Adoption of Emissions Abating Technologies by U.S. Electricity Producing Firms Under the SO2 Emission Allowance Market

A DISSERTATION
SUBMITTED TO THE FACULTY OF THE GRADUATE SCHOOL
OF THE UNIVERSITY OF MINNESOTA
BY

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IN PARTIAL FULFILLMENT OF THE REQUIREMENTS
FOR THE DEGREE OF
Doctor of Philosophy

August, 2012

Acknowledgements

I want to express that during the preparation of this thesis I have received help from numerous people, many of whom will probably be unfairly left out of this section. I want to thank my advisory committee for their guidance: Frances Homans, Elizabth Wilson, but specially I want to express my gratitude to Phil Pardey and Jay Coggins for their valuable advice and timely inputs.

I am greatly indebted to the following people and institutions for their support in various ways during my research: Matt Sobek from Minnesota Population Center, Adrian Bonilla and Juan Ponce from Facultad Latinoamericana de Ciencias Sociales, Santiago Gangotena, Carlos Montufar and Pablo Lucio Paredes from Universidad San Francisco de Quito, Andrew Jarvis and Ruben Echeverria fromCentro Internacional de Agricultura Tropical, and Rowland Joiner and David Evert from Quantum Connections. I also want to acknowledge the Center for International Food and Agricultural Policy of the University of Minnesota which financed the SO2 allowance historical data.

I am grateful to people that contributed in many ways to the completion of this research: Rebecca Peterson, who provided me with information about EIA form 423; Kevin Lillis for valuable clarifications on form EIA 767; Robert Schnapp from EIA, who was very helpful in clarifying various issues about EIA data that helped me to understand form FERC-423 and the dynamics of coal prices. Natalie Ko, for providing EIA 767 data sets previous to 2001, not available on the web. Ellen Carson helped me finding books and references more than once. Patrick Jardine's help on proof reading my dissertation was key.

I want to express my especial gratitude to Germán Creamer, whose continued support and generosity were essential to complete my research.

Finally I want to send a thought of gratitude to late Professor Edward Schuh, dear mentor and wise teacher who guided me towards this path.

Dedication

To Rafaela and Bernardo, for being always a source of strength and inspiration...

to my mother for her optimism and loving support...

and to Gabriela, the warmth of my heart.

Abstract

The objective of this research is to determine the adaptation strategies that coal-based, electricity producing firms in the United States utilize to comply with the emission control regulations imposed by the SO_2 Emissions Allowance Market created by the Clean Air Act Amendment of 1990, and the effect of market conditions on the decision making process. In particular, I take into consideration (1) the existence of carbon contracts for the provision of coal that may affect coal prices at the plant level, and (2) local and geographical conditions, as well as political arrangements that may encourage firms to adopt strategies that appear socially less efficient.

As the electricity producing sector is a regulated sector, firms do not necessarily behave in a way that maximizes the welfare of society when reacting to environmental regulations. In other words, profit maximization actions taken by the firm do not necessarily translate into utility maximization for society. Therefore, the environmental regulator has to direct firms into adopting strategies that are socially efficient, i.e., that maximize utility. The SO_2 permit market is an instrument that allows each firm to reduce marginal emissions abatement costs according to their own production conditions and abatement costs.

Companies will be driven to opt for a cost-minimizing emissions abatement strategy or a combination of abatement strategies when adapting to new environmental regulations or markets. Firms may adopt one or more of the following strategies to reduce abatement costs while meeting the emission constraints imposed by the SO_2 Emissions Allowance Market: (1) continue with business as usual on the production site while buying SO_2 permits to comply with environmental regulations, (2) switch to higher quality, lower sulfur coal inputs that will generate less SO_2 emissions, or (3) adopting new emissions abating technologies.

A utility optimization condition is that the marginal value of each input should be equal to the product generated by using it and to the activities that are required by

new regulations. The comparative technological and scale efficiency factors of coal-based electricity producing plants are calculated using the Data Envelopment Analysis (DEA) framework, and used as proxies to test this condition.

In the empirical analysis, econometric models of the response of firms to emissions control are analyzed around the following aspects: (1) characterization of the behavior of firms and their efficiency, (2) relevant variables that trigger the adoption of technology, that is, the acquisition of *scrubbers*, and (3) the influence of exogenous variables, such as the existence of contracts, distance from mine to plant, and local conditions of the region where plants are located.

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Introduction

The comparatively recent awareness of environmental changes with the potential to cause negative global social consequences of unprecedented dimensions has brought to public attention what decision makers have been already tackling for years: the necessity to control polluting emissions in the environment. The final report of the bi-partisan Project 88 of the U.S. Congress (Stavins, 1989), concluded that the environmental and economic debt that the nation was acquiring by not establishing appropriate environmental regulations was ineludible, and would be unjustly transferred as an impoverishment to future generations.

The negative side effects of SO_2 emissions have been thoroughly evaluated, especially health deterioration issues caused by acid rain and other unwanted impacts that generate significant social costs. Acid rain caused by sulfate acid deposition can be detrimental to ecosystems, plants and animals, aquatic and terrestrial (Smith et al., 2010). The U.S. Congress passed the Clear Air Act in the early 1970s to cut down both NO_x and SO_2 among other emissions considered hazardous for health and the quality of the environment[1] . The 1990 Clean Air Act Amendments (CAAA), created an allowance market for SO_2 emissions in an attempt to curb emissions at minimal social costs. The SO_2 allowance market allows market forces to set the price of abating pollution and transfers the direct cost of abating SO_2 emissions to electricity producing plants, and ultimately, to consumers of energy. In this way, the social cost of producing energy is passed on to the net beneficiaries of

[1] A preliminary analysis shows that expected health benefits due to a reduction in mortality by exposure to sulfates exceeds expected costs in almost all scenarios (Burtraw et al., 1997).

electricity production: the consumers.

In particular, it is estimated that in the United States alone the electricity-generating industry produced and emitted in 2008 nearly 7.9 million short tons of SO_2 emissions as a byproduct of their activity, out of a total of 9.5 million tones (EPA, 2008)[2] . Despite the fact that SO_2 emissions have consistently been reduced since the start of the CAAA in 1990, they are still considered to be high and new restrictions are being planned[3] .

Given that the electricity generating sector is regulated by state-level Public Utility Commissions (PUCs), the question arises whether or not electricity producing firms, when seeking to optimize their profits, are at the same time making socially efficient choices, or, in contrast, do market factors that affect their SO_2 abatement decisions make them appear less efficient[4] . Some of the market realities that pertain to the SO_2 allowance market efficiency are:

- Distance from mines to electricity producing plants.
- Legal and regulatory differences among states and local jurisdictions.
- The existence of formal relationships or contracts that affect the quantity, quality and price of coal.

I analyzed three strategies that firms follow when facing emission restrictions:

1. Reducing emissions from the input side by buying larger amounts of low sulfur coal as fuel,
2. Adopting Flue Gas Desulphurization (FGDS) equipment to substantially reduce SO_2 emissions, and

[2] SO_2 emissions generated by electricity producing plants, accounted for 83.3% of the total sulfur emissions in 2008. More information can be seen at Table B.1, Appendix B.

[3] Muller and Mendelsohn (2009) estimate that the cap of 8.5 million tons of emissions set for 2010 is too lenient and that an optimal cap would have been 1 million tons.

[4] The term *socially efficient* is used in a general way to include also externality costs. These are difficult to assess and are not part of the scope of this research

3. Conducting business as usual (or with minor variations), and buying SO_2 allowances to compensate for the excess of emissions generated.

To evaluate the economic efficiency of coal burning electricity producing firms I developed an econometric model to explain underlying relationships among prices and quantities of low sulfur and high sulfur coal, SO_2 allowances, and Flue Gas Desulphurization units (FGDs), and their relationship to the calculated efficiency of electricity producing operations.

The analysis specifies empirical equations that can be tested in order to obtain further information about the effects of economic factors on the choice of technology by firms. Specifically, I examine:

- The decision to buy SO_2 abating technology,
- The evolving relationship over time between technical efficiency factors and the strategic decision to adopt scrubber technology.

As expected, I found a strong correlation between technical efficiency[5] and various economic and geographic factors. Also, relations tested between the three operational strategies of firms and relevant variable such as prices of low and high sulfur coal; SO_2 allowances prices; and the operation and maintenance cost of abating technology (*scrubbers* or FGDs), show that firms make the expected trade-offs among these factors when deciding how to react to the CAAA.

As a general conclusion, the plants tend to behave in a way that appears less efficient for reducing emissions, even though some market conditions create circumstances that affect the market and influence company policy. Therefore, the electricity production sector does not behave always as a perfectly competitive market. Two examples of market factors that may affect the adoption of technology by firms analyzed in this research are the market

[5] For the measurement of efficiency a normalized Data Envelopment Analysis is used. Thus the efficiency values obtained using this methodology uses are benchmark values taken from the universe of plants studied.

power of coal mines when bidding contract and setting the price of coal with energy firms; the restructuring of the electricity sector in 2000; and the effect of transportation cost of coal.

0.1 Objective

The objective of this research is to determine wheter investment in SO_2 emissions abating technologies and innovation by coal-based electricity producing firms represent efficient cost reducing decisions. The underlying assumption is that the Clean Air Act Amendments of 1990 created a competitive cap-and-trade market for SO_2 allowances that lowered overall emission levels. However, institutional and political arrangements, as well as geographical and market circumstances affect SO_2 allowance market in ways that will be examined in this research.

0.2 Organization

The research can be broadly divided into two parts:

- The analysis begins with the assumption that the SO_2 allowance market, created by the 1990 CAAA, behaves as a perfectly competitive market. This option is considered in an analytical model

- In the second part of the study, special market circumstances and different variables that may affect the decision to adopt technology by firms, are brought into play. An econometric model is run to test some relationships under this assumption.

In Chapter 1, historical events that led to the CAAA of 1990 and the creation of the SO_2 allowance market are discussed. In this chapter, there is a general discussion about the institutional arrangements that play a key role in the SO_2 allowance market. There is also an examination of the political circumstances that may influence the strategic behavior of firms regarding SO_2 abating decisions and pertinent geographic factors that affect the U.S. coal market. This chapter points out some imperfections of the SO_2 allowance market.

In Chapter 2 a description of the data sets developed for this study is given. Chapter 3 presents econometric models designed to test the effects of certain market characteristics on coal prices, such as transportation distances, and coal buying contracts; while in Chapter 4 the methodology for measuring the efficiency of firms is described, and econometric models that examine the decision process of firms when facing the CAAA, are proposed.

A model to describe the relationships among *scrubbers* adoption, and other parameters such as costs of coal, technology choice and SO_2 allowances is tested in Chapter 5. The consequences of technology adoption costs, SO_2 allowance prices, and the prime price paid for lower sulfur coal on the strategic abatement decision taken by electricity producing firms, are analyzed from the assumption that SO2 allowance and coal markets behave competitively.

General results from the statistical analysis are presented on each chapter, and conclusions follow in Chapter 6.

Chapter 1

Conceptual Background

1.1 Market and Regulatory Developments

The U.S. Congress passed the Clean Air Act Amendments of 1990 that includes, under Title IV, an allowance market for the control of sulfur dioxide (SO_2) emissions, by way of the acid rain control initiative. This constituted a market based mechanism for controlling the cost of abating SO_2 emissions and a movement away from more traditional command-and-control types of regulations. Carlson et al. (2000), argued that savings in SO_2 emissions abatement costs in the electricity sector were \$700 to \$800 million per year when adopting this mechanism compared with traditional command and control regulation procedures.

The regulation of SO_2 and NO_x emissions mostly affects the electricity producing sector (Banzhaf et al., 2002), mainly because 50% of the electricity produced in the United States is based on burning coal, which accounts for nearly 70% of the total SO_2 emissions in the United States Furthermore, coal-sourced electricity is likely to be a principal source of energy for at least several more decades given that the United States has the largest amount of coal reserves in the world[1] . Within this perspective, some authors suggest that there are greater gains for society when control policies induce R&D activities that

[1] According to Council (2010), the United States has the largest proven reserves of coal.

create new emission abatement technologies that reduce the cost of abating emissions in the future (see, for example, Fischer, 2004)[2] .

To make things more complicated, the elements that play an important role in the process of reducing pollution and emissions to acceptable social costs are dynamic and stochastic in nature. The innovation process, filled with uncertainties, creates new investment and return scenarios at different stages, which is why a dynamic approach is necessary. Nonetheless, there is some counter-intuitive empirical evidence that shows more emissions abating innovations were developed before the beginning of the SO_2 allowance market in 1995. However, Popp (2003b) argues that pollution abating innovations before 1995 were more abundant only in the number of patents, but that after Title IV of CAAA 1990, new patents led *to more environmentally-friendly innovations, as measured by the effect of the new innovations on air quality.*

Research has been conducted in regards to the way that electricity generating plants react to new environmental regulations that can impose more production restrictions and cost increases. The decision process of electricity generating firms can be reduced to a profit maximization problem, that for the case of the electricity producing sector, it can be simplified into a cost minimization problem[3] .

In the SO_2 cap-and-trade market, (without specific requirements from a command-and-control type of regulation) some companies will opt to use their geographical advantage to

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[2] In evaluating the direct social costs and benefits, as well as the possible externalities and spillovers of environmental control regulations and environmental quality, there are many aspects that are left out by economists because of a lack of available data, or uncertainty issues, such as the cost of loss of wild habitat and biodiversity, or the real costs to society of health problems generated by acid rain, for example. There are also questions concerning certain assumptions that are commonly used to quantify the value of these costs, such as perfect information and the shapes of the *preference* and *production* functions.

[3] For example, Baker and Shittu (2006) develops a framework to profit maximization behavior of firms under CO_2 emissions taxes, and uses the *marginal abatement cost* minimization as a tool to determine profit maximization behavior. The same author provides a good review of methodologies used for measuring profit maximization and cost minimization in firms under emissions control ([Baker et al., 2008]). Arimura (2002) builds a simple model with two of the strategies used in this study, where firms aim to minimize abating costs.

reduce their emissions by buying more low-sulfur coal instead of investing in new technologies (Stavins, 2005).

Two key questions arise *do companies in the electricity production sector underinvest in innovation and technology adoption because they ignore important considerations*[4] *in their investment decisions?* Or, alternatively, *do they invest efficiently in innovation and technology adoption though it is not readily apparent because of market circumstances that are difficult to observe, such as transportation prices, coal contracts, or regional regulations, among other factors?*

In this chapter the theoretical, historical, and institutional backgrounds that influence the electricity production sector and the environmental regulations that affect it are described.

1.1.1 Historical and Institutional Background

Some of the main regulatory modifications and institutional changes that have affected production prices and, therefore, pollution abatement strategies of the electricity production market are:

- The Clean Air Act and its amendments.
- The deregulation and subsequent restructuring of electricity markets in some parts of the United States.
- The Staggers Act of 1980, that greatly altered railway transportation prices of coal.
- The actions of political groups and interests.

1.1.2 The Clean Air Act

The Clean Air Act is a comprehensive body of regulations and laws originated from the Air Pollution Control Act of 1955, which sought to establish standards for air pollutants

[4] *Such as the real rate of return of investing in FGDs*

produced by stationary and mobile sources with the objective of lowering emissions that are hazardous to human health and safety. An important amendment was passed in 1970 that greatly shaped what the act has become today. In 1977 and 1990, new amendments were introduced that sought to achieve the original goals of the act, that were not being attained. A key aspect of the 1990 amendment was the introduction of market-oriented policies to regulate the emissions of SO_2. Title IV of the Clear Air Act was modified to include, among other instruments, the creation of an allowance market for SO_2 emissions. The CAA amendment envisaged that electricity producing firms would be required to comply with the new regulations in two phases:

Phase I Starting in 1995, it required units identified in Table A in Title IV of the CAAA to reduce emissions greater than 2.5 pounds of SO_2/mmBTUs, with generating capacity over 100 MW.

Phase II Affected all plants having fossil-fueled boilers, including those affected in Phase I, with generating capacity over 25 MW. All plants were enforced to comply with Phase II by the year 2000.

History

The Clean Air Act of 1970 introduced a major effort by the government to reduce and control emissions by means of establishing standards. The following instruments, among others, were created for that purpose:

- The National Ambient Air Quality Standards, known as NAAQS, part of the national maximum standards for environmental concentrations of sulfur dioxide (SO_2), carbon monoxide (CO), nitrogen oxides (NO_x), ozone (O_3) and lead (Pb).
- The State Implementation Plans, or SIPs, which were the responsibility of each state, and contained strategies to comply with the standards in a prescribed time period.

- The New Source Performance Standards, or NSPs, imposed restrictions on newly built plants so that the emission rates of new coal fired plants could not exceed 1.2 lbs. of SO_2 per million Btu.

- The National Emission Standards for Hazardous Air Pollutants, abbreviated as NESHAPs

In 1975, it was clear that many plants could not comply with the NAAQs, and some provisions were added in 1977 to the CAA to take into account the so called non-attainment areas covered by the NAAQS[5] . The term "non-attainment areas" was applied to those areas where one or more quality standards had not been met at the time.

In 1990 a further substantial set of changes were made to the CAA, and a more comprehensive set of regulations with an increased scope of operation was devised. In a clear tendency towards decentralizing environmental control, the 1990 amendments expanded the reach of environmental regulations to include toxic pollutants, and emission allowance markets were created to transfer much of the decision making regarding pollution abating investments to the electricity producing firms.

1.1.3 The SO_2 Allowance Market

The sulfur dioxide permit market was created by Title IV - *Acid Deposition Control*[6] of the 1990 CAA amendments (abreviated as CAAA), with the purpose of reducing emissions that cause acid rain. This policy has been lauded as a major experiment to use market forces to help reduce emissions at lower social costs while simultaneously promoting the adoption of abatement technology (Stavins, 2005).

When it was launched, the SO_2 allowance market distributed, at no cost, *SO_2 allowances* among electricity producers in direct proportion to their historical emission rates. Each permit or allowance entitles the owner to produce and dispose into the atmosphere

[5] For a detailed discussion of the history of the CAA, see Ellerman et al., 2000

[6] Title IV from the 1990 amendment substituted the previous Title IV that dealt with noise reduction.

1 ton of SO_2 emissions per year. In this way, the costs of lowering SO_2 emissions were intended to be set by market forces. The rationale is that electricity producing units will minimize their marginal costs of production, including the cost of the SO_2 emissions that have to be accounted for in excess of the permitted amount, ultimately resulting in a minimization of the social costs of jointly producing SO_2 and elcctricity[7] . Companies can follow any of the following strategies that minimize costs in order to comply with the environmental regulations:

- Capital investments and abating technology adoption
- Substantive changes in operational expenses, including:
  - buying SO_2 allowances to offset excess emissions,
  - switching to lower sulfur coal.

Plants with lower marginal costs for emissions abatement will reduce emissions more than their allotted amount in order to sell their unused SO_2 allowances to companies that are not as efficient in abating emissions. In this way, the electricity producing firms decide which strategy to follow and the overall social cost of emissions reduction should be optimal.

The Environmental Protection Agency (EPA) was designated to enforce Title IV of the CAA. These allowances can be used during the year of issuance, saved for future use, or traded in an allowance market - very much like a commodity[8] . If a utility fails to comply with the CAAA emissions provisions by not having enough allowances to offset its annual SO_2 emissions allowance, the EPA imposes penalties that are well above the compliance costs[9] .

The allowance market created in Title IV was devised to reduce emissions in two phases.

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[7] For some detailed discussion on this see Bohi and Burtraw, 1992.

[8] SO_2 allowances can actually be traded on the forward, futures, and options markets. The emission allowances are traded through the Chicago Board of Trade (CBOT).

[9] A penalty fee of $2,000 per ton of emission is imposed on plants that do not comply with CAAA, under EPA's Account 426.3 - Penalties (Chalstrom, 1993). This incentive can become muted when SO_2 allowance prices rise, as was the case in 2008, when allowance prices rose to values of approximately $1,800 per Ton.

Phase I Went into effect in 1995 and allowances were issued as to set the limit of emissions to 2.5 pounds of SO_2 per million British thermal units of heat energy used as input ($lb/mmBTUs$)

Phase II Went into effect in 2000. The permits issued reduced the corresponding allowable emissions of SO_2 to 1.2 $lb/mmBTUs$.

Phase I of the Clean Air Act

During Phase I, the goal was to reduce overall SO_2 emissions from 10 million tons (1985 levels) to 8.7 million tons per year for 263 producing units[10] . The largest polluting plants were operated by 61 electric utilities largely located east of the Mississippi River (Stavins, 2005).

The EPA allocated the allowances to these designated Table A plants on the basis of an emissions rate of 2.5 lb of SO_2 per mmBTU of heat input[11] . The initial allocation of permits was distributed in a grandfathered scheme. Specifically, allocations of emissions permits were based on the average heat input of each generating plant between 1985 and 1987. In addition, 168 units voluntarily joined the program using the voluntary "opt-in" provision included in the Substitution Provision of the CAAA. The rest of the plants that were not included in Phase I of the CAAA were subject to the command-and-control standards and regulations that were in place at the time.

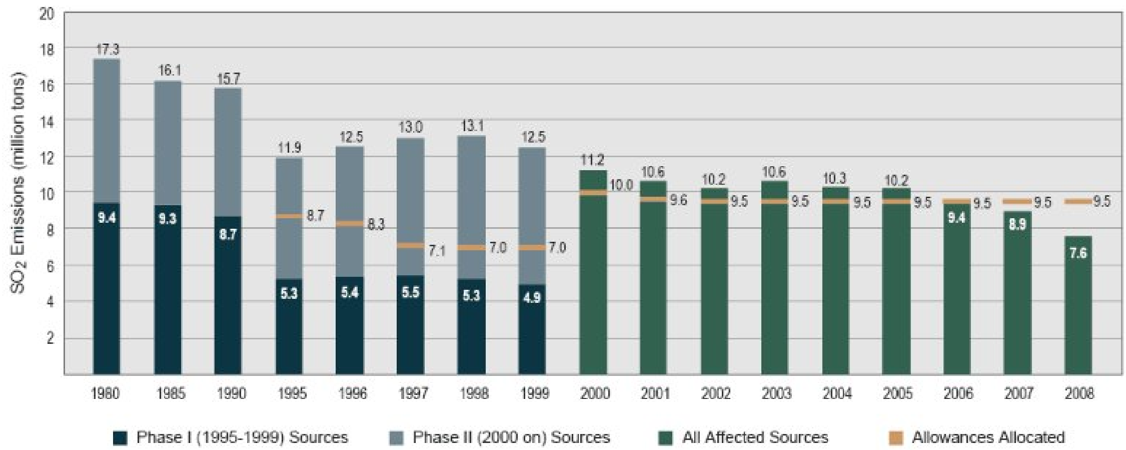
Allowances were distributed for the equivalent of 8.7 million tons of SO_2 emissions in 1995 but gradually the overall allocations were reduced to 7 million tons for the years 1998 and 1999 (Figure 1.1.3)[12] .

[10] The CAA legislation refers to the term unit, meaning a single generator and associated boiler. A generating power plant can have more than one unit. In this research, I will simplify this specification, and units will be aggregated into plants. For further explanation about this issue, see Section 2.

[11] The 110 plants that were directly affected by Phase I of the CAAA of 1990 are known as *Table A* plants, making reference to the table where they were mentioned in the CAAA.

[12] More information can be found in the report published by EPA in their web page: http://www.epa.gov/airmarkt/progress/ARP_4.html

Figure 1.1: SO2 emissions from Acid Rain Program Sources, 1980 - 2008, (Source EPA)



(Source EPA, 2009)

Phase II of the Clean Air Act

With Phase II of the Clean Air Act of 2000, the EPA expanded the scope of restricted plants to include all units over 25 MW (generating capacity). The allowance allocation was further tightened at the same time, and the EPA allocated allowances to electricity producing plants equivalent to an emissions rate of 1.2 pounds of SO_2/mmBtu of heat input, multiplied by the plant's baseline heat input for the period 1985-1987.

The EPA set the overall emissions cap at 10 million tons of SO_2 for the year 2000, and reduced it to 9.5 million tons in 2002. It was kept at that level until 2010 when the Act places a cap at 8.95 million on the number of allowances issued to units each year.

1.1.4 Deregulation and Restructuring of Electricity Markets

The electricity production sector has traditionally been considered a *natural monopoly* industry, therefore, government regulation for socially efficient production of electricity was required. Regulations dealt with energy and fuel prices, entry of new firms, investments, quality of the services, among other aspects (Joskow, 1997). Power markets in particular, requiring large investments that posed a natural barrier to entrant companies offered the possibility of large vertical integration among trading utilities. Electricity retail competition and restructuring trends of the electricity producing sector began in Massachusetts, Rhode Island and California in early 1998. By the year 2000 more than 10 states were undertaking the restructuring of their electricity sectors, and many other states were planning to implement restructuring programs (Joskow, 2005).

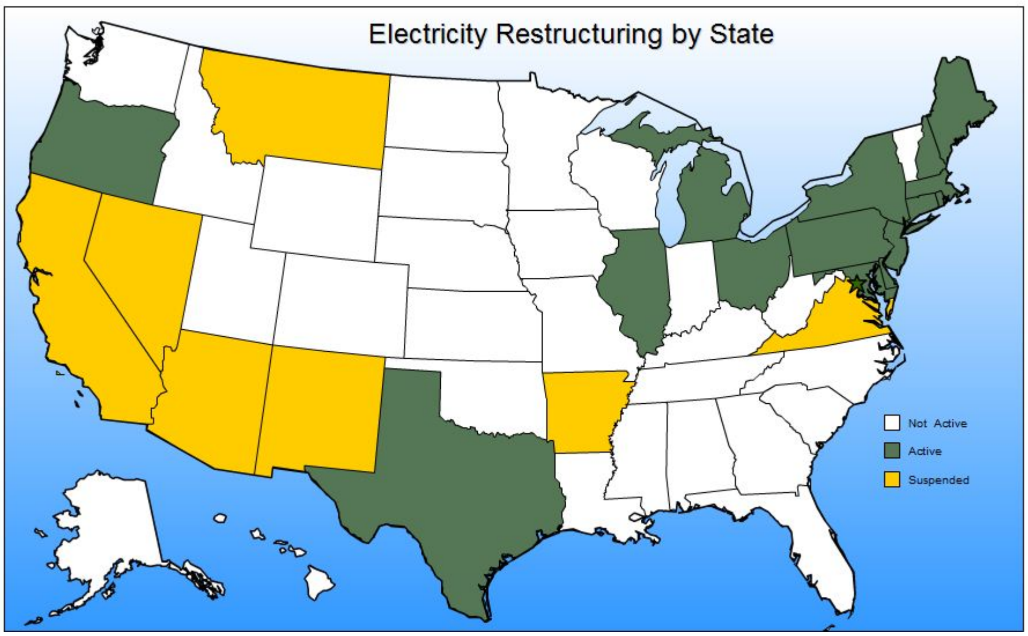
With recent advances in electricity generation technology dramatically reducing the initial investment to generate electricity, important changes have occurred in the electricity production sub-sector. For example, in some countries, simple households are able to produce more than enough electricity to cover their energy needs, and to pour the remaining electricity into the public networks[13] . A recent renewable-energy credit program in the United States allows small producers of green energy to sell it back to the grid. The increase in the number and variety of electricity generating sources, together with the deregulation of electricity production, has caused the sector to begin behaving more like a competitive market. Some local governments and utility regulators are allowing consumers choose among a different energy suppliers on the basis of competitive prices and products (war).

Regarding the restructuring of the electricity producing sector in the US, various authors agree that it had a very beneficial effect in reducing production costs and increasing the consumer welfare (Sutherland, 2003, Decisions).

Nevertheless, the restructuring process of the electricity sector has not been completed as it was stopped in various states due to legal obstacles. Figure 1.1.4 shows a map with the latest status of the restructuring process elaborated by the EIA (2003). The colors represent the state of enacting of the restructuring, purple colored states were reported as most active in 2003: these states had either enacted enabling legislation or issued a

[13] For more information on sources of financing, check for example DSIRE (http://www.dsireusa.org/), an incentive based initiative for renewable energy and energy efficiency.

Figure 1.2: Status of the Restructuring of Electricity



(source: EIA, http://www.eia.gov/cneaf/electricity/page/restructuring/restructure_elect.html) regulatory order to implement retail access[14] . States colored in yellow were not actively pursuing restructuring[15] . green colored states pointed at a delay in the restructuring process or the implementation of retail access[16] . California had suspended retail access.

Governments around the world have begun treating the electricity production processes differently from other processes that still behave essentially as natural monopolies and require large amounts of investment, such as companies dedicated to the physical transmission and distribution of electricity, where *one* transmission company can carry the electricity from a few producing plants.

1.2 Influence of Local Regulations and Geographical Factors

In addition to federal regulatory agencies such as EPA, there are a host of *local regulators* referred to as state-run agencies, for example Public Utility Commissions (PUCs).

As mentioned in Section 1.1.3, the SO_2 allowance market intends for the SO_2 abatement costs to be set by market forces and covered by the beneficiaries, thereby optimizing the cost and benefits from jointly producing electricity and environmental pollutants such as SO_2. Actions taken by the PUCs can distort the marginal costs of deploying abatement technologies and using low-sulfur coal, as well as SO_2 allowance prices. Some ways in which PUCs can distort the calculation of marginal costs by firms is given by their capacity to introduce changes on discount rates to be applied to emission abating technologies in the calculation of their production costs, or allowing firms to increase the discount rate they use for depreciating abating technology (Bohi and Burtraw, 1992).

If PUCs allow too much of the abating technology capital and not enough emissions

[14] These states are: Arizona, Connecticut, Delaware, District of Columbia, Illinois, Maine, Maryland, Massachusetts, Michigan, New Hampshire, New Jersey, New York, Ohio, Oregon, Pennsylvania, Rhode Island, Texas, and Virginia.

[15] The reported states were Alabama, Alaska, Colorado, Florida, Georgia, Hawaii, Idaho, Indiana, Iowa, Kansas, Kentucky, Louisiana, Minnesota, Mississippi, Missouri, Nebraska, North Carolina, North Dakota, South Carolina, South Dakota, Tennessee, Utah, Vermont, Washington, West Virginia, Wisconsin, and Wyoming.

[16] Arkansas, Montana, Nevada, New Mexico, and Oklahoma.

allowances to be considered in the rate base, companies will over invest in technology and economic welfare will not be maximized (Coggins and Smith, 1993). Arimura (2002), concludes that regulations by state governments and PUCs can create bias in the decision making process of local concerns when choosing between buying more low sulfur coal, or installing scrubbers. Furthermore, firms located in high sulfur coal producing states tend to buy more high sulfur coal, and *local coal protubsection* measures, most probably set up by PUCs, increased consumption of high sulfur coal in these states up to 50% relative to states that don't need to protect the high sulfur coal sector.

1.2.1 The Coal Market

There are three regions that provide most of the coal that is consumed in the United States.

- Western region and Powder River Basin.
- Interior region (which includes Illinois, Indiana and Kentucky).
- Appalachian region.

The Western region provides almost all of the low sulfur sub-bituminous coal that is consumed in the United States. The sub-bituminous coal from the Powder River Basin (PRB) has a lower sulfur content, but a slightly lower heat content per ton. Mining in this region is done on the surface which eases the extraction of coal and reduces prices at mine-mouth dramatically.

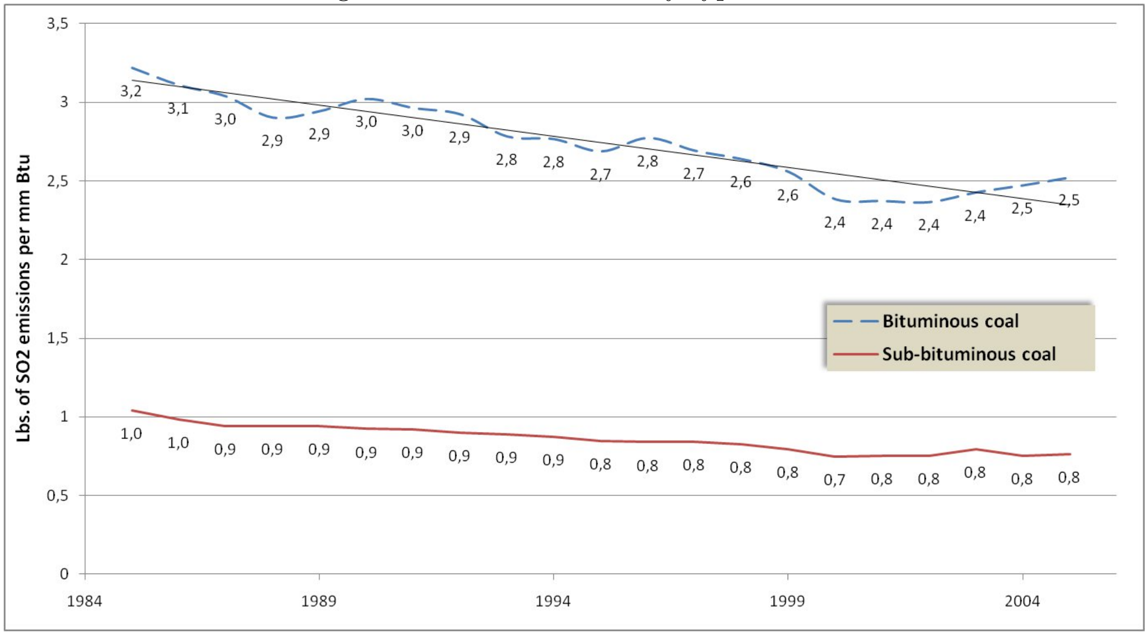
The other two regions produce medium to high volatility, bituminous coal with higher sulfur content. Mining is done underground and is more labor intensive than in the Western region

The CAAA has created an incentive for mines and coal producers to reduce their sulfur content. In Figure 1.2.1 the SO_2 emissions to heat input rate, in pounds of SO_2 per million of BTUs of heat input, is displayed for bituminous and sub-bituminous coal[17] . The

[17] SO_2 emissions were calculated from the content of sulfur in coal, assuming that all reported sulfur from the input coal would be poured into the air in the form of emissions.

data indicates a clear downward trend in the content of sulfur in both, bituminous and sub-bituminous coal, from 1985 to 2005.

Figure 1.3: SO2 emissions by type of coal



(source: form FERC 423)

1.2.2 Railway Transportation Prices

An important component of the cost of coal delivered to electricity producing plants is the cost of transportation from the mine-mouth to the plant site. This item is especially important for the sub-bituminous coal coming from the PRB region and can account for two-thirds of the delivered price of coal in some cases.

In 1970, the largest railroad, Penn Central, declared bankruptcy, and other railroads followed suit. To avoid further bankruptcies of railroad companies and the possible collapse of the industry (Grimm and Winston, 2000), a revision to the regulatory regime for the railroad industry was called for, and the Staggers Act of 1980 was drafted. Railroad companies were given more operating and pricing freedom. The Staggers Act ended the Burlington Northern Santa Fe (BNSF) Railroad's monopoly on transportation of freight going from the PRB region to the east. This opened the railroad services market all the way to the Union Pacific Railroad (UPR), which allowed for transportation prices of low sulfur coal from the PRB region to drop substantially.

Nevertheless, there is evidence that there were some market distortions created by the railroad companies that directly affected SO_2 emission abatement costs. Some authors[18] argue that the market power exercised by the BNSF and UPR railroads meant these companies were able to capture important parts of the *regulatory rents* that followed from the abatement costs imposed by CAAA from Phase I[19] , on detriment of Table A plants[20] .

Technological changes in railroad, and new investments might have had a role in the reduction of SO_2 emissions, and low sulfur prices affected firms decision making significantly (). **?** (**?**) argue that due to the market power of railroad firms, declining of coal mining and transportation costs had a bigger effect on the adoption of low sulfur coal for electricity generation than the CAAA of 1990.

1.2.3 Coal Buying Contracts

There are some references in the technical literature that examine the contractual relationship between coal mines and energy producing firms when relationship-specific costs are saved by means of fixing *ex-ante* a long-term relationship. Joskow (1987, 1988) asserts that in a vertical market relationship between mines and plants, long term contracts are beneficial for both when there exists a cost-minimizing supply relationship, as it is more effective than repeated bargaining, and helps avoiding *opportunistic* behavior.

[18] Winston et al., 2004 go to the extent of modeling the market power that BNSF and UPR acquired as a duopoly.

[19] See Busse and Keohane, 2004

[20] Staggers act spurred a wave of mergers in the early 80s that consolidated the market power of BNSF and UPR

Other good reasons for the existence of coal contracts between mines and plants are:

- Diminishing the consequences of asymmetries and lags of information.
- Cases of risk aversion when considering income effects.
- Improved monitoring of performance.

Contracts pose the risk of bringing in market rigidities that can lower the social benefit of coal buying contracts.

1.2.4 Political Issues and Stakeholders

The historical facts that led to the drafting of the CAA described in Section 1.1.2 are not as straightforward as they might seem[21]. As it happens, after overcoming the first hurdle of having most decision-making and influential parties agree to the need for a general body of environmental regulations and standards, the next step was to establish consensus from the diverse stakeholders to move forward. Basically, the main stakeholders during this decision process were the following:

- Legislators from various states that had different and sometimes conflicting positions regarding performance standards and emission rates to be imposed.
- The constituencies from some states that were more directly affected by the CAA, having for example, larger SO_2 emissions per unit of generated energy. These were the so-called *loser* states that had a bigger burden to reduce SO_2 emissions[22].
- Environmentalist groups that wanted to see sizable reductions of SO_2 emissions.
- Midwestern utilities that could not sustain their businesses if the emission rate standards became too stringent.

[21] For the contents of this part, I draw substantially from Ellerman et al., 2000.

[22] At the time of the discussion of the CAA, the top nine polluting states accounted for 60% of SO_2 emissions and were all located in the Midwest or bordering the Appalachian region

- Owners of mines that produced high sulfur coal, mainly from the Appalachian area.

- Workers from high sulfur coal mines, represented mainly by the United Mine Workers Union[23] .

The political solution to this stalemate was to require all newly built plants to comply with strict emission rate standards, forcing them to install Flue Gas Desulphurization units (scrubbers) and make them less sensitive to the content of sulfur in coal. This way, there would be no special incentives in new generating plants to buy low-sulfur coal instead of high-sulfur coal.

It is evident from the writings associated with the drafting of the CAA, that some interest groups exercised substantial leverage power over local regulations, which affected incentives in the coal market with subsequent implications for the electricity production sector. This is the case especially in high-sulfur coal producing states in the Appalachian region.

On the other hand, some authors state that in 1990 there was a bigger commitment of the bipartisan majorities with a collective vision that eased the way to major decisions in the face of environmental degradation and climate change (**?**). In today's political debate, successful cap-and-trade environmental instruments may fall victims of a deep division of views by both dominant parties, regardless of their successful achievements in the past.

[23] To understand some of the dynamics, an emission rate standard lower than 1.2 lb/mmBtu, proposed by hardliner environmentalists and interest groups was considered by Appalachian coal producers, as well as mine workers that would lose many jobs.

1.3 Relevant Milestones

Table 1.1: Regulatory and Institutional Milestones

Year	**Milestone**	**Comments**
1955	The Air Pollution Control Act	- First federal air pollution legislation - Funded research for the scope and sources of air pollution
1963	Clean Air Act	- Authorized the development of a national program to address air pollution related environmental problems - Authorized research into techniques to minimize air pollution
1967	Air Quality Act	-Authorized enforcement procedures for air pollution problems involving interstate transport of pollutants - Authorized expanded research activities
1970	Clean Air Act	- Authorized the establishment of National Ambient Air Quality Standards - Established requirements for State Implementation Plans to achieve the National Ambient Air Quality Standards - Authorized the establishment of New Source Performance Standards for new and modified stationary sources

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Table 1.1 – Continued

Year	Milestone	Comments
		- Authorized the establishment of National Emission Standards for Hazardous Air Pollutants - Increased enforcement authority - Authorized requirements for control of motor vehicle emissions
	Bankruptcy of Penn Central Transportation Company	Caused profound changes in the railway regulatory system in the U.S. Amtrak was created.
1973	Oil Embargo	The Yom Kippur War pushes the Organization of Arab Petroleum Exporting Countries to declare an oil embargo. First "energy crisis."
1976	Railroad Revitalization and Regulatory Reform Act	Outlined regulatory reforms in the railroad industry and provided transitional operating funds following the 1970 bankruptcy of Penn Central Transportation Company.
1977	Amendments to the Clean Air Act of 1970	- Authorized provisions related to the Prevention of Significant Deterioration - Authorized provisions relating to areas which are non-attainment with respect to the National Ambient Air Quality Standards

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Table 1.1 – Continued

Year	Milestone	Comments
	Department of Energy Organization Act	The Federal Energy Administration and Energy Research and Development Administration are abolished.
	Emergency Natural Gas Act	
1978	National Energy Act Creation of TRAIN	Which included, among others, the Power Plant and Industrial Fuel Use Act TRAIN (Transportation by Rail for Agricultural and Industrial Needs) is an organization formed by a group of major railroads to support further deregulation of the railway industry.
	Public Utility Regulatory Policy Act	Stimulated the development of a non-utility power sector selling electricity produced primarily from cogeneration facilities and renewable energy facilities to local utilities under long-term contracts (Joskow, 1989)
1980	The Staggers Act	It allowed *secret* contracts between carriers and shippers, not limited to large-investment situations and not effectively subject to regulatory review.
1981	Reorganization of DOE	Major reorganization of the Deppartment of Energy, as well as decontrol of crude oil and refined products

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Table 1.1 – Continued

Year	Milestone	Comments
1986	Chernobyl nuclear accident	A Soviet nuclear accident occurs at Chernobyl Reactor #4.
1990	Amendments to the Clean Air Act of 1970	- Authorized a program to control 189 toxic pollutants, including those previously regulated by the National Emission Standards for Hazardous Air Pollutants - Authorized programs for Acid Deposition Control - Established permit program requirements - Expanded and modified provisions concerning the attainment of National Ambient Air Quality Standards - Expanded and modified enforcement authority
	Staggers Rail Act	- Deregulated the American railroad industry - Replaced the regulatory structure that existed since the 1887 Interstate Commerce Act
1991	Gulf war	Operation Desert Storm is launched
1992	UN Framework Convention on Climate Change	An Intergovernmental Negotiating Committee produced the text of the Framework Convention
	Energy Policy Act	- Required alternative fuel vehicle use in some private/government fleets (102nd Congress H.R.776.ENR, abbreviated as EPACT92)

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Table 1.1 – Continued

Year	**Milestone**	**Comments**
		- Removed important barriers to broader unregulated nonutility generating facilities - Expanded the Federal Energy Regulatory Commissions (FERC) authority to order utilities to provide transmission service to support wholesale power transactions.
1993	Regional Clean Air Incentives Market (RECLAIM) Initiated	The RECLAIM was initiated by California's South Coast Air Quality Management District (SCAQMD), and it was the first market-based emissions control instrument in the United States.
1995	Begins Phase I of the Clean Air Act Amendment	Phase I of the SO_2 permit market was scheduled to begin in 1995 with the forced inclusion of nearly 263 older boilers, plus 174 newer boilers that voluntarily entered during Phase I. Boilers included in Phase I were granted permits at the rate of 2.5 pounds per mm Btu of average annual heat input over 1985-87, the *baseline*.

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Table 1.1 – Continued

Year	Milestone	Comments
	I UNFCCC Conference of Parties	Took place in Berlin. It voiced concerns about the adequacy of countries' abilities to meet commitments under the Body for Scientific and Technological Advice (SBSTA) and the Subsidiary Body for Implementation (SBI).
1997	Kyoto Protocol	Established legally binding obligations for developed countries to reduce their greenhouse gas emissions
1999	Deregulation and Restructuring of Electricity Markets	In late 1999 FERC promoted more aggressive restructuring and wholesale regulations, and market institutional change agenda, that ended up in the Regional Transmission Organization (RTO) rule (Order 2000). This was one of a few efforts on the direction of making the electricity producing sector more competitive.
2000	Begins Phase II of Clean Air Act Amendment	Phase II of CAAA was scheduled to begin in 2000, and it granted SO_2 emission permits at a rate of 1.2 pounds per mm Btu over the *baseline*.
2005	Energy Policy Act	Introduced tax incentives for conservation and use of alternative fuels

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Table 1.1 – Continued

Year	**Milestone**	**Comments**
	Clean Air Interstate Rule announced by EPA	Introduction of new imposed cuts on NO_x and SO_2 in more than a decade.
2008	CAIR rules and Federal Implementation Plans become active	Big reductions of SO_2 and NO_2 emissions were achieved. There were some actions taken to court asked to vacate it, but without complete success. *baseline*.

Sources: EPA and EIA

1.4 Conceptual Framework

If the quality of the environment is deemed a public good, pollution is seen as a public *bad* that generates environmental quality degradation, and creates negative externalities to other sectors of the economy and the society. The development of new abating technologies is considered responsible for part in the reduction of marginal costs of abating emissions[24] . Externalities from production processes such as coal-based electricity supplies give rise to market failures that can hinder the development of new pollution control technologies (Bellas, 1998).

As new knowledge has the non-rivalry and non-excludability characteristics of public goods, there are externalities that can negatively impact technology producing firms. Even with an appropriate intellectual property (IP) framework in place, the prospects that follow-on or *invent-around* technologies develop at considerably lower costs, still make R&D investments uneconomic for first round innovators and creators of technology, and therefore deter innovation. For instance, under competitive economy assumptions, and in the absence of environmental policies, firms might opt to lower their production costs at the expense of environmental quality by using cheaper but more polluting production processes[25] . Environment control policies can compel companies to *internalize* part of the environmental cost of production, forcing them to lower emission or increase pollution abatement.

A market based instrument such as a cap-and-trade regulatory system can create sufficient flexibility in the business environment, and enough incentives for firms to pursue strategies that protect the environment, increase innovation, and reduce aggregate costs (Chan et al., 2012).

[24] Carlson et al. [2000] and Burtraw et al. [2005]. Carlson et al. argue that 20% of the reductions of SO_2 emissions during Phase I of the CAAA were due to technology change, while 80% were due to changes in the coal input.

[25] I.e., some firms may act as *environmental free-riders*, by taking advantage of insufficient pollution controls by the government, and by not assuming the social costs created by the externalities of their production activities.

The prices of inputs and outputs, as well as new costs created by environmental regulations are taken as given by the firms[26] , and clearly affect their revenue maximizing decisions. Regarding the adoption of abating technologies, the firm's reaction to new regulations depends on the returns to investment on technology and the requirements of the PUCs regarding definitions around operational costs and investments[27] .

Timely intervention by the government may be required to reduce the social costs of environmental degradation. Pollution controls and regulations put in place by the government are intended to internalize the social costs generated by environmental degradation due to the firm's production activities, that otherwise would constitute costs borne by others outside the firm, and by society. In the electricity generation sector, the U.S. government chose a *cap-and-trade system* as its emission control method.

Based on an initial Internet survey of companies selling emissions-abatement technologies to U.S. electricity producers, it was concluded that the electricity producers outsourced production of new technologies to abate polluting emissions. That is, electricity producing firms either purchased abatement technologies or paid third party firms for developing new pollution abating technologies. Therefore, purchasing and licensing arrangements are an important element in the adoption dynamics of abatement technology use.
Even though the electricity generating sector is regulated by the government, companies that produce technologies can be considered to operate in a competitive market, since they compete with each other to secure clients and increase they market shares.

Nevertheless, in this research, I will initially consider the abatement technology producing sector as a sub-sector of the electricity producing sector.

Environmental control regulations, issued by the government, are intended to correct

[26] These new compliance costs need to be internalized by including them in the production cost functions of the firms.

[27] As an example, if PUCs allow the costs of scrubbers to earn a higher rate of return than what is spent on allowances by the firms, the marginal cost of scrubbers will be smaller than that of of allowances, and there will be an incentive (distortion) to buy technology. Similarly, what consideration PUCs give to expenditures on scrubber technology (expenditure, investment, or to be added to the ratebase, for example), will bias the utility's investment strategy. See Bohi and Burtraw [1992] for a more detailed explanation

environmental externalities. In a perfectly competitive market, firms will maximize their profit functions when generating energy[28] and will react to new environmental control regulations by adopting one of the following strategies[29] .

1. Paying the new costs of emissions and continuing business as usual.
2. Using higher quality inputs (lower sulfur coal) that generate less pollution.
3. Upgrading their processes and equipment to lower emissions. This includes buying new technology to abate emissions, or investing in R&D to improve or create new pollution abating technologies.

[28] Some authors, e.g., Esty and Porter, 1998, mention aspects that could be included here, such as the increased productivity due to the new regulations. Such considerations fall out of the scope of this research.

[29] By competitive market, the following assumptions are made: All firms and the government have perfect information. There is no asymmetry of information between government and firms. *(Unrealistic)*; Rational behavior: Enterprises choose investments with the highest expected returns, among those with the same risk. *(Realistic)*; There are no transaction costs or taxes (Unrealistic); There exists a risk-free interest rate *(Unrealistic)*; All assets are marketable *(Realistic)*; Firms cannot affect prices *(Realistic. Sometimes Unrealistic.)*; Control regulations are taken as given by the firms. *(Realistic)*

Chapter 2

Data Sets

In the previous chapter there was a general historical and legal background that intended to explain some of the behavior of companies when selecting an environmental compliance strategy under the provisions of Table IV of the CAAA of 1990, which created a SO2 allowances market. In this chapter, the data used in the next chapters in an empirical analysis is described.

In this part we present a general discussion of the data sets used in the research. The data relate to the following variables used in the analysis:

- SO2 allowances: permit allocations and their prices.
- FGDs (Scrubbers): efficiency, prices, and quantities.
- Coal: Types, quantities, prices, origin, distances to plant, sulfur content, and purchase type (i.e., if there was a contract or not).

2.1 SO2 Allowance Prices

A monthly data set of SO_2 allowance prices from August, 1994 to August, 2009, was obtained from Cantor Fitzgerald[1] , and are plotted in Figure 2.1.

Figure 2.1: SO2 allowance prices

(Source: Cantor Fitzgerald)

From 1995 until 2004 SO_2 allowance prices were lower than expected and quite stable. Spot prices stayed between US$ 150 and US$ 200 per ton(Lashof, 2009). Two primary factors are held responsible for the low prices of SO_2 allowances(EPA, 2009):

- The decision of many plants to switch to low cost, lower sulfur coal mined in parts of Appalachia, the Illinois Basin, as well as the Powder River Basin in Wyoming.
- The advances in scrubbing technologies and environmental technological innovations, which translated into reduced expected marginal costs of scrubbers[2] .

[1] A historical monthly SO2 spot prices data set was obtained from CantorCO2e LP, subsidiary of Cantor Fitzgerald Environmental Brokerage, for the period January 1995- September 2009.

[2] Ellerman et al., 2000 estimate the reduction in allowance prices due to this reduction by as much as

In this period, a study coordinated by EPA shows that volatility of SO2 allowance prices is very comparable to the volatility of other energy related commodity prices. At the end of 2003 the Clean Air Interstate Rule (CAIR) was proposed. Its proposal of considerable additional SO2 reductions to the electricity generating sector starting 2010, created ripples in the spot market allowance prices, and prices started to climb(EPA, 2009).
But the trend upward of allowance prices is not only the effect of CAIR. There were some market drivers that influenced the price(CCFE, 2004)[3] :

- The increase in prices of low sulfur coal.
- Climatic conditions that caused unexpected behaviors on energy prices. More specifically, Hurricane Katrina struck the Gulf Coast in August and Hurricane Rita struck Texas in September, 2005.
- The increase of the price of natural gas. Being that natural gas is a source of energy for generating electricity with less SO_2 emissions, its 'price upward trend increased the demand for cheaper coal, and therefore for SO_2 allowances to comply with the CAAA. The prices of natural gas can be seen in Figure 2.2.
- State utility regulations that allowed cost recovery for scrubbers resulted in a substantial detriment of the demand for SO_2 allowance.

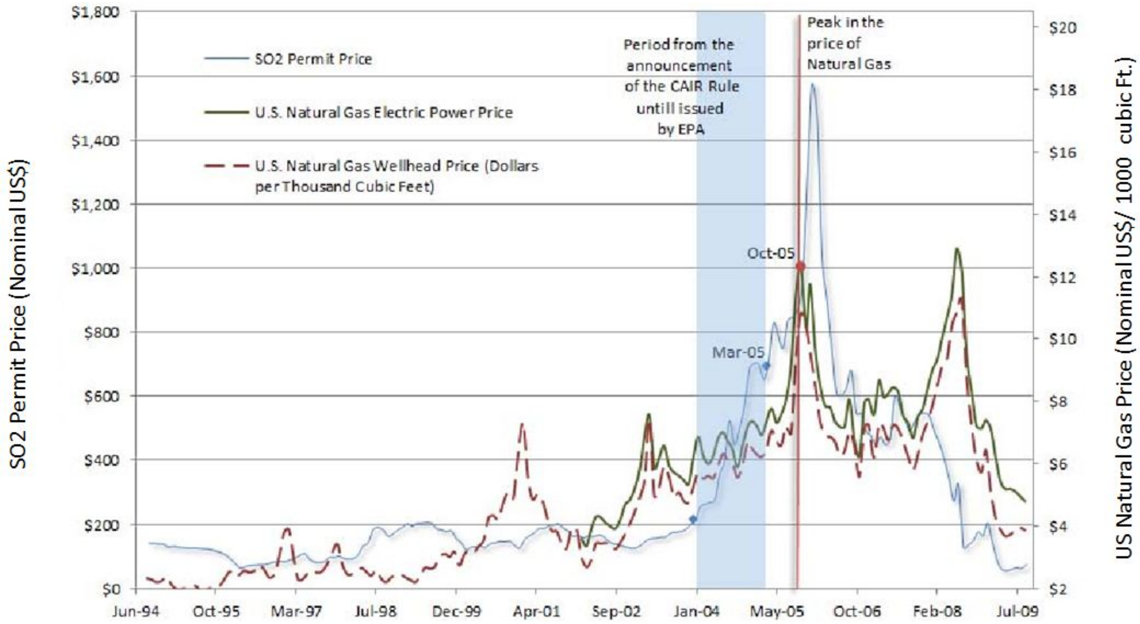
2.2 Coal Data

Information covering coal purchases by nearly 190 utilities that had to report on 569 steam electric generating plants of 50 MW or greater, was obtained from Form No.423 in the FERC survey. FERC form 423 is contained in a data set available online that includes monthly information on the types of fuel purchased, fuel cost, fuel origin, fuel quantity and fuel quality, used by electricity producing plants.

40 percent from original estimates.

[3] For some time series modeling approximations see Appendix D.1

Figure 2.2: SO2 allowance prices and U.S. Natural Gas Prices



(Source: Cantor Fitzgerald)

The Federal Energy Regulatory Commission (FERC) began compiling data on the cost and quality of fossil fuels used by (regulated) power plants with a nameplate capacity of at least 50 MW in July 1972. These data were reported in FERC Form 423 which has been used over the years for different purposes related to the regulatory information required under the Federal Power Act (FPA), and that can affect public utility rates.

After the Energy Policy Act of 1992 (EP Act 1992), which precipitated a gradual movement of electricity generating sector towards a competitive market, many utility plants began selling off their electricity generation assets to unregulated entities. Transactions made by these unregulated entities were not necessarily reported to FERC, and thus a significant amount of fuel receipt data was lost. To help close the widening information gap, beginning in year 2002 the Energy Information Agency (EIA) began collecting information similar to that reported in FERC Form 423. Thus Form EIA-423 was used to report data on the cost and quality of fossil fuels used by the nonutility side of the industry. Form

EIA-423 was modeled after the survey Form FERC 423.

As the electricity generating industry continued to derregulate, FERC retired their Form 423 in 2008 ([EIA, 2005]). Collection of all utility and nonutility fuel receipts data were conducted by EIA, and FERC Form 423 was merged into Schedule 2 of Form EIA 923, which also includes data from former EIA906, EIA920 and EIA767 Forms. EIA compiled the data from FERC Form 423 since 2002, in anticipation of this eventual change in data reporting protocols.

In Table 2.1 the status of the reported advance of the restructuring of the electricity sector, as described in Section 1.1.4, is displayed together with the number of records for each state in the data set used. It can be seen that most states that are actively involved in the restructuring process have very few plants reporting consistently and therefore, the frequency of records of these states is low.

Table 2.1: Restructuring Status of States in Coal Data Set

State	State code	Frequency in data set	Activ/Not active
Arizona	AZ	161	AC
Connecticut	CO	0	AC
District of Columbia	DC	0	AC
Delaware	DE	0	AC
Illinois	IL	249	AC
Maryland	MA	0	AC
Michigan	MI	620	AC
Maine	MI	0	AC
Massachusetts	MS	0	AC
New Hampshire	NH	41	AC
New Jersey	NJ	43	AC

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Table 2.1 – continued from previous page

New York	NY	140	AC
Ohio	OH	557	AC
Oregon	OR	0	AC
Pennsylvania	PA	309	AC
Rhode Island	RI	0	AC
Texas	TX	235	AC
Virginia1	VA	262	AC
Alabama	AL	226	NA
Alaska	AR	93	NA
Colorado	CO	381	NA
Florida	FL	338	NA
Georgia	GA	291	NA
Hawaii	HA	0	NA
Idaho	IA	342	NA
Indiana	IN	729	NA
Iowa	IO	0	NA
Kansas	KS	187	NA
Kentucky	KY	672	NA
Louisiana	LA	48	NA
Minnesota	MN	232	NA
Missouri	MO	508	NA
Mississippi	MS	108	NA
North Carolina	NC	440	NA
North Dakota	ND	0	NA
Nebraska	NE	221	NA

Continued on next page

Table 2.1 – continued from previous page

South Carolina	SC	408	NA
South Dakota	SD	0	NA
Tennessee	TN	167	NA
Utah	UT	158	NA
Vermont	VE	0	NA
Washington	WA	36	NA
Wisconsin	WI	259	NA
West Virginia	WV	473	NA
Wyoming	WY	144	NA
California	CA	0	NA
Montana	MT	21	NA
New Mexico	NM	79	NA
Nevada	NV	90	NA
Oklahoma	OK	174	NA

(Source: EIA and author's data set)

The FERC 423 survey has changed a little over time, but the following information can be obtained on a continuous, monthly basis from 1972 until 2009:

- Date: Year, month of coal purchases
- Coal mine
  - Location[4]
  - Type of mine
- Coal transactions

[4] From this variable, the distance between mines and plants is calculated

  - Coal price
  - Type of contract. Collapsed into to two categories
    * No contract, therefore, coal spot market prices apply
    * With contract
  - Expiration date of contract
- Coal quality
  - Sulfur content (as percent of weight)
  - Ash content
  - Heat content (million of Btus per short ton)

Statistical information of the contents of sulfur and cost of coal is given in Tables 2.2, and 2.3. A summary of the data compiled, stratified by different types of energy sources, can be seen in Appendix D.2, Table D.1. Coal data are described under category 1 of general fuels, and as as Table D.2 reveals, data on Sub-bituminous and Bituminous coal are by far the most abundant.

In Table 2.2, the content of sulfur as percentage of the total weight, is shown for four different types of coal. It can be seen in the bituminous and sub-bituminous coal the general downwards trend in content of sulfur through time. Table 2.3 displays the purchased quantity for the four types of coal. In this table, it is evident that in the 70s bituminous coal was extensively used by electricity generating plants. This tendency, however, changed over time due among others, due to the new environmental regulations, and the opening of new inexpensive sources of low sulfur coal. As the Powder River Basin, Wyoming, started providing substantial amounts of inexpensive sub-bituminous coal, which corresponds to the low sulfur coal available in the coal market, the prices of sub-bituminous coal dropped making it available for electricity production. Appalachian coal corresponds mostly to the bituminous type, and contains higher proportions of sulfur.

As shown in Table 2.3, in the year 2009 almost 90% of the coal purchased by plants was either bituminous or sub-bituminous coal. It is evident from Table 2.3 that the demand for bituminous and sub-bituminous coal, apart from being significant, is relatively stable in time. This is not the case for the other types of coal, from which only Lignite coal has some significant demand, but it is small and only for a short period of time. For this reason, in this research only data related to bituminous and sub-bituminous coal will be analyzed.

Table 2.2: Statistical values of % contents of sulfur for different types of coal

Period	Antracite	Bituminous	Lignite	Sub-bituminous
1972-1979	0.64625	1.975	0.6425	0.62875
1980-1989	0.624	1.69	0.808	0.474
1990-1999	0.625	1.57	0.961	0.376
2000-2007	0.64	1.35	0.89625	0.33375

Source: form FERC 423.

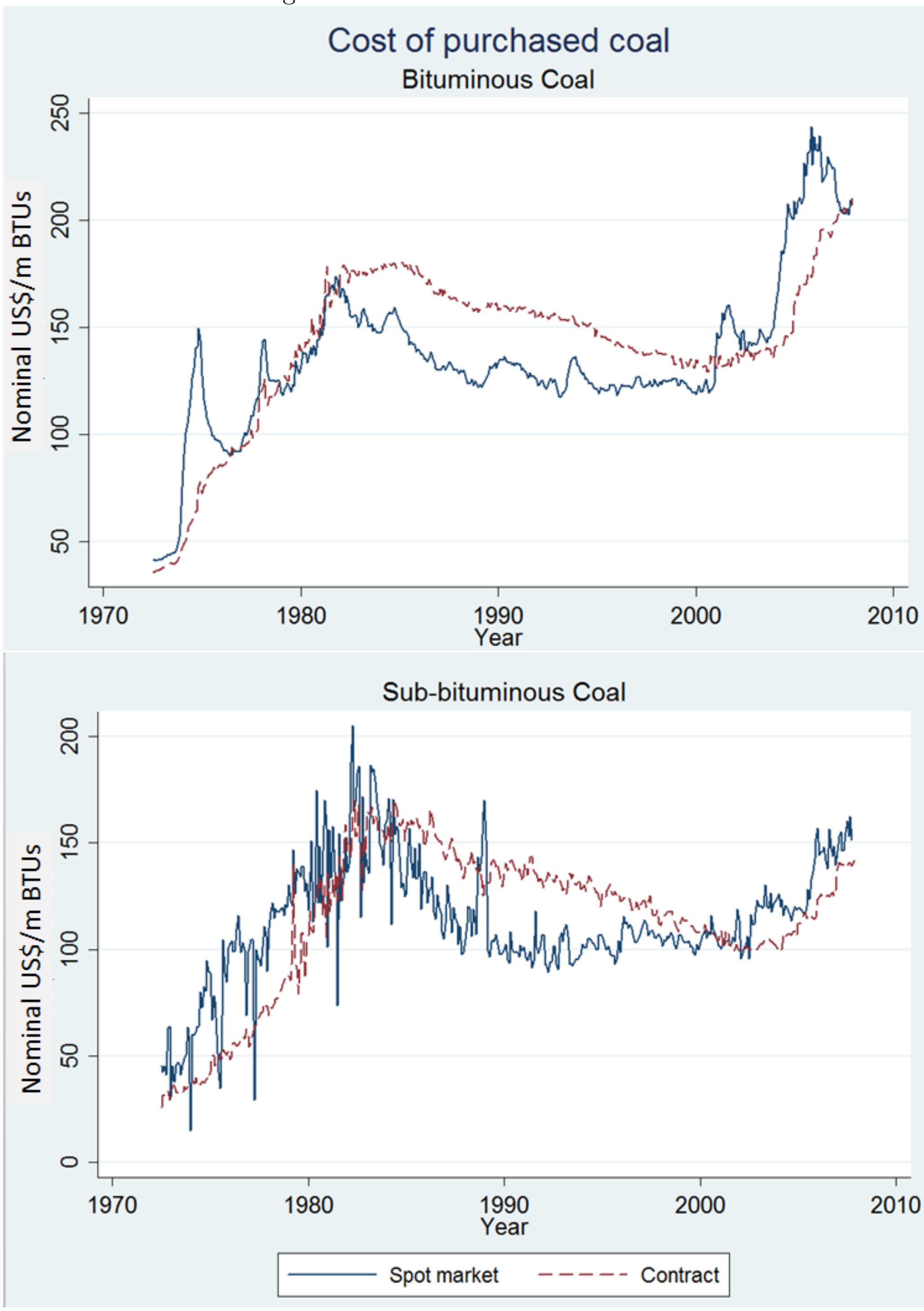
Table 2.3: Quantities of purchased coal in millions of tons

Period	Antracite	Bituminous	Lignite	Sub-bituminous
1972-1979	1.0075	300.33125	16.54125	54.86125
1980-1989	0.5375	306.36375	43.25375	143.90875
1990-1999	0.675	451.86125	78.345	282.09125
2000-2009	0.01	341.6825	42.7625	356.9675

Source: form FERC 423.

The behavior of coal prices can be seen in Figure 2.3. Figure 2.4 shows the content of SO_2 over time. In Figure 2.3 the behavior of Bituminous and Sub-bituminous coal prices are plotted against time . Data on coal prices paid at plant level were taken from FERC Form 423 that includes information on the types of fuel purchased, fuel cost, origin, quantity, and quality for the years 1985 to 2005.

Figure 2.3: Evolution of Coal Prices



(Source: form FERC 423)

2.3 SO2 Emissions

Rates of SO_2 emissions for 251 plants operated by 125 firms were obtained from data reported in FERC Form No. 423, "Monthly Report of Cost and Quality of Fuels for Electric Plants" for the period between July 1972 and December 2005. This form provides information about the content of sulfur in coal purchased by electricity producing plants expressed as a percentage of the coal purchaed[5] . Using form FERC 423 reports I assembled 903,020 fuel buying transactions from which 618,398 records were for bituminous coal purchases, and 66,043 records pertained to sub-bituminous coal purchases (EIA, 2005).

The amount of SO_2 emissions were computed from sulfur content by multiplying the total weight of *sulfur* contained in the coal by a factor of two[6] . The contents of sulfur in purchased coal can be seen in Figure 2.4 The coal upgrading processes or coal "washing" does not affect the results, i.e. is transparent in this data set, as the data used contains the reported contents of sulfur at the plant level, regardless of wether there was a cleaning process before or not.

2.4 Factors Affecting Behavior of Coal Prices

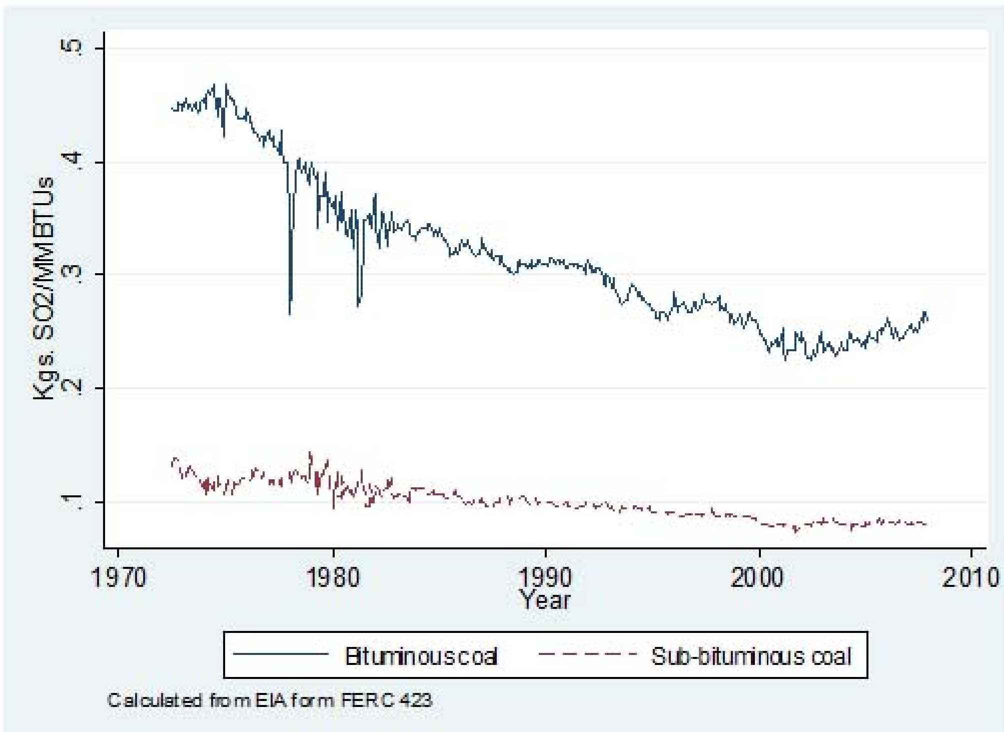
Some of the factors affecting coal prices are:

- *Transportation costs.* Even though transport costs have been falling yearly in recent years, they are still high compared with the mined price of coal. In some cases, the expenses of transporting the coal exceed its cost. Low-sulfur coal from Wyoming is delivered to Chicago and Alabama at prices that range between \$12 to \$14 per short ton. In 2008, due to an increase of diesel prices, there was a sudden spike

[5] For a more detailed description of form FERC 423, refer to the section on coal data, Section 2.2.

[6] Note that by doing this, we are assuming that all the *sulfur (S)* is transformed into $sulfur\,dioxide\,(SO_2)$ when the coal is burned for producing electricity, and since the molecular weight of SO_2 is double that of *sulfur*, a scaling factor of 2 is used, even though Coggins and Swinton (1994) suggest 1.7.

Figure 2.4: Calculated emissions of SO2 from Bituminous and Sub-bituminous coal

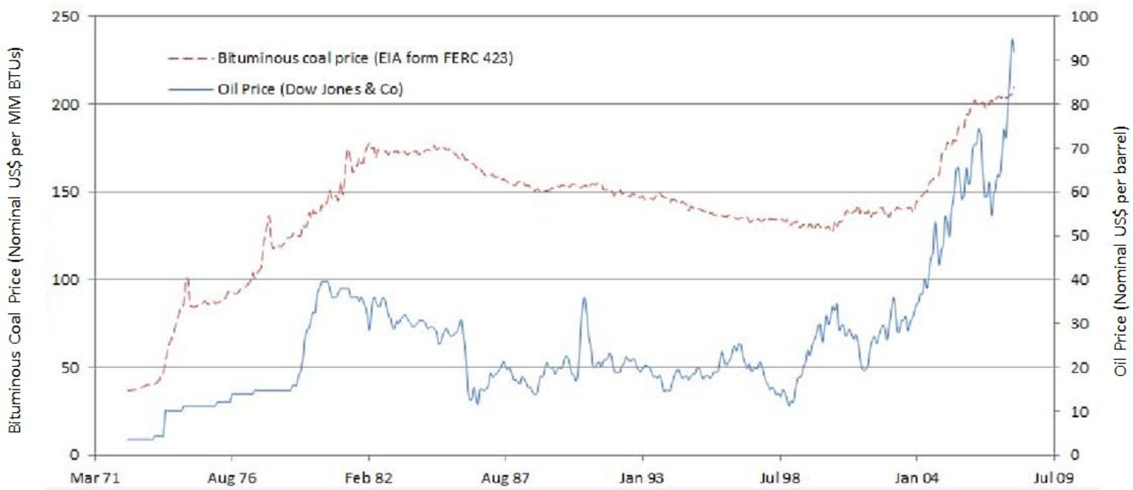


(Source: EIA)

in transportation costs that had a direct bearing on the price of coal delivered to electricity producing plants.

- *Oil prices.* It can be seen in Figure 2.5 that the increase in price of Appalachian coal peaked in 2008 at the same time oil prices peaked and just before the financial crisis of 2008. Therefore, looking at this figure, we could infer that oil prices seem to explain part of the difference between western and Appalachian coal prices.

Figure 2.5: Historical oil and coal prices



(Sources: EPA and form FERC 423)

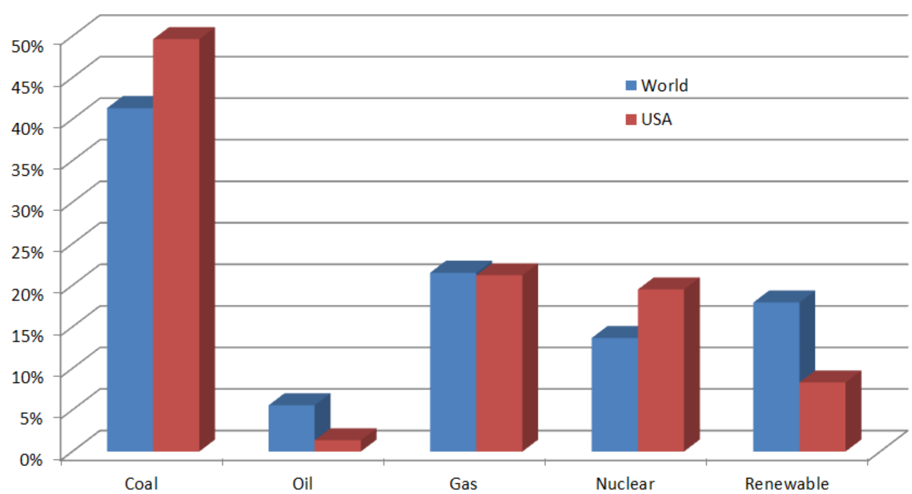
Even though in the United States, the electricity generated by burning oil is very small, at a world level, the consumption of oil for this purpose is substantial. In the following table the total energy consumption by region and by type of fuel is presented for different regions of the world. It can be seen in the present values and future projections, that the *liquids* category accounts for more than 30 percent of the fuel consumption used to generate electricity(EIA, Energy Outlook, 2011).

Region	History			Projections			
	2006	2007	2008	2015	2020	2025	2030
Total World							
Liquids	171.7	172.7	173.0	187.2	195.8	207.0	216.6
Natural gas	107.5	110.9	114.3	127.3	138.0	149.4	162.3
Coal	127.2	133.3	139.0	157.3	164.6	179.7	194.7
Nuclear	27.8	27.1	27.2	33.2	38.9	43.7	47.4
Other	47.1	48.5	51.3	68.5	82.2	91.7	100.6
Total	**481.3**	**492.6**	**504.7**	**573.5**	**619.5**	**671.5**	**721.5**

(Source: EIA)

The different fuel sources at worls level and in the United States are displayed in Figure 2.6. It can be seen that oil plays an important role in the international electricity generation, while in the U.S. it is very small.

Figure 2.6: Electricity Generated by Fuel Source



(Source: EIA)

- *Legal and political issues and State effects.* The Powder River Basin produces coal from surface mines, whereas in eastern states, coal mines are more likely to be underground and businesses require more labor intensive and sophisticated mining techniques which adds to the cost of coal from mine sources. A corollary is that the Appalachian region is likely to be more influenced by trade unions and other institutions that seek to source coal consumption from local mines. There are incentive programs in some of these states seeking to achieve this outcome. On the other hand, each state pursues their own energy strategy. There are special cases such as Texas, where there is significant production of lignite coal.

- *Design limitations.* Some electricity generating plants have difficulty in processing different types of coal because of their original design features. This is particularly evident for some plants seeking to switch from bituminous Appalachian coal, with high heat content, to softer Sub-bituminous coal with less heat content. Physical and infrastructure modifications are necessary for handling different types of coal, and boilers need to be modified so that they may burn coal that varies from their original specifications. Some plants, however, have the capacity to blend different types of coal.

- *Contract relationships.* A high percentage of the coal delivered to electricity plants is subject to contracts between the coal mines and the plants. Some of these contracts are long-term, upwards of 20 to 30 years in duration. The price of coal will vary in different ways under this regime, creating an alternative type of market. Contract prices are different from spot market prices in most cases as displayed in Figure 2.3.

- *External shocks.* There are many factors from other markets that affect U.S. coal markets. For example, internal U.S. coal prices have risen in the wake of increased exports from the United States to other countries, mainly in Asia and Europe.

- *Changes in coal mining costs.* Increased coal mining activity of Wyoming's Powder Basin River has meant that mining companies have been able to lower mining prices, as it is less costly to extract coal from surface mines than it is to extract it from underground mines. In surface mines, heavy machinery and intensive extraction techniques can be used.

2.5 Emission Abating Technology Data

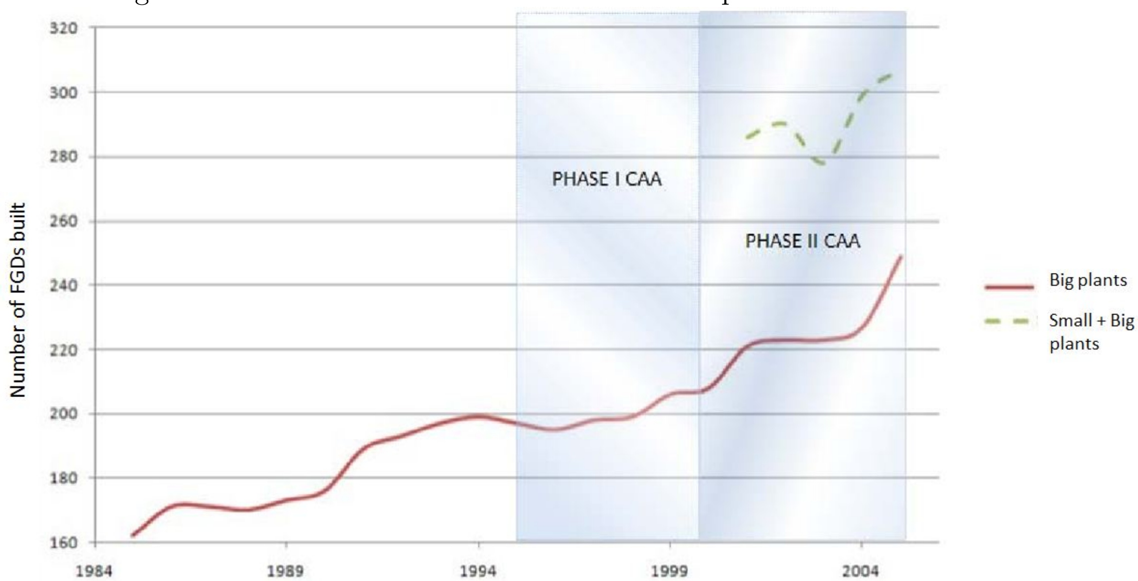
Information regarding the use of Flue Gas Desulfurization units (i.e., *Scrubbers* or FGDs) was obtained from Form EIA 767. This form contains data on coal-based electricity generating plants with a generator nameplate rating of 100 megawatts or more through 2000, and 10 megawatts or more thereafter. Figure 2.7 displays the number of FGDs reported per year between the years 1985 and 2005. The anticipation by firms of the restriction of SO_2 emissions from Phase I of CAAA can be seen as a slight increase in the implementation of FGDs before 1995, and a plateau after it. Phase II has a similar effect on the behavior of firms. The dashed line that starts in 2000 corresponds to smaller plants that started filling form EIA 767 from that year.

The information provided in form EIA 767 is aggregated at boiler level. The latest version of Form EIA 767 included more than 220 data fields distributed across 10 schedules. From these, the following parts contain information of relevance for this study:

- Schedule 7: Flue Gas Particulate Collector Information,
- Schedule 8. Flue Gas Desulfurization Unit Information,
  - Part A. Annual Operations
  - Part B. Design Parameters

Survey EIA 767 includes information on the following types of FGD units: Jet Bubbling Reactor (BR); Circulating Dry Scrubber (CD); Mechanically Aided Type (MA); Packed Type (PA); Spray Dryer Type (SD); Spray Type (SP); Tray Type (TR); and Venturi Type (VE).

Figure 2.7: Evolution of the number of FGDs reported in Form EIA 767



(Source: Form EIA 767, EIA)

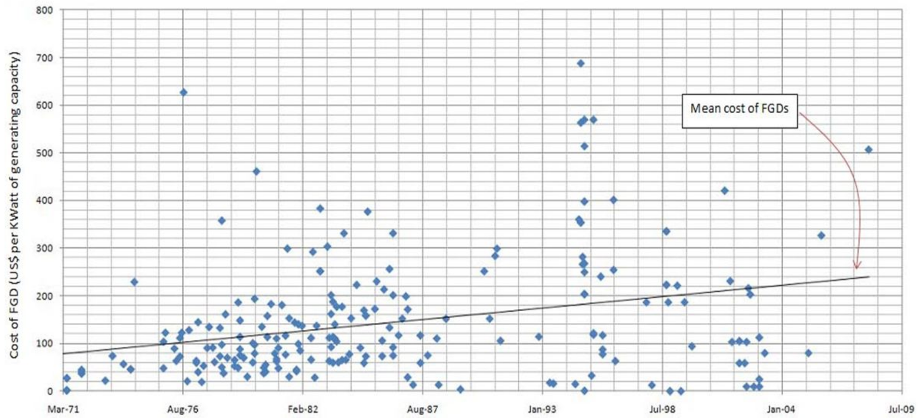
The information included in Form EIA-767 for the years 1996 and beyond is available at EIAs web site[7] . The Energy Information Administration (EIA) ceased collecting information on Form EIA-767 in 2005. Beginning in 2007, most of the data collected by survey EIA-767 was included in Form EIA-860 and Form EIA-923.

Information on 618 installed scrubbers was extracted from Form EIA 767. Figure 2.8 plots the cost in US$ per KWatt for installing the FGDs for each of the reported plants for different years. The continuous line represent the mean of FGD prices over time. As can be seen, FGD prices increase in time. Also, it is evident from the Figure that there are big price variations even during the same periods of time. Aggregated values of costs of FGD units used in this study, were obtained from the Electric Power Annual Reports

[7] The data sets can be downloaded from: http://www.eia.gov/cneaf/electricity/page/eia767/. Data sets for years 1985 to 1995 were reportedly taken out of the web site due to errors in the data set. This information was obtained upon request to the person in charge of the data set.

from EIA[8] .

Figure 2.8: Cost of FGD units reported in Form EIA 767, (US$ per KWatt of capacity)



(Source: Form EIA 767)

Table 2.4 describes the number of scrubbers reported each year in the data set used in this research.

2.6 States and Regions Used in the Research

The U.S. Census Bureau designates a number of statistical regions that do not respond to any historical, or cultural relationship. These regions were used for the purpose of this analysis as they comprise states that have geographical similarities. Table 2.5 provides a listing of states grouped by regions. Figure 2.9 provides a mapped representation of this grouping.

Table 2.5: U.S. Census Bureau Regions

Macro-region	Region Number	Region/Division	States included

[8] Information was extracted from years 1994, 1996 and 2000

Northeast	R1	New England	CT, ME, MA, RI, VT
	R2	Middle Atlantic	NJ, NY, PA
Midwest	R3	East North Central	IL, IN, MI, OH, WI
	R4	West North Central	IA, KS, MN, MO, NE, ND, SD
South	R5	South Atlantic	DC, DE, FL, GA, MD, NC, SC, VA, WV
	R6	East South Central	AL, KY, MS, TN
	R7	West South Central	AR, LA, OK, TX
West	R8	Mountain	AZ, CO, ID, MT, NV, NM, UT, WY
	R9	Pacific	AK, CA, HI, OR, WA

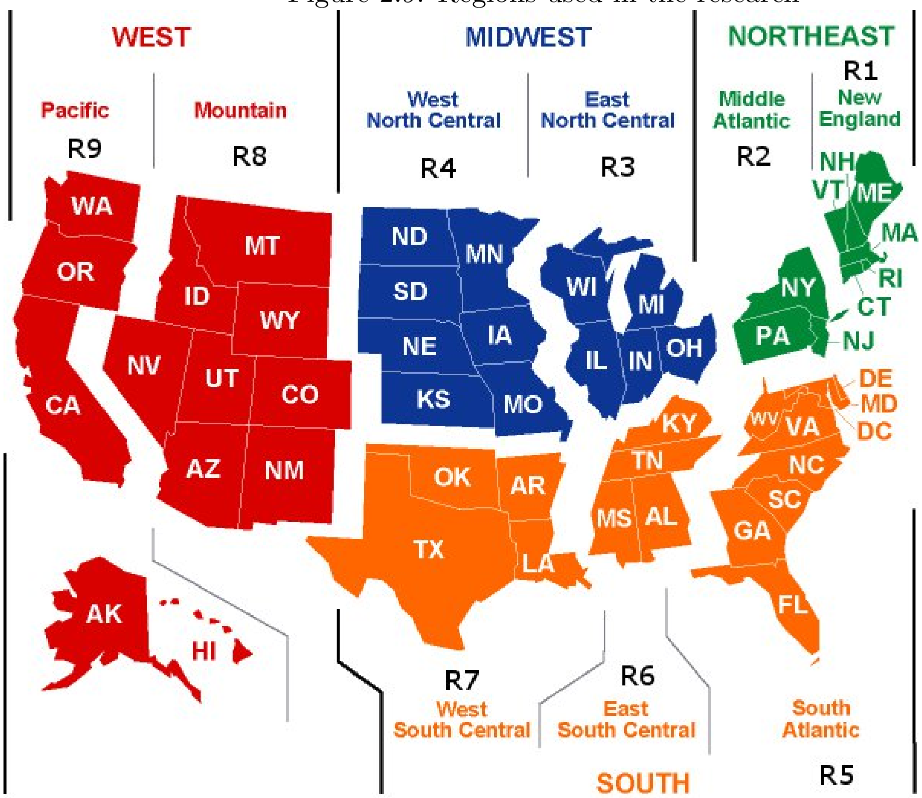
(Source: U.S. Census Bureau)

The reported state specific consumption of coal for electricity generating purposes for the years 1985 to 2005 is detailed in Appendix D, Tables D.3, D.4, and D.1. This tabulation reveals that in some states (for example Alabama, Illinois, Louisiana) there is an abrupt change in the reported consumption of coal between 2000 and 2005[9] . At least some of this abrupt change in coal consumption may well be ascribed to the deregulation of the electricity producing sector that began in 2001 and to Phase II of the CAAA. As the derregulation process unfolded, different states pursued different energy policies, and in some instances opted not to comply with the previously established (national) coal consumption standards. This led to inconsistencies in the data from Form FERC 423.

For this reason, only 27 states were selected for inclusion in this research, including: Alabama (AL), Arizona (AZ), Arkansas (AR), Colorado (CO), Florida (FL), Georgia (GA),

[9] States where changes in reported consumption changes are sharp are underlined. Robert Schnapp from EIA was very helpful in clarifying this and other issues that helped me to understand form FERC-423 and the dynamics of coal prices.

Figure 2.9: Regions used in the research



(Source: U.S. Census Bureau)

Table 2.4: Number of FGDs Operating per Year

Plant Region	**Year**				
	1985	**1990**	**1995**	**2000**	**2005**
New England	-	-	-	-	-
Middle Atlantic	11	12	17	18	12
East North Central	22	28	36	42	41
West North Central	19	19	20	21	13
South Atlantic	11	12	21	21	25
East South Central	15	23	27	29	27
West South Central	1	7	7	8	5
Mountain	21	28	34	43	39
Pacific	-	-	-	-	1

Source: EIA form 767. Numbers correspond to data set used in the research

Iowa (IA), Indiana (IN), Kansas (KS), Kentucky (KY), Michigan (MI), Minnesota (MN), Missouri (MO), Mississippi (MS), North Carolina (NC), North Dakota (ND), Maine (ME), Nevada (NV), Ohio (OH), Oklahoma (OK), South Carolina (SC), Tennessee (TN), Utah (UT), Virginia (VA), Wisconsin (WI), West Virginia (WV), and Wyoming (WY).

Chapter 3

Some Factors Affecting the Adoption of Technology

As discussed in Chapter 1, there are a number of external factors, such as variation in prices of natural gas and transportation costs that influence coal prices, that might distort the SO_2 allowance market. Namely, any changes affecting the coal market or the transportation industry will influence the prices of coal at the plant level, and by implication the SO_2 allowance prices. The strategic behavior of electricity producing companies is shaped by other aspects that can't be explained by profit maximization behavior. In this section we present some findings on certain conditions that can affect the decision process of choosing the means of abating emissions by firms.

3.1 Relationship Among Coal Prices and Number of Contracts

The existence of purchase contracts between coal mining companies and energy generating plants may change the structure of coal prices paid by electricity generating with direct consequences for the strategies firms might deploy in the force of costly SO_2 emission permits. To assess the relationship between the coal price (for different types of coal) and the number of transactions (FREQ), the following empirical relationship was structured:

$$\begin{Bmatrix} FREQ_t \\ CSub_t \\ CBit_t \end{Bmatrix} = \begin{Bmatrix} a_1 \\ a_2 \\ a_3 \end{Bmatrix} + \begin{bmatrix} b_{1t-1} & \dots & b_{1t-\tau} \\ b_{2t-1} & \dots & b_{2t-\tau} \\ b_{3t-1} & \dots & b_{3t-\tau} \end{bmatrix} \times \begin{bmatrix} FREQ_{t-1} & \dots & FREQ_{t-\tau} \\ CSub_{t-1} & \dots & CSub_{t-\tau} \\ CBit_{t-1} & \dots & CBit_{t-\tau} \end{bmatrix} + \begin{Bmatrix} \varepsilon_{1t} \\ \varepsilon_{2t} \\ \varepsilon_{3t} \end{Bmatrix} \tag{3.1}$$

The vriable $FREQ$ denotes the number of transactions of each type of coal in time, $CSub_t$ is the price paid for the *sub-bituminous* coal in year t ($t = 1, t-1, \dots t-\tau$), $CBit_t$ for the *bituminous* coal in year t ($t = 1, t-1, \dots t-\tau$), and $CMean_t$ is the mean cost of coal for period t, calculated as the average price paid for *bituminous* and *sub-bituminous* coal in all transactions[1] .

A Vector Autorregresive (VAR) expression of the frequency $FREQ$, expressed as a function of its own lags, and of prices of coal of Equation (3.1), can be expressed as follows[2] .

$$\begin{aligned} FREQ_t \quad = \quad & A_0 + \sum_i^{lags} A_i \cdot FREQ_{t-i} + \sum_i^{lags} A_{1i} \cdot CMean_{t-i} + \sum_i^{lags} A_{2i} \cdot CSub_{t-i} \\ & + \sum_i^{lags} A_{3i} \cdot CBit_{t-i} + \varepsilon_t \end{aligned} \tag{3.2}$$

Coal prices are calculated for each year[3] and over all the 249 electricity generating plants included in the research.

Figure 3.1 plots the number of contracts and coal prices for different types of coal stratified into: (1) contractual, and (0) spot market transactions[4] . In the year 2000 a

[1] Working in Stata for example, the command used to obtain this value is: `egen cmean = rowmean(costsub costbit)`.

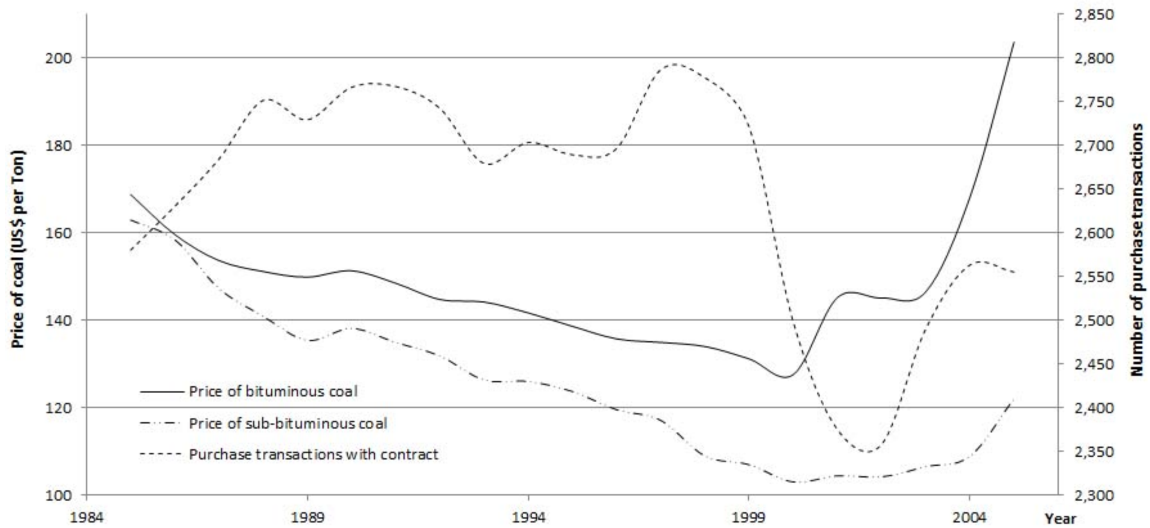
[2] Vector Autoregressive systems (VAR) are widely used in *time series* analysis as an alternative approach to simultaneous equations systems, for a weakly stationary processes. In this case, all included variables are assumed to be jointly endogenous. See Enders, 2004.

[3] The coal price data are reported in FERC Form-423 on a monthly basis, Equation (3.2) will be calculated using years as the time unit. Therefore, the mean $\mu = E(CT_{tj})$ is computed for every year by averaging across all monthly values of prices in all plants.

[4] The dummy variable describing the existence of coal purchasing contracts was defined correspondingly

marked change in the behavior of coal prices and the frequency of contracts can be seen. The main cause for this difference is, most probably the changes in the market structure due to phase II of the CAAA, and the deregulation of the electricity producing sector that began around the year 2000. The aggregated yearly prices of coal are displayed in Table D.4.

Figure 3.1: Purchase transactions with contracts (FREQC), and bituminous and sub-bituminous coal prices



(Source: Form FERC 423)

To summarize both cases (transactions done under coal contracts, and transactions done in the spot market) in one variable in our analysis, we used the prime spread paid for the contract coal over the spot market, represented by the ratio of contract prices to spot

as 0 when the coal was bought at the spot market, and 1 for the case where transactions were done under contract.

market coal prices, instead of coal prices per se.[5]

$$\frac{Price\,Purchase\,Under\,Contract}{Price\,Spot\,Market}$$

The prime spread paid for contract coal over the spot market for bituminous coal is:

$$RCBit = \frac{Price\,Bituminous\,Coal\,Under\,Contract}{Price\,Bituminous\,Coal\,at\,Spot\,Market}$$

and for sub-bituminous coal:

$$RCSub = \frac{Price\,Sub\,bituminous\,Coal\,Under\,Contract}{Price\,Sub\,bituminous\,Coal\,at\,Spot\,Market}$$

To account for the effect of an evident structural change in the market, an *exogenous* dummy variable is introduced in Equation (3.2)[6] .

$$\begin{aligned} FREQ_t \quad = \quad & A_0 + \sum_i^{lags} A_i \cdot FREQ_{t-i} + \sum_i^{lags} A_{1i} \cdot RCMean_{t-i} + \sum_i^{lags} A_{2i} \cdot RCSub_{t-i} \\ & + \sum_i^{lags} A_{3i} \cdot RCBit_{t-i} + \sum_{j=1999}^{2001} B_j \cdot DYr_j + +\varepsilon_t \end{aligned} \tag{3.3}$$

Notice that even though the change in the electricity market structure occurred in 2000, we will consider the general possibility of the adjacent years (1999 to 2002) also affecting the frequency of contracts. In the empirical section below it is shown that 2000 is the year where a structural change occurs in the model.

[5] Notably, the VAR algorithm converged more rapidly using the ratios of prices rather than the prices of coal, and shorter lags were required to achieve similarly statistical significance. The resulting estimations lead to similar conclusions in both cases.

Other than this, and considering the possibility that the underlying process can be represented as a ARCH-type of time series, I tried predicting the number of contracts, $FREQ$, in terms of the *standard deviation* of coal prices, testing the following equation

$$FREQ_t = \alpha_0 + \sum_i^{lags} \alpha_{1i} \cdot \sigma(CMean)_{t-i} + \sum_i^{lags} \alpha_{2i} \cdot \sigma(CSub)_{t-i} + \sum_i^{lags} \alpha_{3i} \cdot \sigma(CBit)_{t-i} + \varepsilon_t$$

where $\sigma(CC)_t$ is the *standard deviation* of the mean cost of coal (The standard deviation is computed using $\sigma(CT)_{tj} = \sqrt{\sum E(\mu - \hat{CT}_{tj})}$.) for period t, $\sigma(CSub)_t$ for the *sub-bituminous* coal, and $\sigma(CBit)_t$ for the *bituminous* coal.

[6] In the Vector Autoregressive systems (VAR) approach an *exogenous* variable is then an independent variable that has some explanatory power. For a more detailed explanation, see Enders, 2004, Hamilton, 1994, or Kirchgaessner and Wolters, 2007, among others.

3.1.1 Empirical Results

To check for the effect that the existence of contracts can have on coal prices, the number of transactions done under contracts was related to spot market prices of coal. The following equation[7] :

$$FREQ_t = A_0 + B \cdot DY_{2000} + \sum_i^{lags} A_i \cdot FREQ_{t-i} + CoPr + \varepsilon_t \qquad (3.4)$$

was tested for $lags = (1, 2, 3)$, and where the following 2 equal versions of the term $CoPr$ were used:

$$CoPr = \begin{cases} \sum_i^{lags} (A_{1i} \cdot RCMean_{t-i} + A_{2i} \cdot RCSub_{t-i}) & 3.4(1) \\ \sum_i^{lags} (A_{2i} \cdot RCSub_{t-i} + A_{3i} \cdot RCBit_{t-i}) & 3.4(2) \end{cases}$$

Note that after the ireation, $RCMean$ in Eq. 3.4(1) is substituted by $RCBit$ in Eq. 3.4(2). They are similar in essence as in $RCMean$ Eq. 3.4(1) includes the effect of $RCBit$.

Table 3.1 shows the estimation results for Equation 3.4. Only the part of the VAR equation that describes $FREQ$ is presented (i.e., the first row of Equation (3.1)).

In choosing the number of significant lags on each case, the Akaike-Schwarz information criterium (Schwarz, 1978), in combination with the Log Likelihood ratio, were used as decision criteria. In the following table different statistical parameters are compared for the models of Equation (3.4).

In Table 3.1, LL indicates the Log Likelihood ratio; FPE is the final prediction error calculated from the estimation; AIC the Akaike-Schwarz information criterium; $RMSE$ is the root mean squared error for the equation explaining the FREQ variable; $R2$ is R-squared; $CHI2$ is the chi-squared test. Equation (3.4)(1) and Equation (3.4)(2) present relatively low values of the RMSE and LL parameters, which indicate a better fit.

The significant elements of Equation (3.4)(1) and Equation (3.4)(2) are shown in the

[7] Note that year 2000 is taken as the year that triggers the dummy variable for collecting the change of regime and re-structuring of the electricity sector is taken as 2000.

Table 3.1: Results for the FREQ - Coal price models

FREQ			
Var		**Eq 3.4(1)**	**Eq 3.4(2)**
FREQ	L1.	.38⋆	.36⋆
	L2.	-.22	-.27
	L3.	-.046	.081
RCSub	L1.	-31	-33
	L2.	-38⋆	-40⋆
	L3.	3.9	-6.3
RCBit	L1.		24
	L2.		63‡
	L3.		-2.6
RCMean	L1.	24	
	L2.	70‡	
	L3.	-18	
DR2000		-9.6‡	-11‡
Const		201‡	195‡
Tests	LL	63	62
	FPE	1.4e-05	1.5e-05
	AIC	-59	-58
	RMSE	2.4	2.4
	R2	.97	.97
	CHI2	617	627

legend: $\star: p < 0.05$; †, : $p < 0.01$; ‡, : $p < 0.001$

following expressions, standard errors are closed in parenthesis.

$$
\begin{array}{llll}
FREQ_t = & & & \\
200.8 - 9.61\,DR2000 + & .38\,FREQ_{t-1} - & 37.56\,RCSub_{t-2} + & 23.84\,RCMean_{t-2} \\
(37.16) \quad (2.14) & (.17) & (17.48) & (13.99) \\
+69.79\,RCMEAN_{t-2} + & \varepsilon_t & & \\
(17.63) & & &
\end{array}
\tag{2}
$$

$$
\begin{array}{llll}
FREQ_t = & & & \\
194.93 - 11.35\,DR2000 + & 0.36\,FREQ_{t-1} - & 40.13\,RCSub_{t-2} + & 23.88\,RCBit_{t-1} \\
(31.23) \quad (2.21) & (0.17) & (15.69) & (12.65) \\
+62.72\,RCBit_{t-2} + & \varepsilon_t & & \\
(14.01) & & &
\end{array}
\tag{4}
$$

The estimated parameters in both cases are of similar magnitude and illustrate the close relationship that exists between ratios of sub-bituminous coal and the number of transactions made under coal contracts. Notice that the main difference between Equation (3.4)(1) and Equation (3.4)(2), is that in the second one, $RCMean$ is used instead of $RCBit$ to estimate $FREQ$. This corroborates what is shown in Figure 3.2: that the behavior of $RCMean$ and $RCBit$ are similar.

There is a positive correspondence between the frequency of contracts and its first lagged value. This *sticky* behavior of firms reflects a tendency to maintain a similar contractual strategy for two consecutive years[8] . The ratio of contract price to spot price of sub-bituminous coal for contemporary and three previous periods has a negative effect on the actual number of contracts, which translates into the fact that if the prime[9] for coal bought under contract increases, the number of contracts decrease. This behavior, illustrated in

[8] According to Joskow (1988), coal purchasing contracts used to be normally agreed for long periods of time, and 20 years was common. This number has gone down in recent years, but it is still considerably long.

[9] As mentioned before, the prime is the amount in excess that firms pay for coal under contract when compared to coal bought in the spot market.

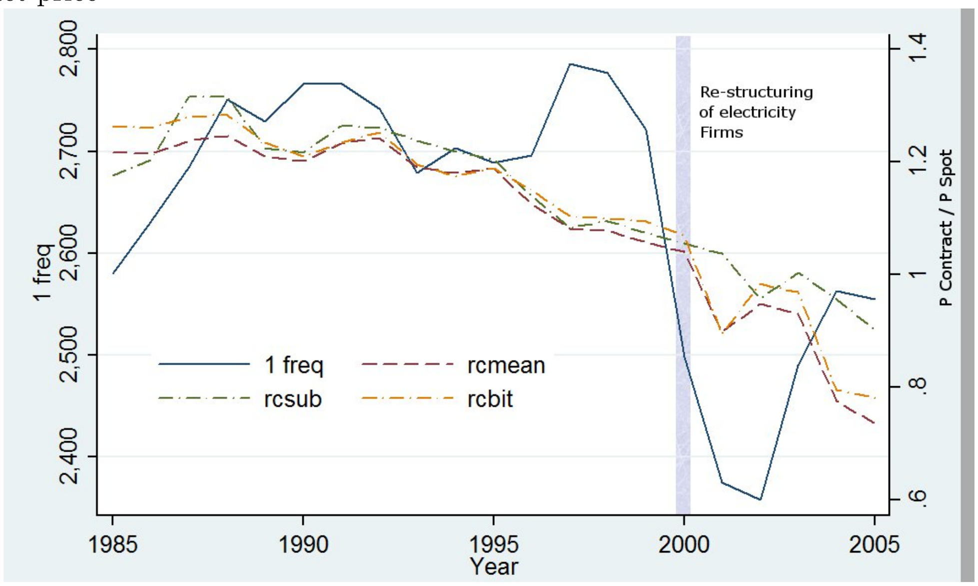
Figure 3.1, reflects a rational response by the electricity producing companies: if prices of sub-bituminous coal bought under contract increase with respect to the spot market price, firms will tend to buy less coal under contracts and more coal at the spot market. Some companies might consider switching to other low sulfur fuels or SO_2 abating technologies, and move away from sub-bituminous coal from the Powder River basin region.

An increase in the prime spread paid for the contract sub-bituminous coal over the spot market, is accompanied by a decrease in the number of contracts, which leads us to think that electricity producing plants have more negotiating power than coal mines, and withdraw from contract transactions as the prime goes up. For the case of the prime spread paid for the contract bituminous coal, the results point at the opposite conclusion: because coal producing mines have more negotiating leverage, when the prime paid for contract transactions becomes more expensive, more coal buying transactions are done under contract regime.

The prime spread for bituminous coal has the opposite effect on the frequency of contracts. In this case, the demand for bituminous coal is more inelastic than for sub-bituminous coal, and coal mines seem to have more negotiation leverage than mines producing sub-bituminous coal. Being that the prices of bituminous coal are more volatile than for sub-bituminous coal, electricity producing firms prefer transactions under contract to diminish the risk. This risk-averse behavior gives some negotiation power to coal mines.

Also noticeable is the change of regime that happened in the year 2000, and reflected in the estimate of coefficient DR2000. To connect this to the dynamics of the coal market and the way coal prices were related to coal contracts in the period of the research, it is helpful to look at the behavior of the *ratios* of prices of coal in the **spot market** to the prices of coal under **contract**, as shown in Figure 3.2. Before the re-structuring of the electricity sector, electricity producing firms would pay a prime to mines for the coal bought under contracts, as coal was more expensive under contracts than in the spot market. After the re-structuring of the electricity sector, plants seem to benefit more from the existence of contracts, as spot prices were higher than contract prices of coal[10] .

Figure 3.2: Variation of contracts (FREQC) and ratio of spot market coal prices Vs. contract price



Finally, the constant term is sufficiently big as to say that there is still a large proportion of contracts that can not be explained by the terms chosen in the suggested equations.

3.2 Restructuring of the Electricity Sector

To check the effect of the change of regime under the restructuring of the electricity sector, Table 3.2 shows the resulting estimations and statistical parameters for different "starting" years of the electricity sector re-structuring, using Equation (3.4)(2) in the following

[10] As can be seen in Figure 3.2, around the year 2000, the ratio (Contract price) / (Spotprice) crosses the unity and becomes less than 1.

regression[11] :

$$FREQ = A_0 + \sum_{i=0}^{3} (A_{1i} \cdot RCSub_{t-i} + A_{2i} \cdot RCBit_{t-i}) \quad 3.4(2)$$

Table 3.2: Comparison of different years for electricity restructuring effect

Var		**DR1999**	**DR2000**	**DR2001**	**DR2002**
FREQ					
RCSub		-24	-69$\star$	4.7	24
	L1.	-19	-59$\star$	-5.6	-27
	L2.	-57	-31	-54	-31
	L3.	.46	-61$\star$	9.8	26
RCBit		33	29$\star$	1.3	40
	L1.	23	70†	.76	-15
	L2.	69	65†	60	74
	L3.	5.9	17	15	-41
DR1999		-5.3			
DR2000			-17‡		
DR2001				-11$\star$	
DR2002					-5.7
Const		204$\star$	288‡	203‡	183†

legend: $\star$: $p < 0.05$; †, : $p < 0.01$; ‡, : $p < 0.001$

As shown, Equation (3.4)(2) has more coefficients with significant values for the year 2000 than for the other years. Table 3.3 shows test values for the estimated models. Where

[11] This means that the term $DR2000$ of Equation (3.4) was substituted consecutively by $DR1999, DR2000, DR2001, and\, DR2002$ for the corresponding years.

rss is the residual sum of squares, $R2$ is the value R-squared, F is the F statistic, LL is the log likelihood under additional assumption of i.i.d. normal errors.

Table 3.3: Statistical fit for different values of electricity re-structuring effect

	1999	2000	2001	2002
RSS	162	24	97	156
R2	.89	.98	.93	.89
F	8.8	52	12	7.2
LL	-45	-28	-41	-45

The result with the biggest statistical significance was obtained for year 2000, where there is stronger evidence of a structural change in the behavior of the frequencies of contracts than for the other years considered. As a matter of fact, in the iteration process to choose the explanatory variables, the estimated parameter DR2000 is the only one among the year dummy variables that showed statistical significance to explain the number of contracts $FREQ$.

3.3 Causality Coal Prices - Number of Contracts

In this section we analyze the causality between coal prices and the frequency of transaction made under contracts. A useful tool was developed by Granger in 1969 to analyze the case of two variables x and y, where one of them, x, has explanatory power over the other, y, as proposed in Section 3.1. In our case, we want to test if variations in *coal prices* causally prior to variations in the $frequency$ of contractual transactions, or vice versa.

A variable x is said to Granger-cause another variable y, if the lags of the causing variable x can help explain the future behavior of the variable y. In a vector autorregressive (VAR) model, as the one presented above, the null hypothesis that coal prices do not Granger-cause the frequency of contracts is tested using a Wald Test. If true, all the coefficients on the lags related to coal prices will be zero in Equation (3.2).

For testing Granger causality, the dependent variable *FREQ* is regressed on its own lagged values, and then regressed on lagged values of the explanatory variables, given by the *cost of coal*. Then the null hypothesis that the estimated coefficients on the lagged values of *cost of coal* are jointly zero, is tested using a Wald Test. If the null hypothesis cannot be rejected, it is equivalent to failing to reject the hypothesis that *cost of coal* does not Granger-cause the variable *FREQ*.

Even though the term *causality* suggests a *cause and effect* relationship between two variables, Lütkepohl (2005) introduces the concept of *instantaneous causality* as a nonzero correlation between two sets of variables. The direction of the instantaneous causation cannot be easily inferred and *must be obtained from further knowledge on the relationship between the variables*[12] .

To say that coal prices *Granger-cause* the frequency of contracts implies that firms, plants, as well as mines, are utilizing coal contracts to some degree as a strategy to cope with variations in coal prices in the market, and is therefore affecting their cost structure and profit. In this case, even though there might be a positive result indicating Granger-causality of coal contracts over coal prices, it would be risky to accept it without analyzing the role played by other variables such as oil and natural gas prices, or coal trade balance, that may be a more important determinant of coal prices, and are not included in the scope of this research.

3.3.1 Empirical Results

The null hypothesis that coal prices have no forecasting power on the future behavior of the number of contracts is tested in Equation (3.4)(1) and Equation (3.4)(2), whose estimated parameters are described in the previous section. Some relevant results obtained are shown in Table 3.4.

For both Equation (3.4)(1) and Equation (3.4)(2), it is clear that the null hypothesis

[12] See Lütkepohl 2005, Section 2.3, for a more rigorous mathematical explanation.

Table 3.4: Granger causality tests for some variables

Eq.	**Explained Var**	**Forfecasting Var**	Chi^2	$Prob > Chi^2$
Equation (3.4)(1)	FREQ	RCSub	11.819	0.008
	FREQ	RCMean	20.242	0.000
	RCSub	FREQ	3.4254	0.331
	RCMean	FREQ	6.6436	0.084
Equation (3.4)(2)	FREQ	RCBit	20.871	0.000
	FREQ	RCSub	13.731	0.003
	RCBit	FREQ	5.0478	0.168
	RCSub	FREQ	4.8474	0.183

that $RCSub$ Granger-causes $FREQ$ can be rejected, and therefore, the prime paid for the sub-bituminous coal under contract Granger-causes FREQ, i.e., has a definite influence in the number of contracts. In a similar way, it can be stated that $RCBit$ (and $RCMean$) Granger-causes $FREQ$, and therefore the prime paid for the bituminous coal (the mean prime paid for coal) affects the number of contracts.

Regarding the primes paid for sub-bituminous and bituminous coal under contracts, there is no conclusive argument that $Freq$ Granger-causes $RCSub$ or $RCBit$, as both models show that the null hypothesis can be rejected.

3.4 Transportation Costs

To estimate the influence of transportation costs on the strategic behavior of firms, we assume that they will take into account the price of bituminous and sub-bituminous coal in their abating strategy.

When compared to the distances that the bituminous coal is transported from the mine mouth to the plant site, on average sub-bituminous coal is transported longer distances. This can be seen in Figure 3.3 and Figure 3.4. The average distance that bituminous coal is transported over the period analyzed is 216 miles, while for the sub-bituminous coal the average distance was 676 miles, as can be seen. The Gaussian univariate density function of the transportation distances of sub-bituminous coal shows two smaller peaks: one close to the bituminous coal average distance, 216 miles, and at about 1,200 miles (Figure (3.4)). It is needless to mention that given these circumstances, transportation prices have a bigger effect on the sub-bituminous cost structure than for the case of bituminous coal, and therefore we focus on the effects of transportation distance on sub-bituminous coal price.

To determine if distance and the existence of contracts play an important role in the price of coal, we start by analyzing the influence distance on the price paid by plants for coal, and then the effect on the coal price of the existence or not of contracts. Starting by the following general expression:

$$CSub = a_0 + a_1 \cdot DistSub + \varepsilon$$

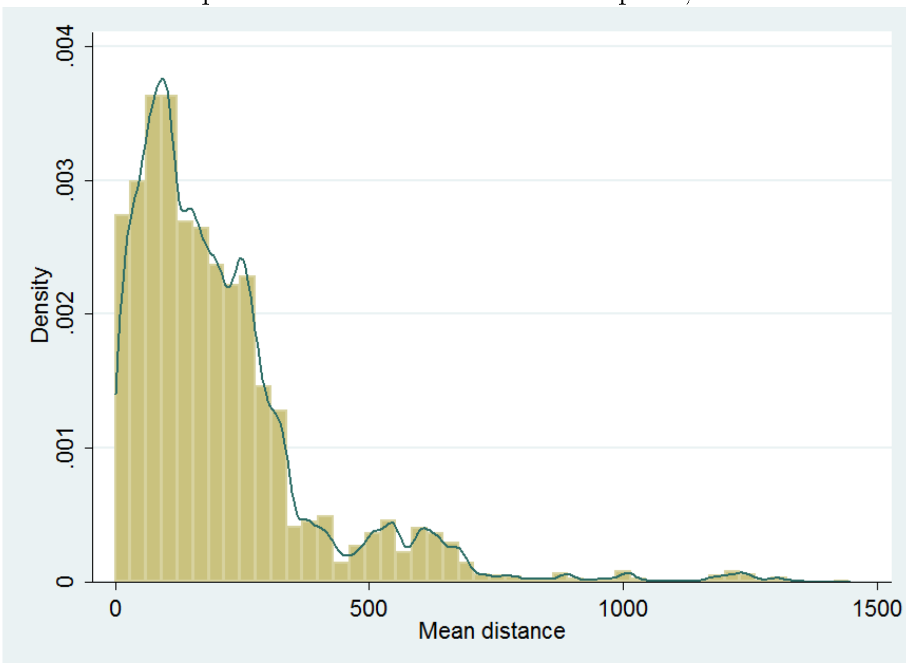
to include the effect of the beginning of pahse II of the CAAA, and to analyze separately the transactions done under contract and at spot market, we rewrite the previous equation as follows:

$$\begin{aligned} Spotmarkettransactions &: \\ CSub_0 &= a_0 + b_0 \cdot DistSub_0 + DR_{2000} + \varepsilon \\ Contractpurchass &: \\ CSub_1 &= a_1 + b_1 \cdot DistSub_1 + DR_{2000} + \varepsilon \end{aligned} \tag{3.5}$$

where subindexes $0, 1$ differentiate transactions bought at the spot market (0), and under coal contracts (1).

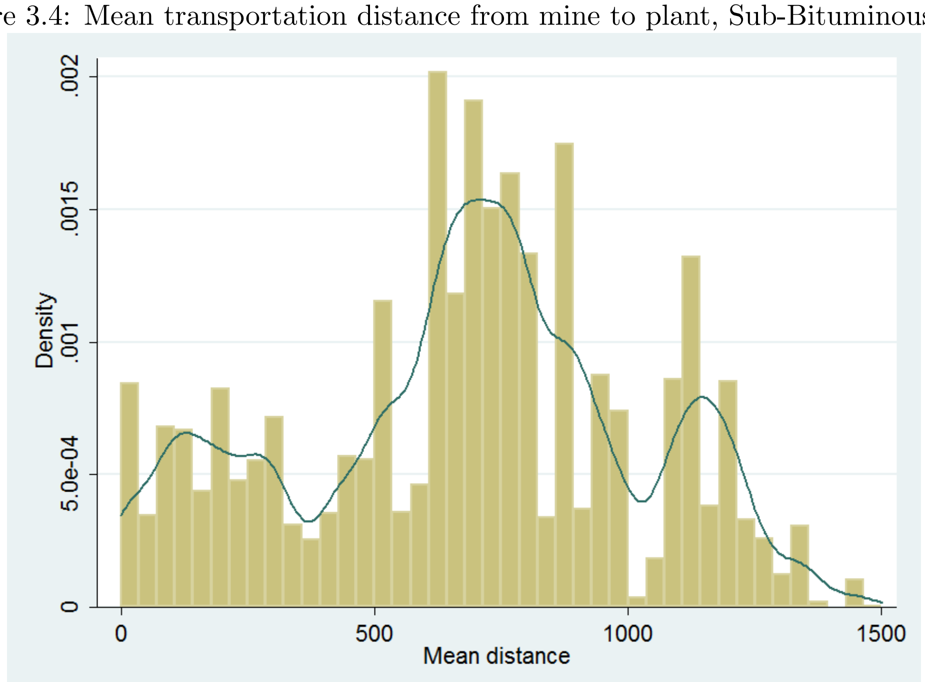
Sub-bituminous coal, with low content of sulfur, is mined mainly in the Powder River Basin in Wyoming, from where it is shipped across the country to energy plants. Therefore,

Figure 3.3: Mean transportation distance from mine to plant, Case of Bituminous coal



(Source: form FERC 423)

Figure 3.4: Mean transportation distance from mine to plant, Sub-Bituminous coal



(Source: form FERC 423)

as opposed to bituminous coal, sub-bituminous coal needs to be transported for longer distances from the extraction site to the plant, as it can be seen in Figure 3.4. The region in which the plant is located as shown in Figure 2.9 is used as proxy for this variable. Equation (3.6) shows the relationship between cost of coal and distances as tested:

$$
\begin{aligned}
CSub_0 &= A_0 \cdot DistSub_0 + \sum_{i}^{regions} B_{0i} \cdot DReg_i + DR_{2000} + \varepsilon \\
CSub_1 &= A_1 \cdot DistSub_1 + \sum_{i}^{regions} B_{1i} \cdot DReg_i + DR_{2000} + \varepsilon
\end{aligned} \tag{3.6}
$$

The variable $DistSub$ denotes the distance from mine to plant for sub-bituminous coal, and $DReg_i$ is a distance dummy variable for plant i that reflects the distance information from mine to the region.

3.4.1 Empirical Results

The two versions of Equation (3.5) were used to examine the relationship between the cost of sub-bituminous coal in the absence of contracts (0) and when coal for electricity sales are made under contract (1).

Aggregated plant level data were utilized to estimate the parameters of the equations and the results can be seen in Table 3.5, where the column *Cost Sub 0* corresponds to the case when coal is bought without a contract, and *Cost Sub 1* when the transaction is done under a coal contract. $DistSub_0, DistSub_1$ represent the distances from mine to plant for purchases made on the spot market (0) and under contract (1), for sub-bituminous coal.

Even though the explanatory power of these expressions is limited, as can be concluded looking at the values of the adjusted R-squared R_a^2, it conveys significant information about the relationship between distance and coal prices under various combinations of regimes: contract/spot, and before/after 2000. In general, the coal price under contract starts from a higher initial value, but increases at a lower rate than the spot market coal price. Before

Table 3.5: Results for the Coal price - Distance models

Variable	Spot market	Under contract
DistSub	.034‡	.0074†
DR_{2000}	-8.6⋆	-12‡
Cons	79‡	106‡
R_a^2	.17	.012

legend: $\star: p < 0.05$; $\dagger,: p < 0.01$; $\ddagger,: p < 0.001$

2000, at around 1000 miles, both prices are equivalent, and for bigger distances, contract coal prices are smaller than spot prices. The beginning of phase II of CAAA in the year 2000 reduces sub-bituminous coal prices in both cases, but in a bigger amount for contract coal.

In order to check any additional regional effects. we include the region parameter as described in Equation (3.6). Table 3.6 displays the estimation values for Equation (3.6).

Table 3.6: Estimations of Distance and Regions in the Sub-bituminous Coal Price Model

Variable	Spot market	Under contract	Arbitrage Value
DistSub	.0074⋆	-.022‡	
$DReg_3$	17‡	-45‡	62
$DReg_4$	-9.1‡	-77‡	67.9
$DReg_5$	59‡	-	59
$DReg_6$	29‡	-30†	59
$DReg_7$	10†	-47‡	57
$DReg_8$	-	-77‡	77
DR_{2000}	-5.6	-9.8†	
Cons	92‡	189‡	
R_a^2	.38	.18	

legend: $\star: p < 0.05$; $\dagger,: p < 0.01$; $\ddagger,: p < 0.001$

The estimated values for the distance *DistSub* indicate that the general behavior described before is amplified even more when we consider the regions. Starting from a much higher price for the case of contracts (US$ 189.43 in this case), the price of sub-bituminous coal increases at a much slower rate than the spot market coal price. As a matter of fact, the coal price under contracts *decreases* with the distance. For example, an increase in 100 miles of transport add slightly less than 75 cents per ton of sub-bituminous coal on the spot market, while they *reduce* the price by 2.2 US$ under contract[13] . The impact of the deregularization of the electricity producing sector is smaller but has the same behavior as above.

For the coal bought in the spot market, the value related to the region seems to follow logic: regions 5 and 6, corresponding to the South Atlantic (DC, DE, FL, GA, MD, NC, SC, VA, and WV) and East South Central (AL, KY, MS, and TN) are the most affected by the region parameter. This increase in price matches the larger distance between these regions and the sub-bituminous producing mines in the Powder River Basin, Wyoming. Regions 3 and 7, corresponding to East North Central (IL, IN, MI, OH, and WI) and West South Central (AR, LA, OK, and TX) are closer to the PRB and their values are correspondingly smaller. Region 4, West North Central (IA, KS, MN, MO, NE, ND, and SD) includes states that are close geographically to the PRB, and thus the region parameter diminishes the price. Regions 8 and 9[14] are in a distance range such that it doesn't add or subtract anything to the equation. Finally, regions 1 and 2 don't show any values because their consumption of sub-bituminous coal from the PRB is insignificant.

The estimation of regional effects for coal bought under contracts shows very similar results to the spot market with slight differences that are worth analyzing. The third column of Table 3.6 displays the difference in price between contract and spot market purchases, and is expressed in US$ per Ton.

The value of column 3 constitutes an *arbitrage value* that coal producing mines obtain

[13] It is important to note that these values only explain the price of sub-bituminous coal to a limited extent, i.e., nearly 18% for the case of contract coal price. Nevertheless, the estimation has significant values and it would be expected that a more accurate model would show similar trends to the ones obtained in this research.

[14] See Section 2.6for the definition of the regions.

Table 3.7: Estimated Values of Regional Coefficients

Variable	**Estimated Values**		**Transformed Values**		Arbitrage
	Spot Market	**Contract**	**Spot**	**Contract**	**Value**
$DReg_3$	17.06	-44.94	26.13	32.28	6.15
$DReg_4$	-9.07	-77.22	0	0	0
$DReg_5$	58.87	0	67.94	77.22	9.28
$DReg_6$	29	-30.24	38.07	46.98	8.91
$DReg_7$	10.33	-47.08	19.4	30.14	10.74
$DReg_8$	0	-76.76	9.07	0.46	-8.61

out of the negotiation of coal price with electricity producing plants in different regions. The arbitrage value encompasses hidden differences among the regions and part of it is uncovered by the data in Table 3.7.

According to these results, the big winners are electricity producing plants located in region 8. Two important circumstances that explain this result are: the fact that mines in this region are much closer to the source of sub-bituminous coal than the national average, and the existence of a small demand for coal when compared with a big supply of coal in the region[15] . Regions 3, 5, 6 and 7 have to pay a higher arbitrage price than the rest. This is probably due to transportation issues originated when passing from the Union Pacific (UP) and Burlington Northern Santa Fe (BNSF) freight railroad system in the west, to the CSX Transportation (CSXT) or Norfolk Southern Railway (NS) systems in the east. There are possibly other factors that increase the negotiation leverage of mines nor explained by the switch of transportation companies, as is the case of region 7.

[15] This makes sense when considering that the PBR produces an important proportion of sub-bituminous coal consumed in the U.S., most of which is exported to the other regions.

Chapter 4

Plant Efficiency Assessment

One of the objectives of this research is to determine if investment in SO2 emissions abating technologies and innovation by coal-based electricity producing firms are efficient in optimizing their profits. In Section 1.1 the question around the efficiency of firms is posed around the investment on emissions abating technology. In this chapter, the Data Envelopment Analysis framework (DEA) is used to assess the efficiency of plants, and utilized to obtain conclusions about the behavior of firms.

4.1 Introduction

To measure the cost effectiveness of the SO_2 allowance market, two ways are most commonly used (Burtraw, 1996):

- Productive efficiency or cost-effectiveness
- Allocative or market efficiency

Some authors tried to measure the cost of undesired outputs as part of a productive process[1] . Building at the work of Caves et al. (1982a, 1982b), Pittman (1983) developed empirical,

[1] In the case of environmental control policy making, undesired outputs are seen as public *bads* (i.e. liabilities) as opposed to public *goods*.

multilateral indexes for the assessment of shadow prices of undesired outputs and found that taking into account output *bads*[2] changes slightly the productivity assessments, and, therefore, it is necessary to consider these *negative* output for a more accurate assessment of the indexes.

From Farrell's very important work (1957)on productivity measurement[3] , Charnes et al. (1978) introduced the concept of *Data Envelopment Analysis* (DEA) in a pioneering publication. This concept is taken later by researchers, such as Fare et al. (1989) that extend it to include undesired outputs. Later the concept of a *distance function* is added to calculate the shadow price of undesirable outputs that are jointly produced with goods (Fare et al., 1993). A distance function approach is used by Coggins and Swinton (1994) to determine the shadow price of SO_2 emissions in Wisconsin, in an attempt to assess a market value for SO_2 allowances.
The econometric model used to analyze and draw conclusions about the behavior and evaluation of firms is based on the Data Envelopment Analysis to measure the *efficiency* of firms to be tested later against other relevant variables, in order to establish significant relationships and draw conclusions.

4.2 Technical and Scale Efficiency Factors

Data Envelopment Analysis (DEA) is a widely used methodology to measure productive efficiency[4] . One of the advantages of this methodology is that being a benchmark index, it does not need information about costs or profits of the firm. Given a set of variables that describe the performance of companies in terms of production inputs and outputs, the DEA methodology consists of finding the optimal weights μ, ν for outputs and inputs, respectively, that maximize the following mathematical problem expressed in *ratio* form

[2] Some industries, such as the electricity producing sector, produce jointly output *goods* and *bad* (negative) outputs as byproduct.
[3] The Piece-Wise-Linear Convex Hull approach to frontier estimation proposed by Farrell was considered only two decades after he published his article in 1957 (Coelli, 2005)
[4] This section draws mainly from Coelli, 2005.

for the case of I firms[5] :

$$\max_{\mu,\nu} \quad (\mu' y_i/\nu' x_i), \tag{4.1}$$
$$s.t. \quad \mu' y_j/\nu' x_j \leq 1 \quad j = 1, 2 \ldots, I$$
$$\mu, \nu \geq 0$$

where y_i represents the production output for firm i and is part of a $M \times 1$ matrix $\mathbf{Y}$; x_i represents the inputs needed by firm i for its production activity, and is part of a $N \times 1$ matrix $\mathbf{X}$. Note that the restriction of the *efficiency measure* implies that $\{\mu' y_j/\nu' x_j\}$ has to be at most equal to 1.

To avoid having an infinite number of solutions that solve Equation (4.1) we impose the restriction $\nu' x_i = 1$. Using the *duality* property in linear programming, we obtain the *envelopment* form of Equation (4.1)

$$\min_{\lambda,\theta} \quad \theta, \tag{4.2}$$
$$s.t. \quad -y_i + Y\lambda \geq 0$$
$$\theta x_i - X\lambda \geq 0$$
$$\lambda \geq 0$$

The variable θ represents the *efficiency score* of firms and reflects the *closeness* to the production frontier. The more efficient the firm, the closer θ gets to 1,with 1 being the efficiency score for the most efficient firms.

When not all firms are operating in an optimal scale, the constant returns to scale (CRS) approach can render confusing results, and Technical Efficiencies can be distorted by Scale Efficiencies[6] . To avoid this a Variable Returns to Scale model can be used. One more

[5] Even though this methodology is based on interfirm efficiency benchmarking, the maximization problem is solved as a Linear Programming (LP) problem for **each** one of the I firms.

[6] See Coelli, 2005 for a more extended explanation.

restriction needs to be added: $\sum \lambda_i = 1$.

Substituting $x_i^* = \theta x_i$, Equation (4.2) will then be rewritten in the following way:

$$\begin{aligned} \min_{\lambda,\theta} \quad & \theta, \\ s.t. \quad & -y_i + Y\lambda \geq 0 \\ & x_i^* - X\lambda \geq 0 \\ & \lambda \geq 0 \\ & \sum \lambda_i = 1 \end{aligned} \tag{4.3}$$

Equation (4.3) can be expressed as an input-oriented cost minimization DEA as shown in Equation (4.4), and can be used to determine a normalized Efficiency Factor - TEF, and a Scale Efficiency Factor - SCEF.

$$\begin{aligned} \min_{\lambda,x_i} \quad & w_i' \cdot x_i^*, \\ s.t. \quad & -y_i + Y\lambda \geq 0 \\ & x_i^* - X\lambda \geq 0 \\ & \lambda \geq 0 \\ & \sum \lambda_i = 1 \end{aligned} \tag{4.4}$$

If some of the input variables are *non-discretionary*, i.e. if the firm has no *discretionary* control over them, the optimization control θ can only be applied on the discretionary variables. Denoting *non-discretionary* variables as z_i, Equation (4.4) becomes[7] :

$$\begin{aligned} \min_{\lambda, x_i} \quad & w_i' \cdot x_i^*, \\ s.t. \quad & -y_i + Y\lambda \geq 0 \\ & x_i^* - X\lambda \geq 0 \\ & z_i - Z\lambda \geq 0 \\ & \lambda \geq 0 \\ & \sum \lambda_i = 1 \end{aligned} \tag{4.5}$$

There are some examples in the technical literature of ways to include environmental variables in a DEA model. Bessent and Bessent, 1980, take into account uncontrollable and controllable inputs to analyze the *opportunity cost*[8] of varying its values. Fried et al., 1999 also included environmental variables in a DEA model.

The level of SO_2 emissions as an undesirable environmental output. According to some authors (Zhu, 2003), given the fact that SO_2 emissions are a product associated with the generation of electricity, and thus jointly produced, it must be considered as a production *bad* (i.e., negative output), as opposed to a production *good* (E.g., electricity). As the used DEA model uses the Input/Output relationship to create a production envelope, it requires special considerations when including a production *bad* in the equation. There are two ways in which pollution can be introduced in the DEA model:

Emissions Scaled and considered as an output As the profit function of the firm is negatively affected by the production of emissions, these have to be scaled in a way that the bigger they are, the smaller the production associated to them[9] .

[7] Notice that the non-discretionary variable z_i is not affected by the efficiency score θ.
[8] In this part of the research, the opportunity cost is defined as how much the value of the objective function (efficiency) can be improved if inputs are reduced by one unit.
[9] This is the one recommended by Zhu, 2003.

Emissions Considered as Inputs Considering the emissions as production inputs results in the DEA model to optimize (minimize) their *use* (production) in the generation of electricity, resulting in the minimization of emissions.

In this research, the second option is used to include SO_2 emissions in the DEA analysis, and they are represented as a non-discretionary input, noted by z_i in Equation (4.5).

4.3 Econometric Models

In this section we describe the econometric models utilized in the empirical analysis of the data using the DEAP methodology described in the previous section.

4.3.1 Technology Efficiency Equation

The *Technology Efficiency factor* represents the relative distance of the production level of the firm for the given inputs to the optimal production level located at the production frontier.

Panel data models have been widely used for incorporating the time dimension to the traditional cross-section econometric analysis. In this way, variations in time and trends can be included in the cross-section analysis.

A maximum-likelihood estimator is used for the estimation of the parameters. A random-effects model is used to allow the intercepts have different values[10] . A relationship of the technical efficiency factors (TEF) and other variables, such as the decision of adopting scrubber technology, Coal Prices, SO_2 allowance prices, and others, are then

[10] The random-intercepts model allows for more control of unobserved heterogeneity at the cluster level, in this case, at the regional level.

tested using a panel-data model.

$$\begin{aligned} TEF = \quad & \alpha_0 + \textstyle\sum_i^{lags} \alpha_i \cdot L_i.CFGD_i + \sum_i^{lags} \beta_i \cdot L_i.CBIT \\ & + \textstyle\sum_i^{lags} \gamma_i \cdot L_i.DistBIT_i + \sum_i^{lags} \delta_i \cdot L_i.DistSUB + \sum_i^{regions} \eta_i \cdot DRG_i \\ & + \xi_1 \cdot DY2000 + \xi_2 \cdot MAXR + \cdots + \varepsilon \end{aligned} \tag{4.6}$$

where TEF is the *technical efficiency factor*; $CFGD_i$ correspond to the *investment* costs of scrubbers, $CBIT$ is the cost of bituminous coal, $DistBIT$ the distance between bituminous coal mines and plants, while $DistSUB$ is the distance between sub-bituminous coal mines and plants, $MAXR$ is the nameplate maximum rating energy generation, and DRG_i refers to the the dummy variable corresponding to region i, $DY2000$ is the dummy variable that incorporates the effect of the beginning of phase II of the CAAA in the year 2000. The i-th lag is indicated as Li. For example, $L3.DistBIT$ is the third lag of the distance between bituminous coal mines and plants, and is equivalent to $DistBIT_{t-3}$.

4.3.2 Scale Efficiency Equation

To understand the meaning of the *scale efficiency factor, (SCEF)*, there is need to understand the fact that energy production is carried out under a variable returns to scale (VRS) assumption. The SCEF can be interpreted as the ratio of the average product of a firm operating at its best to the product when operating under conditions of technical optimality. In other words, the Scale Efficiency factor is a measure of the distance between the actual Variable Returns to Scale (VRS) production frontier hyperplane, and the optimal Constant Returns to Scale (CRS) hyperplane. This methodology has been used by authors in the past to measure and compare efficiency among firms[11] .

[11] Fare et al., 1994, Zhu, 2003

In a similar way, for the scale efficiency we have:

$$\begin{aligned} SCEF = \quad & \alpha_0 + \textstyle\sum_i^{lags} \alpha_i \cdot L_i.SO2PermitPr + \sum_i^{lags} \beta_i \cdot L_i.BtusSub \\ & + \textstyle\sum_i^{lags} \gamma_i \cdot L_i.DistBIT_i + \sum_i^{lags} \delta_i \cdot L_i.DistSUB + \sum_i^{regions} \eta_i \cdot DRG_i \\ & + \textstyle\sum_i^{lags} \theta_i \cdot L_i.CostSub + \sum_i^{lags} \phi_i \cdot L_i.CostFGD_i \\ & + \xi_1 \cdot DY2000 + \xi_2 \cdot MAXR + \cdots + \varepsilon \end{aligned} \tag{4.7}$$

Where the parameters have the same meaning as for the TEF, $CostSub$ is the cost of sub-bituminous coal, $SO2PermitPr$ is the price of the SO_2 allowances, and $BtusSub$ is the total energy input bought by plants, in million BTUHs.

4.3.3 Considerations for the Econometric Runs

For calculating the Technological and Scale Efficiency Factors, an equation similar to Equation (4.5) was fitted using Tim Coelli's Deap program (Coelli, 2005). From the original universe of 569 electricity generating plants only 249 plants had at least 90 percent of the necessary information used in this research for the years 1985 to 2005, and therefore, these plants were selected. Out of this sample, 117 plants had installed or installed FGDs during the same period. From the selected plants, 14 were located in the Middle Atlantic region, 60 in the East North Central region, 42 in the West North Central, 52 in the South Atlantic, 31 in the East South Central, 17 in the West South Central, and 33 in the Mountain regions.

For the Data Envelopment Analysis, the following inputs and outputs were taken into account.

- One output
  - Eneregy production in MW-H
- Four inputs
  1. Input of heat produced from burning bituminous coal (in million BTUs).

2. Input of heat produced from burning sub-bituminous coal (in million BTUs).

3. SO_2 emissions produced from burning bituminous coal, So2sBit (in Tons)[12] .

4. SO_2 emissions produced from burning sub-bituminous coal, So2sSub (in Tons).

In Figure 4.1, a scatter plot of the important values for the DEA analysis are displayed: energy input (BTUs) and emissions (CO2s), considered as inputs, and electricity generation (MWH) as output. Figure 4.2 shows a two dimensional representation of the hull formed by the envelopment of the production points displayed in Figure 4.1. Note that as energy input increases, there is a certain point from where the hull starts decreasing.

An output oriented, two-stage solution process was chosen, and *Variable Returns to Scale* were allowed in the production function. In Figure 4.3 the distribution of Technical Efficiency Factors (TEF) for the different regions included in the research can be seen. In Figure 4.4 the distribution of Scale Efficiency Factors (SCEF) is shown.

For selecting the equations that describe the dependent variable in sections 4.4.1 and 4.4.2, the general procedure below was followed:

1. A *static* stepwise (forward) process was applied to explain the dependent variable using an extensive[13] list of explanatory variables. The *static* term refers to the fact that ordinary linear regressions were considered for each step of the optimization process.

2. The *best* explanatory variables were selected for the next step. The criteria used was a 10% confidence margin, thereby erring on the side of being generously inclusive,

[12] For this research, emissions, treated as production *bads* in Section 4.2 (negative or harmful outputs), were included as inputs in DEAP model. In this way, the output emissions were treated as inputs, making it *more efficient* to use (produce) *less of them* when generating electricity. Zhu ((2003)) recommends not to place the production *bads* as inputs, but in practice, the results of putting emissions as inputs were very similar to the results of considering them as outputs. On the other hand, by putting SO_2 emissions as inputs the convergence improved slightly, so this alternative was chosen.

[13] The list was not exhaustive for obvious reasons. For example, only a limited number of lags were considered.

Figure 4.1: Scatter plot of DEA points, for energy and emissions (BTUs and CO2s) as inputs, and electricity generation as output (MWH)

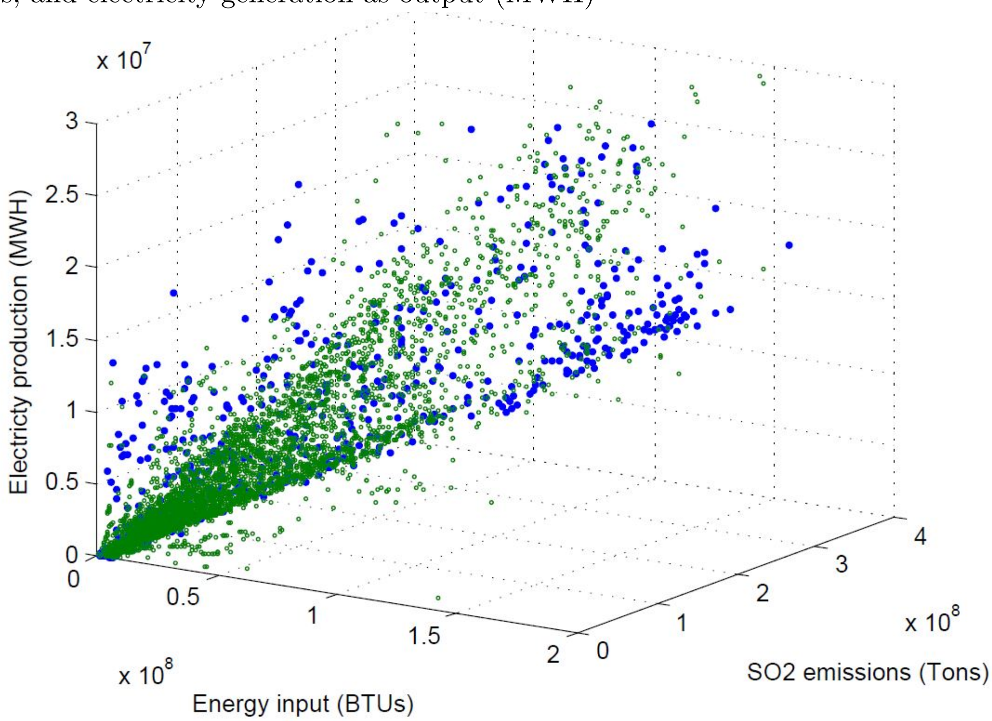


Figure 4.2: Hull representation of the envelopment of production points

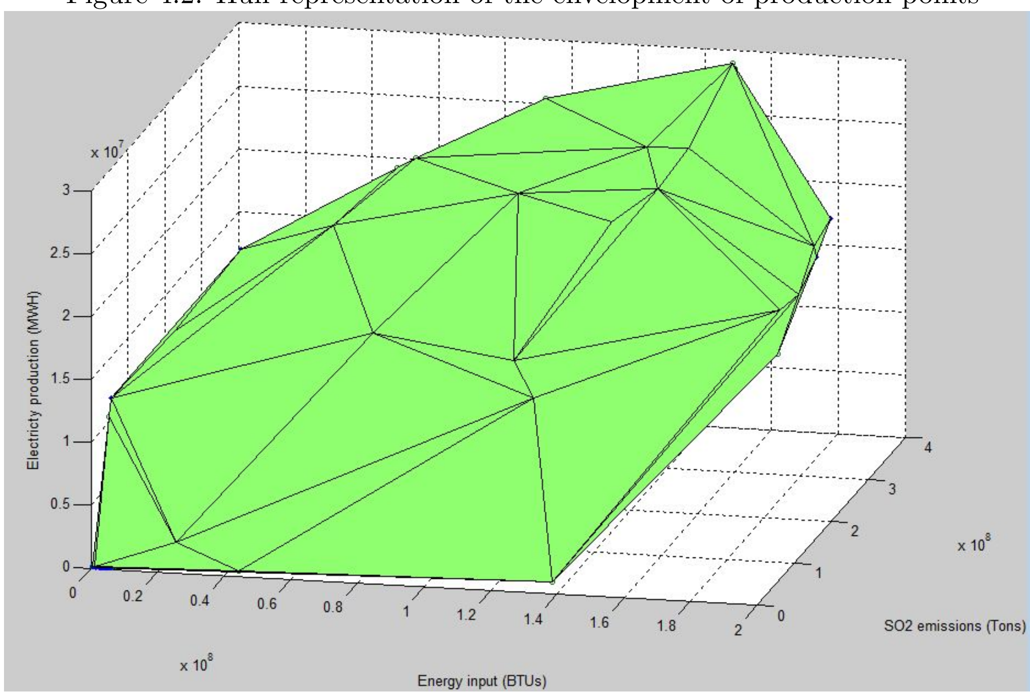


Figure 4.3: Distribution of Technical Efficiency (TEF) values by region

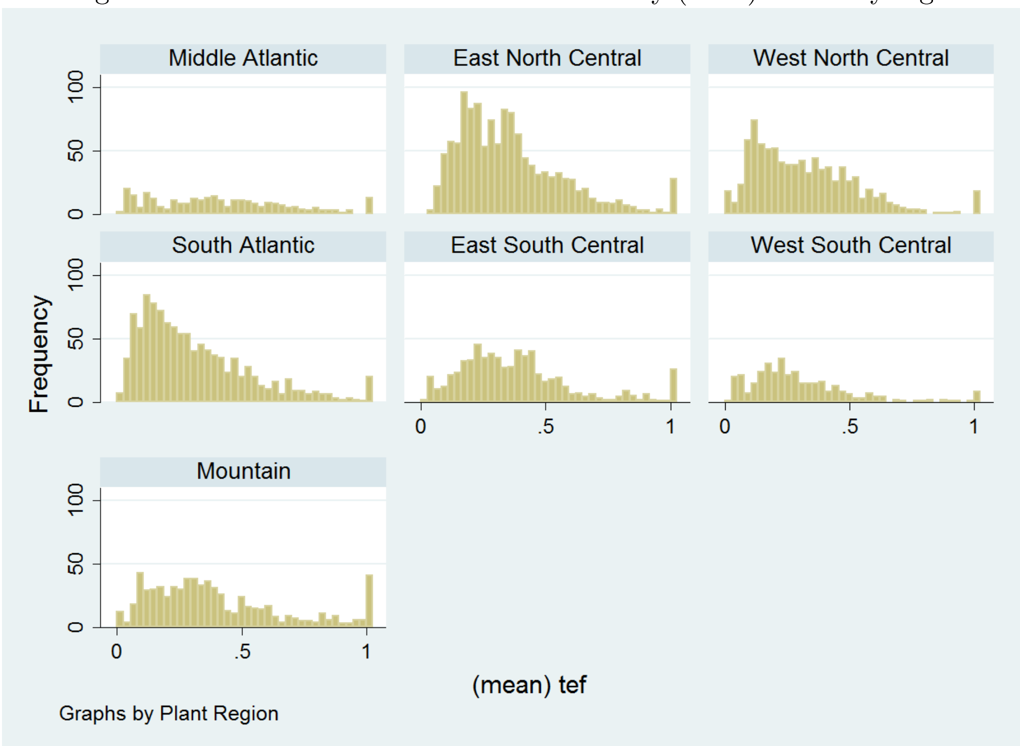
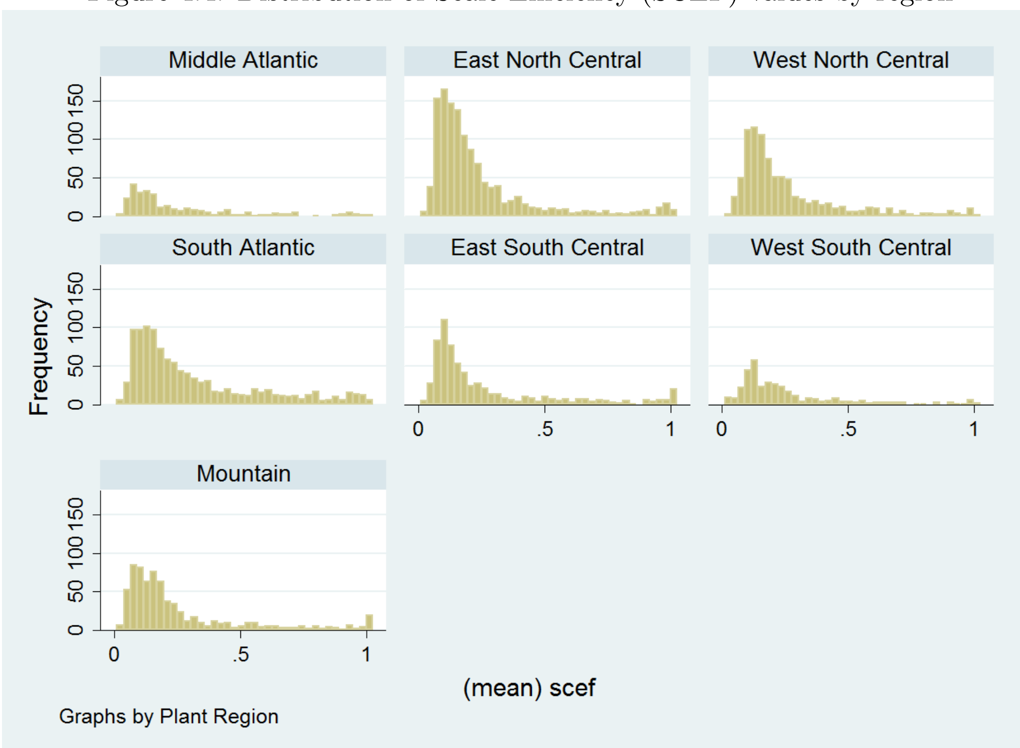


Figure 4.4: Distribution of Scale Efficiency (SCEF) values by region



given that the significance of some variables could change in the next step.

3. An *iterative* stepwise process was applied using the chosen variables, and the panel-data regression algorithm.

4.4 Empirical Results

4.4.1 Technical Efficiency Equation

The Technical Efficiency Factor, TEF, solves the problem of maximizing the output, i.e. produced energy (MWH), while using the same amounts of inputs: coal (BTUs) and SO_2 emissions.

For testing the relationship among the variables described in Equation (4.6), various combinations of the lagged parameters were analyzed utilizing a stepwise iterative process of the *maximum likelihood random effects* panel data regression method.

In Table 4.1, the outputs of the model described in Equation (4.6) can be seen in detail for three types of transactions:

1) Contract transactions Coal buying transactions that were conducted under contract schemes.

2) Spot market transactions Coal buying transactions done without contracts, i.e. on the spot market.

3) All transactions Both kinds of buying transactions: with contracts, and on the spot market.

σ_u and σ_e are derived using the overall within-individual and between-individual covariation matrices. The goodness of fit was tested using the log likelihood ratio, LL, and the *chi square*, χ^2, that are presented in the same table.

The Technology Efficiency factor measure the efficiency of use of inputs to produce more outputs, in other words, it gauges how close inputs and outputs are from the production frontier.

Table 4.1: Results from regression models for Technical Efficiency TEF

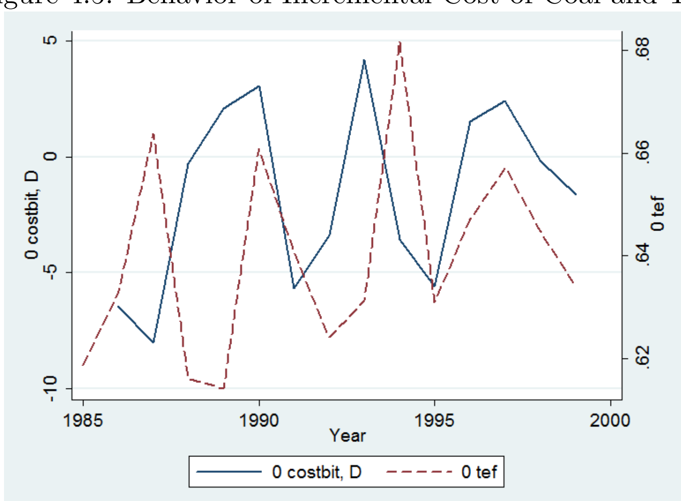
Estimation of TEF				
Var	Lag	With Contracts	Without Contracts	All Cases
CBIT	L3	.00063	-.00044	.00058
CFGDi	L3	.0012‡	.00032	.00046⋆
DistSub	L1	-.00015	.00031	.00055†
	L3	.00023	-7.3e-05	-.00039
DistBit	L1	-3.8e-05	-1.7e-05	-7.4e-05⋆
MAXR		-.048	-.061	-.052†
DRG_3		.00021‡	.00021‡	.0002‡
DRG_4		.052	.13⋆	.095⋆
DRG_7		.2‡	.32‡	.29‡
DRG_8		.26⋆		.33‡
DY2000		.29‡	.44‡	.37‡
Statistics				
σ_u		.12‡	.1‡	.12‡
σ_e		.11‡	.1‡	.11‡
LL		141	106	254
χ^2		1131	.	1623

legend: $\star : p < 0.05$; $\dagger : p < 0.01$; $\ddagger : p < 0.001$

The estimation reveals that the cost of bituminous coal $CBIT$ positively affects the increment of TEF after three periods of time for **contract transactions** and **all transactions**. This result leads us to infer that if prices of bituminous coal increase, plants will start switching to sub-bituminous coal rather than investing in scrubber technology, as the

markup price of bituminous coal will increase operation costs of FGDs, lowering the rate of return of this strategy and making it less attractive. For **spot market transactions**, on the other hand, the effect of $CBIT$ on TEF is negative in the third lag. These results, in any case are not significant and therefore only help to better perceive the factors affecting the efficiency factor TEF, but do not explain it.
The general case suggests for example that, for every increase of 50 dollars in the price of bituminous coal, the technical efficiency of electricity producing plants will increase nearly three percent in the next three periods of time.

Figure 4.5: Behavior of Incremental Cost of Coal and TEF



The delayed effect of $CBIT$ is shown in Figure 4.5 that plots the first difference of the price of bituminous coal, on one side, and the TEF factor on the other. The lagged correlation between the two variables can be seen in the Figure.

Regarding the cost of technology, the investment cost of FGDs ($CFGDI$), has significant estimations with 95% confidence for the general case, and with 99.9% confidence for the contract transactions. The investment cost of technology ($CFGDI$) is accounted as a *capital* cost by electricity producing firms, and as can be seen that it has a positive influence on value of TEF three periods of time later. There is no apparent explanation of why an increase in the cost scrubbers ($CFGDI$) will increase the technical efficiency (TEF) of firms. Nevertheless, the conclusion obtained by inverting the causality makes more sense, i.e., if firms are investing more in FGDs, the TEF increases, and because of the increased demand on technology, the investment cost $DFGDI$ increases. To test this hypothesis, a simple experiment was conducted. A three lag VAR model was estimated for $TEF, CGFDI, CFGDOM$:

$$\left\{\begin{matrix} TEF_t \\ CGFDI_t \\ CFGDOM_t \end{matrix}\right\} = \left\{\begin{matrix} a_1 \\ a_2 \\ a_3 \end{matrix}\right\} + B + \left\{\begin{matrix} \varepsilon_{1t} \\ \varepsilon_{2t} \\ \varepsilon_{3t} \end{matrix}\right\}$$

with

$$B = \begin{bmatrix} b_{1t-1} & b_{1t-2} & b_{1t-3} \\ b_{2t-1} & b_{2t-2} & b_{2t-3} \\ b_{3t-1} & b_{3t-2} & b_{3t-3} \end{bmatrix} \times \begin{bmatrix} TEF_{t-1} & TEF_{t-2} & TEF_{t-3} \\ CGFDI_{t-1} & CGFDI_{t-2} & CGFDI_{t-3} \\ CFGDOM_{t-1} & CFGDOM_{t-2} & CFGDOM_{t-3} \end{bmatrix}$$

The estimation tests of the VAR model were:

Equation	**RMSE**	R^2	χ^2
TEF	.068763	0.6258	21.74007
CFGDI	4.06729	0.9412	208.0077
CFGDOM	.140934	0.7784	45.673

The Granger-causality tests for these equations resulted as follows:

Equation	**Excluded**	χ^2	$Prob > \chi^2$
TEF	CFGDI	2.7524	0.431
TEF	CFGDOM	2.4946	0.476
CFGDI	TEF	24.563	0.000
CFGDOM	TEF	4.7519	0.191

In this brief test, it can be seen that the null hypothesis that $CFGDI$ or $CFGDOm$ Granger-cause TEF can be rejected, and therefore, no causality can be established. The same can be concluded when testing for the Granger-causality ofTEF over $CFGDOM$. On the other hand, the null hypothesis that TEF Granger-causes $CFGDI$ can not be rejected, and therefore, it shows evidence that firms seeking to modify their technical efficiency, are affecting the investment cost of FGDs.

The distance between coal mines and electricity generating plants shows the opposite effect for sub-bituminous coal $DistSub$ when compared to bituminous coal $DistBit$, and for the general case. A positive estimation for the first lag of $DistSub$ reflects the effort made by plants striving to become more efficient. For doing so, these plants need to buy more sub-bituminous coal even if it has to be transported for longer distances. A bigger $DistSub$ means a bigger effort by the plant to be more efficient. The value of $DistBit$ is almost negligible, and will not be analyzed.

The size of the plant also seems to affect the technical efficiency TEF, as can be said for the **general** case with a 99% conifdence. There is a negative relationship between the plant size $MAXR$[14] and TEF.

As for the effect of the region where the plant is located, there is strong evidence that for plants located in the *West South Central* region[15] , and in the *Mountain* region[16] , the TEF value is bigger than the national average by nearly 30%. This could be caused by the vicinity of the Powder River basin, where the main sources of sub-bituminous coal in the country are located, together with special emission conditions for the West South Central region. The *West North Central* region[17] is also benefited from the closeness to the main mines of sub-bituminous coal i the country. The positive effect on plants located in the *East North Central* region[18] is much smaller but positive, and can be attributed to good transport conditions from the Powder River basin mines, and to more stringent

[14] For assessing the size of the plants, the plants' plate maximum rate of electricity generation, $MAXR$, is used.

[15] The West South Central region is represented by DRG_7, that is formed by: AR, LA, OK, TX

[16] The Mountain region is coded as 8, and encompasses the following states: AZ, CO, ID, MT, NV, NM, UT, WY

[17] The West North Central region is represented by DRG_4, that includes the following states: IA, KS, MN, MO, NE, ND, SD

[18] The East North Central region corresponds to code 3, and includes: IL, IN, MI, OH, WI

environmental regulations.

The effect of the beginning of phase II of the CAAA can be seen in the parameter $DY2000$. The positive value of $DY2000$ points at a substantial gain of TEF efficiency that occurred around the beginning of phase II. This value is close to forty percent for the **general** case. As pointed before, some of this value could be attributable to the de-regulation of the electricity sector, that had a positive effect on electricity producing firms.

4.4.2 Scale Efficiency Equation

Similar to the case for TEF, for finding the best estimate of the model described in Equation (4.7), various combinations of the lagged parameters were analyzed utilizing a stepwise iterative process was applied to the *maximum likelihood random effects* panel data regression was utilized.

In Table 4.2, the outputs of the estimated parameters that describe the models can be seen in detail. The goodness of fit was tested using the Log Likelihood ratio, LL, and the *chi squared* test, χ^2. In Table 4.2, these values are presented for the different models estimated.

Scale efficiency factors (SCEF) measure the close relationship of the production process to a range of return to scales that render optimum production. Coelli, 2005 gives a simplified interpretation of SCEF by stating that in a firm with multiple input/output production technology where the production function is allowed to become any of the following: decreasing, constant and increasing returns to scale, an efficient regime of the returns to scale production would be as close as possible to constant returns to scale.

Table 4.2: Results from regression models for Scale Efficiency SCEF

Estimation of SCEF				
Var	Lag	With Contracts	Without Contracts	All Cases
SO2PermtPr	L2	.0061‡	.0034	.0053‡
	L3	.0047‡	.0038	.005‡
BtusSub	L2	-3.2e-09	-2.5e-09	-2.7e-09
DistBit	L1	.001†	.0011†	.00077⋆
	L2	-.00061	-.0012†	-.00055
DistSub	L3	.0013⋆	.0017‡	.0015‡
CostSub	L3	-.0078	-.0036	-.01‡
CFGDi	L1	-.0016	-.004⋆	-.0021
MAXR		-.00034	-.00047‡	-.00033†
DRG_8		.98⋆	1.3‡	1.2‡
DY2000		.35⋆	.61‡	.57‡
Statistics				
σ_u		.66‡	.18	.47‡
σ_e		.53‡	.61‡	.58‡
LL		-195	-129	-288
χ^2		309	549	540

legend: $\star: p < 0.05$; $\dagger: p < 0.01$; $\ddagger: p < 0.001$

Regarding the effect of the price of SO_2 allowances, $SO2PermtPr$ in the scale efficiency ($SCEF$) of plants, all the cases analyzed suggest that an increase in the SO_2 allowance price will encourage an increase in the scale efficiency $SCEF$ two and three periods later. For the case of **contract transactions**, the change in $SCEF$ can be as high as six percent for every ten dollars of change in the price of allowances two periods later, and five percent three periods later. In the **spot market** prices of allowances do not affect the scale efficiency significantly. The positive effect of $SO2PermtPr$ on $SCEF$ seems to indicate that when prices of allowances increase, firms switch any of the other two strategies (buy more low sulfur coal, or, acquire FGDs), improving the scale factor. An increase of allowance prices can send a message of increased risk to firms triggering the risk averse behavior described in this paragraph.

The effect of SO_2 allowance prices could not be seen in the TEF model above. This reflects the fact that firms seem not to consider allowance prices when deciding about investments for improving production efficiency and therefore, allowance prices do not affect TEF. On the other hand, permit prices might be considered when deciding on the operation regime, and firms try to get close to production conditions that are in an appropriate level of returns to scale.

The effect of distance among mines providing bituminous coal and plants ($DistBit$) on the scale efficiency $SCEF$ is positive in the first lag and then it turns negative for the second lag. These results can be interpreted as follows: some plants will start buying bituminous coal from mines that are located farther away from their usual sources, in order to improve the scale efficiency of their electricity production process, but this increase has a positive effect only in the short term. If for any given reason, the increase of the distance among mines and plants continues for more than one period of time, it will start having a negative effect on the scale efficiency of those electricity producing plants.

The effect of the distance between mines providing sub-bituminous coal and plants ($DistSub$) on the scale efficiency $SCEF$, similar to TEF, is positive in the third lag. This again reflects the effort made by plants striving to become more efficient, and the need to buy more sub-bituminous coal from farther mines.

The cost of sub-bituminous coal, $CSUB$, has a negative consequences for the third lagged period. The medium term reaction of plants to a change in price of sub-bituminous coal, described by the parameter associated with the third lag of $CSUB$, is switching out of *Strategy (2): Buy relative larger amounts of coal with lower content of sulfur to produce less SO2 emissions*, and buying less and less sub-bituminous coal. This trend starts acting negatively on $SCEF$ efficiency factor. The changes in $CSUB$ are important: an increase of ten dollars in the price of the sub-bituminous coal, could cause a decrease in $SCEF$ of nearly ten percent three periods later.

The cost of investment in new technology ($CFGDI$) has a negative effect on $SCEF$ in the next period for the case of transactions on spot market. The significance is not extremely high. The negative impact might point at the effect that buying and installing new scrubbers has on the proportion of bituminous and sub-bituminous coal used for inputs, making them less scale efficient[19] .

Similar to the case of estimation for TEF, the size of the plant seems to bear negatively on the scale efficiency $SCEF$. Bigger plants seem to be less scale efficient in a general sense as well as technically.

Plants located in the *Mountain* region[20] , the value of $SCEF$ is significantly bigger than the national. This again can be attributed to the vicinity of the Powder River basin, that enhance $SCEF$ for this region.

Also, the effect of phase II of the CAAA is positive, as was the case for TEF. The value of $DY2000$ reflects an important increase of $SCEF$ efficiency associated to the beginning of phase II . The value of the $SCEF$ efficiency gain is almost sixty percent for the *general* case.

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[19] As shown in the TEF section, plants become at the same time *more* technically efficient. This *complementarity* of behavior can be seen in other parameters as well.

[20] Coded as 8, includes the following states: AZ, CO, ID, MT, NV, NM, UT, WY

Chapter 5

Emissions Abating Technology Adoption

In this chapter, based on conceptual ideas and initial empirical evidence, we build two econometric models to analyze the behavior of firms regarding the adoption of technology, and test the explanatory power of the efficiency factors TEF and $SCEF$ analyzed in Chapter 4.

5.1 General Considerations on Technology Adoption

Traditionally there has been the general belief among economists that market based environmental control regulations will accelerate innovation on new emissions abatement technologies more than *command-and-control* regulations. Some research has been done in this direction (Popp, 2003b, Popp, 2006, Milliman and Prince, 1989, **?**), that confirms this trend. But more important is the fact that diffusion of technology is linked to development of new technologies in both directions: (1) the technology has to exist to be adopted, and (2) diffusion of technology spurs new innovations. met (), when arguing in favor of taxes as a emissions control instrument when compared to cap-and-trade states that, *with* *an economy-wide emissions tax or cap-and-trade system, the marginal emissions cost to a firm is equal to the emissions price or tax*, and that all emissions costs at the margin would be equalized across the economy. But taxes will not always guarantee the desired reductions of emissions (**?**) and cap-and-trade instruments can distribute abatement costs more efficiently.

In general, there is evidence that the SO_2 emissions permit market has induced new innovations (Burtraw et al., 2005, **?**), even though some of the benefits realized with this instrument are also due to positive externalities such as low sub-bituminous coal and transportation prices, and the exogenous development of new abating technologies.

Capital costs of *scrubbers* have been consistently going down since the 90s (EPA), and at the same time the efficiency of FGDs for removing SO_2 gases from emissions has increased, and has become more reliable (Popp, 2003a, **?**).

The assumption that under an appropriate emission trading policy the social net benefit of abatement can be maximized requires that plants have strong incentives to minimize the cost of abatement. Plants face three options when adapting to the new environmental emission regulations, as mentioned in Section 1.4:

1. Paying the new costs of emissions and continuing business as usual.
2. Using higher quality inputs (coal) that generate less pollution.
3. Upgrading their processes and equipment to lower emissions. This includes buying new technology to abate emissions, or investing in R&D to improve or create new pollution abating technologies.

There are some circumstances that could change this situation. The influence of regulations by public utility commissions (PUCs) that can distract firms from a socially efficient solution (Arimura, 2002) is one of these. PUCs can alter the decision of a firm by allowing certain costs to be included in the calculations of the rate base by plants, for example, if PUCs allow the cost of allowances to be included in this calculation, this could motivate plants to buy SO_2 permits instead of switching to low sulfur coal, or buying abating technologies. In determining the value of a permit, Coggins and Swinton (1994) equate SO_2 allowances price to the marginal cost of abatement at the equilibrium of the allowance market, but point out that because the decision of buying a *scrubber* is *irreversible*, all things equal, there might be a bias in favor of buying SO_2 permits instead of FGDs if firms are risk-averse.

5.2 Empirical Evidence of Technology Adoption

Figure 5.1 reports the aggregated strategic behavior of firms, which can be contrasted with Figure 2.7. Figure 5.1 depicts the decision of building new FGDs adopted by firms in time. A few spikes can be clearly seen around the years 1985, 1990, 1995, 2000 and 2005. An analysis of the circumstances includes the following causes for these peaks in adoption of technology:

- Information shocks about the changes that new regulations included in the Clean Air Act would entail occurred before 1985[1] .
- Amendments to the Clean Air Act of 1970 were approved by the congress in 1990, sending a clear message to the electricity producing sector, and a new wave of adoption of abating technology by electricity producing firms.
- The beginning of phase I of the CAAA, that affected 263 older boilers and 174 newer ones, limiting their emissions of SO_2.
- The beginning of Phase II of the CAAA, that affected all boilers, and limited even

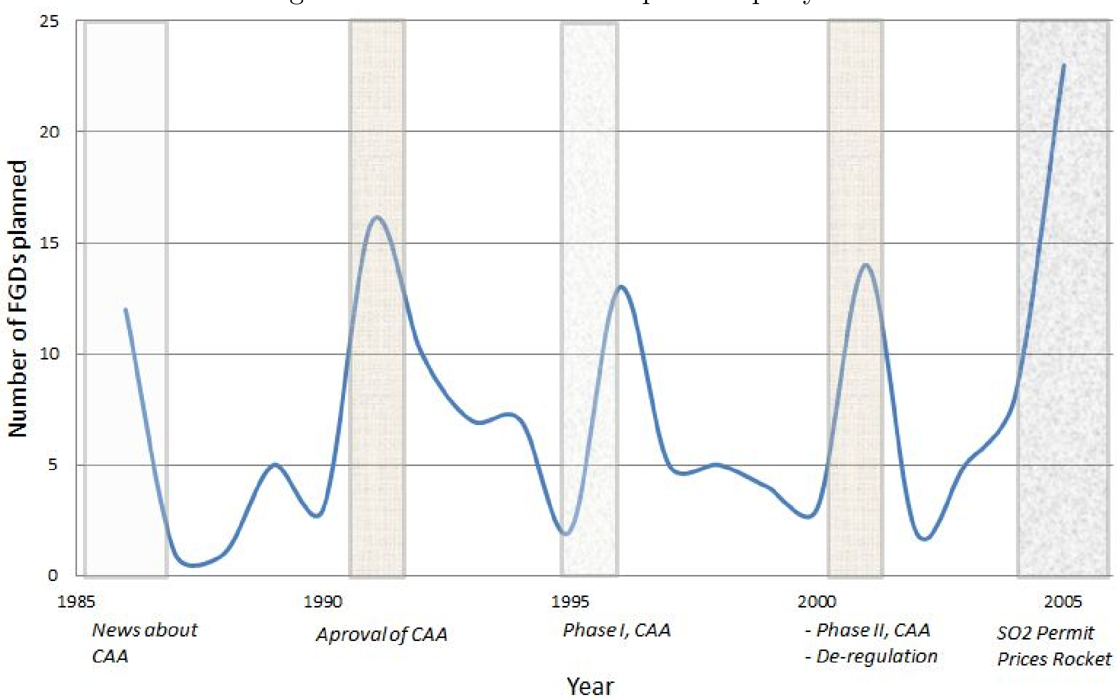
[1] There are some references in the technical literature to this fact. Popp [2004] finds evidence on the reactions of scrubber technology patents, before Phase I of the CAAA was enacted. Our data set starts in 1985, and therefore Figure 5.1 has been elaborated from that date on, but still, it is evident from the figure that there was some kind of peak before 1985.

more $S0_2$ emissions[2] .

- The extremely rapid climb of SO_2 allowance prices that occurred between 2004 and 2006.

Declines that occurred in 1985 and 1992 are probably due to external information shocks about changes in regulations that influence firms' behavior.

Figure 5.1: Number of FGDs planned per year



(Source: Form EIA 767)

After processing the information about FGD and coal purchased by plants[3] , the information on technology adoption, purchases of bituminous and sub-bituminous was

[2] The deregulation and restructuring of electricity markets, that started to take place at the end of 1999, and that was followed by the majority of states in the next years. This event could have influenced the decision of adopting FGD technology, but there is no proof of that.

[3] Formas EIA 767 and FERC 423 correspondingly

disaggregated at state level to analyze the relationship between the two strategies described above in Section 1.4. As an example of plants using Strategy (2): Buy relative larger amounts of coal with lower content of sulfur to produce less SO2 emissions, the investment strategies for buying new FGDs or buying lower sulfur coal is shown in Figure 5.2

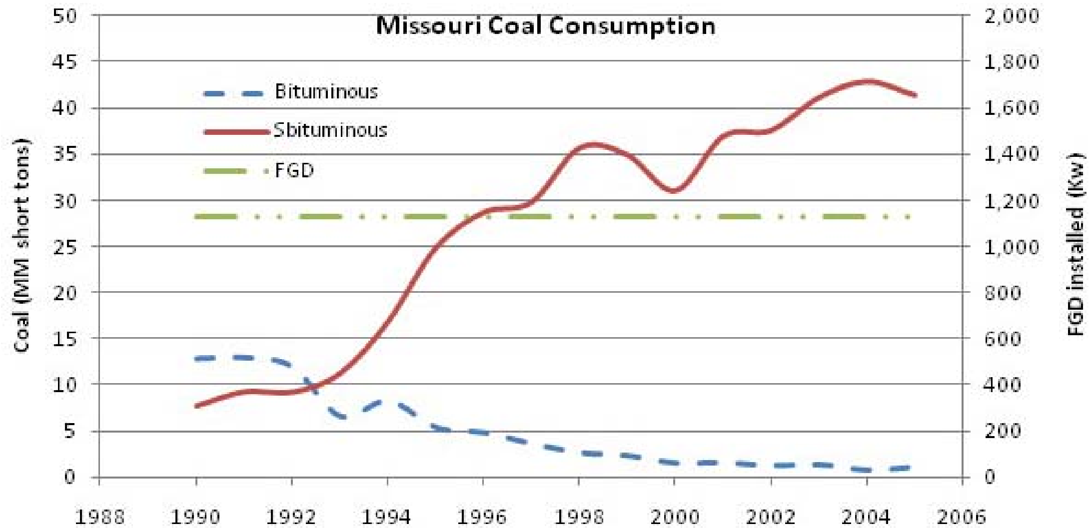
Since Missouri is located in the area of influence of Wyoming, it will be easier for plants operating in that area to utilize cleaner coal. The same can be said for Alabama, as can be seen in Figure 5.2

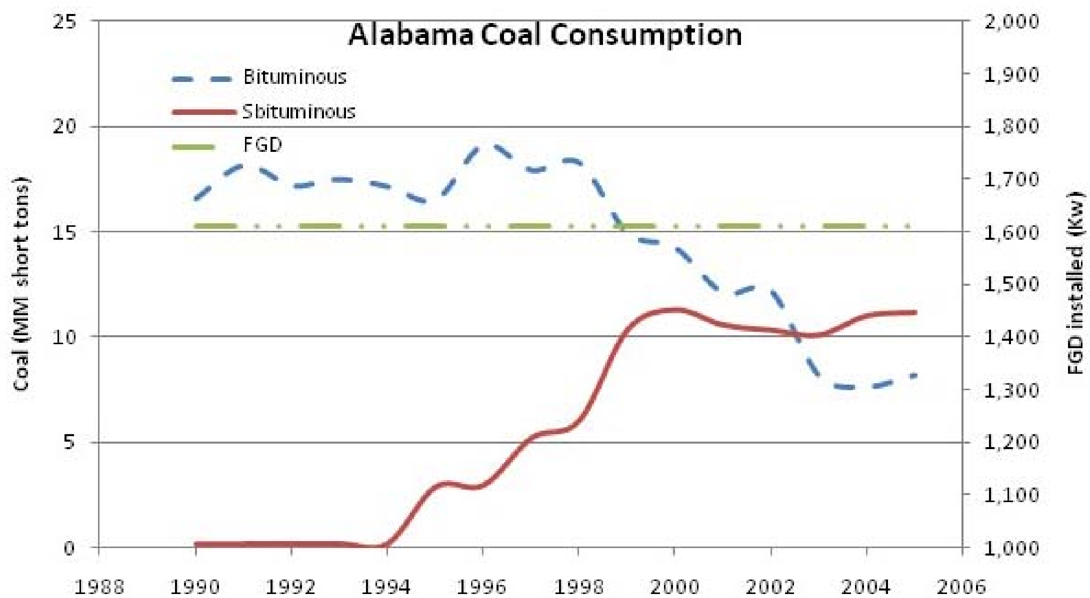
For an example of Strategy (3): Firms invest in new pollution abating technologies, we can examine the behavior of plants in Florida, displayed in Figure 5.3. Plants operating in Florida have chosen consistently invest in new FGDs as their strategy to reduce SO_2 emissions. .

Some states might choose to follow a mixed strategy. Such is the case with Colorado, as seen in Figure 5.3.

In the next section, an econometric model will be presented that intends to determine which parameters are key in explaining the decision of the adoption of technology.

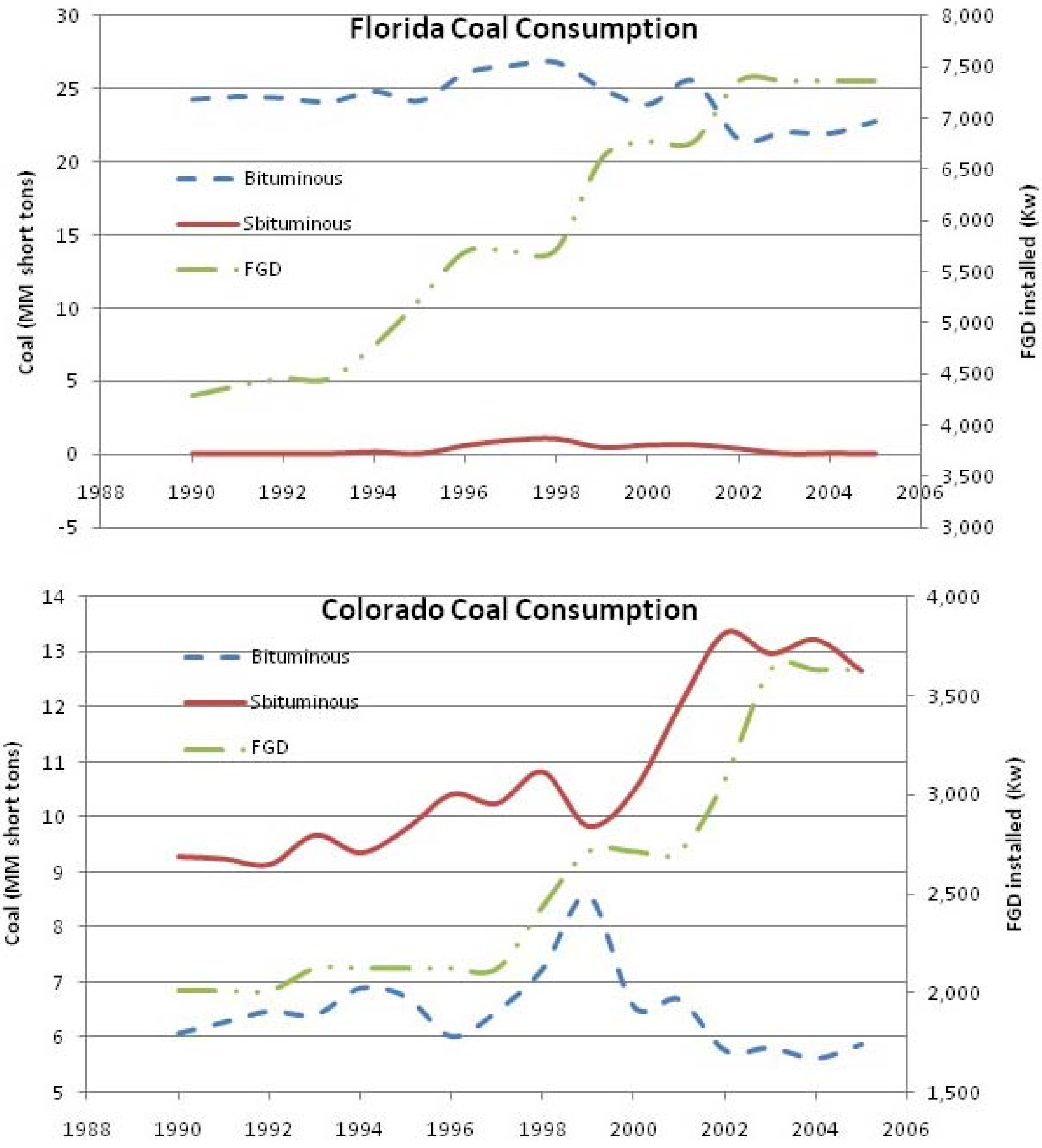
Figure 5.2: Expenditures in FGDs, Bituminous and Sub-bituminous coal





(Source: EIA)

Figure 5.3: Expenditures in FGDs, Bituminous and Sub-bituminous coal



5.3 Econometric Models

For analyzing the decision of firms to invest in technology, tow models were tested:

1. A **LOGIT** model, where the dependent variable is the option to adopt technology, $FGDOPT$.

2. A **TOBIT** model, that models the amount of electricity generated by boilers with scrubbers, $FGDMXRA$.

5.3.1 LOGIT Model for the Option of Adopting Technology

The technology adoption decision process is represented by the variable $FGDOPT$, which reflects the decision of an enterprise to invest in FGD technology and is equal to 0 before the FGD is built, and set to 1 starting from the year the plant buys a FGD, and this value is kept in the following years.

A Logit regression model is used to examine those factors which influence the decision to buy scrubber technology $FGDOPT$. A logistic regression model allows us to establish the relationship between the binary outcome variable $FGDOPT$ and a group of explanatory variables. In other words, the log odds of the outcome is modeled as a linear combination of the predictor variables. A forward-selection stepwise estimation process[4] was used to select which variables had a more significant explanatory power on the option to select technology.

To explain the decision of adopting scrubber technology $FGDOPT$, we initially assume it will be driven by contemporary and lagged values of various parameters.

First we consider the parameters that can be used to test the three optional strategies that firms opt to face environmental regulations, described in Section 5.1. These variables are:

- The price of SO_2 allowances, $SO2PermtPr$ to reflect Strategy (1).

[4] A stepwise two-phase methodology, as described in Section 4.4was utilized here.

- The cost of sub-bituminous coal $CostSUB$, and bituminous coal $CostBit$, and the amount of coal (bituminous $QBit$, and sub-bituminous $QSub$) purchased, for measuring the weight of Strategy (2) in the decision.

- The cost of technology investment $CostFGDi$, and the cost of operation and maintenance of scrubbers $CostFGDOM$, to test Strategy (3).

In addition, and in an attempt to understand the empirical evidence shown in Section 5.2 and in Chapter 3, the distance between sub-bituminous (bituminous) mines and plants $DistSub$ ($DistBit$), the contents of SO_2 in bituminous coal $SO2sBIT$, and geographical circumstances caused by the region where plants are located, represented by dummy variables $DREG_1$ thru $DREG_9$, were included in the model[5] .

These parameters were utilized in the econometric model to describe the decision to adopt technology by firms shown in Equation (5.1).

$$\begin{aligned} Logit \qquad (FGDOPT) = \sum_{i}^{lags} [&\alpha_{1i}\, L_i.SO2PermtPr + \alpha_{2i}\, L_i.CostSUB + \alpha_{3i}\, L_i.CostBIT + \\ &+\alpha_{4i}\, L_i.QSUB + \alpha_{5i}\, L_i.QBIT + \alpha_{6i}\, L_i.CostFGDi + \alpha_{7i}\, L_i.CostFGDom \\ &+\alpha_{8i}\, L_i.DistSub + \alpha_{9i}\, L_i.DistBit + \alpha_{10i}\, L_i.SO2sBit + \alpha_{11i}\, DREG_i +] + \varepsilon \quad (5.1) \end{aligned}$$

In a similar way as for the efficiency factors, for each parameter, L_i is a lag operator indicating the i-th lag of the parameter associated to it.

Empirical results

The option to invest in technology, represented by the variable $FGDOPT$, as described in Equation (5.1), was tested to select the parameters that better explained the technology adoption $FGDOPT$, eliminating those lagged parameters that lacked special statistical significance by stepwise iteration. Table 5.1 shows the resulting significant parameters that were estimated from Equation (5.1).

[5] Regions 1 and 9 were taken out of the analysis because they had very few coal-based electricity generating plants reporting to FERC.

Table 5.1: Estimated Coefficients for the Logit regression of the Option to Acquire FGDs

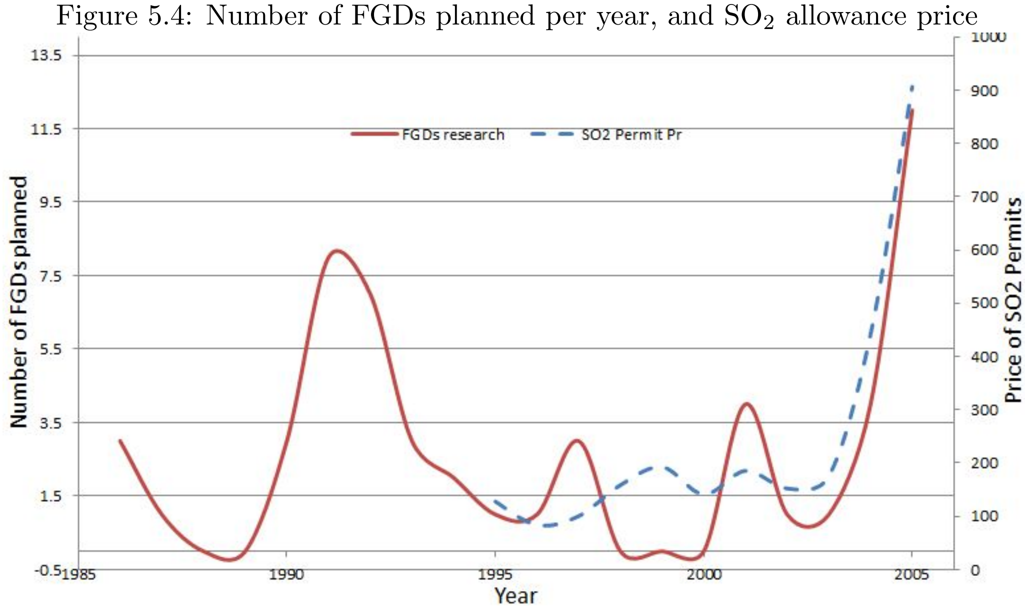
Logit of FGDOPT						
Par	**Lag**	**Value**	**Odds Ratios**	**Std. Error**	**Z Test**	$P > \|z\|$
SO2PermtPr	L1	.0089455	1.008986	.0095531	0.94	0.349
	L2	-.0437258	.9572164	.0244232	-1.79	0.073
CostSub	L1	.1898343	1.209049	.0756291	2.51	0.012
	L3	.1035518	1.109103	.0727481	1.42	0.155
QSUB	L1	2.61e-06	1.000003	9.07e-07	2.88	0.004
QBIT	L3	.0000163	1.000016	8.60e-06	1.90	0.058
CostFGDi	L3	.0896085	1.093746	.0318663	2.81	0.005
CostFGDOM	L1	-10.57522	.0000255	3.11613	-3.39	0.001
	L3	-14.46575	5.22e-07	3.451456	-4.19	0.000
DistSub	L1	.1467928	1.158114	.0428799	3.42	0.001
	L2	-.0955895	.908837	.0396644	-2.41	0.016
SO2sBIT	L1	-2.20e-07	.9999998	7.24e-08	-3.04	0.002
DRG4		-40.42498	2.78e-18	7.439396	-5.43	0.000
DRG5		-79.08738	4.50e-35	28.59719	-2.77	0.006

Statistics		
σ_u	13.00818	3.267284
ρ	.9809286	.0093977
LL	-22.22321	
$\chi^2(14)$	111.73	Prob $> \chi^2 = 0.00$

The statistical parameters are presented in the same table. *LL* stands for the log likelihood; χ^2 is the *chi* squared value, and for this case, with fourteen degrees of freedom, it is equal to 112. The p-value associated the chi-square with 12 degrees of freedom is 0.00, which indicates that the model as a whole is statistically significant.

Regarding Strategy (1) *Paying the new costs of emissions and continuing business as usual.* the estimation of the SO_2 allowance price parameter $So2PermtPr$ shows contradictory effects for the first and second lags. Notice that the statistical significance of these estimations is quite low. The mixed effects are most probably due to the lack of solid correlation between these parameters. This can be seen in Figure 5.4, where the

Figure 5.4: Number of FGDs planned per year, and SO_2 allowance price



(Source: Data used in the research)

number of FGDs planned per year used in the research[6] , and the historical SO_2 allowance prices, are plotted. In this figure, it is shown how the number of scrubbers planned per year and the price of SO_2 permits are apparently uncorrelated, until the price of the emission allowances starts to shoot up around 2004.

[6] Note that he figure reports data used in the research, which is different from the original data set, reported in Figure 5.1.

In relation to the second strategy: *Using lower sulfur coal as input that generate less pollution*, we need to look at the estimates of the parameters associated with the price of coal, and coal quantities purchased.

The cost of coal which really affects the decision to acquire technology is that of sub-bituminous coal. The first and third lagged values of the cost of sub-bituminous coal $CostSub$ has a positive effect on the probability of acquiring technology. The analysis shows that the first lag of the cost of carbon is statistically very significant. The results agree with the assumptions made for the behavior of firms that try to minimize costs: if the price of sub-bituminous coal rises, Strategy (2) becomes financially less attractive for firms, and they are more inclined to acquire new FGDs. On the other hand, if the price of sub-bituminous coal decreases, Strategy (2) turns out to be more attractive and firms are less likely to invest in scrubbers.

The other parameters associated with the Strategy (2) are the quantities purchased of bituminous coal, $QBit$, and sub-bituminous coal, $QSub$. The estimation of the model indicates that an increase in the amount of bituminous coal purchased affects the decision to acquire technology after three cycles. This behavior makes sense, since due to the substitution effect of two similar commodities, an increase in purchases of bituminous coal may be due, or is equivalent, to an increase in the price of sub-bituminous coal.

On the other hand, purchases of sub-bituminous coal increase the likelihood that plants buy FGDs only one cycle later. While the value of this parameter is comparatively much lower than that associated with the purchased amount of bituminous coal, this value corresponds to an unexpected behavior, probably the result of external shocks.

Turning to Strategy (3): *Upgrading their processes and equipment to lower emissions*, and as expected, there is a clear relationship between the adoption of technology and its cost. The estimations, nevertheless, show mixed results for the effect of FGD investment costs, $CostFGDi$, and operation and maintenance costs of FGDs, $CostFGDOM$, on the decision of investing in technology $FGDOPT$.

The effect of the capital cost of scrubbers on the decision of adopting technology is positive, implying that an increase in the investment cost of scrubbers, increases the probability that firms adopt abating technology. This behavior seems to challenge logic, as we would expect the opposite. But this result can be explained by the combination of three possible factors:

- Exogenous regulations or conditions.
- Reported increase of efficiency of FGDs.

For the second scenario, the *real options behavior of firms* is reflected in a risk-averse reaction when they have to decide between a perfectly reversible transaction, such as buying SO_2 allowances or switching to low sulfur coal, versus an irreversible investment, such as buying abating technology. This type of bias was mentioned in Section 5.1, and it would be illustrated in the following way: even though investment costs are going down, firms are buying more FGDs at a much slower pace.

The second explanation to the estimated behavior of $CostFGDI$ is the presence of *exogenous regulations or conditions* that can alter the decision of firms to buy scurbbers, as it could be with contractual commitments with sub-bituminous mines or transport companies, that would deter firms from investing in technology even when the investment cost is decreasing. As before, plants invest less in scrubbers even when capital costs are going down.

For the case of a *reported increase of efficiency in FGDs*, firms perceive that this increase in removal efficiency by FGDs decreases the marginal cost of abatement. In this way, the perception is that even though capital cost goes up, the reduction of marginal cost of abatement, due to the increased amount of SO_2 emissions that can be eliminated comfortably offsets the increase in capital cost[7] . Because there has been a downwards

[7] It is important to note here that the investment cost of scrubbers is given in US$ per KW of operation

trend in the prices of scrubbers, this explanation the least probable of the three presented.

The cost of operation and maintenance of scrubbers, represented by $CostFGDOM$, as expected, has a negative impact on the probability of investing in new technology. This fact is reflected in the low odds ratio value for the estimation of the first and third lags of $CostFGDOM$, meaning that if the value of $CostFGDOM$ increases, the probabilities of adopting abating technology decreases. As was mentioned in Section 5.1, operation and maintenance costs of SO_2 abating equipment have increased consistently through time since the 90s, affecting negatively the decision of adopting technology.

The O&M costs are added directly to the marginal costs of abatement when companies calculate returns on investment in FGDs. Thus, the results show that an increase in O&M costs discourages firms to opt for Strategy (3) *Upgrading their processes and equipment to lower emissions*, as logic dictates.

The first lag of the estimation of the parameter related to the distance between sub-bituminous mines and electricity plants, *DistSub*, connects an increase in the distance between mines and plants to an increase in the probability of buying FGD technology. This behavior corresponds to what was expected, since an increase in the distance from where the sub-bituminous coal has to be shipped to the power plant can be interpreted as an increased demand for sub-bituminous coal. This behavior corresponds to Strategy (2): *Using lower sulfur coal as input that generate less pollution.* As the demand for sub-bituminous coal increases, coal needs in many cases to be transported from a greater distance, and the marginal cost of abating emissions for plants choosing Strategy (2) increases, incrementing the odds that firms choose Strategy (3) and purchase FGDs.

The effect of the first lag of *DistSub* mismatch, however, is contrary to the result described in the second lag. An increase in the transport distance of sub-bituminous coal results in a decrease in the probability that firms adopt emissions abatement technology.

capacity of the plant. When the efficiency of FGDs increases, it results in more SO_2 removed from emissions, but the cost of the scrubber is not affected.

This result may represent a causal relationship where companies that choose Strategy (2) over Strategy (3) continue buying sub-bituminous coal even if they have to obtain it from mines farther away.

There is a negative correlation between the content of SO_2 in the bituminous coal, $SO2sBit$, and the decision to buy FGDs. It is clear that the negative correlation between the amount SO_2 in bituminous coal (and therefore, an increase in SO_2 emissions resulting from burning the coal) and the probability of buying FGDs reflects a preference for Strategy (2) over Strategy (3), where firms buy more coal with lower content of sulfur instead of FGDs.

The estimation of the dummy variables $DREG4$ and $DREG5$ indicates that the probability of adoption of abatement technology in plants located in the West North Central region[8] and in the South Atlantic region[9] is much smaller. For the case of the West North Central region, this could be attributed to its closeness to the main sources of sub-bituminous coal. It is more likely that the availability of less expensive low sulfur coal makes Strategy (2) more attractive than Strategy (3).

The minor differences between the econometric results and the practical values analyzed in Section 5.2 is probably due to the selection of data used in the econometric runs. Only plants with complete data for 90% or more of the periods analyzed were chosen for the model estimation, and quite a few plants were left out.

LOGIT Model for Adopting Technology with Efficiency Factors

The option to invest in technology, represented by the variable $FGDOPT$, was analyzed in Section 5, using the model described in Equation (5.1). In this section the technical efficiency factor, TEF, and the scale efficiency factor, $SCEF$, are included in these equations

[8] Corresponding to region (4): IA, KS, MN, MO, NE, ND, and SD

[9] This is region (5), that includes DC, DE, FL, GA, MD, NC, SC, VA, and WV

to see their explanatory power in the estimation of the adoption of technology, FGDOPT.

To explain the decision of adopting scrubber technology $FGDOPT$, we include lagged values of the TEF and $SCEF$ efficiency factors in the model presented above. These were added to the contemporary and lagged values of the following parameters: the cost of investment of technology $CostFGDi$, operation and maintenance cost of scrubbers $CostFGDOm$, the cost of sub-bituminous coal $CostSUB$, the quantity of coal (bituminous $QBIT$ and sub-bituminous $QSUB$) bought, distance between sub-bituminous mines and plants $DistSub$, and the contents of SO_2 in bituminous coal $SO2sBIT$, were utilized to describe the decision to adopt technology by firms.

$$\begin{aligned} Logit \quad (FGDOPT) = \sum_{i}^{lags} [&\alpha_{1i}\, L_S O2i.PermtPr + \alpha_{2i}\, L_i.CostSUB + \alpha_{3i}\, L_i.CostBIT \\ &+\alpha_{4i}\, L_i.QSUB + \alpha_{5i}\, L_i.QBIT + \alpha_{6i}\, L_i.CostFGDi + \alpha_{7i}\, L_i.CostFGDom \\ &+\alpha_{8i}\, L_i.DistSub + \alpha_{9i}\, L_i.DistBit + \alpha_{10i}\, L_i.SO2sBit \\ &+\alpha_{11i}\, TEF_i + \alpha_{12i}\, SCEF_i + \alpha_{13i}\, DREG_i] + \varepsilon \end{aligned} \tag{5.2}$$

As before, for each parameter, L_i is a lag operator for the i-th lag.

The results from the estimation of the parameters for model shown in Equation (5.2) are presented in Table 5.2. The tests and the statistical parameters are shown in the same table.

Table 5.2: Estimated Coefficients for the Logit of the Option to Acquire FGDs

Logit of FGDOPT						
Par	**Lag**	**Value**	**Odds Ratios**	**Std. Error**	**Z Test**	$P > \lvert z \rvert$
SO2PermtPr	L1	.0144891	1.014595	.0109909	1.32	0.187
	L2	-.0574055	.9442111	.032373	-1.77	0.076
CostSub	L1	.1568691	1.169843	.0832702	1.88	0.060
	L3	.1079753	1.11402	.0856147	1.26	0.207
QSUB	L1	2.04e-06	1.000002	9.61e-07	2.12	0.034
QBIT	L3	.0000211	1.000021	9.09e-06	2.32	0.020
CostFGDi	L3	.0835492	1.087139	.0377988	2.21	0.027
CostFGDOM	L1	-9.38723	.0000838	3.924874	-2.39	0.017
	L3	-17.8027	1.86e-08	4.280446	-4.16	0.000
DistSub	L1	.1798173	1.196999	.0551988	3.26	0.001
	L2	-.1175742	.8890746	.0535411	-2.20	0.028
SO2sBIT	L1	-3.21e-07	.9999997	1.08e-07	-2.98	0.003
TEF	L2	14.8196	2729414	6.393219	2.32	0.020
DRG4		-50.6173	1.04e-22	10.2167	-4.95	0.000
DRG5		-85.42945	7.92e-38	38.05834	-2.24	0.025
Statistics						
σ_u		13.83878		3.540355		
ρ		.9831117		.0084951		
LL		-20.347585				
$\chi^2(14)$		90.02		Prob $> \chi^2 = 0.00$		

In a similar way as before, LL stands for the log likelihood; χ^2 is the *chi* squared value.

Also, in Table 5.2 the estimated coefficients computed as odds ratios are presented.

Comparing Table 5.1 with Table 5.2, the contribution of TEF and SCEF coefficients can be analyzed. Firstly, the impact of the second lag of TEF on the adoption of technology is substantial. SCEF on the other hand, has disappeared completely from the model as no significant parameters could be estimated that explained the adoption of technology, $FGDOPT$.

The second lag of the technical efficiency factor is statistically significant, and has a substantial effect on the probability that plants adopt abatement technology, as can be seen in the estimation of TEF in Table 5.2.

The important contribution of TEF in the definition of FGDOPT causes other variables to change their relevance. Such is the case of the regional effect, represented by $DREG_4$ and $DREG_5$, where the tendency of investing less in abating technology in regions 4 and 5 is increased substantially.

Also, the introduction of TEF and SCEF in the FGDOPT estimations seems to increase the fit of the models for every case, as is reflected in the reduction of the Log-likelihood ratio.

The introduction of TEF into the model also affects the significance of key parameters discussed above in relation to the different strategies that firms follow. And so, the effect as well as the significance of the first lag of the price of SO_2 allowances, $SO2PermtPr$, increased notoriously, highlighting even more the direct relationship between permit prices and the probability of buying FGDs, that could be reflected in Strategy (1), i.e. buying SO_2 allowances and continuing business as usual.

The third lag of the cost of operating and maintaining scrubbers has a more important effect in the estimation of Equation (5.1) than that of Equation (5.1), emphasizing even more the negative correlation between $FGDOM$ and $FGDOPT$, and pointing at a decision in line with Strategy (3), and *buying FGDs*.

5.3.2 TOBIT model that Describes the Option to Use FGDs

A **TOBIT** model, that models the amount of electricity generated by boilers with scrubbers, $FGDMXRA$, as a function of the relevant variables, is developed and estimated in this part.

The technology adoption decision process is represented by the variable $FGDMXRA$, which quantifies the amount of electricity produced byu oilers with scrubbers, and reflects the decision of plants to use FGD technology.

The Tobit regression model is used in this case, as it is a censored methodology that won't allow the values of generated electricity to be negative. Similar to the case of the Logit model, a forward-selection stepwise estimation process was used to select which variables had a more significant explanatory power on the option to select technology[10] .

The decision of using scrubber technology to generate electricity, $FGDMXRA$, is assumed to be influenced by contemporary and lagged values of some relevant parameters. As before, we consider the parameters that can be used to test the three optional strategies that firms opt to face environmental regulations.

In addition to these variables, distances between sub-bituminous and bituminous mines and plants $DistSub$ ($DistBit$), as well as the the contents of SO_2 in bituminous coal $SO2sBIT$, and geographical circumstances caused by the region where plants are located, represented by dummy variables $DREG_1$ thru $DREG_9$, were included.

The general model utilized in the iteration process to find the best estimations that describe the decision to use technology by firms to generate electricity is as follows:

$$\begin{aligned} TOBIT \qquad (FGDMXRA) = \sum_{i}^{lags} [&\alpha_{1i}\, L_i.SO2PermtPr + \alpha_{2i}\, L_i.CostSUB + \alpha_{3i}\, L_i.CostBIT + \\ &+\alpha_{4i}\, L_i.QSUB + \alpha_{5i}\, L_i.QBIT + \alpha_{6i}\, L_i.CostFGDi + \alpha_{7i}\, L_i.CostFGDom \\ &+\alpha_{8i}\, L_i.DistSub + \alpha_{9i}\, L_i.DistBit + \alpha_{10i}\, L_i.SO2sBit + \alpha_{11i}\, DREG_i +] + \varepsilon \end{aligned} \tag{5.3}$$

For each parameter, L_i is a lag operator indicating the i-th lag of the parameter associated

[10] Again, a stepwise two-phase methodology, like the one described in Section 4.4was utilized here.

to it.

Empirical results

Table 5.3 displays the estimated parameters that were statistically significant in Equation (5.3).

Table 5.3: Estimated Coefficients for the Logit regression of the Option to Acquire FGDs

Tobit of FGDMXRA					
Par	**Lag**	**Value**	**Std. Error**	**Z Test**	$P > \|z\|$
SO2PermtPr	L3	.677236	.3467233	1.95	0.051
CostBit	L3	-1.147671	1.186343	-0.97	0.333
CostSub	L3	2.444221	1.377136	1.77	0.076
CostFHGDi		-3.230523	1.15291	-2.80	0.005
	L3	-1.192533	1.292108	-0.92	0.356
CostFGDOM	L3	-71.3477	62.19812	-1.15	0.251
SO2sBit		1.22e-06	5.74e-07	2.12	0.034
DRG3		-1313.468	240.1852	-5.47	0.000
DRG4		-1357.021	230.0198	-5.90	0.000
DRG6		-988.8158	317.7615	-3.11	0.002
DRG7		-1335.876	374.5892	-3.57	0.000
Statistics					
σ_u		1413.025		160.4373	
ρ		.9740495		.0066841	
LL		-953.34412			
$\chi^2(14)$		228.50		Prob $> \chi^2 = 0.00$	

As before, The statistical tests are presented by LL, the log likelihood; χ^2 the *chi* squared value. The p-value associated the chi-square with 11 degrees of freedom is 0.00, which indicates that the model as a whole is statistically significant.

The results from the $TOBIT$ model are in most cases similar to those obtained above for the $LOGIT$ model, and described in Table 5.1. Nevertheless, some parameters have a behavior that is closer to the expected one in this model. The effect of SO_2 allowance prices, for example, influences the decision of using scrubbers by firms in an unambiguous way. An increase in the prices of allowances is related to an increase in the use of electricity three periods later.

It is also worth noticing that in this model the effect of capital investment costs of scrubbers displays a closer to expectations. As a matter of fact, an increase of the investment costs of FGDs will influence firms three periods down the road, to use less scrubbing in the electricity production. Operation and maintenance costs of scrubbers behave alike in both models.

Plants located in the East North Central, the West North Central, the East South Central, and the West South Central regions, seem to use less scrubbing for producing electricity. These regions are relatively close to the Powder River Basin region, and this geographical circumstance could explain these results.

Chapter 6

Conclusions

The decisions of firms when choosing from among the different strategies as described in Section 1.4 has been analyzed to determine if investment in SO_2 emissions abating technologies and innovation by coal-based electricity producing firms are efficient in optimizing their profits by minimizing the marginal abatement cost. This takes into account institutional and political arrangements, as well as geographical and market circumstances that affect the performance of the SO_2 allowance market.

Under the assumption that the Clean Air Act Amendments of 1990 created a competitive cap-and-trade market of SO_2 allowances that helped lower emission levels, we developed an empirical framework to determine if firms choose economically efficient alternatives when facing environmental control regulations for SO_2 emissions.

We set up an analytical framework, assuming a marginal abatement cost-minimizing behavior, to test if firms are efficient when reducing the marginal abatement costs related to emissions. The results of this research show that firms with comparatively higher technical efficiency factors adopt more efficient strategies to reduce marginal abatement costs, giving a strong indication that firms are acting as efficiently as possible when adapting themselves to the new emissions regulations imposed. The experimental analysis of the decision process was done at a disaggregated plant level, as different plants belonging to the same firm can follow different strategies.

In analyzing possible strategies that firms adopt to offset the effects of new environmental regulations in ways that minimize their costs, three general paths were assumed: (1) paying the new costs of emissions and continuing with business as usual on the production site, (2) using higher quality inputs (coal) that generate less pollution, (3) upgrading their processes and equipment to lower emissions. This includes buying new technology to abate emissions, or investing in R&D to improve or create new pollution abating technologies.

All the results obtained in the empirical analysis reinforce the conclusion that when following pollution control regulations such as the Clean Air Act, firms tend to respond to the imposition of the new *emission abating* costs by choosing an emissions cost minimization strategy. This behavior seems to hold even when there are distortions and external shocks that might affect the SO_2 allowance market, such as local regulations and subsidies; transaction costs imposed by the existence of contracts, or railway transportation, and regulatory changes, among others.

6.1 Some Conditions Affecting Optimal Behavior

In Chapter 1, some important circumstances that influence the behavior of firms when choosing among strategies, are discussed and examined using empirical data in Chapter 3. In particular two main conditions are considered that might affect the decision of firms facing new or more stringent pollution control regulations.

As concluded in Section 3.1, the existence of a formal relationship by way of coal provision contracts between coal mines and electricity generating firms, affects the price paid by electricity generating plants in various ways for bituminous and sub-bituminous coal. The relationship between the evolution of coal prices versus the frequency of contracts over time, shown in Figure 3.1, is reflected in the estimation results of Equation (3.4)(2) and (4). An increase in the prime spread paid for the contracted purchases of bituminous coal over the spot market tends to increase the frequency of contracts, $FREQ$, while the opposite result was obtained for the prime paid for sub-bituminous coal contracts. From this, we can conclude that bituminous coal producing firms have more leverage over coal prices than sub-bituminous mines.

In the same section the influence of the beginning of phase II of the CAAA was tested, and the results indicated that there is a significant structural change around the year 2000, as can be seen in the estimation of the dummy variable $DR2000$ in Table 3.1. As a confirmation of the structural change that occurred in the year 2000, the expression for $FREQ$ was tested for different years, and it was concluded that the best fit was obtained when assuming the structural change in the year 2000. Furthermore, in Section 3.3 the results imply that firms, plants, as well as mines, are utilizing coal contracts to some degree as a strategy to cope with variations in coal prices in the market.

In Section 3.4 a simple model that equates transportation distance of coal and coal prices of sub-bituminous coal is used to analyze coal purchases done under contract and at the spot market price. As expected, Equation (3.5) indicated that distance between coal producing mines and electricity plants influences the prices paid for the sub-bituminous coal at the plant level. It is interesting to note that the coal price for transactions under contract starts from a higher initial value than the spot market, but afterward increases with distance, but at a lower rate.

The effect of the region where plants are located, is examined in Equation (3.6), in Table 3.6, and shows clearly that in addition to the effect that the mine to plant distance has on coal price, the region where the plant is located also impacts this price. Also, there is a statistically significant difference between the effect of mine to plant distance for transactions done under contracts versus spot market. Empirical data suggests that mines receive a higher *base price* under contracts, but spot market prices increase at a higher rate with distance. For some regions, i.e. the West North Central and the Mountain regions, the base price is considerably smaller than for others (South Atlantic region) in transactions under contracts or at spot market. To summarize, the West North Central region (4) pays a relatively lower price for the sub-bituminous coal, while plants in the South Atlantic region (5) have to pay a relatively higher price for sub-bituminous coal.

6.2 Efficiency Factors

The technology efficiency factor measures the efficiency of use of inputs to produce more outputs, in other words, it measures how close inputs and outputs are from the production frontier. For our research, SO_2 emissions were considered a *negative* output, and therefore together with coal were taken to be inputs in the empirical model used here, while produced electricity energy is the output. It is noteworthy to mention that the values of SO_2 emissions were calculated from the sulfur contained in the fuel coal. Scale efficiency factors, SCEF, deliver a quantifiable measure of the type of returns to scale of the production technology. In other words, SCEF measures the distance between the actual variable returns to scale (VRS) production frontier hyperplane, and the optimal constant returns to scale (CRS) hyperplane.

For both TEF and $SCEF$, the model has a lower likelihood ratio (i.e., it has more explanatory power) for the sub-sample containing only records of coal buying transactions in the spot market, than for the sub-sample of coal purchased under contract transactions. It is also noticeable that in many cases the coefficients on the explanatory variables vary among the two types of transactions. It is interesting to notice the *complementary* behavior of some independent variables when comparing the models explaining TEF and $SCEF$. Some variables' effect on TEF is the opposite to that on SCEF, which can be related to the fact that both factors measure complementary efficiency conditions of the production process. The most striking case is the effect of the capital cost of abatement technology, $CFGDi$, that has an opposite effect for TEF and $SCEF$.

The price of bituminous coal has a positive influence on TEF as expected. When bituminous coal price increase, some plants with fewer design limitations to switch between different types of coal, will direct part of their production to using low sulfur coal. On the other hand, if the price of sub-bituminous coal increases, the scale efficiency $SCEF$ decreases. The reaction of plants to an increase in price of sub-bituminous coal is to buy less sub-bituminous coal. This trend causes the $SCEF$ to decline, indicating a drop in scale efficiencies.

To maintain their efficiency, firms choose between buying more SO_2 emission allowances versus the option of cashing out their SO_2 allowances, if their emissions are too big; or keeping and banking the owned allowances versus selling them at a good price, if their emissions are low. The results show that firms adopt a risk averse strategy, using their SO_2 allowances if *perceived risk* increases, and switching away from buying allowances as an emissions compliance strategy.

The size of the plant has a significant effect on the technical efficiency factors of plants, TEF, but it is not as big for the case of scale efficiencies $SCEF$. The beginning of phase II, CAAA, was associated with a significant increase en both, TEF and $SCEF$.

The geographic effects on the efficiency factors can be seen in the regional effects detected. Electricity generating plants located closer to the Powder River Basin seem to benefit more by their proximity to big sub-bituminous coal sources. Consequently, plants located in the West South Central and Mountain regions have comparatively high TEF levels, while plants located in the East North Central and the West North Central regions had relatively smaller TEF levels compared with electriciy plants located elsewhere in the country. Plants located in the mountain region can have TEF levels 37 percent greater than the other regions. For the case of scale efficiencies, $SCEF$, only plants located in the Mountain region achieved any scale efficiency due to their location.

An interesting outcome of the TEF and $SCEF$ factors analysis is the fact that the beginning of phase II that occurred around the year 2000, had a positive effect of considerable proportions on both. Part of the possitive effect on TEF and $SCEF$, could be due to gains from the deregulation of the electricity producing sector, as corroborated in some results from previous researches around the effects of the derregulation of the electricity sector.

6.3 The Technology Investment Decision

The econometric analysis of the decision of buying technology by electricity producing plants, $FGDOPT$, was tested for various parameters as described in Section 5.3. The main purpose of the analysis was to test the behavior of firms when selecting among the strategies described in Section 1.4, reflected partially in the empirical behavior of plants reported in Section 5.2. The estimations of the econometric model for $FDGOPT$ show that the fit is improved, i.e., the log likelihood of the model decreases, by introducing the variable TEF to the set of explanatory variables.

As a parameter to describe the adoption of strategy one, paying the equivalent costs of emissions and continuing business as usual in the production process, the SO_2 allowance price parameter shows an unexpected effect on the decision of adopting technology, but the effect is not statistically significant. In Figure 5.4 these results can be corroborated visually: the number of scrubbers planned per year and the price of SO_2 permits are apparently uncorrelated until the price of the emission allowances starts to shoot up around 2004.

In relation to the second strategy (using lower sulfur coal as input to lower emissions), we observe the effect of the cost of coal, and the quantities purchased on the decision to acquire technology. Lagged values of the cost of sub-bituminous coal have a positive effect on the probability of acquiring scrubber technology. These results are in line with a cost minimizing behavior of firms, such that as the price of sub-bituminous coal rises, firms are more inclined to acquire new FGDs.

The estimated effect of values of quantities of coal purchased due to the decision to buy scrubbers are neither large nor statistically significant. They show a substitution effect of two similar commodities: an increase in purchases of bituminous coal may be due, or is equivalent, to an increase in the price of sub-bituminous coal, expressed in the model as an increase in the probability that firms invest in FGDs.

Turning to strategy three, acquiring emissions abating technology, a strong relationship between the adoption of technology and its cost was established, but the results are mixed. We found that an increase in the investment cost of scrubbers increases the probability that firms adopt abating technology. Some arguments to explain this behavior are the existence of exogenous regulations or conditions that influence the decision process, such as the way in which PUCs allow electricity generating plants to recover their investment; or the reported increase of efficiency of FGDs, that still makes them attractive to firms even when their price goes up.

The cost of operating and maintaining scrubbers, on the other hand, showed a negative effect on the probability of investing in new technology. As firms add operation and maintenance costs into the marginal production costs, an increase in operation and maintenance costs discourages firms to opt for abatement technology.

The estimation of the parameter related to the distance between sub-bituminous mines and electricity plants shows mixed results. An increase in the distance in the near past (i.e. the first lag) relates directly to an increase in the probability of buying FGD technology. This can be interpreted as an increased demand for sub-bituminous coal, and it produces an equivalent effect to an increase in sub-bituminous price. An increase in the distance in purchase transactions realized further in the past (in this case, in the third lag), on the other hand, corresponds to a decrease in the probability of buying scrubbers. This relationship can be explained as an increased demand for sub-bituminous coal, which corresponds to strategy two, buying lower sulfur coal, instead of buying FGDs.

The model shows some conclusive trends in the behavior of firms located in the West North Central region and the South Atlantic region. Plants belonging to these regions are more reticent to adopt abatement technology, as indicated by significant negative value of the coefficient on the geographical dummy variable.

Finally, the technical efficiency factor TEF is statistically significant, and has a substantial bearing on the probability that plants adopt abatement technology. Not surprisingly, in plants that have higher technical efficiency standards the probability of acquiring scrubber technology increases. The important contribution of the technical efficiency factor in the definition of the option for technology improves the results of the statistical tests indicating a better fit. Some estimations change in an considerale way. The regional effect for example, increases substantially when considering the technical efficiency in the model.

6.4 Conclusions about the Methodology

We used the Data Envelopment Analysis methodology to assess the efficiency of plants regarding their closeness to technical frontiers of production and the type of returns to scale under which production of electricity was done. The resulting benchmark coefficients, TEF and SCEF, were useful for indicating which firms were efficient from those which were not.

To test the suitability of these variables, panel data regressions were run, and results analyzed to check that they would be describing an economically plausible reality. This was the case for most variables, and the estimation of proposed models resulted in factors that could matched their expected behavior in real situations. These models were later tested for the analyzing the technology adoption decision process by firms.

The Logit methodology used for estimating FGDOPT is robust and by iteration four econometric models were chosen for analysis. The analyzed models returned results that were statistically significant and largely consistent among the models.

As mentioned before, the inclusion of the efficiency factor TEF in the logit model describing the probability of adoption of technology $FGDOPT$, increased the fit of the equation, and the statistical significance of the other estimated parameters.

6.5 Limitations of the Research

In the analysis, banking of SO_2 allowances was not considered. According to EPA, in the year 2008 alone, 125 thousand allowances were traded on the spot market for a net value close to 43 million US$. The Regional Clean Air Incentives Market (RECLAIM) however, prohibits the banking of allowances. The behavior of plants could actually vary from those displayed in the relationships of the econometric equations if banking were to be considered. Further data on SO_2 allowances transactions among the agents in the electricity producing sector would be necessary to carry out a more complete analyses that would take into account from specific banking strategies. On the other hand, the storage of coal by plants would not greatly influence the operating strategies of plants, as coal storing capacity is limited in most plants, and extends for only a few days.

The effect of SO_2 emissions abating technology can still be more finely tuned to take into account the real reduction of emissions of scrubbers, as well as the amount of energy CONSUMED BY ELECTRICITY GENERATING PLANTS to make then work. A technical efficiency factor that takes into account these aspects would look somewhat different from the ones obtained in this research.

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Appendix A

Glossary and Acronyms

Care has been taken in this thesis to minimize the use of jargon and acronyms, but this cannot always be achieved. This appendix defines jargon terms in a glossary, and contains a table of acronyms and their meaning.

A.1 Glossary

Stationary Sources Sources of pollution emissions that are immobile or fixed, it applies mainly to industrial sources. The other category is *mobile sources*.

Emission Allowance Emissions allowances are government-authorized rights to discharge a specific quantity of pollutant, usually allocated on the basis of historical pollution activity. Allowances are generally denominated in unit (i.e., ton) increments, with the overall cap measured in total units. (EPA, Types of Trading, found at http://www.epa.gov/airmarkets/, retrieved Oct. 2004.)

SO_2 Allowance Is an emission allowance that authorizes a electricity producing firm to discharge one ton of SO2. At the end of each year, the source must hold an amount of allowances at least equal to its annual emissions. SO_2 forms when sulfur contained in fossil fuels is burned. Some of its negative effects are to inhibit visibility, increase acid rain, and deteriorate human health.

British Thermal Unit, Abr. BTU Energy unit of of heat input. BTUs are commonly used as a measure of energy contained in the coal, as input fuel. Equivalence: 1 million BTUs = 1 mmBTUs = 293.1 KW-H

Kilowatt hour, Abr. KW-H Unit of electricity energy. Used frequently to meassure electricity production by generating plants. Equivalence: 1 KW-H = 3,412 mmBTUs

Generarting unit A *unit* is a single generator and associated boiler. A generating power plant can house one or several units, which may be of different sizes, vintages, type, or fuel input.

A.2 Acronyms

Table A.1: Acronyms

Acronym	Meaning
BNSF	Burlington Northern Santa Fe railroad company
BTU	British Thermal Unit of energy. Equivalence: 1 million BTUs = 293.1 KW-H
CAA	Clean Air Act
CAIR	Clean Air Interstate Rule
CAAA	Clean Air Act Amendments of 1990
CAC	Command-and-control environmental control
CBOT	Chicago Board of Trade. Emission allowances trading entity
CRS	Constant Returns to Scale

Continued on next page

Table A.1 – continued from previous page

Acronym	Meaning
DEA	Data Envelopment Analysis
EIA	U.S. Energy Information Administration
EPA	U.S. Environmental Protection Agency
EPACT92	Energy Policy Act of 1992 (102nd Congress H.R.776.ENR)
EPV	Expected Present Value
FCCC	United Nations Framework Convention on Climate Change
FERC	Federal Energy Regulatory Commission
FGD	Flue Gas Desulphurization unit, or *Scrubber*
FPA	Federal Power Act
GBM	Geometric Brownian Motion
IPF	Intellectual Property Framework
KW-H	Kilowatt - Hour 1 KW-H = 3,400 million BTUs
NAAQ	National Ambient Air Quality Standards
NESHAP	National Emission Standards for Hazardous Air Pollutants
NPV	Net Present Value
NOx	Oxides of nitrogen
NSPS	New Source Performance Standards
PRB	Refers to the Powder River Basin mining area located mainly in Wyoming, and that provides most of the low-sulfur coal in the U.S. coal market
PSD	Prevention of Significant Deterioration
PUC	Public Utility Commission
PURPA	Public Utility Regulatory Policy Act

Continued on next page

Table A.1 – continued from previous page

Acronym	Meaning
ROA	Returns on Assets. Is a financial performance indicator = Net Income divided by Total Assets
ROR	Rate of return
SIP	State Implementation Plans
SO_2	Sulfur Dioxide
UNFCCC	United Nations Framework Convention on Climate Change
UPR	Union Pacific railroad company
VRS	Variable Returns to Scale

Appendix B

Miscellaneous Tables

Table B.1: SO2 emissions by source

Source: 2008 National Emissions Inventory, EPA

Source Type	SO2 emissions (tons)	Percentage
Electricity Generation via Combustion	7,875,926.81	83.33%
Other	747,296.60	7.91%
Pulp and Paper Plant	284,328.64	3.01%
Petroleum Refinery	122,999.15	1.30%
Portland Cement Manufacturing	108,644.73	1.15%
Steel Mill	60,924.87	0.64%
Ethanol Biorefineries	55,169.22	0.58%
Primary Metal Production	46,920.51	0.50%
Institutional - schools, hospitals, prisons	34,911.59	0.37%
Oil or Gas Field (On-shore)	34,408.10	0.36%
Coke Battery	15,896.27	0.17%
Airport	13,383.17	0.14%

Continued on next page

Table B.1 – continued from previous page

Source Type	SO2 emissions (tons)	Percentage
Breweries/Distilleries/Wineries	9,933.62	0.11%
Landfill	7,139.00	0.08%
Gas Plant	6,381.17	0.07%
Military Base	5,857.66	0.06%
Municipal Waste Combustor	5,011.44	0.05%
Pharmaceutical Manufacturing	4,779.85	0.05%
Brick Manufacturing & Structural clay	3,845.31	0.04%
Wastewater Treatment Facility	2,358.88	0.02%
Hot Mix Asphalt Plant	2,227.11	0.02%
Off-shore Oil or Gas Platform	824.33	0.01%
Automobile/Truck Manufacturing	577.63	0.01%
Rail Yard	539.28	0.01%
Printing/Publishing	322.57	0.00%
Pipeline compressor station	304.89	0.00%
Gold Mine	230.93	0.00%
Bulk Terminals/Bulk Plants	126.14	0.00%
Plywood, Particleboard, OSB, etc	104.50	0.00%
Dry Cleaner - Petroleum Solvent/laundries	28.52	0.00%
Soy Biofuel Plant	28.19	0.00%
Crematories - Animal	10.11	0.00%
Crematories - Human	9.12	0.00%
Lumber/sawmills	5.34	0.00%
Chemical Manufacturing	4.85	0.00%
Concrete Batch Plant	4.66	0.00%

Continued on next page

Table B.1 – continued from previous page

Source Type	SO2 emissions (tons)	Percentage
Mines/Quarries	2.44	0.00%
Auto Body Shops & Painters	1.41	0.00%
Gasoline/Diesel Service Station	0.96	0.00%
Dry Cleaners - Perchloroethylene	0.72	0.00%
Tank Battery	0.07	0.00%
Bakeries	0.01	0.00%
Source: 2008 National Emissions Inventory, EPA		

Appendix C

Description of the Fields

In this section, a brief description of the fields included in the analysis is given.

C.1 Descriptive Fields

yr	Year
pltcode	Plant code
pltregion	Plant Region
pltst	Plant State
t	Time variable for XTREG per plant

C.2 Coal Related Fields

Variable		Obs	Mean	Std. Dev.
contrsw	Type of buy: 1 contract, 0 Spot market	85741	.6477531	.4776732
qsub	Quantity of sub-bit. coal bought	85741	64401.44	147581.9
qbit	Quantity of bituminous coal bought	85741	81557.65	115313.3

Variable		Obs	Mean	Std. Dev.
distsub	Mean distance from mine to plant, sub-bit. coal	19858	677.3628	339.7602
distbit	Mean distance from mine to plant, bituminous coal	53044	206.8814	188.114
paidsub	Total amount paid for consumed sub-bituminous coal	85741	7406992	1.85e+07
paidbit	Total amount paid for consumed bituminous coal	85741	1.18e+07	1.72e+07
costbit	Average cost of Bituminous coal	64423	145.0201	38.70424
costsub	Average cost of Sub-bituminous coal	26599	113.4782	37.3694
btussub	Total content of heat in MM BTUs obtained from sub-bituminous coal	85741	1128814	2589666
btusbit	Total content of heat in MM BTUs obtained from bituminous coal	85741	1945837	2726284
so2ssub	Tons of SO2 emissions generated, sub-bituminous coal	85741	513.5742	1368.556
so2sbit	Tons of SO2 emissions generated, bituminous coal	85741	2737.852	5080.954
so2permitpr	Spot market SO2 permit price	46877	239.8736	244.7657
rq	Percent of quantity bought that is for sub-bit. coal	85741	.2856236	.4402208
rpaid	Percent of amount paid that is for sub-bituminous coal	85741	.2828437	.4385625

C.3 Fields Related to Technology Adoption

Variable		Obs	Mean	Std. Dev.
cttot	Installed Cost of FGD Unit - Total (thousand dollars)	24965	54105.81	53591.42
fgdicost	Average Installed Costs of FGDs, mills per KW-H	63182	123.4405	48.21386
fgdomcost	Average O&M Costs of FGDs, mills per KW-H	63158	1.440017	.8996893
fgdso2r	Weighted average of sulfur removal by FGDs	24965	83.40159	14.07795
fgdmxra	Name plate Max Rating for genrators serviced by FGD unit	40751	575.7969	735.7625
fgdopt	Indicator of existence of FGD Unit $(yr >= yrsrv \& yr <= yrfinal)$	89078	.3291497	.4699071
fgdsel	Year when FGD Unit construction is decided	40751	.030306	.1714301
fgdsel1-fgdsel5	Year when FGD Unit construction is decided lagged by 1, 2, ... 5			
fgdmwh	Equivalent MWH that FGD unit process	87425	40137.07	50628.18
yrfinal	FGD Unit last operating Year	40751	2020.776	11.14268
yrr	FGD Unit first time reported Year	40751 1	989.986	7.486757
yrsrv	FGD Unit Actual or Projected Inservice Year	40751	1987.85	10.99388

C.4 Fields Related to Energy Generation

Variable		Obs	Mean	Std. Dev.
mwh	Total electricity production, MW-H	85612	503082.9	490746.7
maxrating	Maximun nameplate production capacity, MW	86434	1089.568	1100.647
mwheq	Equivalent production of electricity, after substracting FGD unit usage	85612	463194.6	457388

C.5 Fields Related to SO_2 Allowances

Variable		Obs	Mean	Std. Dev.
so2po	Initial allocation of SO2 permits	45805	21350.61	31938.9
so2sfgd	SO2 emissions that are eliminated by FGD unit	23187	3807.159	6159.049
so2seq	Equivalent SO2 emissions, after taking into account FGD action	85741	2270.745	3560.507

C.6 Fields Related to Efficiency and Scale Factors

Variable		Obs	Mean	Std. Dev.
tef	Technical efciency factor from DEAP	89076	.5287384	.23335
scef	Scale efciency factor from DEAP	89048	.8332797	.4174113
rs	Returns to Scale: c: constant, i: increasing, d:simishing, from DEAP			

C.7 Dummy Variables

dy1990...dy2000	Dummy variable for year 1990, 94, 95, 96, 2000
dreg1...dreg9	Dummy variable for regions 1, 2...9
dpermit	Dummy variable that indicates existence of allowance market

Appendix D

Outputs and Tables

D.1 Modeling of the SO_2 Allowance Price

A closer look at the behavior of the SO_2 allowance prices indicates that it is different from that assumption. To understand better the behavior of the SO_2 allowance prices, take the first difference of allowance prices, as displayed in Figure D.1. We can observe two marked periods of time: before 2005 and after 2005. Differences of the time series allows to remove the unit root that the following Dickey-Fuller test find in the series:

```
. dfuller so2allpr, lags(3)
Augmented Dickey-Fuller test for unit root         Number of obs   =       177

                               ---------- Interpolated Dickey-Fuller ---------
                  Test         1% Critical       5% Critical      10% Critical
               Statistic           Value             Value             Value
------------------------------------------------------------------------------
 Z(t)             -1.691            -3.484            -2.885            -2.575
------------------------------------------------------------------------------
MacKinnon approximate p-value for Z(t) = 0.4357
```

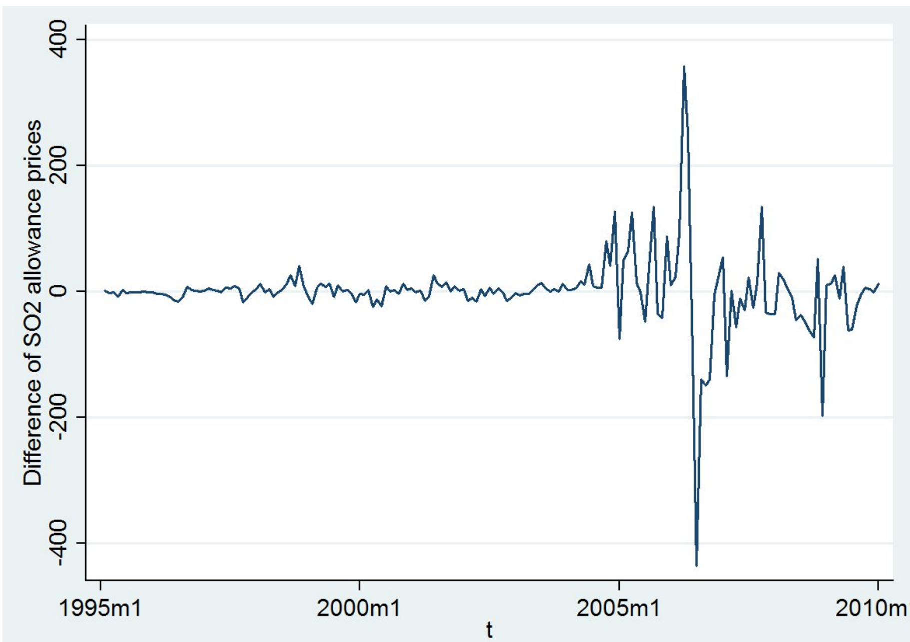

Figure D.1: First differences of SO2 allowance prices, (Source Cantor)

To model this heteroeskedastic series effectively, we use a Generalized version of the Autorregresive Conditional Heteroeskedastic time series model (Called GARCH)[1] of the form:

$$
\begin{aligned}
y_t &= a_0 + \sum_{i=1}^{p} a_i y_{t-i} + \epsilon_t \\
\epsilon_t &= \nu_t \sqrt{h_t} \\
h_t &= \alpha_0 + \sum_{i=1}^{q} \alpha_i \epsilon_{t-i}^2 + \sum_{i=1}^{p} \beta_i h_{t-i}
\end{aligned}
$$

Where ν_t is a white noise process. After some testing, we found that a GARCH(1,1) was a good model for the first difference of the series.

```
. constraint define 1 [_cons]=0

. arch d.so2allpr, noconstant arch(1/1) garch(1/1) constraints(1)

...

ARCH family regression


Sample: 1995m2 - 2010m1                                 Number of obs   =       180

Distribution: Gaussian                                  Wald chi2(.)    =         .

Log likelihood = -832.9337                              Prob > chi2     =         .


 ( 1)  [ARCH]_cons = 0

------------------------------------------------------------------------------

             |                 OPG

  D.so2allpr |      Coef.   Std. Err.      z    P>|z|     [95% Conf. Interval]

-------------+----------------------------------------------------------------

        arch |
```

[1] The GARCH model was developed by Bollerslev, in 1986, as a continuation of Engle's development of the Autorregresive Conditional Heteroeskedastic time series model, ARCH

```
         L1. |   .8412158   .1148453     7.32   0.000     .6161232    1.066308
       garch |
         L1. |   .5842329   .0273036    21.40   0.000     .5307188    .6377471
       _cons |  (omitted)
------------------------------------------------------------------------------
```

The corresponding set of equations is:

$$
\begin{aligned}
y_t &= a_0 + \delta y_{t-1} + \epsilon_t \\
\epsilon_t &= \nu_t \sqrt{h_t} \\
h_t &= \alpha_0 + \alpha_1 \epsilon_{t-1}^2 + \beta_1 h_{t-1}
\end{aligned}
$$

D.2 Form FERC 423 Summary Tables

Table D.1: FERC 423 Records by type of fuel

	Coal	**Petroleum**	**Gas**	**N/Cat**	**Total**
Antracite Coal	3,991				3,991
Bituminous Coal	660,442				660,442
Lignite Coal	7,483				7,483
Coal-based Synfuel	988				988
Subbituminous Coal	82,999				82,999
Waste/Other Coal	210				210
Wood	917				917
Bunker Oil		42			42
Bitumen		4			4
Crude Oil		354			354
CTO Petroleum		3			3
Distillate Fuel Oil		4,450			4,450
Fuel Oil 2		91,785			91,785
Fuel Oil 4		1,121			1,121
Fuel Oil 5		1,927			1,927
Fuel Oil 6		62,297			62,297
HV Petroleum		7			7
Fuel/Gasoline		840			840
Kerosene		1,181			1,181
Liquified Gas		1,109			1,109
Coal-Oil Mixture		36			36
Petroleum Coke		4,798			4,798

Continued on Next Page...

Table D.1 – Continued

	Coal	**Petroleum**	**Gas**	**N/Cat**	**Total**
Residual Fuel Oil		891			891
Rerefined Motor Oil		113			113
Top Crude		5			5
Waste/Other Oil		177			177
Blast Furnace Gas			461		461
Coke Oven Gas			333		333
Landfill Gas			159		159
Natural Gas			295,614		295,614
Other Gas			337		337
Gaseous Propane			31		31
Refinery Gas			631		631
Refuse	935	1	140		1,076
No Category				8,800	8,800

Table D.2: FERC 423 Records by type of coal & Year

Year	Antracite Coal	Bituminous Coal	Lignite Coal	Subbituminous Coal
1972	105	12,880	62	313
1973	207	25,039	124	591
1974	324	31,919	106	689
1975	221	32,907	112	733
1976	259	24,399	129	688
1977	219	30,961	141	831
1978	215	31,018	160	1,014
1979	84	8,290	56	352
1980	70	7,658	64	405
1981	80	7,609	57	396
1982	89	6,393	63	481
1983	227	16,681	200	1,317
1984	205	20,875	203	1,421
1985	176	17,727	223	1,416
1986	110	19,541	249	1,591
1987	128	20,762	261	1,625
1988	146	19,332	280	1,732
1989	138	22,022	270	1,794
1990	161	20,979	287	2,001
1991	173	18,022	304	2,104
1992	143	18,734	330	2,014
1993	90	19,260	302	2,374
1994	90	19,477	301	2,905

Table D.2 – Continued

Table D.2 – Continued

Year	Antracite Coal	Bituminous Coal	Lignite Coal	Subbituminous Coal
1995	86	16,798	272	2,827
1996	78	18,422	264	2,956
1997	82	18,361	264	3,083
1998	64	18,912	275	3,277
1999	20	16,187	259	3,290
2000	1	13,724	260	3,151
2001		14,762	245	3,497
2002		11,923	187	3,856
2003		11,189	176	3,681
2004		13,567	178	3,869
2005		12,072	169	3,769
2006		11,620	170	4,347
2007		10,213	172	4,408
2008		16,224	244	6,482
2009		3,983	64	1,719

Table D.3: Reported millions of tons of coal, per state

Year	AL	**AR**	**AZ**	**CO**	**FL**	**GA**	**IA**	IL	**IN**	**KS**	**KY**	LA
1990	22.2	10.9	15.4	15.3	24.3	27.9	15.6	26.5	49.4	15.8	35.2	11.6
1991	24.3	12.5	17.0	15.5	24.5	24.7	16.3	26.8	46.4	14.4	30.6	12.2
1992	24.9	11.6	16.3	15.6	24.4	22.9	15.1	25.5	47.9	13.6	32.3	12.7
1993	25.9	10.8	18.4	16.1	24.1	23.4	15.9	28.1	43.8	16.5	35.1	13.1
1994	27.2	11.8	18.4	16.2	25.0	28.8	17.1	32.9	53.5	17.7	36.5	13.4
1995	28.1	14.1	15.8	16.5	24.3	28.5	18.2	34.0	49.7	17.8	36.9	13.4
1996	29.5	14.7	15.0	16.4	27.0	28.9	18.2	37.5	51.9	17.9	38.4	12.5
1997	30.4	11.9	16.8	16.7	28.6	28.4	16.7	40.8	53.8	16.7	39.6	13.2
1998	30.9	14.2	18.8	18.1	29.2	31.8	21.7	40.0	57.2	18.4	37.0	14.0
1999	30.2	15.4	19.7	18.4	26.1	33.3	21.5	36.3	57.3	19.6	35.6	13.9
2000	32.1	14.6	19.0	17.0	25.2	35.6	21.5	14.3	51.7	19.3	32.3	9.8
2001	29.9	14.6	19.3	18.7	27.3	34.4	22.0	16.3	52.0	21.3	33.8	8.1
2002	28.9	13.7	17.3	19.1	21.9	30.9	21.6	12.7	43.9	21.0	32.1	8.1
2003	30.0	13.6	18.3	18.8	22.3	34.7	21.4	8.2	53.7	21.4	33.2	6.2
2004	29.6	14.2	19.6	18.8	22.4	36.6	21.2	10.3	52.7	20.2	33.0	4.5
2005	31.3	12.3	20.1	18.5	22.8	38.2	20.3	6.3	51.8	20.3	33.9	4.8
1990	29.7	16.7	24.4	3.9	9.5	19.6	20.9	7.9	1.3	2.8	15.2	7.5
1991	28.9	16.4	25.2	3.7	10.4	18.2	21.7	8.9	1.3	2.0	12.9	8.1
1992	27.9	15.4	24.5	3.2	10.9	20.7	23.4	7.8	1.2	2.2	14.9	7.9
1993	27.9	16.3	19.5	3.3	8.8	21.2	23.6	8.7	1.3	1.8	14.9	7.4
1994	31.4	18.0	27.5	4.3	10.3	21.3	23.4	8.9	1.3	2.1	15.3	7.6
1995	31.2	17.0	31.0	4.3	9.3	19.8	22.3	10.1	1.4	2.2	14.7	7.4
1996	30.2	17.0	33.8	5.4	7.9	24.6	23.6	10.3	1.3	2.4	15.0	7.3

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Table D.3 – Continued

Year	AL	**AR**	**AZ**	**CO**	**FL**	**GA**	**IA**	IL	**IN**	**KS**	**KY**	LA
1997	32.2	17.8	33.6	6.0	9.2	26.2	23.1	10.6	1.6	2.1	15.8	6.9
1998	35.0	18.2	38.7	5.9	10.5	27.8	24.2	11.9	1.4	2.3	15.8	8.0
1999	33.4	16.8	37.7	6.4	10.4	25.6	24.6	12.0	1.3	2.6	16.1	8.1
2000	32.7	17.9	33.0	5.3	0.3	22.4	24.7	10.8	1.5	1.8	14.8	7.9
2001	33.6	18.3	39.3	6.1	0.3	25.9	24.2	12.9	1.7	0.2	11.5	8.1
2002	32.2	18.4	39.2	5.2	6.1	22.3	25.4	12.4	1.5	0.6	9.7	7.6
2003	33.0	19.5	43.1	5.8	6.4	27.2	25.2	12.6	1.5	0.5	16.5	12.6
2004	34.5	17.7	44.2	6.2	6.7	27.6	25.0	12.5	1.6	0.6	16.6	8.7
2005	35.8	18.8	43.1	6.5	7.0	28.2	25.4	12.3	1.7	0.6	19.7	7.9
1990	10.6	51.4	14.5	45.0	9.4	21.4	83.6	14.0	8.5	17.8	33.1	22.9
1991	9.2	49.5	15.9	41.0	9.2	18.7	87.2	13.3	8.6	19.1	28.5	22.5
1992	10.4	50.7	16.8	41.3	9.3	20.4	87.6	12.8	8.9	17.6	28.3	24.2
1993	7.5	48.2	16.4	37.4	9.8	22.5	90.8	14.0	8.9	18.0	24.0	23.6
1994	8.3	49.6	17.2	39.0	11.2	21.4	89.2	14.3	9.3	19.7	31.0	25.6
1995	7.6	47.8	19.7	38.7	9.8	24.1	89.6	13.5	8.6	21.7	30.4	24.0
1996	7.9	52.3	19.6	41.0	11.0	23.6	94.2	13.7	11.0	23.0	31.4	23.6
1997	8.3	52.7	18.4	44.1	11.8	26.4	92.5	15.1	11.9	23.6	31.6	23.2
1998	9.3	53.5	19.7	44.7	12.9	27.0	96.4	14.9	12.7	23.8	34.1	26.0
1999	4.0	51.6	21.0	34.8	12.9	27.5	101.3	14.2	12.9	24.3	36.8	25.4
2000	1.3	46.7	18.4	10.1	14.3	27.7	93.0	15.4	12.6	22.5	26.9	25.0
2001	0.8	39.8	17.1	0.7	15.4	24.2	85.8	13.7	10.8	24.3	23.8	24.2
2002	0.7	29.5	20.6	0.9	14.6	30.2	36.7	14.7	11.3	22.9	25.6	24.3
2003	0.8	40.1	19.1	0.8	12.0	28.4	36.2	14.6	11.0	24.4	24.9	25.3
2004	0.7	41.0	18.9	0.8	14.5	31.1	39.7	15.8	10.7	24.0	23.9	25.5

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Table D.3 – Continued

Year	AL	**AR**	**AZ**	**CO**	**FL**	**GA**	**IA**	IL	**IN**	**KS**	**KY**	LA
2005	0.6	40.7	19.4	0.8	15.6	30.9	37.5	16.5	12.3	23.7	27.8	25.0

Table D.4: Evolution of coal prices (Mean prices)

Year	**cmean0**	**csub0**	**cbit0**	**cmean1**	**csub1**	**cbit1**
1985	140,33	127,35	142,09	170,82	149,83	179,55
1986	134,27	119,88	135,79	163,07	144,25	171,15
1987	127,15	103,74	129,85	157,38	136,55	166,25
1988	123,45	101,14	126,22	153,89	133,11	162,08
1989	125,43	106,33	129,34	151,77	130,27	159,72
1990	126,13	106,7	131,47	151,54	129,81	159,06
1991	121,47	101,75	127,09	149,73	128,63	156,81
1992	117,88	98,83	122,77	146,54	124,58	153,77
1993	120,10	98,28	126,63	142,98	121,63	151,45
1994	118,22	98,74	125,09	139,52	120,27	146,91
1995	113,89	97,26	120,34	135,39	117,18	143,14
1996	115,98	98,58	121,31	130,52	112,36	139,48
1997	118,35	101,53	123,74	128,04	109,97	136,57
1998	116,41	96,19	123,23	125,42	105,36	135,55
1999	116,10	97,69	121,63	122,88	104,95	133,11
2000	114,53	97,71	120,44	119,15	103,13	128,77
2001	135,58	99,49	149,36	121,81	103,19	133,64
2002	131,28	106,09	142,61	124,45	101,59	140,23
2003	134,97	104,31	145,04	125,48	104,66	140,50

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Table D.4 – Continued

Year	**cmean0**	**csub0**	**cbit0**	**cmean1**	**csub1**	**cbit1**
2004	167,81	110,52	186,25	130,23	105,64	148,04
2005	203,32	129,33	224,62	149,69	116,82	175,50

cmean=Bit + Sub-bit, csub= Subbituminous, cbit= Bituminous

0= Spot market, 1= contract