The impact of environmental regulation on productivity: the case of electricity generation under the CAAA-1990

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Abstract

This paper measures the impact of the 1990 Clean Air Act Amendment on the productivity and output of US coal-fired power generating units. The Act led to power units adopting a number of different pollution abating behaviors, one of which was an input change to lower SO_2 emitting coal. A key feature of coal generating units is each one is designed to burn a particular variety of coal, with significant deviations from the targeted coal characteristics resulting in productivity loss. The main innovation of my paper is to quantify the effect that switching to cleaner coal had on productivity, output, generation costs, and ultimately, the corresponding cost pass-through on prices. With data spanning over twenty one years, I first compute the ideal coal type of each unit in my sample and document ensuing deviations caused by switching to cleaner coal, finding deviations reaching magnitudes of over 30%. I then incorporate the effect of this deviation directly into a production function to explicitly quantify the resulting productivity loss. Estimated output losses range from 1% to 4%, varying across regions, over time, and mainly depending on the proximity of generating units to low-sulfur coalmines. Additional costs caused by the regulation were significant in magnitude, representing up to 11% of electricity price in one of the regions considered. Finally, certain evidence of cost pass-through to prices was observed in some regions.

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Keywords: productivity, production function, environmental regulation, sulfur, electricity, coal.

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1 Introduction

This paper evaluates the impact of the Title IV of the 1990 Clean Air Act Amendment (commonly referred to as Acid Rain Program) on the performance of coal-fired electricity generating units. Between 1985 and 2005, coal was the main source of electricity generation in U.S., roughly accounting for 40% of the industry. Additionally, coal-fired generating units produced most sulfur dioxide emissions in an industry that explains more than 70% of total emissions in the country. Given the importance of coal in both energy and pollution production, understanding how the Act affected the behavior of coal fired power units is crucial to the planning and analysis of future energy regulations.

Why might environmental regulations affect productivity? Under the Acid Rain Program, generating units had three main compliance alternatives: burn low-sulfur coal to guarantee an emission level below the permits allocated, purchase pollution permits to cover the excess of emissions, or retrofit a flue gas desulfurization system (a.k.a. scrubber), that could reduce emissions up to 99%. A salient feature of the production technology is each coal-fired boiler is designed to burn a particular type of coal. Coal is characterized by a number of attributes, including heat, sulfur, ash, and moisture contents. When a generating unit departs significantly from its design coal specifications it suffers an efficiency loss. With regards to the sulfur dioxide regulations, if a unit decides to switch from high- to low-sulfur coal, if the characteristics of the cleaner coal differ substantially from those the unit was designed for its productivity will likely decrease. Installing a scrubber system entails a different type of efficiency loss. While a scrubber allows a unit to burn its ideal coal type, it consumes additional electricity which reduces the net output generated by the unit. Naturally, if the unit simply buys permits to cover the emissions that exceed the initial allocation and no other further action is taken, then its productivity will remain unaffected. In order to measure the impact of the Acid Rain Program on productivity and output, I carefully estimate the electricity generation production function for coal-fired units. To capture of effects of the regulation, I augment a standard production function to include two additional features. First, I create a variable that quantifies the relative deviations from each units desired or unconstrained coal type. Second, I construct a dummy for scrubber usage to account for the electricity losses explained by these devices. I include both of these variables in the production function as affecting the total factor productivity term. By distinguishing among different groups of units that were differentially affected by sulfur dioxide regulations at different points in time and exploiting the rich heterogeneity of units characteristics I am able to estimate the impact of the Acid Rain Program. Also, since the period in question was marked by market restructuring and deregulation processes in several states, I incorporate controls to capture these potential confounding effects.

I find that productivity and output losses caused by the CAAA-1990 ranged from 1% to 4%, affecting more than 70% of the units. The effect of market restructuring and deregulation processes on productivity were not statistically significant. In terms of compliance cost (i.e. additional generation costs caused by the sulfur dioxide regulation) my estimates shows that they represented between 1.6% and 11% of the electricity price by 2004 and 2005, depending on the region considered. Additionally, certain evidence of cost pass-through to prices is observed in some regions. However, the latter seems unrelated to the market restructuring condition of the corresponding state. Some of the states where a close relationship between electricity prices and compliance cost is observed were deregulated markets and some of them were regulated markets. Lastly, environmental goals seem to have been successfully achieved during this period.

1.1 Some historical background

In response to growing concerns over sulfur dioxide emissions (SO_2) in the 1970s, Congress passed two important amendments to the Clean Air Act. The first amendment, enacted in 1970, established The New Source Performance Standards (NSPS). These new standards required any power generating unit constructed after 1971 to keep SO_2 levels below certain region-specific emission threshold. Each new unit was free to choose the manner in which the threshold would be met. However, in 1977, a second amendment was passed which mandated that new units must adopt scrubbers to guarantee compliance with more stringent emission standards.[1] Consequently, many utilities reacted to the new regulations by extending the lifespan of older units built before the seventies in order to delay the construction of new ones. The high levels of pollutants in the air during the eighties were almost entirely caused by those older units that were excluded from these regulations. A consensus for the need of a new wave of environmental policies targeting those older units was eventually reached that culminated with the passage of a new amendment to the Clean Air Act in 1990. Title IV of the CAAA-1990 established a nationwide market for tradeable emission permits (allowances), where an overall emission cap equal to 50% the 1985 emission level was established. This new amendment required affected units to offset emissions with permits at the end of each year, but did not specify the manner in which they had comply with the regulation. As a result, some units opted for blending different fuels incorporating a higher proportion of low-sulfur coal in their mix, some others chose to retrofit a scrubber or reduced the output level (if it was feasible and/or allowed), while others simply bought pollution permits from other utilities.[2]

On the other hand, until early 1990s the U.S. electricity market was predominantly dominated by vertically integrated monopolies over generation, transmission and distribution of electricity in certain geographical area.[3] State regulators determined electricity prices based on accounting costs

[1] An FGD is a technology used to remove sulfur dioxide from exhaust flue gases of fossil-fuel power plants. Scrubber adoption for units built after 1977 has been considerably high, although not 100% enforced.

[2] See for example Ellerman, Joskow, Montero, Schmalensee, Bailey [11] for an analysis of the behavior and performance of the market for emissions permits, quantification of the emission reduction, compliance costs, and cost savings associated with the trading program during the first three years of the program. Also, see Schennach [27] for a complete analysis of the economics of pollution permit banking. Frey [14] in turns studies the scrubber adoption choice in a context where cap-and-trade programs (Acid Rain Program) overlaps complex and stringent command-and-control regulations (CAAA-1977). Additionally, for a comparison pollution control techniques choices by regulated firms under emissions standards, emissions taxes, and tradeable permit systems both in an empirical and a theoretical fashion, see Keohane [20] and [21].

[3] Those utilities are typically referred to as regulated investor owned utilities (IOU).

of service. The main concern at that time was the high electricity prices observed in some states. As a result, market restructuring and deregulation episodes occurred in some of those states. The idea that market oriented policies could improve the economic efficiency was the main support for the changes.[4] A paper by Fabrizio, Rose, and Wolfram [12] tests whether thermal power plants became more efficient after market restructuring took place. They find evidence that labor input and materials were used more efficiently after deregulation but cannot find evidence in the case of fuel input. One possible reason could be that fuel consumption decisions are usually made at the boiler level rather than at the plant level. Boilers differ in technology and are designed to burn a particular type of fuel. Since most facilities have more than one boiler, several "fuel efficiencies" might coexist in a single plant producing blurry estimates for fuel input demand.

Finally, interactions between market restructuring episodes and environmental regulations could in principle be possible.[5] Since the goal of this work is to identify the impact of the Acid Rain Program on units' performance, I will control for market restructuring effects.

1.2 Related literature

This work relates to two strands of the economic literature. The first strand is concerned with the estimation of production functions, and is primarily concerned with identification and endogeneity issues, potential multicollinearity of production factors, and with the selection bias that emerges when there are many episodes of firms exiting the market. These topics where first addressed in Marschak and Andrews [24] work in 1944 identifying the *transmission bias*, i.e. the fact that firms productivity is transmitted to the firms optimal choice of inputs giving rise to an endogeneity problem.[6] Focusing specifically on the U.S. electric power industry, the empirical attempts to estimate a production function are relatively scarce when compared to other industries. Instead, most of the existing papers have generally estimated cost functions, with an early exception being Nerlove [25]. An advantage of the cost function estimation approach is it typically avoids the endogeneity problem: the error term (the unobserved productivity shock) is usually not present in the cost function. Most authors justify using this approach by arguing that power plant managers minimize costs in a context of cost-of-service regulation and take the quantity to be produced as given. However, this argument is less valid under the new regulation regimes of the 1990s, since several states have deregulated or restructured wholesale electricity markets and those that are

[4] Several papers discussed the incentives of IOU under different regulatory schemes. In particular, cost-of-service regulation is questioned in terms of its ability to limit utilities' profits and in terms of static and dynamic cost minimization. See for example Joskow [19], Hendricks [18], and Laffont and Tirole [22].

[5] In an empirical paper that studies the NO_x Budget Program under the Title IV of the CAAA-1990 Fowlie [13] found some evidence that deregulated IOU plants operating in restructured electricity markets were more reluctant to adopt capital intensive environmental compliance options than regulated IOU plants or publicly owned plants. (Note: NO_x stands for nitric oxide and nitrogen dioxide emissions. The Acid Rain Program regulated emissions of SO_2, NO_x, and also particulate matter)

[6] See for example Ackerberg, Caves, and Frazer [2], Gandhi, Navarro, Rivers [15], Olley, and Pakes [26], Levinsohn, and Petrin [23], for a discussion of these issues.

still regulated have a certain degree of flexibility in the amount of electricity each unit is called to produce.[7] Further, cost function estimation requires additional restrictions on the data[8], such as homogeneity conditions, which are not needed when estimating a production function.[9]

The second strand of the literature related to this paper studies the impact of environmental regulations on electric utilities efficiency. Some of these papers, like Sueyoshi, Goto, and Ueno [28], Bernstein, Feldman, and Schinnar [7], and Yaisawarng and Klein [29], use data envelopment analysis or best-practice frontier techniques to evaluate the performance of electric power plants under different environmental regulations. A seminal paper by Gollop and Roberts [16] measures the effect of sulfur dioxide emission restrictions on the rate of productivity growth in the electric power industry over the period 1973-79. They propose a firm-specific measure of regulatory intensity, which combines the severity of the emission standard, the extent of enforcement, and the unconstrained emission rate relevant to the firm.

This work makes contributions to both strands of the literature. In contrast to the majority of empirical papers in the electricity generation industry, I use a flexible functional form and am able to recover the total factor productivity directly. In addition, I also construct a unit-level measure of regulatory intensity akin to Gollop and Robers original approach, but incorporate the variable directly into the production function, allowing me to directly measure its effect on productivity. I add to the literature of production function estimation by exploiting a rich data set that allows me to solve the transmission bias problem by using exogenous input prices as instruments. The estimated model is based on a novel hedonic approach applicable to environments where characteristics and quality of inputs matter in the production function and where a discrete classification among different varieties of inputs is hard to handle in practice and unrealistic. As a result, I am able to illuminate how environmental policies affect generating units and to quantify impact of the Acid Rain Program in particular.

The remainder of this paper is organized as follows. Section 2 describes in more detail the electricity generation market and the different environmental regulations under analysis. Section 3 provides the results of the reduced form analysis that motivate the production function model

[7] Cost minimizing assumptions are not superior than regular profit maximizing assumptions for electric utilities. If we believe that a plant manager in a regulated market only try to reduce costs given some fixed electricity price, it is also likely that she will not make a big effort to achieve that goal either. By definition, effort is costly to her and given the usual regulatory design she will be able to include any extra cost in the next rate case, where many of those cost are presumably inefficient. Additionally, it could be also true that some timing pattern exists regarding the amount of effort the manager makes along each rate case. Effort could vary depending upon the proximity of a rate review, making the cost minimizing assumption difficult to handle in practice. A recent paper by Abito [1] explicitly models managers' behavior in a context of firms' cost optimization under environmental regulations.

[8] An exception is Atkinson and Halvorsen [4], which developes a generalized cost function approach that does not need implausible assumptions about cost minimization behavior.

[9] In the dual approach the most common functional forms adopted are Cobb-Douglas and CES production functions. The main reason behind those choices is that it is very simple to derive input demand equations under the cost minimization assumption. Some papers following this empirical strategy are Bushnell and Wolfram [9] which investigates the changes in operating eciency at plants that have been divested from utility to non-utility ownership, and Fabrizio, Kira, and Rose [12] which studies efficiency of firms that were deregulated.

presented in Section 4. This section discuss the empirical strategy to be implemented. Section 5 presents the estimation results. Section 6 evaluates the impact of the policy in question. Section 7 estimates the compliance costs and evaluates the evolution of electricity prices during the relevant period. Finally, Section 8 shows how the sulfur dioxide regulation performed in terms of the originally proposed environmental goals, whereas Section 9 concludes.

2 Compliance groups and market overview

In order to analyze the impact of the Acid Rain Program on productivity, it is crucial to distinguish when and how each unit was were affected by the regulation. For clarity, I will describe in the chronological order the policies which were implemented and how they affected targeted units. In 1970 all existing units were subject to state level emission rate standards or command-and-control regulations. State level emission rates were commanded under State Implementation Plans (SIPs) as a result of the National Ambient Air Quality Standards (NAAQS). After the amendments to the Clean Air Act in 1970, newly constructed electric generating units had to follow New Source Performance Standards (NSPS). Starting in 1971, the NSPS required a subset of large, new coal-fired units to have emission rates below 1.2 pounds of SO2 per million Btu (lbs/mmBtu). There was no restriction on the compliance method, and units were able to install scrubbers or burn low-sulfur coal. In 1977, the NSPS were modified in such a way that all new units constructed after 1978 were virtually required to install scrubbers.[10] Title IV of CAAA-1990 departed from previous regulations in that the method of pollution abatement was flexible and the amount of abatement for each unit was not predetermined. The NSPS were essentially overridden under Title IV, although existing sources still have to comply with state regulations.

Title IV established the first nationwide market for tradable pollution permits in the U.S. This was significantly different from the emission rate standards and abatement technology requirements that were in place previously. The purpose of Title IV was to cut SO_2 emissions by 50 percent from 1980 levels. The program was implemented in two phases. Phase I originally required the reduction of emissions through a tradable pollution permit system beginning in 1995 to a group of 263 large and dirty units. Under Phase I, each affected unit was allocated a number of permits sufficient to achieve an emission rate equal to 2.5 lbs of SO_2 per million Btu according to the units average heat input registered during 1985-1987. One permit entitled the unit to emit one ton of SO_2 and could be used in the allocated year, banked for future use, or traded with other firms. The second phase of the program began in 2000 and included all units larger than 25 MW of nameplate capacity. Under Phase II, each unit was allocated permits sufficient to emit at a rate of 1.2 lbs of SO_2/mmBtu, once again using the base years 1985-1987 for the allocation computation. An important feature of Title IV was each firm was free to choose among several compliance alternatives: install a

[10] The tightness of the new standards was such that the only way of complying with the regulation was through the adoption of a FGD unit. Some of the standards were set to levels well below 0.6 lbs SO_2/mmBtu, a number impossible to reach without a scrubber.

scrubber, buy low-sulfur fuel, trade pollution permits, or simply reduce the amount of electricity produced (trimming strategy). Utilities choosing to drastically reduce output from a unit reached by Phase I of the program were required to incorporate a substitute unit, i.e. a different unit initially not subject to the regulation in exchange for the original unit that would reduce output levels. All these different compliance alternatives have different implications for output productivity and costs. Table 1 summarizes the different sulfur dioxide regulations and the corresponding targeted compliance groups.

Table 1: Different Stages of Sulfur Dioxide Regulations

	Legislation	Implementation	Units Affected	Regulation type	Requirement
1	CAAA-1970 NSPS-D	1971 - 1977	Newly constructed units, larger than 73 MW of nameplate capacity	Command-and -control	Keep emissions < 1.2 lbs/mmBtu
	CAAA-1977 NSPS-Da	1978 -	Newly constructed units, larger than 73 MW of nameplate capacity	Command-and -control	Further emission reductions. (Tacit requirement of FGD adoption)
2	Title IV of CAAA-1990	1995 - 1999 (Phase I)	A subset of old units not reached by NSPS, with high emission rates	Cap and trade (units built before 1995 receive some free permits)	Cover annual emissions with an equal number of allowances
3	Title IV of CAAA-1990	2000 - (Phase II)	All generating units with capacity 25 MW or more	Cap and trade (units built before 1995 receive some free permits)	Cover annual emissions with an equal number of allowances

Note: State level emission rates mandated by the SIPs existed since the effective implementation of the NAAQS in 1970.

2.1 Data

This paper utilizes data from three different sources: the Energy Information Administration (EIA), the Federal Energy Regulatory Commission (FERC), and the Environmental Protection Agency (EPA). EIAs Form-767 include all generating units that have a nameplate capacity of 10 MW or more. From this annual survey, important unit and plant characteristics are gathered (e.g. age, capacity, boiler type, generator characteristics, type of ownership, plant location, etc.). Other important variables included in the survey are: heat input, emissions of major pollutants, quality and quantity of fuels used, information on installed scrubbers, regulatory information such as the unit's phase, state-level emissions standards, and NSPS status. FERC's Form 423 gathers data on monthly fuel shipments at the plant level. Among other variables it includes: delivered cost of fuels, fuel characteristics, quantities, type of purchase (spot vs. contract), mine location and mine type for coal transactions, type of transportation, etc. The EPA provides data on allowance allocations and annual pollution emissions for some units.

2.1.1 Different compliance groups

Although some overlaps may exists according to the classifications made in Table 1, for simplicity I will consider three mutually exclusive groups of units. The first group which I call "NSPS" includes all units constructed after 1971 with capacity larger than 73 MW.[11] The second group comprises the older units regulated under Phase I of Title IV, a.k.a. "Table A" units. It also includes some units that opted in during this phase of the program as substitute or complementary units. I will name this second group of units "Phase I". Finally, the "Phase II" units will be those older units that did not enter during the first phase of the program.[12]

Table 2 shows some descriptive statistics for the three groups of units in 1990, the year the CAAA-1990 was passed.[13] It is apparent that NSPS units were, on average, larger (higher capacity in MW) and younger than Phase I and Phase II units. They also burned cleaner coal varieties than Phase I but almost the same as Phase II. There is commonly a trade off between heat and sulfur contents and therefore NSPS units normally consumed coal with lower heat content. Nevertheless, the heat rates, namely the ratio between the amount of energy consumed and the net electricity generated, were very similar among the three groups.[14] Finally, more than a half of NSPS units had a scrubber system in 1990 while only eight percent of Phase II units and none of Phase I units did so.

[11]NSPS units were treated under a different regulation and were constrained from the onset. They will serve as a control group when analyzing the effects of the Acid Rain Program.

[12]Some clarification is necessary here. The second phase of Title IV technically reaches all units, however, the units that I call NSPS were previously subjected to equal or even stricter regulations and will not be considered as members of this group. As a consequence, NSPS units will serve as a control group when analyzing the effects of the Title IV program.Strictly-speaking NSPS units were treated under a different regulation and were constrained from the onset. Figure 11 in Appendix D shows an example of how different vintages of units were affected by each sulfur dioxide program mentioned above.

[13]The data set is reduced due to missing data and data inconsistences. The original data set has 875 coal-fired boilers/generators while this paper only uses 613.

[14]Notice that the heat rate can be considered the inverse of fuel input productivity. A similar measure for labor productivity is typically used in economics where output level is divided by the number of hours worked or the total number of employees.

Table 2: Summary of units characteristics by compliance group in 1990.

				Difference in means (t-statistic)		
Variable	Phase I (n=229)	Phase II (n=243)	NSPS (n=144)	Phase I-Phase II	Phase I-NSPS	Phase II-NSPS
Nameplate Rating	311	248	537	62***	-227***	-288***
(MW)	(256)	(225)	(240)	(20)	(23)	(22)
Capacity Factor	.55	.46	.61	.09***	-.06***	-.15***
(0-1)	(.18)	(.20)	(.15)	(.02)	(.02)	(.02)
Boiler Age	44	45	26	-1.2*	18.6***	19.8***
(years in 2005)	8	8	4	(.64)	(.57)	(.55)
Heat Rate	10.5	10.9	10.6	-.41***	-.07	.34***
(million btu/MWh)	(1.5)	(1.4)	(.7)	(.12)	(.11)	(.10)
Share of Coal	.99	.95	.99	.04***	-.001	.04***
(%)	(.02)	(.17)	(.01)	(.01)	(.001)	(.01)
Coal Heat Content	11831	11570	9980	260**	1850***	1590***
(btu per pound)	(811)	(1688)	(1929)	(108)	(151)	(173)
Coal Sulfur Content	2.16	1.05	1.13	1.12***	1.04***	-.08
(% per pound)	(.80)	(.61)	(1.11)	(.06)	(.10)	(.09)
Coal Ash Content	9.86	9.25	9.23	.61***	.64*	.03
(% per pound)	(2.03)	(2.96)	(4.09)	(.21)	(.32)	(.35)
Scrubber	.00	0.08	0.56	-.08***	-.56***	-.48***
(%)	(.0)	(.27)	(.50)	(.02)	(.04)	(.04)

Notes:
(a) In the first three columns Standard Deviations are in parenthesis
(b) In the last three columns Standard Errors are in parenthesis
(c) ***Denotes differences are significant at .01; ** at .05; and * at .10

2.1.2 Mine locations and coal characteristics

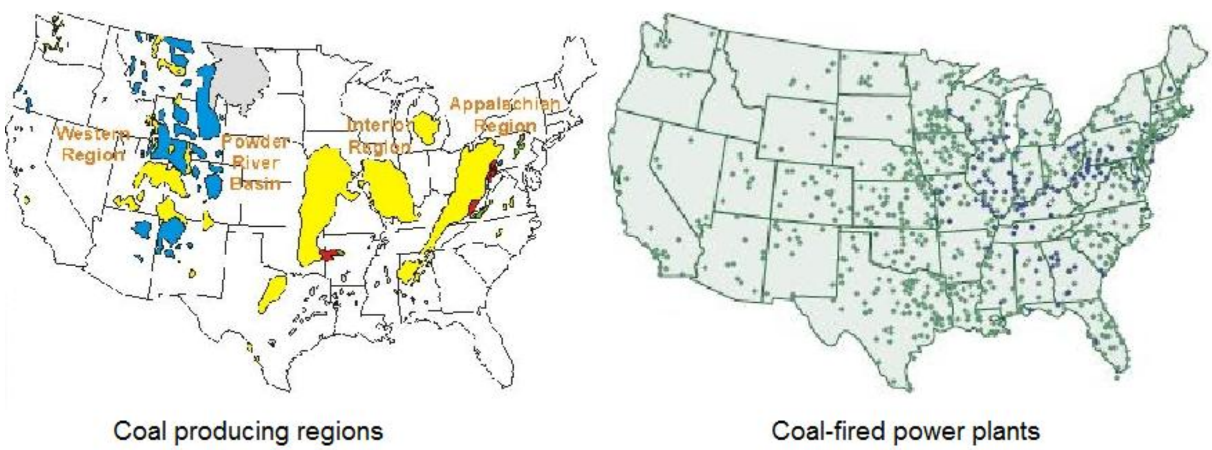
To better understand the way electric utilities make their choices about coal varieties it is important to consider where coal mines are located and the main characteristics of the coal extracted from each them. The distances between coal mines and power plants and the transportation type (rail, barge, and less usually truck) are important determinants to the total delivered cost of coal. Figure 1 displays the locations of coal mines and coal-fired power plants. Two important trends are apparent. First, we note four main coal producing regions: Western Region, Powder River Basin, Interior Region, and Appalachian Region. Second, most coal plants are located in the eastern half of the country.

Coal quality and sulfur content vary both across and within regions. These variations are key elements explaining the heterogeneity in sulfur dioxide abatement costs.[15] Using data from

[15]U.S. coal could be ranked into four general categories. They range from lignite through subbituminous and bituminous to anthracite, reflecting the progressive response of individual deposits of coal to increasing heat and

the FERC's Form 423, Table 3 presents some descriptive summary statistics about monthly coal shipment data at the plant level for the years 1985-2005. Central Appalachia -parts of West Virginia, Kentucky, Virginia and eastern Tennessee- was the primary coal-producing region during the period of analysis, especially before the second phase of the Title IV of CAAA-1990. This region produces both medium and low-sulfur coals. After railroad deregulation in the 1980s, the major source of low-sulfur coal has shifted to the Powder River Basin (PRB)-Montana and Wyoming-. Northern Appalachia -parts of Ohio and Pennsylvania- and the Interior Region -mainly Illinois and Indiana-, are prime sources of high-sulfur coal. Other states like Alabama, Texas, and Oklahoma, and also states in the West North Central Region have supplied medium and high-sulfur coals during this period, however, their production has steadily declined since early 1990s.

Figure 1: Coal production regions and power plant locations



Source: Department of Energy, Energy Information Agency (EIA)

The trade off between sulfur content and heat content is remarkable for the PRB coal. In contrast, it is possible to find medium- and low-sulfur coals with high Btu content in the Central Appalachia Region. It is important to keep in mind that most NSPS units -and starting in 2000 all generating units- had a tacit emission rate standard of 1.2 lbs SO_2/mmBtu. Coal with an implicit emission rate below that limit is commonly referred to as *compliance coal* and the only two regions able to supply it during the entire period of analysis were PRB and Central Appalachian. Additionally, while PRB coal comes mainly from surface mining, Northern and Central Appalachia and the Interior coals are almost equally extracted from underground and surface. Typically underground mining is more costly than surface mining because of the larger amount of physical

pressure. The carbon content of coal supplies most of its heating value, but other factors also influence the amount of energy it contains per unit of weight. About 90 percent of the coal in this country falls in the bituminous and subbituminous categories, which rank below anthracite and, for the most part, contain less energy per unit of weight. Bituminous coal predominates in the Eastern and Mid-continent coal fields, while subbituminous coal is generally found in the Western states and Alaska. Lignite ranks the lowest and is the youngest of the coals. Most lignite is mined in Texas, but large deposits also are found in Montana, North Dakota, and some Gulf Coast states capital needed. Finally, spot purchases represented roughly 20% during this period, so medium and long-term contracts were the most usual type of transaction.

Table 3: Coal characteristics by regions. Years 1985-2005

Coal production region	Heat (btu/lbs)		Ash (% in wt)		Sulfur (% in wt)	
	mean	*sd*	*mean*	*sd*	*mean*	*sd*
Northern Appalachia	12275	(759)	11.2%	(4.0%)	2.5%	(1.0%)
Central Appalachia	12301	(648)	10.7%	(2.9%)	1.5%	(1.0%)
Interior	11082	(978)	8.7%	(2.2%)	2.4%	(0.9%)
Powder River Basin - West	9083	(966)	7.1%	(4.3%)	0.4%	(0.2%)
AL	12279	(490)	10.6%	(2.2%)	1.2%	(0.6%)
TX and OK	6843	(1180)	14.2%	(6.0%)	1.1%	(0.4%)
West North Central	9472	(1279)	7.8%	(3.9%)	3.9%	(0.6%)

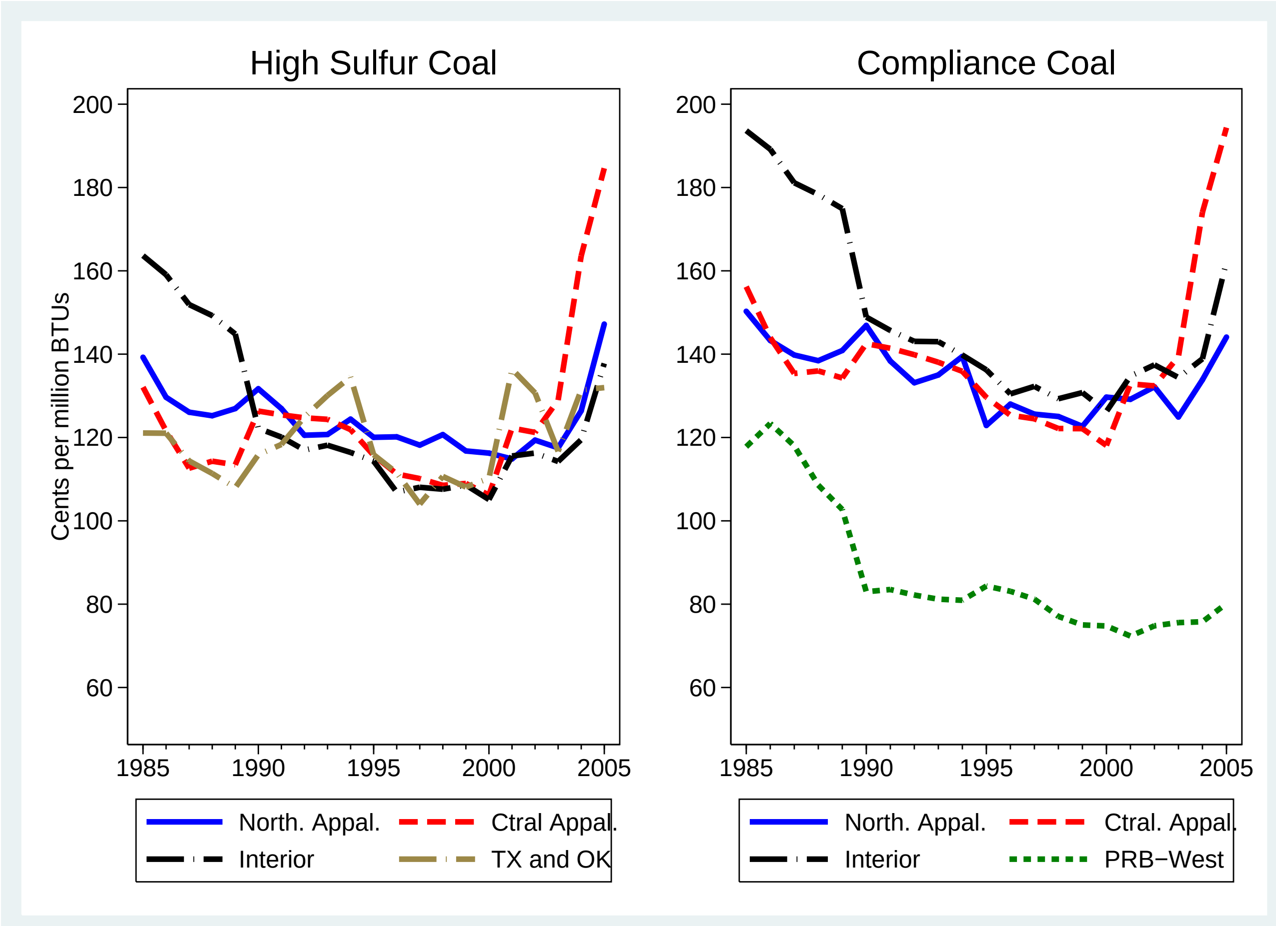
Coal production region	Under-ground	Spot market	Emission rate (lbs/mmbtu)			
			mean	*sd*	p05	p95
Northern Appalachia	57.1%	27.8%	3.86	(1.66)	1.89	6.71
Central Appalachia	56.0%	24.8%	2.33	(1.71)	0.98	5.98
Interior	43.6%	19.6%	4.02	(1.55)	1.56	6.31
Powder River Basin - West	10.5%	14.6%	0.77	(0.31)	0.39	1.49
AL	53.9%	16.4%	1.85	(0.89)	0.82	3.33
TX and OK	0.1%	1.8%	2.56	(1.19)	1.23	5.29
West North Central	8.8%	10.5%	6.73	(1.20)	4.77	8.32

Source: Form 423, FERC.

Figure 2 illustrates the evolution of average commodity coal prices in the most important producing regions during the last three decades. Prices are expressed in cents per million Btu. The panel on the left shows prices of high-sulfur coals, while the right panel depicts prices of compliance coals (i.e. with implicit emission rates below 1.2 lbs SO_2 per million Btu).[16] There are two main observations drawn from Figure 2: first, low-sulfur coal was typically more expensive than high sulfur coal, and second, there were two phases with opposite trends. A downward sloped trend from 1985 until 2000, and then a marked reversion with prices climbing up rapidly. The only exception is Powder River Basin Region, where prices were relatively more stable after the initial decline.

[16]The computation of the different coal prices is based on the regression equations estimated in Section 4.1.1 of the paper. Concretely, I regress delivered cost of coal on sulfur, heat, ash, distance and year dummies for each of the regions listed above. Then, in order to estimate the commodity price I consider a distance equal to zero in the corresponding regression equation.

Figure 2: Coal prices in main production regions: high-sulfur vs. low-sulfur.



2.1.3 Deviations from the ideal coal type

As mentioned in the introductory section, coal-fired boilers are designed to burn a specific variety of coal. The particular variety chosen responds to the initial and the expected coal market conditions, the regional availability of that variety, and the different transportation modes, among other things. The crucial point is that many of these determinants that were originally considered when the boiler was constructed may change along with other relevant institutional facts. Environmental regulations constitute a clear example of how a coal variety that is initially optimal for a given generating unit could eventually be substituted for a different variety once the policy is implemented. In extreme cases, it is also possible to observe a boiler reconverting its technology to burn a different fuel like natural gas, or even for a boiler to exit the market because production is no longer cost efficient.[17] There is a capital cost of converting a boiler to burn lower-sulfur coal. This capital cost depends upon the differences in quality between the high- and low-sulfur coals used. For example, a switch

[17]See for example Dardati [10] for an empirical paper that evaluates exit/entry decisions in the power generation industry comparing different environmental schemes in US and Europe.

made with coals purchased from Central Appalachian is not very costly to the unit since both high- and low-sulfur coals extracted from this region are quite similar in quality. On the other hand, switching from Central Appalachian high-sulfur coal to PRB low-sulfur coal -a variety very different from eastern coal- would require a much larger capital investment to retrofit the boiler.

In order to capture the main mechanism through which sulfur dioxide regulations impact unit's total factor productivity, I create a variable that measures the distance from the actual coal used relative to the unconstrained ideal coal type for each unit. I define R -hereafter referred to as *relative deviation*- in the following manner:

$$R_{jt} = \left| \frac{E_j^* - E_{jt}}{E_j^*} \right| \tag{1}$$

where E_{jt} is the observed emission rate and E_j^* is the free emission rate. Emission rates in turn are calculated in pounds of SO_2 per million Btu, which is an implicit characteristic of each variety of coal. EIA's Form 767 provide data on heat and sulfur contents at the unit level on a monthly basis. I am able then to compute monthly emission rates for each generating unit. The emission rate observed in month m is simply the ratio between the sulfur content and the heat content multiplied by a conversion factor (a scalar).[18] Since the format of other data used in this analysis is on an annual basis, I compute annual average emission rates, E_{jt}, for each boiler. The unconstrained emission rate, E_j^*, is computed using the average emission rates from the pre-regulation period 1985-1988.[19] It is precisely the stability of E_{jt} observed during this time frame what validates the approximation of E_j^* using these years.[20]

Figure 3 shows the evolution of R over time and across regions, while Table 4 shows the number of units in each compliance group by geographical region.[21] From Figure 3, it becomes clear that as sulfur dioxide regulations became more stringent, fuel switching arose as a more popular compliance strategy which is reflected in the increase in R. For most of the regions, there were two jumps in the relative deviation measure: 1995 and 2000, which corresponds to the beginning of phase I and phase II, respectively.[22] This phenomenon was more pronounced in the Great Lakes, West North

[18] To calcuate emission rates I use the conversion formulas proposed by the EPA.

[19] There could have been some anticipation of the Acid Rain Program to be included in the CAAA-1990. To avoid this effect, I decide to exclude 1989 from the computation of E_j^*.

[20] There are at least two alternatives for the computation of the unconstrained emission rates which in my opinion are less desirable. One method would be to use the emission rate for the least expensive fuel type purchased by the plant or a set of plants owned by the same utility in a certain area. This alternative violates the observation that there are technological constraints and also that the ideal type of fuel is not necessary the less expensive one. A second alternative is to use some summary measure (e.g. the average) of emission rates of high-sulfur coals, i.e. only including coals with an emission rate above 1.2 lbs SO_2/mmBtu. Once again, this alternative does not contemplate the technological constraints faced by the boiler. Some units might have been designed to burn low-sulfur coals.

[21] Regions are defined as follows: **Northeast**: PA, NY, NJ, CT, RI, MA, VT, NH, ME. **West**: AZ, CA, CO, ID, MT, NV, NM, OR, UT, WA, WY. **Great Lakes**: IL, IN, OH, MI, WI. **West North Central (WNC)**: IA, KS, MN, MO, NE, ND, SD. **South**: AL, AR, DE, FL, GA, KY, MD, MS, NC, OK, SC, TN, TX, VA, WV, LA.

[22] West Region is a special case because most coal-fired units have cheap access to low-sulfur coal and no major boiler retrofits were needed.

Central, and South regions. In the Northeast, fuel switching was important during Phase I and less pronounced during Phase II instead. This most likely occurred because a higher proportion of units were subject to Phase I regulation and also Northeastern units mainly purchase coal extracted from the Appalachian Region where the differences in qualities (other than sulfur) are small.[23]

Figure 3: Evolution of variable R by region.

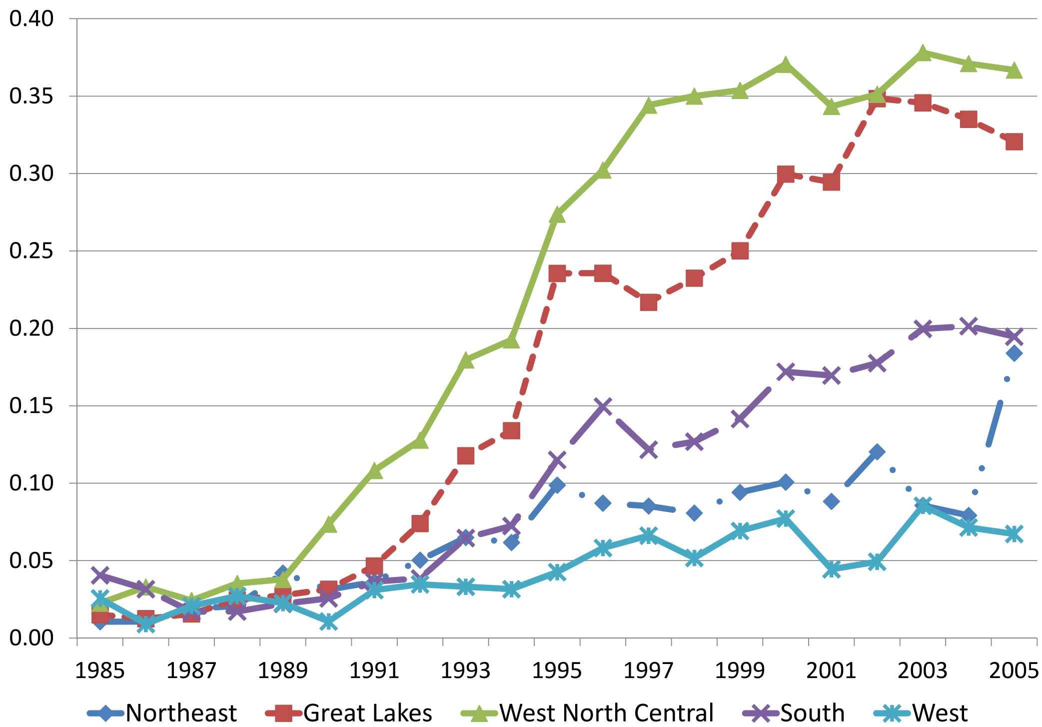


Table 4: Unit location by compliance group

	Phase I	Phase II	NSPS	All groups
Northeast	42	49	5	96
Great Lakes	116	77	34	227
West North Central	39	29	34	102
South	111	164	103	378
West	0	30	42	72
All regions	308	349	218	875

Note that during the period from 1985-1990 (the period used to compute the unconstrained value of E in equation1), the value of R is not zero, as one would expect if firms where truly

[23]See Section 2.1.2 for a detailed description of the different coal characteristics by producing regions.

unconstrained in their choice of coal. This occurs because although one could in principle rank different coal varieties in a finite number of categories, the true classification is not discrete. Rather, there exists continuous ranges for features like ash, sulfur, Btu, and moisture contents, which in turn explain certain overlaps among coals from different regions. Hence, using those years as a benchmark, a simple rule of thumb indicates that any value of R below 3 percent should not be attributed to a response to environmental regulations and should be consider as normal fluctuations around the unconstrained ideal emission rate -i.e. unconstrained ideal coal type.[24]

3 Some reduce form evidence of the policy impact

As a first approach to study the impact of sulfur dioxide regulation on productivity, I present some empirical evidence of the units behavior during the two phases of the Title IV program. First, I want to see the relative evolution of units output and total demand of heat by comparing the affected units (treated group) with the non-affected units (control group). Additionally, I want to check the effect of Acid Rain Program on the coal input productivity -defined in this case as the ratio between output and fuel input. Finally, I want to check whether changes in variable R were different across the treatment and control groups. With those objectives in mind, I estimate the average treatment effect on the treated

$$ATET = \mathbb{E}\left[Y(T=1)|T=1\right] - \mathbb{E}\left[Y(T=0)|T=1\right]$$

where $T = 1$ indicates the generating unit is under treatment and $T = 0$ indicates the unit belongs to the control group. Table 5 defines the treated and control groups for the two program evaluations.[25] To take advantage of the data structure I match similar observations in the base line period using a gaussian kernel propensity score, and then compute the difference-in-differences. The estimation of the propensity scores is based on a logistic regression that uses the following set of covariates: nameplate capacity, capacity factor, gross emission rate, unit's age in 2005, regional dummies, a dummy variable that is equal to one if the unit is an IOU, and a dummy variable that assumes the value one if the unit has a scrubber. Table 6 presents the estimates of the $ATET$. Only observations with common support are used for estimation of the diff-in-diffs -i.e. I drop treated units with propensity scores higher than the maximum or less than the minimum observed in the control group. Covariate imbalances were also tested but no major problems were detected.

Table 6 presents the results of this exercise. The last column of the first row displays the

[24] Plant level date from FERC's Form 423 reveal that two different shipments coming from exactly the same coalmine in a given month present certain differences in terms of coal characteristics. If heat and sulfur contents differ, the corresponding emission rate also differ -by construction.

[25] I do not include 1989 in the base line period and 1999 in the follow-up period of the first phase of the program because some policy anticipation might have occurred during those years. By excluding them I avoid the overestimation of the $ATET$.

Table 5: Treated and control group definitions

Program	Treated group	Control group	Base line	Follow-up
Title IV - Phase I	Phase I units with $E^* > 2.5$	NSPS units and Phase II units with $E^* < 1.2$	1986-1988	1996-1998
Title IV - Phase II	Phase II units with $E^* > 1.2$	NSPS units and Phase II units with $E^* < 1.2$	1986-1988	2002-2004

See Table 1 for concrete definitions of NSPS, Phase I, and Phase II units, respectively.

$ATET$ on the quantity of coal produced, which following the standard convention in the literature is measured in annual total amount of heat consumed. In both phases of the Acid Rain Program the sign of the $ATET$ is negative, suggesting that the regulation negatively affected the treated units when compared with the control units. However, in the second phase of the program the big standard error indicates the result is not significant. Something similar occurs with the effects on output (annual net electricity generation measured in GWh), where the $ATET$ is negative in both cases but it is significant only in the first phase of the program. Notice that these findings do not necessary mean output levels and coal input demands decreased for affected units. In fact, for treated units both variables remained practically unchanged during the first phase and slightly increased during the second phase. Most of the additional demand of electricity that was gradually incorporated over time during the sample period appear to have been absorbed by the units in the control group, namely NSPS units. The estimates of the $ATET$ for fuel input productivity have the expected negative sign but are not statistically significant. Finally, as an obvious response to the SO_2 program the variable R responded positively indicating that fuel switching was relatively important among affected units, especially during the first phase of the program. In sum, the (weak) results obtained in this section suggest that treated groups coal demand and output were presumably affected. Most of affected units switched to different varieties of coal. Since output level and input composition are changing across units and over time and because the production technology is such that departures from the design characteristics harm productivity, the natural step is to incorporate all these elements in a production function setting. In the next section I introduce R as an argument of the unit's total factor productivity. The main idea is to obtain the differentiated effect of the environmental policy in question and to capture the input biasing essence of the Title IV regulation by accounting for other confounding effects in the input mix composition.

Table 6: Kernel Propensity Score Difference-in-Differences

Title IV - Phase I	Base line			Follow up			
	Control	Treated	Diff	Control	Treated	Diff	Diff-in-Diff
Total Heat	17.13	15.71	-1.42	21.38	15.58	-5.80	-4.38**
(Btu$\times 10^{12}$)	(1.00)	(1.00)	(1.41)	(1.08)	(1.00)	(1.47)	(2.04)
Generation	1662.0	1565.1	-96.9	2068.7	1543.9	-524.9	-428.0**
GWh	(101.5)	(101.1)	(143.2)	(109.2)	(101.9)	(149.4)	(206.9)
Fuel Productivity	94.01	95.79	1.79	93.83	95.26	1.44	-0.35
(KWh/mmBtu)	(0.55)	(0.54)	(0.77)	(0.59)	(0.55)	(0.80)	(1.11)
Relative deviation	0.022	0.03	0.008	0.122	0.364	0.243	0.234***
(Variable R)	(0.012)	(0.012)	(0.017)	(0.013)	(0.012)	(0.018)	(0.025)
Title IV - Phase II	Base line			Follow up			
	Control	Treated	Diff	Control	Treated	Diff	Diff-in-Diff
Total Heat	12.45	11.34	-1.12	16.92	13.85	-3.07	-1.95
(Btu$\times 10^{12}$)	(0.81)	(0.81)	(1.15)	(0.89)	(0.82)	(1.21)	(1.67)
Generation	1201.8	1110.0	-91.8	1631.8	1348.8	-283.0	-191.2
GWh	(81.2)	(81.2)	(114.8)	(88.6)	(82.1)	(120.8)	(166.6)
Fuel Productivity	92.94	93.44	0.499	94.334	92.406	-1.929	-2.428*
(KWh/mmBtu)	(0.62)	(0.62)	(0.877)	(0.678)	(0.627)	(0.923)	(1.274)
Relative deviation	0.015	0.031	0.017	0.118	0.162	0.044	0.028*
(Variable R)	(0.009)	(0.009)	(0.012)	(0.01)	(0.009)	(0.013)	(0.016)

Note: Bootstrap standard errors using 100 replications are shown in parenthesis.

4 Model: the production function

The relevant individual or economic agent in my model is the combination boiler-generator, henceforth simply referred to as *unit*. I will only consider boilers and generators associated to each other in a one-to-one relationship. This simplification allows me to measure inputs and output for each unit in a straightforward and accurate way. The unit's output, Y, is represented by the annual net electric energy produced in a given period of time. I will follow the convention of using annual megawatt-hours to measure output. The inputs entering as arguments in the production function are capital, labor, and total heat -K, L, and H, respectively.[26]

Capital input is measured by the generator's nameplate capacity in MW.[27] Capital decisions are

[26] Other potential inputs like materials are not available in the samples used for this research.

[27] I could also measure capacity in terms of the boiler's maximum steam flow capacity. It turns out that the correlation between maximum steam flow and the generator's nameplate capacity is above .99, so the distinction between them is irrelevant. Because output is measured in annual MWh it makes more sense to have capacity measured in MW.

made in advance of output decisions, essentially at the time of the unit construction or retirement. Less frequently, some capacity adjustments occur once or twice during the unit's lifespan.[28] Labor is also decided in advance of output decisions. Labor is reported at the plant level in my sample, and the allocation among units in a given plant is not perfectly delimited. Because environmental regulations are enforced at the unit level, I am interested in measuring output at the unit level rather than at the plant level. Therefore, I impute labor to each unit according to its share in the plant's annual net generation.[29] Labor input is of course used for different tasks in a power plant; some tasks are shared by all units, but most of them are unit-specific tasks. For instance, tasks related to the rail car (or barge) unloading, coal handling, coal burning, ash removal, maintenance of the unit and auxiliary equipment, and pollution abatement equipment operation are all unit specific.[30]

Conversely, fuel decisions are made in real time in response to dispatching and operation changes. According to the production function literature, I consider fuel as a flexible, non-dynamic input, while capital and labor could be consider as inflexible, dynamic inputs. The variable H_{jt} corresponds to the total amount of heat used by boiler j to generate electricity in year t and is expressed in million of British thermal units (mmBtu). Suppose there are m fuel types, then the unit's total heat used is $H_{jt} = \theta^1 X^1_{jt} + ... + \theta^m X^m_{jt}$, where X^i is the quantity of fuel used and θ^i is the heat content per unit of fuel i, for $i = 1, ..., m$. The generic production function is thus represented as follows:

$$Y_{jt} = F(K_{jt}, L_{jt}, H_{jt}) \exp\{\gamma_0 + \gamma_R R_{jt} + \gamma_f f_{jt} + \gamma_t Dt_t + C_{jt}\gamma_C + \varepsilon_{jt}\} \tag{2}$$

The variable R is the measure of relative deviation from ideal coal type introduced before, f is a dummy variable that assumes the value one if the unit has an active scrubber, Dt is the year dummy for year t, and C is a vector of control variables. This vector may consist of institutional variables that account for different regulatory regimes, different ownership types, environmental regulations, and any other relevant unit characteristic that potentially affects total factor productivity.

I choose a transcendental logarithmic form for the production function $F(\cdot)$. The *translog* function provides the desired flexibility to accommodate the particularities of power industry without the need of unrealistic settings that usually appear in the literature when more rigid functional forms like the Cobb-Douglas, the Constant Elasticity of Substitution (CES), or Leontieff forms are

[28] In the sample used for this work only 77 capital adjustments took place during the period 1985-2005 from a total of 876 units in operation. The average adjustment was an increment of 7%, with a standard deviation of 9%. Only 8 units adjusted their capacity twice, while the remaining 61 units did it once.

[29] Other valid alternatives could be to allocate labor according to unit's share in the plant total capacity or to unit's share in plant's total coal consumption.

[30] Maintenance and repair expenditures may be inversely related to the net amount of electricity generated since most of the times the unit needs to be out of service for major works. However, we do not have access to data on these variables at the boiler level. A very rough estimation at the plant level implies that materials and maintenance expenditures can be retrieved as the residual of non-fuel expenses once labor costs are subtracted. This quick estimation indicates that operating costs other than labor and fuel represent (on average) 2.5% of the plant's total revenues for electricity sales.

used. For estimation purposes, the concrete form for equation 2 is

$$\begin{aligned} y_{jt} &= \gamma_0 + \alpha_h h_{jt} + \alpha_k k_{jt} + \alpha_l l_{jt} + \alpha_{hh} h_{jt}^2 + \alpha_{kk} k_{jt}^2 + \alpha_{ll} l_{jt}^2 \\ &+ \alpha_{hk} h_{jt} k_{jt} + \alpha_{hl} h_{jt} l_{jt} + \alpha_{kl} k_{jt} l_{jt} + \gamma_R R_{jt} + \gamma_f f_{jt} + \gamma_t D t_t + C_{jt}\gamma_C + \varepsilon_{jt} \end{aligned} \tag{3}$$

where $y = \ln(Y)$, $l = \ln(L)$, $k = \ln(K)$, and $h = \ln(H)$. Notice that productivity enters in a Hicks-neutral fashion.

This representation of the production function reflects the assumptions made about the underlying economic model of production. For example, one may think of log-productivity as if it were composed of two components: an unobserved shock (η) which realizations occur after output decisions are made, and a second component (ω) that is anticipated and observed by the firm (but not by the researcher) at the beginning of each period and before output decisions are made. Additionally, one may assume further that the anticipated log-productivity term is fixed over time for each unit, so a panel fixed effect model can be used, i.e. $\omega_{jt} = \omega_{jt-1}$ for all t.

An alternative representation for ω assumes anticipated productivity evolves according to some dynamic process, e.g. a first order Markov process in which case $\omega_{jt} = \phi(\omega_{jt-1})$ where $\phi(.)$ is some arbitrary function to be determined. Another possibility is to contemplate some serial correlation at the unit level for the unexpected innovation term (η) -assuming for example an ith order autoregressive process- and include unit fixed effects for the anticipated part, i.e. ω_j constant over time. I will explain below the specific assumptions about the error term and discuss the estimation strategy.

4.1 Production function estimation

Endogeneity concerns naturally emerge in the estimation of production functions. From the above description of the inputs, capital input is unlikely to be correlated with the log-productivity shock, ε, in the short- and medium-run. Labor input is perhaps more flexible than capital and to some extent is correlated with current output, however, it does not respond immediately to productivity shocks. The quantity of labor input is typically decided in advance of productivity shock realizations. It is usually based on previously made seasonal forecasts.

Fuel input decisions, however, are contemporaneous to productivity shocks and therefore some corrective measure is needed. Specifically, there are two potential endogeneity problems in estimating the production function in equation 3. The first concern I confront is that ε may be contemporaneously correlated with h. If it is true that output decisions are made after the unit observes its efficiency, then the manager may increase the quantity of fuel used in response to positive shocks of productivity. This type of behavior induces positive correlation, violating the OLS exogeneity condition $E\left[\varepsilon_{jt}|h_{jt}\right] = 0$. Second, a selection bias may arise if the decision to retire a unit is driven by the realization of unobserved productivity shocks. In our sample, the selection bias does not seem to be particularly problematic. Electric utilities operated in a more stable environment than firms in other industries where the selection problem is more acute.[31] Both types of problems mentioned above have been largely studied in the literature, although the former has received more attention (perhaps because its solution is somehow easier to handle).

Now, the variables R and f are clearly key pieces of the model that help explain the impact of SO_2 regulations on productivity. A natural question that emerges then is whether they are also exogenous variables. R by construction is a choice variable, and one may be concerned whether more productive units are more prone to adopt scrubbers (variable f) or to follow a fuel switching strategy (variable R). These concerns are addressed in Appendix B.

Some of the commonly proposed estimation methods to tackle the simultaneity problem are: a) instrumental variables (IV); b) panel data models including first differences, individual dummy variables, fixed effects (FE), and random effects (RE); c) correlated random effects which combines the attributes of FE and RE models; d) different approaches based upon the generalized method of moments (GMM)[32]; e) control function techniques[33]; and more recently, f) methods that exploit the firm's first order conditions.[34]

I adopt a GMM approach and use exogenous fuel prices at the plant level as instruments. In equation 3, the variables that are potentially correlated with the error are all the terms where h is involved. Coal prices are likely to be highly correlated with fuel input demand, but uncorrelated, for instance, with how efficiently a boiler burns fuel to heat the water to produce saturated steam and generate electricity. There are many other variables that account for coal price variation: coal quality (approximated by btu content), sulfur and ash contents, the type of purchase (spot or contract), shipment type (rail, barge, truck), and the shipment distance from coal mine. In the next subsection I will explain in more detail how my instruments are constructed.[35]

4.1.1 The choice of appropriate instruments

A major critique of using input prices as instruments to estimate production functions is that input prices usually do not have enough exogenous variation across firms (or units in this paper). If all units face the same coal price there is little hope for identifying the parameters of interest using IV or GMM approaches. However, it turns out that coal delivered costs are highly dependent on the location of the unit, or more precisely, on the distance from the unit to the coal mine. This is specially true for low-sulfur coal from Powder River Basin (PRB) and units located in the western part of the country. The variation in coal quality and sulfur content among coals from different regions is also a key source of heterogeneity in coal prices. In general, a unit does not buy different

[31] The problem of selection bias is explored in depth in the seminal paper by Olley and Pakes [26] which studies the telecommunication equipment market in United States.

[32] For example the approaches suggested by Arellano and Bond [3], Blundell and Bond [8]

[33] See for example Olley and Pakes [26], Levinsohn and Petrin [23]; Ackerberg, Caves and Frazer [2]

[34] See for example Gandhi, Navarro and Rivers [15], and Zhang [30], among others.

[35] In order to test the sensitivity of the estimation results, other instruments have been explored, including state's electricity demand, and weather-related demand drivers -heating and cooling degree days. The results reported in this paper are robust to those alternatives.

varieties of coal from the same region and different varieties of coal from different regions all at once. Moreover, some NSPS units without scrubbers were constrained by regulation to burn a specific variety of low-sulfur coal. Hence, in order to have a set of exogenous coal prices for every unit I must estimate and impute coal prices econometrically.

Following a strategy similar to Keohane [20], I estimate price regression equations for coal from each region of table 3. Coal prices are a function of distance and coal quality, among other things. In the estimated regressions I only use spot transactions to reflect the true available prices each unit face at each point in time. Appendix A presents a sample price regression for the Central Appalachian Region. Based on the corresponding regression coefficients I generate predicted coal prices at the boiler level for coals from appropriate districts using the corresponding average sulfur, ash, and btu contents. Based on the characteristics of the unit, each unit is left with the cheapest available low-sulfur coal price and the cheapest available high sulfur coal price. Those prices, the square of the prices, and the interactions of prices and labor and capital are the instruments used to estimate the production function. The moment conditions identifying the parameters of the model are thus

$$\mathbb{E}\left[\varepsilon_{jt}(\alpha,\gamma)z_{jt}\right] = 0$$

where $\varepsilon_{jt}(\alpha,\gamma)$ is the error term in equation 3, and z_{jt} is the vector of instruments which includes labor, l_{jt}, capital, k_{jt}, and the exogenous coal prices in years t and $t-1$, q_{jt} and q_{jt-1}. It also includes the square of these variables and all the interactions, the relative deviation, R_{jt}, the scrubber flag, f_{jt}, and depending on the specification z_{jt} may include some other control variables.

4.1.2 Identification strategy

There is a lot of temporal and spatial heterogeneity among the electric generating units that I use to identify the coefficients of interest in the production function. In my sample, there are hundreds of units each with its own legal and institutional environment. Pollution reduction mandates and electricity market restructuring, however, were not randomly assigned to units. Regarding sulfur dioxide regulations, it is well known that both, the assignment of standards made through the State Implementation Plans following the CAAA-1970, and the pollution permit allocations during the two phases of Title IV program, critically depended upon units' characteristics and geographical features where those units operated, for example the concentration of sulfur dioxide emissions from air contaminant sources. On the other hand, earlier works suggest that market restructuring is correlated with higher electricity prices in the cross section.[36] To address these concerns, I exploit the rich panel data on output, inputs and characteristics describing most electric generating units during an extensive interval of time. My panel includes observations before and after market restructuring and sulfur dioxide regulations were implemented.

Finally, because all the environmental reforms were made at the time market restructuring and

[36] See for example Bushnell and Wolfram [9] for a detailed analysis.

deregulation were implemented in some states, I incorporate two control variables similar to those used in Fabrizio, Rose, and Wolfram [12].[37] The first is a dummy variable equaling one when the generating unit belongs to an investor owned utility (IOU) and is located in a State that restructured its electricity market, since the year of the first formal hearing. The second control variable is a dummy that takes on a value of one if the unit is publicly owned after 1992, and zero otherwise. Hence, the treated group is composed of restructured IOU units, while the control group consists of non-restructured IOU units and publicly or cooperatively owned units.[38]

5 Estimation results

In this section, I present the results from estimating the production function in equation 3. The data suggest that log-productivity shocks are persistent, i.e. for a given unit ε_{jt} is correlated over time. Additionally, the estimation must account for endogeneity of fuel input. As a consequence, I implement a two-step GMM approach using the set of instruments described in the previous section and compute robust standard errors clustered at the unit level. This estimation strategy solves the endogeneity problem and also allows for arbitrary heteroscedasticity and serial correlation of the error term. This approach is more flexible a priori than other estimation alternatives that incorporate units' fixed effects and assume shocks follow a specific autoregressive process, AR(k) for some k=1,2,...,n. Moreover, the fact that the exogenous coal prices are significantly correlated with the quantity of coal demanded (i.e. amount of heat), validates the choice of instruments without the need of stronger assumptions such as cost minimization or profit maximization behavior (needed to retrieve the first order conditions), or an implausible strict monotonicity condition of some auxiliary function (e.g. investment function).

Table 7 presents the estimation results for several GMM specifications. Column (i) estimates the model using dummies that assume the value one for Phase I units and Phase II units once the CAAA-1990 was passed and after it was effectively implemented. Column (ii) incorporates the relative deviation, R. Column (iii) only has the two market restructuring dummies described in the previous section, while column (iv) includes both the relative deviation measure and the market restructuring dummies. All the models presented in Table 7 include a scrubber dummy. (Appendix C presents the OLS estimates. The organization of the table for OLS is similar to the one described above for GMM).

Some comments about the estimates in Table 7: having a scrubber decreases productivity in the order of 1 to 2 percent. Second, the relative deviation, R, is clearly negative and statistically significant indicating environmental policies do matter for productivity (see models ii and iv). Third,

[37] The construction of the two market restructuring dummy variables was based on information provided by *Status of Electricity Restructuring by State*, EIA.

[38] The reason for the inclusion of the second dummy variable described above is to capture deviations in the behavior of publicly or cooperatively owned units after the restructuring process occurs.

Table 7: Generalized Method of Moments - Production Function Parameter Estimates.

Parameter	(i)		(ii)		(iii)		(iv)	
α_h	8.3244***	(1.7985)	8.1121***	(1.7637)	8.5937***	(1.7586)	8.1502***	(1.7596)
α_k	-5.3436**	(2.2480)	-4.8610**	(2.2122)	-5.6916**	(2.2100)	-4.9685**	(2.2210)
α_l	-2.5913**	(1.2482)	-2.7593**	(1.1689)	-2.5918**	(1.1758)	-2.7066**	(1.1874)
α_{hh}	-0.3569***	(0.0948)	-0.3430***	(0.0940)	-0.3720***	(0.0937)	-0.3456***	(0.0938)
α_{kk}	-0.1722	(0.1810)	-0.1291	(0.1732)	-0.1922	(0.1736)	-0.1385	(0.1753)
α_{ll}	-0.0599	(0.0687)	-0.0734	(0.0647)	-0.0555	(0.0658)	-0.0694	(0.0660)
α_{hk}	0.5288**	(0.2527)	0.4711*	(0.2476)	0.5664**	(0.2473)	0.4836*	(0.2489)
α_{hl}	0.2829**	(0.1367)	0.3018**	(0.1282)	0.2840**	(0.1299)	0.2959**	(0.1307)
α_{kl}	-0.2710***	(0.0918)	-0.2762***	(0.0877)	-0.2803***	(0.0893)	-0.2743***	(0.0894)
γ_f	-0.0026	(0.0098)	-0.0190**	(0.0087)	-0.0151	(0.0101)	-0.0191**	(0.0089)
γ_R			-0.0429***	(0.0162)			-0.0415**	(0.0173)
γ_{ph1}	0.0547***	(0.0113)						
$\gamma_{\text{ph1-post89}}$	-0.0292***	(0.0083)						
$\gamma_{\text{ph1-post94}}$	-0.0358***	(0.0098)						
γ_{ph2}	0.0539***	(0.0130)						
$\gamma_{\text{ph2-post89}}$	-0.0119	(0.0109)						
$\gamma_{\text{ph2-post94}}$	-0.0387***	(0.0133)						
$\gamma_{\text{iou-drg}}$					0.0077	(0.0097)	0.0028	(0.0103)
$\gamma_{\text{mnc-post92}}$					0.0060	(0.0085)	0.0035	(0.0083)
α_0	-40.7901***	(8.5733)	-40.0196***	(8.2777)	-41.9492***	(8.2600)	-40.1433***	(8.2592)
Observations	12,203		12,203		12,203		12,203	
Hansen's J	3.19304	(0.5261)	3.3894	(0.4949)	3.2628	(0.5149)	3.2950	(0.5097)

(a) Robust standard errors clustered by electricity generation unit are shown in parenthesis.
(b) All models include year dummies (not shown in the table) to control for year fixed effects.
(c) Hansen's test statistic $\chi^2_{(4)}$ and the corresponding p-value associated (shown in parenthesis).

the evidence of a market restructuring effect on productivity is quite poor. Both coefficients $\gamma_{\text{iou-drg}}$ and $\gamma_{\text{mnc-post92}}$ are very close to zero and are not significant (iii and iv). This finding follows Fabrizio, Rose, and Wolfram [12] who also could not find significant differences in fuel input demands between restructured and non-restructured firms. Fourth, model (i) (which does not include R but incorporates dummy variables for Phase I and II units) is very informative. Conditioning on the covariates, both groups are more productive on average than NSPS units. A possible reason is that most NSPS units were constrained right from the onset -many years before Title IV regulation was passed. Finally, productivity for Phase I and Phase II units started to decreased in advance of the effective implementation dates, 1995 and 2000, respectively. Once again, this constitutes some evidence that units react in anticipation of the environmental regulation when the concrete policies are known in advance.

Table 8 reports the elasticities of the average output with respect to each input and also several ratios of percentiles of the productivity distribution for both the GMM models and the OLS models (shown in Appendix C). It also reports the sum of the elasticities. Because the second-order approximation used to estimate the production function does not impose any homogeneity restriction, the sum of elasticities is not strictly-speaking an estimate of returns to scale. However, it has a similar interpretation and is to some extent informative.

Table 8: Heterogeneity in Productivity and Average Input Elasticities

	OLS				GMM			
Productivity ratios	(i)	(ii)	(iii)	(iv)	(i)	(ii)	(iii)	(iv)
75/25	1.0871	1.0861	1.0863	1.0859	1.1337	1.1354	1.1384	1.1355
	(0.0011)	(0.0012)	(0.0011)	(0.0011)	(0.0023)	(0.0021)	(0.0019)	(0.0020)
90/10	1.1664	1.1623	1.1623	1.1621	1.2698	1.2708	1.2797	1.2709
	(0.0019)	(0.0018)	(0.0020)	(0.0017)	(0.0027)	(0.0034)	(0.0030)	(0.0029)
95/05	1.2217	1.2167	1.2173	1.2170	1.3686	1.3679	1.3803	1.3676
	(0.0032)	(0.0023)	(0.0023)	(0.0024)	(0.0044)	(0.0048)	(0.0047)	(0.0054)
99/01	1.3280	1.3172	1.3184	1.3175	1.7204	1.7172	1.7266	1.7064
	(0.0044)	(0.0041)	(0.0050)	(0.0046)	(0.0325)	(0.0272)	(0.0307)	(0.0228)
Elasticities								
Heat (mmBTU)	1.0387	1.0316	1.0330	1.0325	0.7730	0.7699	0.7621	0.7704
	(0.0000)	(0.0001)	(0.0001)	(0.0001)	(0.0035)	(0.0031)	(0.0033)	(0.0031)
Capital (MW)	0.0248	0.0205	0.0206	0.0201	0.2642	0.2627	0.2686	0.2619
	(0.0005)	(0.0005)	(0.0005)	(0.0005)	(0.0026)	(0.0022)	(0.0025)	(0.0023)
Labor (employees)	-0.0036	0.0011	-0.0008	0.0001	0.0315	0.0330	0.0339	0.0330
	(0.0003)	(0.0002)	(0.0002)	(0.0002)	(0.0014)	(0.0014)	(0.0012)	(0.0012)
Sum	1.0599	1.0532	1.0528	1.0527	1.0687	1.0657	1.0646	1.0653
	(0.0007)	(0.0007)	(0.0007)	(0.0007)	(0.0008)	(0.0008)	(0.0008)	(0.0007)

Note: bootstrap standard errors are reported in parenthesis (200 replications)

It is interesting to compare the OLS and the GMM estimates in Table 8. As expected, the distribution of log-productivity is not dramatically dispersed because technology is relatively more similar among units in the power industry than in other more sophisticated industries. It is also apparent that OLS models present less dispersion in log-productivity than the corresponding GMM specifications. The values of R^2 in OLS regressions are very close to one implying that there

Table 9: Test Statistics for Hypothesis Tests

Null Hypothesis	Test Statistic	D. of F.	P-value
Labor coefficients jointly considered	14.1	4	0.0069
Capital coefficients jointly considered	39.6	4	0.0000
Heat coefficients jointly considered	796.1	4	0.0000
Constant Returns to Scale	15.5	2	0.0004
Complete global separability (l,k,h)	13.1	3	0.0044
Linear separability (l, k) and h	12.9	2	0.0016
Linear separability (l, h) and k	13.0	2	0.0015
Linear separability (k, h) and l	11.5	2	0.0032
Non-linear separability (l, k) and h	45.3	3	0.0000
Non-linear separability (l, h) and k	116.5	3	0.0000
Non-linear separability (k, h) and l	44.2	3	0.0000

Note: Test statistic is asymptotic χ^2 under the null (Wald Test).

is practically nothing left in the error term once the part explained by the model is accounted for. These results suggest that technology in this industry is rather simple in the following sense: one can predict output with the only inclusion of labor, capital, and fuel inputs. Nevertheless, it is evident that the *transmission problem* discussed before is severe in the OLS models and is addressed using the GMM approach. Hence, with the exception of the average output-elasticity of heat, the elasticities of output with respect to capital input and with respect to labor input are both increased when GMM is implemented. Remarkably, output-elasticity of labor input is positive (above 3%) and significant in all GMM models while it is not significantly different from zero in OLS models. Output-elasticity of capital in OLS models is 2% while it is around 26% in the GMM specifications.[39] Lastly, the sum of the elasticities is approximately 1.06 in all models, suggesting the presence of moderate increasing returns to scale.

For the remainder of this paper, I will only use GMM (ii) estimates, i.e the model that incorporates variable R but excludes irrelevant variables like market restructuring dummies. Table 9 reports several test statistics for different hypothesis tests using the parameter estimates of the translog production function approximation. In the upper part of the table I check the joint significance of all coefficient associated with each production factor. Clearly, all the production factors are significantly different from zero at the 1%. In the middle part of the table, the null hypothesis of constant returns to scale is also rejected. Following Berndt and Christensen [5] and [6], I carry out different separability tests. In all cases separability is rejected. As a special case, the rejection of complete global separability suggests Cobb-Douglas is not a good approximation for the production

[39]The elasticity of output with respect to labor may seem rather small. However, labor input at the plant level accounts for 3% of total costs on average, confirming somehow the precision of our estimates.

function in this industry (the rejected hypothesis in this case is $\alpha_{hl} = \alpha_{hk} = \alpha_{kl} = 0$). Global linear separability and global non-linear separability are tested as follows: consider for example (k,l) separable from h, in which case linear separability entails testing the null hypothesis: $\alpha_{lh} = \alpha_{hk} = 0$, while non-linear separability entails testing the null hypothesis: $\frac{\alpha_l}{\alpha_k} = \frac{\alpha_{hl}}{\alpha_{hk}} = \frac{\alpha_{ll}}{\alpha_{kl}} = \frac{\alpha_{kl}}{\alpha_{kk}}$. Lastly, Table 10 presents estimates for the Direct Elasticity of Substitution, as an approximation of substitution patterns observed in the short and medium run.[40] Although DES are small for most factor pairs, they are all significantly different from zero. This constitutes some indirect evidence against a production function with Leontief form. As expected, substitution between labor and capital is higher than substitution between labor and fuel or capital and fuel. In sum, results in Table 9 and Table 10 confirm the flexible production function I adopted in this paper.

Table 10: Direct Elasticity of Substitution

	Percentile of the distribution				
Factors	10th	25th	50th	75th	90th
H and K	0.316	0.336	0.348	0.355	0.360
H and L	0.132	0.224	0.295	0.341	0.368
K and L	0.206	0.517	0.930	1.173	1.358

Note: only observations satisfying the required regularity conditions are used for calculations.

6 Impact of sulfur dioxide regulations on output

In the previous section the production function parameters were estimated. I now use those estimates to evaluate the effect of Title IV program on output. A simple but very informative exercise is to "turn off" variable R for all units and set $\gamma_f = 0$ for those Phase I and Phase II units that installed scrubbers after 1990, and then compute the counter-factual output level that would have been produced without the implementation of the environmental policy in question. I will evaluate the impact on output as follows

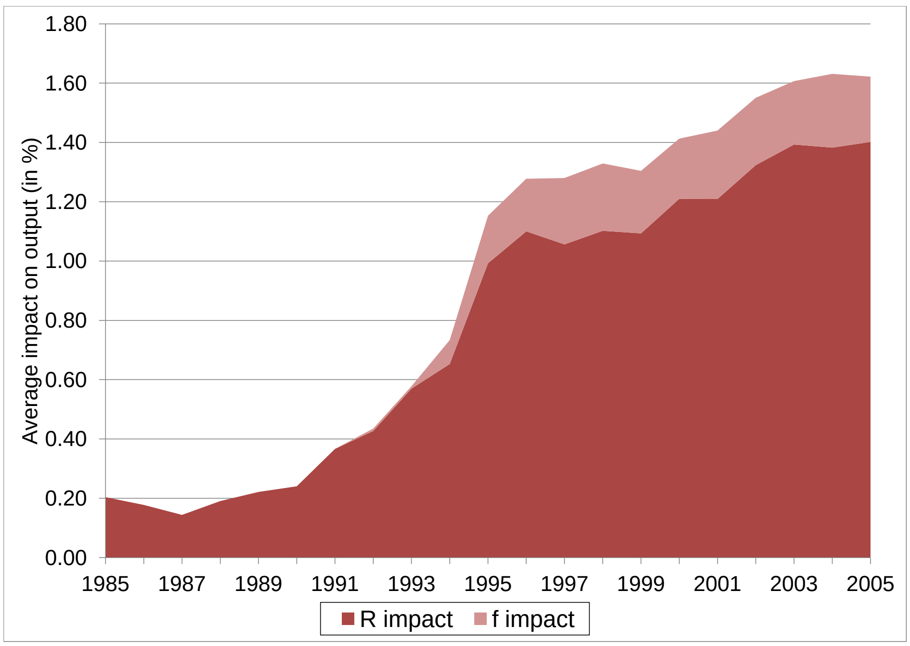
$$\frac{Y^*_{jt} - Y_{jt}}{Y^*_{jt}} = 1 - e^{\left(\gamma_R R_{jt} + \gamma_f f_{jt}\right)}$$

where Y^* and Y are the counterfactual and the factual output levels, respectively. Before 1990, most units have R equal to zero and some units have values very close to zero. The reason behind this was explained in Section 2.1.3: for each unit the unconstrained emission rate is approximated

[40] Substitution between pair of production factors are calculated using only those observations that satisfy the two regularity conditions: (i) monotonicity, and (ii) quasi-concavity.

by the average emission rate during the years 1985 to 1989. Thus, small departures from the unit's unconstrained emission rate might exist even during those years. Figure 4 depicts the evolution of the average policy impact on output for the entire period 1985-2005 including only the units affected by the regulation, i.e. $R > 0$ or $f = 1$ for units that adopted the scrubber after 1989.[41] Clearly, scrubber adoption was not a popular compliance strategy until late 1990s. Instead, an overwhelming majority of affected units opted for fuel switching, sometimes in combination with pollution permits purchases, which in many cases acted as a complementary strategy. Figure 4 emphasizes the input biasing character of the regulation.

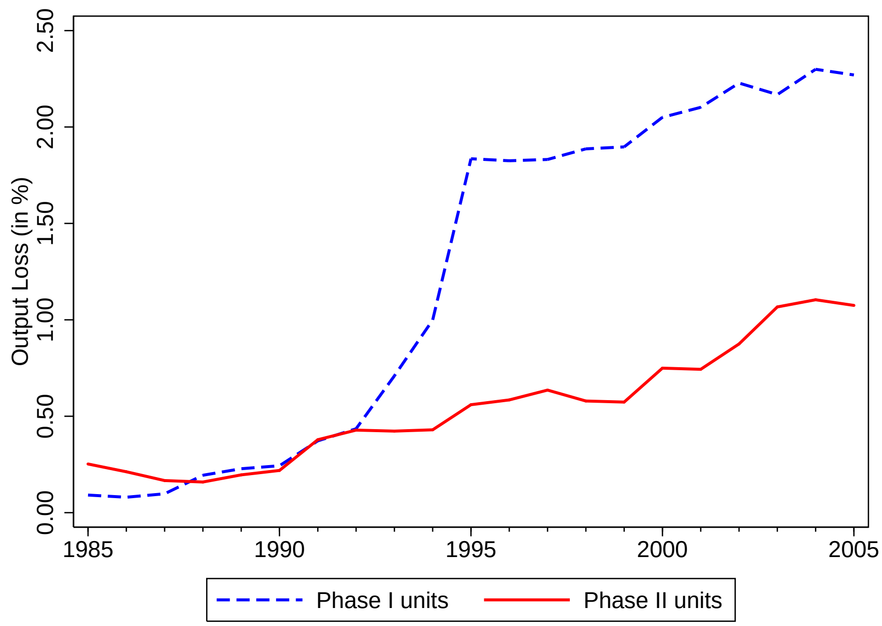
Figure 4: Decomposition of the $S0_2$ Regulation Impact: R and f effects
(All affected units. Weighting variable: Y_{jt})



It is also interesting to see how the two affected groups of units, Phase I and II boilers, responded in different ways to the Title IV regulation (see Figure 5). Not surprisingly, the output losses were significantly larger among Phase I units which were all things equal the dirtiest emission sources. Thus, for the group of Phase I units that chose the fuel switching option one can observe larger *relative deviations*. Considering output losses below 0.25% as the benchmark for normal output fluctuations, it is evident that some units adapted their behavior in advance of the effective implementation of the sulfur dioxide regulations. Even though one can distinguish two significant *jumps* in output losses during the years 1995 and 2000, the trend of output losses is positive since 1990 indicating certain policy anticipation. This finding is not at odds with the way the units make their decisions since fuel quality adjustments require capital investments.

[41]Presumably, units that already had adopted a scrubber in 1989 did not do it in response to Title IV regulation. Most of them were NSPS units subject to more stringent environmental regulations.

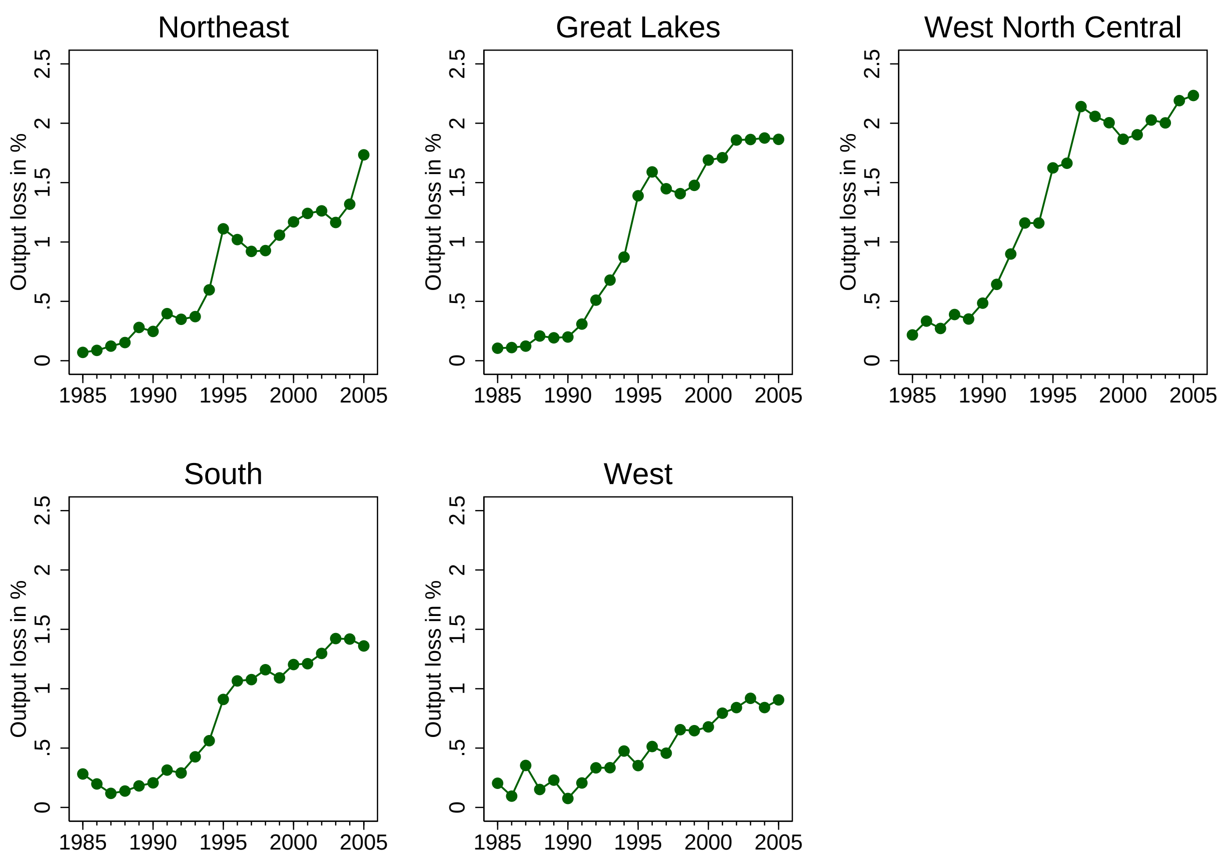
Figure 5: Estimated output loss by compliance group
(Affected units. Weighting variable: Y_{jt})



The differentiated impact of the environmental policy across geographical regions is presented in Figure 6. Since fuel switching was the compliance strategy that most units followed in both phases of the program, a simple inspection of the evolution of R in each region (see Figure 3) is informative about the policy impact intensity. The Great Lakes (GL) and the West North Central (WNC) were, on average, the most affected regions. In these two regions units reacted early to the policy because they have a majority of Phase I units. The policy impact on output in the South and Northeast regions followed a similar pattern to GL and WNC. However, the magnitude of the impact was smaller, most likely because the composition of units in South and NE is quite different from GL and WNC. They have proportionally more Phase II units, and in the case of the South Region a significant number of NSPS units as well. Observing the location of coal mines (Figure 1) and comparing the characteristics of the coal produced in each region (Table 3), it is also clear that units located in the NE have a closer access to low- and medium-sulfur coal from Central Appalachian mines. Mines in the PRB are far from both groups of units. In the case of the West Region, one could in principle state that it only suffered the impact of the regulation during the second phase of Title IV program. However, due to the easy access to low-sulfur coal from PRB the average impact was always below 1%.

Lastly, Figure 7 and Table 11 show how the policy impact on output was distributed across the affected units. In Figure 7 we observe how the distribution shifted to the right by comparing the

Figure 6: Impact of sulfur dioxide regulation by region
(Mean values over all units conditioning on $R_{jt} > 0$, and using Y_{jt} as weighting variable)



histograms in 1995 and 2005. On the other hand, Table 11 breaks down the distribution of impact into quintiles for each year, using the net electricity generation as weights. Thus, for each quintile it shows the average impact on potential output. Once again, two phenomena are detected: the number of affected units increased progressively over time, and also the magnitude of the impact increased during the same period.

Figure 7: Distribution of estimated output loss: 1995 vs. 2005
(All affected units. Weighting variable: Y_{jt})

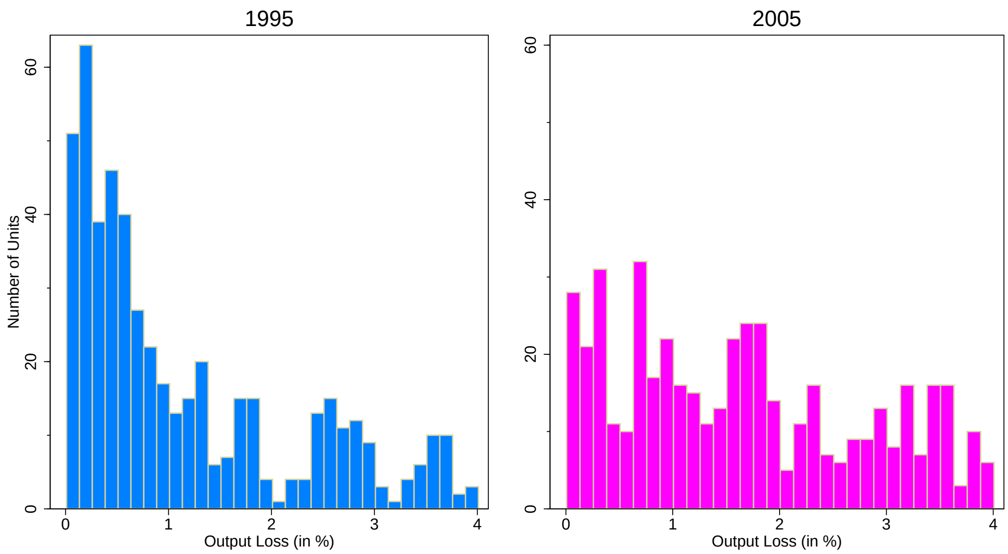


Table 11: Distribution of SO_2 regulation impact by Year
(Mean values for affected units. Weighting variable: Y_{jt})

	Quintile				
Year	1st	2nd	3rd	4th	5th
1990	0.02%	0.06%	0.15%	0.30%	0.96%
1991	0.04%	0.13%	0.26%	0.43%	1.22%
1992	0.03%	0.14%	0.29%	0.51%	1.32%
1993	0.06%	0.23%	0.41%	0.62%	1.79%
1994	0.05%	0.21%	0.41%	0.81%	2.09%
1995	0.10%	0.32%	0.65%	1.32%	2.80%
1996	0.10%	0.34%	0.73%	1.55%	3.00%
1997	0.10%	0.31%	0.75%	1.55%	2.90%
1998	0.13%	0.38%	0.85%	1.59%	2.89%
1999	0.11%	0.37%	0.80%	1.67%	3.01%
2000	0.12%	0.49%	1.01%	1.79%	3.11%
2001	0.13%	0.44%	0.94%	1.74%	3.14%
2002	0.17%	0.58%	1.15%	1.90%	3.29%
2003	0.14%	0.60%	1.24%	2.05%	3.37%
2004	0.17%	0.66%	1.30%	2.08%	3.36%
2005	0.18%	0.67%	1.31%	2.04%	3.31%

7 Compliance costs and electricity prices

So far, I have analyzed the impact of the Title IV regulation on productivity and output. It would be interesting, however, to see how these outcomes translated into cost increments, and ultimately, whether they affected wholesale electricity prices. In order to analyze the evolution of compliance costs, I represent the static profit function of unit j in year t as follows

$$\begin{aligned}\Pi_{jt}\left(R_{jt},f_{jt}\right) &= p_{jt}Y\left(R_{jt},f_{jt}\right)-q_{jt}H(R_{jt},f_{jt})-r_{jt}K_{jt}-w_{jt}L_{jt}-z_t\left[S(R_{jt})-\hat{S}_{jt}\right]\\ &- \mathbb{1}\{f_{jt}=1\}\left[C^f\left(S(R_{jt}),K_{jt},t\right)-z_t\phi S(R_{jt})\right)\right]\\ &- \mathbb{1}\{R_{jt}>R^{crit}\}C^s\left(K_{jt},t\right)\end{aligned} \tag{4}$$

where p_{jt}, q_{jt}, r_{jt}, w_{jt}, and z_t are the electricity price, the average fuel price, the return to capital, average wage rate, and allowance price, respectively. When a unit operates a scrubber, it can reduce SO_2 emissions in ϕ percent.[42] To simplify the presentation, let's assume that output and heat can be represented simply as functions of R, and f. The total gross sulfur dioxide emissions, S_{jt}, is a function of R_{jt}. The allocated free permits are $\hat{S}_{jt}$.

$C^f(\cdot)$ is the scrubbing cost which includes operating costs and capital cost, while $C^s(\cdot)$ is the fuel switching capital cost.[43] The latter is "activated" whenever the unit utilizes a fuel that implies a relative deviation that is significantly larger than some critical tolerance value, R^{crit}.[44] As a consequence, I am able to decompose the Title IV regulation compliance costs into four categories:

i) Value of output lost caused by scrubber operation ($f=1$) or by fuel switching ($R>R^{crit}$)

ii) Fuel switching cost: includes low-sulfur coal premium and levelized annual capital cost

iii) Scrubbing cost: operating costs and levelized annual capital cost

iv) Allowance trading outcome (could be positive if $S<\hat{S}$)

The first component of the compliance cost is computed as $p_{jt}\times\left(Y^*_{jt}-Y(R_{jt},f_{jt})\right)$, where p_{jt} is the wholesale electricity price for unit j in year t, and $Y^*_{jt}=Y(0,0)$ is the potential (maximum) output. The second component is simply the cost difference between the observed and the unconstrained coal type, plus the corresponding capital cost if $R>R^{crit}$. Using the information provided in Figure 3 about the evolution of the variable R, I define $R^{crit}=.04$, so that capital investment to retrofit the boiler are needed only if the relative deviations are above 4%.[45] Scrubber operating and capital costs were estimated econometrically using data from the EIA's Form 767. I only consider units that retrofit a scrubber after 1990 in response to the CAAA-1990.[46] For the allowance cost I use the annual average price observed in the spot market.

[42] I assume that the emission reduction rate is $\phi=95\%$

[43] Capital costs are levelized and expressed as annual values.

[44] See Appendix B for an explanation about medium-run pollution abatement compliance choices.

[45] If a unit originally designed to burn high-sulfur coal switched to low-sulfur coal, but eventually decides to adopt a scrubber, then I will assume it does not need further capital investments to come back to the unconstrained high sulfur-coal.

[46] The scrubber capital cost for a unit built simultaneously with an FGD device is typically smaller than the capital cost of a unit that retrofits a scrubber after its construction. Because the observations with scrubbers are scarce, to improve the estimation results I use all observations but include a dummy for those units that are retrofit scrubbers. Capital and operating cost estimation outcomes are available upon request.

Tables 12 and 13 report the compliance cost decomposition for the years 1995, 1999, 2000, and 2005. Because one of the goals of this section is to compare the evolution of compliance costs with wholesale electricity prices, I redefine some of the geographical regions by including or excluding some states. The criterion I follow to construct the new regions is to separate those states that restructured their electricity markets during the period of analysis from those that did not. I use the geographical proximity and other regional similarities to form the groups. As a result, Delaware and Maryland are incorporated to the Northeast Region because all of them restructured their electricity market. The Great Lakes Region was split into a group that includes Illinois, Michigan and Ohio (restructured states), and a second group that includes Wisconsin and Indiana (regulated). Besides Delaware and Maryland, Texas was also excluded from the South Region. Texas constitutes a special case since it is relatively large in terms of the number of coal-fired generating units it has and it is far from the Central Appalachian Region, i.e it does not have easy access to low-sulfur coal mines whereas DE and MD do.

From the comparison of compliance costs between units with and without scrubbers it is possible to understand why it was not very popular during the period of analysis. In almost all regions and during all the period under study the compliance cost for scrubbed units was on average above the corresponding cost for units without scrubber systems, with a few exceptions in some regions in 2005. The main component favoring FGD adoption in 2005 has been the value of pollution permits saved due to the emissions reduction achieved. This effect was driven by the significant increments of allowance prices in 2004 and 2005 which corresponded to a new age of environmental policies being discussed by the EPA (Figure 12 in Appendix D shows the evolution of allowance prices).[47] Those savings in terms of pollution permits more than offset the high investment expenditure required to retrofit a scrubber. The column "FGD" in tables 12 and 13 reflects that fact.[48] Notice also that in most cases the value of the output loss was larger for scrubbed units. The reason is units adopting scrubbers are typically the ones facing higher constraints in terms of the implicit relative deviation from ideal coal characteristics needed to comply with the Acid Rain Program, whereas units switching to lower sulfur coal in general need smaller adjustments to comply with the regulation. Average fuel costs in turn were usually slightly positive for units without scrubber systems. The opposite happened with scrubbed units that on average saved money. This is expected, since scrubbed units use less expensive fuels, i.e. medium- or high-sulfur coals.

[47]The EPA's Clean Air Interstate Rule was approved in March 2005, affecting 27 eastern states, including the District of Columbia.

[48]In fact, the column "FGD" includes both capital and operating costs, but the latter only represents 14% (on average) of the total annual scrubbing cost. It is evident that the capital cost is the most significant part of the FGD adoption choice.

Table 12: Compliance cost decomposition
(Mean values for each region and using Y_{jt} as weighting variable)

Year 1995

	Units without FGD unit				Units with FGD unit				
Region	Total	Output	Permits	Fuel	Total	Output	FGD	Permits	Fuel
Northeast, MD , DE	-0.29 (1.23)	0.33 (0.46)	-0.10 (0.59)	-0.53 (1.03)	4.06 (2.53)	2.38 (0.28)	3.31 (2.26)	-1.63 (0.32)	-0.01 (0.23)
IL, MI, and OH	0.75 (1.47)	0.49 (0.56)	-0.09 (1.22)	0.35 (1.39)	1.84 (0.39)	1.80 (0.00)	2.95 (0.41)	-1.87 (0.23)	-1.03 (0.12)
WI, and IN	0.96 (1.10)	0.49 (0.44)	-0.16 (0.72)	0.63 (1.01)	2.36 (1.09)	1.54 (0.02)	2.86 (0.96)	-1.34 (0.17)	-0.7 (0.57)
West North Central	1.19 (0.96)	0.62 (0.64)	-0.21 (0.52)	0.78 (0.98)					
TX	0.50 (1.23)	0.04 (0.06)	0.00 (0.00)	0.46 (1.19)					
South (excl. TX, MD, DE)	0.87 (1.30)	0.28 (0.36)	-0.13 (0.76)	0.72 (1.43)	2.37 (1.55)	1.61 (0.27)	2.53 (1.48)	-1.38 (0.36)	-0.38 (1.03)
West	0.27 (0.87)	0.12 (0.14)	0.00 (0.00)	0.15 (0.85)	2.26 (0.00)	1.75 (0.00)	0.57 (0.00)	0.00 (0.00)	-0.05 (0.00)

Year 1999

	Units without FGD unit				Units with FGD unit				
Region	Total	Output	Permits	Fuel	Total	Output	FGD	Permits	Fuel
Northeast, MD , DE	-0.32 (2.31)	0.27 (0.44)	0.03 (0.77)	-0.61 (2.31)	3.40 (1.80)	1.95 (0.22)	3.21 (1.44)	-2.08 (0.44)	0.31 (0.45)
IL, MI, and OH	0.49 (1.57)	0.52 (0.56)	-0.04 (1.25)	0.00 (1.20)	6.10 (0.97)	1.70 (0.06)	7.52 (1.32)	-2.44 (0.43)	-0.67 (0.08)
WI, and IN	1.07 (1.33)	0.54 (0.47)	-0.19 (0.87)	0.72 (1.25)	2.23 (1.80)	1.58 (0.13)	3.06 (1.64)	-2.01 (0.42)	-0.39 (0.54)
West North Central	0.87 (1.32)	0.79 (0.68)	-0.40 (0.90)	0.48 (1.20)					
TX	0.59 (1.17)	0.15 (0.16)	0.00 (0.00)	0.45 (1.08)					
South (excl. TX, MD, DE)	0.72 (1.25)	0.33 (0.39)	-0.16 (0.74)	0.55 (1.39)	1.96 (1.90)	1.55 (0.23)	2.78 (1.78)	-1.51 (0.98)	-0.86 (1.17)
West	0.29 (0.97)	0.13 (0.13)	0.00 (0.00)	0.16 (1.00)	1.61 (0.69)	1.83 (0.12)	0.57 (0.22)	0.00 (0.00)	-0.78 (0.85)

(a) Costs are expressed in dollars per MWh.
(b) Total compliance cost is broken down into output loss cost, scrubbing cost, allowance cost, and fuel switching cost.
(c) Standard deviations are reported in parenthesis.

Table 13: Compliance cost decomposition

(Mean values for each region and using Y_{jt} as weighting variable)

Year 2000

	Units without FGD unit				Units with FGD unit				
Region	Total	Output	Permits	Fuel	Total	Output	FGD	Permits	Fuel
Northeast, MD , DE	1.29 (0.80)	0.30 (0.49)	0.95 (0.72)	0.05 (0.60)	5.19 (2.10)	2.24 (0.27)	3.55 (2.17)	-0.64 (0.05)	0.04 (0.15)
IL, MI, and OH	1.15 (1.81)	0.72 (0.63)	0.46 (1.03)	-0.03 (1.12)	4.06 (0.42)	1.70 (0.03)	3.15 (0.42)	-0.49 (0.04)	-0.31 (0.01)
WI, and IN	1.83 (1.30)	0.55 (0.45)	0.46 (1.02)	0.83 (1.26)	4.99 (2.47)	1.51 (0.07)	4.35 (2.45)	-0.41 (0.16)	-0.46 (0.70)
West North Central	1.12 (1.07)	0.85 (0.69)	-0.10 (0.32)	0.37 (1.16)					
TX	0.95 (0.80)	0.24 (0.10)	-0.04 (0.26)	0.75 (0.92)					
South (excl. TX, MD, DE)	1.42 (1.40)	0.39 (0.38)	0.42 (0.55)	0.61 (1.37)	2.81 (2.26)	1.55 (0.22)	2.59 (1.91)	-0.43 (0.27)	-0.90 (1.22)
West	0.40 (0.82)	0.15 (0.15)	0.05 (0.12)	0.19 (0.93)	1.34 (0.98)	1.79 (0.16)	0.82 (0.48)	-0.54 (0.33)	-0.73 (0.80)

Year 2005

	Units without FGD unit				Units with FGD unit				
Region	Total	Output	Permits	Fuel	Total	Output	FGD	Permits	Fuel
Northeast, MD , DE	4.29 (2.25)	0.63 (0.87)	4.25 (4.03)	-0.58 (0.67)	2.99 (2.00)	2.90 (0.70)	5.02 (1.96)	-4.10 (0.78)	-0.83 (0.00)
IL, MI, and OH	2.48 (5.48)	0.83 (0.63)	2.01 (4.29)	-0.36 (1.68)	4.15 (4.42)	2.03 (0.01)	4.86 (3.50)	-2.00 (0.54)	-0.73 (0.00)
WI, and IN	3.64 (3.46)	0.69 (0.62)	2.10 (4.71)	0.85 (1.93)	2.55 (3.39)	1.74 (0.06)	3.99 (2.48)	-1.96 (0.72)	-1.21 (0.96)
West North Central	1.03 (1.93)	0.92 (0.70)	-0.13 (1.39)	0.25 (1.71)					
TX	2.09 (0.47)	0.83 (0.76)	-0.82 (1.01)	2.08 (0.44)					
South (excl. TX, MD, DE)	3.24 (3.43)	0.52 (0.53)	1.94 (3.23)	0.79 (2.14)	0.25 (3.20)	1.74 (0.32)	2.34 (1.56)	-2.61 (1.57)	-1.22 (1.62)
West	0.50 (1.32)	0.30 (0.26)	0.06 (0.91)	0.14 (1.35)	0.88 (1.96)	2.26 (0.11)	1.17 (0.99)	-2.20 (1.18)	-0.36 (1.05)

(a) Costs are expressed in dollars per MWh.
(b) Total compliance cost is broken down into output loss cost, scrubbing cost, allowance cost, and fuel switching cost.
(c) Standard deviations are reported in parenthesis.

According to these findings, it was probably expected in 2005 that the incorporation of more stringent regulations would further impact the relative prices of high- and low-sulfur coal and on allowance prices. The reversion of the trend in the relative compliance costs and also other technical constraints (the fact that some emission reduction levels are only achievable with the help of a scrubber but not with fuel switching) would translate into massive adoption of abatement technologies. In fact, that was exactly the case in most eastern states, especially after the introduction of the EPA Clean Air Interstate Rule (CAIR).[49] Today, boilers that adopted an FGD system represent more than 60 percent of coal-fired, steam electric generation capacity in the U.S. [50]

Figures 8 and 9 illustrate the evolution of electricity prices and compliance costs after the introduction of CAAA-1990. All values are expressed in $/MWh.[51] By the end of the period of analysis (2004-2005), the ratio between compliance cost and electricity price ranged from 1.6% in the West Region to almost 11% in the Northeast+DE+MD Region, indicating there was a well differentiated cost burden across the geographical regions considered here.

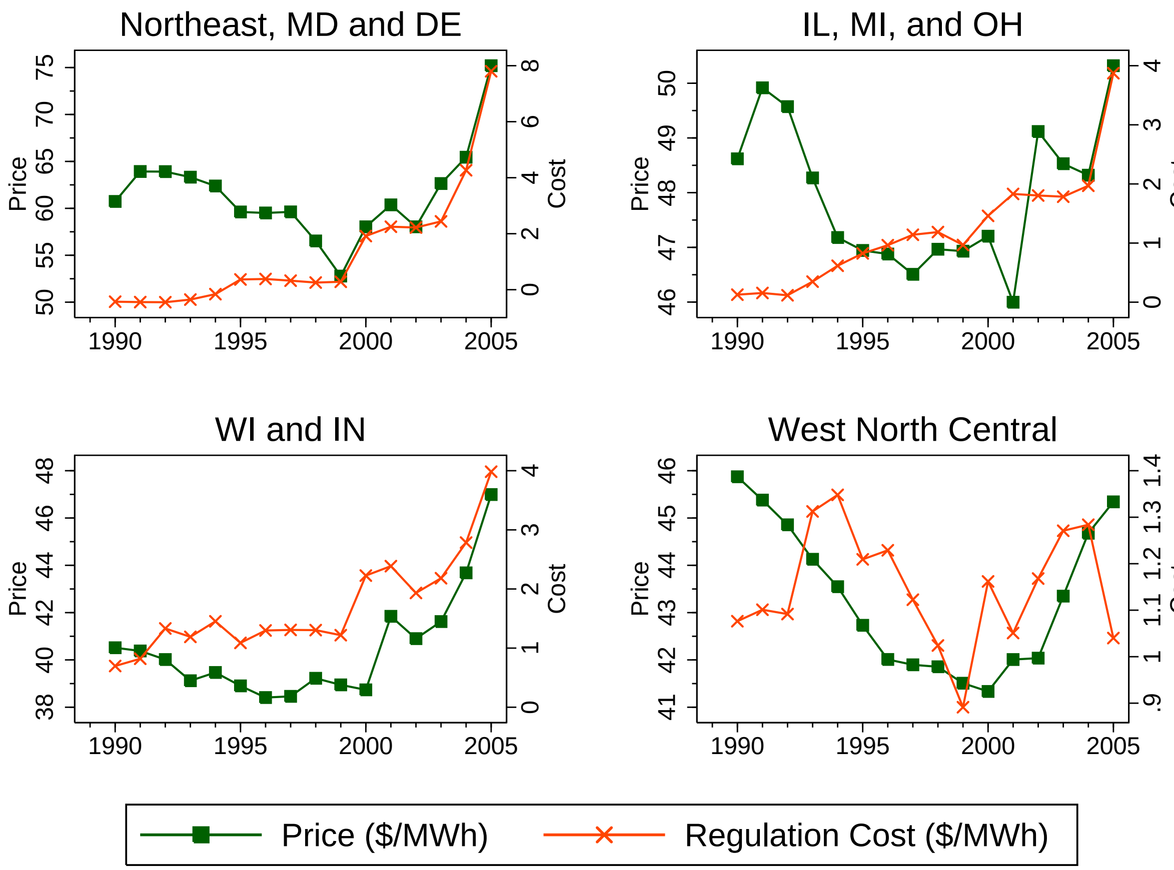
In the seven regions defined in this section, there is an initial declining trend in electricity prices until late 1990s and a pronounced increase afterwards. Average prices fluctuated between $38 and $55, with two exceptions: the Northeast Region+DE+MD, and Texas. In the first case, even though the cost impact of the Acid Rain Program was about $8 on average, electricity prices reached $75 in 2005 from and initial value of $60 in 1990. The lowest price registered in this region was $53 in 1999. Therefore, even ignoring the initial price drops and using as benchmark the price registered in 1990 ($60), the final increment in price was almost the double the additional cost attributed to the implementation of the Acid Rain Program. In the case of Texas, the situation is drastic. Prices rose from $40 to $70 between 1990 and 2005 while the estimated average compliance cost was slightly below $2. Surprisingly, many market reforms were put in force in these two regions and clearly higher electricity prices were an unexpected result after market restructuring. Other causes apart from environmental regulation must explain the larger price adjustments observed during this period.

[49]On March 10, 2005, EPA issued the CAIR. This rule provides states with a solution to the problem of power plant pollution that drifts from one state to another. CAIR covers 27 eastern states and the District of Columbia. The rule uses a cap and trade system to reduce the target pollutants (SO_2 and NO_X) by 70 percent.
States must achieve the required emission reductions using one of two compliance options: (1) meet the states emission budget by requiring power plants to participate in an EPA-administered interstate cap and trade system that caps emissions in two stages, or (2) meet an individual state emissions budget through measures of the states choosing.

[50]Many coal-fired units have been retrofitted and are able now to burn Natural Gas contributing also to the reduction of SO_2 emissions, especially after the boom of the shale gas extracted from Texas and other southern states that turned natural gas affordable.

[51]It would be ideal to report electricity generation prices. However, since those prices are not available prior to 1995, I use prices for industrial costumers. Industrial consumers usually take the electricity at higher voltages, and do not need transport or distribution services. These factors make the price of power for industrial customers closer to the wholesale price of electricity

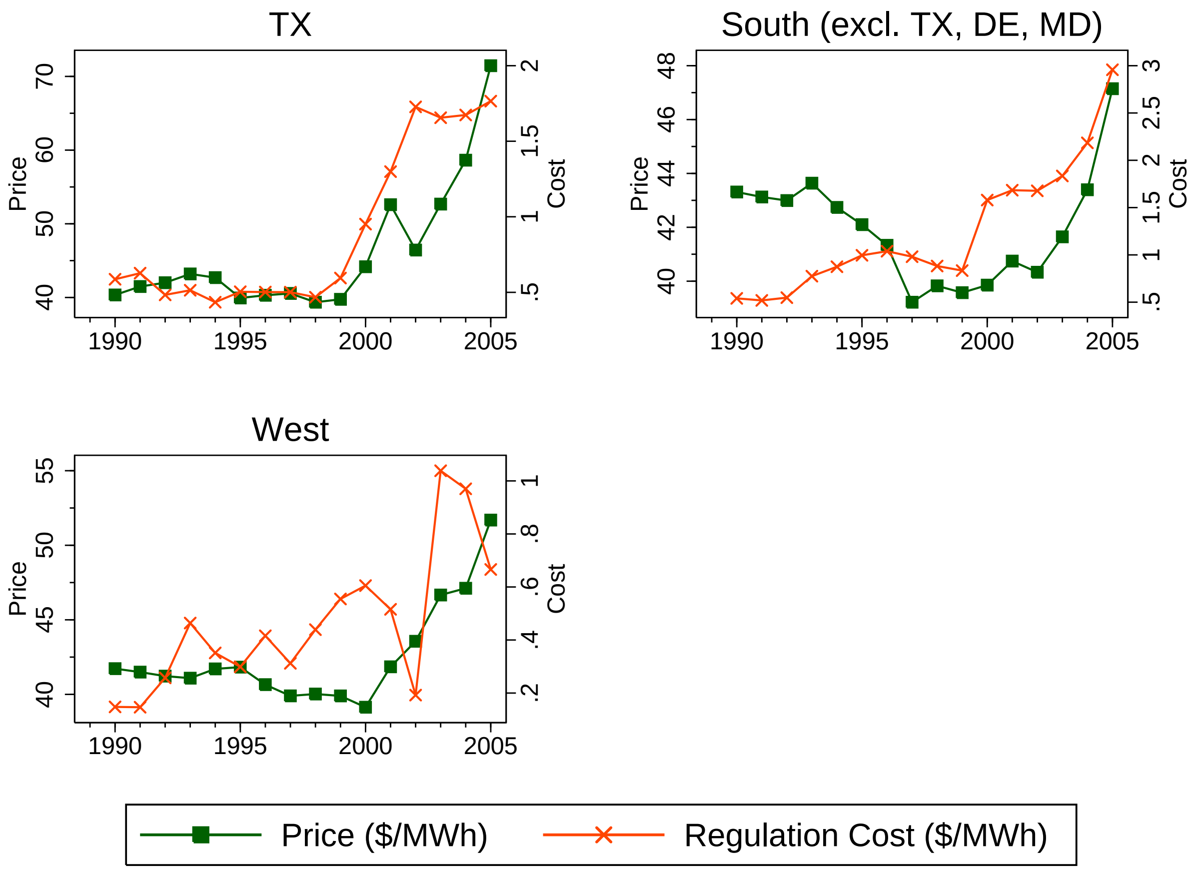
Figure 8: Compliance cost pass-through to electricity prices



In Illinois, Michigan, and Ohio (all restructured markets) the average electricity price was about the same in 2005 and 1990 -around $50. However, the price evolution presents a u-shaped pattern, with relatively flat prices between 1997-2001 (reaching a minimum of $46 in 2001). The estimated average compliance cost was about $4 indicating a fair cost pass-through to prices when considering those flat prices as the starting point. In the case of Wisconsin and Indiana (both regulated markets), the evolution of the estimated average compliance cost resembles the path of the average electricity price, although the ratio between the increment in price and compliance cost is around 2.

The West North Central Region presents an erratic evolution of estimated average cost (with many fluctuations going up and down) and a similar u-shaped price evolution. While the estimated average additional generation cost due to the program was about $1.4, the average price increased by $5 between 1990 and 2005. A similar phenomenon happened in the South Region excluding Texas, Delaware, and Maryland. The additional cost was $3 whereas the price increase was $8. Finally, in the West Region the increment in the average price and the average compliance cost seem unrelated. Remember that this region is characterized by a cheap access to compliance coal

Figure 9: Compliance cost pass-through to electricity prices



and the pool of units consists of many NSPS units and no Phase I units. As a result, a price increment of \$15 cannot be explained by a modest additional generation cost of \$1.

8 Environmental goals of the program

The assessment of the Acid Rain Program in terms of its impact on generating units productivity and output is clearly the main goal this research. It is also important, however, to evaluate how effective the policy was regarding the original environmental goals sought. This last section briefly shows the performance of the program in terms of sulfur dioxide emission reduction and compares the estimated emissions with two counterfactual possibilities that will be described below.To simplify the exposition and to make the Title IV program comparable with the previous regulations (the CAAA-1970 and the CAAA-1977), I define the outcome variable as the weighted average emission rate computed across all units. To be consistent with the rest of the paper, emission rates are measured in pounds of sulfur dioxide per million Btu, while the environmental goals of Title IV program were set in terms of the aggregate emission level considering all emission sources (i.e. all generating units). Nevertheless, allowances were allocated to existing units using baseline emission levels computed during 1985 to 1987, and implicitly considered a desired emission rate of 1.2 lbs SO2/mmBtu to be met in 2000.

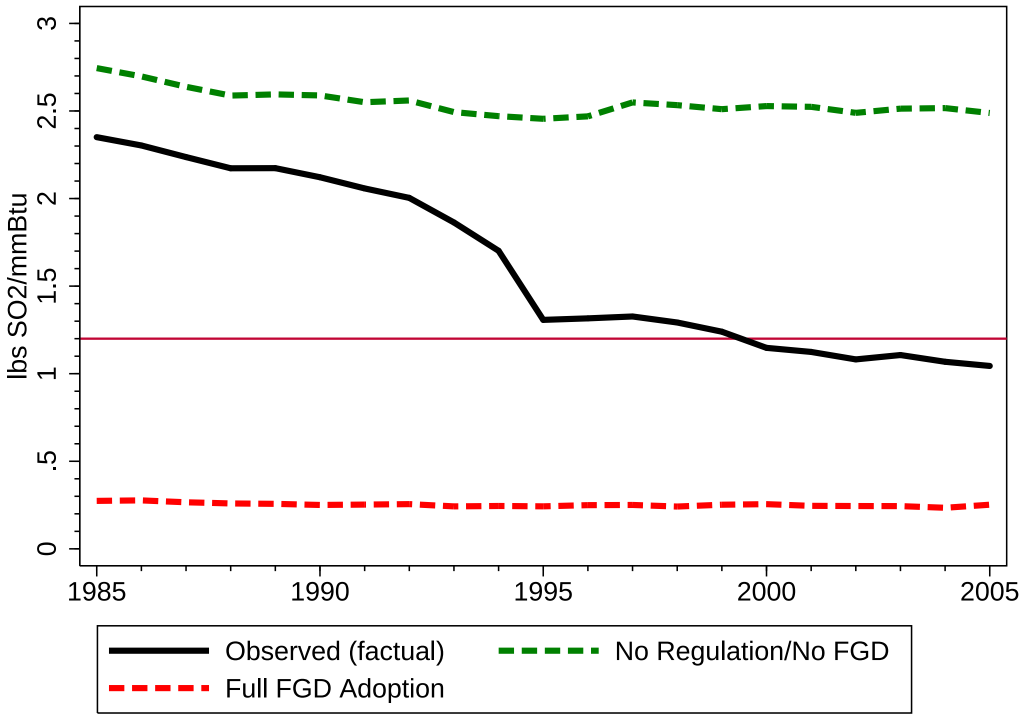
Figure 10 presents the following exercise. The solid dark line is the estimated factual emission rate. It started from values close to 2.4 lbs/mmBtu and crossed the desired line of 1.2 lbs/mmBtu soon after the implementation of the second phase of the Acid Rain Program. The two counterfactuals shown in the graph are:

i. Complete absence of sulfur dioxide regulations (green dash line)

ii. All units adopt scrubbers and burn the unconstrained coal variety (red dash line)

The first counterfactual would raise the average emission rate to a level above 2.5 SO_2 lbs/mmBtu. The second counterfactual would drop the average emission rate below .3 SO_2 lbs/mmBtu. These two values represent an upper and lower bound for the average emission rate. Regarding the second counterfactual, if more stringent sulfur dioxide regulations were implemented to the extent that all units were required to have scrubbers, there would be an average emission rate very close to zero pounds of SO_2 per million Btu. According to the EIA, that was precisely the trend observed during the last seven years after the implementation of the EPA's Clean Air Intrestate Rule in March 2005. Many utilities have made the investments in scrubbers in response to several regulatory initiatives, including the CAIR. The increase in installed scrubbers has helped create a reduction of SO2 emissions, which were 68 percent lower in 2011 than the 1990 level and 46 percent lower than the 2007 level. Other factors in that reduction include coal-fired plants burning less coal (more natural gas) and switching to a lower sulfur coal.

Figure 10: SO_2 Emission Rates: Observed vs. Counterfactuals
(Mean values over all units using Y_{jt} as weighting variable)



9 Concluding comments

This paper estimates the electricity generation production function for coal-fired units in U.S. during the period 1985-2005. The main model takes into account all the relevant technological particularities and market conditions that characterize this industry. Specifically, each generating unit is designed to burn a particular type of coal. However, there are different qualities of coal characterized by heat, sulfur, ash, and moisture contents. Additionally, the production technology is such that significant deviations from the targeted design (i.e. ideal coal characteristics) harm productivity. The most important contribution of my research on theoretical grounds is the inclusion of the key variable R, which represents the observed deviations of coal actually burned with respect to the boilers ideal fuel design characteristics. This variable enters the production function directly, affecting the units total factor productivity. The relevance of R is illustrated by the fact that most units affected by the Title IV regulation opted (fully or partially) for a fuel switching compliance strategy, which gave rise to important relative deviations from those ideal design characteristics, and ultimately, affected productivity.

The period of analysis was marked by stringent nationwide environmental regulations, but also by some restructuring processes in certain states, so a careful empirical strategy was implemented to account for these potentially confounding influences. The estimation procedure was based on the Generalized Method of Moments developed by Hansen [17] and proved to be effective in dealing with the transmission bias first introduced by Marschak and Andrews [24] -i.e. correlation between the error term and the unit's flexible input demands. A hedonic price regression was used to compute coal prices at the plant level, which were used as instruments in estimation to address the transmission bias. With the production function parameter estimates I was able to measure the impact of the Clean Air Act Amendment of 1990 on output, productivity, generation costs, and ultimately, the corresponding pass-through to prices.

Market restructuring processes proved not to be significant in determining units productivity. In contrast, estimated output losses due to the implementation of the Acid Rain Program ranged from 1% to 4%, varying across regions, over time, and mainly depending on the proximity of generating units to low-sulfur coal sources. Additionally, compliance cost by the end of the period (years 2004 and 2005) were significant in magnitude and represented between 1.6% and 11% of the electricity price, on average, for the regions considered in this paper. Also, certain evidence of compliance cost pass-through to prices was observed in particular states. However, this phenomena was unrelated to the restructuring condition of the states, since some of them were deregulated markets while others were still regulated. Finally, environmental goals expressed in terms of emission rate reductions seem to have been successfully achieved during this period. Concretely, the threshold rate of 1.2 lbs SO2/mmBtu was reached at the beginning of the 2000s.

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Appendix

A Estimation of exogenous coal prices.

The following table shows a sample coal price regression for the Central Appalachian Region during the years 1985-2005.

Table 14: Coal price regression for Central Appalachian Region

Dependent variable:	Spot delivered cost of coal				
Regressor	Coef.	Std. Err.	Regressor	Coef.	Std. Err.
btu content	0.012	(0.002)	year1985	1.013	(31.450)
sulfur content	-9.973	(2.060)	year1986	-10.167	(30.407)
ash content	0.588	(0.453)	year1987	-18.679	(29.713)
distance x year1985	0.064	(0.019)	year1988	-17.257	(29.959)
distance x year1986	0.053	(0.020)	year1989	-17.839	(29.799)
distance x year1987	0.060	(0.017)	year1990	-11.005	(31.473)
distance x year1988	0.048	(0.016)	year1991	-12.435	(31.982)
distance x year1989	0.053	(0.010)	year1992	-13.455	(32.478)
distance x year1990	0.081	(0.011)	year1993	-15.097	(32.410)
distance x year1991	0.074	(0.011)	year1994	-17.379	(31.329)
distance x year1992	0.065	(0.011)	year1995	-23.373	(30.904)
distance x year1993	0.070	(0.011)	year1996	-27.427	(30.697)
distance x year1994	0.077	(0.009)	year1997	-28.147	(30.810)
distance x year1995	0.084	(0.008)	year1998	-30.236	(30.549)
distance x year1996	0.089	(0.007)	year1999	-30.526	(30.819)
distance x year1997	0.086	(0.005)	year2000	-34.295	(30.923)
distance x year1998	0.087	(0.005)	year2001	-18.687	(31.427)
distance x year1999	0.081	(0.007)	year2002	-19.756	(33.104)
distance x year2000	0.080	(0.008)	year2003	-12.962	(32.710)
distance x year2001	0.107	(0.014)	year2004	22.775	(31.926)
distance x year2002	0.118	(0.018)	year2005	43.395	(34.157)
distance x year2003	0.098	(0.015)			
distance x year2004	0.073	(0.019)			
distance x year2005	0.127	(0.034)			
Observations	194,967				
R^2	0.9705				

Source: FERC's Form 423. Distance is in miles, from plant county to coal mine county.

B Compliance choices and the exogeneity of R and f

Compliance strategies, although revised every period, are not subject to corrections to small productivity fluctuations. Remember that the Clean Air Act was last amended in 1990, but the effective implementation of the law started in 1995 for some units and 2000 for the remaining units. The quantity of annual permits allocated to each unit was known since 1990. As a result one can imagine (as it effectively occurred for most units) that compliance decisions were taken well in advance of the effective implementation dates.

Scrubber adoption and fuel switching choices are both subject to capital costs. For NSPS units the construction of the unit is realized together with the construction of the scrubber device. In this case, the entry decision and the scrubber adoption decision are made at the same time. For units already operating, the retrofit of a scrubber is a high cost investment expenditure. In the case where a unit opts for the fuel switching alternative, there is a capital cost of converting the boiler to burn low-sulfur coal. The magnitude of this capital cost depends on the differences in quality between the current high-sulfur coal and the targeted low-sulfur coal. The main point is that small productivity shocks are not likely to modify the compliance strategy choice. A unit would need severe changes in the environmental regulations, large variation in permit prices, or pronounced changes in fuel relative prices (and also expectations of persistence once those changes occur) in order to effectively revise the compliance strategy adopted.

On the other hand, coal contracts are executed in the following way: a number of shipments with the corresponding estimated delivered quantity are agreed in advance. Most of the time, those quantities are not completely fixed, allowing for some adjustments according to the power plant's demand. Recall that the majority of coal purchases are made through contracts rather than spot transactions. Therefore, it is crucial to keep this in mind to understand how the coal market operates.

Both facts described above, i.e. the execution of coal contracts and the compliance choice made by the unit, imply that once a positive (negative) productivity shock is observed, the unit should react by increasing (decreasing) the demand for coal of the same variety it is already using. From the decomposition of variable R below it will be clear that a higher demand of the same quality of coal does not affect the value of R. Omitting the subscripts of unit j at time t, suppose the unit demands coal type m, so R is as follows

$$R = \left| \frac{E^* - E^m}{E^*} \right|$$

where the free or unconstrained emission rate is E^* and the observed or current emission rate E^m is simply a linear transformation of the ratio between the sulfur content and the Btu content of coal type m. Hence, a higher (lower) demand for coal m leaves E^m, and therefore R, unaffected.

To analyze the exogeneity of f in more detail, consider the (static) profit function for the unit

j in time t once the compliance strategy was decided.[52] For ease of the exposition and without loss of generality, let's consider three leading extreme cases:

A) Buy enough permits to back up emissions so that $R_{jt} = 0$ and $f_{jt} = 0$

B) Adopt a scrubber and burn ideal coal type so that $R_{jt} = 0$ and $f_{jt} = 1$

C) Only purchase low-sulfur coal so that $R_{jt} > 0$ and $f_{jt} = 0$

The profit functions under these three strategies are

$$\Pi_{jt}^{A} = p_{jt}Y_{jt} - q_{jt}H_{jt} - r_{jt}K_{jt} - w_{jt}L_{jt} - z_t\left[S_{jt} - \hat{S}_{jt}\right] \tag{5}$$

$$\Pi_{jt}^{B} = p_{jt}Y_{jt} - q_{jt}H_{jt} - r_{jt}K_{jt} - w_{jt}L_{jt} - z_t\left[S_{jt}(1-\phi) - \hat{S}_{jt}\right] - C^{B}\left(S_{jt}, K_{jt}, t\right) \tag{6}$$

$$\Pi_{jt}^{C} = p_{jt}Y_{jt} - q_{jt}H_{jt} - r_{jt}K_{jt} - w_{jt}L_{jt} - z_t\left[S_{jt} - \hat{S}_{jt}\right] - C^{C}\left(K_{jt}, t\right) \tag{7}$$

where S and $\hat{S}$ are the actual gross sulfur dioxide emissions, i.e. before scrubbing, and the number of allocated free emission permits (grandfathering), repectively. ϕ is the scrubber emission reduction rate (.95 on average), $C^B(\cdot)$ is the levelized scrubbing cost which includes operating and maintenance costs plus capital cost, $C^C(\cdot)$ is the levelized capital cost of fuel switching, p is the electricity generation price in \$/MWh, z is the pollution permit price measured in dollars per ton of SO_2, q is the coal price in \$/mmBtu, w is the average wage rate in dollars, and r is the return to capital. Thus, for some fixed levels of L_{jt}, K_{jt} and H_{jt}, it is possible to compare the three extreme cases just subtracting one profit equation from another in the following way

$$\Delta\Pi_{jt}^{A-B} = p_{jt}F(K_{jt}, L_{jt}, H_{jt})e^{\gamma_0+\varepsilon_{jt}}\left[1 - e^{\gamma_f}\right] + C^{B}\left(S_{jt}(0), K_{jt}, t\right) - z_t\phi S_{jt}(0) \tag{8}$$

$$\begin{aligned}\Delta\Pi_{jt}^{A-C} &= p_{jt}F(K_{jt}, L_{jt}, H_{jt})e^{\gamma_0+\varepsilon_{jt}}\left[1 - e^{\gamma_R R_{jt}}\right] + \left[q_{jt}(0) - q_{jt}(R)\right]H_{jt} \\ &- C^{C}\left(K_{jt}, t\right) - z_t\left(S_{jt}(0) - S_{jt}(R)\right)\end{aligned} \tag{9}$$

$$\begin{aligned}\Delta\Pi_{jt}^{B-C} &= p_{jt}F(K_{jt}, L_{jt}, H_{jt})e^{\gamma_0+\varepsilon_{jt}}\left[e^{\gamma_f} - e^{\gamma_R R_{jt}}\right] + \left[q_{jt}(0) - q_{jt}(R)\right]H_{jt} \\ &- z_t\left[S_{jt}(0)\left(1-\phi\right) - S_{jt}(R)\right] - \left[C^{B}\left(S_{jt}(0), K_{jt}, t\right) - C^{C}\left(K_{jt}, t\right)\right]\end{aligned} \tag{10}$$

The key aspects to consider when choosing the compliance strategy to follow are: the lost revenues (i.e. value of output losses), the cost premium for low-sulfur coal, the differences in permits used or saved, the levelized costs of fuel switching and scrubbing. Focusing on the idiosyncratic log-productivity shock, ε, equation 8 compares the difference in profits between option A (permit

[52]One can think of this as a two stage profit maximization problem where units choose first the compliance method and then make the production choice. A natural assumption is to consider compliance decisions are made at the beginning of the game and those decisions are only revised when a new regulation is passed or drastic market changes are observed.

purchases) and option B (scrubber adoption). It is apparent that the more productive a unit is the higher the revenue loss due to scrubber adoption. Something similar occurs in equation (9) when I compare strategy A versus strategy B (fuel switching/blending). Of course, the final outcome when comparing different alternatives takes into account the remaining terms in these equations (i.e scrubber costs and permits saved in (8), and fuel cost differences, capital costs, and permits saved in (9)). The main point I want to highlight is this simple exercise isolates the log-productivity effect on compliance choices. From equation 10, the effect of productivity shock is ambiguous and clearly depend on the value of R. For instance, considering a unit highly constrained that requires a large deviation from its ideal coal type (i.e. high R), then higher log-productivity favors scrubber adoption. The opposite happens for a low-R unit. If following strategy C implies a minor deviation from its ideal coal type, then high log-productivity reduces the incentives for FGD adoption. Because there is no reason a priori to believe there is a positive (negative) correlation between R and ε, or a positive (negative) correlation between f and ε, I assume that R and f are econometrically exogenous in the production function in equation 3.

C Ordinary Least Squares - Production Function Parameter Estimates

Table 15: Ordinary Least Squares - Production Function Parameter Estimates.

Parameter	(i)		(ii)		(iii)		(iv)	
α_h	1.1278***	(0.1053)	1.1533***	(0.1105)	1.1421***	(0.1103)	1.1459***	(0.1105)
α_k	0.1671	(0.1369)	0.2057	(0.1438)	0.2020	(0.1452)	0.2115	(0.1442)
α_l	0.1379	(0.0933)	0.1383	(0.0885)	0.1536*	(0.0887)	0.1441	(0.0888)
α_{hh}	-0.0045	(0.0054)	-0.0045	(0.0057)	-0.0042	(0.0057)	-0.0041	(0.0057)
α_{kk}	-0.0333***	(0.0123)	-0.0316**	(0.0125)	-0.0335***	(0.0126)	-0.0320**	(0.0125)
α_{ll}	-0.0152**	(0.0060)	-0.0140**	(0.0058)	-0.0136**	(0.0059)	-0.0139**	(0.0059)
α_{hk}	0.0125	(0.0147)	0.0079	(0.0152)	0.0094	(0.0153)	0.0076	(0.0153)
α_{hl}	-0.0029	(0.0092)	-0.0043	(0.0090)	-0.0058	(0.0090)	-0.0052	(0.0090)
α_{kl}	0.0051	(0.0139)	0.0084	(0.0139)	0.0090	(0.0139)	0.0096	(0.0138)
γ_f	-0.0279***	(0.0069)	-0.0565***	(0.0067)	-0.0533***	(0.0067)	-0.0552***	(0.0067)
γ_R			-0.0268***	(0.0081)			-0.0242***	(0.0081)
γ_{ph1}	0.0593***	(0.0069)						
$\gamma_{\text{ph1-post89}}$	-0.0081**	(0.0036)						
$\gamma_{\text{ph1-post94}}$	-0.0049	(0.0042)						
γ_{ph2}	0.0548***	(0.0080)						
$\gamma_{\text{ph2-post89}}$	-0.0002	(0.0040)						
$\gamma_{\text{ph2-post94}}$	-0.0009	(0.0039)						
$\gamma_{\text{iou-drg}}$					0.0141***	(0.0047)	0.0115**	(0.0047)
$\gamma_{\text{mnc-post92}}$					-0.0032	(0.0057)	-0.0043	(0.0057)
α_0	-4.5216***	(0.5851)	-4.7330***	(0.5990)	-4.6710***	(0.5977)	-4.7042***	(0.5985)
Observations	12,795		12,795		12,795		12,795	
R^2	0.9971		0.9969		0.9969		0.9969	

Note:
(a) Robust standard errors clustered by electricity generation unit are shown in parenthesis.
(b) All models include year dummies (not shown in the table) to control for year fixed effects.

D Omitted figures

Figure 11: Compliance groups

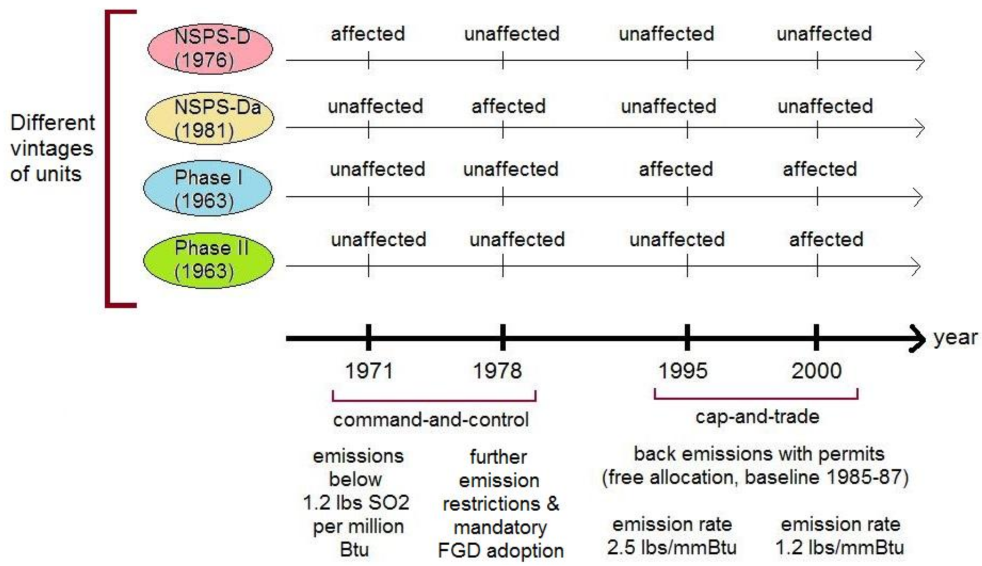

Figure 12: Evolution of allowance prices