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ECONOMIC EFFICIENCY OF SO_x STANDARDS

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ABSTRACT

The economic efficiency of the SO_x New Source Performance Standards (NSPS) is examined by comparing the costs to comply by flue gas desulfurization with a combination of low sulfur coal, physical coal cleaning, and smaller FGD systems. The analysis is performed on a site specific basis. In some instances, the NSPS were found to be inefficient. In such cases the NSPS increased costs between 1 and 8 percent. A number of implications for policy design are discussed.

The New Source Performance Standards (NSPS) of the Clean Air Act (PL-91-604) regulate sulfur dioxide (SO_2) emissions from new and refurbished coal-fired power plants. The NSPS require the installation of flue gas desulfurization (FGD) systems for SO_2 control. The purpose of this research has been to investigate the economic efficiency of these regulations and to test the hypothesis that alternative methods are less costly than the required large FGD systems for achieving a given level of SO_2 emission abatement.

Between 1971 and 1978, the real cost to construct coal-fired power plants increased nearly 69 percent [1]. Eighty percent of the increase was accounted for by the cost of constructing air pollution control equipment; 50 percent of the increase was devoted to FGD equipment, the only SO_2 abatement technique sanctioned by the NSPS [1]. In 1982, the cost of FGD systems made up 10 to

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20 percent of power plant construction costs.[1] An FGD system for a 500 megawatt (MW) coal-fired power plant costs approximately 60 million dollars to construct [2]. Operating costs are commensurately expensive.

An enormous investment will be required for SO_2 control in the future if the NSPS remain unchanged. This is particularly true since the role of coal will increase to approximately 1.43 billion short tons by the year 2000, compared to 7000 million tons today [3]. Additionally, currently operating systems that are replaced will be required to employ FGD. It is estimated that SO_2 control expenditures will average between 5 and 7 billion 1979 dollars annually during the next twenty years, increasing American electric bills by nearly 10 percent [3].

As presently developed, the NSPS establish an upper limit of 1.2 lb SO_2 per 10^6 Btu input with the SO_2 averaged every thirty days. In addition, fossil fuel-fired power plants are required to reduce postcombustion SO_2 emissions by a certain percentage which is based on a sliding scale: 70 to 90 percent when emissions fall below 0.6 lb $SO_2/10^6$ Btu but at least 90 percent for emissions between 0.6 and 1.2 lb $SO_2/10^6$ Btu. Emissions are not required to fall below 0.2 lb $SO_2/10^6$ Btu.

The cost of compliance with SO_2 regulations has increased dramatically for two reasons. First, it is expensive to achieve greater SO_2 reduction because technological methods are costly; also, low-sulfur coal. In addition, low-sulfur coal should cost more than high-sulfur coal, because the economic advantages gained by burning low-sulfur coal should be reflected in its price.

Second, the percentage reduction requirement increases abatement costs by forcing utilities to install FGD which is the only technology capable of achieving a postcombustion percentage reduction of SO_2 greater than 70 percent. Moreover, Congress mandated that "non-technological processes," such as the burning of low-sulfur coal, cannot contribute to the percentage reduction requirement. Finally, Section 125 of the 1977 Clean Air Act revisions gave state governors the authority to force coal-fired boilers to burn local coal if it was determined that serious disruption of local employment was caused by a power plant's consumption of out-of-state coal. The practical effect of Section 125 is that a power plant which attempts to comply with the NSPS by importing low-sulfur coal and installing a relatively small FGD system could be forced to purchase local high-sulfur coal and a necessarily large FGD system.

Strict regulatory systems, such as the NSPS, attempt to achieve particular pollution levels by placing a ceiling on stationary and mobile source emissions and ambient concentrations of pollutants, and by insuring that control technologies are installed. But, resources can be misallocated by forcing abatement technologies upon polluters. In reality, each polluter is faced with a

[1] Original flue gas desulfurization data obtained and data generated from an original TVA cost estimation model which is described in [2].

variety of abatement options (i.e., FGD, fluidized bed combustion, low-sulfur coal, coal cleaning). Each polluter possesses a unique least cost abatement function which may differ from that of other polluters because of differences in plant and machinery, factor prices, management techniques, etc. The optimal abatement technique might be chosen for some firms by the technology forcing policy. But it is evident that there is potential for misallocation of resources when a single technology is forced upon all firms. For example, it might be more efficient to use lower-sulfur coal and a small FGD system rather than the regulated solution of high-sulfur coal and a large FGD system. A regulatory change allowing less FGD and greater utility flexibility to achieve the desired abatement level may result in large savings.

The aim of this research has been to investigate whether combinations of low-sulfur coal, coal cleaning, and smaller FGD systems are less costly than large FGD systems to achieve the desired level of abatement. Fluidized-bed combustion is not considered because it is still under development for utility applications. Environmental dispatching techniques are not studied because this analysis focuses on minimizing cost for a single power plant rather than for an entire power system.

In this analysis, we do not attempt to determine whether the NSPS result in the optimal level of SO_2. Such an analysis rests in quantifying the benefits and costs of changes in the pollution level. Instead, an attempt has been made in this article to quantify the costs of compliance with the NSPS and to determine if these costs can be reduced. No judgement has been made about whether the level of pollution attained by the NSPS is optimal.

A linear programming model has been developed, the objective of which is to minimize construction and operating costs, including SO_2 control costs, for any new coal-fired power plant. This model is discussed in detail elsewhere [4]. In this article, the methodology is used to determine the costs associated with achieving SO_2 abatement by various means. The emphasis is placed on SO_2 control by the means mentioned above, although the generalized procedure is extendable to other control methods.

PREVIOUS RESEARCH

Previous research in this field has been conducted on a large rather than small scale. Input-output modeling techniques have been used to predict the national economic and environmental consequences of variations in the NSPS [5]. The most recent ICF study partially tested the hypothesis of the research undertaken in this article [6]. ICF determined that a "uniform" SO_2 emissions ceiling of 0.6 lb $SO_2/10^6$ Btu without abatement technology restrictions will result in less expenditure nationally than the current NSPS. Thus, ICF demonstrated that utilities will attempt to reduce costs when permitted to seek their own abatement methods. But, ICF predicted that national SO_2 emissions will be slightly higher than that achieved under NSPS if the "uniform" ceiling is imposed, and that the geographic distribution of SO_2 will change dramatically; the western states will be more heavily polluted and the eastern region will experience a corresponding decrease in pollutants. This will occur because a uniform emissions ceiling of 0.6 lb $SO_2/10^6$ Btu will be less strict than the state standards for western power plants. Similarly, such a ceiling will increase in the West under the 0.6 lb $SO_2/10^6$ Btu standard. Similarly, ICF demonstrated that the uniform emissions ceiling will cause decreased emissions in the East, where many power plants emit more than 0.6 lb $SO_2/10^6$ Btu.

The ICF analysis differs from this research in several significant ways. First, ICF did not attempt to determine if the level of SO_2 abatement achieved under NSPS could be attained for less cost. Second, ICF did not include coal cleaning as an abatement technology. Finally, ICF had to make numerous simplifying assumptions to operate with the aggregate model.

The model designed in this analysis has several advantages over an aggregate model. Specifically, fewer generalizations and simplifying assumptions are made. The economic and environmental circumstances surrounding each power plant are very site-specific. The single power plant model used here will take such site-specific factors into account. In addition, a site-specific model is useful to policy makers because it can be used in conjunction with a utility to determine the least cost abatement procedure.

METHODS

The goal of the methodology is to investigate the economic efficiency of the NSPS. This is accomplished by comparing the costs of full scrubbing systems with alternative SO_2 abatement procedures in a range of typical situations. A model employing linear programming techniques was designed to analyze SO_2 abatement costs at a given power plant [4]. The simplex algorithm was used to determine results. Since the model is discussed in detail elsewhere, only a brief summary is presented here.

Objective Function

The objective of the model is to minimize construction and operating costs, which vary as the fuel mixture changes. The fuel mixture is varied to determine the least cost combination of fuels (SO_2 input) and FGD that satisfies regulations. The fuel mixture choice, therefore, determines the magnitude of costs. It was assumed that numerous coals of varying characteristics can be purchased and mixed in linear combinations and that coals can be cleaned to any technically feasible level, the costs of which are known.

The cost to utilize (i.e., purchase, clean, transport, burn, etc.) any coal can be calculated in a cash flow model and represented by the term C_i, where C denotes cost and i denotes a particular coal. The C_i term for a cleaned coal includes PCC costs. The objective function of the model can be expressed as:

$$\text{Minimize:} \qquad Z = \sum_{i=1}^{n} \alpha_i C_i + \ldots + \alpha_n C_n + C(FGD) \qquad (1)$$

where:

Z = total construction and operating costs
α = decimal fraction of coal i in fuel mix
C_i = cost to solely utilize coal i
$C(FGD)$ = cost to construct and operate the FGD system.

The α's are the variables for which the linear program solves. The α's determine the percentage of the fuel mixture composed of each fuel as well as construction and operating costs. The C_i terms are calculated in a cash flow model prior to running the linear program. The problem is bound by demand, regulatory, and operational constraints.

FGD costs are determined as a function of S input and output. This function was developed by linear regression of FGD cost data obtained from the TVA and appropriate for a wide range of S input and output.

In brief, the constraints are handled as follows: The demand constraint specifies that a fixed annual Btu input must be provided. The regulatory constraint is provided by the NSPS, which provides an emissions ceiling, and, implicitly, an emissions floor. The operational constraint limits the ash plus sulfur (A + S) content of the coal to 17.5 percent.

The solution of the linear programming problem was developed in two stages. First, the optimal NSPS abatement procedure was determined. This was done as follows for the 0.6 lb $SO_2/10^6$ Btu to 70 to 90 percent regulation. The emissions ceiling was set to 0.6 and the linear program was run repeatedly for every reasonable S input to S output ratio (S_{out}/S_{in}) between 0.3 and 0.1 (i.e., in increments of .01). This process was repeated for the 1.2 lb $SO_2/10^6$ Btu – 90 percent regulation when S_{out}/S_{in} corresponding to 90 to 95 percent S removal were tested. This procedure produced a set of thirty-five points giving the minimum cost to operate the power plant at each allowable level of desulfurization while satisfying the emissions ceiling. One or more of these points are optima, indicating the minimum cost solution and the optimal level of desulfurization and fuel mixture under the NSPS.

The second stage of the linear programming problem was to determine if an FGD system which removes less than 70 percent of potential emissions (and resulting fuel mixture) is more efficient than the regulated solution. The goal was to determine if the level of SO_2 abatement achieved under the NSPS can be attained for less cost (or, if the same expenditure can purchase more SO_2 abatement). This was accomplished as follows. The regulated ceiling was set to equal the emissions output attained in the NSPS optimal solution. S_{out}/S_{in} was varied from the lowest feasible level up to 0.3 corresponding to 70 percent removal. The lowest ratio was determined by calculating the percentage emission reduction required to attain the NSPS SO_2 output determined previously, when the lowest-sulfur coal in the potential fuel mixture is burned. The result of this two stage procedure was a function which gives the costs incurred when trading-off between FGD, low-sulfur coal, and coal cleaning to achieve a given emissions reduction.

Description of the Cash Flow Model

The purpose of the cash flow model is to calculate the cost to solely utilize each coal in the potential fuel mixture. The results become the C_i terms in the objective function of the linear program (Equation (1)). The components of the cash flow model are the costs which differ among the coals of the potential fuel mixture. These are: raw coal costs, coal transportation, PCC, UMW contribution, power plant operation and maintenance, and ash disposal. It was assumed that all costs inflate at the same rate. Thus, the relative differences between the C_i terms remain constant through time. All costs were analyzed and converted to dollars per million Btu of input ($\$/10^6$ Btu).

CASE STUDY

The hypothetical power plant was located approximately fifty miles west of Pittsburgh, Pennsylvania, near the town of Sewickley on the Ohio River. This area was chosen for several reasons. First, the variety of coal available in this region is similar to that which is available in all of northern and southern Applachia. Thus, an analysis of western Pennsylvania will allow generalizations to be made about the effects of the NSPS in the East. Second, data were accessible for this region. Finally, the area chosen is classified as Class II by the regional EPA office, and it is thus more likely that a new power plant in this region will be subjected to the NSPS.

The coals chosen for the analysis were studied by Versar [7]. Four coal types were chosen: two from western Pennsylvania, one from nearby Tucker County, West Virginia, and one from Dickensen County, Virginia. The range of sulfur and ash contents of these coals is similar to that of all Eastern coal [8]. A total of nine coals were used in this analysis. These include the four raw coals plus five physically cleaned coals. The physical properties of the coals are presented in Table 1. The highest-sulfur raw coal that was chosen contained 5.99 lb $SO_2/10^6$ Btu while that of the lowest-sulfur coal was 1.25 lb $SO_2/10^6$ Btu. This compares to a range of 1 to 6 lb $SO_2/10^6$ Btu for most Eastern coal. The ash content of the raw coals ranges from 11 to 29 percent, similar to the ash content range of all Eastern coal.

Raw coal costs were developed using published representative long-term contract prices for coal from the appropriate region adjusted for the specified levels of Btu, sulfur, and ash shown in Table 1 [9]. A sulfur premium of 0.0375 \$/ton percent S was used; the ash penalty/premium was \$0.0025\$ per ton percent ash. Coal cleaning costs were obtained from the literature [7]. Data were available for the cost of two cleaning processes for the Butler coal, and one process for each of the three remaining coals. Note that the cleaning process for each coal is unique and that the effectiveness and costs of various processes vary considerably.

Transportation costs were taken to be \$0.00027/ton-mile based on data developed by EPRI [1] and updated with the Coal Week Transportation Cost Index [9]. Shipping distances were taken to be the shortest distance from the mine to the power plant. The UMW pension contribution cost is \$1.51 per ton of coal purchased. Operation and maintenance costs were developed by analyzing costs at five TVA coal-fired power plants [11]. A relationship relating costs to A+S was derived indicating the costs to be \$5.33 per ton A+S when updated using the Chemical Engineering Plant Cost Index [12]. Ash disposal costs were \$2.82 per ton in 1982 dollars [12].

An FGD cost equation was derived which would yield FGD costs for a given SO_2 input and desired percentage reduction. The data needed to develop the relationship were provided by the Division of Energy Demonstration and Technology of TVA [2]. FGD was provided by the wet limestone process.

The model was tested by means of a case study of a new boiler on a site previously chosen. This excluded site-specific siting costs from consideration. The overall utility of the methodology is not adversely effected by this assumption.

Base Case

The results of the case study are shown in Figure 1 as a plot of cost (\$/10^6 Btu) versus percent SO_2 reduction by FGD. The least cost solution occurs with an FGD efficiency of 74 percent at which point the plant operates under the 0.6/70-90 percent NSPS constraint with emissions of 0.6 lb $SO_2/10^6$ Btu. The fuel mix is comprised of coals 3 (98%) and 2. This indicates that the benefits of the Butler cleaning process outweigh the costs. On the other hand, several combinations of coals and cleaning processes were shown to be uneconomical. Thus, a policy requiring all coals to be cleaned might be as inefficient as one requiring some other desulfurization technology.

The results are dominated by the highly cleaned Butler coal which was extremely inexpensive to use. The Butler coal was nearer than the low-sulfur fuel to the power plant. Also, the lower-sulfur coal had an inherently high Btu content, which increased its price even further.

Table 1. Characteristics of Raw and Cleaned Coals

Coal Seam, County, State	Level of Cleaning	Sulfur (%)	Btu/Lb	Ash (%)	lb SO_2 / 10^6 Btu	Total Costs $ / 10^6 Btu
1. Upper Freeport, Butler, PA	0	3.45	11,510	23.9	5.99	1.163
2. Upper Freeport, Butler, PA	2	2.21	12,971	14.4	3.41	1.279
3. Upper Freeport, Butler, PA	3	1.58	13,704	9.7	2.30	1.380
4. Lower Kittanning, Cambria, PA	0	1.86	13,508	12.8	2.75	1.491
5. Lower Kittanning, Cambria, PA	3	1.22	14,139	8.7	1.72	1.602
6. Bakerstown, Tucker, W.VA	0	0.92	10,750	28.7	1.71	1.498
7. Bakerstown, Tucker, WV	4	0.82	12,072	19.9	1.35	1.746
8. Clintwood, Dickensen, VA	0	0.87	13,891	11.2	1.25	1.670
9. Clintwood, Dickensen, VA	4	0.83	14,382	8.1	1.15	1.892
10. High-Sulfur Coal	0	4.89	9,780	29.9	10.00	1.138
11. High-Sulfur Coal	2	4.33	12,370	24.7	7.00	1.264

Addition of a High-Sulfur Coal

The Base Case analysis was constrained in two ways. First, it was not possible for the power plant to emit more than 0.6 lb $SO_2/10^6$ Btu because the highest-sulfur coal in the potential fuel mixture contained less than 6 lb $SO_2/10^6$ Btu. Second, the dominance of the Butler coal could have shadowed some interesting and likely results. The effects of these problems were tested by replacing the Butler coal with a very high-sulfur coal. Data for this coal were obtained from Versar which had developed PCC costs for a Missouri coal which has characteristics that are similar to high-sulfur Ohio coal [9]. It was therefore assumed that a coal similar to the Missouri coal could be purchased fifty miles from the power plant, in Ohio. The sulfur content of the Missouri coal is slightly higher than that of the average high-sulfur Ohio coal, so, the sulfur content was

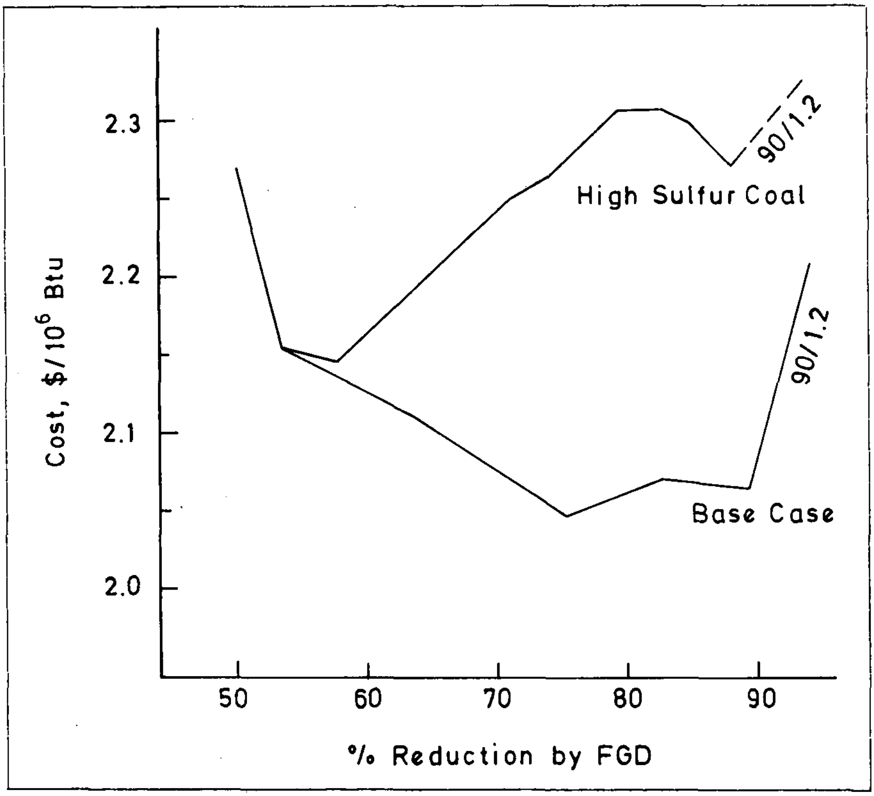

Figure 1. Effect of availability of high-sulfur coal for fuel mixture.

slightly reduced. Table 1 shows the physical characteristics of this coal (coal9) and its cleaned product (coal 10).

Two cases were tested with the high-sulfur coal. The costs shown in Table 1 were used in the first case, the results of which are shown in Figure 1: the results indicate an instance when NSPS would be inefficient. The optimal solution occurred with 58 percent desulfurization and a fuel mixture containing 69 percent coal 8 and 31 percent coal 6. Emissions would be 0.6 $SO_2/10^6$ Btu. NSPS would force 70 percent desulfurization, with a fuel mixture containing 61 percent coal 8, 29 percent coal 10, and 10 percent coal 9. Emissions would again be 0.6 lb $SO_2/10^6$ Btu. NSPS would increase costs by approximately 3 percent and force the utility to purchase a higher-sulfur coal and a larger FGD system than necessary.

The sensitivity of the solution to the price of high-sulfur coal was tested by reducing the purchase price of coals 9 and 10 by 10 percent. The results of this case demonstrated an instance when the NSPS can be extremely inefficient. The NSPS forced the power plant to emit 0.73 lb $SO_2/10^6$ Btu and desulfurize 90 percent of potential emissions. But, it was calculated that the power plant could emit 0.73 lb $SO_2/10^6$ Btu for over 7 percent less cost by purchasing a much lower sulfur fuel mixture and desulfurizing 48 percent of potential emissions.

ANALYSIS OF MID-WESTERN POWER PLANTS

The model was tested by a case study of an eastern power plant. The key inputs to the model for mid-western and western power plants are much different. Western coal is generally very low in sulfur, and coal cleaning is fairly ineffective due to the low pyritic sulfur content. In addition, SO_2 emission regulations are stricter than the NSPS in many western states. The combination of low-sulfur coal and strict regulation results in very low SO_2 emissions from western power plants. In fact, it is doubtful that emissions could be further reduced at most western power plants, since FGD systems and low-sulfur coal are already employed. Thus, the analysis undertaken in this article would be inappropriate for a western power plant; abatement costs cannot be significantly reduced in western power plants because there are no alternative abatement procedures. However, it would be useful to analyze whether the optimal level of SO_2 is attained by western regulations.

The situation in the mid-western states is much different. High-sulfur coal is produced in this region and low-sulfur western coal is accessible. The mid-western situation, therefore, mose closely resembles that in the East. The NSPS may be least efficient in the Mid-west because of the wide divergence in the sulfur levels of the available coal. The NSPS may force mid-western power plants to burn very high-sulfur coal, whereas it may be more economical for such plants to consume low-sulfur coal. On the other hand, it may be too costly to transport low-sulfur coal to the Mid-west. An analysis in this region must take these costs into account. It is worth noting that ICF, Inc. demonstrated that coal shipments from the West to the Mid-west and some eastern states would increase 15 percent as a result of changing the NSPS regulations to a uniform 0.8 lb $SO_2/10^6$ Btu standard [6]. This indicates that a relaxation of the FGD constraint may lead to greater low-sulfur coal consumption in the Mid-west.

POLICY IMPLICATIONS

It was shown earlier that in certain instances the level of abatement achieved by the NSPS can be attained for less cost and therefore that the NSPS can be economically inefficient, and that pollution abatement costs differ by location. Uniform emission standards, such as the NSPS, do not take account of these cost differences. The implication of this for policy design is that, in spite of the administrative advantages of a uniform standard, regulations should be determined on a site-specific basis. Polluters should be given sufficient flexibility to minimize abatement costs. For instance, an analytical method similar to that developed here might be used to determine an optimal abatement procedure for each power plant.

Environmental regulations must not only permit the minimization of abatement costs, but also lead to the attainment of the optimal level of pollution. An efficient environmental policy accomplishes this by ensuring that the costs of pollution abatement are off-set by the benefits created by the reduction in the pollution level. The optimal level of pollution can be determined only after the marginal benefit function has been ascertained. Although it is extremely difficult to estimate the value of benefits resulting from environmental improvement, nevertheless, it can be noted that the value of benefits resulting from environmental improvement vary by location, as do abatement costs. Numerous examples of this are detailed in the literature [13, 14]. These examples, and the results of the analysis conducted here, highlight the need for a case-by-case approach to environmental regulation. An attempt should be made to analyze the benefits and costs of pollution and its abatement at every location. This is particularly applicable to the NSPS. The permissible level of SO_2 emissions should be determined on a site-specific basis. The benefits and costs of SO_2 emissions reduction differ by site and an efficient environmental policy should take such differences into account.

Cost-benefit assessment did not contribute significantly to the design of existing environmental policies. Most environmental legislation was conceived in the mid-1960's and 1970's and was designed in an atmosphere of perceived environmental crisis. The goal of Congress in designing the legislation was to ensure that environmental quality adequately safe-guarded the health and welfare of the public [15]. The role of special groups cannot be ignored. For example, according to Ackerman and Hassler, the high-sulfur coal lobby was instrumental in the establishment of the NSPS FGD requirement [16]. The high-sulfur coal lobby favored the establishment of the NSPS because it was known that power plants have less incentive to purchase low-sulfur coal if full scrubbing FGD systems are required, a fact that was demonstrated in this analysis. It was also demonstrated here that a relaxation of the FGD requirement may lead to increased consumption of low-sulfur coal. Thus, it is in the interests of the high-sulfur coal industry to see that the FGD requirement is retained in the NSPS. It is suggested that the methodology presented here is one which can be used to make explicit the costs of achieving political goals through environmental regulation.

SUMMARY AND CONCLUSIONS

The economic efficiency of congressionally mandated methods for the control of SO_2 emissions from new coal-fired power plants has been evaluated.

These methods, contained in the NSPS of the Clean Air Act, require that SO_2 emission be controlled by the installation of FGD systems. In addition, the hypothesis that alternative SO_2 control methods are less costly than the legally mandated FGD systems has been explored. Physical coal cleaning, the use of low-sulfur coal, and "partial scrubbing" FGD systems were analyzed as alternatives to the "full scrubbing" systems required by the NSPS.

A linear programming model was designed to minimize power plant operating costs. The model was used to calculate the minimum cost to operate the power plant with any sized FGD system. In addition the optimal SO_2 output was calculated for every FGD system size. The following fuel related costs were included: coal purchase costs, physical coal cleaning, UMW contribution, coal transportation, power plant operation and maintenance, FGD, and ash disposal. The model was bound by demand, environmental, and operational constraints. The model had two stages of operation. First, the least cost expenditure and resultant SO_2 output were determined for the power plant subjected to the NSPS. Second, the minimum cost of obtaining this level of pollution was then determined when the model was freed from the FGD constraint imposed by the NSPS.

A case study was designed in which a hypothetical 500 MW power plant located in Western Pennsylvania was analyzed. A variety of coals were chosen for the potential fuel mixture. The calorific and impurity contents of the coals were similar to that of typical eastern coal. Thus, it was expected that generalizations about the effect of the NSPS upon eastern power plants could be observed from the results.

The base case demonstrated a situation in which the most efficient abatement technique would be sanctioned by the NSPS. A single coal dominated the results. This coal was inexpensive to purchase and clean, and, in addition, was mined near the power plant. These factors may have skewed the results. A number of other situations were demonstrated in which the NSPS would be inefficient. In such cases, the NSPS increased costs between 1 and 8 percent. In most of these cases, the power plant would use an uncleaned low-sulfur coal allowing a FGD SO_2 reduction of approximately 50 percent. This demonstrated that it is not always economically efficient to use physical coal cleaning for SO_2 control.

This analysis has several implications for policy design. It was demonstrated that abatement costs vary by location. An efficient environmental policy must be flexible so that polluters can minimize abatement costs. Uniform standards, such as the NSPS, can be inefficient because such policies do not adjust to site-specific cost factors. The policy implication of this is that the NSPS should be redesigned to allow polluters greater flexibility in the choice of abatement technique. The model designed here could be used to help determine the optimal abatement technique for the desired level of SO_2 emission.

Finally, this analysis has demonstrated a method for quantifying the cost of achieving political goals through environmental regulation. The NSPS protect the high-sulfur coal industry and this protection is not achieved without cost. It is worthwhile to make these costs known so that the costs of political decisions can be assessed.

NOMENCLATURE

The following symbols are used throughout this article, and are defined as follows:

A + S	=	ash plus sulfur, percent;
C(FGD)	=	cost to construct and operate the FGD system;
C_i	=	cost to solely utilize coal i;
S_{in}	=	SO_2 input, lb $SO_2/10^6$ Btu;
S_{out}	=	SO_2 output, lb $SO_2/10^6$ Btu;
Z	=	total construction and operating costs; and
α_i	=	percentage of fuel mixture composed of fuel C_i.

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