clustered by state in Specifications 1 and 2. Significance at the 1%, 5%, and 10% level are indicated by ***, **, and *, respectively.

	(1) 1990-1992	(2) 1990-1992	(3) 1990	(4) 1990
Cents/KWh	0.720**	0.645	1.064***	0.669*
	(0.313)	(0.431)	(0.317)	(0.390)
ln(SO_2/Net MWh)			-0.668	-0.617
			(0.506)	(0.529)
ln(Coal Quant./Net MWh)		-0.292		-0.252
		(0.415)		(0.464)
ln(Gas Quant./Net MWh)		0.053		0.038
		(0.067)		(0.062)
ln(Pet Quant.)-ln(Net MWh)		0.274		0.302
		(0.280)		(0.321)
Intercept	-4.684**	-3.041	-10.136***	-5.830
	(2.029)	(7.303)	(3.331)	(7.939)
N	141	138	46	46
pseudo R^2	0.166	0.299	0.233	0.299
SE Clustered by State	Yes	Yes	No	No

Table 3
Restructuring and Emissions

This table reports estimates of panel regressions of SO_2 emission amounts at the plant level as a function of restructuring and other control variables. The sample consists of all firms in the EPA-EIA- Fabrizio et al. (2007) sample over the following years: 1985, 1990, 1995-1999. The dependent variable is defined as one plus annual emissions level of SO_2 (in ton), all converted into natural logs. All other variables are as described in Table 1. Small [Large] plants are plants with gross MW capacity below 575 MW [equal or above 575 MW]. Old [New] plants are plants in which the oldest unit was installed in 1960 or earlier [after 1960]. IOU [Muni] is an indicator variable which equals one if the plant belongs to an investor-owned utility firm [utility firm owned by government, municipality, or members of a co-op]. The regressions are estimated with an OLS model and include plant-epoch- and year-fixed effects. Standard errors are double clustered by plant-epoch and year dimensions and are reported in parentheses below coefficient estimates. Significance at the 1%, 5%, and 10% level are indicated by ***, **, and *, respectively.

	(1) All	(2) All	(3) Small Plants	(4) Large Plants	(5) Old Plants	(6) New Plants	(7) IOU only	(8) Muni only
Restructured	-0.330***	-0.200*	0.016	-0.396***	-0.162	-0.240**	-0.232*	-0.124
	(0.084)	(0.090)	(0.153)	(0.080)	(0.129)	(0.078)	(0.096)	(0.158)
ln(Net MWh)		0.784***	0.744***	0.904***	0.719***	0.935***	0.807***	0.730**
		(0.087)	(0.107)	(0.093)	(0.090)	(0.119)	(0.081)	(0.218)
Dummy (Scrubber=1)	-0.854***	-0.844***	-0.547*	-1.164**	-0.516	-0.940***	-0.682**	-1.344***
	(0.206)	(0.207)	(0.230)	(0.329)	(0.292)	(0.251)	(0.239)	(0.305)
Dummy (Phase I =1)	-0.494***	-0.452***	-0.486***	-0.436***	-0.345**	-0.593***	-0.420***	-0.509**
	(0.081)	(0.071)	(0.127)	(0.077)	(0.101)	(0.098)	(0.086)	(0.146)
Plant-Epoch FE	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
Year FE	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
N	3467	3467	1691	1776	1785	1682	2787	680
adj.R^2	0.95	0.96	0.94	0.96	0.95	0.96	0.96	0.95
adj.R^2 within	0.04	0.15	0.13	0.20	0.11	0.21	0.15	0.14

Table 4
Examining Parallel Trends

This table reports estimates of panel regressions of SO_2 emission amounts at the plant level as a function of restructuring and other control variables. The sample consists of all firms in the EPA-EIA- Fabrizio et al.(2007) sample over the following years: 1985, 1990, 1995–1999. The dependent variable is defined as one plus annual emission level of SO_2 (in ton), all converted into natural logs. The regressions include the following control variables: Phase I, and Scrubber, as in Table 3, as well as an indicator variable that takes on a value of one starting from year t+4 and onward (not shown). Specifications 2,3,5, and 6 also include ln(MWh). *Large* plants are plants with gross MW capacity equal or above 575 MW. *IOU* [*Muni*] is an indicator variable which equals one if the plant belongs to an investor-owned utility firm [utility firm owned by government, municipality, or members of a co-op]. The regressions are estimated with an OLS model and include plant-epoch- and year-fixed effects. Standard errors are double clustered by plant-epoch and year dimensions and are reported in parentheses below coefficient estimates. Significance at the 1%, 5%, and 10% level are indicated by ***, **, and *, respectively.

	IOU			MUNI		
	(1)	(2)	(3)	(4)	(5)	(6)
	All	All	Large Plants	All	All	Large Plants
t-3	0.459**	0.172	-0.262	0.851	0.724	0.587
	(0.177)	(0.160)	(0.142)	(0.741)	(0.789)	(0.897)
t-2	-0.127	-0.036	-0.203	-0.399**	-0.043	0.176
	(0.121)	(0.105)	(0.171)	(0.137)	(0.273)	(0.591)
t-1	-0.243	-0.126	-0.221	0.089	0.395	0.245
	(0.137)	(0.133)	(0.178)	(0.260)	(0.280)	(0.603)
t	-0.326**	-0.152	-0.431***	0.022	0.285	-0.322
	(0.097)	(0.095)	(0.102)	(0.252)	(0.249)	(0.379)
t+1	-0.405**	-0.279*	-0.412**	-0.336	-0.123	-0.539
	(0.127)	(0.134)	(0.145)	(0.244)	(0.234)	(0.569)
t+2	-0.368***	-0.203	-0.462***	-0.532	-0.287	-1.152
	(0.098)	(0.110)	(0.101)	(0.357)	(0.346)	(1.214)
t+3	-0.400**	-0.255	-0.496***	-0.476	-0.082	0.022
	(0.122)	(0.137)	(0.123)	(0.367)	(0.297)	(0.569)
Plant-Epoch FE	Yes	Yes	Yes	Yes	Yes	Yes
Year FE	Yes	Yes	Yes	Yes	Yes	Yes
N	2787	2787	1494	680	680	282
adj.R^2	0.953	0.958	0.961	0.947	0.952	0.952
adj.R^2 within	0.038	0.152	0.193	0.061	0.144	0.237

Table 5
Restructuring and Emission Cleaning Expenditure

This table reports estimates of panel regressions of plant-level capital expenditures, as well as of operations and management costs associated with emission abatement, as a function of restructuring and control variables. The sample in Panel A consists of all plants in the EIA- Fabrizio et al. (2007) sample over the period of 1985–1999. The sample in Panel B is refined to include only plants with positive coal input in a given year. All variables are as described in Table 1. Each dependent variable, except *Scrubber* indicator, is converted into natural logs (a value of one is added before the transformation). All regressions are estimated with an OLS model and include plant-epoch- and year-fixed effects. Standard errors are double clustered by plant-epoch and year dimensions and are reported in parentheses below coefficient estimates. Significance at the 1%, 5%, and 10% level are indicated by ***, **, and *, respectively.

Panel A: All Plants

	(1) ln(Abate. CapEx)	(2) Dummy (Scrubber=1)	(3) ln(Abate. Costs, total)	(4) ln(SO_2 Costs)
Restructured	-0.823***	-0.005	-0.436*	-0.614**
	(0.217)	(0.010)	(0.224)	(0.232)
ln(Net MWh)	0.216*	0.000	-0.009	0.225*
	(0.116)	(0.004)	(0.111)	(0.115)
Dummy(Scrubber=1)	0.117		4.839***	1.427**
	(0.671)		(0.872)	(0.540)
Dummy(Phase I=1)	-0.323	0.124***	-1.550***	0.732*
	(0.287)	(0.033)	(0.414)	(0.348)
Plant-Epoch FE	Yes	Yes	Yes	Yes
Year FE	Yes	Yes	Yes	Yes
N	7810	7940	7810	7810
adj.R^2	0.42	0.95	0.76	0.59
adj.R^2 within	0.01	0.07	0.06	0.02

Panel B: Coal-Operating Plants

	(1) ln(Abate. CapEx)	(2) Dummy (Scrubber=1)	(3) ln(Abate. Costs, total)	(4) ln(SO_2 Costs)
Restructured	-0.791**	-0.003	-0.619***	-0.588*
	(0.280)	(0.016)	(0.199)	(0.307)
ln(Coal quant.)	0.195	0.003	-0.008	0.264
	(0.203)	(0.010)	(0.167)	(0.196)
Dummy(Scrubber=1)	0.054		5.136***	1.291**
	(0.679)		(0.786)	(0.545)
Dummy(Phase I=1)	-0.503	0.123***	-0.672**	0.488
	(0.321)	(0.034)	(0.301)	(0.364)
Plant-Epoch FE	Yes	Yes	Yes	Yes
Year FE	Yes	Yes	Yes	Yes
N	5169	5169	5169	5169
adj.R^2	0.35	0.94	0.79	0.54
adj.R^2 within	0.01	0.06	0.10	0.01

Table 6
Restructuring and Fuel Type

This table reports estimates of panel regressions of plants' reliance on different fuel types in the production process as a function of restructuring and control variables. The sample consists of all plants in the EIA- Fabrizio et al. (2007) sample over the period of 1985–1999, with the exception of Specifications 2 and 4 of Panel B, which rely on sample that includes only plants with positive coal input in a given year. ln(Sulf. Coal) is one plus the amount of sulfur in coal used for burning, calculated as the percentage amount of sulfur reported times the amount of coal reported. ln(Ash) is one plus the amount of ash, produced in the process of coal burning, measured in the same way as the amount of sulfur. All the remaining variables are as described in Table 1. In Specifications 4-6 of Panel A and all specifications in Panel B the dependent variable is converted into natural logs (a value of one is added before the transformation). All regressions are estimated with an OLS model and include plant-epoch- and year-fixed effects. Standard errors are double clustered by plant-epoch and year dimensions and are reported in parentheses below coefficient estimates. Significance at the 1%, 5%, and 10% level are indicated by ***, **, and *, respectively.

Panel A: Fuel Mix

	(1) Prim. Coal	(2) Prim. Gas	(3) Prim. Petrol.	(4) ln(Coal Quant.)	(5) ln(Gas Quant.)	(6) ln(Pet. Quant.)
Restructured	0.007*	0.032**	-0.043***	0.012	0.590**	-0.415***
	(0.004)	(0.013)	(0.013)	(0.030)	(0.228)	(0.104)
ln(BTU)	0.003	0.002	-0.008	0.359***	0.608***	0.350***
	(0.002)	(0.009)	(0.009)	(0.039)	(0.124)	(0.074)
Dummy (Scrubber=1)	-0.002	-0.006	0.008*	0.025	-0.191	-0.129
	(0.005)	(0.007)	(0.004)	(0.044)	(0.494)	(0.154)
Dummy(Phase I=1)	0.000	-0.008	0.008	0.015	0.232	0.216*
	(0.006)	(0.007)	(0.006)	(0.027)	(0.240)	(0.112)
Plant-Epoch FE	Yes	Yes	Yes	Yes	Yes	Yes
Year FE	Yes	Yes	Yes	Yes	Yes	Yes
N	7598	7598	7598	7788	7788	7788
adj.R^2	0.99	0.94	0.88	0.99	0.94	0.86
adj.R^2 within	0.00	0.01	0.01	0.16	0.01	0.04

Panel B: Coal Quality

	(1) ln(Sulf.Coal)	(2) ln(Sulf.Coal)	(3) ln(Ash)	(4) ln(Ash)
Restructured	0.116**	0.142**	0.067	0.058
	(0.044)	(0.050)	(0.046)	(0.040)
ln(Net MWh)	0.285***		0.323***	
	(0.034)		(0.040)	
ln(Coal Quant.)		0.808***		0.941***
		(0.040)		(0.020)
Dummy(Scrubber=1)	0.417***	0.410***	0.137**	0.117***
	(0.097)	(0.087)	(0.052)	(0.039)
Dummy(Phase I=1)	-0.451***	-0.444***	-0.085**	-0.086**
	(0.063)	(0.067)	(0.035)	(0.031)
Plant-Epoch FE	Yes	Yes	Yes	Yes
Year FE	Yes	Yes	Yes	Yes
N	7788	5169	7788	5169
adj.R^2	0.99	0.94	0.99	0.95
adj.R^2 within	0.13	0.36	0.08	0.44

Table 7
Restructuring and Production Efficiency

This table reports estimates of panel regressions of various measures of plant-level operation efficiency as a function of restructuring and control variables. The sample consists of all plants in the EIA- Fabrizio et al. (2007) sample over the period of 1985–1999. All variables are as described in Table 1. Each dependent variable, except *Capacity Factor*, is converted into natural logs. All regressions are estimated with an OLS model and include plant-epoch- and year-fixed effects. Standard errors are double clustered by plant-epoch and year dimensions and are reported in parentheses below coefficient estimates. Significance at the 1%, 5%, and 10% level are indicated by ***, **, and *, respectively.

	(1) ln(BTU)	(2) Capacity Factor	(3) ln(Net MWh)	(4) ln(BTU)
Restructured	-0.012**	-0.056***	-0.166***	-0.009
	(0.005)	(0.010)	(0.032)	(0.006)
Capacity Factor				0.151***
				(0.044)
ln(Net MWh)	0.914***			0.885***
	(0.008)			(0.015)
Dummy(Scrubber=1)	0.007	0.009	0.007	0.006
	(0.007)	(0.025)	(0.061)	(0.007)
Dummy(Phase I=1)	-0.002	-0.009	-0.053	-0.002
	(0.005)	(0.011)	(0.036)	(0.005)
Plant-Epoch FE	Yes	Yes	Yes	Yes
Year FE	Yes	Yes	Yes	Yes
N	7940	7940	7940	7940
adj.R^2	0.997	0.853	0.941	0.997
adj.R^2 within	0.947	0.026	0.015	0.948

Table 8
Restructuring, Production Costs, and Fuel Type

This table reports estimates of panel regressions of plant reliance on different fuel types in the production process as a function of restructuring, state-level production costs, and control variables. The sample consists of all plants in the EIA- Fabrizio et al. (2007) sample over the period of 1985–1999. *High Electr. Price* is a proxy for high production costs at a state level and is constructed as described in Section 4.2. Fuel costs are the natural log of the total annual fuel expenses, in $1,000. All other variables are as described in Table 1. In Specifications 5-7 the dependent variable is converted into natural logs (a value of one is added before the transformation). All regressions are estimated with an OLS model and include plant-epoch- and year-fixed effects. Standard errors are double clustered by plant-epoch and year dimensions and are reported in parentheses below coefficient estimates. Significance at the 1%, 5%, and 10% level are indicated by ***, **, and *, respectively.

	(1) ln(Fuel Costs)	(2) %Prim. Coal	(3) %Prim. Gas	(4) %Prim. Pet	(5) ln(Quant. Coal)	(6) ln(Quant. Gas)	(7) ln(Quant. Pet)
Restructured	0.012	0.006	-0.006	-0.001	-0.040	0.153	-0.190
	(0.021)	(0.004)	(0.010)	(0.010)	(0.025)	(0.257)	(0.124)
Restr.*High Electr. Price	-0.006**	0.000	0.008**	-0.009***	0.011*	0.090*	-0.047**
	(0.003)	(0.000)	(0.003)	(0.003)	(0.006)	(0.042)	(0.020)
ln(BTU)	0.849***	0.003	0.008	-0.013	0.366***	0.664***	0.321***
	(0.016)	(0.002)	(0.008)	(0.008)	(0.041)	(0.117)	(0.077)
Scrubber Dummy	0.015	-0.002	-0.009	0.012	0.021	-0.229	-0.109
	(0.032)	(0.005)	(0.009)	(0.008)	(0.044)	(0.495)	(0.150)
Phase I Dummy	-0.061*	0.000	-0.009	0.009	0.015	0.229	0.218*
	(0.029)	(0.006)	(0.007)	(0.006)	(0.027)	(0.239)	(0.114)
Plant-Epoch FE	Yes	Yes	Yes	Yes	Yes	Yes	Yes
Year FE	Yes	Yes	Yes	Yes	Yes	Yes	Yes
N	7937	7598	7598	7598	7788	7788	7788
adj.R^2	0.98	0.99	0.94	0.88	0.99	0.94	0.86
adj.R^2 within	0.71	0.00	0.02	0.03	0.16	0.02	0.04

Table 9
Restructuring and Emissions by Fuel Capacity Groups

This table reports estimates of panel regressions of plant-level SO_2 emission amounts as a function of restructuring and other control variables. The sample consists of all firms in EPA-EIA- Fabrizio et al. (2007) sample over the following years: 1985, 1990, 1995–1999. The dependent variable is defined as one plus annual emission level of SO_2 (in ton), all converted into natural logs. All other variables are as described in Table 1. *Coal, no Gas* [*Gas, no Coal*] are plants that have used a positive amount of coal input [gas input] but have never used gas [coal] throughout our sample period. *Gas and Coal* are plants where the cumulative amounts of each coal and gas inputs used throughout our sample period are strictly positive. Since *Scrubber* is not used in plants with no coal-based operation, the indicator variable is excluded in Specification 2. The regressions are estimated with an OLS model and include plant-epoch- and year-fixed effects. Standard errors are double clustered by plant-epoch and year dimensions and are reported in parentheses below coefficient estimates. Significance at the 1%, 5%, and 10% level are indicated by ***, **, and *, respectively.

	(1) Coal, No Gas	(2) Gas, No Coal	(3) Gas & Coal
Restructured	0.148**	-0.701**	0.241
	(0.053)	(0.229)	(0.155)
ln(Net MWh)	0.823***	0.671***	0.972***
	(0.070)	(0.147)	(0.122)
Dummy(Scrubber=1)	-1.002**		-0.498
	(0.275)		(0.270)
Dummy(Phase I=1)	-0.519***	0.236	-0.777***
	(0.060)	(0.338)	(0.152)
Intercept	-1.932	-5.074**	-4.631**
	(1.061)	(2.030)	(1.810)
Plant-Epoch FE	Yes	Yes	Yes
Year FE	Yes	Yes	Yes
N	1446	1044	871
adj.R^2	0.94	0.86	0.87
adj.R^2 within	0.43	0.11	0.33

Table 10
Restructuring, Retail Access and Emissions

This table reports estimates of panel regressions of plant-level SO_2 emission amounts as a function of restructuring and other control variables. The sample consists of all firms in EPA-EIA- Fabrizio et al. (2007)sample over the following years: 1985, 1990, 1995-1999. The dependent variable is defined as one plus annual emission level of SO_2 (in ton), all converted into natural logs. *Retail* is an indicator variable that takes on a value of one starting from the year in which a state has implemented retail access. All other variables are as described in Table 1. *Coal, no Gas* [*Gas, no Coal*] plants are plants that have used a positive amount of coal input [gas input] but have never used gas [coal] throughout our sample period. Since *Scrubber* is not used in plants with no coal-based operation, the indicator variable is excluded in Specification 3. The regressions are estimated with an OLS model and include plant-epoch- and year-fixed effects. Standard errors are double clustered by plant-epoch and year dimensions and are reported in parentheses below coefficient estimates. Significance at the 1%, 5%, and 10% level are indicated by ***, **, and *, respectively.

	(1) All	(2) Coal, no Gas	(3) Gas, No coal
Restructured	-0.200*	0.145**	-0.711**
	(0.089)	(0.051)	(0.234)
Retail	0.018	0.206	-0.242
	(0.164)	(0.110)	(0.336)
ln(Net MWh)	0.784***	0.838***	0.659***
	(0.091)	(0.062)	(0.157)
Dummy (Scrubber=1)	-0.846***	-1.008**	
	(0.209)	(0.274)	
Dummy (Phase I=1)	-0.452***	-0.520***	0.242
	(0.071)	(0.059)	(0.344)
Plant-Epoch FE	Yes	Yes	Yes
Year FE	Yes	Yes	Yes
N	3467	1446	1044
adj.R^2	0.96	0.95	0.86
adj.R^2 within	0.15	0.43	0.11

Table Appendix A-1

This table reports estimates of panel regressions of percentage of plant boilers at the plant level that are primarily gas based (Columns 1 and 3) and natural log of plant-level heat energy used to generate electricity (in BTU) as a function of restructuring and other control variables (Columns 2 and 4). The sample consists of all firms in the EPA-EIA-Fabrizio et al. (2007) sample over the following years: 1985-1999. The regressions include also the control variables ln(BTU) in Columns 1 and 3 [ln(MWH) in Columns 2 and 4], Phase I, and Scrubber, as in Table 3, as well as an indicator variable that takes on a value of one starting from year t+4 and onward (not shown). *IOU* is an indicator variable which equals one if the plant belongs to an investor-owned utility firm. Muni is an indicator variable which equals one if the utility firm is owned by government, municipality, or members of a co-op. The regressions are estimated with an OLS model and include plant-epoch- and year-fixed effects. Standard errors are double clustered by plant-epoch and year dimensions and are reported in parentheses below coefficient estimates. Significance at the 1%, 5%, and 10% level are indicated by ***, **, and *, respectively.

	IOU		MUNI	
	(1)	(2)	(3)	(4)
	Prim. Gas	ln(BTU)	Prim. Gas	ln(BTU)
t-3	-0.003	0.002	0.036	-0.025
	(0.010)	(0.005)	(0.022)	(0.022)
t-2	0.022	-0.004	0.032	-0.007
	(0.020)	(0.005)	(0.031)	(0.013)
t-1	0.034	-0.000	0.043	-0.010
	(0.023)	(0.007)	(0.037)	(0.012)
t	0.049*	-0.015***	0.017	-0.045*
	(0.026)	(0.004)	(0.040)	(0.022)
t+1	0.042**	-0.015	0.018	0.008
	(0.017)	(0.010)	(0.046)	(0.024)
t+2	0.047**	-0.013	0.016	0.033
	(0.021)	(0.008)	(0.050)	(0.030)
t+3	0.060**	-0.011	-0.017	0.007
	(0.023)	(0.009)	(0.048)	(0.039)
Plant-Epoch FE	Yes	Yes	Yes	Yes
Year FE	Yes	Yes	Yes	Yes
N	6102	6320	1496	1620
adj.R^2	0.937	0.997	0.955	0.995
adj.R^2 within	0.011	0.956	0.004	0.917

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