CURBING ACID RAIN: ALLOCATING SULFUR DIOXIDE CONTROL COSTS UNDER AN EMISSIONS CONTROL PROGRAM

Staff Working Paper
January 1984

Congress of the United States
Congressional Budget Office

NOTES

All dates are expressed in calendar years.

Monetary figures are expressed in various types of dollars, all explicitly identified.

All references to 31 eastern states imply inclusion of the District of Columbia.

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SUMMARY

For many proponents of legislation to control acid rain, a key issue is how to allocate the clean-up costs. Particular concern focuses on the costs of controlling emissions of sulfur dioxide (SO_2), a key source of the problem. Roughly two-thirds of the nation's SO_2 emissions come from electric power plants, so control measures tend to concentrate on these sources. Though acid rain affects a broad region--much of the eastern half of the nation--the suspected origin lies largely in the Midwest, the site of many older power plants burning coal with a moderate to high sulfur content. Two questions therefore are central to the debate: **Should parties responsible for the emissions (the Midwestern states and electricity consumers in them) pay the entire cost of the clean-up?** Or, on the other hand, **Should clean-up costs be spread more evenly throughout the region affected, since it is the entire region that would enjoy the benefits of curbed SO_2 emissions?**

THE BASE PLAN

One proposed approach to covering at least part of the costs of reducing SO_2 emissions is a trust fund financed by a fee on electricity generated by existing coal-, oil-, and gas-fired power plants. This plan

serves as the base case in the Congressional Budget Office's analysis. Fee receipts would be used to reimburse part of the expense to utility firms of reducing SO_2 emissions by eight million tons per year, roughly one-half the volumes emitted by eastern utilities in 1980 (the last year of complete data most often used). The fee would begin in 1985 at 1 mill per kilowatt-hour and would rise to 3 mills per kilowatt-hour in 1987, staying at that level until expiring in 1999. Trust fund outlays would reimburse 90 percent of the capital and 50 percent of the operating cost of the emissions control equipment (most commonly, "scrubbers") over the 1996-2005 period. (Capital expenses also would be reimbursed over the 1992-1996 construction period.)

Emissions reductions would start in 1996 and would apply throughout the eastern-most 31 states (including the District of Columbia). Annual utility emissions of SO_2 would be reduced by the requisite eight million tons as a result of a mandate that all existing power plants not exceed an emission level of 1.5 pounds of SO_2 per million British thermal unit (Btu) of fuel consumed. Compliance would require installation of scrubbers or other comparable equipment, and to protect employment in the midwestern coal-production industry, would not allow switching to lower-sulfur-content fuels. (Though switching to low-sulfur fuels can often be a cost-effective strategy, it can shift coal-production patterns from areas producing high-sulfur coal to areas producing a low-sulfur coal, generally a shift from east to west.

This affects employment in the mining industry. With control technology required instead, coal-market employment would be little affected.)

ANALYSIS

Analysis of this plan points to several conclusions. With current scrubber technology, meeting a uniform SO_2 emissions limit on all power plants of 1.5 pounds per million Btu by 1996 would entail an average annual cost of roughly $2.4 billion (in 1983 dollars) and a total cost of roughly $33 billion over the 1992-2005 period. (Without the cost reallocation scheme embodied in the fee/trust fund plan, most midwestern and some southern states would bear the majority of program expense.) Using the revenues of $28 billion (in 1983 dollars) from a regionally imposed electricity fee instead, however, would redistribute the program's expense (see Summary Table, first two columns). States with high emissions control costs--the Midwestern states --would receive more from the fund than they paid. States with low costs--most New England and some southern states--would pay more than they received.

The program's highest annual cost would begin in 1996, and in most cases, the maximum effect on electricity prices also would occur that year. With a fee system, no state would experience a rise in electricity prices

SUMMARY TABLE. PERCENT INCREASES IN 1996 ELECTRICITY PRICES ATTRIBUTABLE TO DIFFERENT SO_2 EMISSIONS CONTROL AND FEE PROGRAMS, BY STATE (In percent increases)

State	Control Program with Electricity Fee (Base Case) a/	Control Program Without Fee b/	Control Program with Emissions Trading c/	Control Program with Emissions Growth Offsets d/	Control Program with Emissions Fee e/
Alabama	2.3	3.1	1.9	3.8	2.1
Arkansas	1.8	0.0	1.5	3.1	0.2
Connecticut	0.8	0.2	0.7	1.3	0.2
Delaware	1.2	0.0	1.0	2.0	0.7
District of Columbia	2.3	2.2	1.9	3.8	0.8
Florida	1.6	1.4	1.2	2.7	1.2
Georgia	2.5	3.3	2.0	4.1	2.7
Illinois	2.0	2.8	1.7	4.2	2.1
Indiana	4.0	8.0	3.4	6.0	5.2
Iowa	2.6	4.4	2.1	5.3	2.6
Kentucky	3.3	4.4	2.7	4.6	4.1
Louisiana	1.7	0.0	1.4	3.0	0.1
Maine	1.1	0.3	0.9	1.8	0.3
Maryland	2.0	1.9	1.6	3.2	1.4
Massachusetts	1.0	0.3	0.8	1.5	1.0
Michigan	2.0	1.8	1.6	4.3	1.6
Minnesota	2.2	3.1	1.5	3.9	1.8
Mississippi	2.4	3.2	2.0	3.9	1.6
Missouri	4.5	9.7	3.5	9.0	6.0
New Hampshire	1.0	0.3	0.8	1.5	1.4
New Jersey	1.4	1.4	1.1	2.3	0.6
New York	0.8	0.8	0.6	1.0	0.6
North Carolina	1.7	1.3	1.2	2.9	1.3
Ohio	3.1	5.4	2.5	4.5	3.9
Pennsylvania	1.7	1.6	1.3	2.7	2.1
Rhode Island	1.0	0.3	0.8	1.6	0.2
South Carolina	1.6	1.3	1.2	2.8	1.1
Tennessee	3.1	4.2	2.5	3.8	3.8
Vermont	1.1	0.3	0.9	1.7	0.1
Virginia	1.5	1.2	1.1	2.6	0.8
West Virginia	3.3	4.4	2.8	5.5	3.3
Wisconsin	3.6	8.2	3.0	6.8	4.1

SOURCE: Congressional Budget Office.

NOTES: By 1996, all options would require an eight-million-ton annual reduction in SO_2 emissions from 1980 level. Maximum price increases mostly occur in 1996, the first year of maximum program cost, although states that have low control costs may actually experience their peak prices in 1992.

a. Includes a 3 mill per kilowatt-hour graduated fee.
b. Costs of emissions control program without fee.
c. Involves a strategy of using the least-expensive emission reductions first.
d. Includes cost of reducing an additional 2.4 million tons of SO_2 per year to compensate for increase between 1985 and 1996.
e. Involves a graduated $223 per ton fee on 1980 SO_2 emissions from electric utilities.

of more than 4.5 percent that year. Without the fee, in contrast, the same emissions reduction plan could raise prices by almost 10 percent in the Midwest. The total cost of the control program would be the same in either case, since electricity demand is not assumed to rise or fall as a result of the price changes attributable to different programs analysed.

ANALYSIS OF VARIATIONS

The analysis also explored the effects of several modifications to the base case plan:

- Whether program costs would be lowered by allowing more flexible emissions reduction schemes,
- Whether they would rise if further reductions were mandated to offset increases in pollution levels over time, and
- Whether a fee specifically on SO_2 emissions, instead of on power generation, would similarly reallocate costs among states.

For one test, the base case program was modified to allow emissions reduction "trading"--substituting low-cost emissions reductions for high-cost ones within a state to achieve the same net emissions reduction as the original eight-million-ton plan. Each state would still meet its share of the eight-million-ton emissions reduction, but some plants would be controlled beyond the limit of 1.5 pound SO_2 per million Btu while others would be

permitted to meet a more relaxed standard.The CBO found that such an approach would lower total costs from $33 billion to $25 billion (in 1983 dollars), could lower the fee starting in 1987 from 3.0 to 2.5 mills per kilowatt-hour, and would limit overall electricity price increases throughout the region in 1996 to 3.5 percent.

In contrast, costs would rise if the program were designed both to attain the original eight-million-ton SO_2 reduction and to hold that level through 1996, despite any additional emissions increase that might occur. By 1996, roughly 2.4 million tons of SO_2 emissions might be added each year to the 31-state region from power generation and industrial growth. Maintaining the original eight-million-ton figure would raise total program costs from $33 billion to $54 billion (in 1983 dollars) and would require a 5 mills per kilowatt-hour fee starting in 1987 to cover the increase. Though the fee would still reallocate costs among eastern states, aggregate electricity prices could rise by as much as 9 percent in 1996, the first year of maximum program cost.

Finally, applying a charge on SO_2 emissions to raise the same $28 billion (in 1983 dollars) as would the 3.0 mill per kilowatt-hour fee would also redistribute costs, but by less than would the electricity fee. By charging utilities in each state $223 per ton of SO_2 emitted in 1980 (instead of the 3 mill electricity fee) and holding such revenue levels constant,

roughly the same amount of money could be raised as in the base case program. But the effect on cost reallocation would be different. In the Midwest, statewide electricity prices could rise by as much as 6 percent in 1996, compared to 4.5 percent under the electricity fee, since states with relatively few emitters (a few New England and some southern states) would contribute less to the fund. Such an approach would be closer to the "polluter pays" principle, embodied in an eight-million-ton SO_2 reduction program without a fee or cost reallocation scheme (Summary Table, column 2).

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PART I. THE ACID RAIN TRUST FUND CONCEPT

A prominent issue in the Congress' deliberations over the Clean Air Act concerns the design of a program to control "acid rain." Most proponents of acid rain legislation are calling for reductions in sulfur dioxide (SO_2) and in some cases nitrogen oxide (NO_x) emissions, since these compounds are known precursors to acid deposition particles. This paper examines several approaches to assigning control costs to show how an electricity or emissions fee used to pay for control would allocate clean-up expenses. 1/

Because electric utilities that burn fossil fuels (oil, gas, and coal) are responsible for roughly two-thirds of all SO_2 and one-third of all NO_x emissions, proposed control programs have focused mainly on these sources. Acid rain control legislation submitted to the Congress over the past year tend to concentrate on SO_2. Such bills typically stipulate that annual SO_2 emissions in the eastern half of the United States be reduced by eight and 12 million tons below levels now allowed under current law. This represents

1. The effectiveness of an emission control program in abating acid deposition is not examined. For further information on the relationship of pollutant emissions and acid rain deposition, see Office of Technology Assessment, Acid Rain and Transported Air Pollutants: Implications for Public Policy (forthcoming).

SO_2 reductions of roughly one-half to two-thirds in utility emissions from levels recorded in 1980, the last year of complete record most often used.

Though the acid rain problem is generally recognized to be a broadly regional one affecting most of the eastern half of the United States, control proposals tend primarily to affect the Midwest, the site of the most numerous emitters believed responsible for the problem. Thus, most control programs would impose the highest clean-up expenses on the Midwest, since they would require parties responsible for the emissions to pay for control. This reflects the "polluter pays" principle common to many U.S. environmental laws. Seeking ways to allocate costs differently throughout the region affected, the debate has shifted to developing cost-sharing alternatives. 2/

One such option would involve creating a federal trust fund financed by a fee imposed on electricity fee generated throughout the eastern-most 31 states (plus the District of Columbia). The fund would be used to reimburse part of the utilities' costs for installing control equipment (most commonly, "scrubbers," the one fully demonstrated technology) on the applicable sources. This approach would allocate costs differently from the

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2. Several proposals recently calling for such allocation schemes have been submitted. For example, see H.R. 3400 (introduced by Congressman Sikorski), S.R. 2001 (introduced by Senator Durenburger), and statements by Senator Glenn in the U.S. Senate, April 14, 1983.

"polluter pays" scheme, since the fund would transfer revenues collected from areas with few emitters within the region to areas with many emitters. By spreading costs among all states, however, it would limit the maximum cost burden on any one state. Moreover, by requiring installation of emissions control hardware rather than allow fuel switching from relatively high-sulfur coals commonly burnt in the Midwest to low-sulfur coals, a secondary goal of the plan would be to prevent employment losses in the Midwest, where much high-sulfur coal is produced. [3]

Use of an electricity fee to reallocate costs of a regional emissions control program is a recent development, although it has a similar precedent in the nuclear waste trust fund. In December 1982, the Congress established this fund to help pay for the disposal of radioactive waste residues from nuclear power generation. (The nuclear waste legislation imposes a 1 mill per kilowatt-hour fee on power generated by nuclear plants, and monies in

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3. The sulfur content of U.S. coal deposits tends to coincide with region: most low-sulfur coal is found in the West, most high-sulfur coal in the Midwest, and the East contains a mixture of both. Unless limited by regulation, schemes calling for substantial reduction in SO_2 emissions from utilities most likely would involve substantial shifts from high-sulfur coal use, with an attendant loss of employment in the high-sulfur-coal-producing Midwest. Although fuel-switching can be a cost-effective alternative, this analysis assumes that an emission control plan and cost reallocation scheme would be established to help subsidize pollution control equipment, and not fuel-switching. For more information on coal markets, see Congressional Budget Office, The Clean Air Act, the Electric Utilities and the Coal Market (April 1982). For information on potential employment effects of acid rain control programs, see Office of Technology Assessment, Acid Rain and Transported Air Pollutants.

the fund are used to establish and maintain disposal facilities for the nuclear power industry.) The two funds would differ in approach, however: parties paying into the nuclear waste fund do so in proportion to the benefits they receive, whereas an acid rain trust fund, as described in Part II, would reallocate benefits by transfering money from low polluters to high polluters.

For the purpose of analysis, the Congressional Budget Office developed a base case program for curbing SO_2 emissions and tested the effects of that hypothetical plan against several variants. The base case and results of analysis of it are presented in Part II. Alternatives and comparisons are reviewed in Parts III-V. An Appendix summarizes CBO's analytic assumptions and method.

PART II. THE BASE CASE PROGRAM

The Congressional Budget Office's base case program has three components:

- o A sulfur dioxide control program stipulating use of emissions control technology,
- o A temporary electricity fee and federal trust fund system, and
- o A reimbursement program for defraying the costs to the utilities of emissions control.

MECHANICS OF THE PROGRAM

By 1996, emissions control under the base case program would reduce annual total SO_2 emissions in the area affected by roughly eight million tons from recorded 1980 levels. All fossil-fuel-fired power plants in the 31 states bordering on and east of the Mississippi River would be involved. The eight-million-ton reduction would be achieved by requiring all operating power plants to meet a maximum emissions level for SO_2 of 1.5 pounds per million British thermal unit (Btu), except for those plants built under the most recent standards promulgated under the Clean Air Act, the New

Source Performance Standards of 1978.[4] Most of the reduction burden would fall on coal-fired power plants built before 1980, since the 1978 standards have much stricter emission limits, and other non-coal plants typically emit much less SO_2.

The Trust Fund and the Fee. A trust fund, supported by a fee on electricity generation, would be established to help pay the program's costs. The fee would apply to all electricity generated from oil-, gas-, and coal-fired power plants not meeting the 1978 standards. The fee would be 1 mill per kilowatt-hour in 1985, 2 mills in 1986, and 3 mills in 1987; it would stay at that level, unadjusted for inflation, until expiring at the end of 1999. Receipts would go to the trust fund, earning annual interest, until expiring at the end of the year 2005, six years after the fee expired.

Reimbursement. Each year between 1992 and 2005, trust fund receipts would go to reimburse firms' capital costs for compliance with the program's emission regulations. (The assumed method of compliance is installation of control equipment--probably SO_2 scrubbers. In practice, it would probably be necessary to allow alternate methods of compliance--such as fuel switching--for the few power plants unable to install control

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4. The 1978 standards require between 70 and 90 percent SO_2 removal (using scrubbers) and limit emissions from new power plants to levels below 1.2 pounds per million Btu. See The Clean Air Act, The Electric Utilities, and the Coal Market, Chapter II.

equipment for technical reasons or only at excessive cost.) Reimbursements for capital expenses, disbursed after approval of applications, would begin in 1992 to cover construction through 1996, the year when control limits would take effect. Capital, interest, and depreciation on control hardware would be amortized over the 14-year period, and 90 percent of this amortization would be reimbursed each year. Part of the operating expenses would also be reimbursed, starting in 1996 and ending in 2005; each year for ten years, 50 percent of the first-year operating costs would be reimbursed as equal payments (not adjusted for inflation).

How the trust fund might be managed is open to question. The scenario used in this analysis calls for fee revenues to be collected by the federal government, with an agency, such as the Treasury, responsible for managing the trust. States would be responsible for most of reimbursement activities, however. The federal government would pass the necessary money from the fund to the states at the beginning of each year, starting in 1992 and continuing through 2005. Each state would review the capital reimbursement applications and determine an annual budget for covering 90 percent of their value; likewise, the states would also determine the necessary budget to cover 50 percent of annual operating costs. Once payments to the utilities began, the amounts for capital and operating expenses would not change (unless the utility stopped operating its control equipment). The Environmental Protection Agency could have oversight

authority over all requests, and could be empowered to alter payments if a reimbursement request did not fall within a reasonable bound of cost, or if the applying utility failed to comply.

RESULTS OF THE ANALYSIS

The base case program would require SO_2 emissions reductions in 26 of the 31 states (see Table 1, fourth column). The cost of the program, measured in constant 1983 dollars, would total roughly \$33 billion over the 1992-2005 period and would average \$2.4 billion each year. To pay for 90 percent of the capital and 50 percent of the operating costs, annual payments from the fund would run \$3.3 billion (in nominal dollars) over the 1992-1995 period and would rise to \$4.9 billion (in nominal dollars) after 1995 (see Table 2).

As shown in the first column of Table 2, annual fee revenues to the trust fund would fall slightly after 1987 because of declining electricity production from the plants paying the fee. Payouts for capital charges would start in 1992 and for operating charges in 1996. Both capital and operating cost reimbursements would end in 2005. The payments for capital costs shown in Table 2 are based on the projected nominal cost of the

TABLE 1. UTILITY PLANT SO_2 EMISSION REDUCTION REQUIREMENTS AND COSTS OF THE BASE CASE ACID RAIN CONTROL PROGRAM, BY STATE

State	In Thousands of Tons of SO_2 Per Year: 1980 Utility Emissions (Baseline)	Required Reductions	SO_2 Emissions After Controls	Percent Reduction
Alabama	543	209	334	38
Arkansas	27	0	17	0
Connecticut	32	0	32	0
Delaware	53	11	29	21
District of Columbia	5	0	5	0
Florida	726	247	479	34
Georgia	737	353	384	48
Illinois	1,126	656	470	58
Indiana	1,540	1,010	529	66
Iowa	231	108	123	47
Kentucky	1,008	586	421	58
Louisiana	25	0	25	0
Maine	16	1	15	6
Maryland	223	77	146	35
Massachusetts	276	67	209	24
Michigan	565	178	388	32
Minnesota	177	44	133	25
Mississippi	129	58	71	45
Missouri	1,141	776	364	68
New Hampshire	81	38	42	47
New Jersey	110	27	83	25
New York	480	161	319	34
North Carolina	435	18	418	4
Ohio	2,172	1,350	822	62
Pennsylvania	1,466	655	811	45
Rhode Island	5	0	5	0
South Carolina	213	64	149	30
Tennessee	934	554	380	59
Vermont	1	0	1	0
Virginia	164	6	157	4
West Virginia	944	470	474	50
Wisconsin	486	293	193	60
Total	16,071	8,017	8,028	50

SOURCE: Congressional Budget Office and E.H. Pechan and Associates, Incorporated.

NOTES: Emission reductions based on each state's meeting 1.5 pound SO_2 emission limit per million Btu on all power plants.

TABLE 2. PROFILE OF THE TRUST FUND UNDER THE BASE CASE PROGRAM, 1985-2005 (In millions of nominal dollars, inflation adjusted)

Year	Fee Revenues	Reimbursements from Fund	Interest on Fund Balance	End-of-Year Balance a/
1985	1,217	0	0	1,191
1986	2,410	0	93	3,665
1987	3,578	0	291	7,504
1988	3,543	0	598	11,613
1989	3,507	0	926	16,013
1990	3,472	0	1,278	20,728
1991	3,437	0	1,655	25,783
1992	3,403	3,325	1,790	27,572
1993	3,369	3,325	1,936	29,510
1994	3,335	3,325	2,091	31,567
1995	3,302	3,325	2,256	33,752
1996	3,269	4,907	2,304	34,366
1997	3,236	4,907	2,352	34,994
1998	3,204	4,907	2,402	35,637
1999	3,172	4,907	2,454	36,295
2000	0	4,907	2,506	33,830
2001	0	4,907	2,308	31,164
2002	0	4,907	2,095	28,280
2003	0	4,907	1,864	25,161
2004	0	4,907	1,614	21,787
2005	0	4,907	1,344	18,138

SOURCE: Congressional Budget Office.

NOTES: To reduce emissions from 1980 levels by roughly eight million tons per year, the program would impose a maximum emission rate of 1.5 pounds of SO_2 per million Btu on all power plants. Revenues based on 1 mill per kilowatt-hour fee in 1985, 2 mills per kilowatt-hour fee in 1986, and 3 mills per kilowatt-hour fee in 1987 through 1999 on electricity generated by coal, oil, and gas. Assumed annual interest rate is 8 percent for both the fund and capital.

a. Equals remaining balance, including interest from start of year after withdrawal of reimbursements and administrative expenses, plus fee revenues accruing at end of year.

control equipment in 1992, and payments for operating expenses are projected on the basis of costs in 1996, the first year of the emissions control program. In all cases, a 6 percent inflation rate is assumed.

At the end of the trust fund's lifetime, $4.7 billion in 1983 dollars (roughly $18 billion, as shown in Table 2, in nominal dollars) would remain. This money could either be returned to the Treasury, reimbursed to contributors to the fund, or distributed among reimbursement payees. 5/

State contributions to the fund from utilities (shown in Table 3) would total $28 billion (in 1983 dollars); reimbursements back to the states to pay for clean-up costs would come to $25 billion (also in 1983 dollars). Less money would be returned to the states than was collected from them, as the fund would produce a surplus, and administration and overhead expenses would be withdrawn from fee collections. The third column of Table 3 shows the total amount each state would have to pay for the emissions control program, with or without the fee. The fourth column indicates the net costs of the program to each state. Throughout the area affected, the program itself would cost roughly $33 billion (1983 dollars) over the 1992-2005 period; with the fee-supported trust fund, it would cost $36

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5. For the purposes of this analysis, values other than whole and one-half mills were not used as fees. Minor adjustments to the fee could be made over the fee collection period of the program to avoid a surplus, although at some risk of a shortfall.

TABLE 3. STATE-BY-STATE TRUST FUND POSITIONS UNDER BASE CASE PROGRAM (In millions of 1983 dollars)

State	Amount Paid to Fund	Amount Received from Fund	Cost of Emission Control Program	Distribution of Costs with Fee a/
Alabama	1,067	969	1,313	1,412
Arkansas	431	0	0	431
Connecticut	328	45	58	341
Delaware	155	0	0	155
District of Columbia	77	43	58	92
Florida	1,823	923	1,199	2,099
Georgia	1,084	984	1,334	1,434
Illinois	1,742	1,753	2,294	2,284
Indiana	1,618	3,030	3,921	2,509
Iowa	422	566	736	592
Kentucky	1,251	1,151	1,500	1,600
Louisiana	859	0	0	859
Maine	127	18	23	132
Maryland	689	383	514	820
Massachusetts	516	71	92	536
Michigan	1,336	648	896	1,584
Minnesota	482	483	666	665
Mississippi	493	448	607	653
Missouri	1,119	2,476	3,182	1,824
New Hampshire	93	13	17	97
New Jersey	914	508	681	1,087
New York	1,458	777	1,053	1,734
North Carolina	1,029	449	599	1,179
Ohio	2,495	3,704	4,813	3,604
Pennsylvania	1,838	1,022	1,369	2,185
Rhode Island	79	11	14	82
South Carolina	601	262	350	688
Tennessee	1,175	1,089	1,436	1,521
Vermont	62	9	11	64
Virginia	779	340	454	893
West Virginia	1,625	1,448	1,933	2,111
Wisconsin	600	1,554	1,998	1,044
Total	28,369	25,178	33,120	36,311

SOURCE: Congressional Budget Office.

NOTES: To reduce emissions from 1980 levels by roughly eight million tons per year, the program would impose a maximum emission rate of 1.5 pounds of SO_2 per million Btu on all power plants. Revenues based on 1 mill per kilowatt-hour fee in 1985, 2 mills per kilowatt-hour fee in 1986, and 3 mills per kilowatt-hour fee in 1987 through 1999 on electricity generated by coal, oil, and gas. Assumed annual interest rate is 8 percent for both the fund and capital.

a. Equals sum of columns one plus three minus column two, except for minor differences caused by rounding.

billion (1983 dollars)--roughly $3 billion more. If the trust fund surplus were returned to the states, the fee/trust fund program would appear to cost slightly less than a control-alone program, because of the timing of investment. The trust fund would generate interest income for several years before being used.

Distributional and Price Effects. The fee/trust fund system would redistribute program costs over the 31-state region, departing from the "polluter pays" principle. Typically, high-emission states bearing a large share of the clean-up program (Ohio, Indiana, and Missouri) would receive more from the fund than they paid, while other states (Florida, North Carolina, Lousiana, and most New England states) would pay more than they received. Thus, the fee/trust fund system would transfer revenues from many northern and some southern states to the Midwest (as shown in column 2 of Table 3).

The most trivial effect on electricity prices would occur in 1985, the only year in which the fee was 1 mill per kilowatt-hour (see Tables 4 through 6, illustrating 1985, 1992, and 1996). The largest price increases typically would occur in 1996, the first year of the full control program. 6/ The first column of each table shows the expected price increase of the entire

6. For reference, each mill of extra charge adds roughly 75 cents (in nominal value) to a residential electricity consumer's monthly bill.

TABLE 4. EFFECT OF ENERGY FEE ON 1985 ELECTRICITY PRICES UNDER BASE CASE PROGRAM, BY STATE
(In nominal mills per kilowatt-hour)

State	Average Program Cost Across All Types of Electricity in State	Projected 1985 Electricity Rates Without Program a/	Percent Rate Increase Attributable to Program
Alabama	0.8	64.2	1.2
Arkansas	0.9	57.2	1.6
Connecticut	0.7	103.5	0.7
Delaware	1.1	103.1	1.0
District of Columbia	0.9	60.1	1.5
Florida	0.9	82.4	1.1
Georgia	0.8	59.7	1.3
Illinois	0.8	73.7	1.1
Indiana	1.1	64.7	1.7
Iowa	0.9	71.5	1.3
Kentucky	1.0	55.7	1.8
Louisiana	0.9	60.8	1.5
Maine	0.7	78.4	0.9
Maryland	0.9	70.1	1.2
Massachusetts	0.7	90.4	0.8
Michigan	0.8	66.9	1.2
Minnesota	0.7	66.4	1.1
Mississippi	0.8	61.9	1.2
Missouri	1.1	61.8	1.7
New Hampshire	0.7	89.2	0.8
New Jersey	0.9	99.1	0.9
New York	0.6	122.4	0.5
North Carolina	0.8	67.4	1.1
Ohio	1.1	75.3	1.4
Pennsylvania	0.9	83.6	1.0
Rhode Island	0.7	87.4	0.8
South Carolina	0.8	68.5	1.1
Tennessee	0.9	53.3	1.7
Vermont	0.7	80.4	0.9
Virginia	0.8	74.2	1.0
West Virginia	1.1	60.3	1.8
Wisconsin	0.7	59.9	1.2

SOURCE: Congressional Budget Office.

NOTES: The emissions control program imposes a maximum emission rate of 1.5 pounds of sulfur dioxide per million Btu on all power plants to reduce emissions roughly 8 million tons from 1980 levels. Revenues based on 1 mill per kilowatt-hour fee in 1985, 2 mills per kilowatt-hour fee in 1986, and 3 mills per kilowatt-hour fee in 1987 through 1999 on electricity generated by coal, oil, and gas. The assumed interest rate is 8 percent per year for both the fund and capital.

a. Based on 1982 average electricity prices recorded by the Department of Energy, adjusted by an assumed 6 percent inflation rate.

TABLE 5. EFFECT OF ENERGY FEE ON 1992 ELECTRICITY PRICES UNDER BASE CASE PROGRAM, BY STATE
(In nominal mills per kilowatt-hour)

State	Average Program Cost Across All Types of Electricity in State	Projected 1992 Electricity Rates Without Program a/	Percent Rate Increase Attributable to Program
Alabama	2.1	96.6	2.1
Arkansas	2.2	86.1	2.6
Connecticut	1.8	155.7	1.1
Delaware	2.6	155.0	1.7
District of Columbia	2.3	90.3	2.5
Florida	2.3	123.9	1.8
Georgia	2.1	89.7	2.3
Illinois	2.1	110.8	1.9
Indiana	3.2	97.3	3.3
Iowa	2.6	107.5	2.4
Kentucky	2.3	83.8	3.3
Louisiana	2.2	91.5	2.4
Maine	1.8	117.8	1.5
Maryland	2.3	105.3	2.1
Massachusetts	1.8	135.9	1.3
Michigan	2.1	100.6	2.1
Minnesota	1.9	99.9	1.9
Mississippi	2.1	93.1	2.2
Missouri	3.3	92.9	3.5
New Hampshire	1.8	134.1	1.3
New Jersey	2.3	149.0	1.5
New York	1.6	184.1	0.9
North Carolina	1.9	101.4	1.9
Ohio	3.0	113.2	2.7
Pennsylvania	2.3	125.7	1.8
Rhode Island	1.8	131.5	1.3
South Carolina	1.9	103.0	1.9
Tennessee	2.4	80.2	3.0
Vermont	1.8	120.9	1.5
Virginia	1.9	111.5	1.7
West Virginia	2.9	90.7	3.2
Wisconsin	2.4	90.1	2.6

SOURCE: Congressional Budget Office.

NOTES: The emissions control program imposes a maximum emission rate of 1.5 pounds of sulfur dioxide per million Btu on all power plants to reduce emissions roughly 8 million tons from 1980 levels. Revenues based on 1 mill per kilowatt-hour fee in 1985, 2 mills per kilowatt-hour fee in 1986, and 3 mills per kilowatt-hour fee in 1987 through 1999 on electricity generated by coal, oil, and gas. The assumed interest rate is 8 percent per year for both the fund and capital.

a. Based on 1982 average electricity prices recorded by the Department of Energy, adjusted by an assumed 6 percent inflation rate.

TABLE 6. EFFECT OF ENERGY FEE ON 1996 ELECTRICITY PRICES UNDER BASE CASE PROGRAM, BY STATE
(In nominal mills per kilowatt-hour)

State	Average Program Cost Across All Types of Electricity in State	Projected 1996 Electricity Rates Without Program a/	Percent Rate Increase Attributable to Program
Alabama	2.8	121.9	2.3
Arkansas	2.0	108.7	1.8
Connecticut	1.7	196.5	0.8
Delaware	2.3	195.7	1.2
District of Columbia	2.6	114.0	2.3
Florida	2.5	156.5	1.6
Georgia	2.8	113.3	2.5
Illinois	2.8	140.0	2.0
Indiana	5.0	122.9	4.0
Iowa	3.6	135.8	2.6
Kentucky	3.5	105.8	3.3
Louisiana	2.0	115.5	1.7
Maine	1.7	148.8	1.1
Maryland	2.6	132.9	2.0
Massachusetts	1.7	171.6	1.0
Michigan	2.5	127.0	2.0
Minnesota	2.8	126.1	2.2
Mississippi	2.8	117.5	2.4
Missouri	5.3	117.3	4.5
New Hampshire	1.7	169.3	1.0
New Jersey	2.6	188.1	1.4
New York	1.9	232.4	0.8
North Carolina	2.1	128.0	1.7
Ohio	4.4	142.9	3.1
Pennsylvania	2.6	158.6	1.7
Rhode Island	1.7	166.0	1.0
South Carolina	2.1	130.0	1.6
Tennessee	3.1	101.2	3.1
Vermont	1.7	152.6	1.1
Virginia	2.1	140.8	1.5
West Virginia	3.8	114.5	3.3
Wisconsin	4.1	113.7	3.6

SOURCE: Congressional Budget Office.

NOTES: The emissions control program imposes a maximum emission rate of 1.5 pounds of sulfur dioxide per million Btu on all power plants to reduce emissions roughly 8 million tons from 1980 levels. Revenues based on 1 mill per kilowatt-hour fee in 1985, 2 mills per kilowatt-hour fee in 1986, and 3 mills per kilowatt-hour fee in 1987 through 1999 on electricity generated by coal, oil, and gas. The assumed interest rate is 8 percent per year for both the fund and capital.

a. Based on 1982 average electricity prices recorded by the Department of Energy, adjusted by an assumed 6 percent inflation rate.

program averaged over all types of electricity used in each state; these costs would approximate the average price rise consumers in each state would experience for the year shown. The second columns show the projected yearly electricity rates without the program. The third columns show the percentage increases resulting from the new charge.

In 1985, as Table 4 shows, while the fee was set at only 1 mill per kilowatt-hour, the resulting change in electricity prices would not exceed 2 percent in any state. In 1992, electricity prices would rise further, as construction costs for the control equipment entered the rate base of electricity charges. But the highest aggregate costs for the program would be experienced in 1996, the first year that both capital and operating expenses would be charged (see Table 5). In that year, electricity costs in some midwestern states could rise by as much as 4.5 percent (Missouri). Such price effects would decline over time, since the relative effect of emissions control costs on inflated future electricity prices would diminish. By the year 2000, the expected price increase for Missouri, for example, would be less than 2 percent. 7/

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7. It should be noted that the peak electricity price for some states having low emissions reduction costs--such as Arkansas, Connecticut, and Florida--would occur in 1987. Because most states would also bear pollution control costs, which reach their peak starting in 1996, most states would also experience their highest electricity price rises in 1996. Those states that primarily pay only the electricity fee would have lower price increases in 1996, however, since the fee would stay the same and the nominal underlying electric rates would be higher.

To understand how the fee system would redistribute SO_2 control costs, Table 7 shows the effect in 1992 and 1996 of the eight-million-ton annual emissions reduction without the offsetting fees and reimbursements. Though the fee would not affect the total cost of compliance, the distribution of costs would be uneven: midwestern states would experience electricity price increases up to 9.7 percent in 1996 without the fee, compared to 4.5 percent with it (as shown in Table 6). Some southern and most New England states, however, would have smaller price increases without the fee. For example, 1996 electricity prices in Louisana and Maine would increase 1.7 and 1.1 percent, respectively, under the fee program, but only 0 and 0.3 percent without the fee.

TABLE 7. EFFECT OF SO_2 CONTROL PROGRAM WITHOUT FEE ON 1992 AND 1996 ELECTRICITY PRICES
(In nominal mills per kilowatt-hour)

State	1992 Average Program Cost Across All Types of Electricity in State	Percent Increase for 1992 Attributable to Program	1996 Average Program Cost Across All Types of Electricity in State	Percent Rate Increase for Year 1996 Attributable to Program
Alabama	1.9	2.0	3.8	3.1
Arkansas	0.0	0.0	0.0	0.0
Connecticut	0.3	0.2	0.5	0.2
Delaware	0.0	0.0	0.0	0.0
District of Columbia	1.4	1.5	2.6	2.2
Florida	1.4	1.1	2.2	1.4
Georgia	1.9	2.2	3.8	3.3
Illinois	2.4	2.1	4.0	2.8
Indiana	6.1	6.3	9.8	8.0
Iowa	3.7	3.4	6.0	4.4
Kentucky	2.8	3.4	4.7	4.4
Louisiana	0.0	0.0	0.0	0.0
Maine	0.3	0.3	0.5	0.3
Maryland	1.4	1.3	2.6	1.9
Massachusetts	0.3	0.2	0.5	0.3
Michigan	1.1	1.1	2.2	1.8
Minnesota	1.9	1.9	4.0	3.1
Mississippi	1.9	2.1	3.8	3.2
Missouri	7.3	7.8	11.4	9.7
New Hampshire	0.3	0.2	0.5	0.3
New Jersey	1.4	0.9	2.6	1.4
New York	0.9	0.5	1.8	0.8
North Carolina	0.9	0.9	1.7	1.3
Ohio	4.7	4.2	7.8	5.4
Pennsylvania	1.4	1.1	2.6	1.6
Rhode Island	0.3	0.2	0.5	0.3
South Carolina	0.9	0.9	1.7	1.3
Tennessee	2.5	3.1	4.2	4.2
Vermont	0.3	0.3	0.5	0.3
Virginia	0.9	0.8	1.7	1.2
West Virginia	2.7	3.0	5.0	4.4
Wisconsin	5.9	6.6	9.3	8.2

SOURCE: Congressional Budget Office.

NOTES: Program requires an eight-million-ton annual reduction from 1980 utility emission levels of SO_2, based on imposing a maximum emission rate of 1.5 pounds of SO_2 per million Btu.

PART III. A CHANGED EMISSIONS CONTROL PROGRAM AND FEE DESIGN

How would costs be affected by changing the design of the sulfur dioxide emissions control program and fee? To answer this question, this study looked at three changes in the basic program design:

- Allowing states to use emissions reduction "trading" to achieve lower control costs (analyzed below);
- Requiring states to achieve more emission reductions than the original eight million tons to accommodate possible future emissions growth (Part IV); and
- Requiring the fee to be based on SO_2 emissions rather than on electricity production (Part V).

LOWERING PROGRAM AND FEE COSTS BY ALLOWING EMISSIONS TRADING WITHIN STATES

Emissions reduction trading (also called "bubbling") tends to produce lower total control costs than do uniform regional emissions limits (as in the base case program) that achieve identical areawide emissions reductions. An emissions trading scheme starts with a predetermined emissions reduction level that must be met within a given area, such as a state. But within the confines of that area, adherence to a uniform emissions level is not required. Instead, polluters that can reduce emissions at lower costs than can others would meet stricter emissions limits than would polluters whose

control costs were higher. Thus, polluters within the area would trade their emissions reduction requirements, but overall, they would still meet the required net level of control. Likewise, applied to the base case program, emissions trading would seek to lower 1980 annual SO_2 levels by eight million tons, but it would achieve that goal differently. It would allow power plants with high average emissions reduction costs to forego meeting the new control measures, so long as power plants with low average control costs met stricter and compensating control standards within the area. In this modification, the emissions reduction requirements--to lower SO_2 emissions by eight million tons-- would be the same as under the base case, but costs would be lower.

Cost Effects. In fact, a lower fee could be used to finance the trust fund. Only 2.5 mills per kilowatt-hour would be needed over the 1987-1999 period to help reimburse 90 percent of capital and 50 percent of operating expenses (see Table 8). Average annual program costs would fall from $2.4 billion to $1.8 billion (in 1983 dollars) over the 1992-2005 period, and the overall cost of the program would fall from $36 billion to $30 billion (in 1983 dollars). Moreover, roughly $6.7 billion (in 1983 dollars) would be left in the trust fund at the close of the program. The effect on the states' net trust fund position and electricity prices also would be lessened (see Tables 9 and 10). With emissions trading, the maximum price rise in 1996 (occurring in

TABLE 8. TRUST FUND BALANCE INFORMATION FOR SO_2 EMISSIONS CONTROL PROGRAM WITH EMISSIONS TRADING, 1985-2005
(In millions of nominal dollars)

Year	Fee Revenues	Reimbursements from Fund	Interest on Fund	End-of-Year Balance a/
1985	1,217	0	0	1,191
1986	2,410	0	93	3,665
1987	2,982	0	291	6,908
1988	2,952	9	550	10,379
1989	2,923	9	828	14,096
1990	2,893	9	1,125	18,078
1991	2,864	0	1,443	22,348
1992	2,836	2,519	1,580	24,166
1993	2,807	2,519	1,728	26,141
1994	2,779	2,519	1,886	28,242
1995	2,752	2,519	2,054	30,482
1996	2,724	3,728	2,136	31,564
1997	2,697	3,728	2,223	32,703
1998	2,670	3,728	2,313	33,902
1999	2,643	3,728	2,409	35,166
2000	0	3,728	2,510	33,885
2001	0	3,728	2,407	32,497
2002	0	3,728	2,296	30,993
2003	0	3,728	2,175	29,365
2004	0	3,728	2,045	27,602
2005	0	3,728	1,903	25,692

SOURCE: Congressional Budget Office.

NOTES: Program requires an eight-million-ton annual reduction from 1980 utility SO_2 emission levels, based on imposing an equivalent maximum emission rate of 1.5 pounds of SO_2 per million Btu on all power plants in a state, but allowing some to be controlled more than others, depending on cost. Revenues based on 1 mill per kilowatt-hour fee in 1985, 2 mills per kilowatt-hour fee in 1986, and 2.5 mills per kilowatt-hour fee in 1987 through 1999 on electricity generated by coal, oil, and gas. The assumed interest rate is 8 percent per year for both the fund and capital.

a. Equals remaining balance including interest, from beginning of year after withdrawal of reimbursements and administrative expenses, plus fee revenues occurring at end of year.

TABLE 9. STATE-BY-STATE TRUST FUND POSITIONS OF SO_2 CONTROL PROGRAM WITH EMISSIONS TRADING AND ENERGY FEE (In millions of 1983 dollars)

State	Amount Paid to Fund	Amount Received from Fund	Cost of Emission Control Program	Distribution of Costs with Fee a/
Alabama	909	837	1,119	1,119
Arkansas	367	0	0	367
Connecticut	280	24	32	288
Delaware	132	0	0	132
District of Columbia	66	32	43	76
Florida	1,553	482	636	1,706
Georgia	923	850	1,137	1,210
Illinois	1,484	1,556	2,021	1,949
Indiana	1,378	2,500	3,260	2,138
Iowa	306	408	529	480
Kentucky	1,065	922	1,205	1,348
Louisiana	732	0	0	732
Maine	108	9	12	111
Maryland	587	288	380	680
Massachusetts	439	38	50	452
Michigan	1,138	562	772	1,348
Minnesota	411	224	313	500
Mississippi	420	387	517	551
Missouri	953	1,688	2,202	1,467
New Hampshire	79	7	9	81
New Jersey	779	381	504	901
New York	1,242	551	744	1,435
North Carolina	876	130	185	931
Ohio	2,124	2,841	3,717	3,000
Pennsylvania	1,565	767	1,013	1,812
Rhode Island	67	6	8	69
South Carolina	512	76	108	543
Tennessee	1,000	878	1,132	1,254
Vermont	53	5	6	54
Virginia	664	99	140	705
West Virginia	1,384	1,236	1,660	1,808
Wisconsin	511	1,328	1,711	895
Total	24,158	19,111	25,165	30,213

SOURCE: Congressional Budget Office.

NOTES: The emissions control program involves an eight-million-ton per year reduction from 1980 utility sulfur dioxide emission levels, based on imposing an equivalent maximum emission rate of 1.5 pounds of sulfur dioxide per million Btu on all power plants in a state, but allowing some to be controlled more than others, depending on cost. Revenues based on 1 mill per kilowatt-hour fee in 1985, 2 mills per kilowatt-hour fee in 1986, and 2.5 mills per kilowatt-hour fee in 1987 through 1999 on electricity generated by coal, oil, and gas. The interest rate is 8 percent per year.

a. Equals sum of columns one plus three minus column two, except for minor differences caused by rounding.

TABLE 10. EFFECT ON 1996 ELECTRICITY PRICES OF BASE CASE PROGRAM WITH EMISSIONS TRADING, BY STATE
(In nominal mills per kilowatt-hour)

	Average State Costs Across All Types of Electricity	Projected 1996 Electricity Rates Without Program a/	Percent Rate Increase Attributable to Program
Alabama	2.3	121.9	1.9
Arkansas	1.6	108.7	1.5
Connecticut	1.4	196.5	0.7
Delaware	1.9	195.7	1.0
District of Columbia	2.1	114.0	1.9
Florida	1.9	156.5	1.2
Georgia	2.3	113.3	2.0
Illinois	2.4	140.0	1.7
Indiana	4.2	122.9	3.4
Iowa	2.8	135.8	2.1
Kentucky	2.9	105.8	2.7
Louisiana	1.6	115.5	1.4
Maine	1.4	148.8	0.9
Maryland	2.1	133.0	1.6
Massachusetts	1.4	171.6	0.8
Michigan	2.1	127.0	1.6
Minnesota	1.9	126.1	1.5
Mississippi	2.3	117.5	2.0
Missouri	4.1	117.3	3.5
New Hampshire	1.4	169.3	0.8
New Jersey	2.1	118.1	1.1
New York	1.5	232.4	0.6
North Carolina	1.5	128.0	1.2
Ohio	3.6	142.9	2.5
Pennsylvania	2.1	158.6	1.3
Rhode Island	1.4	166.0	0.8
South Carolina	1.5	130.0	1.2
Tennessee	2.5	101.2	2.5
Vermont	1.4	152.6	0.9
Virginia	1.5	140.8	1.1
West Virginia	3.2	114.5	2.8
Wisconsin	3.5	113.7	3.0

SOURCE: Congressional Budget Office.

NOTES: The emissions control program involves an eight-million-ton per year reduction from 1980 utility sulfur dioxide emission levels, based on imposing an equivalent maximum emission rate of 1.5 pounds of sulfur dioxide per million Btu on all power plants in a state, but allowing some to be controlled more than others, depending on cost. Revenues based on 1 mill per kilowatt-hour fee in 1985, 2 mills per kilowatt-hour fee in 1986, and 2.5 mills per kilowatt-hour fee in 1987 through 1999 on electricity generated by coal, oil, and gas. The annual interest rate assumed is 8 percent.

a. Based on 1982 average electricity prices recorded by the Department of Energy, adjusted by an assumed 6 percent inflation rate.

Missouri) would be lower--3.5 percent, compared to 4.5 percent in the base case, and roughly 7 percent using the trading approach without a fee. 8/

To achieve a satisfactory SO_2 emissions reduction while permitting trading, the control program could be modified to allow each state to submit an alternative plan that provides the same emissions reductions as an emissions cap of 1.5 pounds of SO_2 per million Btu for all plants within a state. Once the trading plan was in place, individual plants would still be subject to specific emissions controls, but not necessarily to the same standards. Enforcing the individual emissions regulations would not differ from enforcing the uniform standard, but the administrative costs of determining the individual emissions limits could be greater. For example, designing the emissions control level for each plant might be more difficult and time-consuming than simply applying a uniform standard.

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8. The costs of emissions trading using emissions control equipment can compare favorably with the costs of the same reduction program that allows fuel switching but that requires compliance with a uniform limit of 1.5 pounds of SO_2 per million Btu (i.e., no emissions trading). For example, the program discussed above with trading would average $1.8 billion per year (in 1983 dollars), while the base case program, modified to allow fuel switching but not emissions reduction trading, would average $1.7 billion per year.

PART IV. RAISING EMISSIONS CONTROL AND FEE COSTS BY INCLUDING A MARGIN FOR EMISSIONS GROWTH

Preserving the emissions reduction program over time--that is, holding total sulfur dioxide emissions stable at eight million tons below 1980 levels--would involve compensating for new emissions that occurred as economic growth led to greater production and industrial activity. Doing so could raise the total amount of emissions reductions needed at the outset and thus, could raise the costs of the program and the fee that finances it.

Emissions growth during the 1980-1996 period alone could add roughly 2.4 million tons of SO_2 to annual levels (see Table 11), although such estimates are quite speculative (see Table 11). To negate, or "offset," this emissions growth (beyond the original eight-million-ton reduction) would increase the average annual control costs over the 1992-2005 period from \$2.4 billion (in the base case) to \$3.9 billion in 1983 dollars. Total control costs from 1992 through 2005 would rise from \$33 billion to \$54 billion. [9]

9. A true emissions "cap" would restrict emissions growth even after 1996. This analysis does not estimate the cost of offsets needed to compensate such growth and assumes these costs are not covered by the trust fund. Thus, only offsets between now and 1996 are estimated in this study.

TABLE 11. EMISSIONS REDUCTION REQUIREMENTS AND COSTS OF SO_2 EMISSIONS CONTROL PROGRAM ALLOWING OFFSETS FOR EMISSIONS GROWTH, BY STATE

State	In Thousands of Tons SO_2 Per Year 1980 Emissions	Required Reductions	Additional Offsets Needed	Percent Reduction
Alabama	543	209	97 a/	56
Arkansas	27	0	65	240
Connecticut	32	0	0	0
Delaware	53	11	0	21
District of Columbia	5	0	0	0
Florida	726	247	106	49
Georgia	737	353	38	53
Illinois	1,126	656	453 a/	98
Indiana	1,540	1,010	132	74
Iowa	231	108	102 a/	91
Kentucky	1,008	586	0	58
Louisiana	25	0	147 a/	88
Maine	16	1	0	6
Maryland	223	77	79	70
Massachusetts	276	67	0	24
Michigan	565	178	261 a/	78
Minnesota	177	44	57	57
Mississippi	129	58	45	80
Missouri	1,141	776	236 a/	89
New Hampshire	81	38	0	47
New Jersey	110	27	63 a/	82
New York	480	161	0	34
North Carolina	435	18	1	4
Ohio	2,172	1,350	19	63
Pennsylvania	1,466	655	71	50
Rhode Island	5	0	0	0
South Carolina	213	64	54	55
Tennessee	934	554	0	59
Vermont	1	0	3	300
Virginia	164	6	26	20
West Virginia	944	470	143	65
Wisconsin	486	293	188 a/	99
Total	16,071	8,017	2,386	65

SOURCE: Congressional Budget Office and E.H. Pechan and Associates, Incorporated.

NOTES: Emissions reductions based on power plants in each state meeting a 1.5 pound SO_2 emissions rate, including any additional emissions reductions that may be necessary to account for utility or industrial emissions growth in the state.

a. Sufficient emissions offsets are not available in state to meet this figure. Additional reductions would have to be purchased from other states.

To meet the costs of additional emissions control, revenues to the trust fund would have to increase after the first two years. In fact, a fee of 5 mills per kilowatt-hour starting in 1987 would be needed to support the trust fund and original reimbursement formula (see Part I). The 5 mill fee would leave roughly $6.8 billion (in 1983 dollars) in the fund at the program's completion (see Table 12). The fee and emissions cap would raise total program costs from $36 billion to $58 billion (in 1983 dollars) over the 1992-2005 period (see Table 13). The higher costs would raise electricity prices in some states by as much as 9 percent (see Table 14), though without the fee, they would rise by as much as 20.5 percent. In contrast, the base case program would not raise electricity prices in any state by more than 4.5 percent in 1996.

Higher costs rises would occur in all states but would be most noticeable in the Midwest. For example, under the base case program, 1996 electricity prices would rise 4.5 percent in Missouri, 4 percent in Indiana, 2.6 percent in Iowa, and 3.1 percent in Ohio. In contrast, with the fee and emissions growth offsets, electricity prices could rise by as much as 9 percent in Missouri, 6 percent in Indiana, 5.3 percent in Iowa, and 4.5 percent in Ohio. As in the base case, however, the fee would still tend to hold down the increase in electricity prices in any one state; without it but with emissions offsets, electricity prices in Missouri, Indiana, Iowa, and Ohio could rise by as much as 20.5, 10.5, 10.2, and 6.4 percent, respectively.

TABLE 12. PROFILE OF TRUST FUND FOR UNDER SO_2 EMISSIONS CONTROL PROGRAM WITH OFFSETS
(In millions of nominal dollars)

Year	Fee Revenues	Reimbursements from Fund	Interest on Fund	End-of-Year Balance a/
1985	1,217	0	0	1,191
1986	2,410	0	93	3,665
1987	5,964	0	291	9,890
1988	5,904	0	789	16,551
1989	5,845	0	1,321	23,685
1990	5,787	0	1,892	31,328
1991	5,729	0	2,503	39,522
1992	5,672	5,362	2,726	42,479
1993	5,615	5,362	2,966	45,655
1994	5,559	5,362	3,220	49,027
1995	5,503	5,362	3,489	52,610
1996	5,448	7,996	3,565	53,577
1997	5,394	7,996	3,642	54,563
1998	5,340	7,996	3,721	55,571
1999	5,286	7,996	3,801	56,603
2000	0	7,996	3,883	52,427
2001	0	7,996	3,549	47,913
2002	0	7,996	3,188	43,033
2003	0	7,996	2,797	37,759
2004	0	7,996	2,375	32,057
2005	0	7,996	1,918	25,895

SOURCE: Congressional Budget Office.

NOTES: The emissions control program involves an eight-million-ton per year reduction from 1980 utility sulfur dioxide emission levels, based on imposing a maximum emission rate of 1.5 pounds of sulfur dioxide per million Btu on all power plants in a state. It also requires all utility and industrial sulfur dioxide emission growth by 1996 to be offset by additional emission reductions. Revenues based on a 1 mill per kilowatt-hour fee in 1985, a 2 mills per kilowatt-hour fee in 1986, and a 5.0 mills per kilowatt-hour fee in 1987 through 1999 on electricity generated by coal, oil, and gas. The interest rate is 8 percent for both the fund and capital.

a. Equals remaining balance, including interest from start of year after withdrawal of reimbursements and administrative expenses, plus fee revenues accruing at end of year.

TABLE 13. STATE-BY-STATE TRUST FUND POSITIONS UNDER SO_2 EMISSIONS CONTROL PROGRAM WITH OFFSETS (In millions of 1983 dollars)

State	Amount Paid to Fund	Amount Received from Fund	Cost of Emission Control Program	Distribution of Costs with Fee a/
Alabama	1,701	1,703	2,272	2,269
Arkansas	686	42	55	699
Connecticut	523	19	25	529
Delaware	246	0	0	246
District of Columbia	123	69	91	146
Florida	2,905	1,333	1,769	3,341
Georgia	1,728	1,730	2,308	2,305
Illinois	2,777	4,865	6,383	4,294
Indiana	2,578	3,907	5,096	3,768
Iowa	673	1,267	1,671	1,077
Kentucky	1,993	1,011	1,327	2,309
Louisiana	1,370	84	110	1,396
Maine	202	7	10	205
Maryland	1,099	611	813	1,300
Massachusetts	822	30	40	831
Michigan	2,129	2,478	3,370	3,021
Minnesota	769	1,079	1,419	1,109
Mississippi	786	787	1,050	1,049
Missouri	1,784	5,066	6,622	3,339
New Hampshire	148	5	7	150
New Jersey	1,457	810	1,078	1,724
New York	2,324	81	110	2,353
North Carolina	1,640	824	1,113	1,929
Ohio	3,976	4,258	5,597	5,315
Pennsylvania	2,929	1,629	2,166	3,466
Rhode Island	126	5	6	127
South Carolina	957	481	650	1,126
Tennessee	1,872	683	891	2,080
Vermont	99	4	5	100
Virginia	1,242	624	843	1,461
West Virginia	2,589	2,468	3,274	3,395
Wisconsin	956	2,942	3,842	1,856
Total	45,210	40,904	54,012	58,318

SOURCE: Congressional Budget Office.

NOTES: The emissions control program involves an eight-million-ton per year reduction from 1980 utility sulfur dioxide emission levels, based on imposing a maximum emission rate of 1.5 pounds of sulfur dioxide per million Btu on all power plants in a state. It also requires all utility and industrial sulfur dioxide emission growth by 1996 to be offset by additional emission reductions. Revenues based on a 1 mill per kilowatt-hour fee in 1985, a 2 mills per kilowatt-hour fee in 1986, and a 5.0 mills per kilowatt-hour fee in 1987 through 1999 on electricity generated by coal, oil, and gas. Assumed annual interest rate is 8 percent for both the fund and capital.

a. Equals sum of columns one plus three minus column two, except for minor differences caused by rounding.

TABLE 14. EFFECT ON 1996 ELECTRICITY PRICES OF SO_2 EMISSIONS CONTROL PROGRAM WITH OFFSETS, BY STATE (In nominal mills per kilowatt-hour)

State	Average Program Cost Across All Types of Electricity in State	Projected 1996 Electricity Rates Without Program a/	Percent Increase Due to Program
Alabama	4.6	121.9	3.8
Arkansas	3.4	108.7	3.1
Connecticut	2.6	196.5	1.3
Delaware	3.8	195.7	2.0
District of Columbia	4.3	114.0	3.8
Florida	4.1	156.5	2.7
Georgia	4.6	113.3	4.1
Illinois	5.9	139.9	4.2
Indiana	7.4	122.9	6.0
Iowa	7.2	135.8	5.3
Kentucky	4.8	105.8	4.6
Louisiana	3.4	115.5	3.0
Maine	2.6	148.8	1.8
Maryland	4.3	133.0	3.2
Massachusetts	2.6	171.6	1.5
Michigan	5.5	127.0	4.3
Minnesota	4.9	126.1	3.9
Mississippi	4.6	117.5	3.9
Missouri	10.5	117.3	9.0
New Hampshire	2.6	169.3	1.5
New Jersey	4.3	188.1	2.3
New York	2.3	232.4	1.0
North Carolina	3.7	128.0	2.9
Ohio	6.4	142.9	4.5
Pennsylvania	4.3	158.6	2.7
Rhode Island	2.6	166.0	1.6
South Carolina	3.7	130.0	2.8
Tennessee	3.9	101.2	3.8
Vermont	2.6	152.6	1.7
Virginia	3.7	140.8	2.6
West Virginia	6.3	114.5	5.5
Wisconsin	7.7	113.7	6.8

SOURCE: Congressional Budget Office.

NOTES: The emissions control program involves an eight-million-ton per year reduction from 1980 utility sulfur dioxide emission levels, based on imposing a maximum emission rate of 1.5 pounds of sulfur dioxide per million Btu on all power plants in a state. It also requires all utility and industrial sulfur dioxide emission growth by 1996 to be offset by additional emission reductions. Revenues based on a 1 mill per kilowatt-hour fee in 1985, a 2 mills per kilowatt-hour fee in 1986, and a 5.0 mills per kilowatt-hour fee in 1987 through 1999 on electricity generated by coal, oil, and gas. Assumed annual interest rate is 8 percent for both the fund and capital.

a. Based on 1982 average electricity prices recorded by the Department of Energy, adjusted by an assumed 6 percent inflation rate.

PART V. ALTERING THE DISTRIBUTION OF COSTS PROGRAM BY LEVYING A FEE ON EMISSIONS

Rather than raising revenue by a fee on energy consumption, a levy could be imposed on sulfur dioxide emissions measured at their 1980 levels instead. The effects would be to lessen the redistribution of costs over the states affected and concentrate those costs on states having the greatest responsibility for controlling emissions. Thus, this would more closely conform to the intent of the "polluter pays" principle while still offering some relief to installers of pollution control, since even low-polluting states would contribute some revenues to the fund.

In examining an emissions fee, the base case eight-million-ton SO_2 control standard was applied. A graduated emissions fee was then devised to provide roughly the same amount of revenue as the energy fee produced. Accordingly, a tax of $76 per ton of SO_2 would be imposed in 1985, rising to $150 in 1986, and to $223 between 1987 and 1999. The revenue obtained from these fees would not decline as emissions declined--they would continue to be based on 1980 emissions levels until the fund ran

out. 10/ Such a fee would affect high-sulfur coal and oil users that were not already controlled in 1980. If these sources applied controls in the future, they could then receive a subsidy from the fund.

Roughly $3.8 billion (in 1983 dollars) would remain in the trust fund when it expired (see Table 15), a situation similar to the base case. But each states' net trust fund position would differ from under the base case. The midwestern states would bear the brunt of the control costs (see Tables 16 and 17)--receiving substantial reimbursements from the fund, but also paying the most into it. Electricity price increases would follow a similar distribution, with the midwestern states receiving the greatest increases. Prices in 1996 could rise by 6 percent in Missouri, by 5.2 percent in Indiana, and by 3.9 percent in Ohio. With the base case electricity fee instead, the price increases in these same states would be 4.5, 4.0, and 3.1 percent, respectively. For comparison, without any type of fee, Missouri's power prices could rise by 9.7 percent, Indiana's by 8 percent, and Ohio's by 5.4 percent.

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10. This type of emissions fee is somewhat different from others proposed (see, for example, S.R. 2001 introduced by Senator Durenburger), which typically have declining revenues as emissions fall. The disadvantages of such proposals are that revenues to the fund would fall as fund money was used to control emissions. This would necessitate frequent fee readjustments to maintain revenue goals, and could be difficult to administer. The type of program analyzed in this paper apportions greater revenue responsibilities to those states that were, in 1980, responsible for the majority of emissions. The amount of money available from the trust would be the same as in the base case.

TABLE 15. PROFILE OF TRUST FUND UNDER SO_2 EMISSIONS CONTROL PROGRAM WITH EMISSIONS FEE, 1985-2005 (In millions of nominal dollars)

Year	Fee Revenues	Reimbursements from Fund	Interest on Fund	End-of-Year Balance a/
1985	1,209	0	0	1,182
1986	2,362	0	92	3,609
1987	3,477	0	286	7,342
1988	3,442	0	585	11,337
1989	3,407	0	904	15,616
1990	3,373	0	1,246	20,200
1991	3,340	0	1,613	25,115
1992	3,306	3,325	1,737	26,753
1993	3,273	3,325	1,871	28,530
1994	3,240	3,325	2,013	30,414
1995	3,208	3,325	2,163	32,413
1996	3,176	4,907	2,196	32,828
1997	3,144	4,907	2,229	33,240
1998	3,113	4,907	2,262	33,652
1999	3,082	4,907	2,295	34,061
2000	0	4,907	2,327	31,417
2001	0	4,907	2,115	28,558
2002	0	4,907	1,886	25,465
2003	0	4,907	1,639	22,121
2004	0	4,907	1,371	18,504
2005	0	4,907	1,081	14,593

SOURCE: Congressional Budget Office.

NOTES: The emissions control program imposes a maximum emission rate of 1.5 pounds of sulfur dioxide per million Btu on all power plants to reduce emissions roughly 8 million tons per year. Revenues based on $96 per ton sulfur dioxide emission fee in 1985, $150 per ton emission fee in 1986, and $223 per ton emission fee in 1987 through 1999 on electricity generated by coal, oil, and gas. Assumed annual interest rate is 8 percent for both the fund and capital.

a. Equals remaining balance, including interest from start of year after withdrawal of reimbursements and administrative expenses, plus fee revenues accruing at end of year.

TABLE 16. STATE-BY-STATE TRUST FUND POSITIONS UNDER SO_2 EMISSIONS CONTROL PROGRAM WITH EMISSIONS FEE
(In millions of 1983 dollars)

State	Amount Paid to Trust	Amount Received from Trust	Cost of Emission Control Program	Distribution of Costs With Fee System a/
Alabama	933	969	1,313	1,278
Arkansas	46	0	0	46
Connecticut	55	45	58	68
Delaware	90	0	0	90
District of Columbia	8	43	58	23
Florida	1,247	923	1,199	1,523
Georgia	1,266	984	1,334	1,616
Illinois	1,934	1,753	2,294	2,475
Indiana	2,645	3,030	3,921	3,536
Iowa	397	566	736	567
Kentucky	1,731	1,151	1,500	2,080
Louisiana	43	0	0	43
Maine	28	18	23	33
Maryland	383	383	514	514
Massachusetts	473	71	92	494
Michigan	971	648	896	1,219
Minnesota	305	483	666	488
Mississippi	222	448	607	381
Missouri	1,959	2,476	3,182	2,665
New Hampshire	138	13	17	142
New Jersey	189	508	681	362
New York	825	777	1,053	1,101
North Carolina	748	449	599	898
Ohio	3,731	3,704	4,813	4,840
Pennsylvania	2,519	1,022	1,369	2,866
Rhode Island	9	11	14	12
South Carolina	366	262	350	454
Tennessee	1,604	1,089	1,436	1,951
Vermont	1	9	11	3
Virginia	281	340	454	395
West Virginia	1,622	1,448	1,933	2,108
Wisconsin	834	1,554	1,998	1,278
Total	27,604	25,178	33,120	35,546

SOURCE: Congressional Budget Office.

NOTES: The emissions control program imposes a maximum emission rate of 1.5 pounds of sulfur dioxide per million Btu on all power plants to reduce emissions roughly 8 million tons per year. Revenues based on $96 per ton sulfur dioxide emission fee in 1985, $150 per ton emission fee in 1986, and $223 per ton emission fee in 1987 through 1999 on electricity generated by coal, oil, and gas. Assumed annual interest rate is 8 percent for both the fund and capital.

a. Equals sum of columns one plus three minus column two, except for minor differences caused by rounding.

TABLE 17. EFFECT ON 1966 ELECTRICITY PRICES OF SO_2 EMISSIONS CONTROL PROGRAM WITH EMISSIONS FEE, BY STATE (In nominal mills per kilowatt-hour)

State	Average Program Cost Across All Types of Electricity in State	Projected 1996 Electricity Rates Without Program a/	Percent Rate Increase Attributable to Program
Alabama	2.6	121.9	2.1
Arkansas	0.2	108.7	0.2
Connecticut	0.4	196.5	0.2
Delaware	1.3	195.7	0.7
District of Columbia	1.0	114.0	0.8
Florida	1.9	156.5	1.2
Georgia	3.1	113.3	2.7
Illinois	3.0	140.0	2.1
Indiana	6.4	122.9	5.2
Iowa	3.5	135.8	2.6
Kentucky	4.3	105.8	4.1
Louisiana	0.1	115.5	0.1
Maine	0.5	148.8	0.3
Maryland	1.8	133.0	1.4
Massachusetts	1.5	171.6	1.0
Michigan	2.0	127.0	1.6
Minnesota	2.2	126.1	1.8
Mississippi	1.9	117.5	1.6
Missouri	7.0	117.3	6.0
New Hampshire	2.4	169.3	1.4
New Jersey	1.2	188.1	0.6
New York	1.3	232.4	0.6
North Carolina	1.7	128.0	1.3
Ohio	5.5	142.9	3.9
Pennsylvania	3.3	158.6	2.1
Rhode Island	0.3	166.0	0.2
South Carolina	1.5	130.0	1.1
Tennessee	3.8	101.2	3.8
Vermont	0.2	152.6	0.1
Virginia	1.1	140.8	0.8
West Virginia	3.8	114.5	3.3
Wisconsin	4.7	113.7	4.1

SOURCE: Congressional Budget Office.

NOTES: The emissions control program imposes a maximum emissions rate of 1.5 pounds of sulfur dioxide per million Btu on all power plants to reduce emissions roughly 8 million tons per year. Revenues based on $96 per ton sulfur dioxide emission fee in 1985, $150 per ton emission fee in 1986, and $223 per ton emission fee in 1987 through 1999 on electricity generated by coal, oil, and gas. The interest rate is 8 percent per year.

a. Based on 1982 average electricity prices recorded by the Department of Energy, adjusted by an assumed 6 percent inflation rate.

APPENDIX ANALYTIC METHOD AND ASSUMPTIONS

Costs for the emissions control program were estimated with the aid of a computer-based simulation model, which reports sulfur dioxide emissions and total capital and annual operating costs.[1/] The emissions reduction and control cost estimates were performed by E.H. Pechan and Associates, Incorporated. In analysis of the base case and variants, the main assumptions applied include:

- That power plants affected would reduce SO_2 emissions by roughly eight million tons,
- That the area affected would be the eastern-most 31 states,
- That emissions reductions would be achieved by available control technology, such as wet and dry lime or limestone scrubbers,
- That no fuel switching to low-sulfur fuels would be permitted,
- That reductions would be enforced by an overall emissions limit of 1.5 pounds of sulfur dioxide per million Btu, except in the emissions trading variant,
- That compliance for all options would begin in 1996,
- That installation of control equipment would start in 1992 to meet the 1966 deadline.

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1. The emissions model used is designed to simulate the effect of different emissions reduction schemes on each major steam electric unit in the continental United States. The model does not use linear programming or econometrics, but instead selects incrementally, unit by unit, the lowest cost control strategy to meet a given situation.

The analysis did not consider pollution control technology that is under development but not currently available, such as the limestone injection process using multi-stage burners (the so-called LIMB technology). Because of the assumed prohibition of fuel switching and unavailability of other technologies, the costs derived probably represent an upper bound for achieving an eight-million-ton SO_2 reduction. 2/

The trust fund fee payment-to-utilities system were simulated separately from the emissions control model. To generate revenue in the base case, a fee on energy was assumed charged on electricity produced from all existing fossil-fuel-fired power plants (coal, oil, and gas). For the emissions fee option, total revenues needed were translated into a dollar per ton of SO_2 value. New power plants built under the most recent federal emission standards (the New Source Performance Standards of 1978) were assumed not charged a fee in all options. The annual quantity of electricity produced subject to the fee was adjusted to account for possible declining electricity production from these plants (estimated at 1 percent per year) owing to age

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2. Costs for prototype advanced technologies have been estimated to be as much as 80 percent lower than the limestone-based systems assumed in this paper's cost estimates. Such estimates are speculative in light of the untested status of the technologies and uncertainty involved when retrofitting control equipment. Both the Congressional Research Service and the Office of Technology Assessment have conducted additional analysis on various energy fees to subsidize different emission reduction schemes. Refer to reports by Robert Friedman, Office of Technology Assessment, and Larry Parker, Congressional Research Service for further information.

and the costs of maintenance. Capital and operating costs to the utilities of the emissions control program were annuitized, and payments from the trust fund were assumed made according to a 90 percent capital and 50 percent operating expense formula. Capital costs were amortized over the 1996-2005 period using an 8 percent nominal interest rate. Operating costs were based on nominal first-year costs, and subsequent reimbursements were based on this value without adjustment for inflation.

Payments from the trust fund were assumed to occur at the beginning of each year, at which time administrative expenses also would be withdrawn from the fund. Administrative expenses were charged in nominal dollars (adjusted in future years for inflation); $25 million (in 1983 dollars) was withdrawn each year except 1996, when $50 million (in 1983 dollars) was withdrawn to account for possible increased expenses at the effective compliance date of the program.[3] Annual interest on the fund balance was imputed each year after payments and administrative costs were deducted, and fee revenues were included at years' end when collected.

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3. Administrative expenses used in this analysis are arbitrary, but probably high. For comparison, the entire grant program from the U.S. EPA to the states for all air quality activities in 1984 was roughly $52 million (for all 50 states). Another comparison might be the superfund management and support budget of $15 to $20 million for 1983 and 1984 (out of total appropriations of $210 and $480 million, respectively).

To determine the effect of the fee and control program on electricity consumers in each state, price effects were allocated on the basis of assumptions about electricity-sharing practices among states. States sharing electricity production were considered members of power pools (see below). 4/

Pool	States Involved
New England Power Pool	Maine, New Hampshire, Vermont, Connecticut, Massachusetts, Rhode Island
Pennsylvania, New Jersey, Maryland Interconnection	Pennsylvania, New Jersey, Maryland District of Columbia
Virginia-Carolinas Reliabilities Group	Virginia, North Carolina, South Carolina
Southern Company and Other Systems	Georgia, Alabama, Mississippi
Middle South Utilities Company, Gulf States Company, and Other Systems	Arkansas, Louisiana

Electricity generated within a pool--hence, electricity price increases --were apportioned to each state on the basis of its ratio of fossil-fuel energy consumption to all forms of electricity consumption within the pool.

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4. To simplify calculations, CBO assumed that pools conformed to state borders. In practice, pooling agreements subdivide some states and include such portions in multi-state pools. To minimize inaccuracy, the power pools chosen for this analysis are ones that primarily conform to state borders. States not part of the specific pools listed above were treated separately.

The final price increase to consumers also included transmission losses, estimated at 10 percent. Thus, a fee of 1 mill per kilowatt-hour on fossil-fuel electricity production would equal a 1.1 mill per kilowatt-hour fee on electricity consumption within a state receiving all its power from fossil fuel-fired plants.