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Estimating Costs of Electric Utility Compliance with Proposed Revisions to the Clean Air Act

E. L. Hillsman
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ESTIMATING COSTS OF ELECTRIC UTILITY COMPLIANCE WITH PROPOSED REVISIONS TO THE CLEAN AIR ACT

by

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LIST OF ACRONYMS AND INITIALISMS

AFUDC	allowance for funds used during construction
BACT	best available control technologies
BOM	U.S. Bureau of Mines
Btu	British thermal unit
DOE	Department of Energy
EEI	Edison Electric Institute
EIA	Energy Information Administration
EPA	U.S. Environmental Protection Agency
EPRI	Electric Power Research Institute
NECDB	Nuclear Energy Cost Data Base
O&M	operation and maintenance
PUC	public utility commission(s)
PWR	present worth of revenue

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John Reed of ORNL assisted in polishing several of the figures and in shepherding the report through various publications procedures.

Finally, we appreciate the skill and patience shown by Phyllis Daley in preparing and revising the manuscript.

ABSTRACT

Several bills have been introduced in Congress to reduce emissions of sulfur dioxide and nitrogen oxides from electric power plants. The effects of these bills on electricity costs depend on features of the bills, on the mix of generating capacity owned by different electric utilities, on the technologies available for complying with the legislation, and on the time horizon used to calculate the costs. A system of computer software has been developed to make utility-specific estimates of the effects of different legislation on electricity costs. Example results from the model suggest that the emissions trading systems proposed in some legislation may have less effect than expected on compliance costs.

1. INTRODUCTION

Several bills have been introduced in the past two Congresses to reduce emissions of sulfur dioxide (SO_2) and nitrogen oxides (NO_x). Each bill set different targets, procedures, and policy options for achieving the desired reductions. These bills were expected to increase the cost of generating electricity for utilities whose plants now emit large amounts of the targeted compounds. The U.S. Bureau of Mines (BOM) has been interested in the effect that these bills might have on the cost of electricity used by aluminum smelters, ferrosilicon producers, and other mineral processing activities for which the cost of electricity is already a significant proportion of production costs. Figure 1 shows the nation's aluminum smelters and (ferro)silicon plants listed by the Bureau of Mines, 1988, and those identified by BOM as using coal-fired electricity. Eleven electric utilities provide power to these plants, and these utilities include some with the lowest as well as some with the highest average emission rates in the country (Table 1).

Much of the U.S. aluminum smelting capacity is the "swing" capacity in the world aluminum market, idled when demand and price are low but brought on line when demand and price are strong. The BOM is concerned that substantial increases in electricity costs could reduce ability of these smelters to compete in the world market.

This report describes the methods used by Oak Ridge National Laboratory and the University of Tennessee to estimate the effect that reducing emissions would have on the cost of generating electricity for these facilities. Although the report presents some results obtained with these methods, its main purpose is to describe the methods used in the research and the present status of computer software developed in support of this research. An assessment of the implications of increased electricity costs for the ferrosilicon industry, based upon estimates made with these methods, may be found in Bennett (1989). The results presented in this report are intended to illustrate the abililities of the software system, and not to be definitive.

1.1 STRUCTURE OF THE PROBLEM AND ISSUES IN THE ANALYSIS

Estimating the effect that reducing emissions will have on the cost of electricity requires the following steps:

- *Determining the requirements and limits imposed by new legislation.* During the course of this research, we were aware of at least seven bills introduced into the 100th and 101st Congresses to reduce emissions of NO_x and SO_2 by electric utilities, including the original draft proposed by the Bush administration. One bill simply would have established an emission fee. The others set specific reduction targets and specified procedures to be used to meet them; we limited our analysis to these six. The details of the bills varied, and each had a number of gray areas whose implications were difficult to model. In addition, the diversity of features in these bills required some simplification to permit analysis. Section 2.1 summarizes the general characteristics of the bills, and Section 4.2 describes individual bills in greater detail and discusses how we incorporated their features into our analysis. Most of our effort has focused

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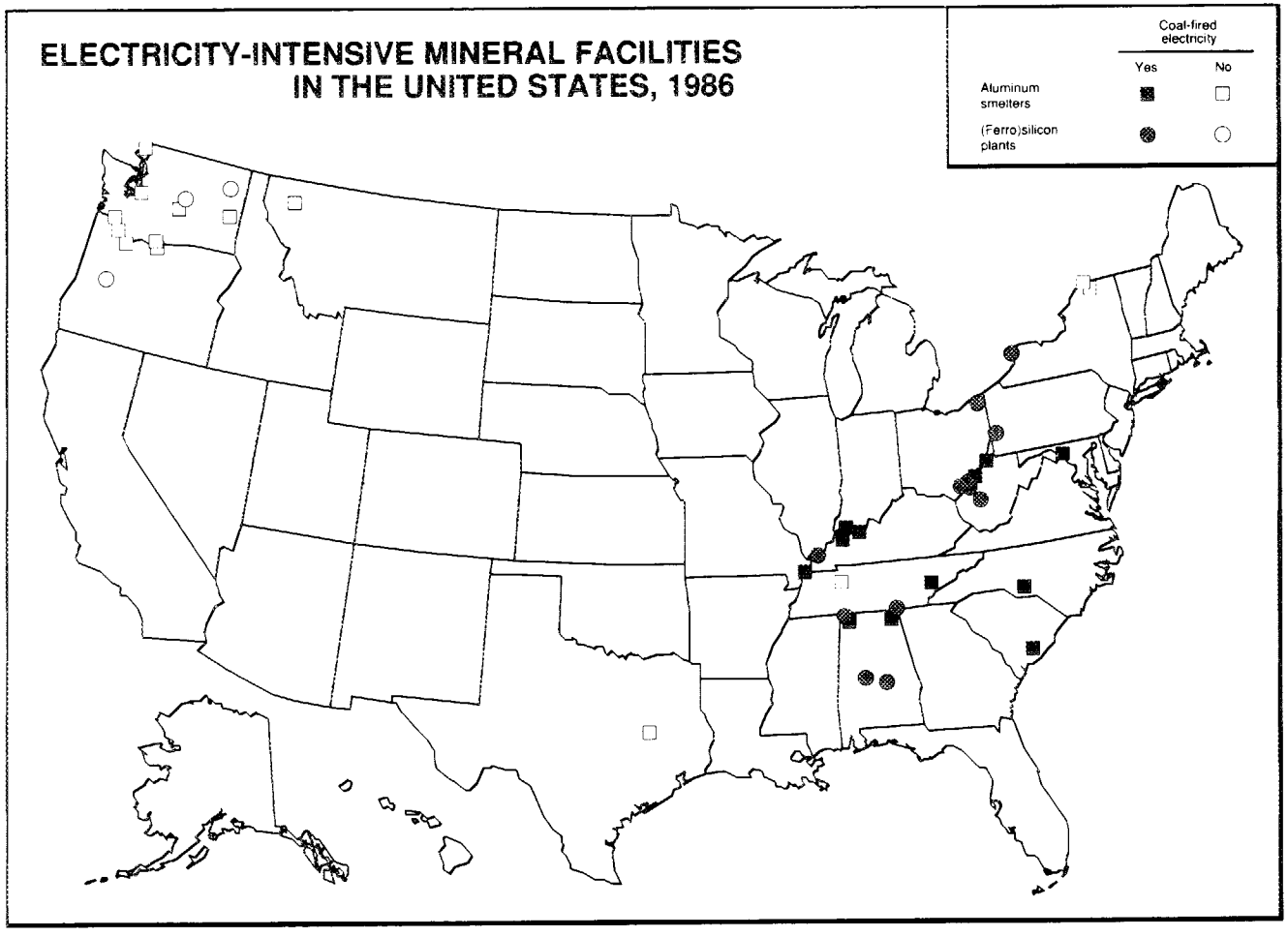

Figure 1. **Locations of aluminum smelters and ferrosilicon plants in the United States.** *Source*: Bureau of Mines 1988. *Minerals Yearbook 1986; Volume I, Metals and Minerals*, U.S. Government Printing Office, and information provided by Bureau of Mines.

Table 1. Base emission rates for the 11 utilities in the analysis

Company	lb $SO_2/10^6$ Btu	lb $NO_x/10^6$ Btu
Alabama Power	1.95	.70
Appalachian Power	.99	.70
Associated Electric	4.96	1.77
Big Rivers Coop	2.42	.72
Cleveland Electric	4.84	.40
Duke Power	1.29	.63
Ohio Power	5.09	1.01
Potomac Edison	2.87	.74
South Carolina Public Service	1.08	.89
Southern Indiana Gas & Elect	4.33	.81
Tennessee Valley Authority	3.00	.90

on a version of the bill proposed by the Bush administration, where special efforts were needed to analyze its provisions for emissions trading. These provisions are discussed in Section 2.2. Following the initial draft of this report, Congress did pass legislation very similar to the original Senate version of the administration's bill. Analysis of this legislation will be reported in subsequent publications.

- *Deciding which control technologies to consider in the comparison.* Some proposed legislation required or prohibited specific control technologies in specific circumstances. Most bills, however, allowed utilities substantial flexibility in choosing which technologies to use and where to use them. Most debate over alternative legislation has focused on the alternatives of switching to low-sulfur coal vs adding flue-gas desulfurization (scrubbers), and on the balance desired between them. Although there are exceptions, coal switching generally is anticipated to be less expensive for utilities and their ratepayers, but more likely to reduce or cause major regional shifts in coal mining employment. We have focused our analysis on these two alternatives.

- *Deciding how to compare costs of alternative control technologies at a power plant.* Although the costs of present operating practices and of control technologies can be calculated by straightforward application of engineering economics, using standard formulas and procedures agreed upon by the electric utility industry (EPRI 1987; DOE 1988), the choice of how to compare them is less straightforward. Arguments can be made in favor of several methods. Section 3.1 of this report discusses this issue in greater detail, and Appendix A presents the formulas used to calculate costs for different methods.

- *Collecting data that describe the costs of present operating practices and of control technologies that might be implemented.* The data used are described in Section 3.4

- *Determining the mix of control technologies that a utility might adopt for its plants in response to these limits.* We have assumed that, given agreement on how to compare the costs of different control technologies (Section 3.1), the mix chosen will be one that minimizes these costs while meeting demand for electricity and legislated emission reduction targets. This assumption lends itself well to the use of linear programming as a model problem-solving technique. Section 4.1 summarizes the linear programming model used to find the mix of control technologies, and Appendix B presents the model in detail.

- *Computing and comparing the costs of different mixes and legislation.* Section 5 reports sample results of applying the model to one way of estimating the costs of different legislation.

Figure 2 illustrates the conceptual structure of the modeling system developed to estimate the effect of legislation on electricity costs. Although the focus of our analysis has been on costs, legislation also will affect technological choices, unit-by-unit emission levels, and the way that existing equipment is used; the modeling system can provide information on these topics as well as information on the added costs of complying with different legislation.

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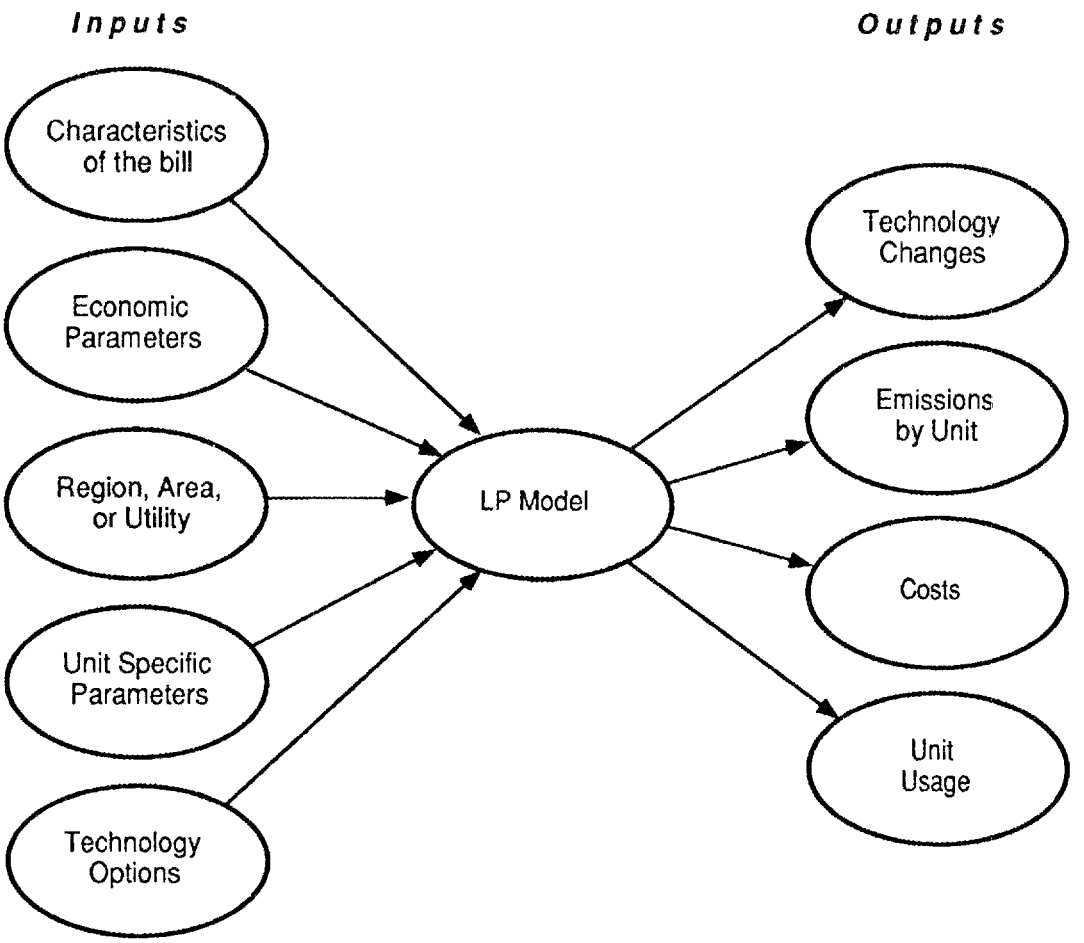

Figure 2. Conceptual structure of modeling system.

2. SUMMARY OF PROPOSED LEGISLATION TO REDUCE ELECTRIC UTILITY EMISSIONS

2.1 GENERAL CHARACTERISTICS OF PROPOSED BILLS

Bills introduced to reduce the emission precursors of acid precipitation had the following general characteristics:

- Most sought to reduce emissions from power plants, industry, and automobiles. We have limited our analysis and the following discussion to features directly affecting electric utilities.

- They emphasized reductions in SO_2 emissions from present levels of 16.5 million tons per year (EIA 1989), by 7.5–11 million tons. Some specified the tonnage reduction to be achieved, while others provided information from which the total reduction could be calculated. The bills specified compliance schedules that ranged between 1993 and 2003.

- Although most also would have reduced NO_x emissions from power plants, the sections of the bills that dealt with NO_x contained much less detail, and often contained too little detail to model their effects. Details in these cases were left to the U.S. Environmental Protection Agency (EPA) administrator to be specified by regulation rather than in legislation. Two bills would have allowed utilities to substitute reductions of NO_x for reductions of SO_2, at specified rates of equivalence, if utilities found it less expensive to do so.

- They required reductions in SO_x emissions in two or three stages, the first typically 6 to 8 years following enactment, the last typically 10 to 14 years following enactment.

- They made some provision to promote the use of "clean coal" technologies rather than scrubbers and coal switching. Typically these provisions included a capital subsidy or extra time for a utility to reduce emissions if it would commit to installing such technology. As in the case of NO_x, the details of these provisions were often insufficient to allow modeling even if there were consensus about the cost and performance of clean coal technologies.

- They permitted utilities varying degrees of flexibility in meeting the reduction targets. A few bills identified compliance measures to be applied to specific power plants, some identified specific compliance measures that utilities might apply but did not specify which plants must use them, and some left the choice completely up to the utility, subject to approval of its plans by the EPA administrator.

- Several bills set emission reduction targets for states, others did so for utilities, and others for power plants. Those that set targets for states or utilities usually allowed

the state flexibility in trading requirements among the utilities that serve it; those that set targets for a utility usually allow the utility flexibility in trading reductions among the plants it operates. This trading within states or utilities should allow compliance at lower cost than setting targets for individual plants (Tietenberg 1985). Analysis of these bills for the small number of utilities of interest to BOM requires processing large amounts of additional information to compute state targets or to include other utilities included in states that these utilities serve. At the time of the analysis for BOM we had only data for the specified utilities. For this reason, when a bill specified a state target, we have treated it as a utility target; this may lead to overcontrol of emissions and an increase the compliance cost estimated for some utilities under these bills.

- Most bills set emission tonnage targets for the nation but specified compliance in terms of emission rates ($SO_2/10^6$ Btu fuel input at a power plant) needed to achieve the national targets. In the long term, if demand for electricity continues to increase, if demand is met by burning coal at these compliance rates, and if no other requirements are imposed, total emissions will increase above the national tonnage targets after they are met. It is unclear why these bills did not specify performance standards in terms of SO_2/kWh generated, which would have given utilities greater incentive to improve generating efficiency (plant heat rate), or in terms of SO_2/kWh delivered, which in addition would have provided incentives to reduce transmission and distribution system losses. Two bills required caps on the total emissions, in varying detail. Caps on emissions provide incentives to improve heat rates, reduce losses and, in addition, improve the efficiency of electricity end-use equipment; by improving end-use efficiency, a utility may be able to shut down some plants with high emissions and satisfy the demand of its present customers or, alternatively, forgo emission reductions at some plants in order to build a new one.

- Some bills levied emission taxes or electricity taxes during the phase-in of emission reductions. Some would have used the proceeds to finance emission controls, or the use of specific control technologies. Most bills levied fines for failure to comply with targets.

- One bill (HR 2497 from the 100th Congress) levied a tax on emissions, with the resulting revenues earmarked for use by emitters subject to the tax in reducing emissions. The bill also granted a tax credit of 25% of the depreciation on control equipment. This bill set no specific targets and contained insufficient detail for us to analyze its effects on the cost of electricity.

- All of the bills required utilities and/or states to submit plans for complying with the legislation to the EPA administrator, who would have to approve or disapprove them. Where a bill required states to submit plans, it seemed likely that the process of obtaining administrator approval would have allowed utilities or ratepayers who objected to parts of a plan to seek changes in it.

The lack of detail in requirements for reducing NO_x mirrors uncertainty about present levels of NO_x emissions. In general, reported levels of both SO_2 and NO_x are based on calculated values instead of on values monitored at powerplant stacks. The calculations use standard formulas (EPA 1978). Unlike SO_2 emissions, NO_x emissions depend on a number of operating characteristics that are difficult to incorporate into the calculations, including the temporal pattern of electrical load and the utility's operation of the unit to meet it (Smith et al. 1987). In some cases, NO_x emissions have been monitored, compared with calculated values, and found to differ by as much as one-half of the calculated values (Mormile et al. 1987). Thus, the implications of requirements to reduce NO_x emissions are uncertain, because the baseline from which the emissions are to be reduced is uncertain. In the absence of either monitoring or better calculations, the emission rates that result from installing control technologies will, therefore, also be uncertain. When this uncertainty is coupled with legislation that would allow utilities to reduce NO_x in lieu of SO_2, calculation of SO_2 reductions becomes more uncertain. The regulations needed to prevent phantom reductions and phantom offsets in the two bills that allow substitution of NO_x for SO_2 remain to be written.

Table 2 lists the six bills analyzed and major features of each. Section 4.2 describes each bill in more detail and discusses how it was represented in the analysis.

Because the emission trading features of the Bush administration-Senate 1630 bill are novel compared to the other bills, because they received substantial attention, and because they are part of the legislation that eventually passed, we discuss them at length in the following section. All discussion of these features applies to the legislation as introduced, and it is possible that some specific points made may differ under the legislation that actually passed.

2.2 TRADING OF EMISSION ALLOWANCES

Emission limits can be placed on individual sources (power plants in this case), and the owner of each source required to meet the limit. It is common, however, for the cost of controlling emissions to vary at different sources. If the total amount of emissions, rather than their location, is the critical factor in protecting the environment, then it may be less expensive to meet the aggregate limit on emissions by reducing emissions first at the sources where controls are less costly, and perhaps not reducing emissions at all at some sources where control costs are very high. Emission trading systems allow this by setting a limit on emissions by a group of sources (power plants in this case) and then allowing the owner(s) of these sources to meet the limit in the least expensive way. Most bills allowed a form of emission trading within individual utilities or states. For example, a utility might be given a limit but might also be given complete freedom in choosing which plants should reduce their emissions. The Bush administration's proposed amendments take this step further and allow utilities to trade emission reductions with each other, with some utilities in effect paying others to reduce emissions for them.

Table 2. Summary of proposed Clean Air Act amendments affecting electric utilities

Bill	Boehlert HR5032 100th	Kerry S57 100st	Cooper HR144 101st	Sikorski HR1470 101st	Mitchell Compromise 101st	Administration S1630 101st
Feature						
Baseline year	1980	1985 NAPAP Inventory	1980	None required	1980	Annual average 1985 — 1987
Utility SO_2 tonnage reductions	3.5 million 1993 8 million 1998 10 million 2003	5.83 million 1996 10 million 2000	3 million 1994 5 million 1997 10 million 2003		Not specified for 1994 10 million 2003	Not specified for 1996 10 million 2000 (from 1980)
Targets	Statewide average	State shares based on 1.0 lb cutoff	State shares based on 1.2 lb cutoff	Statewide average	Generating unit	Utility
Emission rates (lbs $SO_2/10^6$ Btu)	2.0 lbs 1993 0.9 lbs 1998 0.9 lbs 2003	Best available control technologies or 1.0 lbs	None, uses 1.2 lbs to compute state shares	2.0 lbs 1994 1.2 lbs 1998	90% reduction 1994 for listed plants; 1.0 lbs 2003 for units now over 1.2 lbs	None; equivalent to 2.5 lbs for some units in 1996, 1.2 for most in 2000
Cap	None	None	Cap at 2003 levels	None	None	Cap at 2000 levels, banking permitted
Emission trading	Within states	Within states; among neighboring states	Within states; among members of a power pool	Within states (implied)	Within utility	Among utilities; marketing system
Fees	None	.5 — 1.6 mills/kWh, based on emission rate	None	Up to .5 mill/kWh through 1998	1 mill/kWh if emission rate over 1.0 lb	None
Capital subsidy	States administer federal grants up to 50% of capital costs	$147 per ton capital subsidy	None	Capital and operating costs of equipment; amount not specified	$200 per kW for 1994 phase, $150 for 2003	None
NO_x	25% reduction by 1998, details left to EPA administrator	Limits on new units; 2 lb reduction=1 lb SO_2 reduction	3 million ton reduction 1997; state shares	.6 lb standard 1998 for existing units; tighter for new units	No mention in bill summary, 1.0 lb state average in earlier version	Limits for 2000; trading permitted, 1.5 lb reduction=1 lb SO_2 reduction
"Clean coal" technology incentives	Not specific					
Technical options required	None	Coal cleaning for units now burning >2% sulfur; adipic acid for existing scrubbers	None	None	Scrubbers on listed plants for 1994	None
Technical options allowed	All	All	All	All?	All for other plants	All

The emission trading system in the Bush administration-Senate 1630 bill set criteria and formulas to be used to calculate an amount of SO_2 that each utility may emit each year. For the 11 utilities we analyzed for BOM, the amounts on average for the year 2000 were roughly equivalent to the amounts that would be allowed if the nation reduced its annual emissions by 10 million tons; however, we calculated that the actual reduction for the entire nation would only be about 7.5 million tons from present levels under the Bush administration-Senate 1630 bill. Each year, each utility would be issued allowances to emit its calculated amount. After the second phase of the amendments take effect in 2000, the amount of emissions calculated and the number of allowances issued would remain constant.

The bill allows utilities to "trade" (purchase and sell) allowances. The theory underlying the system assumes that some utilities will be able to reduce emissions much less expensively than others. For example, a standard flue-gas scrubber removes 90% of the SO_2 from the stack gases; all else being equal, installing the technology at a plant that burns high-sulfur coal will be less expensive, per pound of SO_2 removed, than installing it at a plant that burns lower-sulfur coal. Similarly, some plants have little space available for retrofitting equipment, storing limestone and sludge, or storing several types of low-sulfur coal for blending, while others have adequate space. Reducing emissions at such a plant is likely to be much more expensive. A utility that can reduce emissions at lower cost than other utilities could reduce its emissions by more than its number of allowances required and sell its "excess" allowances to another utility whose costs are higher. The money it receives for these allowances would pay for the cost of the extra reductions it makes. A utility with high control costs would be willing to pay for additional allowances as long as the price is below the cost of reducing its own emissions.

As an example, assume that two utilities each emit 100,000 tons of SO_2 per year and receive allowances for 80,000 (Table 3). Because of its equipment and fuel mix, utility "A" can reduce emissions by 20,000 tons at a cost of $500/ton in one of its plants, and by another 20,000 tons at a cost of $600/ton in another (the costs are purely for illustration). Utility "B" can reduce emissions by 20,000 tons at a cost of $700/ton in one plant and at higher costs at each of its other plants (its costs may be higher because its equipment is older, because its equipment cannot be modified inexpensively to burn low-sulfur coal, or because of limited space at its power plants to retrofit control equipment or store limestone or scrubber sludge). Utility "A" could reduce emissions by 40,000 tons at an average cost of $550/ton, and sell 20,000 excess allowances at a price greater than $600/ton. Utility "B" would be willing to pay utility "A" up to $700/ton for these 20,000 allowances to be able to continue emitting 100,000 tons per year. If the two utilities agree on a price, each would be better off for having traded allowances, yet the total emissions from the two after trading would be the same as they would have been if no trading had occurred. If no allowances were available for less than $700/ton, utility "B" would be better off by reducing its own emissions.

In addition to the theory underlying the system, two other factors operate to promote trading of allowances. First, the criteria used are roughly equivalent to establishing an emission standard of 1.2 lb $SO_2/10^6$ Btu of fuel burned at a utility's power plants. However, some plants emit at less than this level and under the rules for computing allowances could

Table 3. Example calculations to illustrate emission trading

	Utility A	Utility B	Total
Emissions	100,000 tons	100,000 tons	200,000 tons
Allowances	80,000 tons	80,000 tons	160,000 tons
Without trading:			
Least cost to control first 20,000 tons	$500/ton $10 million	$700/ton $14 million	$24 million
Emissions after controls	80,000 tons	80,000 tons	160,000 tons
With trading:			
Least cost to control first 20,000 tons	$500/ton $10 million	Not controlled	
Least cost to control second 20,000 tons	$600/ton $12 million	Not controlled	
Allowances	Sell 20,000	Buy 20,000	
Allowance price	> $600/ton	< $700/ton	
Emissions after compliance	60,000 tons	100,000 tons	160,000 tons
Control cost	$22 million	$0	$22 million
Adjustment for allowances	-$12 to $14 million	+ $12 to $14 million	$0
Total compliance cost	$10 to $8 million	$12 to $14 million	$22 million

emit at an effective rate of 1.44 lb $SO_2/10^6$ Btu. Thus, there are a few "excess" allowances already built into the system. For example, we calculate that Appalachian Power would be allowed to increase its emissions by about one-sixth above present levels in the second phase, and that Duke Power's clean plants would earn excess allowances that nearly offset the reductions it would be required to make for its plants with higher emissions (Table 4). Our calculations indicate that approximately one-fourth of all utilities would be granted allowances in excess of present emission levels, although the vast majority of these are very small utilities that would receive very small increases. Whether these are regarded as "rewards" for past performance, as subsidies, or as "cushions" for future growth is open to interpretation, but the language in the original administration bill is explicit was granting them.

Table 4. Emission allowances as allocated under Senate Bill 1630 in thousands of tons

	SO_2			NO_x	
	Base	Phase I	Phase II	Base	Phase II
Alabama	364.15	338.55	231.67	131.67	86.86
Appalachian	164.10	164.10	191.41	117.00	82.55
Associated	272.70	115.80	62.51	97.60	81.65
Big Rivers	125.90	85.60	52.04	37.50	24.74
Cleveland	312.60	183.34	107.26	26.30	32.34
Duke	194.00	194.00	189.04	94.10	74.78
Ohio	877.00	399.70	191.98	173.90	118.54
Potomac	504.10	353.70	181.93	129.70	88.46
S Carolina	44.40	44.40	26.24	36.50	20.46
S Indiana	131.91	65.42	41.81	24.89	15.21
TVA	1156.60	785.77	466.43	349.90	247.82

Second, reducing emissions by adding scrubbers or other post-combustion controls involves what economists call "lumpy" investments. A utility that needs to reduce emissions from a plant by 50% to match what it is allowed to emit often can reduce emissions by an additional 20–30% at relatively little additional cost per ton reduced. This is because the capital cost and operating costs of the control equipment are more sensitive to the size of the plant and its generation than to the amount of emission reduction achieved, within broad limits. The "extra" 20–30% then becomes a low-cost reduction that frees additional allowances for trading.

If the demand for electricity increases a utility eventually will need to build a new power plant. If the utility has no excess allowances it must either build a plant that emits no SO_2, reduce its emissions to offset those from the new plant, or purchase additional allowances from another utility equal to those the new plant would require. In many cases, improving electrical end-use efficiency is likely to be less expensive than building new power plants for some time, even before considering the costs of reducing emissions, purchasing

additional allowances, or taking other steps to protect the environment (Cavanagh 1989). In addition, some utilities may find it less expensive to help their customers improve end-use efficiency, and retire some older generating units than to invest in emission controls at these units. The bill says nothing about how utilities may or must reduce emissions, only that their emissions must not exceed the allowances they have.

A number of questions remain about how the system would work in practice, as opposed to in theory (Krupnick, Bohi, and Burtraw 1990). First, although it is likely that public utility commissions (PUCs) would treat the cost of purchasing allowances like other costs and would permit them to affect electricity rates, it is not clear how they would treat the revenue earned by a utility that sells allowances. If the revenue is returned to shareholders, it would not reduce rates. In this event, PUCs will be less likely to allow utilities to undertake additional controls to free up allowances for trading, and the system would have limited effect. Thus, the ultimate effects of trading on industrial or other electricity rates are uncertain.

Second, because the allowance system is so new, we do not know how utilities and PUCs will actually behave. Concern has been expressed that utilities or PUCs with excess allowances would "hoard" them rather than selling them, to preserve flexibility in the future. At least one PUC is now on record stating that it will work to prevent utilities in its state from hoarding allowances, but it remains unclear whether other PUCs will follow suit, or whether the public will permit them to: the public could be persuaded that selling allowances would not be in their best interests. At least one PUC is also on record that it will discourage utilities from selling their allowances. If hoarding occurs, it would reduce the effectiveness of the allowance trading system.

Third, the administration bill mentioned the possibility of "banking" allowances but left specifics of the banking to the EPA administrator. Utilities would receive allowances each year on the basis of their present stock of generating equipment. Some mechanism would have to be established to provide for the long-term commitment and sale of allowances. Otherwise, utilities faced with a 5–10 year lead time on large new power plants and a plant lifetime of 30–50 years would be unlikely to undertake construction on the basis of purchased allowances, and would bank or hoard their own.

Fourth, the design of the allowance system implicitly assumes that a ton of emission reduction in one location is just as desirable, from a national perspective, as a ton of emission reduction in any other location. However, regional rather than national effects of emissions have motivated much of the argument for reducing emissions. Specifically, some states in the Northeast and East have been concerned about the long-range transport of emissions from power plants in the Midwest. Presumably, then, emission reductions in the Midwest would be more valuable for addressing these concerns than would emission reductions in the coastal states of the Southeast. Given the magnitude of emission reduction specified in the Bush administration-Senate 1630 bill, some emission reduction in the Midwest is virtually assured, even with trading. However, the allowance trading system has the potential to shift some emission reductions from the Midwest to other regions, thereby reducing the effectiveness of the bill in solving one of the problems for which it was proposed. Additional analysis will be required to determine how large such a shift is likely.

Finally, the bill specified an allowance system for NO_x as well as SO_2, and specified that the two pollutants could be traded for each other at a rate of 1.5 lb NO_x = 1.0 lb SO_2. As noted in Section 2.1, although there are standard formulas for estimating NO_x emissions based on burner and fuel characteristics, there is a wide variation of actual emissions around what the formulas calculate, and actual NO_x emissions from power plants generally are unknown. The bill required monitoring of actual emissions during the mid 1990s to establish a baseline for the allowance system. We are just beginning to analyze the implications of uncertainty about NO_x emissions for trading, emission control costs, and electricity rates; this analysis has been left to a subsequent report.

3. CALCULATING COSTS

This section explains how costs are calculated and used in the model to compare impacts of proposed legislation.

3.1 PROBLEMS IN COMPARING COST ESTIMATES

Comparison of estimated future costs for two or more emission reduction technologies or pieces of legislation is not always straightforward. First, costs may be estimated using different methods, each of which may be considered "correct" and justifiable. However, each method reflects slightly different assumptions and could yield different rankings of alternative technologies in a least-cost compliance model.

Second, costs can be calculated using a common method but with different assumptions about parameters such as interest rates, taxes, and inflation.

Third, different legislative proposals can require similar levels of emission reduction but impose the requirements in different years. Although most bills established a two-phase schedule for reducing SO_x emissions, they differed in the years specified for these phases to be completed and in the levels of control to be achieved in each; a few specified three phases and, although none specified more than one phase for reducing NO_x, the proposals otherwise had little in common in regulating this pollutant. Depending on the method used and the assumptions made, utilities may find that postponing the implementation of some technologies, such as fuel switching, is much less expensive than implementing them immediately, while postponing others offers little reduction in costs.

Finally, some legislation specifies the use of emission fees, capital subsidies, or other options to redistribute the costs of meeting the regulations, and cost estimates must reflect these options when specified.

Section 3.2 discusses the different methods offered in the model software, and some of the implications of combining these with different implementation schedules and options for redistributing compliance costs. Appendix A discusses the parameters and the formulas used to calculate costs according to the different methods.

3.2 METHODS FOR CALCULATING COSTS

Although conventional engineering economics would evaluate the life-cycle costs of alternative investments over a typical planning horizon of 25–30 years, our analysis includes three situations for which shorter time periods may be appropriate.

First, large electricity users such as aluminum smelters, with existing sunk capital, are less likely to be interested in the utility's life-cycle costs and more interested in the remaining usefulness of their own equipment, which will be partially or fully depreciated by the time the

utility achieves compliance. These users may be interested primarily in the costs of electricity for the first 10 years or so following the final phase of emission reductions.

Second, many potential compliance technologies remain unproven at commercial scales, and the costs of some depend heavily upon assumptions about the availability and cost of different fuels, sorbents, or catalysts over the life of the installation. A utility might reasonably choose a proven technology whose life-cycle costs are slightly higher than an unproven one whose savings are projected to accrue only near the end of its expected useful life.

Third, ratepayers and PUCs have become sensitive to the issue of "rate shock," in which large capital investment costs enter the rate base in a very short period of time, thereby causing a rapid increase in electricity rates. Because proposed legislation requires emissions to be reduced in phases, some potential exists for rate shock in each phase, although each is likely to be less than the rate shock if there were no phasing in of reductions. This potential is likely to be a consideration in PUC approval of emission control strategies. Some PUCs may be willing to accept slight increases in life-cycle costs to reduce first-year costs or rate shock.

At least four methods for calculating the costs of compliance technology could be used to examine these issues:

- first-year costs,
- one-year costs,
- short-period levelized costing (for example, for 10 years), and
- life-cycle levelized costing (for example, for 25 years).

The differences among these methods may be understood more easily by referring to Figure 3, which graphs a hypothetical utility's costs calculated by different methods against time, for a representative bill that reduces emissions in two phases. In Figure 3, equipment is installed to reduce emissions in phase I, causing an increase in cost when the equipment comes on line. Even larger reductions are required in phase II, causing an even larger cost increase at that time. The first-year costs for phase II are 62.83 mills/kWh, costs in 2008 (a one-year cost) are 79.78, while short-period (10-year) levelized costs are 56.53, and life-cycle (25-year) levelized costs are 59.39. Each of these costs can be expressed in terms of a reference of base year's dollars, with the base year chosen for convenience.

First-year costs are defined as the costs of the technology incurred in the first year that a proposal requires emission reductions. All else being equal, capital costs tend to be high the first year that new equipment is brought on-line, because capital equipment payments are high in the first year and decline in succeeding years from depreciation and loan repayment. On the other hand, the cost of fuel and of operating and maintaining equipment tends to increase each year because of inflation and real cost escalation, as discussed in greater detail in Appendix A.

If a bill specifies several phases for emission reductions, the potential exists for a rate shock at each phase. Calculating first-year costs for the second phase and using the model

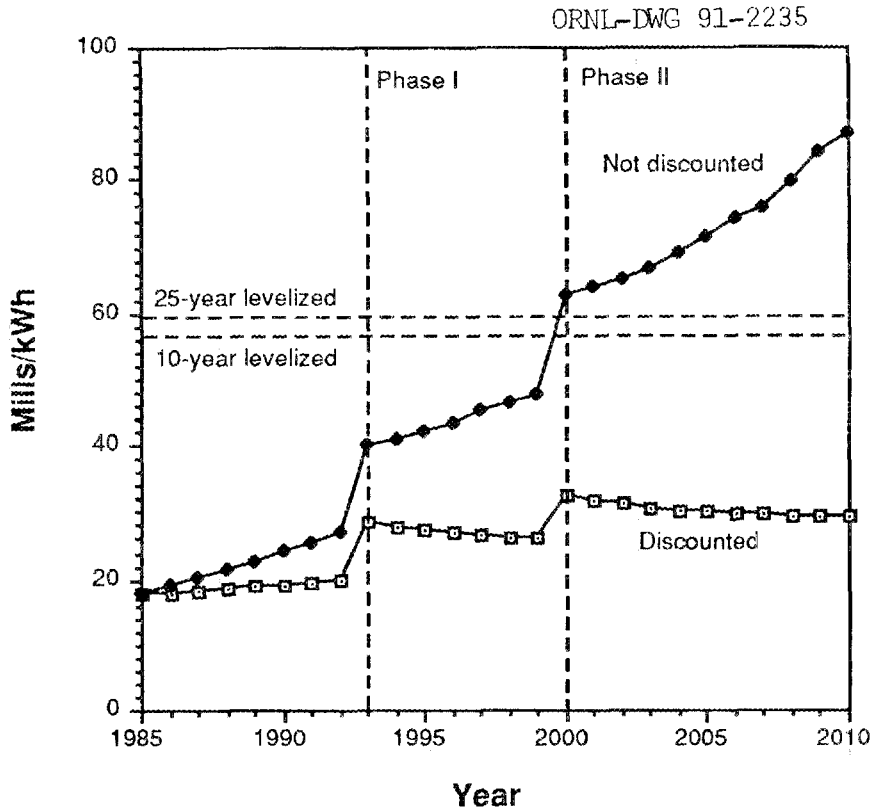

Figure 3. Year-by-year constant dollar costs with a comparison of levelized costs.

to minimize them ignores the rate shock potential of complying with the first phase, and vice versa. The compliance strategy that minimizes first-year costs for the second phase will tend to overcontrol emissions — and increase rate shock — in the first phase. The compliance strategy that minimizes first-year costs in the first phase does not overcontrol emissions in either phase, but it tends to ignore costs in the second phase and may increase the associated rate shock. We plan for future versions of the model software to treat the first-year costs for the two phases as a bicriterion optimization problem, minimizing a weighted function of the first and second phase costs. Initial analysis of a utility would include multiple runs to determine the appropriate weighting factor; subsequent analysis could use this factor as a reasonable approximation unless fine-tuning was desired.

The "one-year costs" are calculated similarly to the first-year costs, except the user has the option of selecting the year for which costs are to be calculated. This is useful for comparing the cost of proposals with different implementation schedules or final phase dates (e.g., for estimating costs in 2008 after any of the bills we examined would have been fully implemented).

"Levelized costs" are a way of averaging costs over time while taking into account the discounting of money over time (EPRI 1987). The model software allows the user to select the period over which the costs are averaged or, rather, levelized. Because capital expenses occur once, at the beginning of the investment, and then depreciate, while variable costs occur throughout its lifetime, the length of the levelizing period can affect the ranking of compliance technologies. Longer periods tend to reduce the importance of capital costs, relative to recurring operating costs, and shorter periods tend to increase the relative importance of capital costs.

The linear programming model can find the least-cost compliance strategy based on any of these methods, and the software could recalculate costs for that strategy using the other methods (e.g., calculate the first-year costs of a strategy that minimizes life-cycle levelized costs). There is no assurance that a strategy that minimizes costs calculated according to one method will minimize costs calculated with another. To obtain the least-cost compliance strategy for a particular method it is necessary to solve for it explicitly.

The current version of the software allows the user to choose among the four costing methods; however, the version used for the BOM analyses had more limited capabilities.

3.3 ECONOMIC ASSUMPTIONS AND METHODS

Each of the four methods of calculating costs requires explicit assumptions about future price changes and the present value of expenditures incurred in the future. These become parameters in the calculations, and are discussed in detail in Appendix A.

3.4 DATA ON PLANT AND COMPLIANCE COSTS

The methods and parameters described in Appendix A can be used to estimate future emissions and costs of existing generating plants and the costs and performance of various technical options for reducing emissions. As described in the following, reasonably good data are available to describe present costs and emissions for existing facilities.

Most public discussion of the costs of the Clean Air Act has focused on SO_2 emissions and on fuel switching and scrubbers as methods for reducing them. Both are proven technologies, and utilities have gained extensive experience with them in complying with the Clean Air Act Amendments of 1977. For modeling purposes it is necessary to have estimates of the added cost of low sulfur coal and of the costs of installing and operating scrubbers.

In addition to SO_2, most of the proposals analyzed placed some limits on NO_x emissions. Several technologies have been designed to reduce NO_x emissions independently of other technologies for reducing SO_2. In addition, a number of "clean coal" technologies are under development or are just now being demonstrated at commercial scale. These promise to reduce emissions of SO_2, NO_x, or both, at lower cost, with less solid waste or effluent, or at greater removal efficiency. Most of the bills analyzed contained provisions to encourage utilities to adopt "clean coal" technologies as part of their compliance strategies.

Based on our survey of NO_x control and clean coal technologies, we have chosen low-NO_x burners to represent stand-alone NO_x control technologies. Low-NO_x burners appear to be suitable for most generating units, at much lower cost than competing technologies. In addition, although some NO_x control technologies can yield greater reductions in NO_x emissions at individual plants, low-NO_x burners appear sufficient to enable utilities to achieve the reductions specified in the bills we analyzed. There is a class of technology known as cyclone burners (Dolezal 1967) that cannot use low-NO_x burners, and a few of the generating units operated by the utilities we analyzed are of this type. However, the costs of technologies for reducing NO_x emissions from cyclone burners appear to be higher than those for using low-NO_x burners on other types of units, and it was not necessary to reduce emissions from the cyclone burners in order to meet the emission targets set in the bills analyzed. Other technologies under develoment would yield greater emission reductions but at greater cost (DOE 1989).

3.4.1 Fuel, Operating, and Maintenance Costs

For most of the plants in our analysis, we have used the costs of maintenance and repair, operation, and fuel reported by the Energy Information Administration for 1985 (EIA 1987). The data series reports expenses for 1985 both as actual dollars spent and as mills/kWh. Our study includes a number of plants not listed in this series, and information for these was drawn from an earlier report of costs in 1981 (EIA 1984). This was the last year data were reported for all privately-owned utility plants. Costs taken from the 1981 report were inflated to 1985 dollars using the gross domestic product deflator. The model software allows users to alter any of these values (Figure 4).

The fuel and operation and maintenance (O&M) costs reported in these documents are given for the whole plant rather than for individual units within the plant (EIA 1987). Older units in a plant typically would have higher O&M costs than the newer units. Also, fuel costs may be higher in older units than newer units because the unit is less efficient. However, there is no clear way to determine an individual unit's cost from the plant information, and the model uses the plant's mills/kWh fuel and O&M costs for each unit within the plant in the base year.

3.4.2 Estimated Low Sulfur Fuel Costs

Utilities typically are charged higher prices for low sulfur coal than for high sulfur coal because of its relative scarcity and preferred environmental characteristics. Besides the additional cost of low sulfur coal, the cost of transportation will vary depending upon the shipping distance of the low sulfur coal.

In this study the cost of low sulfur coal is assumed to be $10 per ton more than the 1985 price of the higher sulfur content coal; $10 was added to the 1985 cost per ton of coal and this sum was multiplied by the amount of coal used in 1985. The $10/ton increase was derived from a study by Edison Electric Institute (EEI), which used three cost differentials

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Select Unit Type Elimit Global Cost Fees Name Print eXit

Select: Company(ies) or State(s)

Select Options	Company: OHIO POWER COMPANY Plant: GEN. J. M. GAVIN 1
* Leave Alone * Add Scrubbers * Switch to Low Sulfur Coal * Add NOx Device * Add Scrubber and NOx Device * Switch to Low Sulfur and Add NOx NA Clean Coal Technology Force Unit to Selected Change Add in Integer Solution	Unit Characteristics Year On-line : 1974 Remaining Life at Phase One : 29 Years Major Fuel Use : COAL Generation : 5986 MWH Unit Capacity : 1300 MW Capacity Factor : 53.00 % Fuel Costs : 20.93 M/KWH O&M Costs : 1.73 M/KWH SOx : 5.83 lbs/MMBtu NOx : .92 lbs/MMBtu First Record

F2 - Accept F3 - Change F4 - Next F5 - Back F6 - Find

Figure 4. Sample software screen showing unit-specific performance and costs.

based on the amount of switching to low sulfur coal nationwide. If the switching was less than 40 million tons nationwide, the EEI used a cost differential of \$3 to \$6/ton. If the switching was 75 to 100 million tons, the EEI cost differential was \$10 to \$12/ton, flattening out to \$15 to \$20/ton for 150 million tons used (EEI 1986). The present analysis for BOM includes only 11 specific utilities, and there is no method of ascertaining the amount of coal switching that would occur nationally, or the effects that this would have on coal markets or prices. The cost differential of \$10/ton was chosen as representative. We assumed that utilities would be able to purchase as much low-sulfur coal as they wanted with this premium, and that this premium adequately captures the additional transportation cost as well as other costs associated with switching to low-sulfur coal. The heating value per ton of low-sulfur coal often is lower than that of high-sulfur coal. In the results presented in Section 5, we have assumed that switching to low-sulfur coal does not change the coal's heating value. However, subsequent to this analysis we have modified the software to allow relaxation of this assumption.

The sulfur content of the low sulfur coal is assumed to be the amount necessary to reduce SO_x emissions to .7 lb/10^6 Btu. Using standard EPA formulas for calculating SO_x emissions (EPA 1978), this yields a sulfur content of .5%.

3.4.3 Cost and Performance of Scrubbers

The costs of adding scrubbers to existing generating units were estimated by using a method suggested in DOE (1988). The procedure treats separately the capital costs and the additional O&M costs caused by adding a scrubber. The O&M costs include both fixed costs and variable costs. Fixed O&M costs are yearly costs, such as O&M personnel, maintenance materials, and administrative and support personnel. Variable O&M costs include such costs as power, scrubber reagent, steam usage, water consumption, and waste disposal costs.

A report by the Electric Power Research Institute (EPRI) estimated costs for various types of scrubbers (EPRI 1984). The type of scrubber chosen by a utility would depend on the costs of specific types at a specific site, the availability of raw materials and the ability to handle the various types of waste products, and the level of emission reduction desired. Because of limited resources available for this study, we have assumed that any scrubbers installed to comply with legislation would be wet limestone scrubbers. The wet limestone scrubber is the type of scrubber most commonly used by electric utilities, and the cost of this technology is likely to be a good upper bound on the cost of controlling emissions. Other control technologies may become less expensive as utilities gain experience with them, but the costs of these technologies remain speculative.

The procedure described in DOE (1988) requires a variety of specific plant and unit information to calculate the costs of retrofitting scrubbers on existing electric utility units. The actual cost of retrofitting scrubbers will vary by the size of the unit and by engineering factors. Because the retrofitting costs and other information were not available in sufficient detail for all the generating units used in this study, in our analysis we have treated some of the costs that would vary from site to site as constants.

The capital cost of adding a wet limestone scrubber to an existing electric utility generating unit was taken from a study by EEI (1986), which used a capital cost of $280/kW (1985 dollars) of generating capacity. Other published estimates have been as low as $240/kW, but the higher value is likely to be high enough to encompass all of the site-specific contingencies for which we lack plant-specific data.

EEI estimated the total fixed O&M scrubber costs to be $13/kW capacity at the unit, and the variable O&M scrubber costs were estimated to be 1.7 mills/kWh generated by the unit. These estimates were consistent with case studies used in the EPRI report (EPRI 1984). Figure 5 illustrates the software screen used to specify the scrubber costs for the analysis.

Because of the high cost of scrubbers, we have assumed that a utility which chooses to install a scrubber on a generating unit will also make additional investments in the unit to improve the unit's availability and extend its lifetime to allow recapture of the cost of the investment. Thus, if a unit now operates at a capacity factor below .65, we assume that adding a scrubber also will entail upgrading to permit operation at a .65 capacity factor. The model software allows the user to modify this assumption. The costs of upgrading the unit are assumed to be covered by the cost of retrofitting the scrubber, and provide additional justification for the assumed $280/kW capital cost. The assumed upgrading makes it possible

for some large utilities to shut down one or more units that have high emission rates by upgrading and adding scrubbers to other units that now have relatively poor performance. The model user is free to alter these assumptions (Figure 5).

A retrofit scrubber is assumed to reduce SO_2 emissions by 90%.

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Select Unit Type Elimit Global Cost Fees Name Print eXit

Select global options used in the analysis

Scrubber Cost Information
Fixed O&M Costs : 13.00 /KW
Variable O&M Costs : 1.70 /MWH
Capital Costs : 280.00 /KW
Scrubber Use Information
Unit capacity factor when scrubber added Use 0 (zero) for the historic factor. : 65.0 %
Unit lifetime after scrubber is on-line. Use 0 (zero) for historic lifetime. : 30 Years
New Scrubber Efficiency : 90.0 %
Minimum unit size for addition : 0 MW

Press:
↑ to go up one line
↓ to go down one line
ESC Return to Main Menu
F1 HELP
F2 Accept and Return to Other Options

Figure 5. Sample software screen showing scrubber costs.

3.4.4 Cost and Performance of NO_x Controls

As with scrubbing technology, a utility's choice of NO_x control technology would vary with specific plant conditions and the desired reduction in emissions. For utility burners other than cyclone burners, low NO_x burners appear to be the control technology of choice. As with wet limestone scrubbers, the low NO_x burner technology is well established. Unlike scrubbers, low NO_x burners are much less expensive to retrofit ($10–20/kW) and, once in place, have virtually no effect on O&M costs and generate no additional waste streams. The 40–70% reduction in NO_x emission rates is less than some technologies that are more expensive, but it appears to be more than adequate to achieve the reductions required by the bills being analyzed. We have assumed a $20/kW capital cost (1986 dollars) and a 60% reduction in emission rates for this technology. These values fall within the ranges reported by Mormile et al. (1987). In addition, we have assumed that cyclone burners would not be retrofitted with any equipment to reduce NO_x emissions.

3.4.5 Other Costs

Other costs of operating a utility would include transmission costs, sunk costs (costs for existing equipment), and business costs (the costs of operating a company). These costs are assumed to be unaffected by any proposed legislation and are not included in the estimates.

3.4.6 Choice of Parameters for Cost Calculations

The capital costs of the added scrubbers, low-NO_x burners, or clean coal technology; their projected O&M costs; the current O&M costs for a plant; and fuel costs can be either levelized or can be projected for a specific year, and, optionally, discounted. The capital costs, O&M costs, and fuel costs also can escalate at different rates relative to the general inflation rate; however, following the assumptions used in DOE (1988), we have assumed a common escalation rate of 1% per year for all types of cost. In addition, we have used the 5% inflation rate and 4.35% real discount rate from this same source. These are the values (Appendix A, Table A.1) used in this study.

For comparing legislative proposals or other scenarios, costs are expressed in mills/kWh. This allows comparison of the cost differences between utilities because the differences take into account the actual cost of the output. The model forces demand for electricity (kWh) to be met; therefore, there is little variation in generation between proposals, and the mills/kWh for different bills can be compared directly.

4. ESTIMATING A MIX OF COMPLIANCE OPTIONS

The methods and data discussed above yield estimates for the cost of implementing specific control options on individual generating units, and this information is sufficient to calculate on a unit-by-unit basis the least expensive control option for each unit. Performing such a calculation does not necessarily yield the least expensive strategy for a utility to use in reducing emissions to specified levels. For example, it is common for coal switching to be the least expensive option at a plant, but for coal switching at all plants to yield higher emissions than permitted by legislation, so that some scrubbing becomes necessary. The operating costs, fuel prices, and generating efficiency (heat rates) vary across power plants, so that the least expensive control costs may be available at plants that are more expensive to operate; when this occurs, the utility may have to trade off generating costs against emission control costs to achieve the least total cost. When emissions must be reduced for two different pollutants, such as SO_2 and NO_x, or in two different stages as most legislation required, additional tradeoffs become necessary. Although intuitive solutions are possible (Alvic 1988), they are difficult to derive consistently across different utilities and across different sets of amendments.

4.1 MODEL SUMMARY

To identify the best set of options for a utility, we model the choice of a utility's overall mix of compliance options for its system using a linear programming model. For a specified method of computing costs (e.g., first-year costs in a bill's second stage of compliance), the model seeks the minimum cost of generating electricity, subject to the following constraints.

- The utility must meet a projected demand for electricity.

- The utility must not exceed a specified emission rate (lb $SO_2/10^6$ Btu input) or a specified tonnage of SO_2 emissions. The specific form of this constraint depends on the particular bill being analyzed; Figure 6 illustrates the software screen used to specify emission tonnages.

- The utility must not exceed limits on NO_x emissions or emission rates (again depending on the bill).

- The utility must maintain an adequate reserve margin (this is an optional constraint that generally is not included in the analyses performed to date).

- The utility must satisfy certain technical constraints on the control options and use options that may be applied to individual plants and units (some combinations of options are not permitted, and information is available for some plants to either require or limit the options they may use).

- The utility may build new generating capacity, subject to present restrictions on emissions from such capacity, if this would be less costly than switching fuels or adding emission control technology at an existing plant.

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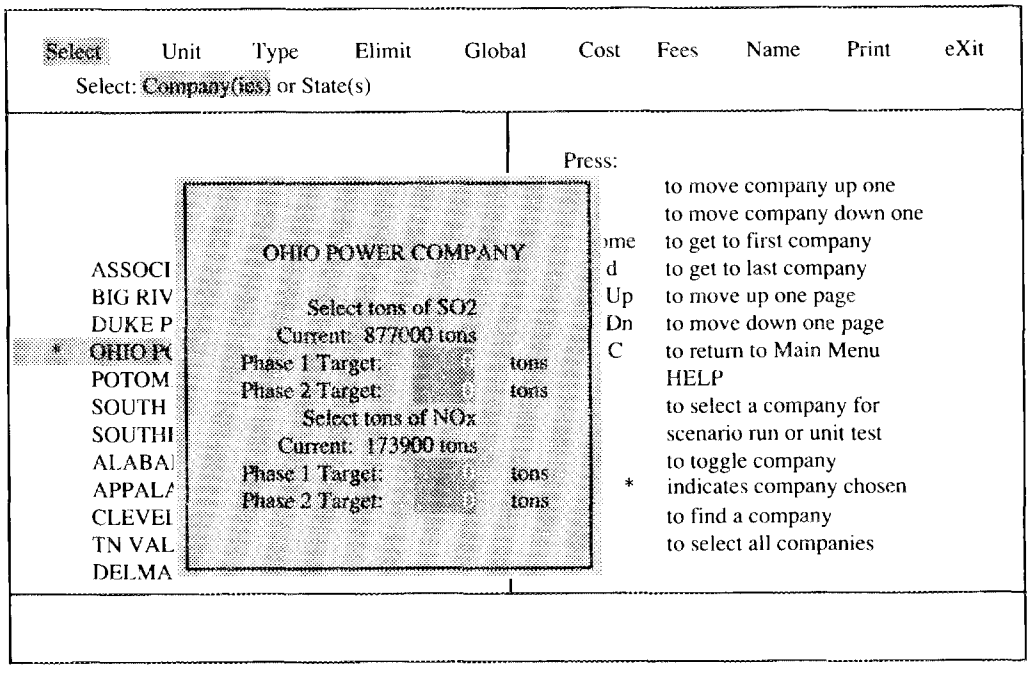

Figure 6. Sample software screen showing emission target.

Appendix B lists the equations that define the model. It is apparent that defining the model variables can become quite complex if there are more than two phases for reducing emissions, or more than four or five emission control technologies that can be applied to a specific generating unit. For this reason, when amendments have specified three phases, as the Boehlert and Cooper bills have, we have omitted one of the three phases from the analysis.

To analyze bills consistently, despite the differences in the years for which they require compliance, we hold constant the demand that each utility must meet, setting demand equal to the amount of electricity it generated in 1985. This ensures that we are comparing the costs of different emission control requirements instead of the costs of meeting additional demand. The model structure would permit the use of demand projected by the utility or by an outside group, and allow the utility to build new capacity to meet it. However, doing so would require additional data to project future demand for electricity. The present model software allows the user to specify different future levels of demand or growth rates (Figure 7), but leaves the responsibility for these values entirely with the user. The model structure

would also allow the definition of technologies to reduce the growth in demand by promoting improvements in electricity end-use efficiency, and to use these to reduce projected emissions as the Boehlert and Bush administration bills allow. Again, however, modeling these options would require additional data on the cost and potential size of these reductions in future demand, and these options have not been included in the analyses performed to date.

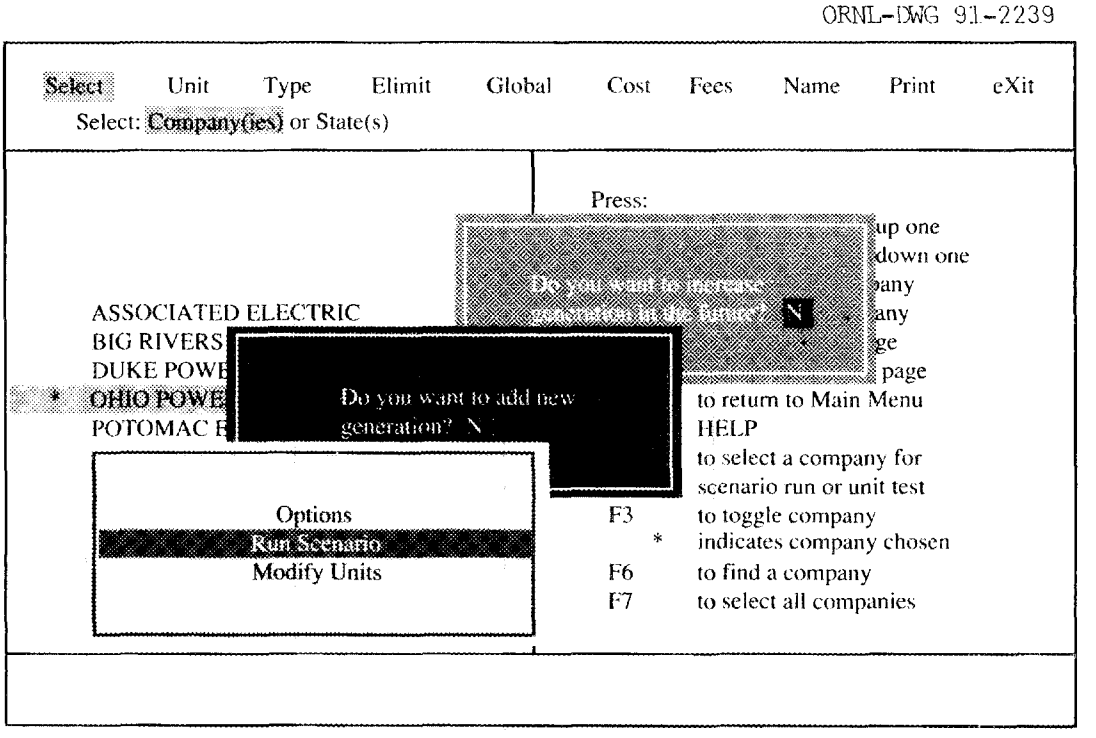

Figure 7. Sample software screen showing generation levels.

The model structure does not consider transmission of electricity between utilities. This reflects a lack of data rather than a fundamental limitation of the modeling structure. When modeling a single utility, it would be simple to allow it the options of purchasing specific amounts of power at specific prices, and it would be possible to increase the utility's projected demand to reflect expected sales to other utilities. When modeling a group of utilities, it would be fairly simple to include a transmission network between utilities to allow them to buy and sell power as appropriate to reduce costs, and allow utilities the option of building additional transmission capacity as needed. The model structure in fact is derived from one that allowed such transfers (Hillsman, Alvic, and Church 1988). Analysis of transmission requires some information about the capacity of the existing transmission system to accommodate inter-utility transfers. Unfortunately, this information is not potentially available at a cost consistent with the resources available for this study (the data used in the

model of Hillsman, Alvic, and Church were crude approximations, and in any case they are now 14 years out-of-date).

It is unclear how much the exclusion of transmission options affects results obtained with the modeling system. First, as noted earlier, we have held demand for electricity constant in order to make consistent comparisons between bills that have different compliance schedules. This practice has the effect of requiring generation to match past patterns of transmission use. The availability of adequate transmission data would not change this, and its use could lead to spurious transmission flows. Thus, improving the representation of transmission also would require projections of demand and would complicate the interpretation of results. Now that Congress has adopted specific amendments to the Clean Air Act, our practice of holding demand constant is no longer necessary, and the assumptions regarding demand and transmission need to be reexamined.

Second, many interchanges of electricity between utilities are seasonal, and are driven by different patterns of demand among utility service areas. These interchanges tend to cancel out on an annual basis, and they seem likely to persist over the period being analyzed. Many other interchanges reflect long-term regional imbalances between demand and generating capacity, or between demand and low-cost generating capacity. Some of these, such as demand in the Northeast served by relatively low-cost Midwestern power plants, also are likely to persist during the period being analyzed. Our assumption of constant demand thus has tended to capture many flows.

On the other hand, many other interchanges reflect different generating costs among utilities, and these could indeed change as different utilities adopt different measures to reduce emissions. In addition, if demand for electricity continues to increase more rapidly than generating capacity, as many utilties expect, there will be increased demand for transmission at a time when there is less excess capacity with which to supply it.

A series of sensitivity analyses is planned to assess the effect of transmission on the model's results once the demand assumptions are relaxed.

Finally, the model structure assumes compliance with the legislation, and therefore does not include the costs of any fines that might be imposed for noncompliance.

4.2 REPRESENTATIONS OF SPECIFIC BILLS ANALYZED

Lacking data describing emission sources other than utilities, we analyzed only those provisions of the bills that directly affected utilities. Where a bill allowed trading of emissions within a state between utilities and other emission sources, we have assumed that no such trading would occur. Because the provisions that most bills made for reducing NO_x emissions lacked sufficient detail for modeling, and because of the large uncertainty about baseline NO_x emissions, we have not yet attempted to model NO_x reductions. Table 2 summarizes the features of the bills described below. The original language of some bills required compliance

by December 31 of target years, and the language of others required compliance by January 1; for ease of comparison, we have added one day to all of the former and state all requirements in terms of the latter.

4.2.1 Boehlert (HR 5032, 100th Congress)

The Boehlert bill required reducing emissions of SO_2 by 10 million tons in three stages through 2003. It set statewide average emission rates and percentage reductions from present levels for each of its three years, and specified that where the emission rate and percentage reduction conflict the smaller reduction was to be the actual target. The bill permitted trading within states, and it established a system of federal grants that states could use as loans or grants to subsidize up to 50% of the capital costs incurred to meet the targets. The bill required a 25% reduction in NO_x emissions by 1998 but left the details of how this was to be accomplished to the EPA administrator. The bill allowed trading of emissions among utilities within each state. It also allowed utilities to choose any option to achieve compliance, including emission control equipment, repowering, conservation, retiring units early, coal cleaning, changing dispatching rules, switching fuels, and other enforceable options. The bill did not place any specific requirement on any specific plant.

We modeled this bill as though it would reduce emissions in two stages: 3.5 million tons by 1993 and 10 million by 2003. We used the emission rates of 2.0 lb $SO_2/10^6$ Btu in 1993 and 0.9 lb in 2003, instead of computing the state reductions it could require, and we applied it only to the 11 utilities and not to the entire states that include them. Appalachian Power could not meet demand under the requirements of this bill if its older units retire at 50 years of age; we allowed these units to operate until they are 70 years old.

4.2.2 Kerry (S 57, 100th Congress)

The Kerry bill set emission reduction targets of 5.8 million tons per year by 1996 and 10 million by 2000. Each state was given a target computed on the basis of how much its 1985 emission rate exceeded 1.0 lb $SO_2/10^6$ Btu, and it would have been required to make a reduction in 1996 equivalent to 7/12 of the total required by 2000. States could require the use of best available control technologies (BACT), or set a 1.0-lb emission rate standard and leave the choice of compliance options to the utilities. The bill allowed trading within states and among neighboring states, with regulations governing trading to be set by the EPA administrator. The bill levied a fee of .5–1.6 mills/kWh on electricity generated with fossil fuels; the fee was based on the emission rate in 1982 and would have lasted for 15 years after enactment. A capital subsidy of \$147/ton SO_2 reduced was offered. The bill set NO_x limits for new generating units, and allowed a reduction of 2 lb NO_x to count as equivalent to 1 lb SO_2. The bill required generating units that now burn coal with more than 2% sulfur to use coal cleaning, and units that now use scrubbers to add adipic acid treatment to further reduce emissions.

We assumed that states would allow utilities to adopt the mix of compliance measures they deem most cost effective for achieving the target emission rates rather than requiring

BACT. The present average emission rate for the 11 utilities in the analysis is 1.51 lb $SO_2/10^6$ Btu, and this implies an emission rate of 1.30 lb $SO_2/10^6$ Btu in 1996, given the target 1.0-lb $SO_2/10^6$ Btu emission rate for 2000. We used this emission rate instead of computing state shares, and applied it only to the 11 utilities. Under our assumption of constant demand, the provisions of the bill for NO_x emissions from new units did not affect our cost estimates, but the tradeoff of 2 lb NO_x for 1 lb SO_2 is potentially significant and would have been examined in future analyses had the bill passed.

The bill's requirements for fees and capital subsidies yielded costs that vary from plant to plant, depending upon present emission rates. To simplify the analysis, we modeled the fee as a flat 1 mill/kWh, and the subsidy as 10% of the assumed cost of scrubbing; these assumptions tend to increase the estimated cost for utilities with high emissions, and reduce it for those with low emissions. Lacking comprehensive data on the costs of coal cleaning and adipic acid treatment, we have ignored these requirements but note their potential to increase the cost of this bill to a level above our estimates. However, even without these requirements, the Kerry bill tended to be the most expensive of the bills analyzed (Section 5).

As for the Boehlert bill, it was necessary to allow Appalachian Power's older units to operate until they are 70 years old to meet demand under the requirements of the Kerry bill.

4.2.3 Cooper (HR 144, 101st Congress)

As with Boehlert's bill, Cooper's bill would have reduced emissions by 10 million tons in three phases through 2003, although at different levels in intermediate years. As with Kerry's bill, Cooper's set state targets computed on the basis of how much each state exceeded a national emission rate in 1980, but the national rate would have been 1.2 lb instead of Kerry's 1.0 lb, with half of the reduction due by the second phase in 1997. Cooper's bill allowed trading of reductions within states and across state lines among members of the same power pool. The bill levied no fees and would not have reimbursed utilities for compliance costs. It required a 3 million ton reduction in NO_x emissions, with each state given a target based on its 1980 baseline rate. Under the bill, the federal government would have shared costs for demonstrations of clean coal technologies. If a utility chose to repower an existing generating unit using clean coal technology, that unit would have received a 2-year extension for complying with the second phase of emission reductions.

In modeling the Cooper bill, we assumed that a 1.2 lb $SO_2/10^6$ Btu rate would apply to each utility instead of computing each state's shares of the national emission reduction total and allowing trading among utilities within each state or power pool. Neither the NO_x emission reductions nor the time extension for using clean coal technologies were modeled.

4.2.4 Sikorski (HR 1470, 101st Congress)

The language of this bill set no national tonnage target for SO_2, but it required each state to meet an average 2.0 lb $SO_2/10^6$ Btu emission rate in 1994, and a 1.2-lb target in 1998.

The bill's language implied that it permitted emission trading within states. The bill provided subsidies to offset the cost of emission control equipment on residential rates, but did not specify the size of the subsidies. The bill set a .6-lb $NO_x/10^6$ Btu standard for existing units by 1998, and tighter standards for units built in the future. The federal government would have shared the cost of demonstrating clean coal technologies, but there were no other provisions to promote these. The bill imposed a fee of .5 mills/kWh through 1998.

We applied the statewide SO_2 emission rates for the two phases to each utility. Because the bill's offset of emission control equipment costs would apply only to residential ratepayers and not the industrial rates of interest in this analysis, we did not include them. The NO_x limit was modeled as an average .6-lb rate for each utility except for Associated Electric, which we found could not meet the rate using the low-NO_x technology we assumed; we therefore allowed Associated to meet a .7-lb average rate.

4.2.5 Mitchell Compromise (101st Congress)

The provisions of this bill were available only as a summary. The bill reduced emissions in two phases. The bill required plants listed in the bill to add scrubbers to reduce emissions of SO_2 by 90% by 1994, and it required all generating units that emitted more than 1.2 lb $SO_2/10^6$ Btu in 1980 to reduce this to 1.0 lb/10^6 Btu by 2003. The summary appeared to allow each utility to meet the 2003 target rate as an average by trading among their generating units. The bill established a 1 mill/kWh fee for electricity generated by plants emitting more than 1.0 lb $SO_2/10^6$ Btu in 1980, and equipment capital subsidies of $200/kW for the 1994 phase and $150/kW in the 2003 phase. A version of the bill introduced in the 100th Congress set a 1.0 lb $NO_x/10^6$ Btu standard for each state, but this wass not mentioned in the summary of the more recent bill.

This bill was modeled as two phases, with scrubbers forced onto the targeted plants for the 1994, and a 1.0-lb average standard required in 2003 for generating units emitting more than 1.2 lb now. The subsidies were incorporated into the cost of control equipment used, and the fee added to the cost of electricity. Again, it was necessary to allow Appalachian Power's older units to operate for as long as 70 years under this bill.

4.2.6 Bush Administration (S 1630, 101st Congress)

Like the Mitchell Compromise, the Bush administration-Senate 1630 bill targeted a set of generating units that would have to reduce emissions during the bill's first phase (1996), but it allowed utilities substantially greater flexibility in how to reduce emissions from these units. The targeted units were subject to a 2.5-lb $SO_2/10^6$ Btu standard. The bill required no specific technical options, such as scrubbers, and it allowed a utility to achieve equivalent tonnage reductions at other units it owns if the utility preferred. In the bill's second phase, for the year 2000, the goal of the legislation was to reduce emissions by 10 million tons from 1980 levels, and the bill used a 1.2-lb standard to achieve this. Unlike other bills, the tonnage allowed in 2000 would become a cap on subsequent emissions. Utilities would be permitted to trade emission reduction requirements. The cap and trading system are discussed in more

detail in Section 2.2. The bill set similar tonnage limits on NO_x for 2000 based on type of equipment and monitoring information to be gathered in 1995 and 1996. Utilities were allowed to trade NO_x reductions with each other, and to trade a 1.5-lb reduction in NO_x for a 1-lb reduction in SO_2 . The bill set no emission fees, equipment cost subsidies, or cost sharing for clean coal technologies, although a unit being repowered with a qualifying clean coal technology would be granted a 4-year extension to reduce its emissions.

The SO_2 tonnage allowances can be calculated for each generating unit and utility from the language of the bill, and we used these tonnages in modeling this bill. We ran the model for individual utilities, with intra-utility but not inter-utility trading of emissions, and we also have run the model allowing the 11 utilities to trade emissions with each other. Although we have performed some preliminary analysis of the NO_x provisions of the bill, we do not report these here.

The model was developed originally for application to individual utilities or states, depending upon the requirements specified in different legislation. Subsequent to the model's development, the Bush administration proposed amendments to the Clean Air Act that would establish a system of tradeable emission allowances for SO_2 emissions by electric utilities. Analyzing this system required some modifications in the use of the model, as discussed below.

4.3 USE OF THE MODEL TO ANALYZE TRADING OF EMISSION ALLOWANCES

To examine trading, the model is run in two steps. In the first step the model is run once for each utility. Each utility is required to minimize the cost of meeting the annual demand of its service area for electricity, but it is permitted to use no more than the emission allowances that it would receive under the original Bush administration-Senate 1630 bill. This is accomplished by setting a constraint on emissions by the utility equal to the number of tons its allowances would permit. The utility is free to trade its allowances among its own power plants as the bill permits, but no trading occurs between different utilities. The results reflect the requirements of the bill without the allowance trading system.

In the second step, the utilities and their power plants are grouped together. Each utility still is required to meet the demand of its service area for electricity using only its own power plants. However, instead of requiring each utility to use only its own emission allowances (which would involve one constraint for each utility), the allowances for all of the utilities are summed and made available to the whole group (with a single constraint for the group). The model then minimizes the cost, for the group of utilities, of meeting each utility's demand subject to the aggregate limit on emissions. The model includes both variable costs and the capital costs of new generating equipment and emission controls, and these are the costs that it minimizes. If the model included only the costs for reducing emissions, then it would minimize only the costs of emission controls, and not necessarily the cost of electricity from controlled plants (because it might do inexpensive things to expensive plants).

Applying the model to the two utilities used in Section 2.2 and Table 3, we would run the model first for utility "A" and then for utility "B." Each would reduce emissions by 20,000

tons. Utility "A" would do so at a cost of $500/ton, or $10 million. Utility "B" would do so at a cost of $700/ton, or $14 million. Because we assume constant generation with and without controls, we would then sum the control costs and divide the resulting $24 million by the combined generation to obtain an average control cost/kWh. In addition, we would report costs for the two individual utilities as we have in the past. Emissions, coal use, and other information also can be calculated from the model solutions and data and reported for separate utilities or as an average. This is what we have reported as the "no trading" or "without trading" case in Section 5.

We would then run the model for the two utilities, combining the 80,000 tons of allowances each receives to yield a combined 160,000 tons, but still requiring each utility to use its own power plants to meet demand for electricity in its service area. If the base costs of generating electricity without emission controls are equal for the two utilities, then the model will trade as in the example. Utility "A" would reduce emissions by 40,000 tons and utility "B" would make no reductions. Total control costs would be $10 million + $12 million = $22 million. We could report these as costs incurred by utility "A," with no increase in costs by utility "B," and we could report an average cost for both. If, in addition, we can estimate the amount that utility "B" pays utility "A" for the 20,000 allowances, then we can adjust the costs reported for each utility. Section 4.4 discusses two methods for estimating the cost of an allowance. Using either method, we can report results from a case with emissions trading for comparison with the cases run without the trading option. Again, emissions, coal use, and other information can be reported for separate utilities or as an average, and the calculated values can be compared with those calculated without trading.

4.4 ESTIMATING THE COST OR PRICE OF AN EMISSION ALLOWANCE

The model does not require a prior estimate of the cost of an allowance in order to find a solution. In the real world, and in the model, trading is driven by differences in utilities' costs of reducing emissions, and not by the cost of the allowances.

To illustrate this point using the example above, utility "A" is willing to sell allowances for 20,000 tons as long as it gets more than $600/ton for them, and utility "B" is willing to pay up to $700/ton for them. If "A" holds out for more than $700/ton then "B" will control its own emissions, "A" will reduce emissions in such a case by only 20,000, and the total control cost will be $24 million. If "B" isn't willing to pay at least $600/ton, "A" won't make the extra reductions and sell the allowances to "B." Again, the total control cost will be $24 million.

The model assumes agreement on a price that makes trading mutually beneficial and, as noted earlier, that yields a control cost *minus allowance cost* of $22 million. The price agreed upon for the allowances to trade affects the total cost of emission control by each company, but not the total cost. For example, if the price is $600/ton, "A" earns $12 million to offset its $22 million investment in reducing emissions, for a net expense of $10 million. "B" pays "A" this $12 million, for a net cost of $12 million to "B" and a total cost of $22 million for both utilities. Increasing the price by $50/ton yields an exchange of $13 million but no change in total control costs.

Thus, if we knew the cost of an allowance before running the model it would not affect the compliance strategy chosen or the total or average compliance cost for the group. However, it would affect the cost of electricity sold by each utility, and it is for this reason that we are interested in estimating the cost of an allowance.

There are two approaches for estimating the market clearing price of the allowances in a group of trading utilities. The more direct approach is to examine the constraint in the linear programming model that limits total emissions in phase II (year 2000). Associated with this constraint is a dual variable that indicates how much the objective function would decrease if the group of trading utilities were permitted to purchase one more allowance from outside the group. This dual variable is the value to the group of obtaining that allowance, and it is a reasonable indicator of what these utilities would pay for an allowance in that year. For a base case in which the group can purchase all the low-sulfur coal it wants at a $10/ton premium, this variable has a value of $550.58/ton SO_2 (ten-year levelized costs, reported as 1985 dollars). This is the value estimated for the Bush administration-Senate 1630 bill in the results reported in Section 5. For comparison, the Bush administration-Senate 1630 bill reserved 2% of the allowances to be made available at a price of $1500/ton in 2000, which if levelized over ten 10 years would be equivalent to $1815.00/ton SO_2 in 1985 dollars. This suggests that the specified price is far above the likely market price. However, if utilities hoard their allowances, or if other market imperfections exist, the price of an allowance may be higher than the model estimates. The reservation of allowances for sale at the $1500/ton price was designed to deal with such market failures.

The second approach to estimating the cost of an allowance is to examine individual cases. For example, in our analyses we have assumed a cost of $280/kW to add scrubbers. For one of Ohio Power's 220 MW Muskingum River units, this yields $61 million in 1988 dollars. Unit 1 at this plant is fairly dirty, emitting 6.27 lb $SO_2/10^6$ Btu. If it operates at a .63 capacity factor and the plant's average heat rate of 9131 Btu/kWh, then it emits about 34,800 tons SO_2/year. A scrubber with 90% removal would reduce this by about 31,320 tons, at a capital cost of $1948/ton. However, if the scrubber is installed in 1996 and we add in its O&M costs, compute its costs in 2000, and discount them back to 1985, the first-year cost is approximately $305/ton. This is probably a mid-range value of the cost per ton of SO_2 removed, but our model indicates that Ohio Power would do this on its Muskingum River units when trading is not permitted and low-sulfur coal is available only at a substantial price premium. Switching this particular plant to burn low-sulfur coal would yield a slightly smaller reduction at roughly half of the cost/kWh, or approximately $164/ton removed, and Ohio Power uses this option in the model when trading is permitted and low-sulfur coal is available in ample quantities at a $10/ton premium. Again, the $1500/ton specified by the original Bush administration-Senate 1630 bill appears well above the likely market-clearing price for an allowance in the absence of a major failure in the market for allowances.

5. RESULTS

To illustrate the model's use, we have run it for each bill using 10-year levelized costs. As noted in Section 3.1, the specification of different compliance years by the bills complicates the comparison of costs for the different bills; the costs of one bill may appear consistently higher than those of another simply because it requires compliance a year or two earlier than the other bills (and thereby yields greater benefits). For the bills analyzed, the differences in compliance years can increase the range of costs by about 5%. To estimate compliance strategies for each bill, we have calculated costs for the compliance years specified in the bill. We ran the model using these costs and then normalized the costs reported by the model in order to remove the effect of the different compliance schedules (Table 5 and Figure 8). In addition, because of the phased nature of compliance in the various bills, the levelization period for each begins in the first year of the first phase and continues through ten years after the first year of the second phase, so that the levelization period actually varies in length from bill to bill. As will be noted below, the differences in length of levelization period affect the interpretation of results, but there is no obvious way to normalize to remove this effect.

As one would expect, the estimated costs of compliance differ substantially depending upon whether a utility has a base (1985) emission rate (Table 1) near or below the average rates specified in most of the bills, or whether the base rate is well above what the bills require. In Table 5 and Figure 8, utilities appear approximately in order from those with high emission rates in 1985 to those with low rates (Table 1); although several utilities have been

Table 5. Increases in mills/kWh under different bills for 11 utilities, using ten-year levelized costs expressed as 1985 dollars

						Administration	
	Boehlert	Kerry	Cooper	Sikorski	Mitchell	No trading	Trading
Cleveland	5.77	7.29	9.12	6.12	5.52	5.45	4.17
Associated	4.39	6.95	3.82	6.83	5.46	4.38	4.30
Ohio	4.29	5.91	5.10	5.01	5.14	4.73	4.41
Potomac	2.62	4.25	2.75	3.58	4.63	3.42	3.02
TVA	2.53	4.60	3.61	3.47	3.41	2.88	2.67
S Indiana	2.29	3.60	2.40	3.07	2.58	2.45	1.78
Alabama	1.94	4.01	2.91	2.79	2.86	2.43	2.12
Big Rivers	1.75	3.29	1.95	2.55	1.94	2.51	2.02
Duke	0.89	2.31	0.41	0.77	1.69	0.09	-0.04
S Carolina	0.28	1.20	0.00	0.72	0.50	1.58	1.33
Appalachian	0.31	1.14	0.00	0.76	0.64	0.35	-0.21

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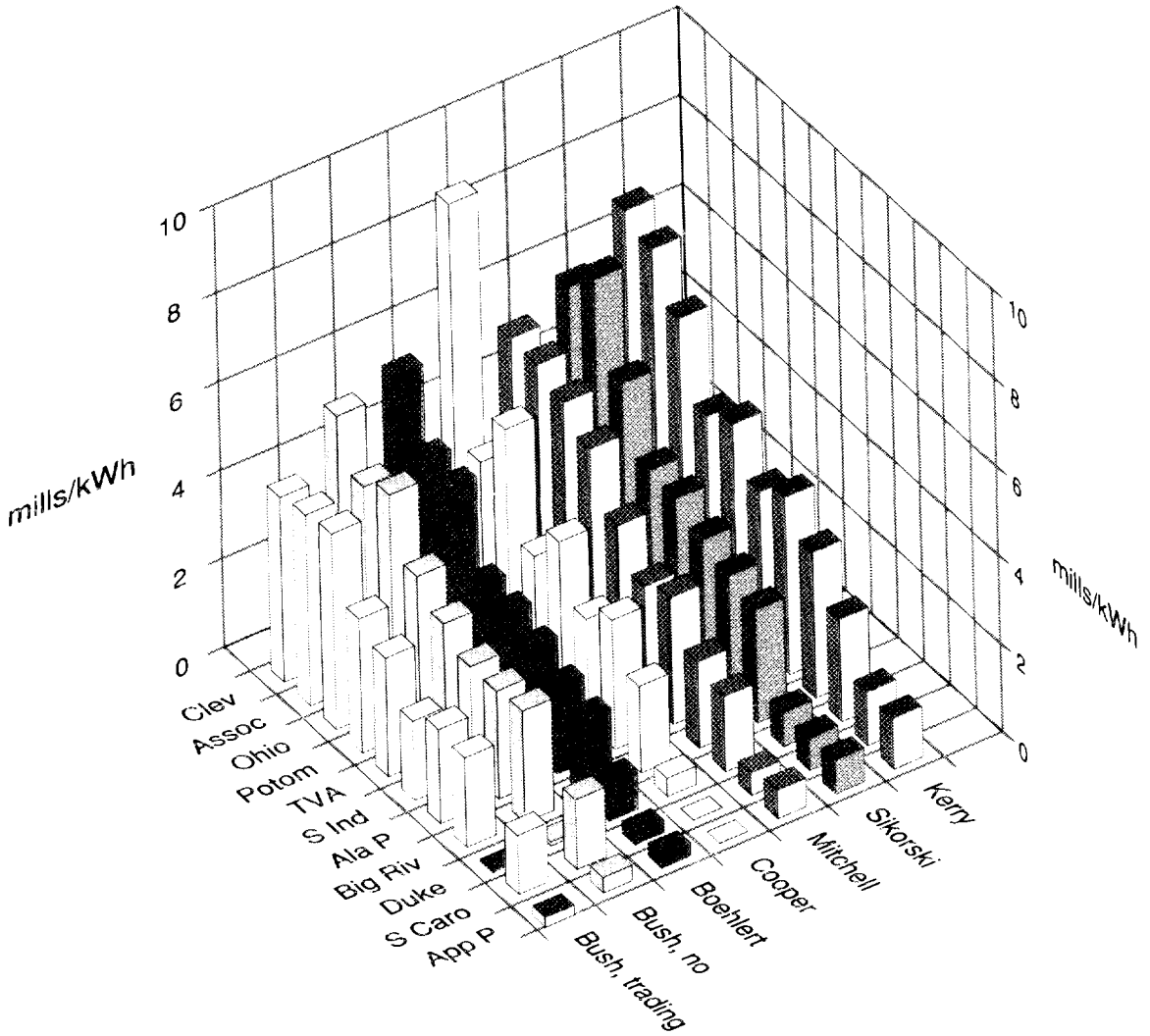

Figure 8. Increases in cost/kWh under different bills for 11 utilities.

interchanged to improve the readability of the chart in Figure 8. In Figure 8, a file of columns from front left to back right represents the effects of the different bills on one utility while a file of columns from right front to back left represents the impacts of one bill on each of the several utilities. The vertical axis is the change in costs in mills/kWh, computed over the first ten years of compliance with the bill and normalized as previously noted.

5.1 UTILITIES WITH LOW EMISSION RATES IN 1985

Appalachian Power, Duke Power, and South Carolina Public Service have the lowest average emission rates, near or below the average rates specified in most of the bills. As expected, none of the proposed legislation for the cleanest 1985 utilities would increase costs by more than 3 mills/kWh, and most bills would increase costs by less than 1 mill/kWh (Figure 8).

The Kerry bill, which had the most stringent average emission rates, yielded the largest increase in electricity costs for Duke and Appalachian. The Mitchell bill's requirement of a 1.0-lb emission rate for units now emitting more than 1.2-lb would make it the second most costly for Duke, which has a number of units that emit just above the 1.2-lb rate.

The Bush administration-Senate 1630 bill would be the most expensive for South Carolina Public Service, because the utility has two plants with extremely low emission rates, and both operated at low capacity factors in our 1985 base year. South Carolina Public Service would receive few allowances for these plants, and these would not be enough to offset the higher emissions at its other two plants. The burden to this utility could be eased slightly by the trading of allowances, or by the use of additional base years averaged with 1985 to define a baseline, as the bill specifies. The allowance trading provisions of the Bush administration-Senate 1630 bill also would allow Duke and Appalachian to earn money from selling their allowances and thereby reduce slightly their average electricity rates.

5.2 UTILITIES WITH HIGHER AVERAGE EMISSION RATES IN 1985

For most of the rest of the utilities in our group, electricity costs would increase more than for the relatively clean utilities. Under the Kerry bill the increase would be greater compared to the other bills, because of its stringent 1.0-lb emission rate. Cleveland Electric's costs, however, would increase most under the Cooper bill, with the Kerry bill second. This occurs because two of Cleveland's generating units would be more than 50 years old in the Cooper bill's phase II year of 2003, and we have forced all units 50 years or older to retire in the model's options. The model's option to add new generation was not activated for these sample runs. Therefore, the only option allowed to Cleveland for making up the generation lost by retirement is to increase output from other units by adding scrubbers to them. Because the Kerry bill's phase II year is 2000, retirement did not affect Cleveland Electric's units, and most units switched to low sulfur coal. Relaxing the 50-year retirement assumption for Cleveland under the Cooper bill would make the costs for that bill lower than under the Kerry bill.

The Boehlert bill would require the smallest increases in electricity rates for most of the remaining utilities. This results in small part because the bill provides a capital subsidy for scrubbers. More importantly, however, the small increases result from the way the bill's schedule affects the economic calculations. For a phase I year of 1993, 10-year levelization includes costs from 1993–2013. This means that the levelization captures the relatively long period of time between phase I and phase II with its relatively low costs. Also, phase I starts earlier in the Boehlert bill than most other bills, which also adds a relatively long low-cost

period. Phase II requires substantial compliance activity by the utilities, but levelization combines these higher costs with those of the long low-cost period and, with the subsidy, lowers the calculated cost of complying with this bill.

For Associated Electric, the Cooper bill causes the smallest increase in electricity rates. This occurs because the bill's phase I target emission level is so close to its phase II target, because the 10-year levelization discounts the costs of complying with phase II, and because the utility has only five generating units to use in complying with an average emission limit (one of which already has a scrubber). Under these conditions, it is less expensive to comply with phase II in phase I than to wait until phase II. Utilities with larger numbers of units can wait until phase II to comply with that year's target, and incur the added cost only on those units necessary to go from phase I to phase II compliance. This pattern also occurs to a lesser extent in Southern Indiana G&E and in Big Rivers Co-op, which also have very few units.

The Bush administration-Senate 1630 bill, with trading, would cause the smallest electricity rate increases only for Southern Indiana and Cleveland Electric, although it would be close to the Boehlert bill for TVA and Alabama Power. The bill allows Cleveland to reduce the amount of scrubbing needed for compliance. In addition, the bill's initial allocations of allowances for Cleveland and Southern Indiana result in targets less stringent than those set by some of the other bills.

A striking result from our calculations is the relatively small effect that the emission allowance trading system in the Bush administration-Senate 1630 bill would have on electricity costs. Only in the case of Cleveland Electric does trading reduce costs by as much as 1 mill/kWh, compared to the same bill without the trading provisions (Table 5). The increases in electricity costs for some companies are as much as 25% lower when trading is allowed, but for most the savings are much smaller, and much smaller than proponents of the trading system have suggested. We suggest the following reasons for the discrepancy.

First, as noted above, the levelization process tends to discount the higher costs of complying with the second phase of the bill. However, we have noted similarly small savings from trading when we have used first-year costs and when we have used life-cycle levelized costs.

Second, the cost of an allowance is a recurring expense in the levelization calculations. Each allowance grants permission to emit one ton of SO_2, and the owner of a generating unit must acquire enough allowances to equal the unit's lifetime emissions. Thus, as with other recurring expenses, the cost of allowances begins to dominate the cost of equipment after a few years. We have noted in the example in Appendix A the tendency for recurring expenses for fuel, operations, and maintenance to dominate one-time capital expenses, so that capital subsidies have little effect on long-term costs. A similar situation applies for allowances.

Third, although the Bush administration S 1630 bill sets some fairly stringent targets, there are many plants with high emission rates, and therefore many relatively inexpensive emission reductions that utilities can make. For example, a scrubber with 90% efficiency of removal on a plant emitting at 5 lb $SO_2/10^6$ Btu reduces emissions at a much lower cost per ton of SO_2 removed than a scrubber on a plant emitting at 1.5 lb $SO_2/10^6$ Btu. Emission

trading occurs based on the marginal cost of reducing emissions, not on the average cost. In a sense, trading tends to occur *after* the most inexpensive reductions in emissions have been made, when the question has become, "Which of the remaining, more expensive, reductions should be made?" Targets are sufficiently stringent that most or all companies can meet them only by making expensive emission reductions after exhausting their less expensive options. Thus, trading will have less effect on their costs than it would if some still have inexpensive options to exploit while others have only expensive ones.

Finally, it should be remembered that although the cost savings from trading are small when expressed per kilowatt-hour, the savings can be substantial when summed over the many kilowatt-hours each utility generates. The 1.28 mill/kWh that Cleveland Electric would save because of trading yields $17.2 million per year at the company's present levels of electricity generation.

5.3 CONCLUSIONS

The utilities used in this study range from clean to dirty and small to large, although they do not have a significant amount of generation from units other than coal. The model's results clearly show the effects that a utility's stock of generating capacity can have on its cost of complying with different legislation.

The model's results for trading are subject to four major qualifications.

- First, at present we run the model only for the 11 coal-fired utilities serving aluminum or ferrosilicon plants. The pattern of trading for these utilities could differ if they were permitted to trade with additional utilities, and the cost of their compliance might be lower than our estimates. As we develop the data for additional utilities, we will be able to expand the range of trading to cover larger sections of the country.

- Second, the way we use the model to analyze emission trading assumes that utilities *will* trade if it reduces the total cost of supplying electricity. The way we use the model does not allow for hoarding of allowances. To model hoarding or other "market imperfections," it would be necessary to change the constraints or costs in the model. Complete hoarding reduces to the "no trading" case and is easily modeled. Partial hoarding is probably a simple change to the model (although not necessarily a simple change to software that runs the model), and the most difficult part may be in deciding what kind of hoarding behavior we want to model.

- Third, the bill allowed utilities to bank excess allowances from one period into others, but it left details of the banking system to the EPA Administrator. Some methods of calculating costs, such as first-year costs for the second phase of the bill, can lead to overcontrol of emissions in the first phase and therefore allowances that might be banked for use in the second phase. Banking, if it occurs, should have the effect of reducing compliance costs from what we have estimated. Analysis of banking may require some modification of the model and, given the bill's limited specification of the banking system, we have left such modifications and analysis until more detail

becomes available. On a related note, our cost calculations treat allowances as a stream of recurring expenses, instead of a stock purchased with a lump sum at the start of a unit's operation and drawn down during its lifetime. Utilities and PUCs may require the latter before approving the construction of new units.

- Finally, as noted in earlier sections, the model contains a number of assumptions that may affect its results regardless of whether or not trading is considered. These assumptions include the following:

  - Demand for electricity has been held constant to facilitate comparisons of costs among bills that require final compliance in different years, and to avoid difficulties in separating cost increases that result because of emission reductions from those that result because of increases in demand. If new generating capacity is built to meet additional demand, the cost of electricity is likely to be higher than we have reported. Now that legislation has been adopted, this assumption can be relaxed. In addition, the model's options to consider demand for power as well as energy can be exercised, and options can be added to consider the effects that improving end-use efficiency may have on compliance costs.

  - Transmission of electricity has in effect been held constant, in patterns that reflect current differences both in demand and in generating costs among utilities. As noted in Section 4.1, the former are likely to persist and should not affect the cost estimates. The latter, however, may change as utilities take steps to reduce emissions, and utilities are likely to respond by shifting their patterns of interchanges in ways that reduce costs from our estimates. Unfortunately, the data needed to analyze transmission options are not available at reasonable cost.

  - We have held each generating unit's output constant unless it makes major investments in emission control equipment, in which case it may increase output. Given the prior decision to hold demand constant, this assumption probably has little effect on our cost estimates, although allowing greater variation in unit output might reduce costs slightly from what we have estimated. This assumption can be relaxed either by increasing the allowable output from all units, perhaps structured by class of unit (size, age, technology), or by using some procedure to randomize the maximum allowable output and make multiple runs of the model. Sensitivity analysis will be needed to assess the effects of these approaches before recommending one over the other.

  - The addition of emission controls to an existing unit is likely to increase its heat rate and fuel consumption, and therefore its costs, above what we have estimated when we hold heat rate constant after adding a scrubber. The modeling software will allow the addtion of emission controls to affect unit heat rates, once data are developed to allow use of this feature.

- The cost of retrofitting a scrubber varies from plant to plant depending on available space, equipment design, and other conditions not easily determined in an analysis of this type. The modeling software can easily be modified to allow the use of plant-specific costs if these are available. We understand that plant-specific estimates of retrofit costs or difficulty may have been developed with public funds, but these are considered sensitive, confidential, or propietary data, and they would not be made available to other users. For a general comparison of bills across utilities, the absence of this information is probably not serious, and on average probably has little effect on our estimates. If the modeling system were to be used to analyze options in depth for a specific utility, this information would be more important and, if the utility were cooperating in the analysis, it probably would be available.

- Our assumption of a $10/ton premium for low-sulfur coal implies that it substitutes for a high-sulfur coal of comparable heating value/ton. However, low-sulfur coals from the western U.S. often have much lower heating values/ton, so the actual cost of switching to low-sulfur coal may be higher than we have estimated with this premium. The assumption that adequate supplies of low-sulfur coal would be available at this premium also may understate the actual cost of coal switching. The modeling software is being modified to allow specification of heat content as well as price premiums for low-sulfur coal, and work is planned to allow estimation of utility- or plant-specific premiums. In addition, work is planned to estimate the cost of modifying a plant to switch coals and to incorporate this cost.

- Finally, although we can estimate increases in costs, total future costs of electricity include a number of costs for which we do not yet have complete data. These include sunk costs for existing plants, transmission, and distribution, and the capital that will be invested to expand transmission and distribution systems in the future. This does not affect our results, only the use that can be made of them. In using our results, BOM so far has needed only the increase in costs for its mineral processing cost models. However, it is possible that future applications may require total costs, and that the additional data needed for such estimates will need to be developed.

Once plans to relax some of these assumptions have been implemented, sensitivity analysis of those that remain should be undertaken to assess their implications for estimates.

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APPENDIX A

PARAMETERS AND FORMULAS FOR CALCULATING COSTS OF IMPLEMENTING CONTROL OPTIONS AT A GENERATING UNIT

A.1 COSTING METHODOLOGY

A.1.1 Escalation and Inflation

A utility that purchases the same goods and services in the future as it does today may pay more in the future because of inflation and real escalation. Inflation is the rise in price levels caused by an increase in available currency and credit without a proportional increase in available goods and services of equal quality (EPRI 1987:2-6). Real escalation, on the other hand, is the annual rate of increase of an expenditure due to factors such as resource depletion, increased demand, and improvements in design or manufacturing (negative rate) (EPRI 1987:2-6). Real escalation is independent and exclusive of inflation, and the rate of real escalation for fuel prices may differ from that for operating costs or plant construction costs.

The apparent escalation rate, which is the total annual rate of increase in cost, includes the effect of both inflation and real escalation. The relationship among inflation, real escalation and apparent escalation is:

$$(1 + e_a)^n = [(1 + e_r)(1 + e_i)]^n,$$

where

e_a = apparent annual escalation rate,
e_r = real annual escalation rate,
e_i = annual inflation rate, and
n = number of years from the base year.

All else being equal a payment A_n in year n for an item costing A_0 in the base year 0 is:

$$A_n = A_0 (1 + e_a)^n$$

where

A_n = payment in year n, and
A_0 = payment if purchase were made in the base year.

These yearly payments should be expressed in dollars, but can be converted to a unit electric cost by dividing by the amount of electricity generated during the year [the electric utility industry typically uses mills per electric kilowatt-hour, or mills/kWh(e), which is used in this paper]. If the unit's generation is constant each year during the life of the power plant or for the plant's improvement, then year-by-year mills/kWh(e) costs can be used in the levelized cost procedure discussed below. However, if generation varies from year-to-year,

then the dollar cost each year must be used. The analysis used in this paper assumes constant power generation during the plant's life.

If inflation is included in the costs, then the costs are said to be in current dollars (which is also referred to as nominal or as-spent dollars). If inflation is removed from the costs, then the costs are said to be in constant dollars. Our analysis calculates annual costs in current dollars and then removes inflation by dividing by the apparent inflation between the payment year and the reference year,

$$C_n = A_n/(1 + e_i)^n$$

where

C_n = payment (or cost) in year n in constant dollars.

The calculation of the yearly costs in current dollars before removing inflation is necessary when dealing with the cost of capital as discussed below. Table A.1 (DOE 1988) gives example inflation rates and real escalation rates used as the baseline for the fuel and operation and maintenance (O&M) costs.

A.1.2 Average Cost of Money

For an electric utility where capital is composed of common stock (equity), preferred stock, and debt (bonds), the average cost of money is calculated by:

$$x = eE + pP + bB.$$

where,

e = rate of return on equity investment,
E = fraction of capital from equity,
p = interest rate on preferred stock,
P = fraction of capital from preferred stock,
b = interest rate on debt, and
B = fraction of capitalization from debt.

Table A.1 lists the default values taken from the Nuclear Energy Cost Data Base (DOE 1988). The average cost of money is the return on rate base in the calculation of the capital cost given below. It should also be used as the allowance for funds used during construction rate or interest rate during the construction period.

A.1.3 Discount Rate

Discounting a projected cost or payment to the present yields the present worth or present value of the payment. In other words, discounting determines the amount of money at present which is equivalent to a payment made at another time. The discount rate is the "effective cost of money." Some analysis procedures (EPRI 1987) use the average cost of

money for the discount rate. For this analysis we have chosen to use the approach in DOE (1988), where the average cost of money is reduced by the tax deduction for debt interest to obtain the discount rate (effective cost of money),

$$d = x - bBt,$$

where,

d = current dollar discount rate, and
t = effective income tax rate.

The constant dollar discount rate, d_0, is obtained by removing the inflation component from the current dollar rate,

$$d_0 = (1 + d)/(1 + e_i) - 1.$$

The reference value of this discount rate used to present value constant dollar costs and to obtain levelized constant dollar costs is .0435 as shown in Table A.1.

The present value (to the reference date) of a payment made at a future date is given by:

$$PV_n = C_n[1/(1 + d_0)^n)] ,$$

where

PV_n = present value (to reference year) of year n cost.

Note that the same present value may also be calculated by

$$PV_n = A_n[1/(1 + d)^n] ,$$

where

A_n = current dollar cost in year n.

A.1.4 Fuel and Operation and Maintenance Costs

A generating unit's fuel and O&M costs are paid each year. The fuel cost for fossil fired plants is proportional to the power output. The operating costs are a mix between fixed costs (i.e., operating staff) which do not vary with plant output and variable costs (i.e., limestone and ash disposal) which vary with plant output (for example, generation). Assuming constant output (equal generation each year), the fuel and O&M costs would not change from year-to-year except when inflation and escalation are taken into account. Therefore, fuel and O&M costs in future years can be estimated by using appropriate inflation and escalation rates applied to costs calculated for a base or reference year.

As an example of fuel costs assume a 600 MW(e) coal-fired power plant operating at 65 % capacity factor. If coal cost 14.36 mills/kWh(e) in 1985, the base year (1985) coal cost is:

A_0 = [cost of coal] [capacity of plant] [hours/year] [capacity factor] [mills/dollar]
A_0 = [14.36 mills/kWh(e)] [600x10^{3}kWh(e)] [8760h/year] [.65] [10^3 mills/$] ,
or

A_0 = $ 49.06 million.

If the expected inflation rate is 5%/year with a real escalation rate of 1%/year, then the expected payment in 1996 would be:

$A_{11} = 49.06[(1 + .05)(1 + .01)]^{11}$, or,
A_{11} = $ 93.91 million.

The cost for this 1996 purchase in 1985 dollars is calculated by removing the inflation between 1985 and 1996, or

$C_{11} = 93.91[1/(1.05)]^{11}$, or,

C_{11} = $ 54.73 million.

The present (1985) value of this 1996 expenditure is obtained by discounting the cost in year 1996 using the effective cost of money,

$PV_{11} = 54.73[1/(1.0435)]^{11}$,

PV_{11} = $ 34.26 million.

The same present value is obtained if the 1996 cost including inflation is discounted using the discount rate including inflation,

$PV_{11} = 93.91[1/(1.0957)]^{11}$, or,

PV_{11} = $34.26 million.

From the example above, it is seen that in the instance of fuel and O&M costs the intermediate steps of inflating and then deflating the costs may be omitted and the present value found by applying the real discount rate to the base cost increased only by the real escalation, or

$PV_n = A_0[(1 + e_r)/(1 + d_0)]^n$, or in the example,

$PV_{11} = 49.06(1.01/1.0435]^{11}$, or,

PV_{11} = $ 34.26 million.

The present value of the unit cost of electricity [mills/kWh(e)] is obtained by dividing the annual cost by the annual generation. The annual generation is

$$G = [\text{plant size, kW(e)}][8760 \text{ h/year}][\text{capacity factor}][10^{-3} \text{ \$/mills}] ,$$

or,

$$G = [600{,}000][8760][.65][10^{-3}] , \text{ or,}$$

$$G = 3.4164\text{x}10^{6} \text{ kWh(e) per year.}$$

The unit cost is:

$$PVU_{11} = [34.26\text{x}10^{6}]/[3.4164\text{x}10^{6}] , \text{ or,}$$

$$PVU_{11} = 10.03 \text{ mills/kWh(e)} .$$

Table A.2 shows the annual fuel payments for the above mentioned plant. The power is generated over a 25-year period starting in January 1996. The second column shows the current dollar cost. The third column shows the constant 1985 dollar cost. The fourth column shows the unit [mills/kWh(e)] cost for the year, also in constant dollars, and the fifth column shows the present value of the cost back to the 1985 reference year. The final column is the constant dollar discount factor [i.e., $1/(1 + d_0)^n$] between the cost year and the reference year (1985).

Because the present value cost is less than the cost in the reference year, it is advantageous to postpone the purchase for as long as possible. When comparing costs of alternative legislation that specifies different compliance phases, it may be useful to compare the total present value of costs resulting from the alternatives. The one having the least present value, all other factors being equal, would be the preferred alternative.

A.1.5 Capital Costs

Capital costs are calculated differently from costs of fuel and O&M because capital costs depend on the investment in plant and equipment. This investment generally is not considered for tax purposes or utility rate making purposes in the year the money is actually paid, but must be accounted for over the life of the investment. The method for utility rate-making purposes is called the revenue requirement method. Theoretically the revenues collected in any given year should equal the revenue requirements for that year. The fuel and O&M costs discussed above form two components of the revenue requirements. The annual revenue requirements due to the capital investment is calculated as

$$RR_n = xV_n + D_{B,n} + P_n + T_n ,$$

where,

RR_n = revenue requirement (from capital) in year n,
V_n = rate base at beginning of year n,

$D_{B,n}$ = book depreciation on invested capital in year n,
P_n = cost of other expenses related to investment such as property taxes and interim replacement of equipment,
T_n = income taxes.

The calculation of the annual revenue requirements is complicated and the reader is referred to a detailed description of the method in (DOE 1988: pp. 59-64, 97-102).

The rate base will decrease each year over the investment life as the plant is depreciated. The book depreciation is constant over the life of the asset as the assumption is usually made in rate making that the plant is "used up" at a constant rate. The property taxes will depend on the appraised value of the asset and are assumed here to be a constant 2 % of the initial invested cost each year. An interim replacement rate equal to 0.5 % of the initial plant investment, escalating at the same rate as inflation is also assumed. An asset is depreciated differently for tax purposes than for book purposes. This fact and the response of PUCs to it add considerable complexity to the calculation.

The tax law allows for accelerated (nonlinear) depreciation of an asset over a life less than the actual asset life. Accelerated depreciation is advantageous and is invariably used. To utilize accelerated tax depreciation, a utility must "normalize" this tax benefit for rate making purposes. Normalization in effect spreads the benefit of accelerated depreciation over the life of an asset for rate making purposes. Fossil power plants are usually depreciated over a 30-year or greater period for book purposes and 20 years for tax purposes. Some specific equipment may be depreciated over shorter periods. The 5-, 15-, and 20-year tax depreciation schedules (actually 6, 16, and 21 years) are shown in Table A.3.

The revenue requirements for capital must be calculated in current dollars since the initial investment on which the whole procedure is based does not inflate (except for interim replacement) after the investment is made. The calculated annual revenue requirements, however, may be adjusted to a reference year's dollars by removing the inflation between the cost year and reference year,

$$CC_n = RR_n[1/(1+e_i)]^n ,$$

where,

CC_n = revenue requirements in constant reference year dollars.

The present value of this cost is given by,

$$PV_n = CC_n[1/(1+d_0)]^n .$$

Table A.4 illustrates the stream of revenue requirements for capital to install a scrubber on the 600 MW(e) coal-fired plant mentioned above. The example assumes that the scrubber costs $280/KWh(e) (1985), and will provide service over 25 years following its installation at the beginning of 1996. The allowed tax depreciation schedule is assumed to be the 15 year schedule shown in Table A.3, and the scrubber costs increase in current dollar

terms (including inflation) at a rate of 6 %/year from January 1985 until the equipment is installed (January 1996). The second column shows the annual revenue requirements for the capital addition in current dollars. The costs are adjusted to constant 1985 dollars in the third column. The fourth column shows the annual unit costs, and the fifth column shows the present value of these annual unit revenue requirements. The last column is the discount factor between the cost year and the reference year.

A.1.6 Levelized Costs

An electric utility must collect adequate revenues to meet its costs including a fair return to its investors. Revenues then must equal revenue requirements (or costs). A levelized cost is a single cost of power (or unit revenue) which is equivalent to the year-by-year costs. Levelization is accomplished by equating the present value of the year-by-year revenue requirement to the present value of the revenue that would be collected if the unit power cost were a constant (levelized cost).

A.1.6.1 Present Worth of Revenue (PWR) Requirements

The present worth of all the year-by-year revenue requirements (including capital, fuel and O&M) is simply the sum of the year-by-year present values,

$$PWRR = \sum_{n=L}^{M} PV_n ,$$

where,

$PWRR$ = sum of the present worth of revenue requirements, dollars,
L = beginning year relative to base year, and
M = final year relative to base year.

The amount of time, n, over which the summation is made depends on the analysis horizon. It can be shorter than or equal to the asset life (book life). If the time horizon is longer than the asset life, the values of PV and the discount factors (see below) for this extended period are both zero.

A.1.6.2 Calculation of Present Worth of Revenues

Revenues depend on the amount of power produced in the period and the unit price of this power. Expressing both the unit price of power and revenues in constant dollars:

$$R_{n,0} = P_{n,0}\, G_n ,$$

where,

$R_{n,0}$ = revenues in year n (constant base year dollars)

$P_{n,0}$ = price for power in year n [base year mills/kWh(e)], and
G_n = power generation in year n [kWh(e)], or,

G_n = [plant size, kW(e)][8760 h/year][capacity factor][10^{-3} \$/mills]

The present value of the revenues is given by:

$$PWR = \sum_{n=L}^{M} [R_{n,0} /(1 + d_0)]^n .$$

Note that the *PWR* is the same as would be calculated if the inflated revenues and inflated discount rate were used.

If the power generation remains constant each year ($G = G_n$) and the year-by-year unit price is replaced by a constant "levelized" price ($LV = P_n$) then:

$$PWR = \sum_{n=L}^{M} [LV]\,[G] \quad [1/(1 + d_0)] .$$

The last summation term is the levelizing factor,

$$LF = \sum_{n=L}^{M} [1/(1 + d_0)] .$$

A.1.6.3 Calculation of Levelized Costs

The levelized cost of any component is obtained by equating the sum of the present value of the costs for that component to that of the revenues, from above:

$$[LV]\,[G]\,[LF] = PWRR ,$$

or rearranging,

$$LV = PWRR /[GxLF] .$$

If power generation is constant as assumed here then, the annual costs could have been converted to mills/kWh(e) before present valuing. The present values of these unit costs are shown in column 5 of Tables A.2 and A.4. The present value of these unit costs are related to the *PWRR* by

$$PWURR = PWRR/G ,$$

where,

PWURR = present value of revenue requirements, expressed as cost per kWh(e) .

Each component of power generation (fuel, O&M, and capital) can be calculated and levelized either separately or together.

The calculation of levelized fuel cost can be illustrated using the information in Table A.2. *PWURR* is shown as the sum of column 5 and the levelizing factor, *LF*, is the sum of the final column. The levelized cost for fuel from the Table A.2 example is,

$$LV_f = 174.23/9.838 ,$$

or,

$$LV_f = 17.71 \text{ mills/kWh(e)} ,$$

where,

LV_f = Levelized fuel cost .

The same procedure can be used to calculate levelized O&M costs and capital costs. Table A.4 shows the capital costs. LV_{cc} , the levelized cost of the capital addition over the 25-year period is:

$$LV_{cc} = 57.48/9.838,$$

or,

$$LV_{cc} = 5.84 \text{ mills/kWh(e)}.$$

If the operating life of the plant addition is longer than the book life there may be years in which only minor capital costs occur for local taxes and repairs and replacements.

Table A.1. Economic and financial parameters used in the model

Inflation rate, percent			5.0
Effective income tax rate, percent			36.64
Cost of capital			
Type of security	Percent of total	Return, percent	
Debt	50.0	9.7	
Preferred stock	10.0	9.0	
Common equity	40.0	14.0	
Average cost of money, percent			11.35
Effective cost of money (discount rate), percent			9.57
Constant dollar discount rate, percent			4.35
Property tax rate, Percent of initial capital investment			2.00
Interim replacement rate, Percent/year of initial investment escalating at rate of inflation			0.50
Coal price real escalation rate, percent/year			1.00

Table A.2. Estimated fuel costs

Year	Cost current $ (10^3 $)	Cost 1985 $ (10^3 $)	Cost Mills/kWhe(e)	Present value	Discount factor
1996	93.61	54.73	16.02	10.03	0.626
1997	99.28	55.28	16.18	9.71	0.600
1998	105.28	55.83	16.34	9.40	0.575
1999	111.65	56.39	16.51	9.09	0.551
2000	118.41	56.96	16.67	8.80	0.528
2001	125.57	57.53	16.84	8.52	0.506
2002	133.17	58.10	17.01	8.25	0.485
2003	141.23	58.68	17.18	7.98	0.465
2004	149.77	59.27	17.35	7.73	0.445
2005	158.83	59.86	17.52	7.48	0.427
2006	168.44	60.46	17.70	7.24	0.409
2007	178.63	61.07	17.87	7.00	0.392
2008	189.44	61.68	18.05	6.78	0.376
2009	200.90	62.29	18.23	6.56	0.360
2010	213.06	62.92	18.42	6.35	0.345
2011	225.95	63.55	18.60	6.15	0.331
2012	239.62	64.18	18.79	5.95	0.317
2013	254.11	64.82	18.97	5.76	0.304
2014	269.49	65.47	19.16	5.57	0.291
2015	285.79	66.13	19.36	5.40	0.279
2016	303.08	66.79	19.55	5.22	0.267
2017	321.42	67.45	19.74	5.05	0.256
2018	340.86	68.13	19.94	4.89	0.245
2019	361.49	68.81	20.14	4.74	0.235
2020	383.35	69.50	20.34	4.58	0.225
			Sum of present values	174.23	9.838

Table A.3. Recovery percentages[a]

Year	Applicable percentage for class of property		
	5-year property	15-year property	20-year property
1	20.00	5.00	3.75
2	32.00	9.50	7.22
3	19.20	8.55	6.68
4	11.52	7.70	6.18
5	11.52	6.93	5.71
6	5.76	6.23	5.28
7		5.91	4.89
8		5.91	4.52
9		5.91	4.47
10		5.91	4.47
11		5.90	4.46
12		5.90	4.46
13		5.90	4.46
14		5.90	4.46
15		5.90	4.46
16		2.95	4.46
17			4.46
18			4.46
19			4.46
20			4.46
21			2.23

[a] Based on Tax Reform Act of 1986

Table A.4. Revenue requirements for capital

Year	Revenue Requirements			Present value	Discount factor
	Current $	1985 $	mills/kWh(e)		
1996	68.99	40.34	11.81	7.39	0.626
1997	66.97	37.29	10.92	6.55	0.600
1998	64.16	34.03	9.96	5.73	0.575
1999	61.52	31.07	9.10	5.01	0.551
2000	59.04	28.40	8.31	4.39	0.528
2001	56.70	25.97	7.60	3.85	0.506
2002	54.48	23.77	6.96	3.37	0.485
2003	52.33	21.74	6.36	2.96	0.465
2004	50.18	19.86	5.81	2.59	0.445
2005	48.04	18.11	5.30	2.26	0.427
2006	45.91	16.48	4.82	1.97	0.409
2007	43.78	14.97	4.38	1.72	0.392
2008	41.66	13.56	3.97	1.49	0.376
2009	39.55	12.26	3.59	1.29	0.360
2010	37.45	11.06	3.24	1.12	0.345
2011	35.35	9.94	2.91	0.96	0.331
2012	33.78	9.05	2.65	0.84	0.317
2013	32.74	8.35	2.44	0.74	0.304
2014	31.71	7.70	2.26	0.66	0.291
2015	30.69	7.10	2.08	0.58	0.279
2016	29.68	6.54	1.91	0.51	0.267
2017	28.68	6.02	1.76	0.45	0.256
2018	27.70	5.54	1.62	0.40	0.245
2019	26.72	5.09	1.49	0.35	0.235
2020	25.76	4.67	1.37	0.31	0.225
			Sum of present value	57.48	9.838

APPENDIX B

CHESHIRE: COMPREHENSIVE HEURISTIC TO EVALUATE SYSTEMATIC HYPOTHETICAL INVESTMENTS TO REDUCE EMISSIONS

This appendix defines the variables and equations of the linear programmming model used to estimate the least-cost mix of compliance strategies for a utility or group of utilities. The model has been formulated in both a continuous and a mixed-integer version. The continuous version allows a utility to partially implement one or more compliance options at a generating unit, although in most solutions most units use only one compliance option; the mixed-integer version can be used to prevent the partial or multiple implementation of compliance options at generating units specified by the user. The continuous version is based heavily upon the BUILD-1 model of Hillsman, Alvic, and Church (1988). The last section reports some comparisons between the two versions.

B.1 CONTINUOUS VERSION

Decision variables

X_{vk} = Generation from existing or planned unit v of technology k in the two time periods, in megawatt-hours. A technology implies a fuel type, set of equipment, and schedule of operations in the two time periods. If the technology is for the unit to operate in one time period but not the other, the cost coefficient for this unit is computed as the cost for the period in which it does operate, and the variable is omitted from constraints on the time period in which it does not operate. If the technology is for the unit to operate with one set of fuel or equipment in one period and with a different set in another, the cost coefficient is computed as the cost of operations for the first period plus the costs of switching and operating in the second, and the variable is entered into the various time period constraints with coefficients that reflect the unit's different generation and emissions performance in the two time periods. All variables X_{vk} are in effect bounded variables; if a unit operates at less than its bound in one time period, it is assumed to operate at the same proportion in the other.

Y_k = Generation from unscheduled new capacity of technology k (note that this could be conservation or purchases from independent power producers as well as conventional technologies owned and operated by the utility, although data to allow these two options are not yet included in the model). Y_k is defined for two time periods and entered into the model in a manner similar to that for X_{vk} above.

Minimize: cost of supplying electricity

$$z = \sum_{i} \sum_{v \in U_i} \sum_{k \in F_v \cup O_v} C_{vk} X_{vk} + \sum_{i} \sum_{k \in T_k} C_k Y_k .$$

Subject to:

A. Limit on SO_2 per region during each time period t. This limit can be expressed in several forms.

1. Some proposed legislation states this as a limit on the rate of emissions per energy input, typically expressed in lb $SO_2/10^6$ Btu.

$$\sum_{i} \sum_{v \in U_i} \sum_{\substack{k \in F_v \cup O_v \\ k \in R_t}} s_{vkt} X_{vk} + \sum_{i} \sum_{\substack{k \in T_k \\ k \in R_t}} s_{kt} Y_k \leq 0, \forall t$$

Note that this formulation allows generation from units with no SO_2 emissions (such as hydro) to count against the regional total. To restrict the calculation only to units that emit SO_2, omit the clean units from the constraint.

2. Some proposed legislation states this either as a limit on the amount rather than the rate of emissions, typically expressed in tons SO_2. Some proposed legislation specifies reductions in amounts from present levels, which may be computed and expressed as limits on amounts.

$$\sum_{i} \sum_{v \in U_i} \sum_{\substack{k \in F_v \cup O_v \\ k \in R_t}} a_{vkt} X_{vk} + \sum_{i} \sum_{\substack{k \in T_k \\ k \in R_t}} a_{kt} Y_k \leq S_{it}, \forall t$$

It is possible to rewrite form 1 of this constraint to be equivalent to form 2, as long as the amount of electricity to be generated is the same in both cases. If generation can vary, then the two forms can give different results. Because we anticipate allowing the amount of generation to vary, we have found it more straightforward to provide for both forms in the software.

B. Limit on low-sulfur coal per region during each time period t

$$\sum_{i} \sum_{v \in U_i} \sum_{\substack{k \in F_v \cup O_v \\ k \in L}} c_{vkt} X_{vk} + \sum_{i} \sum_{\substack{k \in T_k \\ k \in L}} c_{kt} Y_k \leq A_t, \forall t$$

C. Limit on NO_x per region during each time period t

$$\sum_{i} \sum_{v \in U_i} \sum_{\substack{k \in F_v \cup O_v \\ k \in R_t}} n_{vkt} X_{vk} + \sum_{i} \sum_{\substack{k \in T_k \\ k \in R_t}} n_{kt} Y_k \leq 0, \forall t$$

Note that this formulation allows generation from units with no NO_x emissions (such as hydro) to count against the regional total. To restrict the calculation only to units that emit NO_x, omit the clean units from the constraint.

This constraint can be written in alternate form similar to B.1.A.2 above, but proposed legislation has not yet been specific enough to require it.

D. Requirement for net generation (now implemented as an historic generation value, without allowances for power consumption in emission controls)

$$\sum_{i} \sum_{v \in U_i} \sum_{\substack{k \in F_v \cup O_v \\ k \in R_t}} X_{vk} + \sum_{i} \sum_{\substack{k \in T_k \\ k \in R_t}} Y_k \le D_t, \forall t .$$

E. Requirement for capacity and reserve margin during each time period t

$$\sum_{i} \sum_{v \in U_i} \sum_{\substack{k \in F_v \cup O_v \\ k \in R_t}} X_{vk}/(f_{vk} * 8760) + \sum_{i} \sum_{k \in R_t} Y_k/(f_k * 8760) \ge P_t, \forall t$$

F. Limit on generation from each unit (each unit operates only in one technology)

1. For units v that cannot convert to other types, (i.e., where the set F_v is empty and $k = O_v$, as for hydro, nuclear, and noncoal fossil):

$[X_{vk} \le M_v]\text{x}10^6$. [SCALED TO REDUCE RANGE OF MAGNITUDES IN COEFFICIENTS].

2. For units that can operate in different technologies k:

$$[\sum_{\substack{k \in F_v \cup O_v \\ k \in R_t}} X_{vk}/M_v \le 1]\text{x}10^6, \forall t .$$

[SCALED TO REDUCE RANGE OF MAGNITUDES IN COEFFICIENTS].

3. To force a unit to operate in a specific technology k, represent it with B.1.F.1, and replace the inequality with an equality.

G. Groups of units at a plant may be constrained to operate in some technologies jointly (presently implemented only for conversion to low-sulfur coal, $k \in L$)

$$[\frac{X_{vk}}{M_v} - \frac{X_{(v+1)k}}{M_{(v+1)}} = 0]\text{x}10^6, \forall k,t$$ for which this constraint is required

[SCALED TO REDUCE RANGE OF MAGNITUDES IN COEFFICIENTS].

H. Constraints on particulates and/or CO_2 can be added as required.

Coefficients and other notation for B.1

A_t = Amount of low-sulfur coal available in the region in period t, in thousands of short tons per year.

a_{kt} = Amount of SO_2 emitted by new plant of technology k in period t, in thousands of short tons per megawatt-hour.

a_{vkt} = Amount of SO_2 emitted by unit v operating as technology k in period t, in thousands of short tons per megawatt-hour.

c_{kt} = Low-sulfur coal use by new plant of technology k in period t, in thousands of short tons per megawatt-hour.

c_{vkt} = Low-sulfur coal use by unit v operating as technology k in period t, in thousands of short tons per megawatt-hour.

C_k = Cost of generating electricity with new plant of technology k, in dollars/megawatt-hour (equivalent to mills/kilowatt-hour). This may be first-year cost for one or another compliance phase, one-year cost, or cost levelized over the lifetime of the installation or over periods of other duration.

C_{vk} = Cost of generating electricity with unit v using technology k, in dollars/megawatt-hour (equivalent to mills/kilowatt-hour). This may be first-year cost for one or another compliance phase, one-year cost, or cost levelized over the lifetime of the installation or over periods of other duration.

D_t = Demand for electricity in period t, in megawatt-hours per year.

f_k = The maximum capacity factor of new technology k.

f_{vk} = The maximum capacity factor of unit v operating as technology k.

F_v = The set of technologies k that unit v can be economically converted to (mnemonic *F*easible). A technology may be defined on the basis of fuel type, emission control equipment, sulfur content, time period, or other criteria.

i = Index for utilities in region.

k = Index for technologies.

L = The set of technologies that use low-sulfur coal.

M_v = Maximum generation from unit v under its current technology O_v, in megawatt-hours. Note that this limit can be made to vary with the technology to reflect capacity changes resulting from technology changes (but the present implementation does not do so). M_v implies availability and a capacity factor.

n_{kt} = NO_x emission coefficient for new plant of technology k during time period t, computed as

$$[(\text{lb } NO_x/\text{million Btu})_{vkt} - \text{regional limit}] * (\text{unit heat rate})_{vk},$$

where the regional limit for time period t is in lb NO_x/million Btu and, the heat rate is in Btu/megawatt-hour.

n_{vkt} = NO_x emission coefficient for unit v operating as technology k during time period t, computed as

$$[(\text{lb } NO_x/\text{million Btu})_{vkt} - \text{regional limit}] * (\text{unit heat rate})_{vk},$$

where the regional limit for time period t is in lb NO_x/million Btu and. The heat rate is in Btu/megawatt-hour.

O_v = The current (mnemonic *O*riginal) technology of unit v.
P_t = Peak demand for region, plus reserve margin, during time period t, in megawatts.
R_t = The set of technologies that generate during time period t.
S_{it} = The amount of SO_2 that utility i is permitted to emit in period t, in thousands of short tons per year.
s_{kt} = SO_2 emission coefficient for new plant of technology k during time period t, computed as

$$[(\text{lb } SO_2/\text{million Btu})_{vkt} - \text{regional limit}] * (\text{unit heat rate})_{vk},$$

where the regional limit for time period t is in lb SO_2/million Btu and typically is set at 1.2 lb SO_2/million Btu for one or both periods. The heat rate is in Btu/megawatt-hour.
s_{vkt} = SO_2 emission coefficient for unit v operating as technology k during time period t, computed as

$$[(\text{lb } SO_2/\text{million Btu})_{vkt} - \text{regional limit}] * (\text{unit heat rate})_{vk},$$

where the regional limit for time period t is in lb SO_2/million Btu and typically is set at 1.2 lb SO_2/million Btu for one or both periods. The heat rate is in Btu/megawatt-hour.
t = Index for time periods.
T_k = The set of technologies k from which new construction is possible.
U_i = The set of generating units owned by utility i.
v = Index for generating units.

B.2 INTEGER VERSION

The preceding formulation allows for fractional operation of units and, in the case of low-sulfur coal, plants; i.e., a unit might operate partly in its present technology and partly in another, cleaner technology. In some contexts it may be acceptable to treat these fractional units as least-cost, partial implementation of control measures (e.g., partial rather than "full" scrubbing of the stack gases from a unit, or scrubbing of only part of the gases to "full" compliance). In other cases, especially when costs for such partial compliance are unknown but are suspected to differ per megawatt-hour on a life cycle basis from those of complete compliance, it may be preferable to require full compliance for every unit taking compliance measures. These latter cases require the use of integer programming, and a redefinition of variables and coefficients. The right-hand sides of the constraint equations are unchanged, although scaling of constraints B.1.F and B.1.G is no longer necessary.

To implement the integer program, in general it is necessary only to multiply the coefficients defined above by the number of megawatts-hours generated by unit v (or plant p), and to replace the continuous decision variables for that unit with binary variables. Again, rescaling of constraints B.1.F and B.1.G is no longer necessary.

The integer formulation has been designed to allow solution as a mixed-integer program, by substituting integer variables and their corresponding coefficients for their continuous counterparts for specific plants (the constraint pair B.1.G and B.2.G that limits fuel switching to entire plants rather than specific units requires the use of integer variables for an entire plant). Thus the right-hand-side variables are identical between the two versions.

Minimize: cost of supplying electricity

$$z = \sum_{i} \sum_{v \in U_i} \sum_{k \in F_v \cup O_v} C_{vk} X_{vk}^{i} + \sum_{k \in T_k} \sum C_k Y_k.$$

Subject to:

A. Limit on SO_2 per region during each time period t. This limit can be expressed in several forms.

1. Some proposed legislation states this as a limit on the rate of emissions per energy input, typically expressed in lb $SO_2/10^6$ Btu.

$$\sum_{i} \sum_{v \in U_i} \sum_{\substack{k \in F_v \cup O_v \\ k \in R_t}} s_{vkt} X_{vk} + \sum_{i} \sum_{\substack{k \in T_k \\ k \in R_t}} s_{kt} Y_k \leq 0, \forall t$$

Note that this formulation allows generation from units with no SO_2 emissions (such as hydro) to count against the regional total. To restrict the calculation only to units that emit SO_2, omit the clean units from the constraint.

2. Some proposed legislation states this either as a limit on the amount rather than the rate of emissions, typically expressed in tons SO_2. Some proposed legislation specifies reductions in amounts from present levels, which may be computed and expressed as limits on amounts.

$$\sum_{i} \sum_{v \in U_i} \sum_{\substack{k \in F_v \cup O_v \\ k \in R_t}} a_{vkt} X_{vk} + \sum_{i} \sum_{\substack{k \in T_k \\ k \in R_t}} a_{kt} Y_k \leq S_{it}, \forall t$$

B. Limit on availability of low-sulfur coal in the region during each time period t

$$\sum_{i} \sum_{v \in U_i} \sum_{\substack{k \in F_v \cup O_v \\ k \in L}} c_{vkt} X_{vk} + \sum_{i} \sum_{\substack{k \in T_k \\ k \in L}} c_{kt} Y_k \leq A_t, \forall t$$

C. Limit on NO_x per region during each time period t

$$\sum_{i} \sum_{v \in U_i} \sum_{\substack{k \in F_v \cup O_v \\ k \in R_t}} n_{vkt} X_{vk} + \sum_{i} \sum_{\substack{k \in T_k \\ k \in R_t}} n_{kt} Y_k \le 0, \forall t$$

Note that this formulation allows generation from units with no NO_x emissions (such as hydro) to count against the regional total. To restrict the calculation only to units that emit NO_x, omit the clean units from the constraint.

This constraint can be written in alternate form similar to B.1.A.2 above, but proposed legislation has not yet been specific enough to require it.

D. Requirement for net generation (now implemented as an historic generation value, without allowances for power consumption in emission controls)

$$\sum_{i} \sum_{v \in U_i} \sum_{\substack{k \in F_v \cup O_v \\ k \in R_t}} G_{vkt} X_{vk} + \sum_{i} \sum_{\substack{k \in T_k \\ k \in R_t}} G_{kt} Y_k \le D_t, \forall t .$$

E. Requirement for capacity and reserve margin during each time period t

$$\sum_{i} \sum_{v \in U_i} \sum_{\substack{k \in F_v \cup O_v \\ k \in R_t}} X_{vk}/f_{vk} + \sum_{i} \sum_{k \in R_t} Y_k/f_k \ge P_t, \forall t$$

F. Limit on generation from each unit (each unit operates only in one technology)

1. For units v that cannot convert to other types, (i.e., where the set F_v is empty and $k = O_v$, as for hydro, nuclear, and noncoal fossil):

   $X_{vk} \le 1$.

2. For units that can operate in different technologies k:

   $$\sum_{\substack{k \in F_v \cup O_v \\ k \in R_t}} X_{vk} \le 1, \forall t .$$

4. To force a unit to operate in a specific technology k, represent it with B.2.F.1 and replace the inequality with an equality.

G. Groups of units at a plant may be constrained to operate in some technologies jointly (presently implemented only for conversion to low-sulfur coal, $k \in L$)

$X_{vk} - X_{(v+1)k} = 0, \forall k, t$ for which this constraint is required.

H. Constraints on particulates and/or CO_2 can be added as required.

Decision variables for B.2

X_{vk} = 1 if unit v operates as technology k;
= 0 if not.

Y_k = 1 if plant of technology k is built;
= 0 if not.

Coefficients and other notation for B.2

A_t = (No change from continuous model) Amount of low-sulfur coal available per year in the region in period t, in thousands of short tons per year.

a_{kt} = Amount of SO_2 emitted in period t by new plant of technology k generating G_{kt} megawatt-hours per year, in thousands of short tons per year (not per megawatt-hour as in the continuous model).

a_{vkt} = Amount of SO_2 emitted in period t by unit v operating as technology k generating G_{vkt} megawatt-hours per year, in thousands of short tons per year (not per megawatt-hour as in the continuous model).

c_{kt} = Low-sulfur coal use by new plant of technology k generating G_{kt} megawatt-hours per year, in thousands of short tons per year (not per megawatt-hour as in the continuous model).

c_{vkt} = Low-sulfur coal use by unit v operating as technology k generating G_{vkt} megawatt-hours per year, in thousands of short tons per year (not per megawatt-hour as in the continuous model).

C_k = Total (not average as in the continuous model) cost of generating electricity with new plant using technology k, operating at assumed maximum rate, in dollars per year. This may be first-year cost for one or another compliance phase, one-year cost, or cost levelized over the lifetime of the installation or over periods of other duration.

C_{vk} = Total (not average as in the continuous model) cost of generating electricity with unit v using technology k, operating at assumed maximum rate, in dollars per year. This may be first-year cost for one or another compliance phase, one-year cost, or cost levelized over the lifetime of the installation or over periods of other duration.

D_t = (No change from continuous model) Demand for electricity in period t, in megawatt-hours per year.

f_k = The capacity (not capacity factor as in the continuous model) of a new plant of technology k, in megawatts.

f_{vk} = The capacity (not capacity factor as in the continuous model) of unit v operating as technology k, in megawatts.

F_v = (No change from continuous model) The set of technologies k that unit v can be economically converted to (mnemonic *F*easible). A technology may be defined on the basis of fuel type, emission control equipment, sulfur content, time period, or other criteria.

G_{kt} = Generation from new plant of technology k in period t, in megawatt hours per year (no direct counterpart in the continuous model, but essentially similar to M_v there, implying a capacity factor and availability rate).

G_{vkt} = Generation from unit v operating as technology k in period t, in megawatt hours per year (no direct counterpart in the continuous model, but essentially similar to M_v there, implying a capacity factor and availability rate).

i = (No change from continuous model) Index for utilities in region.

k = (No change from continuous model) Index for technologies.

n_{kt} = (Differs from continuous model) NO_x emissions coefficient for new plant of technology k during time period t, computed as

$$(\text{tons } NO_x)_{vkt} - \text{tons if operating at regional limit}$$

where both tonnages are per year from generating G_{kt} megawatt-hours.

n_{vkt} = (Differs from continuous model) NO_x emissions coefficient for unit v operating as technology k during time period t, computed as

$$(\text{tons } NO_x)_{vkt} - \text{tons if operating at regional limit}$$

where both tonnages are per year from generating G_{vkt} megawatt-hours.

O_v = The current (mnemonic *O*riginal) technology of unit v.

P_t = (No change from continuous model) Peak demand for region, plus reserve margin, during time period t, in megawatts.

R_t = (No change from continuous model) The set of technologies that generate during time period t.

S_{it} = (No change from continuous model) The amount of SO_2 that utility i is permitted to emit in period t, in thousands of short tons per year.

s_{kt} = (Differs from continuous model) SO_2 emission coefficient for new plant of technology k during time period t, computed as

$$(\text{tons } SO_2)_{vkt} - \text{tons if operating at regional limit,}$$

where both tonnages are per year from generating G_{kt} megawatt-hours.

s_{vkt} = (Differs from continuous model) SO_2 emission coefficient for unit v operating as technology k during time period t, computed as

$$(\text{tons } SO_2)_{vkt} - \text{tons if operating at regional limit,}$$

where both tonnages are per year from generating G_{vkt} megawatt-hours.

t = (No change from continuous model) Index for time periods.

T_k = (No change from continuous model) The set of technologies k from which new construction is possible.

U_i = (No change from continuous model) The set of generating units owned by utility i.

v = (No change from continuous model) Index for generating units.

B.3 COMPARISON OF CONTINUOUS AND INTEGER SOLUTIONS

The purpose of our application of the continuous model has been to estimate the increase in the cost of generating electricity that would result from complying with new clean air legislation. Thus, our principal interest has been in the value of the objective function, and not in the costs, emissions, or resource usage at individual generating units. Our experience with running the continuous model has been that its optimal solution usually includes at least one unit that operates with more than one compliance strategy. In our initial analyses, we required these units to select only one compliance strategy per compliance phase, using the integer version of the model to enforce this requirement. However, we have noticed that imposing this requirement has very little effect on the value of the objective function.

Table B.1 presents results for a series of runs of both versions of the model, indicating the number of generating units in the utility, the number of units forced to be integers, and the utility cost of generating electricity for each solution. These results are typical. The only cases in which we have noticed substantiallly greater differences between the costs for continuous and integer solutions have been for utilities with small numbers of units, and therefore have limited flexibility for complying with some bills. As Table B.1 illustrates, integer solutions even for these companies can yield very small changes in the cost of electricity.

In view of these results, and the large increases in solution time required for integer solutions, we have concluded that the use of the integer model yields minimal improvements in precision of our cost estimates, and we have decided against using the integer solution in the present analysis. In applications that require reporting and analysis of unit-specific costs, emissions, or resource requirements, we would re-examine these conclusions before making a similar decision against incurring the added computational burden of the integer model.

Table B.1. Comparison of objective function values for integer and non-integer solutions

Company	Continuous Solution			Integer Solution		
	Units	Units integer[a]	Mills/ kWh	Units integer[b]	Mills/ kWh	Percent change from continuous
Alabama	23	15	32.56	23	33.13	1.8
Appalachian	11	10	23.31	11	23.31	0.0
Associated	5	3	27.43	5	27.43	0.0
Big Rivers	9	6	23.34	9	23.93	2.1
Cleveland	19	14	37.14	19	38.46	3.6
Duke	28	25	26.11	28	26.20	0.3
Ohio Power	12	5	30.01	12	30.98	3.2
Potomac	12	9	24.52	12	24.55	0.1
S Carolina	10	9	26.75	10	27.14	1.5
S Indiana	6	3	23.74	6	24.01	1.1
TVA	63	53	26.94	19[c]	26.96	0.1

Mills/kWH are 10-year levelized costs, as calculated for compliance with the Cooper bill described in Section 4.2.3.

a Units in the continuous solution using only one compliance option.

b Units required to use no more than one compliance option.

c Utility has too many units to allow pure integer solution. Mixed integer problem defined by requiring only the non-integer units from the continuous solution to be integer, resolving, identifying additional non-integer units, requiring them to be integer, and repeating. A total of 52 units were integer in the mixed-integer solution reported here.

APPENDIX C

SAMPLE PRINTED OUTPUT FROM CHESHIRE MODELING SYSTEM

Tables C.1 and C.2 present sample printed output from the CHESHIRE modeling system. To simplify the presentation, the results are from a small utility using the integer version of the model. Table C.1 lists each generating unit in the utility being modeled, followed by a flag indicating the requirement for integral operation of the unit, a sequence number, the year the unit began operation, and its capacity in megawatts.

The next two columns list codes indicating which control options the model chose for the unit in phase 1 and phase 2 of the bill. A list of what the codes mean appears below the bottom right of the table; although all of the options were available in this run of the model, some were not chosen.

The next two columns list the cost of electricity in mills/kWh in the base year and using the control options selected by the model, calculated according to the method noted below the lower left of the table (10-year levelized costs in this case). The numbers in the "Totals" row are the average for the entire utility.

The next four triplets of columns give the unit capacity factor in the base period, in phase I, and phase II; the generation in gigawatt-hours for the same three periods; the SO_2 emission rates for the same three periods; and the NO_x emission rates for the same three periods. The numbers in the "Totals" row for generation are the total generated by the units and, for phase I and phase II, are also the amount of generation set in the demand constraints of the model. The numbers in the "Totals" row for SO_2 and NO_x are the average rates for the utility. By crossreferencing the unit's technology and generation with the model's database describing heat rates, fuel use, and costs, other information can be calculated on a unit-by-unit basis and reported as needed.

The final column lists the name of the utility. The information is redundant if only one utility is being modeled, but is useful for distingishing different utilities when trading is analyzed. When trading is analyzed, the "Totals" row of this table reports values totaled or averaged for the set of utilities included in the analysis. Therefore, an additional table is produced that reports costs, generation, total and low-sulfur coal use and emission tonnages for each utility, in a format similar to that of Table C.1.

Table C.2 reports summary statistics from the model run and records the values used for the major parameters in the model. Summary statistics include the tonnage by which SO_2 was reduced, and the increases in cost and generation between the base year and compliance in phase II. This is followed by three columns reporting fuel use by type; at present, low-sulfur coal is reported as the amount of additional low-sulfur coal used to comply with the legislation, but information is available in the database to report present low-sulfur coal use as well. The final three columns report emission tonnages and fuel use for the base and two compliance years. When the model is used to examine emission trading between utilities, the value of an allowance as calculated from the model's dual variables (section 4.4) is also reported.

The defaults section of Table C.2 records the years used for phase I and phase II, with reserve margins and emission limits; the latter appear as rates or as tons, depending upon whether the emission constraints have been expressed as rates or as tons. The next three columns list the costs for scrubbers, low-NO_x burners, and clean coal technology.

The next columns report the assumed maximum age for generating units, which is applied in the absence of information about planned retirements. Below this information are the values for sulfur content, cost premium, and potential penetration by low-sulfur coal.

The final column indicates whether there is an emission fee, its size, the period over which it is imposed, and the emission rates on which it is imposed. The values labelled "Trade Allow P1" and "Trade Allow P2" are used to specify the value of an allowance to be used in calculating the cost of electricity for the utility after the model has been solved, if the user wishes to enter a value to determine its effect. The example does not exercise this option.

Finally, the section "GLOBAL OPTIONS USED" lists the major technologies allowed for reducing emissions in the run. It also indicates whether the mixed-integer form of the model was used.

Table C.1. Sample unit results from CHESHIRE

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ASSOCIATED ELECTRIC**

PLANT NAME		UNIT	SEQ #	YEAR	CAP. MW	MODEL*** ALTERNATE P1	P2	-COST in M/KWh BASE	MODEL	-----C.F.----- BASE	P1	P2	--GENERATION in GWH- BASE	P1	P2	---SOX/MMBTU---- BASE	P1	P2	---NOX/MMBTU---- BASE	P1	P2	-----COMPANY NAME-----
NEW MADRID	•	1	A01	1972	600	LSC	LSC	22.28	27.86	.49	.49	.49	2584	2584	2584	5.59	1.00	1.00	1.66	1.66	1.66	ASSOCIATED ELECTRIC
NEW MADRID	•	2	A02	1977	600	LSC	LSC	23.18	28.78	.51	.50	.50	2663	2663	2663	5.68	1.00	1.00	1.66	1.66	1.66	ASSOCIATED ELECTRIC
THOMAS HILL	*	1	A03	1966	180	LSC	LSC	24.57	30.63	.57	.57	.57	903	903	903	8.35	1.00	1.00	1.95	1.95	1.95	ASSOCIATED ELECTRIC
THOMAS HILL	•	2	A04	1969	285	LSC	LSC	24.52	30.58	.58	.57	.57	1435	1435	1435	8.33	1.00	1.00	1.95	1.95	1.95	ASSOCIATED ELECTRIC
THOMAS HILL	•	3	A05	1982	670	OFGD	OFGD	23.83	23.83	.57	.57	.57	3356	3356	3356	1.65	1.65	1.65	1.85	1.85	1.85	ASSOCIATED ELECTRIC
Totals					2335			23.46	27.43				10945	10945	10945	4.96	1.19	1.19	1.77	1.77	1.77	

** Levelized costs over 10 year period -- Used lbs/mmBtus
• Use Integer Solution
Forced Into Solution

***Base - Same as base year
CCOL - Clean coal technology
LSC - Low sulfur coal
LS/N - LSC and NOx

New - New, unplanned unit
NOx - NOx device
N/U - Not used
OFGD - Base year scrubber

PS/N - Present FGD + NOx
SOx - Scrubber
S/N - SOx and NOx
RET - Retired

Table C.2. Sample summary of assumptions and options

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COOPER HR 144
ASSOCIATED ELECTRIC**

SUMMARY STATISTICS

SOX Reductions
206969 Tons
75.90 %
Cost Increase
$ 43500.52
16.93 % (mills/KWHs)
Generation Increase: .00 %

	Base Year	Phase One	Phase Two
Total Coal in tons:	5272.10	5272.10	5272.10
Total Low Sulfur Coal:		3596.30	3596.30
Percentage of LSC:		68.21	68.21
Total Oil in 1000s bbls:	28.00	28.00	28.00
Total Gas in MMcf:	.00	.00	.00

	Base Year	Phase One	Phase Two
SOx in 1000s tons:	272.70	65.73	65.73
NOx in 1000s tons:	97.60	97.60	97.60
Btus in 10E7:	10.98	10.98	10.98

Value of SOX Allowance: -.00
Value of NOX Allowance: .00

DEFAULTS CHOSEN

	Phase One	Phase Two
Phasing Year:	1997	2003
Reserve Margin (%):	10.00	10.00
SOx Limits(lbs/mmBtu):	1.35	1.20
NOx Limits(lbs/mmBtu):	.00	.00

	Scrubber	NOx Device	Clean Coal
Capital Costs:	280.00	20.00	50.00
Fixed O&M:	13.00		13.00
Variable O&M:	1.70		1.70
Efficiency:	90.00	60.00	50.0/40.0
Lifetime/:	30.00		
Capacity Factor/:	65.00		

Unit Lifetime: 50 years

Low Sulfur Coal
Amount SOX Emissions : 1.00
Percentage Amount: 100.00
Cost Penalty ($): 10.00

Fee	
Amount (mills):	.00
Years (from P1):	0
>mmBTU:	.00
Trade Allow P1	.00
Trade Allow P2	.00
Coal Tax	.00

GLOBAL OPTIONS USED

Leave Alone
Add Scrubbers
Switch to Low Sulfur Coal
Integer Solution

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