TITLE II OF S.1894:
COSTS TO THE ELECTRIC UTILITY INDUSTRY

Staff Working Paper
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PREFACE

This staff working paper considers the potential cost to the electric utility industry of provisions contained in Title II of S. 1894, amending the Clean Air Act, that would control emissions of sulfur dioxide. The analysis contained in the paper is derived, in part, from an earlier study of the bill preceding the adoption of amendments by the Senate Committee on Environment and Public Works. The paper was prepared in response to requests for information on the benefits and costs of S.1894 from Senators Burdick, Mitchell, Stafford, and Chaffee, and from a group of 32 Senators. Similar requests were received by the Congressional Research Service and the Office of Technology Assessment; these agencies are preparing analyses on other impacts and provisions of the bill.

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SUMMARY

The acid rain provisions contained in Title II of S.1894, the "Clean Air Standards Attainment Act of 1987," underwent substantial revision during consideration by the Committee on Environment and Public Works. This staff working paper describes briefly the new provisions applying to sulfur dioxide (SO_2) reductions from electric utilities and, where possible, estimates the effects they would have on utility emissions and costs.1/ A previous staff working paper prepared by the Congressional Budget Office--"Title II of the Proposed Senate Amendments to the Clean Air Act: A Preliminary Economic Analysis"--provided a set of cost estimates for the original bill. Differences from those results are highlighted in this memorandum.

By the year 2000, the SO_2 reduction requirements would raise the annual costs of the electical utility industry by about $6.2 billion. These costs correspond to annual SO_2 emission reductions from these sources of 9.7 million tons (compared with 1980 emission levels) and 13.5 million tons (compared with basecase emission levels in the year 2000). The difference is attributable to projected growth in emissions during the 1990s. Compared with the earlier version of the bill, annual utility costs in 2000 would be lower by about $1.7 billion, and emission levels would be higher by 0.7 million tons. These cost and emission estimates, it must be emphasized, only cover the sulfur dioxide reductions from the electric utility industry. Although this represents the bulk of control costs expected under Title II, requirements to reduce SO_2 from industrial sources, and to reduce nitrogen oxides from electric utility and industrial sources, will add to the cost of the bill. Although these topics are not examined in this report, they are included in a forthcoming Congressional Research Service report.

Annual costs after the year 2000 cannot be predicted with any precision, but could increase by $1 billion to $3 billion depending on the SO_2 reduction strategies adopted by utilities in the 1990s and the availability of less expensive control options. These estimates depend on several assumptions concerning the responses of states and utilities to the complex requirements of the Committee bill, which are discussed more fully below. Finally, the emerging technologies of SO_2 abatement could contribute to lower costs, but in ways that are difficult to estimate at this

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1. The potential benefits of acid rain controls are not evaluated here. They are addressed in a forthcoming analysis being prepared by the Congressional Research Service.

time. The types of technologies that would be favored under Title II would be high-percentage-removal retrofit technologies over other emerging retrofit technologies with lower-percentage removal, along with repowering options that could become commercially available over the next two decades. These are discussed in later sections.

THE REQUIREMENTS OF S.1894

The Committee bill is intended to reduce annual SO_2 emissions from all sources from observed 1980 levels by 5 million tons in 1993, 10 million tons in 1998, and 12 million tons by 2000.2/ To achieve these reductions, states are assigned aggregate emission targets or, in some cases, statewide average emission rates.

To determine which approach is applicable, states are initially divided into two main categories, based on past utility SO_2 emissions. The first group ("excess emission states") consists of states that recorded significant "excess emissions" in 1980 (that is, emissions from utilities of over 0.9 pounds of SO_2 per million Btu). The second main group includes: states with less than 1,000 tons of 1980 excess emissions ("clean states"), states that had less than 150,000 tons of utility emissions in 1985 ("small states"), or states with fewer than 40,000 tons of utility emissions in 1985, over 90 percent of which originated from a single source ("one-source states"). These latter three subcategories are not mutually exclusive; some states may place themselves in more than one category to pursue their interests. States with excess emissions--predominantly states in the Midwest and East--must meet an aggregate emission target. All other states in the second main group--typically Gulf Coast, Western, and small Eastern states--are either exempted from most requirements or are subject to less stringent average emission rates combined with an aggregate emission cap that would allow new-source emission growth beyond 1980 levels. Tables 1 and 2 present a summary of the SO_2 reduction requirements of the bill and identify the states that would likely fall into each group.

States with excess emissions are assigned emission targets proportional to their share of national 1980 excess emissions. They can develop abatement plans for utility and nonutility sources to achieve their targets, although the high level of SO_2 control suggests that abatement choices would be limited. If

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2. In 1980, stationary sources emitted roughly 26.4 million tons of SO2, with electric utilities accounting for 17.5 million tons (about two-thirds) of the total.

states fail to submit acceptable emission reduction plans to the EPA, then a uniform "default" standard (set at a monthly average of 0.9 pounds of SO_2 per million Btu) would be applied to all sources in the state by 1998. This standard would achieve the emission reduction target in most states.3/

So-called clean states--Arizona, California, Colorado, Connecticut, Idaho, Louisiana, Nevada, Oklahoma, Oregon, Rhode Island, Utah, and Vermont--are exempt from all initial requirements until 1998, when new rules take effect as described below. In addition, small states can satisfy the bill's requirements by instituting an annual average emission rate of 0.9 pounds of SO_2 per million Btu on all sources by 1993, provided that total annual statewide emissions remain below 250,000 tons. Once the standards are met, these states would be exempt from any other requirement except for the 1998 rules. Small states include Arkansas, Delaware, Kansas, Maine, Minnesota, Mississippi, New Hampshire, New Jersey, New Mexico, North Dakota, South Carolina, South Dakota, Virginia, Washington, and Wyoming.4/ Only South Dakota could be classified as a one-source state. Under the bill, its Big Stone generating plant would have to install New Source Performance Standard control in 2003, while the state would have to maintain a annual total emission cap of 100,000 tons.

Beyond the statewide emission targets, sources in excess emission states that operated in 1980 would have to achieve a statewide annual average emission rate of 0.9 pounds of SO_2 per million Btus by 1998. In many cases, this average rate provision alone would achieve the emission reduction target for 1998, although additional controls would typically be required

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3. Expressing the standard as a monthly average requires utilities to control emission fluctuations more carefully, and thus is 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 0.9 pounds of SO_2 per million Btus monthly standard was calculated as 0.8 pounds on an annual basis.

4. Total 1985 SO_2 emissions in New Mexico (266,650) and Virginia (310,840) have already exceeded the 250,000 ton cap. Nevertheless, these states could conceivably choose this exemption program, if the cap could be attained through the average emission rate requirements or other additional control.

to attain the tighter targets required in 2000.5/ These same sources are prohibited from exceeding their 1980 emission rate without offsetting the increase through SO_2 reductions elsewhere. Sources that have increased their emission rates since 1980 would have until 1998 to secure the offsets. Since few sources actually exceed their 1980 emission rates, this feature generally would not affect utility costs.

Beginning in 1998, states with excess emissions may choose between two options: to accept the eventual 12 million ton emission target (met by 2000) as an emissions cap; or, after attaining the targets, to phase in the default standards (0.9 pounds of SO_2 per million Btus monthly average) on plants reaching 30 years of age. Small states may substitute the 250,000 ton emission cap (or choose the 30-year standard), while clean states not subject to emission targets would phase in the 30-year standard (although it would have little effect). Finally, all sources, upon reaching age 40, must conform with the applicable New Source Performance Standard (NSPS) in all states beginning in the year 2003.6/

COSTS AND EMISSIONS UNDER THE TWO BILLS

Save for the final provision discussed above--imposing the NSPS on all plants once they are 40 years old--S.1894 is less costly than the Subcommittee bill. The specific revisions that would significantly affect the cost of the Committee bill include:

- Section 182(b)(1)(B) phases in emission reduction requirements and delays achieving a 12 million ton

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5. Although this requirement is also imposed on states with less than 1,000 tons of excess emissions in 1980, by construction it would have little or no effect. States operating under the 150,000 ton exemption would have achieved this average rate by 1993, although the bill exempts them from the 1998 requirement.

6. The current NSPS requires utilities to install technological controls 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 technology achieves 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 NSPS often achieves emission rates well below 0.6 pounds of SO_2 per million Btu.

reduction until the year 2000 rather than by 1996 as in the original bill;

- o Section 182(b)(1)(B) allows clean states to avoid the implied 1980 level emission cap from the excess emission formula. Also, section 182(b)(4)(F) exempts several low-emitting ("small") states from the strict emission reduction targets by substituting a more lenient emission rate requirement and emission cap;

- o Section 182(b)(4)(E) modifies the "pre-compliance cap" found in the original bill, which would have required offsets for new sources in relatively clean areas. This allows some states to take advantage of the above exemptions;

- o Section 183(b)(2)(C) mandates the New Source Performance Standard (NSPS) for plants as they attain age 40.

The first revision--phasing in and postponing the final emission reduction requirements--would lower the total discounted utility cost incurred during the 1990s in virtually all states (when compared with the original proposal) by postponing the bulk of the control cost by two to four years as compared with the original bill.

The next two revisions would lower the control costs incurred in states that currently operate relatively clean fossil-fuel-fired plants, such as those in the Western and Gulf regions. By allowing these clean states to avoid the strict emission targets in exchange for modest emission reductions on existing sources (to be achieved by 1993 under section 182(b)(4)(F)), the revised bill allows slightly more emissions in the states where marginal reductions are typically very expensive. The original "precompliance cap," which required states to offset any new-source emission growth in the 1990s, has been significantly weakened, and would now allow modest emission growth without offsetting reductions in these states.

Imposing the 40-year NSPS, however, could significantly boost costs in the period after 2000, especially in the event that the NSPS itself becomes tighter. Further, utilities' anticipation of the 40-year NSPS could affect their choices about emission control measures in the earlier years.

ANNUAL COSTS AND EMISSIONS IN 2000 UNDER THE REVISED BILL

The annual utility costs and emission reductions attributable to the Committee bill are a function of the choices states would make. These choices would be determined, among other things,

by the current emission levels in each state relative to 1980 levels, the age and technology of a state's plants, and the relative quantities of industrial as against utility emissions within a state. The bill's NSPS requirement might further complicate state and private utility decisionmaking in the 1990s.

It is impossible to predict exactly what decisions would be made by each and every state. A likely set of responses can be constructed, however, that provide a basis for estimating compliance costs and emission reductions in the year 2000.

State Choices

As described earlier, "clean" states would not face the excess emission formula targets. "Small" states would also be exempted from the reduction targets under Section 182(b)(4)(F) of the Committee bill. Most of these states would probably choose the 0.9 pound average emission rate by 1993, and accept the 250,000 ton emission cap, rather than meeting the targets.

Most Eastern and Midwestern (excess emission) states would be constrained by the excess emission formula targets. A significant number of defaults could occur, however--either intentionally or as a result of EPA disapproval of submitted state plans. Default could be a viable option for some states, depending on the ultimate level of emission reductions achieved under default compared with the target levels.7/ Although the default standards would be a more costly way of achieving the reductions, operating in default would ease the administrative burden of allocating emission reductions among sources, and potentially alleviate the need for additional control measures in the 1998-2003 period under the phased-in 30-year default standards option.

States must then choose a post-1998 strategy. States that were not required to attain strict emission targets would almost certainly chose the 30-year default standard. Other states would have to determine whether or not the perpetual offset approach embodied in the emission caps would be more expensive than the phased-in 30-year standards, which would not require new

7. As written, it is unclear whether S. 1894 would excuse a state operating in default as of 1998 from eventually attaining the full 12 million ton reduction target under the allocation formula. While the target would become incorportated in the State Implementation Plan (potentially allowing EPA to insist on additional reductions) the phased-in 30-year standards option after 1998 would allow emission growth beyond the target-level emission caps.

sources to secure emission offsets.8/ This decision (which must be made two years after enactment) would affect utilities significantly during the two decades following 1998, and might provide added incentives for default.

Cost and Emission Estimate

Table 3 displays an estimate of annual emissions and utility cost in the year 2000 under the Committee bill. Utility emissions in 2000 are estimated to be 7.7 million tons of SO_2, compared with a projected basecase level of 21.1 million tons. Thus, the program would achieve an annual emission reduction of roughly 13.5 million tons from electric utility sources. The resulting increase in annual utility costs by 2000 would be approximately $6.2 billion (in 1985 dollars). A comparable cost estimate for a 14.2 million ton reduction in emissions in the year 2000, based on the proposal analyzed in the previous report, would be $7.9 billion.9/

These estimates should be viewed with considerable caution. For example, they do not take explicit account of industrial emissions, which would play an important role in developing compliance plans to meet statewide averages or emission targets; the estimates assume industrial emission reductions of about 1.5 million tons from 1980 levels. Also, the estimates do not treat all states individually (for example, states that qualify for section 182(b)(4)(F) exemptions, such as Delaware and Mississippi, are aggregated into larger regions). Finally, the estimates are predicated on a model that predicts utility choices only by comparing the annual cost of alternatives in specific years. Two additional important sources of uncertainty exist regarding the cost and emission estimates in the year 2000 and beyond: the influence of the 40-year NSPS requirement (slated for 2003), which could lead to higher costs in 2000 depending on utility response; and the potential role of clean coal technology, which could serve to lower costs. These are discussed in the following sections.

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8. The option to "bubble" the 30-year standards under section 183(b)(2)(A)(ii) would only be attractive in limited situations. As written, the bubble approach is only allowed if emissions remain below the emission reduction targets, and retirements or reduced operation would not be credited as emission reductions; that is, the bubble simply "shrinks" as plants retire or are used less.

9. As discussed in the previous report, these estimates may overstate the level of emissions from new sources in 2000; emissions could be lower in those states that chose to operate under the exemptions, but did not experience the amount of new-source growth predicted by the model.

The Effect of the 40-Year NSPS in the 1990s

Utilities would have two options in preparing for the 40-year standard. On the one hand, those in states operating under emission targets might switch to low-sulfur coal (when possible) for their oldest plants during the 1990s, and focus technological reduction efforts on newer units, where the costs of installing retrofit scrubbers are usually lower. While this approach might be less expensive in the 1990s, it would leave many older units unable to meet the NSPS requirement by 2003. Therefore, annual costs would be relatively small during the 1990s, but much higher in the subsequent decade.10/ The cost estimates presented here reflect this short-run emphasis.

Alternatively, utilities might accelerate the installation of NSPS emission controls on older units (those they did not plan to retire) before 2003 in anticipation of the standard, and delay the installation of technological controls on the newer units until the 40-year NSPS requirements took effect. This approach might be especially attractive for utilities located in states that chose to phase in the default standard (0.9 pound of SO_2 per million Btu) in 1998 on 30-year old plants. Instead of meeting a shifting standard over a 10-year period in these states, utilities might preempt the 40-year standard when plants reached 30 years, by installing NSPS controls earlier, or retiring units then, in lieu of expensive retrofits. Under this scenario, the annual costs during the 1990s could be much higher than the estimates provided here.

The Role of Clean Coal Technology

There are two main types of clean coal technologies. The first type--retrofit technologies--would be installed on existing plants primarily to reduce SO_2 emissions from burning coal. Utilities could utilize these technologies during the 1990s along with conventional controls in order to achieve emission reductions required from existing plants. The other main type--repowering technologies--are options that utilities would choose with longer-run considerations in mind, in addition to emission control, such as capacity growth. This section discusses emerging retrofit options under the Committee bill; repowering is discussed in a later section. By postponing the full 12 million ton reduction to the year 2000, and delaying the deadlines for utilities to sign commitments to install innovative clean coal technologies,

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10. The model used by CBO to construct cost and emission estimates predicts utility decisions based on a least-cost response to the bill's requirements for the year 2000, but not beyond.

the new bill could encourage deployment of emerging retrofit technologies. To the extent that this occured, costs could be lower in the year 2000. However, two elements of the bill--the overall level of emission reductions that would necessitate emission removal at high percentages, and the 40-year NSPS requirement--might weaken the incentive for utilities to retrofit with emerging low-percentage-removal technologies.

Two types of emerging retrofit SO_2 technologies--the limestone injection multistage burner (LIMB) and in-duct sorbent injection--may reduce capital and operating costs compared with conventional wet scrubbers. However, wet scrubbing routinely removes well over 90 percent of the potential SO_2 from the flue gas, while LIMB and in-duct sorbent injection currently attain only 40 percent to 80 percent removal. To achieve the 12 million ton reduction goal, emission limits on most plants would have to be very strict. In this situation, these new technologies would be used in conjunction with low- or medium-sulfur coal, making the overall cost per ton of SO_2 removed comparable to that of wet scrubbing. Compared with conventional scrubbers, the newer technologies are most appropriate for smaller, older, boilers used primarily as cycling units. Although these units would require controls under the Committee bill, they would represent a relatively small fraction of the overall emission reduction.

Another hurdle to the market penetration of these promising technologies would be the looming 40-year NSPS percentage reduction requirements. Utilities might be extremely reluctant to assume the risks of operating new technology when it would only provide compliance status for 5 to 15 years. The likely market for these emerging retrofit technologies--smaller, typically older, units--is precisely the segment of the boiler population that would initially face the 40-year NSPS in 2003. However, another emerging technology--the slagging combustor--might achieve the current NSPS removal percentages. Since it is being developed primarily with smaller utility boilers in mind, the slagging combustor could achieve wide-scale commercial deployment.

COSTS AND EMISSIONS AFTER 2000 UNDER THE REVISED BILL

In 1998, states would be faced with additional SO_2 reduction requirements. Under section 183, they could either maintain the emission levels allowed under the excess emission formula targets (by securing emission offsets to accommodate new-source emission growth), or phase in the default standards as plants reached age 30.

The Effects of the ~~1988~~ 1998 Rules

Both approaches are designed to increase steadily the level of control applied to existing sources beyond the year 2000. Under the emission cap defined by the emission reduction formula, any new-source emissions would be offset by reductions elsewhere in the state. In some cases, the 40-year NSPS would provide sufficient offsets after 2003, but this would depend on the age profile of existing capacity relative to projected new-source growth. If reductions beyond those provided by the 40-year NSPS were required, new emission sources could be extremely expensive to site within a state. An exception to this could occur in "small" states (operating under the 250,000 ton emission cap). Several of these states had less than 100,000 tons of SO_2 emissions in 1985, and would not face a significant constraint for the foreseeable future.

Otherwise, states might find it advantageous to phase in the 30-year 0.9 pound monthly standard, since sources built after 1998 would not require emission offsets. This feature could even encourage default in some states especially concerned about new-source growth, although default would remain an expensive approach for most states in terms of meeting the 1998 reduction requirements. The 40-year NSPS could limit this advantage, however, since plants meeting the 30-year standard would face a much stricter standard in 10 years.

"Clean" states would have no emission caps as defined by the reduction targets. While this implies that no older sources would be emitting above a 0.9 pound rate, the 30-year standard could have a limited effect since it is calculated on a monthly basis, and is therefore stricter than an annual average.

The Effects of the 40-Year NSPS

As discussed before, the model underlying the CBO estimates only extends until 2000, while the 40-year NSPS would be first imposed in 2003. Thus, it is difficult to estimate the eventual effect on utility costs of the 40-year NSPS requirement. Since the model also aggregates individual plants into plant categories, it is impossible to forecast the compliance method that would be chosen by specific generating units in the years preceding 2003. The subsequent incremental controls required for the roughly 60 gigawatts of capacity that would be 40 years old or older in 2003 are uncertain. Finally, the model does not predict plant retirements satisfactorily, even though early retirement and accelerated replacement could be widespread in response to the 40-year NSPS.

Notwithstanding these uncertainties, three basic options exist for utilities facing the 40-year NSPS on their plants:

retirement, repowering, and retrofitting. Retirement would require utilities to build replacement capacity conforming to the NSPS (which could be revised by 2003). Repowering utilizes part of the existing facility, but the boiler and generator configuration is either replaced or substantially modified with emerging technologies that conform to the NSPS. Repowering with new technology might be less expensive than constructing a "greenfield" NSPS pulverized coal plant with a wet scrubber, which can cost $1,200 to $1,500 per installed kilowatt. The Department of Energy (DOE) has estimated that the cost of repowering technologies could be as low as $759 per kilowatt for atmospheric fluidized bed combustion; $818 per kilowatt for pressurized fluidized bed combustion; and $1,156 per kilowatt for integrated gasification combined cycle plants (in 1985 dollars). This compares with the DOE estimate of $1,285 per kilowatt for a new NSPS plant. Alternatively, utilities could install retrofit scrubbers at $357 per kilowatt (or, in combination with a life extension project for the boiler and turbines and a scrubber, at $657 per kilowatt).11/ These latter figures are higher than most estimates. In the model used for the CBO estimates, for example, the capital cost of a retrofit scrubber was assumed to be $260 to $290 per kilowatt.

By 2010, about 125 gigawatts of coal-fired capacity would be 40 years old. In the results presented here, over 50 gigawatts of capacity would already be retrofitted by 2000, but it is likely that much of this would occur at relatively new (that is, less than 40-year-old) plants that can be scrubbed at less cost. Therefore, at least 75 gigawatts of the 125 gigawatts of 40-year-old capacity might still have to be scrubbed, replaced, or repowered during the decade.

Estimating the cost of the 40-year NSPS entails comparing the cost of retofitting, repowering, or replacing the affected capacity against what utilities would otherwise do. This procedure introduces an additional element: comparing expenditures over time against the (basecase) alternative of eventual retirement or repowering. If the actual effect of a 30-or 40-year standard would be simply to accelerate eventual replacement or repowering, then the cost of the standard would be less than a mere comparison of costs would indicate.

A hypothetical example can illustrate this point, using a repowering cost of $800 per kilowatt, a life extension cost of $350, and a real discount rate of 5 percent.12/ In the absence

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11. See Department of Energy, "The Role of Repowering in America's Power Generation Future" (November 1987).

12. CBO typically uses a 2 percent real rate (representing the riskless rate on government time preference) to compute present values for government programs. However, for

TABLE 1. SULFUR DIOXIDE EMISSION REDUCTION REQUIREMENTS OF S. 1894

Target Date	Excess-Emission States Over 1,000 Tons of Excess Emissions in 1980 and Over 150,000 Tons of Utility Emissions in 1985	Clean States Less Than 1,000 Tons of Excess Emissions in 1980	Small States Less Than 150,000 Tons of Utility Emissions in 1985	One-Source States Less Than 40,000 Tons of Utility Emissions in 1985, with Over 90 Percent from One Source
Enactment	Sources that increase emission rates above 1980 levels must secure simultaneous offsets.		Annual emission cap of 250,000 tons.	Annual emission cap of 100,000 tons.
5 Years After Enactment	Sources complying with emission limits by switching fuel must be in compliance, including sources in states operating in default.			
1/1/93	5-million-ton reduction target achieved.		0.9 annual average SO_2 emission rate for all sources.	
1/1/98	Offsets secured for sources emitting over their 1980 emission rates between 1981 and enactment. 0.9 annual SO_2 emission rate achieved for all sources operating in 1980. 10 million ton reduction target achieved. All sources in states operating in default meet 0.9 monthly standard. Choice of: (i) 30-year 0.9 monthly standard; (ii) 30-year 0.9 monthly bubbled standard if below mandated targets; or (iii) emission target adopted as perpetual emission cap.	30-year 0.9 monthly standard for all sources.	30-year 0.9 monthly standard for all sources.	30-year 0.9 monthly standard for all sources.
1/1/2000	12 million ton reduction target achieved.			
1/1/2003	NSPS applies to all sources 40 years and older.	NSPS applies to all sources 40 years and older.	NSPS applies to all sources 40 years and older.	NSPS on principal source; NSPS applies to all sources 40 years and older.

SOURCE: Congressional Budget Office.

TABLE 2. STATE CLASSIFICATION UNDER S. 1894

Excess-Emission States Over 1,000 Tons of Excess Emissions in 1980 and Over 150,000 Tons of Utility Emissions in 1985	Clean States Less Than 1,000 Tons of Excess Emissions in 1980	Small States Less Than 150,000 Tons of Utility Emissions in 1985	One-Source States Less Than 40,000 Tons of Utility Emissions in 1985, With Over 90 Percent from One Source
Alabama	Arizona	Arkansas	South Dakota
Florida	California	Delaware	
Georgia	Colorado	Kansas	
Illinois	Connecticut	Maine	
Indiana	Idaho	Minnesota	
Iowa	Louisiana	Mississippi	
Kentucky	Nevada	Montana	
Maryland	Oklahoma	Nebraska	
Massachusetts	Oregon	New Hampshire	
Michigan	Rhode Island	New Jersey	
Missouri	Utah	New Mexico	
New York	Vermont	North Dakota	
North Carolina		South Carolina	
Ohio		Virginia	
Pennsylvania		Washington	
Tennessee		Wyoming	
Texas			
West Virginia			
Wisconsin			

SOURCE: Office of Technology Assessment, based on the National Acid Precipitation Assessment Program inventory for 1980 emissions, and the National Emission Data Survey for 1985 emissions.

of additional requirements, a utility operating a one-gigawatt, 40-year-old plant might invest in a life extension program first, which would enable the utility to postpone a repowering project for 20 years; this strategy would cost $350 million now and $800 million in 20 years. The discounted cost of the latter figure is about $300 million, and thus the current cost of this long-term capital plan is $650 million. Since repowering now would cost $800 million, the utility would choose to invest in the life extension program. If, however, the NSPS requirement caused the utility to repower at 40 years, then the difference--$150 million--could be attributable to the bill. Using a 10 percent capital charge levelization factor, and scaling this example up to the 75 gigawatts of unscrubbed capacity that would be 40 years old in 2010, the annual cost of the NSPS could be as low as $1.1 billion. Alternatively, if utilities would repower existing capacity at 40 years in any case, the net cost of the requirement could conceivably be zero, although this would appear to be optimistic given the situation that utilities will likely confront over the next decade.

This example, although crude, shows that the cost of the 40-year NSPS depends more on basecase assumptions regarding future capacity decisions rather than on the cost of alternative technologies per se. If utilities in the above example simply retrofitted the 75 gigawatts with scrubbers, the capital cost of the NSPS (net of life extension) would be closer to $3 billion annually, with annual operating costs of close to $2 billion. This cost is almost certainly overstated, since the cost of scrubbing (or similar technologies) will probably fall, utilities could repower a significant fraction of this capacity, and, in some cases, capacity could be retired without replacement. Annual costs of the requirement by 2010, although impossible to estimate precisely, would more likely be in the range of $1 billion to $3 billion annually.

Finally, this example depicts utility decisions regarding the 40-year standard in isolation of the bill's other requirements. If, by 2003, utilities had already installed retrofit scrubbers on most units in order to achieve the emission reductions mandated by 2000, they might not undertake repowering projects on the same units. The incentives for preempting the 40-year NSPS by installing retrofit scrubbers on most units could significantly limit the role that repowering would play under the bill.

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utility decisionmaking and cost accounting, a rate of 5 percent more accurately reflects current market rates for long-term debt.

TABLE 3. ANNUAL UTILITY SULFUR DIOXIDE EMISSIONS AND NET ANNUAL COST IN 2000 UNDER S.1894

State	Emissions (In thousands of tons of SO2)		Net Annual Cost (In millions of 1985 dollars)
	Basecase	S.1894	
Alabama, Mississippi	756	318	188
Arizona	146	139	8
Arkansas, Oklahoma, Louisiana	587	522	126
California	34	34	13
Carolinas, North and South	666	425	262
Colorado	136	138	20
Dakotas, North and South	192	69	24
Florida	1,009	331	381
Georgia	1,037	225	337
Idaho	0	0	0
Illinois	1,210	359	343
Indiana	1,844	360	412
Iowa	290	119	67
Kansas, Nebraska	168	132	33
Kentucky	781	232	364
Maine, Vermont, New Hampshire	95	36	32
Maryland, Delaware	534	127	60
Massachusetts, Connecticut, Rhode Island	309	173	24
Michigan	482	293	239
Minnesota	340	90	-70
Missouri	1,159	177	446
Montana	90	60	22
Nevada	89	89	2
New Mexico	95	95	8
New York (Downstate), New Jersey	452	240	157
New York (Upstate)	256	133	53
Ohio	2,687	651	440
Pennsylvania	1,473	472	715
Tennessee	961	259	250
Texas	1,093	296	767
Utah	96	71	19
Virginia, District of Columbia	306	167	103
Washington, Oregon	140	122	21
West Virginia	956	337	215
Wisconsin	514	177	136
Wyoming	122	108	13
U.S. Total	21,105	7,576	6,230

SOURCE: National Coal Model, modified by the Congressional Budget Office.