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Air

EPA

# Electric Utility Steam Generating Units

# Background Information for Proposed $SO_2$ Emission Standards

## Supplement

NSPS

EPA-450/2-78-007a-1

# Electric Utility Steam Generating Units
## Background Information for Proposed $SO_2$ Emission Standards

## Supplement

Emission Standards and Engineering Division

U.S. ENVIRONMENTAL PROTECTION AGENCY
Office of Air, Noise, and Radiation
Office of Air Quality Planning and Standards
Research Triangle Park, North Carolina 27711

August 1978

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Background Information Supplement
for Proposed $SO_2$ Emission Standards for
Electric Utility Steam Generating Units

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# 1. INTRODUCTION

In February of 1978 EPA completed a preliminary analysis of options for revising new source performance standards (NSPS) for new steam electric generating units in the utility industry. The February analysis is contained in the document Electric Utility Steam Generating Units: Background Information for Proposed $SO_2$ Emission Standards (report number EPA-450/2-78-007a). This supplement to the initial February document provides results of additional impact analyses (sections 2 and 3) and contains the results of new areas of investigation (section 4) used in developing the proposed standards.

Sections 2 and 3 contain analyses of projected impacts of alternative NSPS that include consumer and utility costs, national and regional emissions, national coal and oil consumption, and new electric generation construction. Impacts discussed in section 2 were developed in April 1978. After review of these data, it was apparent that many of the impacts projected could be altered appreciably by the basic assumptions used. A review of these assumptions indicated the need for changes based upon additional or more up-to-date information. For example, future electric demand was revised downward to reflect energy conservation measures that have slowed recent growth in national electric demand. These revised assumptions were then applied in August 1978 to develop the impacts given in section 3. A description of the assumptions used in each analysis is given in introductions to the respective sections.

The impact analyses in sections 2 and 3 were projected from ICF Incorporated's coal and electric utilities model. These analyses also contain impacts developed by Temple, Barker, and Sloane, Inc. (TBS) using ICF data. The ICF model simulates the decision making process of utility companies based upon the most economical choice of alternatives. The number, size, and types (coal-fired boilers, oil-fired turbines, etc.) of new power plant generating equipment to be constructed is projected from electric demand growth, fuel availability and costs, emission control costs, and electric generating equipment costs. Once a physical description of the electric utility industry is projected, the model determines the incremental operating costs of each electric generating unit. Based upon the relative costs of operation, a load dispatching order and unit load factors are projected. The model then computes national and regional impacts on utility capital and annualized costs, emissions, coal and oil consumption, etc. Because the model projects utility decisions solely on the most favorable economic choice, it does not take into account other factors that can influence decisions, especially when the projected costs of two alternatives are very close.

Section 4 contains an assessment of FGD performance capabilities and projected FGD performance in new affected units. Performance of dry control systems is also included. Performance test requirements and limitations on bypassing during FGD malfunctions are discussed. Other topics addressed are application of the proposed standards to noncontinental areas and effects of alternative standards on the utilization of high-sulfur and anthracite coals.

# 2. IMPACT ANALYSIS OF APRIL 1978

## 2.1 INTRODUCTION

In April 1978 an analysis of alternatives for preparing revised NSPS for power plants was completed by EPA consultants Temple, Barker, and Sloane Inc. Data supplied on April 17, 1978, from the ICF, Inc. coal and electric utilities model were used in the analysis. Some adjustments to the $SO_2$ emission data were made at a later date after a computational error was discovered. The corrected data are presented in this section. The data presented are analyses of actual 1975 conditions, the impact in 1990 of the current NSPS, and future impacts of five alternatives for revised NSPS.

The "floors" analyzed are maximum control levels (24-hour average), which, when attained, require no additonal percentage of $SO_2$ removel by an FGD control system. A 0.2 lb/million Btu floor would require virtually all coal to be subjected to full FGD control. For the purpose of this analysis, full FGD control is 85% reduction(24-hour basis) except for 3 days/month during which 75 percent reduction is allowed. Higher floors would permit some low-sulfur coals, principally Western coals, to be burned without full FGD control (partial scrubbing). A portion of the flue gas could be bypassed around the FGD system for reheating the stack gas and improving plume buoyancy with the higher floors (0.5 and 0.8 lb/million Btu). Bypassing of flue gas also reduces the energy penalty associated with wet scrubbers since little or no reheat is required.

The "ceilings" analyzed (also expressed in lb/million Btu) are maximum emission limits (24-hour average) that cannot be exceeded except when exemptions are considered. The alternatives with exemptions would allow the ceiling to be exceeded for 3 days in a month, but would not allow less FGD control than is required by the percent $SO_2$ removal standard. The five alternatives considered are:

1. 0.2 floor, 1.2 ceiling, with exemptions.
2. 0.2 floor, 1.2 ceiling, without exemptions.
3. 0.5 floor, 1.2 ceiling, with exemptions.
4. 0.5 floor, 1.2 ceiling, without exemptions.
5. 0.8 floor, 1.2 ceiling, with exemptions.

## 2.2 INPUT ASSUMPTIONS USED BY COMPUTER MODEL

### 2.2.1 FGD Efficiency

In the analysis of alternatives, scrubbers were assumed to be 90 percent efficient on a 30-day average basis when full FGD control was required to attain the floor. In analysis of 0.2 floor alternatives, it was assumed that full FGD control would be required. In analysis of 0.5 and 0.8 floors, it was assumed that less $SO_2$ percent reductions (partial scrubbing) would be permitted when certain very low sulfur coals were burned and that average $SO_2$ emissions would be equal to the floor each 24-hour period.

### 2.2.2 Coal Sulfur Content Variability

The variation in daily potential $SO_2$ emissions that must be controlled by FGD was projected by a statistical distribution of 24-hour averages based upon a relative standard deviation (RSD) of 15 percent. Variation in the average sulfur content of coal consumed in a 24-hour period by electric utility boilers is reviewed in section 4.2.7, where RSD is discussed as a function of coal type and plant size.

When no exemption in the ceiling was allowed, the assumption was that the utilities would purchase coal that would be in compliance with the ceiling when (1) the FGD control efficiency dropped to 75 percent and (2) the projected 24-hour average coal sulfur content is highest (i.e., 3 standard deviations above the long-run mean sulfur content). When an exemption of the ceiling was allowed, it was assumed that the utilities would purchase coal that would be in compliance with the ceiling at 85 percent efficiency (i.e., the ceiling constraint falls 2 standard deviations above the long-run mean sulfur content because the higher $SO_2$ emissions that would be projected by 3 standard deviations would peak through the exemption in the ceiling).

### 2.2.3 Growth in Electric Demand

Growth in the nation's electricity consumption was projected to be 5.8 percent per year through 1985 and 5.5 percent per year thereafter. This is a relatively high growth assumption and therefore results in a high estimate of the number of new plants affected by the revised standard. Construction of nuclear units to satisfy this demand was projected to increase national nuclear capacity to 108 gigawatts (GW) in 1985, 177 GW in 1990, and 302 GW in 1995. Other increases in capacity are expected from new coal or oil-fired electric-generating equipment and other sources.

### 2.2.4 Cost Escalations

A general economic inflation rate of 5.5 percent per year was assumed; however, costs in accompanying tables have been discounted to 1975 dollar values. Present (1975) costs for crude oil ($13 per barrel), coal transportation, and coal mining labor were not increased beyond the general inflation rate. The oil price assumption has a major effect on results since it determines the mix of generation capacity which is used. A low oil price results in more oil consumption and less new coal plant construction as well as less coal consumption than would result if a high oil price is assumed.

## 2.3 COST AND FINANCIAL IMPACTS

### 2.3.1 Cumulative Capital Expenditures

The cumulative capital expenditures given on Table 2-1 consist of the sum of all capital expenditures anticipated from 1976 through 1990. These expenditures include the amounts to be spent on the following types of capital equipment:

- Power plants
- Transmission lines
- Distribution systems
- Scrubbers
- Electrostatic precipitators
- Baghouses.

The capital expenditures include cash expenditures and allowances for funds used during construction (AFDC). While AFDC is not a cash expenditure, it has been included because it is capitalized and becomes part of the consumer rate base. Excluded are the amounts spent on pollution control equipment for pollutants other than $SO_2$ after 1976. Some of the capital expenditures in the years 1985-1990 are for equipment that will not be in service by 1990.

The differences in capital expenditures among alternative NSPS reflect:

1. Number of scrubbers, precipitators, and baghouses constructed.

Table 2-1. NATIONAL COSTS IN 1990 OF ALTERNATIVE NEW SOURCE PERFORMANCE STANDARDS

| | | | Alternative NSPS, 90 percent $SO_2$ removal (increase from current NSPS) | | | | |
|---|---|---|---|---|---|---|---|
| | | | 0.2 floor | | 0.5 floor | | 0.8 floor |
| | | | 1.2 ceiling | | 1.2 ceiling | | 1.2 ceiling |
| | Actual 1975 | Current NSPS | With Exemptions | Without Exemptions | With Exemptions | Without Exemptions | With Exemptions |
| Financial parameters | | | | | | | |
| Cumulative capital Expenditures: 1976-1990, $billions | - | 746.1 | 9.4 | 9.4 | 14.7 | 12.4 | 2.9 |
| Annual revenue requirement, $billions | 46.9 | 142.5 | 3.8 | 4.3 | 3.0 | 3.0 | 0.5 |
| Average consumer rate, mills/kwh | 27.0 | 35.93 | 0.99 | 1.09 | 0.76 | 0.77 | 0.15 |
| Average monthly residential bill* | | | | | | | |
| Apartment | 11.49 | 14.13 | 0.34 | 0.37 | 0.28 | 0.27 | 0.05 |
| Home without electric heat | 21.00 | 34.78 | 0.83 | 0.92 | 0.68 | 0.67 | 0.12 |
| Home with electric heat | 62.60 | 93.46 | 2.24 | 2.49 | 1.85 | 1.83 | 0.34 |
| National average | 21.87 | 45.31 | 1.08 | 1.21 | 0.89 | 0.88 | 0.16 |
| Economic parameters | | | | | | | |
| Present value of NSPS,** $billions | - | 35.5 | 26.1 | 31.5 | 15.6 | 18.1 | 0.7 |
| Annualized costs, $billions | - | 95.7 | 2.0 | 2.2 | 1.3 | 1.5 | 0.3 |
| Incremental cost of $SO_2$ reduction,*** $/ton | - | 0 | 833 | 758 | 619 | 750 | 300 |

*Average monthly bills based on the following use in 1990: apartments 325 kwh/month; homes without electric heating, 800 kwh/month; homes with electric heating, 2,150 kwh/month; national average, 1,042 kwh/month.

**Includes capital expenditures and operating costs through 1990 and operating costs from 1990 to 2020 for all $SO_2$ control equipment and capacity mix changes, discounted at a real rate of 5 percent.

***Incremental costs determined by dividing the incremental annualized cost by the reduction in $SO_2$ emissions, using the current NSPS as a base.

(Source: Annualized costs and incremental costs per ton were prepared by ICF. All other figures prepared by TBS. April 17, 1978.).

2. Type and capacity of new power plant constructed. As NSPS become more stringent, a greater percentage of new plant additions will utilize oil-fired turbines, which cost less to install than coal-fired plants.

3. Type of coal burned in new coal-fired power plants (coal plant design and construction costs vary with the type of coal).

In the 0.2 floor, 1.2 ceiling cases, cumulative capital expenditures are similar. Although the 0.2 floor, 1.2 ceiling without exemptions case has a large amount of less expensive, oil-fired turbine capacity; turbine capacity is only slightly greater than that in the 0.2 floor, 1.2 ceiling with-exemptions case. The relative savings is offset by lower construction costs for coal-burning plants in the case with exemptions.

In the 0.5 floor, 1.2 ceiling cases, cumulative capital expenditures differ. The 0.5 floor, 1.2 ceiling-without-exemptions case will have 4.9 GW more turbine capacity in 1990 than the case with exemptions. This saving, along with the saving attributable to a significantly lower percentage of flue gas scrubbed, creates a relatively lower cumulative capital expenditure in the without-exemptions case.

The 0.5 floor case results in higher total capital costs than the 0.2 floor case. This is due to the change in capacity mix under the two alternatives. The 0.2 floor requires more expensive pollution control equipment which results in utility decisions to delay construction of some new coal-fired capacity and increase their oil consumption, thus lowering their total capital costs. The 0.5 floor does not require as much pollution control capital which reduces the cost of coal generation relative to oil-fired generation and results in more new coal capacity being constructed. This increase in new plant construction offsets the savings in capital associated with lower pollution control capital expenses. Therefore, capital expenditures are higher under the 0.5 floor case. However, if total expenses including fuel and operating and maintenance costs are examined, the 0.5 floor case is less expensive than the 0.2 floor case.

### 2.3.2 Annual Revenue Requirements

The annual revenue requirements in Table 2-1 represent funds necessary to cover all operating costs (fuel, operating expenses, and maintenance expenses, capital costs AFDC, return on equity, and depreciation), and taxes. The 1990 revenue requirements of the alternatives considered are different because of changes in capital-related charges and total fuel charges. These factors vary with the relative amount of energy generated by coal-fired plants and oil-fired turbines. The generation mix as well as total fuel charges are affected by fuel prices.

The annual revenue requirements can be expected to be different for other years. This is due to the increasing total electric generating construction requirement and the timing of the capital expenditures which produces a shift between capital and O&M expenses.

### 2.3.3 Average Consumer Rate

The average consumer electric rate is determined by dividing the annual revenue requirements by the number of kilowatt-hours sold. Under all alternative NSPS, the amounts of electricity sold are equal, so that the percentage change in average consumer rate between alternative NSPS is the same as the percentage change in required revenues.

### 2.3.4 Average Residential Monthly Bill

The average residential monthly bill has been determined by estimating the difference between the average electric rate and the historical average residential electric rate and applying this rate to the estimated electrical consumption. In 1976, residential consumers paid about 50 percent more for electricity than the average cost of each kilowatt-hour produced. The differential in 1990 was estimated by assuming that increased fuel and operating costs would be apportioned equally on a per-kilowatt-hour basis to all customer classes and increased capital costs would be apportioned at the same rate as they are currently, with residential customers paying more than industrial customers. The figures for apartments and homes with and without electric heat reflect the different levels of usage by these types of residence. The figures reflect an increase in electrical consumption of about 50 percent between 1975 and 1990.

The 1990 regional average monthly residential bills in Table 2-2 were estimated by TBS using the national average monthly residential bills reported in Table 2-1 and the regional annualized costs provided by ICF. The regional annualized costs and electric generation figures were used to calculate regional costs per kilowatt-hour. These costs were then adjusted to represent regional residential costs. The ratio of each of the regional residential kilowatt-hour costs to the national average residential costs was used to adjust the national average monthly residential bill.

### 2.3.5 Present Value of NSPS

The present values presented in Table 2-1 represent the real resource cost of the sum of the capital expenditures for NSPS pollution control

Table 2-2. REGIONAL COSTS AND RESIDENTIAL MONTHLY BILLS UNDER ALTERNATIVE NEW SOURCE PERFORMANCE STANDARDS

| | Actual 1975 | Current NSPS | Alternative NSPS, 90% $SO_2$ removal (change from current NSPS) | | | | |
|---|---|---|---|---|---|---|---|
| | | | 0.2 floor | | 0.5 floor | | 0.8 floor |
| | | | 1.2 ceiling | | 1.2 ceiling | | 1.2 ceiling |
| | | | With Exemptions | Exemptions | With Exemptions | Without Exemptions | With Exemptions |
| Annualized costs, $billions | | | | | | | |
| East | - | 43.8 | 1.0 | 1.3 | 0.7 | 0.9 | 0.1 |
| Midwest | - | 24.9 | 0.6 | 0.6 | 0.4 | 0.4 | 0.0 |
| West South Central | - | 13.9 | 0.4 | 0.4 | 0.3 | 0.3 | 0.2 |
| West | - | 13.0 | 0.0 | 0.0 | -0.1 | -0.1 | 0.0 |
| Total | - | 95.7 | 2.0 | 2.3 | 1.3 | 1.5 | 0.3 |
| Average residential monthly bill, $ | | | | | | | |
| East | - | 47.07 | 1.22 | 1.54 | 1.02 | 1.15 | 0.12 |
| Midwest | - | 44.13 | 1.24 | 1.23 | 1.01 | 0.91 | 0.03 |
| West-South Central | - | 53.92 | 1.75 | 1.72 | 1.52 | 1.37 | 0.83 |
| West | - | 36.20 | 0.12 | 0.09 | -0.07 | -0.12 | 0.04 |
| National average | 21.87 | 45.31 | 1.08 | 1.21 | 0.89 | 0.88 | 0.16 |

(Source: Annualized Costs, ICF; Residential Bill, TBS, April 17, 1978.).

equipment and costs (or savings) resulting from generating-capacity changes from 1976 to 1990. The present values include all capital and operating expenses incurred over the 1976-1990 period plus fuel and operation and maintenance expenditures for all NSPS equipment and capacity mix changes. The costs of pollution control equipment consist of capital expenditures for and operation and maintenance of scrubbers, baghouses, and precipitators; and the capital expenditures for and operating costs of additional generating capacity needed to make up for the energy used by the pollution control equipment. Changes in generating capacity mix can result in costs or savings in capital expenditures for generating plants, as well as variations in coal price, and changes in operating costs. The costs of capacity mix changes were computed as changes from a base case: the current NSPS (1.2-lb/million-Btu $SO_2$ ceiling, 0.1 lb/million Btu particulate matter ceiling). In order to calculate the "real reasource costs," financial flows and transfer payments were excluded since they do not measure resources allocated but are really transfer payments. Among the accounting charges and cash flows specifically omitted were: Allowance for funds used during construction (AFDC), depreciation, interest, return on equity, and taxes.

### 2.3.6 Annualized Costs

The 1990 annualized costs were calculated by ICF's model, which included fuel costs and operation and maintenance expenses for all capacity in use, and a capital cost component for new capacity brought on-line after 1975 and in use by 1990. The capital cost component does not include any charges for capacity installed earlier. Capital expenditures were computed using a real fixed charge rate of 0.1, which includes depreciation, dividends, interest, and taxes. Capital expenditures for electricity distribution systems are not included; however, these should not change between the alternative cases examined.

### 2.3.7 Incremental Cost of Emission Reduction

The incremental cost of emission reduction was calculated by dividing the incremental annualized cost of each alternative NSPS by the emission reduction in $SO_2$ emissions. The incremental annualized costs and emissions reductions are the difference between the annualized cost and emissions of each alternative NSPS and the current NSPS.

### 2.3.8 Regional Annualized Costs

The annualized costs of alternative NSPS in 1990 are given on a regional basis in Table 2-2. They were calculated in the same manner as described for the national annualized costs in Table 2-1.

The four regions selected were groupings of Bureau of Census regions:

1. East--New England, Middle Atlantic, South Atlantic, and East South Central
2. Midwest--West North Central and East North Central
3. West South Central--West South Central
4. West--Pacific and Mountain

Although most regional costs increase under the alternative NSPS, annualized costs in the western regional decrease with a 0.5 floor. A change to the 0.5 floor alternative would decrease demand for western coal, and thereby drive down coal prices in the region. This coal price saving is not offset by increased pollution control costs since State regulations in the region are already more stringent than the current NSPS.

### 2.3.9 Annual Emissions of $SO_2$

The amounts of $SO_2$ emitted in 1990 by coal-fired generating plants, are shown in Table 2-3a on a regional basis for each alternative NSPS. Table 2-3a shows a reduction in national $SO_2$ emissions for all alternatives considered relative to retaining the current NSPS.

Table 2-3b further details 1990 emissions by type of emitting plant. The model predicts that as the costs of building and operating new plants increases due to air pollution control expenses, construction of planned new facilities will be delayed. Hence, the predicted increase in new plant emissions (Table 2-3b) under the partial scrubbing options is due not only to the higher emission rates, but also to the increased new capacity predicted under the less stringent standards. Similarly, the model predicts that emissions from SIP/NSPS plants will increase under the revised standards as existing plants are utilized more in order to compensate for the delays in bringing new capacity on line.

## 2.4 IMPACT OF NSPS ALTERNATIVES ON FUEL PRODUCTION

### 2.4.1 Coal Production

The effects of alternative NSPS on total and regional coal production in 1990 are shown in Table 2-4. The amount of Western coal shipped east, a large component of total Western coal production, is reported separately. This figure is affected significantly by the assumptions regarding rail rate increases. This analysis assumes no real price increase and therefore results in a high estimate of the amount of Western coal shipped East.

### 2.4.2 Oil and Gas Consumption

Oil and gas consumed in 1990 by electric utilities, in quads ($1 \times 10^{15}$ Btu) is reported as the increment to oil and gas consumed in 1990 by

Table 2-3a. REGIONAL SULFUR DIOXIDE EMISSIONS IN 1990
UNDER ALTERNATIVE NEW SOURCE PERFORMANCE STANDARDS

| | | | Alternative NSPS, 90% $SO_2$ removal (change from current NSPS) | | | | |
|---|---|---|---|---|---|---|---|
| | | | 0.2 floor | | 0.5 floor | | 0.8 floor |
| | | | 1.2 ceiling | | 1.2 ceiling | | 1.2 ceiling |
| | Actual 1975 | Present NSPS | With Exemptions | Without Exemptions | With Exemptions | Without Exemptions | With Exemptions |
| Annual emissions of $SO_2$ (million tons) | | | | | | | |
| East | 9.1 | 10.8 | -1.1 | -1.4 | -1.2 | -1.1 | -0.6 |
| Midwest | 8.8 | 8.7 | -0.2 | -0.4 | -0.3 | -0.3 | -0.1 |
| West South Central | 0.2 | 2.6 | -0.8 | -0.8 | -0.6 | -0.6 | -0.3 |
| West | 0.5 | 1.3 | -0.2 | -0.2 | 0.1 | 0.1 | 0.0 |
| Total | 18.6 | 23.3 | -2.2 | -2.7 | -2.0 | -1.9 | -1.0 |

Table 2-3b. SULFUR DIOXIDE EMISSIONS IN 1990
UNDER ALTERNATIVE NEW SOURCE PERFORMANCE STANDARDS

| | Actual 1975 | Present NSPS | Alternative NSPS, 90% $SO_2$ removal (total emissions) | | | | |
|---|---|---|---|---|---|---|---|
| | | | 0.2 floor | | 0.5 floor | | 0.8 floor |
| | | | 1.2 ceiling | | 1.2 ceiling | | 1.2 ceiling |
| | | | With Exemptions | Without Exemptions | With Exemptions | Without Exemptions | With Exemptions |
| Annual emissions of $SO_2$ (million tons) | | | | | | | |
| SIP/NSPS Plants[a] | — | 16.8 | 17.2 | — | 16.9 | — | 16.7 |
| New Plants[b] | — | 4.2 | 1.5 | — | 2.1 | — | 3.3 |
| Oil/Gas Plants | — | 2.3 | 2.5 | — | 2.3 | — | 2.3 |
| TOTAL | 18.6 | 23.3 | 21.1 | — | 21.3 | — | 22.3 |
| Total Coal Capacity (GW) | 205 | 465 | 444 | | 460 | | 460 |

[a]Plants subject to existing state regulations or the current NSPS of 1.2 #$SO_2$/MMBtu.

[b]Plants subject to the revised NSPS.

Table 2-4. COAL AND OIL CONSUMPTION IN 1990
UNDER ALTERNATIVE NEW SOURCE PERFORMANCE STANDARDS

| | Actual 1975 | Current NSPS | Alternative NSPS, 90% $SO_2$ Removal (change from current NSPS) | | | | |
|---|---|---|---|---|---|---|---|
| | | | 0.2 floor | | 0.5 floor | | 0.8 floor |
| | | | 1.2 ceiling | | 1.2 ceiling | | 1.2 ceiling |
| | | | With Exemptions | Without Exemptions | With Exemptions | Without Exemptions | With Exemptions |
| Total Coal Production, million tons | 647.4 | 1766.8 | -55.7 | -49.2 | -12.3 | -1.0 | +12.7 |
| Regional coal production | | | | | | | |
| East | 396.3 | 441.3 | +25.3 | +47.5 | +22.6 | +31.9 | -23.5 |
| Midwest | 151.1 | 297.9 | +76.9 | + 8.0 | +54.6 | - 0.7 | + 8.9 |
| West | 100.0 | 1027.5 | -157.8 | -104.6 | -89.4 | -32.1 | +27.3 |
| Western coal shipped East | 20.8 | 455.4 | -156.2 | -126.6 | -109.7 | -58.7 | -26.3 |
| Oil and gas consumption (quads) | 6.5 | 6.3 | +0.8 | +0.9 | +0.2 | +0.2 | +0.2 |

electric utilities under the present NSPS. As noted earlier, these figures are very sensitive to the oil price assumption which is used.

## 2.5 EQUIPMENT CONSTRUCTION IMPACTS IN 1985 AND 1990

### 2.5.1 Generating Capacity

Generating capacity in 1985 and 1990 is reported by type for each alternative NSPS (Table 2-5.and 2-6). The largest differences between cases occur in coal and turbine capacities since under more stringent regulations companies defer coal plant additions, choosing instead to add less expensive turbine capacity. Note that differences in new coal capacity across the various cases. Nuclear capacity in a given year was assumed to be about the same in all cases.

Coal capacity under alternative NSPS is reported in three categories, each affected differently by NSPS: (1) Existing capacity in 1975 (not subject to any NSPS), (2) new plants added from 1976 to 1982 (subject to the current NSPS in all cases), and (3) new plants added from 1983 to 1985 or 1990 (subject to the current or alternative NSPS examined).

### 2.5.2 Coal Capacity With Scrubbers

Coal capacity with scrubbers under alternative NSPS is the sum of existing capacity in 1975, new plants added from 1976 to 1982, and new plants added from 1983 to 1985 or 1990. The amount of capacity equipped with scrubbers through 1982 is similar in all cases. Differences between cases arise because of coverage differences in new plants caused by changes in the on-line dates for new plants and plants under construction due to changes in the NSPS case examined.

## 2.6 MISCELLANEOUS IMPACTS

### 2.6.1 Percent of Flue Gas Scrubbed

The percent of flue gas scrubbed (Tables 2-5 and 2-6) are computed as a weighted average of the percent of flue gas scrubbed by plants equipped

Table 2-5. PHYSICAL DESCRIPTION OF ELECTRIC UTILITY INDUSTRY
IN 1990 UNDER ALTERNATIVE NEW SOURCE PERFORMANCE STANDARDS

| | | | Alternative NSPS, 90% $SO_2$ Removal | | | | |
|---|---|---|---|---|---|---|---|
| | | | 0.2 Floor | | 0.5 Floor | | 0.8 Floor |
| | | | 1.2 Ceiling | | 1.2 Ceiling | | 1.2 Ceiling |
| | Actual 1975 | Current NSPS | With Exemptions | Without Exemptions | With Exemptions | Without Exemptions | With Exemptions |
| Coal capacity,* GW | | | | | | | |
| Existing 1975 | 204.6 | 204.6 | 204.6 | 204.6 | 204.6 | 204.6 | 204.6 |
| New plants, 1976-1982 | -- | 88.4 | 88.8 | 88.8 | 87.7 | 88.8 | 87.3 |
| New plants, 1983-1990 | -- | 171.7 | 151.0 | 148.3 | 166.2 | 164.3 | 167.3 |
| Total coal, 1990 | 204.6 | 464.7 | 444.4 | 441.7 | 459.5 | 457.6 | 459.2 |
| Oil/gas capacity, GW | | | | | | | |
| Steam | 129.0 | 143.5 | 143.5 | 145.6 | 145.6 | 143.2 | 143.5 |
| Combined cycle | 2.7 | 15.9 | 15.3 | 15.3 | 9.9 | 11.7 | 15.9 |
| Turbine | 42.1 | 142.5 | 165.2 | 166.8 | 153.4 | 156.5 | 148.5 |
| Total oil/gas, 1990 | 173.8 | 301.9 | 324.0 | 327.7 | 308.9 | 311.4 | 307.9 |
| Nuclear capacity, 1990, GW | 38.3 | 176.7 | 176.7 | 176.7 | 176.7 | 176.7 | 176.7 |
| Hydroelectric and other capacity, 1990, GW | 68.3 | 87.7 | 86.2 | 85.2 | 86.8 | 85.5 | 86.8 |
| Coal capacity with scrubbers, 1990, GW | 2.5 | 97.4 | 204.9 | 204.9 | 220.8 | 219.4 | 110.5 |
| Flue gas scrubber,** percent | -- | 81.6 | 95.4 | 96.1 | 84.6 | 78.7 | 87.0 |
| Coal plant cost,*** $ | -- | 570.5 | 557.6 | 568.0 | 566.2 | 572.2 | 581.0 |

* Existing plants are not subject to NSPS. New plants, 1976-1982, are subject to the current NSPS in all cases. New plants, 1983-1990, are subject to the specific NSPS selected.

** Percentage of flue gas scrubbed is a weighted average of flue gas scrubbed in each coal capacity category. The percentage of flue gas scrubbed in plants built prior to 1983 is similar in all cases; differences are due to dissimilarities in new plants, 1983-1990.

*** Coal construction costs vary with the type of coal plants are designed to burn. Coal plant cost in 1990 is a weighted average based on the projected mix of bituminous, subbitumonous, and lignite burning coal capacity.

with scrubbers. As with coal capacity with scrubbers, the percent of flue gas scrubbed through 1982 is similar in all cases. Differences between cases again arise from differences in new plants installed after 1982. With the 0.2 floor, flue gas is 100 percent scrubbed at new plants installed after 1982, whereas in other cases the percentage scrubbed ranges from 89.9 to 76.3 percent.

### 2.6.2 Coal Plant Costs

Coal plant construction costs vary with the type of coal the plants are designed to burn--bituminous, subbituminous, or lignite. Coal plant costs in 1990 were computed as a weighted average based on the mix of coal types under alternative NSPS. The costs, including AFDC, are reported in 1975 dollars.

Table 2-6. PHYSICAL DESCRIPTION OF ELECTRIC UTILITY INDUSTRY IN 1985 UNDER ALTERNATIVE NEW SOURCE PERFORMANCE STANDARDS

| | | | Alternative NSPS, 90% $SO_2$ removal | | | | |
|---|---|---|---|---|---|---|---|
| | | | 0.2 floor 1.2 ceiling | | 0.5 floor 1.2 ceiling | | 0.8 floor 1.2 ceiling |
| | Actual 1975 | Current NSPS | With exemption | Without exemption | With exemption | Without exemption | With exemption |
| Coal capacity*, GW | | | | | | | |
| Existing 1975 | 204.6 | 204.6 | 204.6 | 204.6 | 204.6 | 204.6 | 204.6 |
| New plants, 1976-1982 | - | 84.0 | 84.8 | 84.9 | 85.0 | 85.0 | 83.8 |
| New plants, 1983-1985 | - | 31.6 | 24.1 | 19.2 | 25.5 | 22.8 | 29.9 |
| Total coal, 1985 | 204.6 | 320.2 | 313.5 | 308.7 | 315.1 | 312.4 | 318.3 |
| Oil/Gas Capacity, GW | | | | | | | |
| Steam | 129.0 | 145.6 | 145.6 | 145.6 | 145.6 | 145.6 | 145.6 |
| Combined cycle | 2.7 | 12.2 | 11.6 | 11.6 | 11.6 | 11.6 | 12.2 |
| Turbine | 42.1 | 111.2 | 123.1 | 127.9 | 122.5 | 125.2 | 118.8 |
| Total oil/gas, 1985 | 173.8 | 269.0 | 280.3 | 286.1 | 279.7 | 202.4 | 276.6 |
| Nuclear capacity, 1985, GW | 38.3 | 108.3 | 109.2 | 109.2 | 108.3 | 108.3 | 108.3 |
| Hydro electric and other capacity, 1985, GW | 68.3 | 88.2 | 88.2 | 88.2 | 88.2 | 88.2 | 88.2 |
| Coal capacity with scrubbers, 1985, GW | 2.5 | 67.5 | 76.6 | 74.7 | 77.6 | 76.7 | 69.8 |
| Flue gas scrubbed,** percent | - | 84.8 | 89.2 | 88.4 | 86.4 | 84.6 | 87.6 |
| Coal plant cost ,*** | - | 560.0 | 562.8 | 566.2 | 562.8 | 565.4 | 564.5 |

*Existing plants are not subject to NSPS. New Plants, 1976 - 1982, are subject to the current NSPS in all cases. New Plants, 1983-1985, are subject to the specific NSPS selected.

**Percentage of flue gas scrubbed is a weighted average of flue gas scrubbed in each coal capacity category. The percentage of flue gas scrubbed in plants built prior to 1983 is similar in all cases; differences are due to dissimilarities in new plants, 1983-1985.

***Coal consturction costs vary with the type of coal plants are designed to burn. Coal plant cost in 1985 is a weighted average based on the projected mix of bituminous, sub-bituminous and lignite burning coal capacity.

# 3. IMPACT ANALYSIS OF AUGUST 1978 AND RELATED ANALYSES

## 3.1 INTRODUCTION

The August 1978 analysis described in this section differs from the April 1978 analysis in section 2.0 in that a number of assumptions were changed to provide a more accurate assessment of the impact of alternative control options. These assumptions were changed as a result of internal EPA discussions as well as discussions between EPA and other government agencies such as the Department of Energy. The major changes are described below and summarized in Table 3-1.

1. Growth rates - Growth in demand for electricity was estimated to be 5.8% per year (1975-1985) and 5.5% per year (1985-1995) for the April analysis and 4.8% per year (1975-1985) and 4.0% per year (1985-1995) for the August analysis.

2. Nuclear capacity - Installed nuclear capacity in 1985, 1990, and 1995 was assumed to be 108, 177, and 302 GW, respectively, in the April analysis and 97, 167, and 230 GW, respectively, in the August analysis.

3. Oil prices - Prices for residual oil were assumed to be constant at $13/barrel (1975 dollars) for the April analysis. The August analysis used oil prices developed by the Department of Energy. These prices, in 1975 dollars, are $15/barrel in 1985, $20/barrel in 1990, and $28/barrel in 1995. Further evaluation of these values has been conducted and downward revisions resulted. A sensitivity analysis that uses oil prices lower

Table 3-1. COMPARISON OF ASSUMPTIONS

April 1978 and August 1978

| Assumption | April | August |
|---|---|---|
| Growth rates | 1975-1985: 5.8%/yr<br>1985-1995: 5.5% | 1975-1985: 4.8%/yr<br>1985-1995: 4.0% |
| Nuclear capacity | 1985: 108 GW<br>1990: 177<br>1995: 302 | 1985: 97 GW<br>1990: 167<br>1995: 230 |
| Oil prices ($ 1975) | 1985: $13/bbl<br>1990: $13<br>1995: $13 | 1985: $15/bbl<br>1990: $20<br>1995: $28 |
| General inflation rate | 5.5%/yr | 5.5%/yr |
| Annual emissions @ 0.5 floor[1] | 0.5 lb $SO_2$/million Btu | 0.32 lb $SO_2$/million Btu |
| Coal transportation | Increases at general inflation rate | Increases at general inflation rate plus 1% |
| Coal mining labor costs | Increases at general inflation rate | Increases at general inflation rate plus 1% |
| Miscellaneous | A number of miscellaneous changes were made between the April 1978 study and the August 1978 study. These changes were either corrections or refinements of values used in the April study. Examples of these changes included revisions to the level of SIP control assumed in the model, revisions to the scrubbing costs, changes in the assumptions regarding industrial coal consumption, and changes to the coal supply curves used in the April study. | |

[1]See text for clarifying discussion

than those quoted above was performed and these results are also presented in this section.

4. Annual emissions for partial scrubbing - In the April analysis, plants which could comply with the revised NSPS by partial scrubbing were assumed to meet the emission floor (expressed in lbs $SO_2$/million Btu) on an annual average basis. The proposed NSPS, however, would not allow that the floor be exceeded for any 24-hour period. To meet this requirement, annual emissions would have to be less than the level of the floor because of the variability of the sulfur content of coal. Hence, in the August runs, the annual emission factors for partial scrubbing were adjusted downward (e.g., annual emissions when meeting a 0.5 floor were assumed to be 0.32 lb $SO_2$/million Btu). This assumption is also being questioned and more analysis of this issue will be made before promulgation of the revised NSPS.

5. Coal transportation costs - In the April analysis it was assumed that coal transportation costs would not increase at a rate different than the assumed general inflation rate of 5.5% per year. In the August analysis, however, it was assumed that coal transportation costs would increase at a rate of 6.5% per year or 1% per year over the assumed general infation rate.

6. Coal mining labor costs - In the April analysis it was assumed that mining labor costs would not increase at a rate different than the assumed general inflation rate of 5.5% per year. In the August analysis, however, the new UMW contract was included and it was assumed that mining

labor costs would increase at 6.5% per year, or 1% per year more than the assumed general inflation rate.

7. Miscellaneous - A number of miscellaneous changes were made between the April study and the August study. These changes were either corrections or refinements of the values used in the April study and include revisions to the level of SIP control assumed in the model, revisions to the scrubbing costs, changes in the assumptions regarding industrial coal consumption, and changes to the coal supply curves used in the April study.

In addition to presenting the results of the August 1978 analysis this section will also present the results of other studies that analyze impacts relevant to the decision to revise the NSPS for utility boilers. These analyses include studies by DOE and NERA and a joint study performed for the Department of Energy and Interior.

## 3.2 RESULTS OF THE AUGUST 1978 ANALYSIS

The results of the August analysis are presented in terms of impacts on national and regional $SO_2$ emissions, utility consumption of oil and natural gas, national coal production impacts, shipment of Western coal to the East, utility capital expenditures, increases in residential electric bills, annualized costs of control, and present value costs of control.

### 3.2.1 National and Regional Utility $SO_2$ Emissions

Table 3-2 presents estimates of utility $SO_2$ emissions in 1990 and in 1995 for seven different control scenarios. These scenarios are:

1. No change in the current NSPS,

Table 3-2. NATIONAL AND REGIONAL UTILITY $SO_2$ EMISSIONS
(millions of tons $SO_2$ per year)

| | | Control Options | | | | | |
|---|---|---|---|---|---|---|---|
| | | 0.2 | | 0.5 | | 0.67 | 0.8 |
| | Current NSPS | With Exemptions | Without Exemptions | With Exemptions | Without Exemptions | With Exemptions | With Exemptions |
| **1990 $SO_2$ emissions** | | | | | | | |
| Oil/gas plants | 1.05 | 1.40 | 1.43 | 1.24 | 1.27 | 1.24 | 1.23 |
| Coal plants-existing[a] | 13.84 | 13.98 | 14.18 | 13.91 | 14.11 | 13.92 | 13.90 |
| -NSPS[b] | 2.13 | 2.26 | 2.37 | 2.26 | 2.38 | 2.22 | 2.22 |
| -ANSPS[c] | 4.39 | 1.22 | 0.96 | 1.33 | 1.07 | 1.52 | 1.76 |
| Total Nation | 21.44 | 18.86 | 18.94 | 18.75 | 18.83 | 18.89 | 19.11 |
| Eastern region | 10.19 | 8.95 | 8.93 | 8.95 | 8.91 | 8.94 | 8.99 |
| Midwest region | 7.77 | 7.61 | 7.71 | 7.55 | 7.67 | 7.57 | 7.60 |
| West South Central region | 2.25 | 1.49 | 1.50 | 1.38 | 1.38 | 1.45 | 1.56 |
| West region | 1.25 | 0.81 | 0.81 | 0.87 | 0.87 | 0.93 | 0.96 |
| **1995 $SO_2$ emissions** | | | | | | | |
| Oil/gas plants | 0.59 | 0.69 | 0.72 | 0.69 | 0.72 | 0.69 | 0.69 |
| Coal plants-existing[a] | 12.54 | 13.06 | 13.22 | 12.95 | 13.07 | 12.90 | 12.94 |
| -NSPS[b] | 2.23 | 2.36 | 2.36 | 2.40 | 2.42 | 2.37 | 2.26 |
| -ANSPS[c] | 7.89 | 2.36 | 1.97 | 2.47 | 2.09 | 2.37 | 3.15 |
| Total Nation | 23.26 | 18.47 | 18.27 | 18.51 | 18.30 | 18.74 | 19.04 |
| Eastern region | 11.04 | 8.79 | 8.65 | 8.70 | 8.64 | 8.76 | 8.79 |
| Midwest region | 7.91 | 7.45 | 7.38 | 7.43 | 7.29 | 7.39 | 7.45 |
| West South Central region | 2.26 | 1.45 | 1.45 | 1.46 | 1.46 | 1.57 | 1.70 |
| West region | 1.68 | 0.78 | 0.78 | 0.92 | 0.91 | 1.02 | 1.10 |

[a]Existing plants subject to SIPs.

[b]New Plants required to meet the current NSPS of 1.2 lb $SO_2$/million Btu.

[c]Plants required to meet the revised (alternative) NSPS.

NOTE: Totals may not add due to rounding.

2. A minimum emission limit of 0.2 lb $SO_2$/million Btu with three exemptions per month.

3. A minimum emission limit of 0.2 lb $SO_2$/million Btu without exemptions,

4. A minimum emission limit of 0.5 lb $SO_2$/million Btu with three exemptions per month,

5. A minimum emission limit of 0.5 lb $SO_2$/million Btu without exemptions,

6. A minimum emission limit of 0.67 lb $SO_2$/million Btu without exemptions, and

7. A minimum emission limit of 0.8 lb $SO_2$/million Btu without exemptions.

Emission estimates are presented for plants that are burning either oil or natural gas, for existing coal-burning plants subject to SIP regulations, for new plants that would come under the current new source performance standard of 1.2 lb $SO_2$/million Btu, and for those new plants that would be subject to a revised new source performance standard. In addition, $SO_2$ emissions are presented for the Eastern region of the United States, for the Midwestern region, for the West South Central region, and the Western region. Table 3-2 indicates that in 1990 total national utility $SO_2$ emissions would be reduced from approximately 21.4 million tons under the current NSPS scenario to 18.8 to 19.1 million tons, a reduction of approximately 11% to 12% depending upon which of the six alternative control options is selected. As would be expected, emissions from plants directly affected by the revised NSPS are reduced most dramatically. However, some of this reduction is offset by increases in emissions from existing coal-fired plants and oil and gas plants. Under the current NSPS, $SO_2$ emissions from plants subject to the revised NSPS would amount to approximately 4.4 million tons in 1990. This amount would decrease to 1.0 to 1.8 million tons in 1990, a reduction of 59 to 77%. For all other plants, $SO_2$ emissions amount to approximately 17.0 million tons in 1990 under the current NSPS scenario. These emissions are projected to increase to 17.4 to 18.0 million tons under the various control options, an increase of 2 to 6%. Emissions at the regional level in 1990 measured relative to the current NSPS decline the most in absolute terms in the East (1.2 to 1.3 million tons) and in the West South Central region (0.7 to 0.9 million tons). In relative terms, the greatest reductions over the current NSPS case are seen in the West (23 to 35%) and in the West South Central region (31 to 39%).

Similar results are seen with regard to utility $SO_2$ emission in 1995. As compared to the current NSPS, a revised standard would result in a decrease in national utility $SO_2$ emissions from approximately 23.3 million tons to 18.3 to 19.0 million tons, a decrease of approximately 18 to 21%. Again, the decrease is most noticeable in those plants that would be directly subject to the revised new source performance standard and emissions from plants not directly affected by the standard increase. Emissions in 1995 for the ANSPS plants would decrease from approximately 7.9 million tons to 2.0 to 3.2 million tons, a decrease of 59 to 75%.

Emissions at the regional level in 1995 measured relative to the current NSPS decline the most in absolute terms in the East (2.3 to 2.4 million tons). In relative terms, however, the greatest decreases are seen in the West South Central region (25-36%) and in the West (35-54%).

Information on regional utility $SO_2$ emissions from those plants subject to the revised NSPS is also relevant to the decision regarding the appropriate level for the revised NSPS. Table 3-2A presents this information. In Table 3-2B information is presented on the regional amount of coal consumed by utilities subject to the revised NSPS.

### 3.2.2 Utility Oil and Gas Consumption

Total consumption of oil and gas at utilities in 1990 and 1995 is presented in Table 3-3. As was the case with the $SO_2$ emission information presented in Table 3-2, information on utility oil and gas consumption is presented for seven control options. In 1990, utility consumption of oil and gas would increase from 2.6 quads to 2.9 to 3.4 quads, an increase of 12 to 31% depending upon which of the six alternative control options is selected. This translates into an increase in oil comsumption from 1.2 million to 1.4 to 1.6 million bbl/day. In 1995, utility oil and gas consumption increases from 1.7 to 1.9 quads no matter which of the six alternative control options is selected. This represents an increase of approximately 12%.

Table 3-2A. REGIONAL UTILITY $SO_2$ EMISSIONS IN 1990 AND 1995 FOR PLANTS SUBJECT TO THE REVISED NSPS

| | Current NSPS | Control Option (With Exemption) 0.2 | 0.5 | 0.67 | 0.8 |
|---|---|---|---|---|---|
| **I. 1990 ANSPS** | | | | | |
| $SO_2$ Emissions (thousand tons) | | | | | |
| . East | 2081 | 708 | 715 | 748 | 789 |
| . Midwest | 555 | 168 | 171 | 185 | 214 |
| . West South Central | 1161 | 239 | 280 | 354 | 461 |
| . West | 589 | 107 | 161 | 231 | 293 |
| . TOTAL | 4386 | 1222 | 1327 | 1517 | 1756 |
| **II. 1995 ANSPS** | | | | | |
| $SO_2$ Emissions (thousand tons) | | | | | |
| . East | 4039 | 1316 | 1334 | 1382 | 1477 |
| . Midwest | 1180 | 415 | 409 | 457 | 521 |
| . West South Central | 1575 | 424 | 420 | 525 | 659 |
| . West | 1095 | 206 | 309 | 420 | 496 |
| . TOTAL | 7889 | 2360 | 2472 | 2784 | 3154 |

Table 3-2B. REGIONAL UTILITY COAL CONSUMPTION IN 1990 AND 1995 FOR PLANTS SUBJECT TO THE REVISED NSPS

| | Current NSPS | Control Option (With Exemption) 0.2 | 0.5 | 0.67 | 0.8 |
|---|---|---|---|---|---|
| I. 1990 ANSPS | | | | | |
| Coal Consumption (QUADS) | | | | | |
| East | 3.468 | 3.405 | 3.427 | 3.479 | 3.467 |
| Midwest | 1.165 | 0.790 | 0.801 | 0.807 | 0.808 |
| West South Central | 1.934 | 1.671 | 1.971 | 1.964 | 1.954 |
| West | 1.246 | 1.191 | 1.177 | 1.191 | 1.242 |
| TOTAL | 7.813 | 7.065 | 7.376 | 7.440 | 7.470 |
| II. 1995 ANSPS | | | | | |
| Coal Consumption (QUADS) | | | | | |
| East | 6.731 | 6.392 | 6.468 | 6.491 | 6.665 |
| Midwest | 2.211 | 1.935 | 1.924 | 1.990 | 1.996 |
| West South Central | 2.626 | 2.773 | 2.731 | 2.696 | 2.678 |
| West | 2.283 | 2.317 | 2.292 | 1.268 | 2.266 |
| TOTAL | 13.852 | 13.417 | 13.415 | 13.445 | 13.605 |

Table 3-3. UTILITY OIL/GAS CONSUMPTION

| | | Control Options | | | | | |
|---|---|---|---|---|---|---|---|
| | | 0.2 | | 0.5 | | 0.67 | 0.8 |
| | Current NSPS | With Exemptions | Without Exemptions | With Exemptions | Without Exemptions | With Exemptions | With Exemptions |
| I. 1990 utility oil/gas consumption | | | | | | | |
| - quads | 2.6 | 3.3 | 3.4 | 3.0 | 3.0 | 3.0 | 2.9 |
| - million bbl/day | 1.2 | 1.5 | 1.6 | 1.4 | 1.4 | 1.4 | 1.4 |
| II. 1995 utility oil/gas consumption | | | | | | | |
| - quads | 1.7 | 1.9 | 1.9 | 1.9 | 1.9 | 1.9 | 1.9 |
| - million bbl/day | 0.8 | 0.9 | 0.9 | 0.9 | 0.9 | 0.9 | 0.9 |

### 3.2.3 National Coal Production and Western Coal Shipments

Table 3-4 compares the effects of alternative control options in 1990 and 1995 on coal production and the consumption of Western coal in the Eastern portion of the United States. As can be seen from the table, impacts on total national coal production in 1990 are relatively minor no matter which control option is chosen. Total national coal production drops from 1525 million tons for the current NSPS option to between 1499 and 1523 million tons, a decrease of 0.1 to 1.7%. In 1995, total national coal production changes from 1865 million tons under the current NSPS scenario to 1859 to 1872 million tons per year, a change of -0.3% to +0.4%.

Depending upon the option chosen, Appalachian coal production in 1990 varies from an increase of 4 million tons (0.9%) to a decrease of 16 million tons (3.4%) when compared to the current NSPS option. Midwestern production in 1990 varies between no increase and an increase of 43 million tons (16%). Northern Great Plains production in 1990 decreases for all options when compared to the current NSPS with declines of 3 to 45 billion tons (1 to 8%). Finally, Western production is seen to vary little in 1990 with the various options. Western production varies from a decrease of 4 million tons (2.0%) to an increase of 3 billion tons (1.5%) depending on the option.

Analysis of total coal production in 1995 shows similar impacts. The variation in total coal production from the current NSPS case is slight (less than 0.5%) no matter which option is selected. Regional impacts in 1995 also show little change from those described for the 1990 cases.

Table 3-4. NATIONAL COAL PRODUCTION AND WESTERN COAL SHIPPED EAST
(million tons)

| | | Control Options | | | | | |
|---|---|---|---|---|---|---|---|
| | | 0.2 | | 0.5 | | 0.67 | 0.8 |
| I. 1990 national coal production | Current NSPS | With Exemptions | Without Exemptions | With Exemptions | Without Exemptions | With Exemptions | With Exemptions |
| Appalachia | 465 | 449 | 469 | 450 | 467 | 450 | 449 |
| Midwest | 275 | 318 | 277 | 316 | 275 | 294 | 290 |
| Northern Great Plains | 587 | 542 | 558 | 552 | 572 | 584 | 583 |
| West | 198 | 194 | 195 | 200 | 201 | 195 | 201 |
| Total | 1525 | 1502 | 1499 | 1517 | 1515 | 1523 | 1523 |
| Western coal consumed in East | 149 | 118 | 135 | 117 | 140 | 147 | 152 |
| II. 1995 National coal production | | | | | | | |
| Appalachia | 523 | 533 | 557 | 534 | 544 | 512 | 516 |
| Midwest | 332 | 397 | 333 | 390 | 326 | 373 | 364 |
| Northern Great Plains | 815 | 760 | 799 | 751 | 818 | 795 | 795 |
| West | 195 | 176 | 180 | 184 | 184 | 189 | 192 |
| Total | 1865 | 1865 | 1869 | 1859 | 1872 | 1868 | 1866 |
| Western Coal consumed in East | 210 | 130 | 173 | 133 | 204 | 190 | 196 |

Western coal consumed in the East in 1990 under the current NSPS scenario is projected to be 149 million tons. For all control alternatives other than the 0.8 option, decreases in this value are seen which range from 2 to 32 million tons (1 to 21%). For the 0.8 option an increase of 3 million tons (2%) over the current NSPS scenario is seen. In 1995 all control options result in a decrease in the amount of Western coal consumed in the East when compared to the current NSPS. These decreases range from 6 to 80 million tons (3 to 38%).

### 3.2.4 Residential Bills, Capital Expenditures, Present Values, and Annualized Costs

Table 3-5 compares the effects of alternative control options in 1990 and 1995 upon monthly average residential bills, utility capital expenditures, present values, and annualized costs. With regard to monthly national average residential bills, little change is seen in either 1990 or 1995 when the current NSPS case is compared to any of the six alternatives. In 1990 the maximum increase in monthly residential bills is $0.70/month, an increase of 1.6 percent. In 1995 the maximum increase is $1.18/month, an increase of 2.6 percent.

Comparing total utility capital expenditures in 1990 for the current NSPS versus the four control options shows that capital expenditures increase at the most by $8 billion, or 1.7 percent. In 1995, the corresponding figures are $32 billion and 4.4 percent.

Present values increase above the current NSPS case in 1990 by a maximum of $15 billion. In 1995 the present value increases by a maximum of $25 billion.

Table 3-5. RESIDENTIAL BILLS, CAPITAL EXPENDITURES, PRESENT VALUES, AND ANNUALIZED COSTS

| | Current NSPS | 0.2 With Exemptions | 0.2 Without Exemptions | 0.5 With Exemptions | 0.5 Without Exemptions | 0.67 With Exemptions | 0.8 With Exemptions |
|---|---|---|---|---|---|---|---|
| | | Control Options | | | | | |
| I. 1990 Monthly national avg residential bills, $/mo | 43.89 | 44.22 | 44.59 | 44.48 | 44.59 | 44.38 | 44.38 |
| Utility capital expenditures, $ billions | 478 | 478 | 477 | 486 | 485 | 482 | 483 |
| Present value - increase over current NSPS - $ billions | -- | 10 | 15 | 9 | 15 | 10 | 10 |
| Annualized cost - $ billions | 91.5 | 93.4 | 93.8 | 93.2 | 93.6 | 92.8 | 92.6 |
| II. 1995 Monthly national avg residential bills, $/mo | 45.34 | 46.22 | 46.52 | 46.13 | 46.35 | 46.12 | 46.10 |
| Utility capital expenditures $ billions | 733 | 765 | 765 | 759 | 757 | 753 | 752 |
| Present value - increase over current NSPS, $ billions | -- | 16 | 25 | 16 | 24 | 17 | 17 |
| Annualized cost, $ billions | 125.6 | 128.2 | 129.2 | 127.9 | 128.7 | 127.6 | 127.5 |

Finally, annualized costs increase in 1990 from $91.5 billion to a maximum of $93.8 billion, an increase of 2.5 percent. In 1995 the corresponding figures are $125.6 billion, $129.2 billion, and 2.9 percent.

### 3.2.5 Sensitivity of Results to Assumed Oil Prices and Rail Rate Escalation

One phase of the August 1978 analysis conducted by EPA included consideration of the sensitivity of the various impacts to changes in assumptions regarding future oil prices and the amount by which rail rates for coal transportation would increase over time. This section will briefly discuss the results of these sensitivity runs.

The discussion of the August analysis presented up to this point was based upon oil prices of $15/barrel in 1985, $20/barrel in 1990, and $28/barrel in 1995. These values were decided upon by EPA after consultation with DOE and others. After these values were specified they came under some criticism both from people within EPA and also from the Council of Economic Advisors. Discussions ensued which led to the specification of two alternative oil price scenarios. One scenario fixed oil prices at $12.30/barrel in 1985 and $17.00/barrel in 1990. Another scenario specified the prices in 1985 and 1990 to be $12.30/barrel and $12.70/barrel, respectively.

In addition to performing sensitivity analysis on oil prices, EPA also decided to test the sensitivity of the various results to assumptions regarding the rate at which coal transportation rail costs would increase. As noted earlier, the basic set of August analyses specified that rail rates would escalate at a rate of 6.5% per year (general inflation plus 1% per year). An alternative scenario was then specified that set rail rate escalation equal to the general inflation rate of 5.5% per year.

The results of these sensitivity analyses are shown in Table 3-6 for the 0.2 (with exemptions) control option. In 1990, with regard to national utility $SO_2$ emissions, a low oil price scenario has the result of increasing projected emissions from oil/gas plants and coal plants subject to SIPs. Emissions from coal plants subject to the existing NSPS and the revised NSPS decrease relative to the base case, however, but not enough to offset the increases noted above. As a result, total national utility $SO_2$ emissions increase for the low oil price scenario relative to the base. This increase in national emissions is accompanied by increases in each of the four regions of the country being considered in this analysis.

The results of a very low oil price scenario are similar to the low oil price scenario. Again, emissions increase over the base case for oil/gas plants, coal plants subject to SIP, at the national level, and for each of the four regions. Emissions decrease for coal plants subject to the revised NSPS for this scenario as they did for the low oil price scenario. With regard to emissions from coal plants subject to the revised NSPS, however, the very low oil price scenario shows a slight increase in emissions whereas the low oil price scenario showed a decrease in emissions.

Table 3-6. A COMPARISON OF ALTERNATIVE OIL PRICE AND RAIL RATE ASSUMPTIONS UPON RESULTS FOR THE 0.2 (WITH EXEMPTIONS) OPTION IN 1990

| | BASE CASE[1] | LOW OIL PRICE[2] | VERY LOW OIL PRICE[3] | NO RAIL RATE ESCALATION[4] |
|---|---|---|---|---|
| I. National Utility $SO_2$ Emissions (millions of tons)[2] | | | | |
| Oil/Gas Plants | 1.40 | 1.87 | 2.41 | 1.22 |
| Coal Plants - Existing[5] | 13.98 | 14.15 | 14.35 | 13.81 |
| - NSPS[6] | 2.26 | 2.19 | 2.27 | 2.16 |
| - ANSPS[7] | 1.22 | 0.99 | 0.65 | 1.26 |
| TOTAL NATION | 18.86 | 19.20 | 19.68 | 18.45 |
| Eastern Region | 8.95 | 9.08 | 9.35 | 8.84 |
| Midwest Region | 7.61 | 7.68 | 7.80 | 7.46 |
| West South Central Region | 1.49 | 1.58 | 1.63 | 1.33 |
| West Region | 0.81 | 0.86 | 0.90 | 0.82 |
| II. Utility Oil/Gas Consumption | | | | |
| Quads | 3.3 | 4.4 | 6.1 | 3.0 |
| Million bbl/day | 1.5 | 2.1 | 2.9 | 1.4 |
| III. National Coal Production (million tons) | | | | |
| Appalachia | 449 | 440 | 422 | 436 |
| Midwest | 318 | 303 | 281 | 289 |
| Northern Great Plains | 542 | 518 | 498 | 618 |
| West | 194 | 192 | 182 | 194 |
| TOTAL | 1502 | 1454 | 1382 | 1537 |
| IV. Western Coal Consumed in the East (million tons) | 118 | 116 | 118 | 174 |

Table 3-6. A COMPARISON OF ALTERNATIVE OIL PRICE AND RAIL RATE ASSUMPTIONS UPON RESULTS FOR THE 0.2 (WITH EXEMPTIONS) OPTION IN 1990 (CONTINUED)

| | BASE CASE[1] | LOW OIL PRICE[2] | VERY LOW OIL PRICE[3] | NO RAIL RATE ESCALATION[4] |
|---|---|---|---|---|
| V. Selected Economic Information[8] | | | | |
| . Monthly National Avg. Residential Bill, $/mo | 44.22 | 43.66 | 42.62 | NA |
| . Utility Capital Expenditures, $ Billions Cumulative | 478 | 453 | 408 | NA |
| . Present Value - Increase Over Current NSPS, $ Billions | 10 | 15 | 11 | NA |
| . Annualized Cost, $ Billions | 93.4 | 91.3 | 87.1 | NA |

1 1990 Oil Price of $20.00 /bbl; Rail Rate Escalation of 1% over inflation.

2 1990 Oil Price of $17.00 /bbl; Rail Rate Escalation of 1% over inflation.

3 1990 Oil Price of $12.70 /bbl; Rail Rate Escalation of 1% over inflation.

4 1990 Oil Price of $20.00 /bbl; Rail Rate Escalation of 0% over inflation.

5 Existing plants subject to SIPS.

6 New plants required to meet the current NSPS of 1.2 lb $SO_2$/million BTU.

7 Plants required to meet the revised (alternative) NSPS.

8 All economic data is presented in 1975 dollars. All cost information includes costs for controlling particulate emissions for new sources to a level of 0.03 lbs per million BTU.

The alternative rail rate scenario displayed on Table 3-6 shows, relative to the base case, decreases in $SO_2$ emissions from oil/gas plants, coal plants subject to SIPs, coal plants subject to the current NSPS, and at the national level. An increase in emissions is seen for plants subject to the revised NSPS. At the regional level, decreases in emissions relative to the base case are shown for all regions with the exception of the West where a slight increase is seen.

Table 3-6 further goes on to show, as expected, that both the low oil price scenario and the very low oil price scenario result in increased oil/gas consumption at utilities relative to the base case. The results of the alternative rail rate scenario, however, is to decrease the amount of oil/gas consumption at utilities relative to the base case.

Also presented on Table 3-6 is information on coal production. As expected, as oil prices decrease demand for coal decreases at the national level and for each of the four regions under consideration. As rail rates decrease relative to the base case coal becomes relatively less expensive and more coal is produced at the national level. This increased national production is solely attributable to increased Northern Great Plains production, however, since the other three regions show either decreased production or no change in production relative to the base case.

Reducing the price of oil has relatively little effect on the consumption of Western Coal in the East, however, as seen on Table 3-6.

The effect of the alternative rail rate scenario is to increase the base case consumption of Western coal in the East by 56 million tons, or 47 percent.

Finally, Table 3-6 shows the effects of alternative oil price scenarios on various economic factors. Information on the effect of the alternative rail rate scenario is not available. It is seen that lowering the oil price results in a decrease in all of the economic indicators shown on Table 3-6 except for the present value. In the case of this statistic a low oil price scenario results in a present value increase of $15 billion over the current NSPS, a very low oil price results in an increase of $11 billion, and the base case has an increase of $10 billion.

## 3.3 OTHER ANALYSES

In addition to the analyses described above, three other major studies have been conducted which analyze certain impacts of a revised NSPS for power plants. One of these studies was performed by ICF, Incorporated, under a joint contract with the Department of Interior and the Department of Energy. A second study was performed by the Department of Energy and the third study was performed for the Utility Air Regulatory Group (UARG) by National Economic Research Associates, Inc. (NERA).

### 3.3.1 Joint DOI/DOE Study

EPA has been using the report developed by ICF for the Departments of Interior and Energy in order to study the sensitivity of certain results to changes in input assumptions. This section will reproduce one table from the June 1978 draft report entitled The Demand For Western Coal And Its Sensitivity To Key Uncertainties and also describe the major assumptions underlying the study.

Table 3-7 is taken directly from the June 1978 draft report mentioned above. The following is a list of the major assumptions behind the table:

1. High severance tax in the West: North Dakota, Montana, Wyoming, Colorado, Utah, and New Mexico 30 percent severance tax whereas base case has actual state severance taxes.
2. Low severance tax in West: same as above except severance tax is 5 percent.
3. High electricity growth rate: one percentage point higher national electricity growth rate than base case, which is 4.8 percent for 1975-1985 and 4.0 percent for 1985-1990.
4. Low electricity growth rate: one percentage point lower national electricity growth rate than the base case.
5. Higher oil prices: same as DOE high case: $20 per barrel in 1995, $30 per barrel in 1990 in 1975 dollars (relative to $15 and $20 per barrel for 1985 and 1990 respectively used for base case).
6. Lower oil prices: same as DOE low case -- $13 per barrel in 1985 and 1990 in 1975 dollars.
7. Revised new source performance standards: require full scrubbing (i.e., 90 percent removal), whereas partial scrubbing was allowed (i.e., 0.5 pounds of sulfur dioxide per million BTU's

# Table 3-7

1990 REGIONAL COAL PRODUCTION
UNDER DIFFERENT SENSITIVITY ASSUMPTIONS
($10^6$ tons)

| | | Scenario | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Region | Base | High Severance Tax | Low Severance Tax | High Electricity Growth | Low Electricity Growth | High Oil Price | Low Oil Price | 90% Scrubber | 1.2 lb. Standard | High Labor Escalation | Low Labor Escalation | High Rail Rates | Combined Cycle Allowed |
| Northern Appalachia | 225.6 | 233.0 | 206.5 | 248.1 | 204.6 | 240.2 | 206.8 | 227.5 | 207.6 | 217.5 | 232.1 | 242.3 | 224.3 |
| Central Appalachia | 207.1 | 216.2 | 187.1 | 219.0 | 195.4 | 215.0 | 202.5 | 203.4 | 254.5 | 194.0 | 214.7 | 227.5 | 205.8 |
| Southern Appalachia | 13.8 | 13.8 | 13.8 | 13.8 | 13.8 | 13.8 | 13.8 | 13.8 | 13.8 | 13.8 | 13.8 | 13.8 | 13.8 |
| Total | 446.5 | 463.0 | 407.4 | 480.9 | 413.7 | 469.0 | 423.2 | 444.7 | 476.0 | 425.3 | 460.6 | 483.5 | 443.8 |
| Midwest | 313.5 | 332.7 | 277.9 | 339.5 | 277.9 | 328.7 | 296.5 | 323.5 | 254.5 | 287.7 | 323.1 | 350.2 | 310.5 |
| Total | 313.5 | 332.7 | 277.9 | 339.5 | 277.9 | 328.7 | 296.5 | 323.5 | 254.5 | 287.7 | 323.1 | 350.2 | 310.5 |
| Eastern Northern Great Plains | 22.7 | 20.2 | 21.9 | 26.1 | 21.9 | 22.5 | 21.9 | 21.9 | 21.8 | 23.8 | 22.7 | 23.8 | 22.1 |
| Western Northern Great Plains | 528.8 | 518.1 | 652.5 | 656.3 | 455.4 | 545.3 | 492.4 | 517.9 | 590.2 | 598.2 | 503.6 | 424.2 | 519.5 |
| Total | 551.5 | 538.4 | 674.4 | 682.3 | 477.3 | 567.8 | 514.3 | 539.8 | 612.0 | 622.0 | 526.3 | 448.1 | 541.6 |
| Central West | 10.3 | 10.7 | 9.6 | 10.3 | 9.6 | 10.3 | 10.3 | 9.6 | 9.7 | 9.6 | 9.9 | 10.9 | 9.9 |
| Gulf | 104.1 | 107.9 | 104.4 | 107.9 | 95.1 | 104.1 | 104.1 | 104.1 | 94.6 | 104.1 | 104.1 | 107.9 | 104.1 |
| Rocky Mountains | 53.0 | 36.6 | 45.5 | 53.3 | 53.6 | 53.0 | 52.5 | 52.6 | 56.7 | 52.1 | 53.0 | 52.4 | 53.0 |
| Southwest | 47.6 | 37.4 | 43.2 | 64.0 | 41.6 | 47.6 | 30.1 | 48.2 | 53.2 | 48.5 | 48.3 | 38.4 | 48.1 |
| Northwest | 3.7 | 3.7 | 3.7 | 3.7 | 3.7 | 3.7 | 4.4 | 6.0 | 3.7 | 3.7 | 4.6 | 6.0 | 4.4 |
| Total | 218.6 | 196.1 | 206.3 | 239.2 | 203.6 | 218.6 | 201.5 | 220.6 | 217.9 | 217.9 | 219.8 | 215.6 | 219.4 |
| NATIONAL TOTAL | 1,530.1 | 1,530.3 | 1,565.9 | 1,741.9 | 1,372.6 | 1,584.1 | 1,435.5 | 1,528.5 | 1,560.4 | 1,552.9 | 1,529.9 | 1,497.3 | 1,515.2 |
| Western Coal Consumed in East | 133.8 | 102.1 | 233.5 | 198.3 | 109.4 | 144.1 | 128.5 | 119.1 | 195.3 | 191.3 | 111.3 | 49.1 | 130.1 |
| National Utility Fuel Consumption (quads) | | | | | | | | | | | | | |
| - Coal | 21.3 | 21.3 | 21.3 | 25.5 | 18.1 | 22.5 | 19.3 | 21.3 | 21.9 | 21.3 | 21.5 | 21.2 | 21.0 |
| - Oil | 2.9 | 2.9 | 2.9 | 3.2 | 2.5 | 1.5 | 5.0 | 2.9 | 1.9 | 2.9 | 2.7 | 3.0 | 3.1 |

floor) in base case.

8. Current new source performance standards: (i.e., 1.2 pounds per million (BTU's) which can be met with low sulfur coal without scrubbing.

9. High labor cost escalation: same as DOE high range - two percent per year real escalation after 1980, relative to one percent in base case.

10. Low labor cost escalation: same as DOE low range - no real escalation after 1980.

11. High rail rates: 50 percent increase in rates by 1985, relative to no increase in base case.

12. New combined cycle oil plants allowed by federal regulation, relative to such plants being prohibited in the base case.

3.3.2 DOE Proposal

In a memo to EPA dated July 8, 1978, DOE proposed that the revised NSPS for power plants should reflect 85% removal of $SO_2$ on a monthly basis and an emission floor of 0.5 lb $SO_2$ per million BTU averaged on a monthly basis. In a subsequent memo to EPA dated August 11, 1978, DOE reproposed that that NSPS reflect an emission floor of 0.8 lbs $SO_2$ per million BTU averaged on a daily basis. Table 3-8 is taken directly from the DOE memo to EPA dated July 8, 1978 and compares the current NSPS to the EPA full scrubbing (0.2 floor) control option and the alternative partial scrubbing options of 0.5 and 0.8 lbs $SO_2$ per million BTU, averaged on a monthly basis. Impacts for the 0.8 daily averaging time option were not presented in either of the DOE memos referred to above.

TABLE 3-8. COMPARISON OF EPA AND DOE PROPOSALS[1]

| | Current NSPS | EPA Proposal | 0.5 Floor[2] | 0.8 Floor |
|---|---|---|---|---|
| Coal Capacity in 1990 (1000s of megawatts) | 465 | 430-444 | 460 | 460 |
| Present Value Cost through 1990 ($billions) | 36 | 62-73 | 49-51 | 46 |
| $SO_2$ Emissions in 1990 (millions of tons) | 21.3 | 19.0-19.7 | 19.3-20.0 | 20.3 |
| Oil and Gas Consumption in 1990 (millions of bbl/day | 3.1 | 3.5-3.8 | 3.2 | 3.2 |
| Coal Production in 1990 (millions of tons) | | | | |
| East | 441 | 464-466 | 464 | 449 |
| Midwest | 298 | 373-375 | 353 | 313 |
| West | 1027 | 835-869 | 938 | 998 |
| TOTAL | 1767 | 1672-1711 | 1755 | 1760 |
| Western Coal Consumed East of the Mississippi River (millions of tons) | 455 | 275-300 | 345 | 381 |

[1]From DOE memo to EPA dated July 8, 1978.

[2]Values from Tables 4 and 5 of the July 8 memo.

### 3.3.3 UARG/NERA Analysis

The Utility Air Regulatory Group of the Edison Electric Institute (UARG) requested that the National Economic Research Associates, Inc. (NERA) conduct a study to evaluate the impacts of various alternative proposals for the revised NSPS for power plants. NERA evaluated six alternative proposals. These are described in Table 3-9. The major results of the NERA analysis are presented in Table 3-10.

Table 3-9.
DESCRIPTION OF CASES

| Case | $SO_2$ Emissions Standards[1] | | | | | |
|---|---|---|---|---|---|---|
| | Floor (lbs. $SO_2$/MMBtu) (1) | Ceiling[2] (lbs. $SO_2$/MMBtu) (2) | Percent Removal (Percent) (3) | Averaging Time (4) | Allowable Exemptions per Month (5) | Particulate Standard (lbs./MMBtu) (6) |
| Base | - | - | - | - | - | - |
| NSPS | - | 1.20 | - | 30-day | None | 0.10 |
| **Proposed Revisions to Current NSPS:** | | | | | | |
| UARG1 | - | 1.20 | 20-85 | 30-day | None | 0.08 |
| UARG2 | - | 1.20 | 20-85 | 30-day | None | 0.03 |
| EPA1 | 0.20 | 1.20 | 85 | 24-hour | None | 0.03 |
| EPA2 | 0.20 | 1.20 | 85 | 24-hour | 3 | 0.03 |
| DOE1 | 0.50 | 1.20 | 85 | 24-hour[3] | 3 | 0.03[4] |
| DOE2 | 0.80 | 1.20 | 85 | 24-hour[3] | 3 | 0.03[4] |

[1] For all cases scrubber systems are assumed to be 100 percent available and are designed with two redundant modules unless only one operating module is required, in which case there is one redundant module.
[2] The ceiling is 1.20 pounds of sulfur dioxide per million Btu or the SIPS, whichever is more restrictive.
[3] While DOE recommends a 30-day rather than 24-hour averaging time, the 24-hour averaging time with 3 allowable exemptions was used for the purposes of comparing the DOE and EPA percent removal proposals.
[4] While DOE recommends a 0.05 to 0.08 particulate standard, a 0.03 standard was used for purposes of comparing the DOE and EPA $SO_2$ standards.

Table 3-10. SUMMARY OF IMPACTS AS ANALYZED BY NERA FOR UARG[1]

| | Current NSPS | UARG 1 | UARG 2 | EPA 1 | EPA 2 | DOE 1 | DOE 2 |
|---|---|---|---|---|---|---|---|
| 1990 Utility $SO_2$ Emissions (millions of tons) | 20.02 | 18.24 | 18.26 | 16.84 | 16.86 | 16.88 | 17.36 |
| 1990 Annual Cost ($ Billions 1977) | 5.96 | 7.15 | 7.52 | 9.28 | 9.15 | 8.09 | 7.54 |
| $SO_2$ Removed (millions of tons) | 22.09 | 23.87 | 23.85 | 25.27 | 25.25 | 25.23 | 24.75 |
| $/ton $SO_2$ Removed | 270 | 300 | 315 | 367 | 362 | 321 | 305 |
| Present Value Cost Above Current NSPS ($ Billions 1977) | - | 13.50 | 17.70 | 37.66 | 36.18 | 24.16 | 17.92 |
| 1990 Oil/Gas Consumption (million bbl/day) | 0.67 | 0.79 | 0.79 | 0.94 | 0.94 | 0.93 | 0.79 |
| 1990 Total Coal Production (million tons) | | | | | | | |
| Appalachia | 531.0 | 530.1 | 530.1 | 502.9 | 502.9 | 507.4 | 531.9 |
| Midwest | 312.5 | 329.8 | 331.4 | 385.0 | 385.0 | 359.8 | 326.4 |
| West | 665.8 | 642.1 | 640.2 | 598.4 | 604.3 | 624.7 | 643.4 |
| TOTAL | 1509.3 | 1501.8 | 1501.4 | 1486.0 | 1491.9 | 1491.5 | 1502.2 |

[1] "Analysis of the Economic Impact of Alternative Proposed Revisions to New Source Performance Standards", National Economic Research Associates, Inc., August 29, 1978

# 4. DISCUSSION OF REGULATORY TOPICS

## 4.1 INTRODUCTION

This section summarizes many factors considered by EPA in evaluating various regulatory topics. Discussion of these issues gives additional insight into several regulatory requirements drafted and the impacts they may have on electric utility companies and coal producers. The performance of flue gas desulfurization (FGD) systems in the U. S. and Japan and the projected performance of improved systems is discussed in section 4.2. New dry control systems that may reduce $SO_2$ control costs for low-sulfur coal to levels even less than those for partial scrubbing are discussed in section 4.3. Other topics discussed are $SO_2$ control in noncontinental areas (4.4), use of continuous monitoring systems for compliance determinations (4.5), procedures for shifting electric load and maintaining electric system reliability during FGD malfunctions (4.6), and potential impacts upon coal production, Midwestern coal reserves, and anthracite coal (4.7).

## 4.2 FGD PERFORMANCE

### 4.2.1 Overview

EPA has evaluated potential systems of continuous $SO_2$ emission reduction (considering the cost, and non-air quality health and environmental impact, and energy requirements of such reduction) and concluded that FGD systems used to remove $SO_2$ from flue gases have been adequately demonstrated. This section summarizes the test results of these demonstrations and discusses the performance of FGD systems currently available.

FGD systems have been designed to use several different types of absorbers and absorbents. All FGD designs installed and tested have not been equally successful. To evaluate the relative performance of FGD system designs, EPA has tested several absorber designs and absorbents at the Shawnee 10-MW test facility. The Shawnee test results give valuable information regarding FGD system design for high percentage $SO_2$ removal.

EPA has also surveyed the performance test results of full-scale FGD systems and has closely evaluated the continuous, long-term performance of FGD systems by use of continuous monitoring systems at several full-scale power plants. A summary of these tests, surveys, vendor guarantees, and EPA's analysis of requirements for attainment of high percentage $SO_2$ removal are given in the following sections.

### 4.2.2 Prototype FGD Unit Performance

At the Shawnee test facility, several FGD system designs and absorbents were evaluated for 6- to 8-hour or 1-week test periods under controlled operating conditions. The short-term (6 to 8 hours) tests were directed at determining $SO_2$ absorption efficiencies without considering potential long-term operating problems; however, during other portions of the Shawnee test program, these FGD systems were operated for extended periods without scaling problems. A summary of these test runs and conclusions was prepared for EPA by Bechtel Corporation in their report, Flue Gas Desulfurization Systems: Design and Operating Considerations, report number EPA-600/7-030b.

By controlling the operating conditions at Shawnee to specific levels, direct comparisons between performance of different types of absorbers and absorbents were obtained, and the principal factors that have the greatest effect upon absorption efficiency were identified. These data show that a proper balance between (1) absorber design, (2) absorber operating conditions, and (3) type of absorbent must be achieved in order to attain a specific FGD control efficiency. The absorber design determines the amount of contact at the gas-to-liquid interface. The operating conditions determine the concentration and amount of absorbent available to the absorber, and the type of absorbent determines the reactivity or rate of reaction with the $SO_2$.

In the Shawnee tests, venturi absorbers were found to be less effective in comparison to turbulent contact absorbers (TCA) or spray tower absorbers (STA). When tested with less reactive calcium-type absorbents under the same operating conditions, the venturi absorber efficiency was only 40 to 50 percent. However, venturi absorbers can be effective when used in series or when a more reactive absorbent is used. Bechtel has projected that two venturi absorbers used in series can attain greater than 95 percent mean $SO_2$ removal with lime or limestone absorbents. The Shawnee data also contain tests where more reactive absorbents were used. The single venturi absorber tested removed 85 percent $SO_2$ with magnesium oxide enriched limestone and 95 percent $SO_2$ with two sodium-type absorbents during the tests.

The improved performance of venturi absorbers with a more reactive sodium-type absorbents was also demonstrated by an 8-month test program of a 20-MW double-alkali FGD module at the Scholz station of Gulf Power Company. With a single venturi absorber, the FGD module was able to attain over 90 percent average $SO_2$ removal at several pH levels. When a tray tower absorber was added in series with a venturi absorber, up to

99 percent average $SO_2$ removal was obtained. Tests of a few hours duration were performed at each operating condition to determine FGD average efficiencies with each configuration.

In the Shawnee tests, STA and TCA absorbers demonstrated 90 percent average $SO_2$ removal efficiency with either lime or limestone absorbents when the pH levels selected were the maximum that could be used without scale formation. The liquid-to-gas (L/G) ratios needed to attain 90 percent efficiency were 30 to 40 percent lower with the TCA absorber than were needed with the STA.

A second series of tests were run with more reactive magnesium oxide enriched limestone. At the same L/G ratio used in the limestone tests, the TCA absorber efficiency was increased from 90 to 97 percent. The STA absorber also attained 97 percent efficiency and unlike the previous limestone tests, required no greater L/G ratio than the TCA.

An additional factor that can affect operating conditions is the gross load of $SO_2$ removed by the FGD system. This load increases with higher sulfur fuels. Each 1 percent sulfur in bituminous coal is roughly equivalent to 800 ppm of $SO_2$ at the absorber inlet. The flue gas treated at Shawnee typically contained 2000 to 3000 ppm $SO_2$ prior to treatment; however, a few additional tests were run at $SO_2$ inlet concentrations of less than 1000 ppm. The percentage removal efficiency increased for the same absorber, absorbent, and operating conditions at reduced $SO_2$ inlet concentrations. The data show that the absorber design and operating conditions to attain high $SO_2$ absorption efficiency are more moderate for low-sulfur coals. Tests at Mohave power station with full-scale FGD modules (170 MW) also show moderated operating conditions. At 200 ppm $SO_2$ inlet concentrations, L/G ratios of only 20 gal/Mcf were necessary to obtain 95 to 99 percent $SO_2$ removal.

In addition to Shawnee, several other small FGD modules (10 to 20 MW) have demonstrated greater than 90 percent $SO_2$ removal efficiency. In PEDCo's report prepared for EPA, Flue Gas Desulfurization System Capabilities for Coal-Fired Steam Generators, Table 4-7, report number EPA-600/7-78-032b, two prototype units at Gulf Power Company and one operational unit owned by the U. S. Air Force are reported to have attained 95 to 99 percent average $SO_2$ control.

The prototype-size FGD units described in Bechtel's and PEDCo's reports attained removal efficiencies up to 95 percent with high sulfur coal and up to 99 percent efficiency with low sulfur coal during short-term tests. These tests show that absorber design, operation, and abosrbent type can be properly matched to attain high mean FGD efficiency.

### 4.2.3 Full-Scale FGD Systems

#### 4.2.3.1 Vendor Guarantees and Other Statements

Through EPA's contractor, PEDCo Environmental, Inc., the performance guarantees offered by FGD module suppliers were solicited. The results of this survey are summarized in Table 3-10 of the report Effects of Alternative Sulfur Dioxide New Source Performance Standards on Flue Gas Desulfurization System Supply and Demand, report number EPA-600/7-78-033. Ten suppliers of FGD modules reported that they would guarantee $SO_2$ removal performance greater than 90 percent. Five specifically mentioned guarantees of 95 percent. The performance guarantees offered are generally based upon short-term acceptance tests, which are typically 6 to 8 hours duration. Two-thirds of the respondents to the survey stated that under contract, they would be willing to operate and maintain the FGD system after installation.

In December of 1977, EPA held a meeting of the National Air Pollution Techniques Advisory Committee. At that meeting a spokesman for TVA who is also a member of the Utility Air Regulatory Group stated that an 85 percent $SO_2$ removal requirement (24-hour basis) could be attained. A second spokesman from a major vendor of lime FGD systems agreed.

4.2.3.2 FGD Performance Test Results

As of November 1977, 32 operational FGD systems had been installed at utilities in the U. S. These 32 systems serviced 10,717 megawatts of electric generating plant capacity. An additional 34 FGD systems servicing 14,219 megawatts of plant capacity were under construction and contracts were awarded for 20 FGD systems for power plants designed to produce 9,758 megawatts. Table 4-1 lists some of the U. S. FGD units designed for 85 percent, or greater, $SO_2$ removal which are installed, under construction or for which contracts have been awarded. In PEDCo's report, 10 utility size (65 to 170 MW) FGD modules were listed as having demonstrated greater than 90 percent $SO_2$ removal on coal-fired boilers. Table 4-2 lists some of the U. S. facilities reporting 90 percent or greater $SO_2$ removal.

At the beginning of 1978, there were over 500 power plants with FGD systems in Japan. These systems control $SO_2$ emissions from about 31,000 megawatts of electric generating capacity. About half of this capacity consisted of utility boilers. Seven of the boiler installations burn coal with a reported sulfur content of 0.6 percent to 2.5 percent. There are 25 utility and industrial applications of U. S. scrubber technology in Japan. The FGD systems in Japan (both U. S. and Japanese design) on coal-fired boilers reportedly operate with $SO_2$ removal efficiencies ranging from 90 percent to 93 percent and, within a few months after startup, achieve FGD system availabilities of 95 to 100 percent. Table 4-3 provides pertinent data concerning the operation of U. S. design FGD systems installed on coal-fired boilers in Japan. The performance of FGD systems on five utility boilers and two industrial boilers are

Table 4-1. LIST OF U.S. FLUE GAS DESULFURIZATION (FGD) SCRUBBERS INSTALLED UNDER CONSTRUCTION, OR AWARDED-DESIGNED FOR 85 PERCENT OR GREATER $SO_2$ REMOVAL

| Company | FGD type | No. FGD's | Capacity MW | Coal Sulfur, % | Design $SO_2$ removal | Startup date |
|---|---|---|---|---|---|---|
| Existing | | | | | | |
| Arizona Public Service | Limestone | 1 | 115 | 0.4-1.0 | 92 | 10/73 |
| Columbus & Southern Ohio Electric | Lime | 1 | 400 | 4.5-4.9 | 90 | 2/77 |
| Duquesne Light | Lime | 2 | 920 | 1-2.8 | 85 | 10/75 |
| Louisville Gas & Electric | Lime | 1 | 178 | 3.5-4.0 | 85 | 8/76 |
| Northern Indiana Public Service | Wellman Lord | 1 | 115 | 3.5 | 90 | 77 |
| Pennsylvania Power Company | Lime | 2 | 1670 | 4.7 | 92 | 4/76 |
| Philadelphia Electric | MgO | 1 | 120 | 2.5 | 90 | 9/75 |
| Nevada Power | Sodium Carbonate | 3 | 375 | 0.5-1.0 | 85-90 | 4/74 |
| Under construction or contract awarded | | | | | | |
| Allegheny Power System | Lime | 2 | 1250 | 4.5 | 90 | 3/80 |
| Columbus & Southern Ohio Electric | Lime | 1 | 400 | 4.5-4.9 | 90 | 77 |
| Public Service Co. of New Mexico | Wellman Lord | 2 | 715 | 0.8 | 90 | 78 |
| Southern Mississippi Electric | Limestone | 2 | 360 | 1.0 | 85 | 78 |
| Delmarva Power Company | Wellman Lord | 1 | 180 | 7.0-8.0 (coke) | 85-90 | 4/80 |
| Louisville Gas & Electric | Double Alkali | 1 | 277 | 3.5-4.0 | 90 | 11/79 |
| Niagara Mohawk Power Coop. | Aqueous Carbonate | 1 | 100 | 2.5-4.5 | 90 | 6/78 |
| Pennsylvania Power Co. | Lime | 1 | 825 | 4.7 | 92 | 4/80 |

Table 4-2. U. S. PLANTS REPORTING 90 PERCENT OR GREATER $SO_2$ REMOVAL

| Utility | Station | MW | FGD Process | Fuel Sulfur[a],% | $SO_2$ removal,% |
|---|---|---|---|---|---|
| Arizona Public Service | Cholla No. 1 | 115 | Limestone | 0.4-1.0 | 92 |
| Duquesne Light | Phillips | 410 | Lime | 1.0-2.8 | 90+ |
| Northern Indiana Public Service | Mitchell | 115 | Wellman Lord | 3.5 | 90 |
| Philadelphia Electric | Eddystone | 120 | MgO | 2.5 | 95-98 |
| Boston Edison | Mystic | 150 | MgO | 2.5 (oil) | 90 |
| Potomac Electric Power | Dickerson | 95 | MgO | 2.0 (oil) | 90 |
| Southern California Edison | Mohave 1 & 2 | Each 170 | Lime | 0.6 | 95 |
| Kentucky Utilities | Green River | 64 | Lime | 3.8 | 90+ |
| Columbus & Southern Ohio | Conesville | 400 | Lime | 4.5-4.9 | 90+ |

(a) Unless otherwise noted, fuel burned is coal.

Table 4.3. AMERICAN DESIGNED FGD SYSTEMS OPERATING IN JAPAN

| Company | Power Station | Developer, type FGD | Number FGD | Capacity MW | Date of startup | Coal source | Coal sulfur,% | Average $SO_2$ removal, % | Availability, % |
|---|---|---|---|---|---|---|---|---|---|
| EPDC | Takasago | Mitsui-Chemico Limestone | 2 | 500 | 1975 & 1976 | Blended Domestic | 2 | 93 | 98.6 |
| EPDC | Isogo | Chemico-IHI Limestone | 2 | 530 | 1976 | Domestic | 0.4 | 93 | 99+ |
| EPDC | Takehara | Babcock-Hitachi Limestone | 1 | 256 | 1977 | Blended Domestic | 2 | 93 | 97 |
| Mitsui | Miiki | Mitsui-Chemico Carbide Lime | 1 | 156 | 1972 | Blended Domestic | 2.4 | 90+ | 100 |
| Mitsui | Miiki | Mitsui-Chemico Limestone | 1 | 175 | 1975 | Blended Domestic | 2.4 | 90+ | 99 |

described. On oil-fired boilers, up to 98 percent $SO_2$ removal has been reported.

The PEDCo report and a report by J. Ando, <u>$SO_2$ Abatement for Stationary Sources in Japan</u> (report number EPA-600/7-77-103a), discussed several oil-fired boiler FGD systems that have attained high efficiencies. Of the nine FGD systems attaining greater than 90 percent control listed (Table 3-9) in the PEDCo report for oil-fired power plants, four attained greater than 95 percent $SO_2$ removal. Control of oil-fired-boiler $SO_2$ emissions is technically less troublesome than those from coal-fired boilers because (1) the flue gases are not so heavily laden with particulate matter and (2) the physical properties of refined and blended fuel oil (e.g., percent sulfur) are more uniform than coal.

Tests of coal-fired-boiler FGD systems in the U. S. have demonstrated 95 percent or greater control. With the less difficult to scrub low sulfur Western coals, a 170-MW horizontal crossflow spray scrubber module using lime absorbent demonstrated 95 percent average $SO_2$ removal at Arizona Public Service Company's Four Corners station. This same module and a 170-MW TCA absorber each demonstrated 95 percent average removal at Southern California Edison's Mohave station when applied to control of low-sulfur-coal emissions.

Two FGD units owned by the Louisville Gas and Electric Company have demonstrated greater than 95 percent removal of $SO_2$ from high-sulfur-coal emissions during short-term tests when magnesium oxide was added to the lime absorbent. At the Cane Run station MgO was added to lime until the $SO_2$ removal efficiency reached 95 to 96 percent for 3 days. At the Paddy's Run station MgO additions to the lime produced 99.7 to 99.9 percent $SO_2$ removal during 8-hour tests on 2 separate days.

The U. S. system tests were relatively short-term, lasting a few hours or up to 3 days, and may not adequately estimate the range of 24-hour average performance or the mean performance of these systems. The Japanese data reported in Table 4-3 are representative of mean performance because these data are averages of long-term continuous-monitoring system results.

The data averages presented in this section do not define the range of FGD performance expected during normal operation. The results of more extensive test programs to define this range are given in section 4.2.4.

4.2.4 Analysis of FGD Performance Range

Although many FGD modules have been tested, few systems are reported to have been continuously evaluated for more than 3 days. Short-term performance tests under controlled conditions provide good design information that can be used to predict absorber performance under fixed conditions, but they do not reveal how an FGD system would respond to the uncontrolled variations in $SO_2$ concentrations at the absorber inlet that are experienced during boiler operation. These variations are typically due to the fuel quality. Refined fuel oil is typically homogeneous, but coal is not.

Variability of sulfur in coal is an inherent property created during the fossilization process, and all naturally occurring coals can be expected to produce variations in the $SO_2$ concentrations of boiler flue gas. Sulfur in coal is unevenly distributed within a coal seam. Coal shipments, even from the same mine, will have a range of sulfur content, which has been described by statistical distributions in an EPA report (Preliminary Evaluation of Sulfur Variability in Low-Sulfur Coals from Selected Mines, report number EPA-450/3-77-044, Nov. 1977) and in a paper by C. Nelson and J. Dragos "Coal Variability and Sulfur Compliance." An EPA review of the variation in coal sulfur content is given in section 4.2.7.

Two methods are currently feasible for reducing the variation in coal quality. One is coal washing, which can remove pockets of pyritic sulfur, but is ineffective in removing sulfur chemically bound to the organic constituants of the coal. The second method is coal blending, which can be effective when the mean sulfur content of separate coal shipments is monitored. A third method, solvent refining of coal, is currently under development, but may not be economically feasible unless it can completely replace the FGD system for $SO_2$ control. Coal-fired units with FGD systems in Japan are fired with blended coal to reduce the variation in potential emissions resulting from use of coal supplies with different sulfur contents. At least one unit in the United States is installing coal blending facilities specifically for control of coal sulfur variability.

The effect that coal quality can have on FGD performance is evident in tests at Shawnee. In three tests of up to 20 days each, sharp increases in inlet $SO_2$ concentrations lead to corresponding decreases in $SO_2$ removal efficiency. During these tests, no attempt was made to counter this effect by manual or automatic adjustments to the FGD system.

In order to more closely evaluate the $SO_2$ variability effect and the impact of FGD process controls, continuous $SO_2$ emission monitors were placed in three full-scale operational units; Louisville Gas and Electric's Cane Run 4, Pennsylvania Power's Bruce Mansfield 1, and Philadelphia Electric's Eddystone 1. None of these FGD systems has an automated control system, but adjustments to slurry pH were made manually by the process operators. Continuous monitoring performance data were also obtained from Northern Indiana Public Service Company's full-scale Wellman-Lord FGD unit at the Mitchell station.

The continuous monitoring data taken at each of the facilities tested are summarized and evaluated in EPA's report entitled First Interim

Report: Continuous Sulfur Dioxide Monitoring at Steam Generators," June 1978 (EMB Project Number 77SPP23A). The report evaluates the variability in potential emissions at the absorber inlet, in FGD system $SO_2$ removal efficiency, and in emissions to the atmosphere. With minor exceptions, all data were found to best fit a log-normal statistical distribution. The report describes the geometric mean and geometric standard deviations of the FGD inlet data, FGD $SO_2$ removal efficiency, and the FGD outlet data, which represent the emissions to the atmosphere.

Figure 4-1 summarizes the percent $SO_2$ reduction data for each facility. The data displayed are a probability distribution of FGD 24-hour average $SO_2$ removal efficiencies. These data, which do not include periods of startup and shutdown, are representative of the range in FGD 24-hour average performance normal for these systems.

The data in Figure 4-1 give the mean $SO_2$ removal efficiency for each FGD system and the probability of occurrence for higher and lower average FGD efficiencies during 24-hour compliance periods. These data show about the same performance for the lime FGD systems at the Can Run and Bruce Mansfield stations. The regenerable FGD systems at Mitchell (Wellman-Lord) and at Eddystone (MgO) stations show the superior performance of more reactive absorbents.

#### 4.2.5 Projected FGD Performance

##### 4.2.5.1 Mean FGD Performance

A "line of improved performance" is projected on Figure 4-1 through a mean $SO_2$ percent removal level of 92 percent. This projected increase in mean FGD performance level is supported by available information. Shawnee data show that attaining 92 percent efficiency with an MgO enriched-lime or limestone-absorbant is technically easier (requires

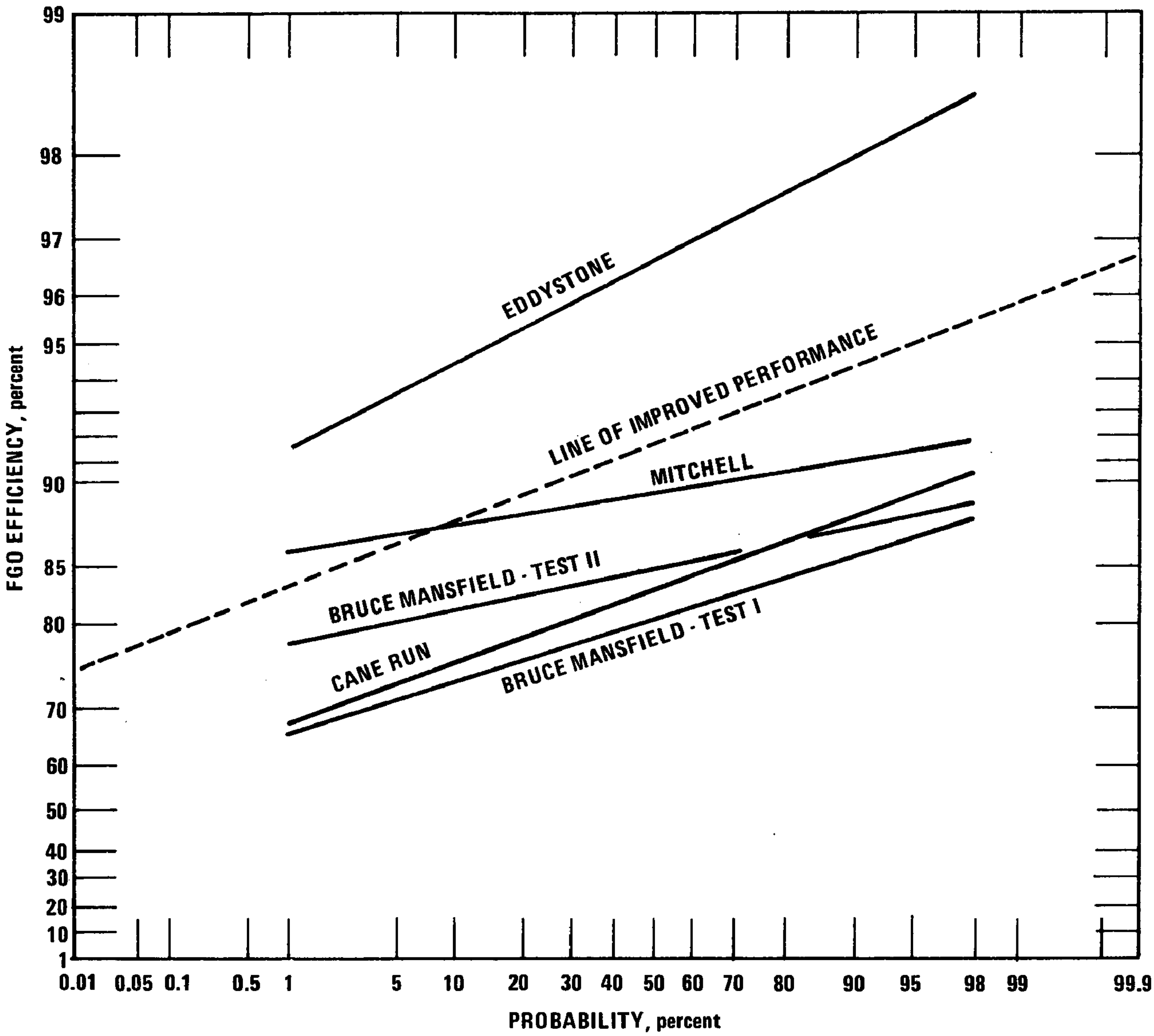


Figure 4-1. FGD 24-hour average efficiency distribution.

lower L/G or pH levels), but that FGD systems can attain 92 percent efficiency without enriching the absorbent when the proper absorber is used. With the TCA absorber and no MgO enrichment, tests at Shawnee showed 92 percent or greater removal when lime or limestone were used. With TCA or similar absorbers using sufficient gas/liquid residence time, reaction tank residence time, and other design factors, the less-reactive calcium-type absorbents enriched with MgO have attained 95 percent mean $SO_2$ removal. With the most reactive absorbents, sodium or magnesium types, all absorbers tested at Shawnee were capable of achieving 95 percent mean $SO_2$ removal.

In addition to the 10-MW pilot plant at Shawnee, several full-scale FGD units have demonstrated 92 percent efficiency. Five American designed limestone systems installed on Japanese coal-fired boilers (Table 4-3), four units installed on Japanese oil-fired boilers, and several tests in the U.S. have demonstrated 92 percent mean FGD efficiency. This level of performance was demonstrated by the full-scale FGD systems at Paddy's Run and at Cane Run by using MgO additions to the lime absorbent. The lime FGD system at the Mohave and Four Corners tests are also examples.

The feasibility of attaining 92 percent mean FGD efficiency is also supported by the performance of regenerable and double-alkali FGD systems. The full-scale units operated at the Mitchell station (Wellman-Lord system) and at the Eddystone station (MgO system) were evaluated with continuous monitoring systems. When the FGD performance data were reduced to 24-hour averages, the mean of these average $SO_2$ removal efficiencies was 90 percent at the Mitchell station and 97 percent at the Eddystone station (Figure 4-1). The ability of the more reactive sodium or magnesium type absorbents to attain over 95 percent removal is also documented by several Shawnee and Scholz station (double alkali) pilot-scale tests.

Double alkali or regenerable FGD systems consistently have higher performance, and their use may be needed for certain applications (midwestern plants using high sulfur coals, plants with limited sludge disposal area, etc.). However, there may not be sufficient vendor capacity to supply only double alkali or regenerable systems to meet the total national demand anticipated for FGD systems resulting from the proposed standards. A survey of vendor capacity is given in the report Effects of Alternative New Source Performance Standards on Flue Gas Desulfurization System Supply and Demand, report number EPA-600/7-78-033. Because of limited regenerable system vendor capacity and higher costs, lime and limestone systems, which have lower performance capabilities, will have wide application and must be relied upon as a basis for a nationally applicable NSPS.

FGD systems capable of attaining 92 percent mean $SO_2$ removal efficiency are currently available from at least 5 to 10 suppliers of lime, limestone, regenerable, and other FGD equipment. Numerous demonstrations of technology have provided design information for such systems and have demonstrated high $SO_2$ removal efficiency on full-scale as well as pilot-scale systems.

4.2.5.2 Minimum FGD Performance

FGD systems should be designed for the most severe operating conditions anticipated, such as maximum boiler load and maximum $SO_2$ inlet concentrations. The $SO_2$ removal efficiency is largely fixed by the absorber design, absorbent type, and by the level of operating parameter selected. Once a mean $SO_2$ percent removal capability has been selected for design into the FGD system, consideration should be given to the minimum 24-hour average performance because a daily (24-hour) basis has been selected for averaging emissions or FGD control efficiency for determining compliance. Thus, compliance during routine operation will depend upon maintaining a minimum percent $SO_2$ reduction each day of power plant operation and will depend on the control of variation in 24-hour average FGD $SO_2$ removal efficiency. The FGD system should achieve a certain minimum $SO_2$ removal (the proposed standard) at maximum boiler load and $SO_2$ inlet concentration and be able to operate at higher absorption efficiencies for all other operating conditions less severe than peak boiler load or peak $SO_2$ inlet concentration.

Once the design capability has been incorporated, process controls must be applied to exercise the capability in response to changing inputs (coal sulfur, boiler load, etc.) and to maintain critical process operating parameters (pH, L/G, etc.) within prescribed ranges. The FGD system cannot be adjusted to control emissions under the worst operating conditions (maximum inlet $SO_2$ concentration and boiler load) and left to function by itself. For example, if the inlet $SO_2$ concentration fell and the lime addition rate to the system was not reduced, pH would rise above safe limits and the system would develop scale.

The variation in FGD efficiency was evaluated by EPA using continuous monitoring data from full-scale boilers equipped with FGD. These data were reduced to 24-hour averages, and probability distributions of 24-hour average FGD efficiency were plotted for each facility (Figure 4-1). The geometric standard deviation (variability) for each distribution

(Table 4-4) was found to be roughly the same (1.014-1.060 percent) for each facility; however, the Cane Run and Bruce Mansfield (test I) data did show higher geometric standard deviations (1.057-1.060 percent). This may be due to factors known to exist at these facilities during the tests. At Cane Run, the boiler is used as a peaking unit and the data base contains results measured during load changes. The data bases for the other facilities also contain results measured during load changes, but the load changes were not as frequent as at Cane Run. At Bruce Mansfield during test I, pH instrumentation problems were experienced. The pH instrumentation was improved prior to test II. Before the pH instruments were repaired and relocated (test I), pH control of the FGD process was hampered.

Table 4-4. $SO_2$ REMOVAL STATISTICS
(24-hour AVERAGING PERIOD)

| Site | No. of points | Mean FGD efficiency (percent $SO_2$ removal) | Geometric standard deviation (percent $SO_2$ removal) |
|---|---|---|---|
| Cane Run | 89 | 89.8 | 1.060 |
| Bruce Mansfield - Test I | 20 | 81.4 | 1.057 |
| Bruce Mansfield - Test II | 11 | 85.3 | 1.029 |
| Eddystone | 8 | 96.8 | 1.014 |
| Mitchell | 25 | 90.0 | 1.015 |

A "line of improved performance" is projected on Figure 4-1 using approximately the same geometric standard deviation recorded for the four facilities tested. The projected performance of an improved FGD system with 92 percent mean $SO_2$ removal is predicted to range from 75 to 97+ percent (24-hour average basis). The probability distribution projects that less than 10 percent of the 24-hour averages (less than 3 days per month) would fall below 85 percent $SO_2$ removal and that the probability of any 24-hour average falling below 75 percent is only 0.01 percent (about once very 4 years assuming 70 percent boiler operability). Less than 75 percent control can easily be avoided by reducing boiler load and shifting electric generation load to another unit or by using improved process controls discussed in section 4.2.6.

4.2.6 FGD Performance Control Improvements

The monitoring data for four full-scale FGD systems tested by continuous monitoring systems have shown that the FGD $SO_2$ removal efficiency variability can be controlled, but not eliminated, by manual operation of the system. Additional automatic control systems can be designed into new FGD controlled steam generators to assist in the control of effects of inlet $SO_2$ concentration variation, on FGD efficiency. The controls currently used by FGD system designs in the United States use pH instruments which do not detect these concentration variations before the slurry reaction tank chemistry has been upset. Instrumentation at the FGD absorber inlet is needed to keep the FGD system in balance when inlet conditions change. A signal from the inlet $SO_2$ continuous monitoring equipment can be used to produce more rapid action by the slurry tank lime feeders for adding absorbent prior to a significant depletion of the absorbent in the reaction tank. Currently used pH controls do not add absorbent until a depletion has occurred. Additional monitoring of inlet gas velocity for automatic control of the mass rate of slurry pumped to the absorber (L/G ratio control) would also contribute to FGD efficiency stability. More automated controls of this type that anticipate impacts of changes in $SO_2$ inlet concentration and changes in gas flow due to boiler load changes have the potential to reduce the variation in 24-hour average $SO_2$ absorber efficiency and to prevent process upsets that can cause scaling. In Japan, these automatic process controls are currently in use (see Sulfur Oxides Control Technology in Japan, Maxwell, Elder, and Morasky, June 30, 1978). Measurement of flue gas volume and $SO_2$ concentration at the scrubber inlet are used to automatically determine slurry make-up volume requirements. Fine tuning of the make-up feed rate is maintained by pH control. The FGD process chemistry stays in balance and the FGD removal efficiency is stabilized.

Steadier FGD operating conditions in Japan have also resulted from using coal blending to reduce variations in the sulfur content of the coal fuel. For example, at the Takehara station, blending of coal controls inlet $SO_2$ between 1150 and 1650 ppm. The blending reduces the burden upon the automatic control systems in adjusting the FGD operation to inlet $SO_2$ concentration conditions. Blending can reduce variations in coal sulfur content in all coal supplies, even shipments from a single mine. Blending of coal at a cost of about $7 per ton (1980 dollars) can produce steadier FGD performance and would allow fewer adjustments to operating controls (pH, lime rates, liquor rates, etc.) to maintain scrubbing efficiency. In addition to more constant $SO_2$ control efficiencies, greater FGD availability due to less scaling that results from process chemistry upsets would be experienced. Availabilities of Japanese FGD units of 97-100 percent are reported.

### 4.2.7 FGD Control at Small Plants

The Japanese units show the potential for improved FGD operating control with blended coal and automated instrumentation. With small-size power plants, these technologies may be needed to attain the proposed percent $SO_2$ reduction standard. Various coal types have different ranges of sulfur content and in smaller power plants the coal sulfur variability can be magnified. The opportunity for coal sulfur variations to average themselves away is less in small plants because they fire smaller quantities of coal in a 24-hour compliance period.

A major U. S. coal company supplied data on Wyoming low-sulfur raw coal to EPA. In their judgment, the data typify Wyoming coals. Assuming 5 percent sulfur retention in the ash, this coal would average 0.84 lb $SO_2$/million Btu for the total amount of coal sampled. The data received were for 306 lots of 600 tons, which were combined into lots weighing 1200 tons, and then further combined into lot sizes of 5000 tons and 10,000 tons. For each lot size group, the mean, standard deviation, and relative standard deviation (RSD) were determined. One important feature of their data is the small lot sizes, which enabled extension of the RSD curve without extrapolation (Figure 4-2).

A second major U. S. coal company supplied data on Illinois high-sulfur washed coals. These data were for 140 lots of coal varying in size from 1000 tons to 14,000 tons, and included lot size, sulfur content, and heating value for each lot. With this information, the RSD versus lot size for Midwestern washed coal was determined (Figure 4-2). The smallest lot sizes used in developing this curve were those in the interval 1200 to 1299 tons.

A 25 MW plant burns an average of only 264 tons of coal in a 24-hour period, but the smallest lot size for which data were obtained was

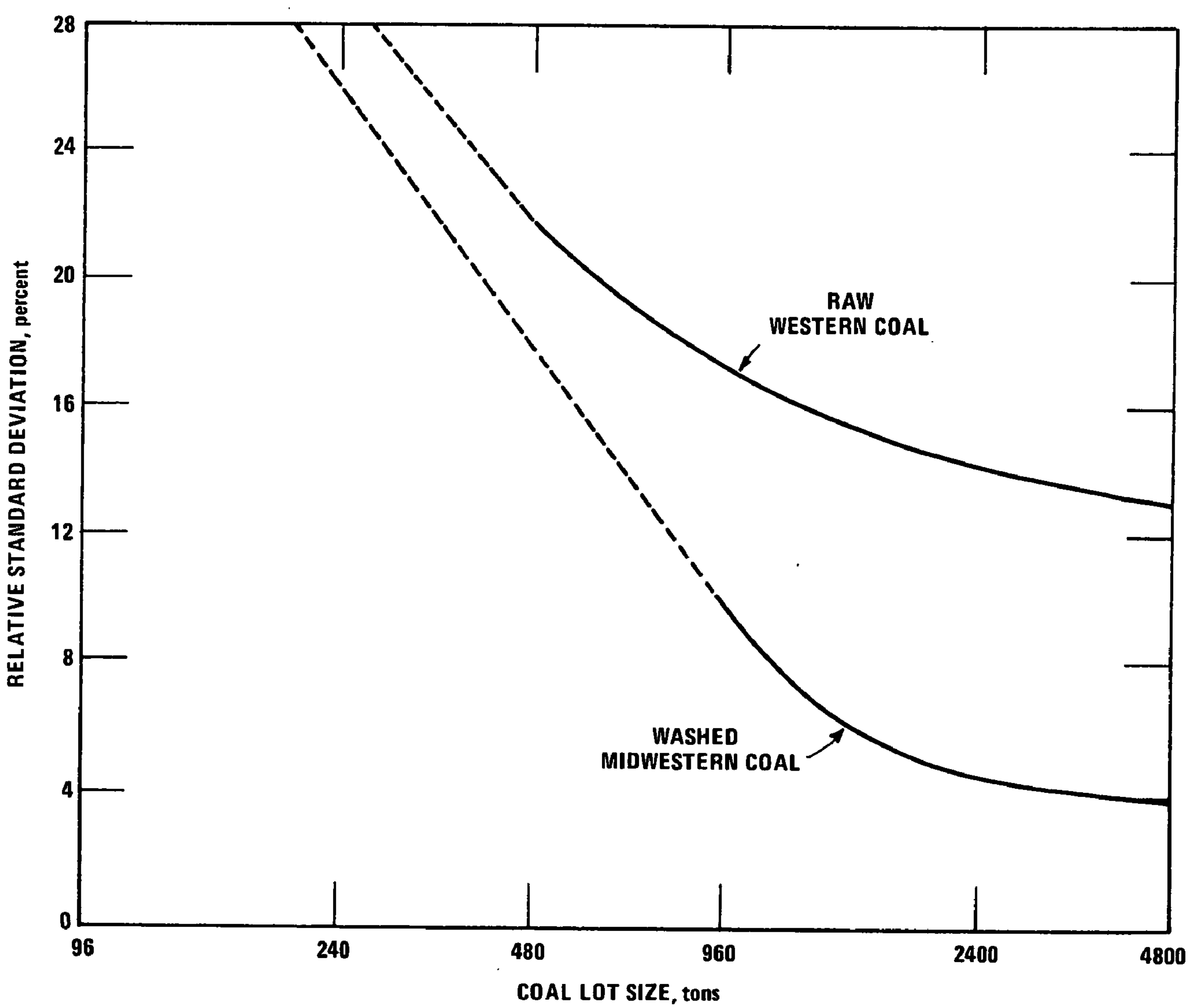


Figure 4-2. Projected RSD for small plants.

600 tons (about 60 MW plant capacity). For illustrative purposes, both RSD curves were extrapolated for small lot sizes (Figure 4-2). The dotted portions of the curves in this figure are not based on data for the tonnages they represent.

The proposed percent $SO_2$ reduction standard can be achieved on many large power plants without coal blending and improved process control instrumentation to reduce FGD efficiency variation. However, in small plants or in plants which are firing certain coal types, closer control of FGD operations may require application of technologies to improve absorber efficiency control (e.g., coal blending and improved process controls). Technologies to attain higher mean $SO_2$ percent removal, (e.g., coal washing plus FGD or regenerable FGD systems) are also available. An appropriate combination of these technologies will enable any power plant regardless of size or coal type to attain the percent $SO_2$ reduction standard.

## 4.3 DRY $SO_2$ CONTROL SYSTEMS

Dry $SO_2$ scrubbing systems have made significant advancements in the past few years and many variations of the system have been developed. One of the more effective systems incorporates the use of a spray dryer and baghouse. In this system a spray dryer (similar to a wet $SO_2$ scrubber) is used with lime, soda ash or other reactants to scrub $SO_2$ from the flue gases. Because of the very minimal use of water in the spray dryer (by design) the flue gas is quickly reheated from a saturated wet gas into a dry particulate-laden gas stream before leaving the spray dryer. Following the spray dryer a baghouse is used to collect all particulate matter (including $SO_2$ reactants). A significant portion of the overall $SO_2$ removal by the dry control system takes place on the filter cake in the baghouse.

Spray drying has been tested at pilot plants, and it appears capable of achieving 85 percent $SO_2$ removal (24- hour average basis) with lime, soda ash, and other reactants. The system is principally limited by economics to coals with less than 1.5 percent sulfur if lime is used. For low sulfur coal applications, spray dryers appear to have several advantages in comparison to wet scrubbers. Experience with spray dryers for $SO_2$ control has been limited to several pilot plants, but these demonstrations have been sufficiently convincing for some utility companies. Full size spray drying units for commercial power plants have been ordered and will initiate operation in the early 1980's.

Some of the potential advantages currently claimed for spray dryer, dry $SO_2$ control systems are:

1. A dry $SO_2$ scrubber does not require certain equipment required for disposal of wet sludge (thickeners, centrifuges and mixers).
2. The dry system is expected to use less costly low carbon steel for most of the equipment because the stack gases are not cooled as much as with a wet scrubber. Less fan corrosion and imbalance are expected.
3. The dry system may have more flexibility of operation. Dry scrubber slurry feed rates can be adjusted with less concern for pH control and dry scrubbers are expected to have more turn-down capability.
4. The capital cost of the dry system is projected to be $20 to $40 per kilowatt less than a comparable wet scrubbing system with full control.
5. A dry $SO_2$ control vendor has estimated that about one-half as many operators and one-third as many maintenance personnel will be required for the dry system as compared to wet scrubbers.

6. The dry system is expected to have only 50 percent of the energy requirements of the wet system. No flue gas reheat is necessary.

7. Annualized costs of particulate matter and $SO_2$ control may be reduced about 15 percent with dry controls in comparison with wet scrubbers (full control).

## 4.4 NONCONTINENTAL AREAS

Several island areas will be affected by the proposed regulations: Hawaii, Guam, American Samoa, the Northern Marianas, Puerto Rico, and the Virgin Islands. A small amount of electric generating capacity will be constructed to meet future needs in these noncontinental areas. In Hawaii, several small units will be constructed on separate islands to provide an additional 1141 MW capacity during the period 1980 to 2000.

Electric generating units in these islands now fire low sulfur oil or waste materials such as bagasse from their sugar industry. In Hawaii, the Virgin Islands, and municipal areas in Puerto Rico, fuel oil containing less than 0.5 percent sulfur is used to comply with State Implementation Plans. New units are also projected to fire low sulfur oil notwithstanding the coal conversion legislation currently being considered by Congress. The coal conversion bill has been drafted with provisions that would exempt Hawaii and other noncontinental areas from requirements to use coal in new electric generating units.

The application of the same proposed standard for all facilities in the United States regardless of geographic location would require FGD systems to be installed on oil-fired units in these islands. Although use of FGD on oil-fired units in Japan has been well-demonstrated, several unique features of U.S. noncontinental areas distinguish them from larger islands such as Japan as well as from the U.S. mainland.

Limited land area is available for FGD sludge disposal, and the groundwater level on many islands is near the surface. Sludge disposal ponds must be lined and must be shallow. Shallow ponds require up to five times more acreage than comparable ponds on the U.S. mainland. Because of the large size pond required, high cost of land and the need for a pond liner, a sludge pond on the island of Oahu, State of Hawaii, is estimated to cost up to $12 million for a 141-MW unit. In contrast, a sludge pond for a 141-MW unit located on the U.S. mainland is projected to cost only $132,000. The increased risk of contaminating ground water levels close to the surface and the much greater cost of sludge ponds detract from the technical and economic feasibility of using throw-away absorbents in FGD systems in these islands.

Alternative disposal methods were also considered. An EPA study of ocean disposal of FGD sludge identified several promising options, but disposal of sulfite-rich FGD wastes was not considered acceptable until more definitive data are available. A second alternative considered was to produce a usable by-product rather than a throw-away sludge, as is typically done in Japan. This would be done either by forced oxidation conversion of sludge to gypsum or construction of a regenerable FGD system that produces either sulfuric acid or a solid sulfur product. There is no significant industrial intrastructure on these islands that could make use of FGD by-products. Although these FGD by-product materials are potentially usable on the U.S. mainland, shipment to the mainland would be costly.

Applying FGD to units in these islands would be more expensive than similar applications on the mainland, and unique environmental problems would be encountered. In addition to potential groundwater contamination, reliance upon FGD controls in these islands could create short-term excursions of high $SO_2$ emissions be cause there would be little opportunity on a small island to shift electric generating load away from a unit with a malfunctioning FGD system to a second generating source.

Use of low-sulfur oil instead of FGD would produce low and constant emissions, would be much less costly, and would avoid potential ground water contamination. The Hawaiian Electric Company has projected that application of FGD on the island of Oahu alone would increase their annual revenue requirements by $56 million.

## 4.5 PERFORMANCE TESTING

### 4.5.1 Particulate Matter

Compliance with the particulate matter standard would be determined by using EPA Method 5 operated at a filter temperature up to 160°C. EPA Method 3 would be used to determine oxygen or carbon dioxide concentrations. These concentration measurements would then be used to compute particulate emission in units of the standard as specified in proposed EPA Method 19.

EPA relies primarily upon Method 5 for gathering a consistent data base for particulate matter standards. Method 5 meets the above criteria by providing detailed sampling methodology and includes an out-of-stack filter to facilitate temperature control. The latter is needed to define particulate matter on a common basis since it is a function of temperature and is not an absolute quantity. If temperature is not controlled, and/or if the effect of temperature upon particulate formation is unknown, the effect on an emission control limitation for particulate matter may be variable and unpredictable.

As applied to the steam generator new source standard, EPA Method 5 originally employed a filter system located out-of-stack and operated at a temperature of 120°C. In October 1975, EPA revised the performance test requirements for steam generators to allow operation of the filter system at temperatures up to 160°C. The purpose of this revision was to prevent collection of condensable gaseous compounds, which would not be controllable by dry control devices operating at stack temperatures found at modern boilers.

In February 1978, EPA promulgated Method 17 for the determination of particulate from sources when specified in applicable subparts.

Method 17 uses an in-stack filter and, therefore, collects particulate matter at the temperature of the stack gas. Since Method 17 measures particulate matter at the stack gas temperature, it is considered to yield comparable results in comparison to EPA Method 5 at stack temperatures of less than 160°C. Method 17 is, therefore, acceptable to demonstrate compliance with the steam generator standard. The method allows a flexible connection between the probe and the sample box and thereby has the advantage of eliminating traversing with the sample box. The method also eliminates possible imprecision in recovering samples from long stainless steel probes used in very large-diameter stacks. Since Method 17 is not applicable for stack gases containing saturated water vapor, it is not applicable to stacks following wet scrubber systems unless demisting and reheat treatment are sufficient to raise the stack gas above its dew-point.

### 4.5.2 Sulfur Dioxide and Nitrogen Oxides Standards

#### 4.5.2.1 Compliance Tests

Compliance with the proposed $SO_2$ and $NO_x$ standards would be based upon the data obtained from a continuous monitoring system. If FGD were used for $SO_2$ control, continuous $SO_2$ emission monitors would be required both upstream and downstream of the FGD system to determine compliance with the 85 percent $SO_2$ reduction requirement. As an option, compliance with the $SO_2$ standards could be determined using both an "as fired" fuel sampler to determine the sulfur content and heating value of the fuel fired to the boiler and a continuous $SO_2$ emission monitor after the FGD system to measure $SO_2$ emissions discharged into the atmosphere. In addition to crediting the $SO_2$ removed by the FGD system, this option would provide credit for sulfur removed by coal pulverizers and in the bottom ash and fly ash. The $SO_2$ percent reduction requirement and emission limitation would both be averaged over a 24-hour (daily) period. If fuel is treated prior to combustion to reduce $SO_2$ emissions, a sulfur removal credit would also be allowed.

Performance testing to determine compliance with the percent reduction requirements for $NO_x$ would not be required. An affected facility would be assumed to be in compliance provided the facility is in compliance with the applicable $NO_x$ emission limitation.

For $SO_2$ and $NO_x$ continuous monitoring, EPA requires the pollutant and diluent gas analyzer to measure the gas concentrations at least once every 15 minutes (Subpart A, General Provision, 40 CFR 60.13(n)). For the purposes of this standard, the 15-minute measurements would be averaged each hour. The hourly average concentrations are recorded (printed out) and then averaged each 24-hour period to determine compliance in accordance with the procedures in EPA Method 19. A minimum of 23, one-hour averages are required to calculate the daily average emission rates.

Emission determinations are not required 1-hour per day to allow for daily zero, span, calibration checks, and adjustments to the continuous monitoring system and for an additional 8 hours per month to allow for routine service. Fewer than 23, 1-hour emission determinations will be averaged on days containing periods of plant startup, shutdown, inoperation, and emergency conditions. One-hour average emissions would be determined during each of these periods except plant inoperation, but would not be included in the daily arithmetic emission average for determining compliance with the proposed $SO_2$ and $NO_x$ standards. Thus, only the data averaging method specified within EPA Method 19 may be used to determine compliance.

When the compliance monitoring system fails to operate properly, the same source owner or operator would obtain emissions data by (1) operation of a second monitoring system or (2) conducting manual tests using EPA reference methods. If a second monitoring system is used, the source owner would have to keep the second system in operation at all times. When conducting the manual tests, the source owner would have to keep trained manpower available to collect the samples.

EPA requires continuous monitors to meet performance specifications promulgated in 40 CFR 60, Appendix B. Since compliance with the $SO_2$ and $NO_x$ standards would be determined by continuous monitors, EPA is currently developing additional quality assurance procedures. These procedures would not change the present performance specifications, but would provide additional periodic field tests to assure the accuracy of the monitoring data. Sections within the proposed regulations are being reserved for the future addition of these requirements. This matter should not pose a problem since new sources affected by the revised standards are not expected to begin operation until 1984.

4.5.2.2 Fuel Pretreatment Credits

Pretreatment of a fuel to remove sulfur or increase heat content would be credited toward an 85 percent $SO_2$ reduction requirement. For example, by pretreatment of a fuel with 1000 ng/J potential $SO_2$ emissions (e.g., about 2.3% S coal) to remove 25 percent of the sulfur, the FGD system $SO_2$ removal requirement would be reduced to 80 percent (750 ng/J reduced to 150 ng/J). An 85 percent emission reduction (1000 ng/J reduced to 150 ng/J) would be necessary if the fuel were burned untreated. Table 4-5 shows the amount of $SO_2$ removal that would be needed in conjunction with fuel pretreatment to achieve an overall 85 percent $SO_2$ reduction.

Table 4-5. RELATIONSHIPS BETWEEN FUEL PRETREATMENT AND POST COMBUSTION CONTROL FOR REMOVAL OF 85% SULFUR DIOXIDE

| Pretreatment $SO_2$ removal % | Post combustion $SO_2$ removal efficiency, % |
|---|---|
| 0 (no fuel pretreatment) | 85 |
| 10 | 83 |
| 20 | 82 |
| 30 | 79 |
| 40 | 75 |
| 50 | 70 |
| 60 | 63 |
| 70 | 50 |
| 80 | 25 |
| 85 | -0- (no post combustion $SO_2$ control |

Fuel pretreatment credits would be given for removal of sulfur from fuel and increase in fuel heat content. Examples of the type of equipment or processes for which credits would be given are:

1. Physical coal cleaning.
2. Solvent refining of coal.
3. Liquefaction of coal.
4. Claus processing for removal of sulfur from gasified coal.
5. Hydrotreating of oils by refineries.

Rotary breakers used to separate rock and other material from raw coal prior to processing or shipment by a coal preparation plant are considered an integral part of the coal mining process and this use would not be considered as fuel pretreatment. Sampling of raw input coal to determine fuel credits would be performed after the coal has passed through a rotary breaker or a course screen rather than from the tipple.

The proposed standard would not require that fuel be pretreated before firing but, as indicated, would allow credit for pretreatment. The amount of sulfur removed by a fuel pretreatment process would be determined by applying Method 19 (Appendix A). The owner or operator of the electric utility who would use the credit would be responsible for insuring that the Method 19 procedures are followed in determining $SO_2$ removal credit for pretreatment.

The fuel monitoring procedures proposed under Method 19 could be made part of the fuel supply contract. Because of the small impact of coal pretreatment on FGD performance, the uniformity of highly processed fuels (such as solvent-refined coal), and the desirability to develop a viable fuel pretreatment crediting procedure, a 90-day quarterly average is being proposed for determining fuel cleaning credits. Through use of Method 19, the fuel supplier could provide a certificate of credits to the coal purchaser with each lot of fuel delivered or for all lots delivered for the calendar quarter. The certificates would have to show (1) sulfur analysis of coal input and output from the preparation plant (ng/J lbs/million Btu), (2) quantity delivered, (3) heat content, and (4) calculation of the pretreatment credit. For example, if the analysis of coal to and from the preparation plant were 5 percent sulfur (3,800 ng/J) and 4 percent sulfur (3,000 ng/J), respectively, on a dry basis, a 20 percent pretreatment credit would reduce FDG removal requirements from 85 percent to 83 percent.

After the utility company receives the fuel and the pretreatment certificate, a summary of credits for all fuel received in a calendar quarter would be prepared for pretreatment credit. The credits for all fuel deliveries would be averaged on a weighted-Btu basis to determine an average credit for the quarter. For example, if half of the heating value of all fuels received were cleaned coal with a 30 percent pretreatment credit and half were for coal with a 20 percent pretreatment credit, the average credit for the quarter would be 25 percent.

After the average pretreatment credit is determined for a quarter (e.g., the first quarter of a year), it would be applied toward determining compliance with the 85 percent removal standard for all 24-hour (daily) periods during the next quarter (e.g., the second quarter of a year). Thus, the average fuel cleaning credit from the first quarter would be considered together with each 24-hour (daily) average percent removal achieved by the FGD system during the second quarter and used to determine compliance with the 85 percent overall $SO_2$ removal requirement. For example, a 25 percent fuel cleaning credit for a first quarter would reduce the $SO_2$ reduction requirement to 80 percent for all 24-hour daily periods during the following quarters, except for three days per month where 67 percent rather than 75 percent would be allowed.

The approach of determining the credit on the basis of the previous quarter's fuel receipts would allow the utility to know before the fact the amount of $SO_2$ removal that must be attained by the FGD system. Without this procedure, the utility owner could not determine until the end of a quarter whether he had used sufficient FGD control to comply with the emission standard.

### 4.5.3 Opacity

Compliance with opacity standards could be determined at any time by visual observations using EPA Method 9. Except during startups, shutdowns, and emergency energy conditions, all data from visual observations would be used for determining compliance with the opacity standard.

A continuous monitoring system for opacity would be required in the stack except when only gaseous fuels are fired. The opacity data from the continuous monitor would not be used to determine compliance with the opacity standard. It would be used to assist in assuring that the particulate matter control system is properly operated and maintained at levels observed at the time the particulate matter performance test is conducted.

If interference with opacity monitoring is expected because of condensed water vapor in the stack, the monitor would be located upstream of the FGD system. If interference with the opacity measurements is expected upstream of the FGD system, the opacity monitor would not be required and operating parameters of the particulate matter control device would be monitored.

4.6 FGD COMPLIANCE

FGD systems are composed of FGD modules, each of which is separate scrubbing system. Because FGD modules are not generally manufactured in sizes over 125-MW capacity, large power plants use multiple FGD modules in parallel.

EPA has analyzed the availability of FGD modules and systems. In PEDCo's report Flue Gas Desulfurization System Capabilities for Coal-Fired Steam Generators, EPA-600/7-78-032b, March 1978, it was stated that with best operation and maintenance FGD modules would be available for service up to 90 percent of the time. A review of the availability of other mature coal-fired electric generating components was also performed for comparative purposes. In Radian's report The Effect of Flue Gas Desulfurization Availability on Electric Utilities, EPA-600/7-78-031b, March 1978, components such as boilers, and turbines were reported to have average availabilities between 80 and 97 percent.

When FGD modules, even those with 90 percent availability, are integrated into an FGD system, the probability that all modules in the system will be available simultaneously diminishes in proportion to the number of modules. For example, an FGD system consisting of four modules without spares could have an availability of only 66 percent ($0.9^4$ = 0.656) if all modules were operated simultaneously.

To address this problem, spare FGD modules may be needed in systems where all FGD modules are often called upon to operate. Even when high FGD module availabilities (90%) are attained, the FGD module will be out of service a significant amount of time (10%) for regularly scheduled maintenance, forced outages, and repairs. When the power plant is operated at maximum capacity, the maintenance problem is compounded because all modules are needed to treat the flue gas. To maintain high FGD system availability, one or more spare FGD modules may be necessary. The Radian report concludes that a base-loaded power plant cannot meet consumer demand without spare FGD module capability.

EPA has concluded that compliance with the proposed standards using FGD control systems could be attained by (1) using 90 percent available FGD modules, (2) using spare FGD modules in base-loaded units, and (3) providing a limited allowance for emergency conditions when the electric generating plant output must be continued to maintain continuity of electric service.

Although a high-quality routine maintenance program will keep FGD modules 90 percent available, the amount of time for such maintenance can be considerable, even continuous. With spares, a module can be rotated out of operation for maintenance even when the power plant is operating at full electrical load. Switching FGD modules need not have a major impact on plant operation. At reduced electrical loads, all FGD modules may not be needed for $SO_2$ control and some modules could undergo maintenance at such times or at times when the entire plant is taken out of service for repair of non-FGD related components.

The Radian report states that mature, coal-fired electric generating plants are reported to have average availabilities of only 70 to 77 percent, even when FGD systems are not used. Thus, a considerable amount of time would also be available for FGD module maintenance when the power plant is not being operated.

If a power plant is base loaded and must therefore operate with a minimum of interruptions, spare FGD modules can keep the availability of the total FGD system of modules above 90 percent. EPA has projected that one spare may be needed for plants up to 500 MW and two spares may be needed for larger plants up to 1000 MW.

Even with a good maintenance program and use of spare FGD modules, complete FGD control may not be maintained for a portion of the plant operating hours. At these times, the proposed regulations would require that the electric generating load be shifted when possible to another electric generating plant. This procedure is necessary to minimize bypassing of uncontrolled $SO_2$ emissions to the atmosphere. Because frequent load shifting is not economical, it also provides an incentive for maintaining the FGD control system. The uncontrolled, incremental $SO_2$ emissions that would result from shifting the load is expected to be no greater than the $SO_2$ emissions that would result from bypassing.

Discharging untreated flue gas to the atmosphere (bypassing of emissions) because of $SO_2$ control system malfunctions would be allowed only during emergency conditions, and even then $SO_2$ emissions from the facility would have to be minimized by operating all available FGD modules to the maximum extent feasible. Emergency conditions are considered to be periods when a power plant and its associated utility system are being operated at full operable capacity except for an amount of capacity equal to the largest single steam generator in the system. Because it may be necessary to meet consumer electric demand, would reduce $SO_2$ emissions, and would be economically reasonable in large power plants, the emergency condition provisions would apply only to (1) plants that have installed at least one spare FGD module or to (2) small plants ($\leq$ 125 MW capacity). Small plants would need only one FGD module (no spare) to attain 90 percent availability, and use of a spare module on a small plant would be economically unattractive. The added cost of a spare module has been evaluated in PEDCo's report, Particulate and Sulfur Oxides Emission Control Costs for Large Coal-Fired Boilers, EPA-450/3-78-007, February 1978.

The emergency condition provisions are necessary to maintain the capability to meet electric demand when adequate generating reserves are not available. A minimal amount of spinning reserves (not greater than the largest unit in the system) must be kept separate from the load shifting procedures to prevent "blackouts" or serious impairment of service continuity.

During periods of emergency, the derating and load shift procedures cannot be implemented without seriously jeopardizing the electric reliability of the utility system. Interconnection capacity (for purchasing power) and spinning reserve capacity must be kept available to handle sudden losses of generating capacity within the utility system. This amount of spinning reserve can typically vary from 75 to 150 percent of the capacity of the largest single unit within the utility company depending upon the characteristics of individual company systems.

The interconnection capacity represents the amount of power that can be brought into the utility from neighboring companies. This amount can be limited by the load carrying capacity of switch gear, transmission lines, etc., used to interconnect the utility company's grid with that of neighboring companies. The interconnected system is automatically the first source of replacement power in the event of a sudden electric generation loss. Power is immediately pulled into the utility system through the interconnections, which spreads much of the lost load over many electric generators in several other utility systems. A small, noncritical frequency drop is typically experienced over a wide area rather than a severe service problem or a blackout in a localized area.

Because the interconnection capacity is so important for immediate reaction to an electric generation loss, a minimum amount of interconnect capacity must be kept available. To maintain or restore this minimum, energency power brought into the utility through the interconnection should be reduced within 10 minutes and entirely replaced as soon as possible by loading spinning reserves or bringing nonspinning reserves into operation. An individual unit in spinning reserve, already synchronized and partially loaded to the electric system, can immediately start assuming additional load; however, a unit cannot be instantly loaded. The rate at which a unit can be loaded (ramp rate) is not the same for all units. Because of the time needed to bring spinning reserves into operation, interconnected capacity must be kept available and the spinning reserves are not usually concentrated in any one unit to minimize response time to satisfy load demands.

In addition to the simple replacement of power generation described above, there are other factors that can at times be critical to the reliable and efficient operation of a utility system. Because localized power factors, transmission line capacity, and other problems contribute to making the overall operation very complex, an amount of capacity defined as "system emergency reserves" should not be involved in the load shifting procedures that are to be implemented to avoid bypassing emissions around an FGD module. These system emergency reserves which equal the rated capacity of the largest single electric generating unit within the electric utility system may be distributed among several electric generating units within the utility company. This procedure is usually necessary (1) to keep reserves available in each local service area and (2) to minimize the amount of time needed to get the emergency reserves into full operation because power increase is typically limited to 2- to 15-MW/min per unit. By bringing several units into operation at once, more capacity can be brought into operation per minute during an emergency.

Emergency condition provisions would not prohibit the installation of bypasses around an FGD system; however, the use of these bypasses can place the owner or operator in violation of the proposed standards unless their use is strictly limited to periods of emergency conditions when only system emergency reserves are available to prevent blackouts. At any time the utility has available reserves (either cold units or spinning units) in excess of emergency reserves, the utility is required to bring them into operation to replace a malfunctioning unit and to simultaneously purchase power in the interim period of time it takes to bring available reserves on-line. During emergency conditions or the time needed to bring a spare module on line, $SO_2$ continuous monitoring emission data would not be included in any 24-hour performance test average. Although these periods would not be included in performance tests, they would be subject to requirements under 40 CFR 60.11(d), which require the maximum control of $SO_2$ emissions feasible even under adverse conditions. Load shifts to other generating units will usually be feasible with purchase power being used in the interim period when units are being brought into service.

Normal procedure would not include the routine use of emission control system bypass during (1) the time a spare FGD module is being dampered into the system to replace a malfunctioning module that is attaining substandard $SO_2$ control, (2) the time a module is being removed for scheduled maintenance service, or (3) the time a module is being brought on line because of an increase in boiler load. A spare FGD module should be brought on line before other modules are removed from service or before load changes are made. Bypass of emissions would only be necessary during emergency conditions. During startup and shutdown all necessary modules should be brought on line to minimize emissions prior to system changes. These procedures may cause utilities to change some operating procedures including those for dispatching load, but will not significantly affect the operation of the electric system or the ability of the utility company to maintain service continuity.

## 4.7 COAL IMPACTS

### 4.7.1 Production and Reserves

The effect of the proposed standards on coal production has been projected by EPA for the period 1985 to 1995 (Section 3). In comparison to coal production under the current NSPS, an 85 percent reduction requirement, a 0.2 lb/million Btu floor, and a 1.2 lb/million Btu ceiling are expected to have almost no impact on total national coal production ($\leq$2 percent decrease) in comparison to the current NSPS (Table 3-4). Regional coal production patterns may shift, however, because of the increased utilization of higher sulfur coal. Midwestern coal production is projected to increase up to 15 percent more than it would have had the current NSPS remained in effect for all new units. About 6 percent decrease in coal production in the Northern Great Plains area and virtually no change in other Western or Appalachian coal production are expected in 1990. Shipments of Western coal to the Midwest and areas further east are expected to decline by about 20 percent. Even with FGD controls, shipment of Western coal to the midwest and other areas will not be totally stopped, but will be reduced. Under the proposed standard, the amount of Western coal shipped east is expected to be less than 10 percent of total national coal production.

A 85 percent reduction requirement would not affect national coal production, but an $SO_2$ emission limitation (ceiling) of 520 ng/J (1.2 lb/million Btu) would restrict the sulfur content of coal that can be utilized even when FGD controls are applied. Although Midwestern coal production does not decline in comparison with the current NSPS, mining of many coal desposits would be restricted by a 1.2 lb/million Btu emission limitation.

Continuous monitoring of $SO_2$ emissions would require strict, daily compliance. The composition of coal varies appreciably even when all shipments are from the same mine (see sections 4.2.4 and 4.2.7). To ensure compliance with the ceiling, $SO_2$ emissions should be based on minimum FGD performance (24-hr basis) and maximum daily average coal sulfur content since these conditions may coincide.

EPA has analyzed the impact on national and regional coal reserves of 24-hour minimum FGD efficiency conditions coinciding with peaking coal sulfur content. Minimum FGD efficiencies were projected form the line of improved performance in Figure 4-1, and coal peak sulfur contents were projected using 15 percent RSD. Two options for selection of the $SO_2$ emission limitation were analyzed: 1.2 lb/million Btu with 3 exemptions per month (option 1) and with no exemptions (option 2). With each of these options, the mean sulfur content of the coal that could be used to comply with the ceiling was projected and used to compute (1) future coal production and (2) the amount of coal reserves that would be restricted by the ceiling. The sulfur content of the coal that would comply with Option 2 is the same as would be required by a 0.8 lb/million Btu ceiling with exemptions and the coal production impacts would also be the same.

The 3-day exemption used in option 1 is based upon variation in FGD performance that would be expected from a unit not using blended coal or automated controls that monitor inlet FGD conditions. An FGD system that achieves 85 percent reduction on a daily basis is expected to have up to 3 days per month of 75 percent efficiency as well as several days of very high (95 to 99 percent) performance. An exemption in the ceiling would allow relief during periods of 24-hour average FGD performance between 75 and 85 percent which can coincide with peaks in coal sulfur content.

An analysis (Section 3) of national and regional coal production in 1985, 1990, and 1995 was performed for each option. There were no significant differences in total national production with either option (Table 3-4). The analysis included use of washed, Midwestern coal when coal washing was necessary to attain compliance with the ceiling. Sufficient national reserves were available to satisfy national demand with either option.

On a regional basis, a ceiling without exemptions (option 2) had the effect of dislocating coal production in the Midwest. Midwestern coal production in 1995 would be reduced by about 14 percent in comparison to option 1. The lost Midwestern production was replaced by increased production in the Northern Great Plains and Appalachian regions and by a small production increase in the West. Thus, option 2 would produce no shortage of coal to meet power plant demand in the Midwest, but would transfer some mining operations to other areas.

Analysis of Midwestern coal reserves restricted by a ceiling without exemptions (option 2) verifies the production dislocations projected. The analysis was performed using coal reserve statistics classified by sulfur content. In the States of Ohio, and Illinois, and in western Kentucky 60 to 90 percent of reserves would be restricted even if coal cleaning were used. Without coal cleaning, over 85 percent of reserves in these States would be restricted by option 2.

This impact upon midwestern coal reserves and production would be avoided by option 1 (1.2 lb/million Btu with a 3 day-per-month exemption).

Even with no coal washing use, 40-65 percent of reserves would not be restricted and option 1 would maximize local coal utilization in Midwestern coal-fired power plants. The power plant would not be exempted from controlling $SO_2$ emissions during the 3-day exemption because the FGD percent reduction requirement would apply.

This analysis of Midwestern coal reserve impacts assumes 15 percent RSD coal sulfur content variability. Eastern and Midwestern bituminous coals often exhibit less coal sulfur variation. In Figure 4-2, washed Midwestern coal, $\geq$ 2000 ton lot sizes, has a RSD of 5 percent or less. High sulfur, Midwestern coal that has a potential problem complying with the 1.2 lb/million Btu ceiling will probably be washed and the 5 percent RSD would be more typical than 15 percent. In addition, coal washing is projected to remove up to 35 percent of the sulfur from Midwestern coal using conventional technology. When consideration is given to these factors, well over half of Midwestern coal reserves are expected to be useable in new power plants subject to the proposed standards.

Use of coal blending would make even more of the Midwestern reserves useable. Very high sulfur coals can be washed and then blended with lower sulfur coals, including lower sulfur Midwestern coals, to produce a fuel that could comply with the ceiling (option 1) when 85% FGD control is applied.

Another alternative available for utilizing high sulfur coals is to install an FGD system capable of greater than 85% efficiency. A few FGD systems (e.g., Wellman-Lord, Magnesium Oxide, Double Alkali, etc.) have shown this capability during performance tests (section 4.2.5). With 90% minimum FGD efficiency, a Midwestern coal containing about 6 to 7 percent average sulfur after coal washing would be expected to comply with option 1. Thus, with (1) coal washing and coal blending or (2) coal washing and a 90% efficient FGD system, virtually all Midwestern coal reserve could be utilized in new power plants.

In addition, solvent refined coal (SRC) plants are being constructed which would utilize high sulfur (>5% average) Midwestern coal. These SRC plants are expected to produce a product that will comply with the option 1 ceiling when fired in new power plants.

4.7.2 Anthracite Coal

The proposed standard would cover anthracite coal in the same manner as all other coals under a uniform $SO_2$ control requirement.

Anthracite coal has not been in significant demand since the 1940's and may not become an economically feasible utility fuel in the near future unless its use is encouraged. Although anthracite coal has $SO_2$ emission characteristics similar to those of low-sulfur Western coal, it has not become a common utility fuel to date because (1) it costs approximately 75 percent more to mine in comparison to local bituminous coal, and (2) anthracite coal-fired power plants are 10 to 15 percent more expensive to construct than plants firing bituminous coal.

The suggestion has been made that anthracite coal should be subject to $SO_2$ control requirements less stringent than those for other coals. One recommendation included a "flexible interpretation" of the emission standards for anthracite coal in which no greater FGD efficiency would be required than that amount (approximately 55 percent control) which would give an $SO_2$ emission rate equivalent to that which would result from using 85 percent FGD control on the local bituminous coal. The recommended "flexible interpretation" for anthracite coals was based on its "inherently low-sulfur content and local socioeconomic conditions." The increased use of anthracite coal would ostensibly increase strip mining jobs in economically depressed areas of Pennsylvania and would assist in correcting acid mine drainage problems associated with many abandoned mines in the area.

When considering reduced $SO_2$ control for anthracite coal, it is appropriate to consider anthracite coal in relation to low-sulfur Western coals. Anthracite coal does not have $SO_2$ emission rates significantly different than those of high-quality low-sulfur Western coal required to meet the proposed 85 percent reduction requirement. With full or partial FGD, low-cost Western low-sulfur coal will have a market, but high-cost anthracite coal may not. The use of low-sulfur anthracite coal in its local market. Since Congress intended that $SO_2$ emissions from low-sulfur Western coals be fully controlled, anthracite coal emissions should be fully controlled as well. Anthracite coal use could be required by State regulation if its use is of local importance.

The use of local anthracite coal under the 85 percent $SO_2$ removal requirement would result in an approximately 4 percent higher cost of electricity to the consumer than if a local bituminous coal were used with 85 percent $SO_2$ removal.

Table 4-6 gives electrical costs associated with partial and full FGD treatment for anthracite coal.

Table 4-6. EFFECTS OF ANTHRACITE USE
ON COST OF ELECTRICITY

| Type of local coal | FGD, % | Electricity rate c/KWh | Variation, % |
|---|---|---|---|
| Bituminous | 85 | 3.46 | baseline |
| Anthracite | 55 | 3.40 | -1.7 |
| Anthracite | 85 | 3.59 | +3.8 |

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Revised Standards of Performance for the control of emissions of particulate matter and nitrogen oxides from electric utility steam generating units are also being proposed. These standards are supported in separate Background Information documents, numbered EPA-450/2-78-005a for nitrogen oxides and EPA-450/2-78-006a for particulates.

16. Abstract

Revised Standards of Performance for the control of sulfur dioxide emissions from electric utility power plants are being proposed under the authority of section 111 of the Clean Air Act. These standards would apply only to electric utility steam generating units capable of combusting more than 73 MW heat input (250 million Btu) of fossil fuel and for which construction or modification began on or after the date of proposal of the regulations. This document contains background information, environmental and economic impact assessments, and the rationale for the standards, as porposed under 40 CFR Part 60, Subpart Da.

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| a. DESCRIPTORS | b. IDENTIFIERS/OPEN ENDED TERMS | c. COSATI Field/Group |
|---|---|---|
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