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Sulfur Dioxide Compliance of a Regulated Utility[1]

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Electric utilities can reduce sulfur dioxide emissions through a variety of strategies, and the cost of abatement can be minimized using tradable permits as under the Clean Air Act Amendments of 1990. Previous theoretical work has analyzed effects of public utility commission regulations on a utility's choice between permits and a single continuous "abatement technology." Our numerical model considers discrete choices among three abatement technologies. Using illustrative parameters, we find that regulatory rules could more than double the cost of sulfur dioxide compliance. They can even make costs with allowance trading higher than costs with command and control regulation. © 1997 Academic Press

Total sulfur dioxide (SO_2) emissions in the United States must be reduced by more than 40% from their 1980 level, according to Title IV of the Clean Air Act Amendments of 1990 (CAAA).[2] Virtually all of this abatement must be undertaken by electric utilities using a variety of technologies such as flue-gas desulfurization equipment (scrubbers), switching to more-expensive low-sulfur coal, or switching output to plants with lower emission rates. To provide flexibility in these abatement activities, the CAAA institutes a system of tradable emission allowances. In theory, with competitive markets, this allowance system can induce utilities to find cheaper means to control emissions than would a conventional command-and-control approach such as a technology standard or uniform performance standard.

However, almost all utilities are regulated by state public utility commissions (PUCs) that decide what costs can be passed on to customers through electricity

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[2] Phase I, from 1995 to 2000, requires 110 of the dirtiest electric utilities to reduce SO_2 emissions to an average of 2.5 pounds per million Btu. Phase II starts in 2000, affects all utilities over 25 megawatts (MW), and limits emissions to 1.2 pounds per million Btu. For an update on how the CAAA is working, see Burtraw [6] or Rico [26].

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prices. By allowing some costs and not others to be passed to electricity customers, these regulatory rules can affect the decisions of utilities about how to comply with the CAAA. As a result, actual compliance decisions may not minimize the cost of compliance.

This paper illustrates the extent to which actual compliance costs can exceed minimum compliance costs. We first discuss the reasons that PUC rules may intentionally or unintentionally provide differential incentives to abate emissions or to buy allowances, and we describe several possible PUC ratemaking scenarios. We then model the decisions of a utility that must comply with the CAAA while facing those PUC rules, and we do so in a way that captures the discrete nature of choices among multiple abatement technologies. We use the model to calculate both cost-minimizing compliance choices and the other choices under PUC rules. We compare these costs under CAAA to those under alternative command-and-control (CAC) regulation.

Previous research has clarified how emission trading can achieve minimum compliance costs [24, 32] and how PUC regulations affect those compliance decisions [4, 8, 27]. For simplicity, these papers consider the choice between trading allowances and a single continuous "abatement technology." Bernstein *et al.* [2] and Winebrake *et al.* [34] considered effects of regulations on multiple compliance choices.[3] These economic models use cost functions that are convex, continuous, and twice differentiable, which is useful to obtain analytical solutions that characterize trade-offs at the margin. Abatement proceeds until its marginal cost equals marginal benefit (the price of an allowance, saved by reducing emissions).

We also model the effects of PUC rules while assuming utility managers comply with the CAAA by maximizing shareholder profits. We extend previous efforts, however, by considering discrete decisions about multiple abatement technologies.[4] In our model, the utility might buy allowances, sell allowances, install a flue-gas desulfurization (FGD) unit, switch to low-sulfur fuel, or switch output between plants with different emission rates. Each of those activities may receive a particular regulatory treatment, and some of those activities are highly discontinuous. Thus we account for more of the compliance decisions made by utility managers, but the model must be solved by numerical rather than by analytical methods.

An advantage of this approach is that we can use specific economic and engineering information about each abatement technology. Each plant in our model has a generating capacity, production efficiency, and emission characteristic. Each type of fuel has a heating value, sulfur content, and market price. Each scrubber has a capital cost, economic life, and discount rate. The model is designed to address issues and provide intuition about the possible effect of PUC regulation on the cost of CAAA compliance, using the abstraction of a fully informed, profit-maximizing utility manager who faces a *given* PUC regulation, output

[3] Bernstein *et al.* [2] focused on results using a "dynamic linear program" in which decision variables are continuous. Winebrake *et al.* [34] provided more detail on their model. Firms can switch fuels and install scrubbers, but output at each plant is fixed. They considered all 110 plants subject to Phase I and an aggregate variable for other firms in Phase II. They found that trading can save over $4 billion during 1995–2005, and they calculated an allowance price of $143 per ton of SO_2. We compare their results to ours below.

[4] Palmer *et al.* [25] considered discrete choices among multiple options, in a model similar to ours, but they were concerned with "social costing" regulations rather than CAAA compliance.

requirement, and allowance price. Later in this paper we vary these exogenous parameters to test the sensitivity of results.[5]

The purpose of the model is to analyze multiple distortions in a second-best world. In this case, the effects of federal environmental policy depend heavily on a separate policy undertaken by a state government with a different agenda. For tractability, however, we ignore other distortions such as taxes or monopoly power in markets for allowances, fuels, or technologies. All environmental costs of mining are assumed to be reflected in the price of coal. Since aggregate emissions are fixed by the CAAA through the total number of allowances, we can ignore benefits of changes in the overall pollution level. This fixed total pollution is reallocated by allowance trading, however, so we implicitly ignore differences in the effects of pollution by location. Thus, our measure of compliance cost does not include all possible social costs, but it does include all compliance costs borne either by shareholders or by electricity customers. This measure is called ‘‘social’’ cost to distinguish it from the purely private cost faced by shareholders that forms the basis of utility decision making.

Using the model, we demonstrate six important results. First, although Bohi and Burtraw [4] showed that symmetric regulatory treatment is *sufficient* to induce cost-minimizing compliance choices, we show that it is not *necessary* for such behavior. Because compliance choices are discrete, rather than continuous, small to moderate changes in one of the regulatory parameters do not necessarily induce any change in compliance at all. At some point, however, the utility may jump to a different more-expensive abatement technology. Second, PUC rules can have unintended effects. One set of rules designed to encourage allowance trading does have the intended effect, but another set of rules designed to discourage local emissions does not. Thus an ‘‘environmentally conscious’’ PUC might end up polluting its state more than the ‘‘market advocate’’ PUC. Third, in the case where PUC rules discourage purchase of allowances out of concern for local emissions, we show that the geographic pattern of pollution can depend on the utility’s initial endowment of allowances. This finding has implications for federal policy regarding initial allocations. Fourth, we show how regulatory rules can provide artificial incentives for mergers and acquisitions. If two utilities are discouraged from pooling their abatement resources by trading allowances, they might pool all of their resources to achieve the same result. Thus an unfettered allowance market might help leave the electric generating industry more competitive as it looks toward possible deregulation in wholesale and distribution markets. Fifth, we use illustrative parameter values and regulatory scenarios to calculate social costs of compliance with the Clean Air Act Amendments. Under certain asymmetric PUC regulations, when our stylized utility minimizes private cost of compliance, the resulting social cost of compliance is often twice the minimum social cost and sometimes nine or ten times the minimum social cost. Finally, we show that

[5]Our model does not address issues about how PUC rules are formed [19], how these policies affect electricity production [8], how PUC regulations affect allowance prices [34], or how actual allowance markets might be affected by such factors as market power [16], manipulation [23], noncompliance [20], transactions costs [30], and state sulfur dioxide limits [9]. We ignore the banking of allowances [10], for reasons such as regulatory uncertainty [22] and price uncertainty [4, 7].

asymmetric PUC rules can make the allowance trading provisions of the CAAA even more expensive than the alternative federal CAC regulation.

In our model, slight deviations from symmetry might induce large changes in behavior and thus large increases in the social cost of compliance. For example, when we model PUC incentives to trade allowances by giving the model utility a small fraction (5%) of the capital gains, we find that private profits are maximized by undertaking all possible abatement in order to sell all possible allowances. Actual reactions to these incentives may be moderated by many other factors not considered in this model. Thus, we do not intend these calculations as predictions of *actual* outcomes, but to provide insight on how PUC and federal regulators can help avoid perverse incentives with the *potential* for substantial excess costs of compliance.

The first section below provides more background on the CAAA and reasons that PUC regulations might provide asymmetric compliance incentives. Section II describes the model and data used to set parameter values. Section III uses the model to calculate effects of particular PUC ratemaking rules, while Section IV analyzes the sensitivity of results to alternative parameter values.

I. THE CAAA AND PUCs

The Clean Air Act Amendments set a national limit on annual sulfur dioxide emissions and created an annual number of emission allowances equal to that limit. An allocation system endows each electric utility with an annual number of allowances based on its historical sulfur dioxide output. These allowances are free to the utility. Each allowance grants the holder the right to emit one ton of sulfur dioxide during or after the year in which the allowance is issued. Electric utilities that burn fossil fuels—primarily coal—must match each ton of sulfur dioxide emissions with an allowance.[6] When the utility's current sulfur dioxide output is greater than the number of allocated allowances, as is commonly the case, the utility may achieve compliance either by abating emissions or by purchasing additional allowances from other holders. A utility that switches fuels or uses other technologies to reduce emissions to a level below its endowment may sell (or bank) the excess allowances. Thus it can balance the market-determined price of an allowance against the cost of abatement technologies that directly reduce sulfur dioxide emissions.

This balancing will be affected by PUC regulations that change the utility's perception of compliance costs and benefits. State PUC regulators set the price of electricity, effectively controlling utility shareholders' recovery from customers of spending on capital equipment and operating costs necessary for electricity production. In this sense, PUC ratemaking amounts to deciding how production costs and occasional gains on asset sales should be divided between shareholders and electricity customers. This regulatory problem applies to sulfur dioxide compliance,

[6] Under CAAA provisions, penalties for noncompliance are high enough that effectively utilities must match each ton of sulfur dioxide output with an emission allowance.

as well. PUC regulators must decide how to allocate gains on allowance sales and spending on emissions abatement and allowance purchases.[7]

In our model, we reduce the sharing of compliance costs and benefits between ratepayers and shareholders to its rudiments, using only four regulatory parameters. Each parameter represents the portion, between zero and one, of a cost or gain that the PUC allocates to shareholders (as opposed to ratepayers):[8]

Parameter	Shareholders' portion of
α	Cost of allowance purchases
β	Gain on allowance sales
γ	Extra cost of fuel (from fuel switching or plant switching)
δ	Cost of investment in FGD units (scrubbers)

In a perfectly competitive industry, all of these gains or costs would accrue to shareholders ($\alpha = \beta = \gamma = \delta = 1$). In traditional ratemaking for electric utilities, however, the PUC assigns all prudent costs of electric operations to electric customers. With respect to sulfur dioxide compliance, this ''cost-plus'' regulation would assign FGD capital costs fully to utility customers as part of the ratebase necessary for the provision of electric service. One standard treatment of compliance fuel costs would involve the ''fuel clause,'' a mechanism by which changes in fuel expense are recovered from ratepayers through automatic adjustments to electricity prices. Cost-plus regulation would deem allowances to be the property of ratepayers and would therefore direct all capital gains to electric customers.[9]

Cost-plus regulation could be represented in our model by setting all four regulatory parameters to zero. In this way, all compliance costs and benefits would be allocated to electricity customers. In a model with strictly profit-maximizing behavior by utility managers, however, the utility's compliance decision is then indeterminate. Since the effect of compliance on profit is always zero, the manager has no criterion for choosing one compliance strategy over another. Possible nonfinancial motives are discussed below.

This result reflects not just a modeling problem, but a more general policy problem faced by PUC regulators with respect to utility production as well as compliance decisions. If shareholders have no stake in the financial outcome of these decisions, and if utility managers consider only shareholder profits, then they have no direct incentive to minimize any of these costs. Furthermore, in general, the regulators cannot perfectly observe utility costs or managerial efforts to reduce them. Joskow and Schmalensee [19] reviewed the design of ''incentive regulations''

[7] Many state PUCs have not yet decided how to treat sulfur dioxide compliance for ratemaking purposes, and industry analysts have widely cited ''regulatory uncertainty'' as an impediment to trades [13, 17, 29].

[8] Similar exogenous cost-sharing parameters are used to model incentives in Bohi and Burtraw [4]. We also use our model below to calculate the effects of more direct PUC actions such as the prohibition of allowance trading or mandated FGD installation, as in Winebrake *et al*. [34].

[9] Wisconsin and West Virginia adopt this approach to allowance transactions [29]. Since the endowed allowances are free to the utility, our model treats all of the revenue from the allowance sale as a capital gain. Actual utilities may buy allowances and sell them later, however, so a PUC can set $\alpha = \beta$ to allocate the net gain from allowance trading.

that best maximize consumer welfare given asymmetric information and the utility's profit maximization.

In the context of our model, this dilemma has a simple solution. By giving shareholders a small stake in *all* of the costs and benefits of compliance, the PUC can give utility managers incentive to make compliance decisions that minimize social cost. This "symmetric regulatory treatment" is represented by setting all four parameters to a single nonzero value. We use this case to calculate the minimum social cost of compliance.

This symmetric regulatory outcome is not guaranteed, however, for a variety of reasons. First, state regulators balance these economic objectives against other social and political objectives. For example, they seek to protect electricity customers and to encourage economic development. States that mine high-sulfur coal may decide to protect local mining employment by discouraging the use of expensive low-sulfur coal. For similar reasons, the PUC may require scrubbers. Other state PUC regulators may wish to protect the local environment by discouraging the purchase of allowances. We simulate effects of all such regulations below.[10]

Second, utility managers may fear changes in the government's allocation of allowances or in the future market price of allowances. To guarantee the utility's continued ability to comply with the CAAA, utility managers may shun reliance on the uncertain allowance market in favor of known abatement technologies. To overcome this natural disinclination, PUCs may deliberately skew the allocation of compliance costs and benefits to create incentives for utilities to participate in the allowance market. Such "allowance trading incentives" are much discussed in the literature [3, 27, 28]. In our model, allowance trading incentives can be represented by assigning to shareholders a positive fraction of all gains or losses from trading ($\alpha = \beta > 0$). These incentives may well be combined with traditional cost-plus regulations that assign all FGD and fuel costs to electricity customers.[11]

Third, even if a PUC wishes to minimize social costs by promulgating symmetric regulatory treatment of all options, they may be thwarted by the sheer complexity of ratemaking procedures. Actual ratemaking involves complicated accounting conventions, the effects of taxes, measuring the utility's true cost of capital, and dealing with the time value of money. These complexities can obscure the true nature of the division of costs between electric customers and utility shareholders. An important question, then, is how far can regulatory parameters deviate from

[10] Penalties on low-sulfur fuel purchases are investigated in sensitivity analysis (Section IV) by raising the shareholders' portion of fuel costs (γ). Forced scrubbing is simulated in Section III.D. Incentives for scrubbing are considered in sensitivity analysis (Section IV) by reducing the shareholders' portion of scrubber cost (δ). Such rules appear in Illinois, Indiana, Kentucky, Ohio, and Pennsylvania [22]. Concern for local pollution is modeled by raising the shareholders' fraction of allowance purchase cost (α) in Section III.B and in sensitivity (Section IV). Policies in New York sought to limit in-state purchases, but also sales to upwind areas.

[11] In a model with uncertainty about future prices and rates of return, both the firm and society may value flexibility associated with decisions that avoid capital costs [7]. In this case, regulations that take a fraction of all net capital gains ($\alpha = \beta > 0$) would take the same fraction of the variance of the returns. If society can diversify away that risk better than firms can, then the asymmetric treatment might be justified.

symmetry without changing the utility's compliance choices away from social-cost-minimizing choices. To explore this issue, we test the sensitivity of total compliance costs to incremental changes in particular regulatory parameter values.

II. THE MODEL

We represent the compliance decision as a constrained optimization problem for one firm with multiple generating plants and fuel alternatives. Exogenous parameter values are set to reflect current information on generating plants, abatement technologies, fuel costs, FGD capital costs, and the allowance price. The utility is a price-taker in the allowance market. We assume a fixed total demand for electricity and a fixed electric generating capacity at each plant. Thus, we avoid the need to account for any of the fixed costs or even variable costs of production, so long as those costs do not vary with compliance choices. We assume total labor and maintenance costs are unaffected by switching a given amount of electricity generation from one plant to another, or by using low-sulfur instead of high-sulfur coal. Thus, managers consider only the *change* in profits from adding a scrubber, paying more for low-sulfur coal, using more of the less-efficient plant, or trading allowances.[12]

The analysis here is based on one time period, a year, with no intertemporal decision making by the utility. We also assume perfect information and perfect certainty. Thus, with no changes in technologies or market prices, the firm would continue to make the same compliance choices period after period. These assumptions also allow us to ignore the CAAA provisions for banking allowances and the associated regulatory issues about whether banked allowances should be included in the utility's rate base and what return these allowance assets should earn.

We first establish baseline sulfur dioxide emissions and fuel costs, finding the utility's choice of fuels and plant usage to meet electricity demand in the absence of restrictions on sulfur dioxide emissions. We then use the model to solve for social-cost-minimizing choices that meet compliance and capacity constraints while generating the required total amount of electricity. The calculated minimum social cost of compliance includes the change in fuel expense from its baseline level, the cost of FGD installation(s), and the net financial effects of allowance trading. Using the same model, we can set regulatory parameters to reflect particular PUC ratemaking rules. We then use the model to find the new profit-maximizing compliance decisions and the new total compliance cost. The difference between this total compliance cost and the earlier-calculated minimum compliance cost is the additional cost attributable to PUC regulations.

A. Parameters and Variables

Diverse economic and engineering information is summarized into parameters for use in our model. Table I presents our notation and definitions of these

[12] Compliance strategies not considered here include plant repowering, fuel-switching to natural gas, coal washing, and demand-side (energy conservation) options. Over time, the utility may also shift the composition of its generating resources away from technologies that use fossil fuels.

TABLE I
Model Parameters and Variables

		Units
Generating plant and FGD parameters ($p = 1, \dots, P$)		
C_p	Net generating capacity at plant p	MW
V_p	Heat rate (an inverse measure of efficiency)	Btu/KWh
K_p	Capital cost of FGD at plant p	$/plant
L_p	Economic life of FGD at plant p	years
R_p	SO_2 removal efficiency of FGD at plant p	fraction [0, 1]
r_p	Annual capital recovery factor for FGD at plant p	fraction [0, 1]
Fuel parameters ($f = 1, \dots, F$)		
P_f	Price of fuel f	$/ton
H_f	Heating value of fuel f	MBtu/ton
S_f	Sulfur content of fuel f	fraction [0, 1]
Regulatory parameters		
α	Allowance purchase cost to shareholders	share [0, 1]
β	Allowance sale gain to shareholders	share [0, 1]
γ	Fuel cost change to shareholders	share [0, 1]
δ	FGD capital cost to shareholders	share [0, 1]
Market and other exogenous parameters		
A_d	Endowed allowances	tons of SO_2/year
D	Demand for electricity	MWh
P_A	Price of SO_2 emission allowance	$/ton of SO_2
ρ	Discount rate (required rate of return)	rate of return [0, 1]
m	Conversion constant, sulfur (S) to SO_2	1.9 units SO_2/unit S
n	Conversion constant, MW to MWh/year	8760 hours/year
Decision variables		
A_b	Allowances bought for SO_2 compliance	tons of SO_2/year
A_s	Allowances sold for SO_2 compliance	tons of SO_2/year
X_{pf}^0	Fuel f burned at plant p, without SO_2 compliance	tons/year
X_{pf}'	Fuel f burned at plant p, with SO_2 compliance	tons/year
Y_p	Binary variable for FGD at plant p	0 no, 1 yes
E	Total firm SO_2 emissions	tons of SO_2/year
Q_p	Net generation at plant p	MWh

Note. Megawatt (MW) is a million watts, a measure of generating capacity or power. Multiplication by 8760 hours/year gives megawatt hours per year (MWh). Multiplication by 1000 gives kilowatt hours per year (KWh). British thermal unit (Btu) and millions of Btu (MBtu) are measures of heat energy. Sulfur dioxide is abbreviated as SO_2.

parameters and other variables.[13] It divides exogenous parameters into four types: generating plant characteristics, fuel characteristics, regulatory parameters, and market parameters.

Each generating plant ($p = 1, \dots, P$) is assigned a net capacity C_p and a heat rate V_p at which it converts fuel energy to electric energy. FGD characteristics are plant-specific and include capital outlay K_p, economic life L_p, and sulfur dioxide removal efficiency R_p. Each fuel ($f = 1, \dots, F$) has a price P_f, a heating value H_f which specifies its energy content, and a sulfur content S_f. The mix of fuels determines both fuel cost and SO_2 emissions.

[13] The table does not show some simple conversions for consistency of units.

The four regulatory parameters have already been discussed. Other exogenous parameters include the number of endowed allowances A_d given to the utility each year by the EPA and the annual demand for electricity D. Endowed allowances can be matched with sulfur dioxide emissions or sold at the market price P_A. Since endowed allowances have no cost to the utility, the gain on the sale of each allowance is the full market price. Parameters and decision variables are given in annual units, so we need the utility's discount rate ρ to convert the total capital cost of each scrubber K_p into its annual equivalent r_p. We do not model the Averch–Johnson [1] effect explicitly, with separate variables for the allowed rate of return and the market rate of return. However, we can account for that effect implicitly by assigning differential regulatory incentives to any compliance technology that appears in the rate base.[14]

The model utility controls several variables. It can buy A_b allowances or sell A_s allowances, but not both.[15] The model utility also selects X_{pf}, the amount of each fuel burned at each plant. If the aggregate sulfur content of the compliance fuel mix X'_{pf} is lower than that of the noncompliance fuel mix X^0_{pf}, then fuel switching contributes to sulfur dioxide abatement. Lower-sulfur coals are generally more expensive than high-sulfur coals, which provides a fuel cost contribution to compliance cost. Finally, the model utility chooses whether or not to install FGD equipment at each plant. This binary decision variable is Y_p. Together, these control variables effectively determine total sulfur dioxide emissions, E, and electric generation at each plant, Q_p.

B. The Objective Function and Constraints

The model consists of a set of profit equations and three types of constraints: the demand constraint, the sulfur dioxide compliance constraint, and plant capacity constraints (Table II).[16] The objective function is the change in shareholder profit due to the four compliance activities, as affected by regulatory parameters. First, shareholders bear a fraction α of the cost of allowance purchases. Second, they receive a fraction β of the value of any endowed allowances that are sold. Third, if the fuel mix chosen for compliance is more expensive than the fuel mix chosen in the absence of compliance, then shareholder profit is reduced by a fraction γ of the additional fuel cost. Fourth, the installation of an FGD unit creates annualized capital costs, and profits are reduced by a fraction δ of the sum of these costs taken across all plants having FGD equipment.

In general, we wish to divide any increase in fuel cost into two components: the cost of switching fuel types and the cost of switching output to a less efficient plant that uses more fuel per unit of electricity. The utility might choose to produce

[14] If scrubbers are treated as capital with an allowed return that exceeds the market return, then the utility is effectively subsidized on that form of abatement. This effect is captured by a reduction in δ, the portion of FGD costs on shareholders. We vary this parameter in sensitivity analysis below. The utility's required rate of return changes continually, and is difficult to measure, so the PUC may be unable to set the allowed rate of return exactly equal to that required rate of return. Holding other parameters constant, we find how much δ can vary before the utility is induced to undertake large FGD investments.

[15] Simultaneous buying and selling is prohibited in this single-period model to preclude a money pump made possible if PUC rules were to allow differential effects on utility profits.

[16] The model is coded in the GAMS (General Algebraic Modeling System) language [5]. Our mixed integer programing problem is solved by a version of the ZOOM solver.

TABLE II

Objective Function and Constraints

Maximize

$$\Pi_{TOTAL} = \Pi_{BUY} + \Pi_{SELL} + \Pi_{FUEL} + \Pi_{FGD},$$

the total change in shareholder profits attributable to allowance purchases, allowance sales, fuel-switching, and FGD (scrubber) installation, where

$$\Pi_{BUY} = -\alpha \cdot A_{\mathrm{b}} \cdot P_A$$
$$\Pi_{SELL} = \beta \cdot A_{\mathrm{s}} \cdot P_A$$
$$\Pi_{FUEL} = \gamma \sum_p \sum_f (X_{pf}^0 - X'_{pf}) \cdot P_f$$
$$\Pi_{FGD} = -\delta \sum_p Y_p (r_p \cdot K_p) \qquad \text{where } r_p \equiv \left[\frac{\rho(1+\rho)^{L_p}}{(1+\rho)^{L_p} - 1} \right].$$

Subject to:

demand constraint	$D = \sum_p Q_p$	where $Q_p \equiv \sum_f (H_f \cdot X_{pf} \cdot 1000/V_p)$
capacity constraints	$Q_p \le C_p \cdot n$	for $p = 1, \ldots, P$
compliance	$E = A_{\mathrm{d}} + A_{\mathrm{b}} - A_{\mathrm{s}}$	where $E \equiv \sum_p \left[(1 - Y_p \cdot R_p) \sum_f (X_{pf} \cdot S_f \cdot m) \right].$

more electricity at a less efficient plant, even in the social-cost-minimizing compliance solution, if the cost of adding a scrubber at that plant is sufficiently smaller than other options. Partitioning extra fuel cost into these two components is somewhat arbitrary. We calculate the cost of "fuel-switching" as total fuel cost minus the cost of the cheapest fuels that would produce the same level of output at each plant. The cost of "plant-switching" then is the total change in fuel cost minus the cost of fuel-switching.

Table II also shows three constraints on the utility's choices. First, the sum of electricity production at all plants must meet fixed annual demand. Each plant's output depends on plant efficiency, fuels used, and fuel heating values. The capacity constraints ensure that each plant's annual output does not exceed its electric generating capacity. The compliance constraint, imposed by the CAAA, holds that allowances must match sulfur dioxide emissions. The last equation shows how total emissions depend on scrubber choices, removal efficiency, and the sulfur contents of fuels used.

C. Exogenous Parameter Values

The parameter values are chosen to illustrate a typical situation for utilities that must comply with the CAAA (Table III). The model utility employs two coal-fired plants to meet demand: a large plant (1000 MW) and a small plant (300 MW). At a maximum, each plant is assumed to be able to run 80% of the time. The large plant is more efficient than the small plant, as is typically the case. The capital costs of FGD equipment for both plants are based on a unit cost of $200 per kilowatt of

TABLE III
Central Parameter Values

Generating plants ($P = 2$)	Large plant	Small plant
Net generating capacity	1,000 MW	300 MW
Efficiency (heat rate)	9,500 Btu/KWh	10,500 Btu/KWh
FGD capital cost	$200 million	$60 million
FGD economic life	15 years	15 years
SO_2 removal efficiency	95%	95%
Fuels ($F = 2$)	**Medium sulfur**	**Low sulfur**
Price	$22.00/ton	$25.50/ton
Heating value	25 MBtu/ton	25 MBtu/ton
Sulfur content	1.5%	1%
Other parameters		
Endowed allowances	44,305 tons SO_2	
Demand for electricity	7.7 million MWh	
Allowance price	$150/ton SO_2	
Discount rate	10%	

capacity, an average figure for the wet FGD systems that have been the most frequently used to date [21]. The sulfur dioxide removal efficiency for this type of equipment is typically 95 percent [21].[17]

For simplicity, the model utility is limited to two fuel choices: a medium-sulfur coal and a low-sulfur coal. These coal types and their characteristics are available to most utilities faced with CAAA compliance [14]. Both types of coal are assigned the same heating value (25 MBtu/ton) for simplicity, but the nature of our results is not sensitive to particular relationships between heat rate and sulfur content. Table III shows mine-mouth prices for these two types of coal, so we add the cost of transportation from the mine to the utility. In "fuel case 1" we add the same transport cost to both types of coal, to represent a utility in the central United States that is equidistant between Eastern sources of medium-sulfur coal and Western sources of low-sulfur coal. More generally, results for compliance costs depend only on the difference between the two fuel prices. Thus, fuel case 1 can be taken to represent any utility facing gross fuel prices that differ by $3.50 per ton. We also report results for "fuel case 2" with a difference of $10 per ton, which might represent an Eastern utility paying extra transport costs for low-sulfur coal.

The utility faces fixed demand of 7.7 million MWh/year, which reflects utilization rates of 70% at the larger plant and 60% at the smaller plant. These capacity factors are typical of actual operations at plants of these sizes [15]. Running the large plant to its maximum 80% of capacity does not meet total demand, so the utility must allocate at least some output to the small plant. The utility is endowed with 44,305 allowances per year, based on the unrestricted (historic) levels of plant

[17] For simplicity, we ignore the possibility that the installation of a scrubber would decrease the fuel efficiency of the plant. This complication would not affect the insights from our model, namely, that small changes in regulatory incentives might not have any affect on compliance decisions, until some point where the utility may jump to a very different compliance solution.

operation and the CAAA Phase II emission limit of 1.2 pounds of sulfur dioxide per million Btu.[18] Engineering data and relationships necessary to model electricity production are taken from El-Wakil [12]. The allowance price of $150 per ton of sulfur dioxide is based on the 1994 EPA auction [18].

III. RESULTS

With no restrictions, baseline sulfur dioxide emissions are 84,180 tons. The utility adds no scrubbers, and it burns only the cheaper, higher-sulfur coal at both plants. In the model, this utility uses the larger, more-efficient plant to the maximum capacity.[19]

With emission restrictions, compliance choices depend on the four regulatory parameters. To deal with the indeterminacy problem mentioned above, when two or more of those parameters are zero, we suppose that the utility has public-relations or other nonfinancial reasons to choose the alternative with lower social costs. To represent these other social pressures, we use an arbitrarily small positive value (0.001), instead of zero, for any one of these parameters for any simulation in which that portion of cost or benefit goes to customers.

A. Minimum Social Costs of Compliance

The profit-maximizing utility in this model will minimize the total (social) cost of compliance as long as it faces any nonzero but symmetric regulatory parameters [4]. Column A of Table IV shows the case with traditional regulation where almost all costs and benefits go to ratepayers, but we give the firm small incentives to minimize social costs ($\alpha = \beta = \gamma = \delta = 0.001$). The same "cost-min" choices apply for any single nonzero value for those parameters, including the competitive case after possible future deregulation ($\alpha = \beta = \gamma = \delta = 1$).

With this symmetrical treatment, the model utility suffers the smallest decrease in shareholder profit by maintaining the baseline 84,180 tons of sulfur dioxide emissions. It therefore complies with the CAAA by using all 44,305 endowed allowances, and it buys an additional 39,875 allowances (at $150 each) for $5.98 million.[20] Profits fall by $5.98 thousand, but the actual (social) cost of this compliance action is still $5.98 million.

To put this magnitude in perspective, we translate it into an amount per household. For this purpose, we wish to know how many households would live in the region covered by this utility if it served the average U.S. mix of residential, commercial, and industrial customers. Total electricity generation by investor-owned utilities in the United States is about 2.8 billion MWh annually [11]. Therefore, the model utility's 7.7 million MWh production represents 0.275% of

[18] The CAAA applies this 1.2 ratio to historic plant utilization to calculate a fixed future emission level. These capped future emissions may not be 1.2 pounds per million of actual future Btu.

[19] In the simulated baseline, the utility uses the larger, more-efficient plant to the maximum 80% of capacity, and it meets remaining demand by running the smaller plant at 27% of capacity.

[20] This purchase of allowances is only permissible under the law if it does not violate local ambient standards (for sulfur dioxide as well as other pollutants).

TABLE IV: Compliance Choices and Costs, for Alternative Parameter Values

	Cost-min	Fuel case 1 ($3.50 difference/ton)			Fuel case 2 ($10 difference/ton)	
	A Traditional cost-plus $\alpha = \beta =$ $\gamma = \delta = 0.001$	B Concern for local pollution $\alpha = 0.15$ $\beta = \gamma = \delta = 0.001$	C Allowance trading incentives $\alpha = \beta = 0.15$ $\gamma = \delta = 0.001$	D Forced scrubbing $\alpha = \beta =$ $\gamma = \delta = 0.001$	B Concern for local pollution $\alpha = 0.15$ $\beta = \gamma = \delta = 0.001$	C Allowance trading incentives $\alpha = \beta = 0.15$ $\gamma = \delta = 0.001$
Compliance choices	[a]	[b]	[c]		[b]	[c]
Fuel-switching	—	Large plant	Both plants	—	—	Both plants
Plant-switching	—	Yes	—	—	—	—
Scrubbing	—	Small plant	Both plants	Both plants	Large plant	Both plants
Allowances bought (sold), tons SO_2	39,875	0	(41,499)	(40,096)	(32,227)	(41,499)
Total SO_2 emissions, in tons of SO_2	84,180	44,305	2,806	4,209	12,078	2,806
Change vs cost-min, in tons of SO_2	n/a	− 39,875	− 81,374	− 79,971	− 72,102	− 81,374
Utility profit (loss), in $millions	($0.006)	($0.016)	$0.889	($0.028)	($0.021)	$0.870
Change vs cost-min, in $millions[a]	n/a	− $0.010	+ $0.895	− $0.022	− $0.015	+ $0.876
Social costs of compliance, all in $millions						
Allowance cost (gain)	$5.98	0	($6.22)	($6.01)	($4.83)	($6.22)
Fuel-switching cost[d]	0	$6.48	$10.34	0	0	$29.54
Plant-switching cost[d]	0	$1.24	0	0	0	0
Scrubbing cost	0	$7.89	$34.18	$34.18	$26.30	$34.18
Total social cost of compliance (TSCC)	$5.98	$15.60	$38.30	$28.17	$21.46	$57.50
Same TSCC, in $ per household	$23	$60	$147	$108	$82	$220
Same TSCC, in $ per ton of SO_2[e]	$150	$391	$961	706	$538	$1,442
Actual cost vs minimum cost						
Excess social cost, in $millions	n/a	+ $9.62	+ $32.32	+ $22.19	+ $15.48	+ $51.51
Percentage change	n/a	+ 261%	+ 640%	+ 471%	+ 359%	+ 962%
$ per household	n/a	+ $37	+ $124	+ $85	+ $59	+ $197
as % of average electric bill ($840)	n/a	4.3%	14.8%	10.1%	7.0%	23.5%
$ per ton of SO_2[e]	n/a	+ $241	+ $811	+ $556	+ $388	+ $1,292

[a] Although the same compliance solution holds for any $\alpha = \beta = \gamma = \delta > 0$, private profits are shown only for $\alpha = \beta = \gamma = \delta = 0.001$. Thus private profits for other regulatory scenarios are compared to this figure.

[b] Columns B show the case with $\alpha = 0.15$, but neither compliance solution is affected by any change in $\alpha \geq 0.01$ (with $\beta = \gamma = \delta = 0.001$). Since α is the share of allowance cost on shareholders, and neither fuel case involves allowance purchases, neither private profits nor any behavior is affected by increases in α (beyond 0.01).

[c] Columns C show the case with $\alpha = \beta = 0.15$, but the compliance solution is not affected by any change in $\alpha = \beta \geq 0.05$ (with $\gamma = \delta = 0.001$). Since β is the share of allowance gain to shareholders, only private profits are affected by increases in β beyond 0.05, in either fuel case.

[d] Fuel-switching cost is total fuel cost less fuel cost calculated using the cheapest fuel of the same amounts at the same plants. Plant-switching cost is total increase in cost of fuel less fuel-switching cost.

[e] For cost calculations per ton of SO_2, the denominator is the difference between unconstrained emissions (84,180) and initial allowance endowment (44,305). This difference (39,875) must be covered by allowance purchases plus SO_2 abatement.

total U.S. generation. If this utility served 0.275% of the 95 million households that live in this country, it would serve 261,250 households. On this basis, the $5.98 million annual compliance cost represents $23 per household.[21]

We next vary one or more of the regulatory parameters. Somewhat arbitrarily, we use 0.15 for any positive share parameter(s), while keeping other parameters at 0.001, to find the private-profit-maximizing behavior for asymmetric regulations.[22]

B. Concern for Local Pollution

State Public Utility Commissions are charged with multiple and sometimes conflicting economic and political objectives. These goals might include the protection of the local environment as well as the local economy. The PUC might want utilities in its jurisdiction to undertake true pollution abatement, rather than to buy allowances. It might especially want to avoid becoming known as the dumping grounds for pollution problems from other regions. Environmental advocates and policymakers in New York, for example, have sought to limit in-state utilities' purchase of allowances. To represent these incentives, we use regulatory parameters that put at least a fraction of allowance purchase costs on shareholders but maintain traditional "cost-plus" treatment of other costs and benefits. Specifically, α is set to 0.15, while $\beta = \gamma = \delta = 0.001$ to pass other costs and benefits to customers.

Under these regulatory rules, the utility's primary objective is to avoid buying allowances. We expect the utility to undertake at least enough abatement technology to get allowance purchases to zero, since the cost of that abatement can be passed to customers. Any further abatement is less important, but would depend on actual abatement costs compared to the price that could be received for sold allowances.

This intuition is reflected by the results in column B of Table IV.[23] The model utility chooses to switch fuels at the large plant and to scrub at the small plant. In addition, the utility shifts generation to the plant with the scrubber. This combination of abatement technologies is just enough to eliminate allowance purchases, and further abatement is not justified by the price for selling allowances. As it turns out, this utility would make the same choices for any value of α above 0.01 (with $\beta = \gamma = \delta = 0.001$). Thus, in this model, just a 1% deviation from symmetry is enough to get shareholders to eschew all allowance purchases completely.

These results illustrate the multiple abatement technologies with discrete decision making. The model utility has no desire to buy an expensive scrubber at the

[21] In a sensitivity test with the allowance price doubled to $300, the utility in this model would still choose to buy allowances. Annual compliance cost would also double, to $46 per household.

[22] Our choice of 0.15 originates with a decision in Connecticut, where the Department of Public Utility Control ruled that United Illuminating Company shareholders could keep 15% of the capital gain from allowance sales—to the extent that those gains are not offset by the cost of FGD investment or fuel-switching that made those allowances available for sale [29]. However, none of the simulations below actually represents the Connecticut case, because none has a gain on allowance sale that exceeds abatement cost. Most PUCs give none of these capital gains to shareholders, a treatment that is consistent with "cost-min" incentives considered above.

[23] In this section, we discuss only columns of the table for the first fuel case ($3.50/ton cost difference). The next section discusses columns for the second fuel case ($10/ton difference).

large plant and thus pays only $7.89 million per year to scrub the small plant. It does not pay for fuel-switching at the small plant with the scrubber, since sulfur at that plant can effectively be removed. The model utility achieves part of the target abatement by switching output to the small plant with the scrubber, even though it is less efficient at producing electricity, because the extra $1.24 million of fuel cost can be passed to customers.

The annual social cost of compliance in this case is $15.60 million, or $60 per household, which is 261% of the minimum social cost for this utility.[24] The state PUC may achieve some benefit not measured here, but the extra cost amounts to $9.62 million per year, or $37 per household. This excess social cost represents a 4.3% increase in the average annual expenditure on electricity ($840 per household, according to [33]).

This policy has some other perverse consequences. First, it may not best advance its own stated goal of reducing local pollution. It prevents the utility from buying allowances and importing pollution, but it provides no further incentive to reduce pollution and sell allowances. Emissions in this case match the endowed allowances, 44,305 tons of SO_2, but the next case shows that additional incentives to sell allowances could reduce emissions to only 2,806 tons.[25]

Second, these PUC rules can reverse the Montgomery [24] result that permit trading makes the allocation of pollution independent of the initial allocation of permits. If these PUC rules prevent trades of allowances, as in column B, then federal government decisions about the initial allocation effectively determine the final allocation. If utilities in high-sulfur coal states would most efficiently buy allowances (as in column A), and their PUCs discourage purchases (as in column B), then this case might provide some justification for their extra permit allocations under the CAAA. Moreover, this result would also affect a natural seller of allowances. PUC rules that prevent purchases must elsewhere prevent sales! These rules could artificially reduce the market price of allowances and induce natural sellers of allowances to use them instead.

A third perverse consequence relates to incentives for mergers and acquisitions. An unfettered emission-permit market allows two firms to take advantage of different comparative efficiencies by shifting abatement to the lower-cost location. Asymmetric regulatory rules restrict external trades, but two such firms can achieve the same overall cost reduction without external trades as a single firm with internal shifts of abatement activities. In the current example, the firm in column B undertakes costly abatement to avoid buying allowances, but it could merge with another firm that has lower abatement cost and share endowed allowances.

[24] Similarly, Winebrake *et al.* [34] found that such restrictions on allowance trades can increase costs by 220–240%. Note, however, that this multiple in our model depends on the assumed price of allowances. If that price were doubled from $150 to $300, then the minimum cost solution doubles from $5.98 to 11.96 million. This "concern for local pollution" case would still involve $15.60 million of abatement cost, which is then 130% of the minimum.

[25] In any case, local pollution is not necessarily related to local emissions. Acid rain in the Adirondack Mountains of New York is more affected by emissions in the midwest than by emissions in New York.

C. *Allowance Trading Incentives*

Because allowance trading is relatively new to a conservative industry, many utility managers consider it risky. They do not know future allowance endowments, or prices, and they may want to guarantee their capability for future compliance by using known abatement technologies. To help overcome this reluctance to participate in allowance markets, PUC regulators may wish to provide incentives that would assign to shareholders some portion of net gains from allowance trading [3, 29]. These ''allowance trading incentives'' could be represented in our model by positive values for α and β. With respect to other compliance options, traditional cost-plus ratemaking would still allow the utility to recover all FGD equipment and fuel costs from ratepayers. We set γ and δ to 0.001, instead of zero, to break the utility's indifference between fuel-switching and scrubbing.

With these incentives, we might expect the managers to invest aggressively in abatement technology (because these costs are virtually irrelevant to their shareholders) and to sell as many allowances as possible (because shareholders receive a positive share of the proceeds). Indeed, this is what the model finds. For any value of α and β above 0.05, the model utility chooses to install FGD units at both plants *and* to switch entirely to low-sulfur coal. This compliance strategy yields the maximum possible reduction of emissions, freeing the maximum number of allowances for sale. These compliance decisions are reflected in column C of Table IV. (For symmetry with other cases, this column uses $\alpha = \beta = 0.15$ to calculate private profits.) Sulfur dioxide emissions fall by 81,374 tons (from the baseline 84,180 tons), and the utility sells 41,499 of its 44,305 endowed allowances. At $150 each, these allowances sell for $6.22 million. If shareholders keep 15% of this amount, then they get $0.934 million minus their 0.001 share of other abatement costs, for a net profit of $0.889 million. Relative to the ''cost-min'' solution with a $5.98 thousand loss, this $0.889 million profit represents a $0.895 million increase in private profits.[26]

The social cost of this outcome, however, is substantially higher than the minimum social cost in column A. The extra cost of using the more expensive, lower-sulfur coal is $10.34 million. The annual cost of the FGD units is $34.18 million. Net of the $6.22 million for selling allowances (split between shareholders and ratepayers), the social cost of compliance under the ''incentive'' regulatory solution is $38.30 million, or $147 per household, more than six times as large as the minimum compliance cost.[27]

Relative to that minimum compliance cost, this utility spends an extra $32.32 million, or $124 per household. This excess social cost represents a 14.8% increase in the average annual expenditure on electricity. A state PUC may choose this regulatory approach to encourage trading, for the sake of benefits not measured here, but it might do so only at a substantial cost to its jurisdiction.

[26] In order to sell allowances, for $\alpha = \beta \geq 0.05$, the utility maximizes abatement. The use of higher values for α and β has no effect on compliance but does increases profit from allowance sales.

[27] This multiple depends on the assumed price of allowances. If that price were doubled from $150 to $300, then the minimum cost solution doubles from $5.98 to 11.96 million. ''Allowance trading incentives'' would still involve $44.52 million of abatement cost, but $12.44 million of gain from allowance sale. The net cost, $32.08 million, would then be 2.7 times the minimum.

D. Forced Scrubbing

The results for asymmetric incentives in Table IV can be compared to a different case in which the PUC or state legislation simply requires utilities to purchase a scrubber for every plant. To save local coal-mining jobs, a state might require scrubbers.[28]

In this case we do not need to "find" the solution that maximizes private profits (but we use $\alpha = \beta = \gamma = \delta = 0.001$ to calculate those private profits, assuming other traditional cost-plus regulation). With two scrubbers, and no fuel-switching, the model utility's sulfur dioxide emissions fall by 79,971 tons, to 4,209 tons. Under the CAAA, it could sell 40,096 of its endowed allowances (at \$150 each) for \$6.01 million, but the two scrubbers cost \$34.18 million (as in column C). Thus the total compliance cost is the difference, \$28.17 million, which represents \$108 per household. Relative to the minimum compliance cost (\$5.98 million to buy allowances), the excess cost is \$22.19 million.

This state rule makes CAAA compliance almost five times as expensive as the cost-minimizing solution of buying allowances. It costs the jurisdiction an extra \$85 per household, the equivalent of a 10.1% increase in the average electric bill.

E. Command-and-Control Regulation

Our results can be used to shed light on the cost savings from the CAAA relative to alternative command-and-control (CAC) regulation of two sorts. Without the allowance trading provisions of the CAAA, the federal government might have had a technology standard or a performance standard.

One kind of technology standard might require a scrubber on every plant. Thus the results for "forced scrubbing" above can be reinterpreted to represent a federal CAC regulation. With this interpretation, the cost of compliance under the command-and-control policy (the \$28.17 million just cited) is almost five times the minimum that is possible under the CAAA (\$5.98 million). Even if the price of an allowance were doubled to \$300, the CAC rule is more than twice as expensive as trading.[29]

The remaining uncertainty is whether the CAAA can achieve the minimum possible cost, given PUC rules. If the state PUC requires scrubbing, then the CAAA makes absolutely no difference (relative to a federal policy of forced scrubbing). If the PUC employs "allowance trading incentives" (column C of Table IV), then we have the surprising result that the use of tradable permits under the CAAA might be even more costly than federal CAC regulation. With the cost parameters selected for this hypothetical utility, we find that CAC regulations (forced scrubbing) generate costs that are almost five times the minimum, but we also find that tradable permits with PUC "allowance trading incentives" (column

[28] Such a rule was passed by Illinois in 1992, but it was subsequently struck down by the Seventh Circuit Court. Bernstein *et al.* [2] found that the Illinois rule would cost the state a half billion dollars over 5 years, or \$60,000 annually per job saved.

[29] Similarly, Bernstein *et al.* [2] and Burtraw [6] found that the cost of the command-and-control alternative is two or three times the cost that is possible under the CAAA.

C) generate costs that are more than six times the minimum. The reason is that ‘‘allowance trading incentives’’ induce the utility to fuel-switch, as well as scrub both plants, in order to sell allowances.

Instead of this technology standard, federal CAC regulation might employ a performance standard. For example, emissions of each utility might be limited to the number of tons of sulfur dioxide represented by the initial endowment of allowances (without trades). In this case, the results in column B of Table IV can be reinterpreted to represent a federal CAC regulation, because in those results the utility used its endowed allowances with no trades. With this interpretation, the cost of compliance under the command-and-control policy (the \$15.60 million in column B) is 2.6 times the minimum that is possible under the CAAA.

Again we have the result that PUC interference *can* make the allowance trading provisions of the Clean Air Act *more* costly than a simple federal CAC regulation. The cost of the CAAA with PUC ‘‘allowance trading incentives’’ (\$38.30 million, column C) is more than twice the cost of the federal performance standard (\$15.60 million, column B). This possibility is robust to changes in the assumed price of allowances, the discount rate, and other parameters.[30]

Our hypothetical utility is a natural buyer of allowances, in the cost-minimizing solution, but federal CAC standards can still cost less than allowance trading in this example when we consider a different utility that is a natural seller of allowances. When these PUC rules induce the natural buyer to undertake expensive abatement in order to *sell* allowances, they necessarily induce some other natural seller to cut back on its cheap forms of abatement—in order to *buy* allowances. This misallocation of abatement is what can make the CAAA more expensive than federal standards. Alternatively, if the PUC used rules like our ‘‘concern for local pollution’’ case (column B), then the costs under the CAAA are identical to a federal performance standard. The point is certainly not that allowance trading will generate zero or negative cost savings, but that PUC rules will be crucial in determining the extent of cost saving under the CAAA.

IV. SENSITIVITY ANALYSIS

To test the robustness of these results, we used the model to calculate alternative outcomes for many different values of parameters. Changes in the allowance price and the discount rate clearly affect the dollar cost of buying allowances or buying abatement technology, and thus the dollar cost of compliance, but they do not affect this utility’s choices under any of the regulatory scenarios. Therefore, in this section, we describe results only for changes in fuel costs and regulatory parameters.

The general conclusion from these sensitivity tests is related to the discrete nature of decisions in our model. In some cases a substantial change in a cost or other parameter value may have no effect on compliance decisions, and in other cases a small change in one parameter may have a substantial effect on compliance decisions.

[30] For fuel case 2, considered in the next section, the cost of CAAA with PUC ‘‘allowance trading incentives’’ (\$57.5 million, in fuel case 2, column C) is almost three times the cost of the federal performance standard (\$21.46 million, in fuel case 2, column B).

A. The Fuel Cost Differential

Table IV shows outcomes for two different assumptions about the fuel cost differential. In fuel case 1, the difference between low-sulfur coal and higher-sulfur coal was \$3.50 per ton, and in fuel case 2 it is \$10 per ton. For "incentive" ratemaking rules (columns C), the model utility chooses the same compliance solution, with the same FGD units and fuel-switching at both plants. The cost of fuel-switching nearly triples, however, so the social cost of compliance rises from \$147 to \$220 per household. This last figure is almost ten times the minimum social cost.

For the other regulatory scenario, where the utility is discouraged from buying allowances, the fuel cost differential does affect behavior (columns B). With the low fuel cost differential, the utility scrubs the small plant and switches just enough fuel at the large plant to use exactly the endowed allowances. With the \$10/ton cost differential, however, the utility avoids fuel-switching by scrubbing the large plant. This discrete increment to abatement leaves 32,227 excess allowances that can be sold.[31] Adding a scrubber to the small plant would produce additional allowances for sale, but the gain from that sale does not offset the cost of the scrubber.[32]

The change in the excess social cost of compliance is more than the change in fuel cost. Indeed, the utility avoids the extra fuel cost by investing in a scrubber that is even more expensive. This new compliance solution costs society an extra \$59 per household.

B. Other Asymmetric Regulatory Rules

In general, our results show how regulatory parameter asymmetries can cause the utility's compliance decision to deviate from the social-cost-minimum solution. As just demonstrated, however, small to moderate changes in parameters might not induce any change in behavior. This raises the question: how much can regulations deviate from perfect symmetry without inducing the firm to deviate from cost-minimizing compliance? Obviously the answer depends on the assumed parameters, but the following calculations may help illustrate the relationships.

Consider a symmetric regulatory treatment where $\alpha = \beta = \gamma = \delta = 0.15$, such that 85% of all compliance costs and benefits are passed to ratepayers. We then vary only α, holding all other regulatory parameters fixed. As it turns out, α can lie anywhere between zero and 0.35 with no change away from the minimum compliance cost.[33] Higher α indicates "concern for local pollution" by penalizing allowance purchases. At $\alpha = 0.40$, the utility combines some fuel-switching with its allowance purchases, increasing the cost of compliance by \$6.1 million (from \$6.0 to \$12.1 million). For α of 0.55 and greater, the profit-maximizing compliance

[31] In a more general model, depending on regulatory treatment, this utility might decide to bank allowances instead of selling them.

[32] The fuel cost differential does not have to triple (from \$3.50/ton to \$10/ton) to induce this discrete change in behavior. Starting at \$3.50/ton, we can raise the fuel cost differential gradually with no change in behavior, until a particular point (around \$8.63/ton) at which the model utility decides to abandon fuel-switching and to scrub the large plant instead of the small plant.

[33] Other utilities face other technological and market price parameters, however, and therefore may undertake large, discrete compliance changes for only a small deviation from symmetry.

strategy includes FGD installation and fuel-switching with no allowance purchases —a change that increases the social cost of compliance by $9.6 million.

Similar results hold for variations of the other regulatory parameters. With all four parameters set to 0.15, an increase in just β represents any form of subsidy to allowance sales. Yet the model utility stays with cost-minimizing compliance until the portion of allowance sale allocated to shareholders reaches 65%. For β values of 0.65 or greater, the utility chooses to scrub the large plant, fuel-switch at the small plant, and sell allowances—increasing social cost of compliance by $16.08 million.

An increase in γ indicates a penalty on more-expensive fuel purchases. Since the symmetric solution does not involve fuel-switching, however, an increase in γ has no effect on compliance. In this case, a decrease in γ to 0.05 induces the model utility to switch fuels at both plants. The social cost of compliance increases by $6.13 million.

Finally, a decrease in δ indicates any kind of subsidy to the purchase of FGD equipment, such as an allowed rate of return that exceeds the market rate of return.[34] A decrease in δ to 0.05 induces the utility to scrub the large plant, and δ at zero induces scrubbing at both plants.

V. CONCLUSION

PUC regulations can fundamentally alter the intended effects of the Clean Air Act. Specifically, allowance trading incentives combined with traditional ''cost-plus'' treatment of spending on abatement can substantially increase the social cost of compliance. Other asymmetric regulatory treatments may have other unintended effects and also can substantially increase costs. Yet, utilities facing other technological and market price parameters might not change their behavior at all.

Although deviations from symmetry can be quite costly, we show that exact symmetry among the regulatory parameters is not necessary to induce cost-minimizing compliance. Thus, PUC regulators may have some latitude in their ratemaking decisions. Small discrepancies in their treatment of abatement and allowance trading are hard to avoid, as a practical matter, but will not necessarily undermine the cost-minimizing compliance solutions intended by the CAAA.

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