TITLE II OF THE PROPOSED SENATE AMENDMENTS TO THE CLEAN AIR ACT: A PRELIMINARY ECONOMIC ANALYSIS

Staff Working Paper
September 1987

The Congress of the United States
Congressional Budget Office

PREFACE

The Clean Air Act, the primary federal statute controlling air pollution in the United States, was last amended in 1977. Recently, a comprehensive set of amendments was approved by the Senate Subcommittee on Environmental Protection. The five titles of the proposed bill would address compliance with the national ambient air quality standards for ozone; limit emissions of pollutants causing acid rain; impose new controls on mobile sources of air pollution; redefine units of measurement for the national ambient air quality standards; and limit routine and accidental emissions of air toxics.

This staff working paper considers the potential economic effects on the electric utility industry of Title II of the proposed amendments, designed to control acid rain. The modelling effort that supports this paper was initiated at the request of Senator Stafford, the ranking minority member of the Senate Committee on Environment and Public Works, for whom a more detailed analysis is underway. A forthcoming study will assess the economic implications of Title V. This paper was prepared at the request of Senators Bingaman, Boren, Byrd, Cochran, Conrad, Dixon, Ford, Garn, Gramm, Hatch, Heflin, Helms, Lugar, McConnell, Murkowski, Nickles, Pressler, Pryor, Quayle, Rockefeller, Sanford, Shelby, Simpson, Stevens, Symms, Trible, Wallop, and Warner. In keeping with the mandate of the Congressional Budget Office (CBO) to provide objective analysis, the report makes no recommendations.

Marc Chupka of CBO's Natural Resources and Commerce Division wrote the report under the supervision of Roger C. Dower and Everett M. Ehrlich. Bob Friedman of the Office of Technology Assessment and Larry Parker of the Congressional Research Service provided valuable assistance and comments--complementary analyses of the proposed amendments are being prepared by these organizations. The paper was edited by Francis S. Pierce, and the manuscript was typed and prepared for publication by Patricia Z. Joy.

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September 1987

TITLE II OF THE PROPOSED SENATE AMENDMENTS TO THE CLEAN AIR ACT: A PRELIMINARY ECONOMIC ANALYSIS

INTRODUCTION AND SUMMARY

Title II of the current Senate proposal to amend the Clean Air Act contains a set of provisions to control emissions of sulfur dioxide (SO_2) and oxides of nitrogen from utility and industrial sources. The heart of any acid rain bill and the subject of this working paper is SO_2 emission reductions from electric utilities. The proposal offers the states a set of choices in order to achieve by 1996, and maintain subsequently, a 12-million-ton reduction in SO_2 emissions from 1980 levels. The statewide emission targets defined in the bill would apply to emissions from all sources, not only from existing utilities but from nonutility combustion sources and from new utility sources built under the New Source Performance Standards (NSPS). Should states fail to submit an acceptable plan conforming to the emission targets, they would be directed, as a default requirement, to implement uniform standards on a plant-by-plant level set at 0.9 pounds of SO_2 per million Btus of fuel burned (based on a monthly average). After 1996, a state could choose either to maintain the assigned aggregate emission target (disallowing any emission growth) or to phase in the uniform 0.9 pound standard on all plants as they reach 30 years in operation. Superimposed on the targets and standards is a "precompliance cap," requiring all states to remain at or below their 1980 emission levels.

Every state would thus initially face two major choices: either to meet the assigned statewide emission target, allocating the emission reductions among the various sources within the state, or to abide by the uniform plant standard and operate in default. In order to capture the potential range of state responses to this proposal, Congressional Budget Office (CBO) researchers performed three simulations with the National Coal Model (NCM7), developed by the Department of Energy and modified for this purpose by CBO. They simulated utility emissions, utility costs, and the effects on coal markets. These simulations form the basis for this report.

The report analyzes three possible responses to the bill's requirements:

o **Target 1**, which specifies a set of state emission targets on electric utilities assuming that industrial sources would account for 1.5 million tons of the total SO_2 reduction. Under these targets, national utility emissions would not exceed 7.0 million tons of SO_2 in 1996;

- **Target 2**, which specifies a more rigorous set of state emission targets on electric utilities by assuming that industrial sources would not contribute at all to the total SO_2 reduction. This target would approximate the overall cost of the bill (under the target approach) if non-utility emitters could be assumed to face the same SO_2 abatement costs as utilities. Under these targets, utilities would reduce their aggregate emissions by the full 12 million tons from 1980 levels, so that national utility emissions would not exceed 5.5 million tons of SO_2 in 1996; and

- The **Default Case**, which assumes that all states would select the plant-by-plant standard (applied to all sources) of 0.9 pound of SO_2 per million Btu monthly as the default requirement for 1996, and would continue to adhere to the new uniform plant-by-plant standards as the only emission requirement.

In order to conform with the basic structure of the NCM7 model, the simulations imposed policy effects in the 1995 target year, and maintained them for the year 2000. The precompliance cap limiting states to the observed 1980 emission levels was imposed on the 1990 solution to determine what effect, if any, the cap would have on intermediate emission levels.

This preliminary analysis analyzes the effects of the bill by examining distinct alternatives. In reality, a more likely outcome would be a combination of emission targets in some states and default standards in others. The results presented here suggest that important regional differences--in electricity generation, fuel use patterns, current emission controls, and prospects for economic and industrial expansion--will determine the cost of the bill's provisions to the states. These regional differences will dictate the incentives that states face for attaining the emission targets or accepting the default provisions, and for selecting the appropriate strategy after 1996.

In Western and Gulf states, the combination of relatively low-emitting electric generating plants and projected growth in electricity demand means that the precompliance cap constitutes the binding requirement. This is captured in the Target 2 scenario; any reduction requirement for these states gives 1980 emissions as a target. The compliance cost for the regions of Texas, Arkansas, Oklahoma, and Louisiana alone is estimated under this cap to be $2 billion annually by 2000. If these states were allowed to default--and avoid the cap--annual costs would be less than $400 million. The overall cost of the cap is lower in Western states, but continues to determine the costs and emissions reductions.

In the East, the reductions from 1980 emission levels required by the 12-million-ton targets are so large that the precompliance cap would be irrelevant in the foreseeable future. Here, the choices betweeen meeting the reduction requirement or operating in default are influenced more by the actual level of the target applied to utilities (i.e. Target 1 or Target 2), as well as the long-term impact of the postcompliance options of maintaining the target or phasing in the 0.9 standard as plants reach age 30. Illinois, Indiana, Michigan, Missouri, and Wisconsin, for example, may incur higher costs attaining, and subsequently maintaining, their emission levels, as opposed to the default situation (where the post-1996 30-year plant standard is already in place for all sources). In cases where the annual costs are similar, the initial complexity of formulating individual standards for sources in 1996 that would achieve the target economically, combined with the long-run problem of providing emission offsets from old sources in order to accommodate the emissions from new sources, may still encourage states to accept the uniform plant standard for 1996, and thus avoid additional emissions controls from existing sources.

The results of the CBO simulations provide a range of possible costs (in 1985 dollars) to electric utilities of Title II. By assuming 1995 as a compliance deadline, Target 1 would cost utilities $6.2 billion annually, rising to $7.9 billion by 2000 as the targets become more expensive to maintain. Additional emission reductions, and costs, would be expected from nonutility emitters. Attributing all of the emission reductions and costs to utilities under Target 2 would cost $8.5 billion in 1995 and rise to $10.7 billion in 2000. To the extent that utility and nonutility emission reduction costs are similar, these figures approximate the cost of the entire bill if the precompliance cap and emission reduction targets are maintained.

Under the scenario that all states default (and are allowed to exceed the precompliance cap in some cases) by controlling existing sources down to the monthly standard of 0.9 pounds of SO_2, annual costs in 1995 are $7.3 billion, and remain constant in 2000. Emissions would grow between 1995 and 2000, from 7.9 million tons to 9.4 million tons per year. If states are not allowed to exceed the precompliance cap through default, the costs to electric utilities of the bill rise substantially--to $8.5 billion annually in 1995 (when emissions would be 7.1 million tons) and $9.3 billion in the year 2000 (when emissions would be approximately 1.4 million tons greater).

Table 1 displays the estimated overall emission and utility cost effects of the three cases modelled, as well as of the default scenario with the precompliance cap. These estimates apply only to electric utilities.

TABLE 1. SUMMARY: RESULTS OF THE SIMULATIONS

	1995	2000
Annual Utility Sulfur Dioxide Emissions (In millions of tons)		
Historical (1980) 17.5		
Base Case	19.8	21.1
Target 1	6.9	6.9
Target 2	5.4	5.4
Default	7.9	9.4
Default with Cap	7.1	8.0
Net Annual Utility Cost (In billions of 1985 dollars)		
Target 1	6.2	7.9
Target 2	8.5	10.7
Default	7.3	7.2
Default with Cap	8.5	9.3
Total Retrofit Scrubbers (In gigawatts)		
Target 1	42	52
Target 2	81	95
Default	116	116
Default with Cap	123	123
Average Cost (In dollars per ton of reduced SO_2 emissions)		
Target 1	538	
Target 2	666	
Default	630	
Default with Cap	725	

SOURCE: Department of Energy National Coal Simulation Model, modified by the Congressional Budget Office.

The provisions contained in the current Senate acid rain proposal would establish an overlapping set of regulations in order to achieve substantial reductions in sulfur dioxide (SO_2) emissions. The following discussion offers a qualitative interpretation of the effects of the bill on electric utility sources. A quantitative analysis of costs, emission reductions, and coal-market effects is presented subsequently. The Congressional Research Service is currently preparing a complementary analysis of other aspects of the Title II requirements.

The primary intent of the proposed acid rain legislation is outlined in Section 181: "Not later than January 1, 1996, there shall be achieved a reduction in annual emissions of sulfur dioxide of twelve million tons and in annual emissions of oxides of nitrogen of four million tons, from the total actual annual level of such emissions between January 1, 1980, and December 31, 1980." The stated intent differs from the goals expressed in many similar bills proposed in the last several Congresses, which assigned targets to older sources while allowing for gradual emission growth from future sources. 1/ The current proposal uses the 1980 emission baseline as a strict aggregate target for all sources, making no distinction between utility and non-utility sources, or between sources currently subject to State Implementation Plans (SIPs) and those sources operating under the typically much stricter New Source Performance Standards (NSPS). 2/ Since emissions from new sources will inevitably grow over the next decades, the targets in this proposal suggest that existing sources would be subject to

1. See Congressional Budget Office, *Curbing Acid Rain: Cost, Budget, and Coal-Market Effects* (June 1986), for a general discussion and analysis of many proposals considered by the 98th and 99th Congresses. Acid rain bills originating is the House of Representatives have typically allowed emissions growth form new sources, while bills originating in the Senate have often employed emission caps.

2. See Congressional Budget Office, *The Clean Air Act, the Electric Utilities, and the Coal Market* (April 1982), for a discussion of the issues surrounding the NSPS. The current (revised) NSPS requires utilities to install scrubbers on new power plants, and allows emission rates above 0.6 pounds of SO_2 per million Btus (to an absolute limit of 1.2 pounds) only if the scrubbers achieve 90 percent removal of SO_2. The minimum percentage removal allowed is 70 percent, and, depending on the sulfur content of the coal burned, the current NSPS often achieves emission rates well below 0.6 pounds of SO_2 per million Btu. The original NSPS, which was effective between 1971 and 1978, limited emissions to 1.2 pounds per million Btus, by whatever method--low-sulfur coal or scrubbers--chosen by utilities.

stricter limits than would be imposed under a 12-million-ton reduction applied only to sources that operated in 1980. Another possible effect of these targets could be to encourage new sources to control their emissions beyond the current NSPS.

The proposed emission targets can be quantified on the basis of the 1980 emission inventory.[3] SO_2 emissions from all sources in 1980 were roughly 26.4 million tons. Combustion sources accounted for most of these emissions: utilities emitted 17.5 million tons and nonutility combustion sources added another 2.9 million tons, while noncombustion stationary sources and area sources accounted for the remaining 6 million tons. If the goal of the bill was achieved, total 1996 emissions of SO_2 would be 14.4 million tons or less. If the entire 12-million-ton reduction came from utilities, their emissions in 1996 would be 5.5 million tons. To the extent that the reductions were shared between utility and industrial combustion sources, the utilities would only have to reduce total emissions from 1980 levels by 10.5 million tons, allowing them to emit a total of 7.0 million tons of SO_2 in 1996.[4]

The next two sections of the bill stipulate the methods by which combustion source emission reductions are to be achieved and subsequently maintained. Section 182 requires that fossil fuel combustion sources operating in 1980 (the vast majority of which are regulated by SIPs) achieve a statewide annual average of 0.9 pounds of SO_2 emitted per million Btus by 1996. Since this provision alone would not reduce overall emissions by 12 million tons, states must also choose between two requirements to achieve this target by 1996, during the "precompliance period" (before 1996).

The first precompliance requirement stipulates that statewide emission targets be developed through an "excess emission" formula, applied to all fossil-fuel-fired combustion sources. This calculation takes the portion

3. The 1980 SO_2 emission inventory was supplied by the Office of Technology Assessment. With minor revisions, these are the same estimates contained in OTA's *Acid Rain and Transported Air Pollutants: Implications for Public Policy* (June 1984). This inventory is widely accepted, and would probably form the basis for emission reduction targets.

4. These figures are based on limiting all nonutility combustion sources to an emission rate of 0.9 pounds of SO_2 per million Btus. The overall emission requirements, therefore, ignore the potential for reductions from noncombustion (industrial process) sources. Some such reductions may already have occurred from industrial process sources as a result of lower production levels (notably in nonferrous smelters and iron and steel mills).

of each state's 1980 emissions arising from sources emitting at rates greater than 0.9 pounds of SO_2 per million Btu of heat input, and divides it by the U.S. total of emissions from sources emitting over 0.9 pounds per Btu to yield the state's share of excess emissions. These resulting factors, which represent the percentage of the total reduction expected from each state, are then scaled up to achieve a total nationwide reduction of 12 million tons. States can meet their emission targets any way they see fit.

If states do not submit acceptable plans for achieving their emission targets during this period, then the second precompliance requirement--a default provision--would be invoked. The default provision stipulates that all fossil-fuel-fired steam generating units comply with a standard of 0.9 pound of SO_2 per million Btu, calculated on a monthly basis as opposed to the current annual average standard. 5/

Section 182 also requires that states obtain compensating emission offsets for sources that emit at rates above 1980 levels, and for all sources built after 1980--irrespective of all other requirements. 6/ As written, this provision ensures that emissions in any state would never exceed 1980 levels. This "precompliance cap" could substantially affect long-run costs in states for which the emission targets or the default option alone would not greatly restrict aggregate emissions--primarily the Western and Gulf region states--since such states would have to secure offsets in order to accommodate growth in emissions from new sources that occurred since 1980. Most sources in these states are already tightly controlled (sometimes beyond levels required by the NSPS), and additional emission reductions could be extremely expensive.

The choice between the two precompliance requirements--the 12-million-ton reduction or the uniform plant-by-plant monthly standard of 0.9

5. Expressing the standards as monthly averages would require utilities to control their emissions more carefully in terms of reducing the variability of actual emissions, which would be more stringent than an identical emission standard expressed in annual terms. Compared with annual emission rates, a standard expressed in monthly terms is roughly 10 percent stricter (perhaps more, if scrubber reliability is a factor). In this analysis, the monthly standard of 0.9 pounds of SO_2 per million Btus will be expressed as 0.8 pounds on an annual basis.

6. Sources that increase emissions, or that begin emitting, between 1980 and the enactment of the bill would have until 1996 to obtained the required offsets, while sources that are built (or existing sources that seek to increase emissions beyond their 1980 levels) between the enactment of the bill and 1996 would have to obtain simultaneous offsets.

pound of SO_2 per million Btu--will be influenced by the two postcompliance options (after 1996) set out in Section 183. The first postcompliance option would require that beginning in 1996 all fossil-fuel-fired steam generating units attain the monthly standard of 0.9 pound of SO_2 per million Btu once they reach 30 years in operation. Therefore, this option would essentially phase in the precompliance default requirements as plants reached age 30. By 2010, virtually all SIP sources would be at least 30 years old, and this provision would become the operative standard for plants currently governed by SIPs if states chose to accept it. If states did not wish to phase in this standard, the second postcompliance option would offer the choice of simply maintaining the emissions cap as mandated by the excess emissions formula, by whatever combination of controls the legislation allowed.

STATE CHOICES UNDER THE PROPOSAL

The final mix of state responses to the requirements and options set out in the Senate proposal would be dictated by the states' current level of emissions and their projected demand for electricity. As structured, the current bill appears to provide some states with strong incentives to adopt the uniform plant standard of 0.9 pound per million Btu during the pre- and postcompliance periods. Policies that offer states latitude in selecting abatement strategies are generally thought to reduce the overall costs of achieving a specific emission reduction. But, under the mandated 12-million-ton reduction targets, the opportunities for economizing by assigning different standards for individual sources might be small and short-lived, as the result of the level of control stipulated by the excess emission formula targets, the relatively short time period for compliance, and the influence of postcompliance options on the choice of precompliance requirements.

The first requirement of Section 182--the 0.9 statewide annual average on State Implementation Plan (SIP) sources--would probably have little effect on the decisions faced by many states since the inclusion of many low-emitting oil- or gas-fired utility and industrial boilers dilutes the overall stringency of the requirement. In most cases, this requirement does not provide enough emission control to achieve a 12-million-ton excess emission formula reduction. Further, if states choose the default standards, this restriction becomes essentially irrelevant.

The 12-million-ton excess emission formula would appear therefore to constitute the operative target in most states--but only to the extent that states did not simply accept the default provision. There are several

reasons why states might choose the default provisions. First, controlling some sources down to emission rates low enough to provide sufficient offsets for plants emitting at higher rates is typically not economical at this level of overall emission reduction. In addition, the latitude granted for allocating the emission control requirements among different sources under the state targets might be partially restricted by the first provision that all SIP sources achieve a statewide annual 0.9 per pound average. Moreover, the administrative effort associated with identifying sources that could emit at higher rates--while still attaining the aggregate emission targets and reducing overall costs--might not be worth the effort, especially since the proposal would impose a two-year deadline to formulate acceptable plans.

Finally, areas that have experienced, or expect to experience, substantial growth in electricity demand and industrial activity might find that the emission cap dictated by the excess emission formula target would be more costly to achieve by 1996 in terms of foregone growth. In addition, all states could face high costs to maintain these targets in the postcompliance period, since they would continually have to seek emission offsets from old sources to accommodate emissions from new sources. Instead, high-growth (and some high-emitting) states might prefer to operate under a strict plant-by-plant standard that would still allow new sources (subject to the NSPS) to be built without regard to a preassigned emissions cap. If states chose the default option, compliance after 1996 could be maintained with no additional controls by choosing the 30-year standard as a postcompliance strategy. Under the default scenario, therefore, the transition into the postcompliance period would appear to be essentially costless, and could provide states sufficient incentive to dispense with the excess emission formula targets altogether.

Although the default requirement would seem to be the rational choice for at least some states, the precompliance cap is likely to limit the number of states that could take advantage of it. In some Western or Gulf states the default requirements would probably allow overall emissions eventually to exceed 1980 levels. In this situation, the precompliance cap would force those states to adopt an aggregate statewide emission target no matter how advantageous the uniform 0.9 standard would be.

MODELLING THE ACID RAIN PROVISIONS

The Congressional Budget Office uses the National Coal Model (NCM) to estimate the emission, cost, and coal-market effects of acid rain proposals

for the electric utility sector. The current version of the model (NCM7) provides forecasts for 1990, 1995, and 2000. 7/

Three simulations were performed in order to capture the range of potential responses under the current proposal:

- o **Target 1**, which specifies a set of state emission targets for electric utilities in which industrial sources are assumed to account for 1.5 million tons of the total SO_2 reduction. Under these targets, national utility emissions cannot exceed 7.0 million tons of SO_2 in 1996;

- o **Target 2**, which specifies a set of state emission targets for electric utilities in which industrial sources do not contribute to the total SO_2 reduction. Under these targets, utilities must reduce aggregate emissions by the full 12 million tons from 1980 levels, and national utility emissions cannot exceed 5.5 million tons of SO_2 in 1996; and

- o The **Default Case**, which assumes that all states will accept the default requirements for 1996, and will continue to adhere to the plant-by-plant standards as the only additional emission requirement. Ultimate emission levels are not established by a preset target.

The NCM7 estimates the cheapest way to produce electricity nationwide, taking into account the cost of purchasing coal from different regions, the expense of transporting it, the cost of using different types of power plants as well as building new ones, and the effect of different emission regulations. Coal is distinguished by its origination in 31 supply regions (more than the actual number of states that produce coal) for shipment to 44 demand regions (representing roughly each state in the continental United States). Coal is further differentiated by sulfur content, coal rank, and energy content, which are later used to determine the type of power plant in which it can be burned. Demand regions are defined, in part, by their prevailing emission regulations and expected growth in electricity demand.

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7. The NCM is maintained by the Energy Information Administration, an independent statistical and analytical agency within the Department of Energy. The basic methodology is explained in the Appendix of the CBO study *Curbing Acid Rain: Cost, Budget, and Coal Market Effects* (June 1986). Many of the assumptions have been changed since that analysis, including those relating to electricity demand growth, rail rates, mining productivity, and scrubber costs.

After a particular policy scenario has been established--including constraints on SO_2 emissions in each demand region--the model estimates an optimal solution based on the lowest annual real power cost that can be obtained in each region under the specified policy. Solutions are provided for three target years: 1990, 1995, and 2000. For this study, the policy changes were considered to be implemented fully by the 1995 solution year, and to continue in the 2000 solution. The precompliance cap was imposed in the 1990 solution.

The CBO Base Case

In the current CBO base case, annual SO_2 emissions from electric utilities are expected to reach 17.5 million tons in 1990, the same level recorded in 1980. This projection reverses the decline in annual emissions experienced during the early 1980s, reflecting the extended retention of old coal-fired capacity regulated by the states, as well as planned additions of new capacity. During the 1990s, emissions are projected to rise steadily to a level of 21.1 million tons in 2000 as additional coal-fired capacity is built, primarily in the Middle and Southern Atlantic states and the Gulf states in response to the projected increase in electricity demand. This new construction (almost 117 gigawatts of capacity by the year 2000) represents a high estimate given the financial, technical, and regulatory barriers that utilities currently face in plant siting and construction. Alternatively, it could be interpreted as the derived demand for new capacity in the first decade of the next century; actual plant completions by the year 2000 will probably be substantially less and it is likely that some of this capacity will never be built. Although this projection may overstate the emissions originating from NSPS capacity in 2000, the bias is offset somewhat by the assumption that there will be no retirement of older SIP regulated capacity. To the extent that plant replacements occur, emissions in 2000 will be somewhat lower, and will decline from the predicted 2000 level during the first decade of the 21st century.

Projections of coal production and mining employment mirror these trends. Total coal production is projected to remain at current levels--close to 900 million tons--over the next two years, increasing to nearly 1.3 billion tons annually by 2000. If regional productivity remains constant over the period (as measured in tons per miner-year), then employment in coal mines will gradually increase as well, rising from 193,000 jobs in 1990 to over 275,000 in the year 2000. The regional composition of production and employment in the year 2000 is also affected by the assumptions regarding new plant construction. Production of high-sulfur coals, such as those mined in Illinois, Indiana, Ohio, and Pennsylvania is buoyed by the addition of NSPS capacity that requires scrubbers and is allowed to burn high-sulfur coal.

Since the projection for 2000 probably overstates the ability of utilities to bring such capacity into operation, the production and employment figures for 2000 in predominantly high-sulfur coal regions may best be interpreted as an upper bound for high-sulfur coal demand during the decade beginning in the year 2000.

Results for 1990

The only policy effect captured in the 1990 solution is the precompliance cap, which would constrain overall state emissions to no more than those recorded in 1980. Although the bill allows new emissions from existing sources that exceed this cap to obtain offsets in 1996, for analytical purposes it was assumed that most emissions constrained by the cap would be from sources built in the late 1980s, and that they would have to obtain immediate offsets. The nationwide annual cost of the precompliance cap would reach $300 million (in 1985 dollars) by 1990, and provide an annual emission reduction of 1.7 million tons of SO_2 as measured against the 1990 base case. The average cost of reducing SO_2 would therefore be $173 per ton.

The states affected directly by this restriction in 1990 tend not to be the highest emitters, but those expecting to experience significant growth in electricity demand from 1980 levels and that already have relatively stringent controls in place. For example, under this cap the NCM region encompassing Arkansas, Oklahoma, and Louisiana would reduce 1990 emissions by 235,000 tons at a marginal cost (the cost of reducing the final ton) of $1,600 per ton, while Colorado would emit 42,000 tons of SO_2 less than in the base case, at a marginal cost of nearly $2,300 per ton. These examples illustrate the potential of the precompliance cap to increase the overall cost of the bill if it includes Western and Gulf states which do not contribute greatly to nationwide emissions but--as the bill is written--could be subject to the cap in the early 1990s.

Results for 1995 and 2000

Significant differences between the three simulation policies emerge in the 1995 and 2000 simulations in terms of emissions, costs, and coal-market shifts. The utility cost and coal-market effects of the two target policies illustrate a general trend that characterizes emissions reduction policies in the 12-million-ton range. Previous studies have shown that coal switching is the dominant least-cost abatement technique for emission reduction levels in the 8- to 10-million-ton SO_2 range. Scrubbers become more prevalent

beyond this level of reduction because they are the only method available to attain very low emission rates necessary for many plants. The price of low-sulfur coal also rises in response to the additional demand from plants that attain reductions from switching coal. Sufficient retrofit scrubber capacity is used to achieve the higher abatement levels to protect high-sulfur coal production, but at substantially higher costs per ton of SO_2 removed. Thus, the increased reliance on scrubbers for 10- to 12-million-ton reduction policies shifts much of the overall cost away from high-sulfur coal producers and onto the electric utilities. Interestingly, the default scenario would allow even more high-sulfur coal production, since the uniform 0.9 pound standard vastly reduces the potential for many plants to achieve compliance without resorting to installing a scrubber. In addition, the default scenario restores the base-case level of new plant construction in the year 2000, since emission offsets would not be required.

The utility cost estimates suggest that many states would find the default scenario attractive, especially in comparison with the annual cost of meeting Target 2. However, the precompliance cap could severely limit the potential for Gulf and Western states to achieve cost savings by operating in default, unless their emissions are allowed to exceed their 1980 levels.

Effect on Utility Emissions. Table 2 shows the estimated 1995 utility emissions under the three policies, as well as projected 2000 emissions under the Default Case. Emissions under the two targets remain essentially constant through 2000.

Under Target 1 and Target 2, SO_2 emissions from utilities in 1995 are reduced by 12.9 million tons and 14.3 million tons, respectively, from a projected base-case level of 19.8 million tons. Under the Default Case, annual emissions are reduced by 11.9 million tons in 1995, to a level of 7.9 million tons. Compared to base-case emissions of 21.1 million tons in 2000, Target 1 and Target 2 result in estimated reductions of 14.2 million tons and 15.7 million tons, respectively, by the beginning of the century. Because of emission growth from new sources, estimated emission levels under the Default Case in 2000 are 9.4 million tons, for a reduction of 11.7 million tons from the base-case level. If states subject to the precompliance cap were not allowed to default, their annual emissions for the Default Case would be 7.1 million tons in 1995, rising to 8.0 million tons in 2000. [8]

8. The emission and cost figures for the default case subject to a cap were calculated by substituting Target 2 emission and cost results for the default figures in states whose default emissions exceed 1980 levels. These states were Arizona, Arkansas, Louisiana, Montana, Nevada, and Texas.

TABLE 2. ANNUAL SULFUR DIOXIDE EMISSIONS FROM ELECTRIC UTILITIES IN 1995 AND 2000, BY STATE
(In thousands of tons of SO_2)

	1995				2000 a/	
	Base Case	Target 1	Target 2	Default	Base Case	Default
Alabama, Mississippi	766	318	232	311	756	299
Arizona	135	85	84	128	146	139
Arkansas, Oklahoma, Louisiana	381	101	86	313	587	522
California	34	34	34	34	34	34
Carolinas, North and South	635	425	340	380	666	411
Colorado	123	74	69	123	136	138
Dakotas, North and South	164	69	68	54	192	65
Florida	929	331	298	571	1,009	651
Georgia	1,007	225	202	268	1,037	302
Idaho	0	0	0	0	0	0
Illinois	1,170	359	297	328	1,210	362
Indiana	1,874	360	256	419	1,844	398
Iowa	274	119	82	129	290	143
Kansas, Nebraska	141	91	91	121	168	132
Kentucky	780	231	209	329	781	347
Maine, Vermont, New Hampshire	93	90	32	34	95	36
Maryland, Delaware	469	127	111	244	534	308
Massachusetts, Connecticut, Rhode Island	261	172	163	195	309	244

(Continued)

TABLE 2. (Continued)

	1995				2000 a/	
	Base Case	Target 1	Target 2	Default	Base Case	Default
Michigan	465	293	240	307	482	323
Minnesota	374	90	85	126	340	162
Missouri	1,110	177	170	249	1,159	302
Montana	90	26	20	60	90	60
Nevada	58	40	40	58	89	89
New Mexico	94	64	64	94	95	95
New York (downstate), New Jersey	400	231	156	328	452	380
New York (upstate)	203	141	91	138	256	202
Ohio	2,513	650	413	344	2,687	523
Pennsylvania	1,476	524	422	469	1,473	472
Tennessee	871	259	189	205	961	284
Texas	740	296	241	623	1,093	977
Utah	96	28	24	71	96	71
Virginia, District of Columbia	249	167	106	188	306	239
Washington, Oregon	68	51	38	50	140	122
West Virginia	953	336	270	331	956	328
Wisconsin	644	205	103	159	514	177
Wyoming	126	111	96	109	122	108
Total	19,766	6,900	5,422	7,890	21,105	9,445

SOURCE: Department of Energy National Coal Simulation Model, modified by the Congressional Budget Office.

a. Emissions in 2000 under Target 1 and Target 2 are identical to their 1995 levels.

The Effect on Utility Costs. As shown in Table 3, the estimated annual cost to utilities of Target 1 would be \$6.2 billion in 1995, rising to \$7.9 billion by 2000. Target 2 costs \$8.5 billion annually in 1995, and nearly \$10.7 billion by 2000. The differences in cost between the two targets in 1995 demonstrate that emission reductions in the range stipulated by the bill become expensive: the additional 1.5 million tons of annual SO_2 reduction achieved by Target 2 compared with Target 1 cost an average of \$1,560 per ton. Annual utility costs also increase over the 1995-2000 period for both targets as emission offsets become increasingly expensive to achieve. In rough terms, the annual cost of the postcompliance cap by 2000 is \$1.7 billion for Target 1, and \$2.2 billion for Target 2. In comparison to maintaining these emission caps, the annual cost of the Default Case remains essentially constant--at \$7.3 billion in 1995 and \$7.2 billion in 2000. If the precompliance cap constrains states from defaulting, then the Default Case costs rise to \$8.5 billion in 1995, and \$9.3 billion by 2000.

By 1995, utilities would retrofit 42 gigawatts of capacity with scrubbers under Target 1, 81 gigawatts under Target 2, and 116 gigawatts under the Default Case. An additional 10 gigawatts would be retrofitted by 2000 under Target 1, and 14 under Target 2, while no additional retrofit scrubbers would be required in the Default Case. In the Default Case with the precompliance cap, 123 gigawatts of retrofit scrubbers would be installed on existing capacity.

Since the composition and timing of the utility costs and emission reductions vary significantly among the three policies examined, the researchers calculated an average cost per ton removed over the life of the programs. On average, Target 1 costs \$538 per ton of SO_2 removed, while Target 2 costs \$666 per ton. Under the Default Case, average cost would be \$630 per ton removed; in this case, the potential savings from a more modest reduction in emissions are offset by the relatively less cost-efficient approach of requiring uniform standards. If some states cannot default because of the precompliance cap, the average price of SO_2 removed would rise to \$725 per ton in the Default Case. This substantial increase in average costs under the default with cap scenario is driven by the high marginal costs of SO_2 reduction in the states subject to the cap. For example, the marginal cost of emission reduction under the cap for the Arkansas, Oklahoma, and Louisiana regions is over \$8,000 per ton. In Texas, the marginal cost under the cap is approximately \$5,000 per ton.

Assuming that a 4 percent real discount rate represents the value that utilities attach to postponing expenditures, the present-discounted program costs of Target 1 would be \$84 billion over the period 1990 through 2015, while the cost of Target 2 would be \$114 billion over the same period. The

TABLE 3. NET ANNUAL UTILITY COST OF THREE CASES, BY STATE (In millions of 1985 dollars)

	Net Annual Costs, 1995			Net Annual Costs, 2000		
	Target 1	Target 2	Default	Target 1	Target 2	Default
Alabama, Mississippi	336	515	388	188	325	337
Arizona	39	40	12	67	68	8
Arkansas, Oklahoma, Louisiana	679	778	97	1,070	1,209	126
California	88	99	75	26	29	13
Carolinas, North and South	193	250	382	262	267	391
Colorado	23	38	34	103	106	20
Dakotas, North and South	11	12	26	24	24	30
Florida	212	271	264	381	457	254
Georgia	331	382	431	337	478	486
Idaho	0	0	0	0	0	0
Illinois	251	347	344	343	461	356
Indiana	432	732	630	412	611	627
Iowa	46	140	54	67	143	52
Kansas, Nebraska	35	34	33	56	39	33
Kentucky	275	340	305	364	380	320
Maine, Vermont, New Hampshire	-1	25	33	153	29	32
Maryland, Delaware	197	235	199	60	130	193
Massachusetts, Connecticut, Rhode Island	76	91	77	24	158	77

(Continued)

TABLE 3. (Continued)

	Net Annual Costs, 1995			Net Annual Costs, 2000		
	Target 1	Target 2	Default	Target 1	Target 2	Default
Michigan	340	432	448	239	329	328
Minnesota	71	76	26	-70	159	21
Missouri	338	375	317	446	466	336
Montana	44	51	17	51	55	22
Nevada	16	17	4	78	78	2
New Mexico	74	75	0	28	29	8
New York (downstate), New Jersey	189	300	108	157	90	59
New York (upstate)	54	134	95	53	190	91
Ohio	632	290	505	440	514	556
Pennsylvania	395	506	649	734	1,166	715
Tennessee	110	192	400	250	381	401
Texas	558	720	257	767	923	231
Utah	61	69	10	77	87	19
Virginia, District of Columbia	27	144	160	103	241	135
Washington, Oregon	8	24	9	118	148	21
West Virginia	4	547	747	215	621	732
Wisconsin	84	245	151	261	258	136
Wyoming	-39	-31	-34	18	27	13
Total	6,189	8,495	7,253	7,902	10,676	7,131

SOURCE: Department of Energy National Coal Simulation Model, modified by the Congressional Budget Office.

discounted cost of the Default Case was estimated at $83 billion (without the cap) and $106 billion if the precompliance cap prevented default. [9]

Table 3 displays the net annual utility costs by region for 1995 and 2000 under the three cases. The regional breakdown of utility costs shows clearly that the annual cost of maintaining the targets exceeds the annual cost associated with the default case in many states. [10] For most states in the West the default is less expensive than either target, while many Eastern states would prefer the default compared with Target 2. Target 2, however, may more faithfully express the precompliance cap provision, since the assumption that nonutility sources contribute to required reductions in Target 1 can allow utilities in some states to emit over their 1980 levels, which also occurs in the Default Case. This explains the large costs under the target approach in Arkansas, Oklahoma, Louisiana, and Texas. If the precompliance cap prevents this outcome, then the savings attributed from invoking the default requirements as modelled here might not be realized in these states. However, emission offsets possibly could be secured from nonutility sources in these regions.

The Effect on Regional Coal Production and Employment. Table 4 shows regional coal production in 1995 and 2000, along with actual 1985 shipments to provide comparisons with the current coal market. For 1995, the three cases do not significantly affect the aggregate level of coal produced, which remains close to 1 billion tons, but the policies do affect the regional distribution of mining. Although coal employment levels are correlated directly with production, regional labor intensity varies depending on the

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9. CBO typically uses a 2 percent real rate (representing the riskless rate of government time preference) to compute present values. Under such an assumption, the net present value of costs would rise to $116 billion under Target 1, $158 billion under Target 2, and $114 billion under the Default Case. The last figure would rise to $146 billion if states could not exceed the precompliance cap through default.

10. Two curious results deserve explanation here. The 1995 annual cost of Target 1 in West Virginia is only $4 million, but jumps to $547 million under Target 2. Meanwhile, the $632 million spent in 1995 in Ohio under Target 1 is lowered to $290 million under Target 2. Under Target 1, West Virginia substantially reduces its export of electricity to Ohio--thereby lowering total statewide generating costs sufficiently to cover the cost of abatement. Ohio, on the other hand, is forced to generate more in the Target 1 case, but avoids some generation cost under Target 2 by importing electricity from West Virginia. In terms of generation, these states essentially comprise one region; the sum of annual costs of both states obeys the usual rule that Target 2 is more costly than Target 1. In similar fashion, the New York-New Jersey region reported seperately in the emission and annual cost tables was grouped together to achieve an aggregate SO_2 target. Costs and emissions, therefore, can vary between the two target policies in ways that reflect the composite region, and not individual states.

TABLE 4. ANNUAL COAL PRODUCTION IN 1995 AND 2000, BY COAL-PRODUCING STATE
(In millions of tons)

State	Actual Production 1985	Projected 1995 Coal Production Base Case	Target 1	Target 2	Default	Projected 2000 Coal Production Base Case	Target 1	Target 2	Default
Alabama	27.7	24.4	20.7	22.7	20.3	21.7	20.1	20.8	20.6
Arizona	9.6	16.5	16.5	16.5	16.5	16.5	16.5	16.5	16.5
Colorado	17.2	29.7	48.8	52.6	47.4	58.7	58.1	54.1	59.2
Illinois	59.2	72.1	47.0	51.3	61.9	117.6	89.8	96.8	92.3
Indiana	33.3	26.3	25.4	23.9	23.1	30.2	29.9	28.5	26.4
Iowa	0.6	0.5	0.0	0.1	0.0	1.2	0.2	0.0	0.4
Kansas	1.0	0.4	0.1	0.1	0.4	0.8	0.3	0.1	0.4
Kentucky	149.9	128.5	138.8	127.8	125.2	143.5	138.1	137.0	146.9
Maryland	2.9	5.9	5.6	6.6	6.0	9.0	7.8	8.2	9.0
Missouri	5.6	6.2	5.4	4.7	6.2	8.0	5.5	5.3	8.0
Montana	33.3	34.6	59.9	56.0	68.6	53.8	87.5	82.5	89.1
New Mexico	22.2	23.4	21.8	21.8	24.6	27.9	25.3	25.3	28.1
North Dakota	26.9	16.3	16.0	16.0	16.1	17.9	17.0	17.0	17.1
Ohio	35.4	37.4	15.0	19.4	37.7	74.2	51.6	48.6	72.8
Oklahoma	3.3	5.7	6.3	6.3	5.9	7.9	6.9	5.6	7.8
Pennsylvania	70.3	80.3	57.2	84.0	70.4	127.5	116.6	129.0	121.9
Tennessee	7.3	13.6	13.4	12.8	12.6	15.8	14.9	14.9	14.6
Texas	45.5	70.1	57.3	57.2	78.7	99.0	62.4	57.2	107.2
Utah	12.8	27.8	26.9	28.6	27.7	32.3	34.9	32.2	37.1
Virginia	40.5	36.0	38.4	36.2	36.0	37.6	42.7	40.5	40.5
Washington	4.4	1.5	0.9	0.5	0.5	0.2	0.2	0.2	0.2
West Virginia	127.1	209.0	245.3	223.8	209.8	225.7	254.5	247.7	239.6
Wyoming	140.7	147.3	135.0	131.7	131.4	157.8	150.7	138.3	146.4
Total	876.7	1,013.5	1,001.7	1,000.6	1,027.0	1,284.8	1,231.5	1,206.3	1,302.0

SOURCE: Department of Energy National Coal Simulation Model, modified by the Congressional Budget Office.

mining technique employed. Thus, shifts in the regional distribution of coal production result in net job losses or gains even if total production remains constant. Estimated levels of coal employment under the three cases are presented in Table 5. The effect of the policies on high-sulfur coal is mixed, however. For example, total shipments from Illinois are reduced compared to the 1995 base case under each policy, but shipments are higher under Target 2 than in the case of Target 1, and under the Default would be higher still. In Ohio, the same relative rankings are obtained, but the shipments under the Default Case are actually slightly higher than the base case. These results stem primarily from the level of retrofit scrubbing in each case.

In the year 2000, however, the two target cases significantly lower total coal production as measured against the 2000 base case. By forcing states to seek ever more costly offsets to accommodate new sources, the more stringent Target 2 lowers coal production in 2000 by nearly 80 million tons compared to the base case. This sizable decline in aggregate production occurs as states shift generation--by any way feasible--into gas-fired units to reduce generation from coal-fired capacity. Compared to the base case, where 3.1 quads of gas are consumed (a quad is one quadrillion or 10^{15} Btu), utilities consume 5.1 quads under Target 2, with most of the difference occurring in the Gulf states. This result causes Texas coal production under Target 2 to be less than two-thirds of base-case 2000 production.

TABLE 5. COAL MINING EMPLOYMENT IN 1995 AND 2000, BY COAL-PRODUCING STATE

State	Estimated Number of Jobs, 1985	Projected Number of Jobs, 1995				Projected Number of Jobs, 2000			
		Base Case	Target 1	Target 2	Default	Base Case	Target 1	Target 2	Default
Alabama	8,480	7,470	6,340	6,950	6,210	6,640	6,150	6,370	6,310
Arizona	980	1,690	1,690	1,690	1,690	1,690	1,690	1,690	1,690
Colorado	2,670	4,600	7,570	8,150	7,350	9,100	9,010	8,390	9,180
Illinois	15,410	18,770	12,230	13,350	16,110	30,610	23,380	25,200	24,030
Indiana	5,910	4,660	4,500	4,240	4,100	5,360	5.300	5,050	4,680
Iowa	140	110	0	20	0	270	50	0	90
Kansas	230	90	20	20	90	180	70	20	70
Kentucky	41,290	35,230	38,230	35,200	34,480	39,520	38,040	37,730	40,460
Maryland	720	1,460	1,390	1,630	1,490	2,230	1,930	2,030	2,230
Missouri	1,290	1,430	1,250	1,080	1,430	1,850	1,270	1,220	1,850
Montana	1,100	1,150	1,990	1,860	2,270	1,780	2,900	2,730	2,950
New Mexico	2,130	2,240	2,090	2,090	2,360	2,680	2,430	2,430	2,690
North Dakota	1,300	790	770	770	780	870	820	820	830
Ohio	9,400	9,930	3,980	5,150	10,010	19,710	13,700	12,910	19,340
Oklahoma	950	1,650	1,820	1,700	2,280	1,820	1,990	1,620	2,250
Pennsylvania	22,680	25,900	18,450	27,090	22,710	41,120	37,610	41,610	39,320
Tennessee	2,550	4,740	4,670	4,460	4,400	5,510	5,200	5,200	5,090
Texas	2,770	4,260	3,480	3,480	4,780	6,020	3,790	3,480	6,520
Utah	2,680	5,820	5,640	5,990	5,800	6,770	7,310	6,750	7,770
Virginia	13,410	11,920	12,720	11,990	11,920	12,450	14,140	13,410	13,410
Washington	570	200	120	70	70	30	30	30	30
West Virgnia	41,190	67,730	79,500	72,530	67,990	73,150	82,480	80,280	77,650
Wyoming	4,770	5,000	4,580	4,470	4,460	5,350	5,110	4,690	4,970
Total	182,620	217,030	213,030	214,130	212,210	275,170	264,400	263,660	273,400

SOURCE: Department of Energy National Coal Simulation Model, modified by the Congressional Budget Office.