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# REPORT TO CONGRESS ON CONTROL OF SULFUR OXIDES

Environmental Protection Agency

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February 1975

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16. ABSTRACT

Energy shortages, primarily of oil and natural gas, have increased the importance of our domestic coal reserves. Although coal is our most abundant source of fossil fuel energy, its increased use without adequate environmental safeguards could aggravate the nation's already serious environmental problems. This report focuses on the compliance status of existing coal-fired steam electric power plants and on alternative methods for compliance with applicable emission regulations. Compliance alternatives include the use of low-sulfur coal, physical coal desulfurization, flue-gas desulfurization, coal gasification, fluidized-bed boilers, supplementary control systems, and energy recovery from solid waste. A review is presented showing the current status of existing coal-fired plants in terms of the sulfur content of coal purchased during the first half of 1974, the involvement of power companies in litigation challenging the applicable regulations, and the programs for achieving compliance with sulfur regulations in State Implementation Plans.

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# REPORT TO CONGRESS
# ON
# CONTROL OF SULFUR OXIDES

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PL 93-319, "Energy Supply and
Environmental Coordination Act
of 1974"

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

February 1975

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Energy shortages, primarily of oil and natural gas, have increased the importance of our domestic coal reserves. Although coal is our most abundant source of fossil fuel energy, its increased use without adequate environmental safeguards could aggravate the nation's already serious environmental problems. This report focuses on the compliance status of existing coal-fired steam electric power plants and on alternative methods for compliance with applicable emission regulations. A review is presented showing the current status of existing coal-fired plants in terms of the sulfur content of coal purchased during the first half of 1974, the involvement of power companies in litigation challenging the applicable regulations, and the programs for achieving compliance with sulfur regulations in State Implementation Plans. Also discussed are a number of factors whose potential effect on compliance efforts cannot be accurately predicted.

### COMPLIANCE STATUS, 1974

In 1974, nearly 390 million tons of coal was consumed by steam electric power plants. Half of this coal, 194 million tons, would comply with sulfur regulations applicable on July 1, 1975. An additional 85 million tons of the coal consumed by power plants was used in plants currently involved in legal actions. Although most of these plants are technically out of compliance, resolution of their compliance problems awaits conclusion of litigation. Of the remaining 111 million tons, roughly 40 percent was consumed in plants that, although not presently in compliance with 1975 State emission regulations, have known plans to comply through the use of flue-gas desulfurization (15.4 million tons), substitution of lower sulfur coal (29.2 million tons), or conversion to oil (1.7 million tons).

Compliance plans are not yet known for plants that burned the remaining 65 million tons (16 percent) of coal consumed in 1974. However, as will be discussed, sufficient supplies of either lower sulfur coal or control systems appear to be available to meet the needs of these plants, as well as those subject to regulations now under legal challenge, and, thus, effect compliance before 1980.

### PROJECTED COMPLIANCE STATUS, 1980

Table 1-1 summarizes the compliance status of existing and new coal-fired steam electric power plants through 1980. Also shown are projections of the availability of flue-gas desulfurization systems, the supplies of low-sulfur coal that conform to New Source Performance Standards, and the potential use of supplementary control systems for certain power

Table 1-1. COAL-FIRED POWER PLANT COMPLIANCE STATUS AND ALTERNATIVES THROUGH 1980 (million tons of coal)

| Compliance status | Existing plants 1974 | Total requirements in 1980 | Control options not known |
|---|---|---|---|
| Already in compliance | 194 | 194 | - |
| Legal disputes, compliance requirements unknown | 85 | 85 | 85 |
| Nonconforming, plans known | 46 | 46 | - |
| Nonconforming, plans unknown | 65 | 65 | 65 |
| New plants, plans known | - | 28 | - |
| New plants, plans unknown | - | 207 | 207 |
| Total coal requirements | 390 | 625 | 357 |

| Potential availability of major compliance alternatives (excluding coal cleaning) by 1980 | |
|---|---|
| Flue-gas desulfurization | 250 - 390[a] |
| Low-sulfur coal (< 1.2 lb $SO_2$/million Btu) | 80 - 200[b] |
| Supplementary control systems | 15 - 35[c] |
| Total available | 345 - 625 |
| Total required, control option not known | 357 |

[a]Based on Environmental Protection Agency survey in the fall of 1974. Estimates have been adjusted to reflect scheduled installations.

[b]Estimates adjusted downward to reflect low-sulfur coal consumption in 1974.

[c]Joint study performed by the Environmental Protection Agency and the Federal Energy Administration during the fall of 1974 showed this value to be 40 - 120. After subtracting out the plants involved in legal disputes and those having acceptable compliance plans, the estimate reduces to 15 - 35.

plants with specific problems. The potential availability of these options is more than adequate to satisfy the requirements of existing and new steam electric coal-fired power plants for which compliance requirements or plans are unknown. It should be noted that some factors can limit the achievement of this potential. These include legislative constraints, availability of capital, and uncertainty that long-term demand will warrant expansion or supply commitments by industry.

Coal requirements for steam electric power plants are expected to grow rapidly through 1980. Based on information developed by the Federal Power Commission, coal consumption is expected to increase by 60 percent, approaching 625 million tons in 1980. Of this 235-million-ton increase, approximately 50 million tons will be consumed in plants that become operational in 1975 or 1976. These plants, in general, will be required to comply with sulfur regulations in State Implementation Plans, but not with New Source Performance Standards. The remaining 185 million tons of additional coal requirements is associated with plants projected to be built between 1977 and 1980. Most of these plants will be required to comply with the New Source Performance Standards.

The rapid growth in new coal-fired steam electric capacity will tend to lower the allowable average sulfur content of steam coal because many of these plants will be required to meet New Source Performance Standards for sulfur. The primary options available to ensure conformance with the New Source Performance Standards are either the use of low-sulfur coal or the application of flue-gas desulfurization systems. Current projections regarding the availability of these options indicate that they can be supplied in volumes exceeding projected requirements. Estimates of the availability of low-sulfur coal by 1980 range from 80 to 200 million tons, and the capacity of vendors to install flue-gas desulfurization systems, based on recent surveys, is between 250 and 390 million tons.

## COMPLIANCE ALTERNATIVES

The major compliance alternatives through 1980 are the application of flue-gas desulfurization systems, the use of coal with the appropriate sulfur content, and the application of supplementary control systems (for plants not subject to New Source Performance Standards). In addition, other technological processes, most of which are presently in the developmental stage, could make substantial contributions after 1980. Among the most important of these options are fluidized-bed combustion; coal conversion including solvent refining, gasification, and liquefaction; and solid waste combustion as an energy source.

Table 1-2 summarizes data on the availability, incremental cost, and environmental impact of these compliance options. To develop incremental costs, a baseline cost was derived from the fuel cost for operating a plant on high-sulfur coal without flue-gas desulfurization. High-sulfur coal costs

Table 1-2. CONTROL STRATEGY ALTERNATIVES

| Alternative | Date of commercial availability | Large-scale supply availability | | Annualized costs mills/kWh[a] | Major environmental impacts |
|---|---|---|---|---|---|
| | | Date | Capacity, million tons | | |
| Low-sulfur coal | Today | 1978-80 | 80-200[b] | 0.5-3.0 | Particulate emissions (controllable) |
| Physical coal desulfurization | Today | 1977 | c | 1.0-2.0 | Residue disposal and water pollution |
| Flue-gas desulfurization | Today | 1978-79 | 250-390 | 2.5-4.0 | Sludge disposal (commercial treatment available) |
| Coal gasification (low Btu) | 1980-83 | 1985 | - | 10.0-15.0 | Air and water pollution |
| Fluidized-bed boilers | 1983-85 | 1985 | - | 2.0-3.0 | Less severe than conventional boilers |
| Supplementary control systems | Today | 1975-77 | d | 0.5-1.0 | Pollutant loadings; sulfate risk |
| Tall stacks | Today | 1975-77 | d | 0.15-0.3 | |
| Energy recovery from solid waste | 1975-78 | 1980 | 23,500[e] | 0[f] | Avoids conventional waste disposal problems |

[a]Incremental cost above current practices (high-sulfur coal without flue-gas desulfurization).

[b]Increment over present levels of low-sulfur coal production.

[c]Fourteen percent of reserves can be cleaned to meet New Source Performance Standards.

[d]Limited only by regulations defining enforceability and reliability.

[e]Equivalent oil savings potential of 236,000 barrels per day by 1980.

[f]Experience suggests power plants would not accept higher prices for solid waste fuel than for conventional fuels; solid waste costs might be less in some instances.

of $0.80 per million British thermal units (Btu) or approximately 8 mills per kilowatt-hour (kWh) have been used in the analysis. As shown in Table 1-1, increased production of low-sulfur coal above that produced in 1974 could range from 80 to 200 million tons by 1980. The incremental cost of compliance by this method, including the cost of plant alterations required to burn low-sulfur coal, is between 0.5 and 3.0 mills/kWh. In some cases, conversion to low-sulfur coal might lead to an increase in particulate emissions from degradation of the collection efficiency of electrostatic precipitators. Additional precipitator capacity or flue-gas conditioning may be required to overcome the resulting efficiency reduction.

Coal cleaning techniques that physically separate inorganic sulfur from combustion coal are available. Based on the average sulfur content of known coal reserves in the United States, coal cleaning techniques could reduce the sulfur content of 14 percent of the reserves to the levels required by the New Source Performance Standards. The incremental cost of coal cleaning is approximately 1.6 mills/kWh.

The capacity of vendors of flue-gas desulfurization equipment to install systems by 1980 is equivalent to 250 to 390 million tons of coal-fired capacity. Incremental costs range from 2.5 to 4.0 mills/kWh. The most important potential environmental problem is the disposal of sludge from nonregenerable systems.

Supplementary control systems and tall stacks are available today and are the least expensive of all the options. Environmental problems associated with supplementary control systems include increased atmospheric loadings of pollutants and the risk of adverse health effects associated with suspended sulfates.

As mentioned earlier, compliance alternatives over the longer term may be expanded to include fluidized-bed combustion systems, gasified- or liquefied-coal products, and in some cases the use of solid waste as a fuel source. With the exception of energy recovery from solid waste, these options must be considered to be in the developmental stage. Coal gasification entails large capital expenditures and potentially serious air and water pollution problems. In addition, the total cost of a gaseous power plant fuel will probably fall in the range of 20 mills/kWh, which is not competitive with the use of flue-gas desulfurization and high-sulfur coal at 10 to 12 mills/kWh. One of the most promising options for the 1980's is fluidized-bed combustion. Preliminary bench-scale testing indicates that the cost of fluidized-bed combustion may be less than conventional systems equipped with flue-gas desulfurization and could potentially improve the energy efficiency of steam electric power plants.

The use of these options compares favorably with the use of low-sulfur oil at current prices. At $11 per barrel, the cost of oil per kilowatt-hour generated is roughly equivalent to 21 mills. Even coal gasification systems would be competitive with low-sulfur oil at these prices.

The compliance alternatives discussed above relate to existing sulfur regulations in State Implementation Plans and to the New Source Performance Standards. In addition to these options, the Environmental Protection Agency expects its efforts to assist the States in revising sulfur regulations or timetables for compliance to significantly contribute to the resolution of existing compliance problems. Efforts by the Environmental Protection Agency and the individual States have already resulted in allowing the legal use of 42 million tons of coal that originally could not have been used in compliance with State sulfur emission requirements. An additional 70 million tons should be legally acceptable by the summer of 1975 as a result of expected revisions to State regulations.

## FACTORS AFFECTING COMPLIANCE

This review of the compliance status of coal-fired electric power plants in 1974 and 1980 is based on announced changes in fuel requirements and a projected rate of construction of new facilities. A number of factors that could affect compliance cannot be forecast accurately. These factors include possible oil-to-coal conversions of power plants, slower growth rates for electricity consumption through 1980, increased demand by the industrial sector for steam coal, and potentially severe natural gas curtailments. In addition, further legislative action by the Congress may alter the authorities now available to resolve potential conflicts between the nation's energy and environmental goals. The factors mentioned and the possible use of new authorities granted by Congress make it extremely difficult to forecast how both existing and new plants may choose to comply with sulfur oxide emission regulations.

With regard to a priority system for installation of sulfur removal equipment, the Environmental Protection Agency does not believe that it is necessary to invoke its authority to prioritize sales at this time. This is based on the conclusion that the availability of compliance alternatives is sufficient to meet power plant control requirements in a free market.

## CONCLUSIONS

This report provides the most recent information available on the compliance status of coal-fired steam electric power plants (based on coal purchased during the first half of 1974), on the availability and cost of compliance alternatives, and on the position of the Environmental Protection Agency regarding the use of priority allocation systems for sulfur removal equipment. The report shows that, although significant compliance problems now exist, the availability of existing compliance alternatives is more than adequate to satisfy projected requirements. Low-sulfur coal, flue-gas desulfurization systems, the temporary use of supplementary controls in limited circumstances, and possible revisions of State sulfur regulations hold the potential for achieving compliance by 1980. However, larger-than-expected natural gas curtailments, substitution of coal for oil by the industrial sector, and delays in nuclear plant construction could significantly increase the demand for coal beyond current expectations. If these changes are significant, requirements may exceed the available supplies of low-sulfur coal or flue-gas desulfurization systems.

## CHAPTER 2. SCOPE OF REPORT

This report is submitted to Congress in conformance with the requirements of Section 119 (k) (1) of the Clean Air Act as amended by the Energy Supply and Environmental Coordination Act of 1974 (ESECA). Section 119 (k) (1) requires the Environmental Protection Agency to report to Congress on nine issues within 6 months of enactment. This report responds to seven of these nine issues as outlined below. The two issues not discussed will be addressed in a subsequent report to Congress required under the Energy Supply and Environmental Coordination Act.

### IMPACT OF FUEL SHORTAGES

Section 119 (k) (1) (A) requires the Environmental Protection Agency to report to Congress on:

> "(A) the present and projected impact of fuel shortages and fuel allocation programs on the program under this act."

There are two basic types of fuel shortages. First, existing supplies can be less than adequate to satisfy domestic energy requirements. Second, existing supplies can fail to conform to sulfur regulations established pursuant to the Clean Air Act. This report is concerned primarily with this second type of fuel "shortage," often referred to as the clean fuel deficit.

Although some sources needing to convert to low-sulfur oil to meet sulfur emission requirements have been unable to obtain sufficient supplies of conforming oil, compliance problems for oil-fired sources are not as serious as those affecting coal-fired units. To date, the shortages of conforming oil have been temporary and have been adequately handled on a case-by-case basis with short-term variances. An insight into the relative importance of coal and oil to the conforming fuels problem may be gained from noting that Federal Power Commission data show (1) that coal accounted for 48 percent and oil 17 percent (including the oil used in peaking units) of the fossil fuel burned in steam electric power plants in 1973, and (2) that the average sulfur content of the coal was 2.3 percent while the average sulfur content of the oil was 0.9 percent. Moreover, pre-combustion oil desulfurization technology is well developed and therefore not controversial.

Consequently, this report focuses on compliance alternatives for coal-fired steam electric power plants. These plants account for over 60 percent of the total sulfur oxide emissions from all sources and consume 85 percent of the combustion coal used in the nation. Coal consumption in these plants will continue to be important in the future with coal use projected to grow at a rate approaching 8 percent per year through 1980.

Chapter 3 of this report reviews the compliance status of coal-fired electric utilities. Compliance data are based on coal purchases for the first 6 months of 1974 (data supplied by the Federal Power Commission), and national projections are based on expected requirements for 1980.

POLLUTION CONTROL--COMPLIANCE ALTERNATIVES

Section 119 (k) (1) (B), (E), and (F) address issues related to compliance alternatives:

"(B) availability of continuous emission reduction technology (including projections respecting the time, cost and number of units available) and the effects that continuous emission reduction systems would have on the total environment and on supplies of fuel and electricity...

"(E) evaluation of availability of technology to burn municipal solid waste in electric power plants or other major fuel burning installations, including time schedules, priorities, analysis of pollutants which may be emitted (including those for which national ambient air quality standards have not been promulgated), and a comparison of health benefits and detriments from burning solid waste and of economic costs;

"(F) evaluation of alternative control strategies for the attainment and maintenance of national ambient air quality standards for sulfur oxides within the time for attainment prescribed in this Act, including associated considerations of cost, time for attainment, feasibility, and effectiveness of such alternative control strategies as compared to stationary source fuel and emission regulations..."

Chapter 4 of this report discusses available control strategies that can be used to assure compliance with sulfur regulations. The discussion covers both continuous and noncontinuous methods of control, including utilization of solid wastes as fuel. As requested by the Congress, the control alternative section includes the status of commercial availability, potential supply, technical effectiveness, costs, and environmental impacts. The Environmental Protection Agency is continuing to analyze various problems related to the cost and availability of emission control systems, including intermittent control systems. As these studies progress, the Agency will provide pertinent results to Congress.

PRIORITIZATION OF POLLUTION CONTROL TECHNOLOGY AND OTHER ISSUES

Section 119 (k) (1) (C), (D), and (G) address the issue of authority to allocate pollution control technology:

"(C) the number of sources and locations which must use such technology based on projected fuel availability data;

"(D) a priority schedule for installation of continuous emission reduction technology, based on public health or air quality...

"(G) proposed priorities for continuous emission reduction systems which do not produce solid waste, for sources which are least able to handle solid waste by-products of such systems..."

Two issues are of importance here. First, the ability of the Environmental Protection Agency to forecast how plants may choose to comply with applicable emission regulations, and, second, the availability of continuous emission reduction technology. With regard to the first issue, the Environmental Protection Agency cannot project which continuous emission control technologies a source may choose to use. This choice is left with the utility. The Environmental Protection Agency can enforce regulations affecting plants that are not in compliance, but the ultimate choice of compliance alternatives is the utility's responsibility. As will be shown in Chapters 3 and 4 of this report, vendor capacity is more than adequate to satisfy maximum requirements, and therefore it is unlikely that priority schedules will be required.

Chapter 5 of this report addresses these issues in more depth and provides a qualitative discussion of some issues not raised by Congress but which could affect compliance problems. These general energy issues include: the rate of growth in the demand for electric power, the growth of nuclear capacity, the potential impact of reversion to coal from oil or gas on the demand for low-sulfur coal or control equipment, and the effect of natural gas curtailments. Also contained in Chapter 5 is a description of the various Federal energy allocation authorities and how they could be used to enhance environmental objectives.

OTHER REQUIREMENTS

Section 119 (k) (1) (H) and (I) relate to the Environmental Protection Agency's steps to monitor the air quality impact of the Energy Supply and Environmental Coordinator Act and its review of State Implementation Plans.

"(H) plans for monitoring or requiring sources to which this section applies to monitor the impact of actions under this section on concentrations of sulfur dioxide in the ambient air; and

"(I) steps taken pursuant to authority of section 110 (a) (3) (B) of this Act..."

The Environmental Protection Agency's response to these two subsections will be included in its report to Congress to satisy the provisions of Section 7 of the Energy Supply and Environmental Coordination Act.

# CHAPTER 3. COMPLIANCE STATUS OF COAL-FIRED POWER PLANTS, 1974 to 1980

## INTRODUCTION

This chapter addresses the compliance status of coal-fired power plants, as derived from coal purchased during the first 6 months of 1974. Data are presented on the compliance status of existing coal-fired power plants with State Implementation Plan regulations for sulfur and with plans by utilities for plants constructed after 1974. The information provided in this chapter is based on reports submitted to the Environmental Protection Agency and other Federal agencies by utilities concerning their current coal consumption and their plans to comply with applicable sulfur regulations. Although these data are the best available, in some instances the plans submitted by utilities are not legal commitments. It is also possible that, for some plants, enforceable compliance schedules have been negotiated by State agencies but have not yet been reported to the Environmental Protection Agency.

## COMPLIANCE STATUS, 1974

In 1974, steam electric power plants consumed approximately 390 million tons of coal. As shown in Table 3-1, roughly 50 percent of this coal could be burned in compliance with existing sulfur regulations of State Implementation Plans. An additional 85 million tons, or approximately 22 percent of the coal consumed in 1974, was used in plants involved in legal disputes. Forty-six million tons could not be burned in compliance with the applicable regulations, but in these cases, plans for achieving compliance are known to the Environmental Protection Agency. The remaining 65 million tons could not be used in compliance with existing regulations, and compliance plans have not been submitted to the Environmental Protection Agency. The compliance categories listed in Table 3-1 are discussed below.

### Conforming Coal

This category is based on a plant-by-plant evaluation in which the sulfur content of the coal used in the first 6 months of 1974 is compared with the July 1, 1975, sulfur regulations in State Implementation Plans. In some cases, the average sulfur content of the coal consumed exceeded the applicable regulation. In such instances, the quantity of coal that fell below the sulfur limit was included in this category with the portion exceeding standards added to the "Non-complying, plans unknown" category.

Table 3-1. COAL USED IN POWER PLANTS, 1974

| Status | Coal use, millons of tons | Percent of total |
|---|---|---|
| Conforming coal | 194 | 49.7 |
| Legal disputes | 85 | 21.8 |
| Nonconforming, plans known | 46 | 11.8 |
| Nonconforming, plans unknown | 65 | 16.7 |
| Total | 390 | 100.0 |

The "Conforming coal" category should be viewed as a minimum estimate of the amount of coal that could be used in compliance with the July 1, 1975, regulations. Excluded from this category are power plants that may have received a variance, plants involved in litigation, and plants in regions where regulations are being revised.

Legal Disputes

Legal issues are of importance because the largest coal consuming States, as shown in Table 3-2, are involved and, in some cases, no legally enforceable regulations exist. Although most of the plants in this category are legally out of compliance, the ultimate status of the use of this coal is dependent upon the resolution of the legal issues involved. A brief review of some of these problems follows.

Table 3-2. STATE SULFUR REGULATIONS INVOLVED IN LITIGATION, 1974 (thousand tons of coal)

| State | Coal use affected by legal actions | Total 1974 consumption |
|---|---|---|
| Indiana | 28,890 | 28,890 |
| Missouri | 8,700 | 16,670 |
| Ohio | 45,900 | 45,900 |
| Pennsylvania | 2,350 | 27,370 |
| Total | 85,840 | 118,830 |

Section 307(b) of the Clean Air Act allows for a petition for review of action of the Administrator including the approval or promulgation of any implementation plan under Section 110. Any such petition must be filed within 30 days from the date of such promulgation, approval, or action; or after such date if such petition is based solely on grounds arising after the 30th day. A source may seek and obtain a stay of enforcement proceedings pending a resolution of the underlying Section 307 challenge.

This situation is best demonstrated in Indiana where two power companies (Northern Indiana Public Service Company and Public Service Company of Indiana) have successfully stayed further enforcement by the Environmental Protection Agency pending a decision on a motion to stay enforcement. The Environmental Protection Agency is unable at this time to estimate when a decision in this case will be rendered.

In Ohio, the Environmental Protection Agency approved the particulate matter portion of the State Implementation Plan and initiated a few enforcement actions. The utilities and the steel industries, however, have challenged the Administrator's approval of the State plan. Also, in September 1974, the Ohio utility hearing examiners issued adverse findings and recommendations concerning the sulfur dioxide control strategy. The examiners concluded that scrubber technology presently does not exist and is not reliable and recommended that further studies be done before any final action is taken on a sulfur dioxide plan in Ohio. In December 1974, however, the Director of the Ohio Environmental Protection Agency, who is empowered with making the final decisions at the State level, concluded that, although control technology does exist, the hearing record did not contain air quality data that demonstrated a need for controls. Because of these recent actions by the State of Ohio, the Environmental Protection Agency does not anticipate any imminent State action on the sulfur dioxide control strategy. To correct this deficiency in the Ohio plan, the Environmental Protection Agency is presently completing the technical studies necessary for a Federal promulgation by the early spring of 1975.

## Nonconforming, Plans Known

Although not presently in compliance with applicable emission regulations, the coal-burning power plants in this category have submitted plans showing an acceptable program. Table 3-3 summarizes the compliance plans submitted to the Environmental Protection Agency.

Table 3-3. KNOWN COMPLIANCE PLANS OF PLANTS NOT MEETING STATE IMPLEMENTATION PLANS, 1974

| Compliance strategy | Coal use, thousand tons | Percent of total |
|---|---|---|
| Low-sulfur coal | 29,230 | 63.0 |
| Flue-gas desulfurization | 15,430 | 33.2 |
| Switching to oil | 1,740 | 3.8 |
| Total | 46,410 | 100.0 |

Nonconforming, Plans Unknown

A significant percentage of the coal consumed in 1974 did not meet applicable sulfur regulations, and a number of the plants consuming this coal have not submitted compliance plans to the Environmental Protection Agency. These plants, however, may be operating under variances to State Implementation Plans or have enforceable plans that are in the review process. This group accounted for approximately 65 million tons of coal consumed in 1974, or slightly over 16.7 percent of the total.

CONFORMING COAL BY SULFUR CONTENT

The 1974 plant-by-plant analysis of coal used by plants in compliance with sulfur emission requirements showed that a substantial portion of the coal exceeded 1 percent sulfur by weight. Sixty-eight percent of the 194 million tons of conforming coal contained more than 1 percent sulfur by weight, and 37 percent of the total contained more than 2 percent sulfur by weight.

It is not possible to estimate accurately the sulfur contents of conforming coal for 1975 or later years. A significant number of State regulations are subject to legal challenges, others are being revised. In addition, several different strategies are available for compliance. One estimate (the maximum in terms of shifts to lower sulfur coal) can be derived from the assumptions that (1) nonconforming plants now opting for a shift to lower sulfur coal make that change and (2) nonconforming plants with no indicated strategy also shift to lower sulfur coal. Under these assumptions the 94 million tons of nonconforming coal would be replaced by conforming coal (29 million tons from the first assumption and 65 from the second). Sixty-six percent of this conforming coal could exceed 1 percent sulfur by weight, and 21 percent could exceed 2 percent sulfur by weight.

These data show that, both for plants using conforming coal in 1974 and for a substantial portion of the plants not now using conforming coal, continuous emission control alternatives are not necessarily limited to low-sulfur Western coal or flue-gas desulfurization.

## COMPLIANCE STATUS THROUGH 1980

Coal use in electric utilities is expected to grow rapidly throughout the remainder of this decade. The Federal Power Commission projects that the demand growth rate for electricity will approach 6.5 percent per annum. The energy required to satisfy this incremental demand will fall almost entirely on new coal-fired and nuclear facilities. The present status of the capital market and the financial situation of many utilities, however, is forcing delays in nuclear installations. The combined effect of these factors is expected to result in an 8 percent per annum rate of growth in coal consumption by electric utilities.

By 1980, approximately 40 percent of the total coal demand by utilities will come from power plants constructed after 1974. Approximately 50 million tons of coal will be consumed in plants coming on-line in 1975 and 1976. These plants are subject to sulfur regulations in State Implementation Plans that apply to facilities constructed prior to 1975. More significant are the plants scheduled to come on-line after 1976. These plants must comply with New Source Performance Standards (1.2 pounds of sulfur dioxide per million Btu, or roughly 0.7 percent sulfur by weight). At present, the primary compliance options for these plants are the use of either low-sulfur coal or high-sulfur coal with flue-gas desulfurization. Table 3-4 provides a preliminary estimate of the sulfur distribution required by 1980. Plants coming on-line after 1976, based on Federal Power Commission estimates of required power generation capacity, will consume approximately 185 million tons of coal. Total coal requirements of existing and new plants are estimated to be roughly 625 million tons. The actual amount consumed will depend on a number of factors including capacity utilization, the demand growth rate for electricity, delays in nuclear power plant construction, and oil-to-coal conversion. These issues will be discussed in Chapter 5.

Table 3-4. 1980 PRELIMINARY ESTIMATE FOR ALL COAL-FIRED PLANTS OF COAL SULFUR CONTENT REQUIREMENTS OR EQUIVALENT FLUE-GAS DESULFURIZATION CAPACITY

| Percent sulfur | Distribution |
|---|---|
| Less than 1.0 | 57.7 |
| 1.0 to 2.0 | 17.7 |
| Greater than 2.0 | 24.6 |
| Total | 100.0 |

The Environmental Protection Agency cannot project how these new plants will choose to comply with State sulfur regulations and with the New Source Performance Standards. However, information based on recent surveys and studies performed by the Environmental Protection Agency demonstrates that the availability of low-sulfur coal and capacity of vendors to install flue-gas desulfurization equipment is sufficient to satisfy projected requirements. New source review procedures at the State level will verify that the plants comply as they come on-line.

Table 1-1 summarized known information on the compliance status of existing or new coal-fired electric utilities through 1980. Also shown was the projected availability of flue-gas desulfurization vendor capacity, of low-sulfur coal, and coal requirements of utilities that could potentially use supplementary control systems. These estimates were adjusted to reflect current coal consumption and compliance plans that rely on flue-gas desulfurization and low-sulfur coal. Table 1-1 shows that the availability of compliance alternatives is sufficient to satisfy the requirements of coal-fired plants that, at present, have not submitted compliance plans.

## THE CLEAN FUELS POLICY

The preceding discussion on the compliance status of coal-fired power plants has focused on existing State sulfur regulations. The Environmental Protection Agency, other Federal agencies, and many States recognized the problems coal-fired utilities would have in complying with the State sulfur regulations promulgated in 1972. Studies performed by the Environmental Protection Agency subsequent to the adoption of State sulfur regulations identified roughly 110 million tons of coal that could continue to be used in 1975 without violating health-related ambient air quality standards. In recognition of the problems that might result from significant quantities of coal not conforming with State regulations, the Environmental Protection Agency adopted its Clean Fuels Policy in the fall of 1972. This policy relied on cooperative efforts by the Environmental Protection Agency and State environmental agencies to extend compliance timetables for secondary standards or to revise emission regulations where primary standards would not be jeopardized. This program has thus far resulted in 42 million tons of coal being made legally acceptable through revisions in the sulfur regulations of State Implementation Plans. The Environmental Protection Agency expects that an additional 70 million tons will be realized by July 1, 1975. These changes in compliance requirements will allow those power plants that are affected by legal problems and those that have not submitted compliance plans to use a substantial portion of the coal they are presently consuming without significant changes in its sulfur content. Additional information on this will be reported in a subsequent report to the Congress.

## CHAPTER 4. COMPLIANCE ALTERNATIVES FOR SULFUR DIOXIDE CONTROL

There is a wide spectrum of opinion on the availability of control systems that can enable compliance with sulfur dioxide emission regulations. This chapter will discuss a range of alternatives in terms of their characteristics in each of the following areas: commercial availability, sulfur removal effectiveness, range of applicability, associated costs of compliance, environmental impact, and energy impact. Pertinent time frames and solutions to potential problems are noted where applicable.

Sulfur emission control options are classified as either continuous or noncontinuous. Continuous control systems reduce sulfur oxide emissions to permanent, specified levels that would be consistent with achieving State Implementation Plan emission limitations and with achieving ambient air quality standards under worst case meteorological conditions. Noncontinuous systems depend on meteorological forecasting to determine when normal emission rates must be reduced to ensure compliance with ambient air quality standards. The distinction here is that continuous systems operate independently of meteorological conditions, while noncontinuous systems are only used during periods of poor atmospheric dispersion.

Continuous control systems are divided into precombustion and post-combustion alternatives. Precombustion alternatives include substitution of low-sulfur for high-sulfur fuels, physical coal cleaning, and coal conversion options such as gasification, liquefaction, and solvent refining. Post-combustion systems cover flue-gas desulfurization, both regenerable and non-regenerable, and fluidized-bed combustion systems. The noncontinuous systems discussed include fuel switching, load shifting, and the use of "tall" stacks. The alternatives mentioned thus far relate to the use of fossil fuels. The final section of this chapter addresses the use of municipal solid waste as an alternative fuel.

### CONTINUOUS STRATEGIES

#### Precombustion Alternatives

The set of control strategies which comprises methods of removing sulfur from the fuel before combustion is included in this section. Both naturally occurring low-sulfur fuels and preprocessed fuels are discussed.

Low-sulfur Fuel--Low-sulfur fuels include low-sulfur coal, natural gas, and low-sulfur oil. Natural gas does not present any significant potential for fuel switching due to the current and projected nationwide shortage of gas. The higher price and concern with dependence on imported oil limits the usefulness of shifting to oil until domestic reserves can be developed. However, development of domestic oil reserves is expected to be accomplished only at steadily increasing costs. Therefore, only low-sulfur coal is addressed as an alternative clean fuel.

Two different grades of low-sulfur coal are of interest: one that conforms to State Implementation Plan requirements and the other that conforms to New Source Performance Standard requirements. In most of the sections below, these categories have similar attributes; however, where necessary, distinctions are noted.

Commercial availability--The extent to which low-sulfur coal is available as a control strategy is dependent upon the rate at which our domestic resources of low-sulfur coal are developed and can be transported to utility coal markets.

The discussion of compliance in Chapter 3 of this report implies a growth rate for coal use by the electric utility industry of slightly more than 8 percent per annum over the 1973-1980 period. The critical issues are whether this volume of coal can be produced in an environmentally safe and economically profitable manner, and whether its quality (sulfur content) will match demand.

Total coal production in 1973 was approximately 600 million tons. The recent demand forecasts made by the Federal Energy Administration in its Project Independence Blueprint ranged from 775 to over 840 million tons by 1980.

The report of the Coal Task Force of the Federal Energy Administration concluded that:

1. By 1980, coal production could equal or exceed 900 million tons per year.

2. The supply of coal is relatively price-elastic in this time frame, i.e., the additional coal could be produced at prices only slightly above existing production costs.

This report indicated that constraints on production existed due to financial limitations, lack of trained manpower, environmental limitations, possible shortages of equipment and materials, and the lack of appropriate transportation facilities, especially rail transport. However, the Task Force concluded that under appropriate financial incentives, coal production on the order of 900 million tons could be forthcoming. Certain policy factors could also have important impacts, especially:

1. Uncertainty over sulfur regulations and the use of intermittent control methods.

2. Restrictions that might result from strip mining legislation now being debated by the Congress.

If these problems can be resolved, large increases in coal supply are possible.

The largest economically recoverable reserves of low-sulfur coal are in the Northern Great Plains, the Four Corners area (where Utah, Colorado, Arizona, and New Mexico meet), the Southwest, and Appalachia. Coal in the Four Corners and Southwest is probably too far from the major markets to be an important source of new supplies except for the localized markets in the Southwest and Far West. There are significant reserves of strippable low-sulfur coal in the East. However, low-sulfur coal in Appalachia has been largely committed for coking coal uses and export. Output expansion for these reserves could be sensitive to strip mining legislation since much of the low-sulfur reserve is located on steep slopes. By far the most significant potential for low-sulfur coal supplies is the Northern Great Plains area.

The most economical sources of medium-sulfur coal production for markets east of the Mississippi River are in Appalachia and the Northern Great Plains.

Actual low-sulfur coal production in 1980 is dependent on the resolution of present disputes over the timetable for compliance and the level of State sulfur regulations. Also important are the relative economics of low-sulfur coal use versus the use of high-sulfur coal and flue-gas desulfurization. Some estimates suggest that low-sulfur coal from the West may be competitive with high-sulfur coal and flue-gas desulfurization in Illinois and even in Ohio.(1) The choice of coals will depend on these costs as well as political and economic decisions in Midwestern states as to how much Western coal will be utilized in existing and new plants. Significant reliance on Western coal for existing power plants would result in dislocations to Eastern coal mining production.

Table 4-1 presents two forecasts of coal production availability in 1980 by sulfur content. The Bureau of Mines estimates are simply extrapolations of past patterns of production by sulfur content. In effect, these estimates do not reflect changes in coal demand structure resulting from efforts to comply with more stringent sulfur regulations.

The other estimates in Table 4-1, developed for the Environmental Protection Agency by Sobotka and Company, Inc., assume the most economic production of coal in order to meet presently applicable sulfur regulations. The Sobotka estimates apply only to steam coal, while the Bureau of Mines estimates include coking coal. Thus, the Sobotka estimates exclude low-sulfur Eastern coal for coking and export. The Sobotka estimates emphasize low-sulfur coal production from the Great Plains on the assumption that, in most areas, it is cheaper than high-sulfur coal plus flue-gas desulfurization. Only 42 million tons of coal below 1.2 pounds of sulfur per million Btu were produced in 1973. The estimates imply that it is possible to boost low-sulfur coal production by three to almost seven times current levels by 1980. Medium-sulfur coal production could be 2.5 times as great as in 1973. Higher sulfur coal production could rise by 50 percent, or remain constant if sulfur regulations are not relaxed and flue-gas desulfurization is not used by the utilities.

Table 4-1. POTENTIAL COAL PRODUCTION IN 1980
(thousand tons)

| Region | Sulfur content | | | |
|---|---|---|---|---|
| | Low[a] | Medium[b] | High[c] | Total |
| Appalanchian | | | | |
| Bureau of Mines | 103,006 | 262,744 | 160,350 | 526,100 |
| Sobotka[d] | 38,000 | 166,000 | 146,000 | 350,000 |
| Midwestern | | | | |
| Bureau of Mines | 1,512 | 15,613 | 205,375 | 222,500 |
| Sobotka | - | 57,000 | 118,000 | 175,000 |
| Montana, Idaho, Wyoming | | | | |
| Bureau of Mines | 1,860 | 79,540 | - | 81,400 |
| Sobotka | 194,000 | 49,000 | - | 243,000 |
| Rocky Mountain | | | | |
| Bureau of Mines | 11,116 | 20,284 | - | 31,400 |
| Sobotka | 36,000 | 34,000 | - | 70,000 |
| Pacific | | | | |
| Bureau of Mines | 12,629 | 19,799 | 1,172 | 33,600 |
| Sobotka | - | 30,000 | - | 30,000 |
| Totals | | | | |
| Bureau of Mines | 130,123 | 397,980 | 366,897 | 895,000 |
| Sobotka | 268,000 | 336,000 | 264,000 | 868,000 |

[a]Coal that would conform to New Source Performance Standards (less than 1.2 pounds of sulfur dioxide per million Btu).

[b]Coal in the range of 1.21 to 3.2 pounds of sulfur dioxide per million Btu.

[c]Coal greater than 3.21 pounds of sulfur dioxide per million Btu.

[d]Developed for the Environmental Protection Agency by Sobotka and Company, Inc., October 1974.

Demands for low-sulfur coal, or its equivalent in high-sulfur coal with flue-gas desulfurization will rise markedly by 1980 due to the construction of new plants subject to New Source Performance Standards. Nevertheless, while low-sulfur coal demands will rise rapidly as new power plants come on line, there will still be a major market for higher sulfur coal; in 1980 about one-fourth of utility coal requirements can be relatively high in sulfur content--at or above 2 percent sulfur--and still comply with existing regulations without flue-gas desulfurization.

There is considerable potential for large increases of low- and medium-sulfur coal production by 1980. Whether this production is realized depends on: (1) factors affecting demand, such as resolution of litigation in several States on sulfur regulations, the degree of reliance on intermittent control approaches, and the economic competitiveness and acceptance by the utility industry of flue-gas desulfurization technology; and (2) factors affecting supply such as transportation facility development, possible strip mining regulations, and the cost and availability of mining equipment.

Effectiveness--All continuous control strategies involve compliance with a specified pollutant emission rate. The sulfur content limitation defined by New Source Performance Standards is a maximum of 1.2 pounds of sulfur dioxide per million Btu. For all other facilities, the emission limitation is determined through consideration of the following factors: (1) dispersion characteristics of the source and the surrounding area, (2) background concentration of the pollutant, (3) total emissions rate of all sources in the area, and (4) expected rate of growth in emissions. The applicable sulfur content limitation is based on allowable emission rates. If the determination of the allowable emission rate is correct and the supply of coal with the necessary sulfur content is assured, this alternative is better than 99 percent effective in assuring that air quality goals are achieved.

Applicability--There are three categories of existing plants to which conversion to low-sulfur coal is potentially applicable as a compliance strategy: oil-fired plants, coal-fired plants using high-sulfur coal, and dual-fired plants burning natural gas. Conversion of oil- and gas-fired plants is limited to those plants that have been previously converted from coal to oil or gas, or those plants that were designed for dual oil/coal or gas/coal operation. All other oil-fired plant conversions would result in unit deratings of 30 to 50 percent. Due to design limitations, some plants currently using high-sulfur coal would encounter unit deratings of 10 to 30 percent if converted to low-sulfur coal.

Environmental impact--The environmental impacts associated with the use of low-sulfur coal include the effects of mining and transport as well as coal usage. Factors of concern in mine development include soil erosion, acid mine drainage, disturbance of wildlife, and land reclamation. Since the presence of sulfur decreases the resistivity of particles and heightens precipitator efficiency, the principal combustion impact of burning low-sulfur coal in plants designed for high-sulfur coal is that particulate emissions increase, sometimes by a factor of ten.(2) This efficiency reduction can be overcome by increasing precipitator capacity or conditioning flue gases.

Coal combustion also creates a substantial fly ash disposal problem. If this waste is not properly disposed of, serious water pollution problems may result. Fugitive dust emissions may also result from coal-handling activities.

Energy impact--Energy impacts of converting units designed exclusively for oil-firing to coal can be prohibitive. Conversion of these units causes unit derating and reduced thermal efficiency. Energy requirements at coal-fired facilities are increased through the requirements for long-distance coal transportation and additional coal-handling and pulverizing requirements. However, this impact is highly variable and, for most plants, is not expected to be significant. Transportation is expected to increase the thermal energy (Btu) required to produce a kilowatt-hour of electricity by 1 to 3 percent.

Cost of compliance--The cost of complying with sulfur oxide standards through the use of low-sulfur coal includes the cost of necessary facility modifications, the cost of the fuel, and the cost of transporting the fuel. Facility modifications include both boiler modifications and associated costs of unit deratings.

The unit deratings associated with conversion of a plant designed to burn only oil necessitate replacement power at a cost of $250 to $350/kW. The combustion system modifications would also be costly, $60 to $90/kW. Therefore, costs and energy considerations practically eliminate this type of conversion.

The capital costs of converting a plant from high-sulfur to low-sulfur coal vary with plant design, averaging approximately $20/kW. This expense includes minor combustion system modifications and upgrading of the particulate emission control system.

Although low-sulfur coal is generally more expensive than high-sulfur coal, the price differential is highly variable, depending on plant location and resultant fuel transportation costs. Differential cost estimates range from zero to $0.25/million Btu. With the inclusion of amortized costs, the incremental cost of compliance by conversion from high- to low-sulfur coal would range from 0.5 to 3.0 mills/kWh. The incremental cost of compliance represents the increase above the cost of plant operation on high-sulfur coal without any sulfur dioxide control equipment. The cost includes any differences in fuel cost, operating and maintenance costs, and amortized capital costs.

Coal Gasification and Liquefaction--Numerous processes of converting high-sulfur coal to a liquid or gaseous form are either available or under development. The products which would potentially supply power plants include liquid fuels and low- to intermediate-Btu gas. The nonutility demand for and expense of high-Btu gas reduce the significance of this option as a practical compliance alternative for utilities. Since gasification is in a more advanced stage of development than liquefaction, most of the following discussion relates to experience with, or estimates concerning, gasification processes.

Commercial availability--While coal gasification processes are currently in commercial use, the wide-scale commercial application of coal conversion is dependent upon improvements in technology, as well as easing of constraints on the construction and expansion of a synthetic fuels industry. Technological advances that increase gasifier efficiencies, ameliorate environmental impacts of the process, and decrease costs must occur. On the construction side, it is estimated that a full-scale plant would require 3 to 5 years and 1.5 million man-hours to construct. This is a substantial commitment of manpower. Additional manpower with special training is required to operate the plant. Therefore, it is concluded that coal conversion processes will have little impact between now and 1985. Technical Appendix A lists various processes and discusses the status of their commercial availability.

Effectiveness--The liquefaction and gasification processes convert high-sulfur coal to clean fuels with negligible sulfur content.

Applicability--The applicability of coal gasification and liquefaction is limited by plant siting considerations. Plants must be located near a mine or must provide transportation for 5 to 6 million tons of coal annually. Location of mine-mouth, low- to medium-Btu gasification plants in the West is constrained by water availability and pipeline transportation costs to distant markets. Siting of plants in the East will be difficult because of potential environmental impacts in these populated areas.

Energy impact--At present, systems to produce low Btu gas realize 65 to 85 percent thermal conversion efficiencies, or only a 20 to 30 percent electrical energy conversion efficiency. Higher pressure combined cycle systems are under development that have the potential for overall cycle efficiencies competitive with those of conventional fossil-fuel-fired power plants.

Environmental impact--The potential environmental impacts of converting coal to liquid or gaseous forms are associated with the scale and nature of the conversion process and the conventional pollution problems associated with coal use. Full-scale systems are expected to process 15,000 tons of coal per day; this processing will emit all compounds emitted by coke ovens as well as trace metals present in coal. Because conversion processes emit "conventional" pollutants, many would be required to use water scrubbers and would have the problems associated with properly treating the effluent. In addition, large quantities of water are needed to support mining, reclamation, and coal processing. Ash from the coal preparation plant, as well as hydrocarbon emissions and odors from sulfur recovery and other auxiliary plants, would be significant problems.

Cost of compliance--The cost of compliance through use of synthetic fuels is determined by the output fuel product cost and the transportation cost from producer to utility. The cost of the fuel output is, in turn, influenced by the associated raw material and conversion process costs. Current cost estimates suggest that substantial technological progress is needed before coal conversion could successfully compete with other compliance options.

There are various estimates of the capital cost of a gasification plant, ranging from $164/kW for a low-Btu gas plant to $460/kW for a high-Btu gas plant. (Cost per kilowatt refers to the gasification plant capital outlay necessary to service 1 kW of power plant capacity.) Most estimates for a low-Btu gas plant fall in the $200 to $300/kW range.(3,4)

The cost of the conversion product is sensitive to the price of coal, plant load factors, capital charges, and the availability of markets. In addition, cost is sensitive to improvements that could be made in the efficiency of the gasification process. A range of $1.50 to $2.00/million Btu is considered a reasonable approximation of the output cost for a low- to medium-Btu low-sulfur fuel. The resultant incremental cost of compliance would be 10 to 15 mills/kWh.

Physical Coal Desulfurization--Physical cleaning of coal is accomplished through size reduction, sorting by specific gravity, and separation through flotation to remove sulfur and other impurities from raw coal. The degree of removal is dependent on inorganic sulfur content and extent of physical processing. Table 4-2 presents washability data for U.S. coal reserves.

Commercial availability--All coal used in the production of metallurgical coke is presently cleaned in a coal preparation plant. Since the technology for use on utility coal would be similar, both the technology and equipment are commercially available. Existing facilities are primarily designed for ash removal and are operating at or near capacity. Hence, increased use by the utility industry of the coal-cleaning process would require installation of new coal-cleaning capacity. Design and construction of a coal preparation plant requires 24 months; a large increase in demand could cause delays because the number of companies designing and constructing these plants is small.

Effectiveness--Sulfur occurs in coal in three forms: organically bound sulfur, sulfate sulfur, and pyritic sulfur. Although organic sulfur is not affected by physical cleaning, as much as 80 percent of the pyritic sulfur can be removed. The pyritic sulfur content of different coals is variable (20 to 80 percent of total sulfur content), with the effectiveness of physical cleaning being highest for coals with a high percentage of pyritic sulfur relative to total sulfur content.

Applicability--It is estimated that 13.6 percent of U.S. coal reserves can be cleaned to conform to New Source Performance Standards (1.2 pounds of sulfur dioxide per million Btu). An additional 54.6 percent could be cleaned

Table 4-2. APPROXIMATE DISTRIBUTION OF COALS BY COAL TYPE AND WASHABILITY OF COALS TO EQUIVALENT SULFUR DIOXIDE EMISSION LEVELS[a]
(percent of total U.S. coal reserves)

| Coal category | Lignite | Subbituminous | Bituminous: Pa., W.Va., E.Ky. | Bituminous: Ill., Ind., W.Ky. | Bituminous: Western states | All other | Subtotal | Cumulative total |
|---|---|---|---|---|---|---|---|---|
| Percent of total reserves | 10.97 | 19.38 | 25.46 | 22.82 | 6.32 | 15.05 | 100 | |
| Naturally low-sulfur coals (< 1.2 lb/million Btu) | 0 | 15.20 | 7.93 | 0 | 3.00 | 2.00 | 28.13 | 28.13 |
| Washable coals[b] | | | | | | | | |
| < 1.2 lb/million Btu | 0 | 2.49 | 5.00 | 0 | 2.83 | 3.24 | 13.56 | 41.69 |
| 1.2 to 1.5 lb/million Btu | 0 | 0.60 | 2.00 | 0 | 0.1 | 1.50 | 4.20 | 45.89 |
| 1.5 to 2.0 lb/million Btu | 0 | 0.70 | 2.79 | 0.5 | 0.1 | 2.00 | 6.09 | 51.96 |
| 2.0 to 4.0 lb/million Btu | 10.97 | 0.39 | 6.20 | 10.97 | 0.19 | 2.00 | 30.72 | 82.7 |
| >4.0 lb/million Btu | 0 | 0 | 1.54 | 11.35 | 0.1 | 4.31 | 17.30 | 100.0 |

[a]Based on analysis performed for the Environmental Protection Agency by Pedco Environmental Specialists, Inc., Cincinnati, Ohio, 1974.

[b]Coal may be washed to conform with these emission requirements.

to emit less than 4.0 pounds per million Btu (see Table 4-2). Coal cleaning results in improved combustion characteristics and reduced boiler maintenance requirements.

Environmental impact--The principal environmental problem associated with coal cleaning is the disposal of coal refuse; 10 to 30 percent of the coal by weight is disposed of as refuse. This refuse can be disposed of in landfills or refuse piles without creating environmental problems, using daily compaction, intermittent covering with clay, and final covering with soil and plantings. Contaminated drainage must be collected and treated; drainage can be minimized by proper design of the refuse pile. Particulate emissions and water pollution problems are present but controllable.

Energy impact--The primary drawback of coal cleaning is the potential loss of combustible portions of the coal. Easily cleaned coals are not a problem, but deep cleaning to remove fine pyrite can cause high losses of heat value. In general, these Btu losses can be held to 5 to 7 percent. The consumption of energy in the coal preparation plant itself is modest.

Cost of compliance--The costs to wash coal depend upon the type of coal, siting costs, and costs for refuse disposal. Capital costs for a complete coal-cleaning operation, including environmental controls, land, the preparation plant, and handling facilities, is estimated to be $20,000 to $30,000 per ton of raw coal feed per hour capacity. Coal cleaning results in a cost increase of $0.10 to $0.20/million Btu over unprocessed coal. This translates to an incremental compliance cost of 1.0 to 2.0 mills/kWh. Further cost increases may result from a need to upgrade power plant electrostatic precipitators.

Chemical Coal Desulfurization--Another precombustion alternative is solvent-refined coal, a chemical desulfurization process. The discussion is necessarily brief because this process is still under development; economic, energy, and environmental problems have not fully surfaced and cannot be quantified.

Commercial availability--This process is currently in the pilot-plant stage and commercial availability is not projected until the 1980's.

Effectiveness--The solvent refining process removes 60 to 70 percent of the organic sulfur and all of the inorganic sulfur in coal.

Applicability--This process produces a uniformly high-grade low-sulfur product from various grades of coal; therefore, it should have wide applicability.

Environmental impact--This process produces a clean fuel not requiring treatment for sulfur dioxide or particulates.

Energy impact--The solvent-refining process upgrades the heating value of any feed coal significantly to a uniform 16,000 Btu/pound.

Cost of compliance--Hittman Associates estimated in 1973 that solvent refining would add approximately \$0.35/million Btu, or the equivalent of 3.5 mills/kWh, to raw fuel cost for a plant processing 10,000 tons/day.

## Postcombustion Alternatives

Another class of compliance alternatives involves removal of sulfur oxides from combustion gases. Flue-gas desulfurization processes are classified as regenerable or nonregenerable based on the marketability of the by-products. Another compliance alternative discussed in this section is fluidized-bed combustion, a modification of current combustion practices.

Flue-gas Desulfurization--Both regenerable and nonregenerable flue-gas desulfurization (FGD) processes are discussed in this section. The major areas of differing impact will be clearly defined. The most common FGD process is the nonregenerable lime or limestone scrubbing system. The most common regenerable processes are magnesium oxide scrubbing (Mag-Ox), catalytic oxidation (Cat-Ox), and sodium solution scrubbing (Wellman Lord). Table 4-3 lists various FGD processes and categorizes their stage of development and performance characteristics.

Commercial availability--Many FGD systems are in operation, under construction, or in planning stages in this country. Table 4-4 gives the numbers of plants in each phase as of October 1974. Technical Appendix B summarizes the operating experience of plants equipped with FGD systems as of October 1974.

There has been some controversy over the reliability of FGD systems. Early systems encountered numerous chemical and mechanical problems, including scaling, plugging, corrosion, and mechanical failures. More recently, the chemical problems have been largely solved by control of the process chemistry. While some mechanical problems remain, unit availability factors of 90 percent have been achieved in some instances. Newer units are expected to realize 95 to 99 percent availability over long time periods.

Another important consideration in commercial availability is vendor capacity. Table 4-5 indicates the industry capacity to design, supply, and install FGD systems. In addition to the projections in this table, some companies have indicated a willingness to license their process, which would significantly expand capacity.

The lime/limestone scrubbing, Mag-Ox, and Cat-Ox processes are the most advanced and hold the greatest promise for near-term commercial application, as indicated in Table 4-3. Approximately 30 to 36 months is required to design, fabricate, and install an FGD system; a phased approach can require 6 to 12 months longer.

Effectiveness--There are two parameters that define the effectiveness of an FGD system: removal efficiency and availability. FGD systems are generally attaining removal efficiencies of 80 to 95 percent, and in some cases over 98 percent. These removal efficiencies are equivalent to emission rates

Table 4-3. COMPARISON OF VARIOUS FLUE-GAS DESULFURIZATION PROCESSES

| Process | Type | Typical sulfur dioxide removal efficiency, percent | End product/ waste product | Stage of development |
|---|---|---|---|---|
| Limestone scrubbing | Nonregenerable | 90 | Calcium sulfite and calcium sulfate sludge | Commercial |
| Lime scrubbing | Nonregenerable | 92 | Calcium sulfite and calcium sulfate sludge | Commercial |
| Sodium carbonate | Nonregenerable | 90 | Calcium sulfite and calcium sulfate | Demonstration unit planned |
| Chiyoda thoro-bred 101 | Nonregenerable | 90 | Gypsum | Pilot plant in USA commercial in Japan |
| Calsox | Nonregenerable | 90 | Calcium sulfite and calcium sulfate | Demonstration unit planned |
| Magnesium oxide scrubbing | Regenerable | 91 | Sulfur dioxide to sulfuric acid or sulfur | Commercial |
| Catalytic oxidation | Regenerable | 85 | 78 percent sulfuric acid | Commercial on coal-fired units |
| Wellman Lord | Regenerable | 90 | Sulfur dioxide/ sodium sulfate | Demonstration unit under construction |
| Citrate process | Regenerable | 95 | Elemental sulfur/ sodium sulfate | Pilot plant |

Table 4-3 (continued). COMPARISON OF VARIOUS FLUE-GAS DESULFURIZATION PROCESSES

| Process | Type | Typical sulfur dioxide removal efficiency, percent | End product/ waste product | Stage of development |
|---|---|---|---|---|
| Phosphate process | Regenerable | 95 | Elemental sulfur/ sodium sulfate | Demonstration unit |
| Ammonium bisulphate | Regenerable | 84 | Sulfur dioxide for sulfuric acid production | Pilot plant |
| Charcoal adsorption | Regenerable | 95 | Elemental sulfur/ vent gas from sulfur production step | Pilot plant |
| S&W/Ionics | Regenerable | 90 | Sulfur dioxide/dilute sulfuric acid | Pilot plant, demonstration unit planned |
| SEGD system | Regenerable | 88 | Sulfur dioxide to produce sulfur or sulfuric acid | Demonstration unit under construction |

Table 4-4. STATUS OF FLUE-GAS DESULFURIZATION SYSTEMS, OCTOBER 1974

| Status | Number of units | Capacity, MW |
|---|---|---|
| Operational | 19 | 3,291 |
| Under construction | 18 | 6,877 |
| Planned | | |
| Contract awarded | 9 | 3,904 |
| Letter of intent signed | 3 | 530 |
| Requesting/evaluating bids | 13 | 6,902 |
| Considering flue-gas desulfurization systems | 37 | 16,472 |
| Total | 99 | 37,966 |

Table 4-5. VENDOR CAPACITY FOR FLUE-GAS DESULFURIZATION[a]

| Year | Cumulative potential capacity, MW | |
|---|---|---|
| | With present facilities | With expanded facilities |
| 1977 | 30,600 | 45,400 |
| 1979 | 76,400 | 128,900 |
| 1981 | 131,800 | 197,700 |

[a]Capacity, including design and installation, based on Environmental Protection Agency survey conducted in the fall of 1974. Vendors responding to survey included: Universal Oil Products, Atomics International, Catalytic Inc., Chiyoda International, Combustion Engineering, Envirotech Systems, Krebs Engineers, Monsanto Environmental Services, Peabody Engineering Corp., Research-Cottrell, Stauffer Chemical, and Joy Manufacturing.

of 0.2 and 1.0 pound of sulfur dioxide per million Btu, depending upon the sulfur content of the coal. As stated above, early FGD processes were unreliable because of chemical and mechanical problems. Recent installations, however, are operating at over 90 percent availability.

Applicability--The factors influencing applicability include plant age, plant space, and plant size, all of which affect the economic viability of FGD processes. These considerations are dealt with in more depth in the cost of compliance discussion below. Nonregenerable processes create the additional concern of availability of suitable sludge disposal techniques. A parallel concern for regenerable processes, although not as critical, is the presence of a by-product market.

While FGD systems are applicable to a wide variety of plant types, the economies of scale are more easily realized at relaitvely new plants. These plants have sufficient remaining life to amortize the large capital expenditure required to install FGD systems.

Environmental impact--There are air, water, and solid waste impacts associated with FGD processes. The air impacts are largely positive, with sulfur dioxide emissions reduced by 80 to 95 percent, and associated particulate removal efficiencies in excess of 99 percent. In addition, nitrogen oxide emissions are reduced by approximately 10 to 20 percent by the scrubbers. (The Cat-Ox process does not entail scrubbing; therefore, nitrogen oxide emissions are not reduced. This process may convert nitrous oxide to nitric oxide.) A negative impact occurs if stack gases are not reheated; localized emissions of acid mist are formed by condensation of sulfur dioxide and sulfur trioxide remaining in the flue gas. In addition, minor negative impacts occur at regenerable plants; sulfur removery plants may emit from 0.17 to 0.35 pound of sulfur dioxide per million Btu and associated sulfuric acid plants may emit approximately 0.2 pound per million Btu.

Sludge disposal is the major environmental problem of nonregenerable systems. The amount of sludge generated is dependent upon sulfur and ash content of the coal, sulfur dioxide removal efficiency, coal usage, load factor, mole ratio of additives, and moisture and composition of the sludge. A 100-MW coal-fired unit would produce about 34,500 tons/year of wet FGD sludge. Proper disposal of such large quantities is required to prevent a threat of contamination to both water and land through percolation of sludge liquor and nonsettling characteristics of sludge material, respectively.

Scrubber sludge is most commonly disposed of through ponding and/or landfill. For the 100-MW example given above, about 0.5 acre of ponding at a depth of 50 feet would be required for sludge disposal per year. Sludge can also be dewatered or stabilized to form a solid for landfill. Physical stabilization or fixation is required to ensure that sludge does not regain its original water content. Alternatively, Japan has oxidized sludge to make commercially marketable gypsum fiber.

Energy impact--The electricity needed to run FGD process equipment and energy for stack gas reheating requires about 3 to 6 percent of a plant's gross energy input (Btu/hour). This penalty may or may not result in a derating of plant capacity depending upon whether power production is turbine- or boiler-limited. If a plant is turbine-limited, the excess steam from the boiler can be used to reheat stack gases. Regenerable processes require additional energy for the sulfur recovery process. The additional energy requirement for the regeneration facility is approximately 3 percent of the total heat input to the boiler for each of the three most common processes.

Cost of compliance--The costs of installing and operating a FGD system are important constraints to application of this control strategy. Capital costs for new installations vary from $60 to $100/kW depending upon plant layout, FGD process design, unit capacity, plant location, amount of reheat required, and other site-specific factors. Retrofit costs typically run 12 to 20 percent higher than new installation costs. In difficult retrofit cases, installation costs could increase by 50 percent or more.

The remaining plant life and capacity factors are important since they determine the number of kilowatt-hours over which the cost of the FGD system can be amortized. For older plants with limited life and lower utilization factors, high capital charges may be prohibitive.

For nonregenerable systems, annualized sludge disposal costs are estimated at $7/kW. FGD operating and maintenance costs are estimated at 0.3 to 1.5 mills/kWh. With capital costs amortized over 20 years of remaining plant life, the cost of compliance would typically range between 2.5 and 4.0 mills/kWh. Average plant power production cost is about 20 mills/kWh, although this cost is highly variable. Furthermore, since cost accounting is done on a system-wide basis, the impact on power production costs also must be calculated on a system-wide basis, with consideration of such factors as type of plants, average capacity factors, and number of plants requiring FGD systems.

Fluidized-bed Combustion--There are two types of fluidized bed combustion: atmospheric-pressure systems and elevated-pressure systems. Both systems employ a sorbent that reacts immediately with sulfur dioxide formed in the combustion process. The fuel is burned in a bed of granular, noncombustible material such as coal ash or lime. Air is passed up through a grid plate under the bed, causing the suspension of granular bed particles. This air serves as the combustion air. Fuel is injected near the base of the bed above the grid plate and burns very rapidly. Flue gases pass over an additional heat transfer surface before being exhausted. Many fuels can be used in this process, including municipal refuse.

Commercial availability--The atmospheric-pressure process is currently in the pilot-plant design and construction phase, whereas the pressurized process is just entering the demonstration plant phase sponsored by the Environmental Protection Agency. Full-scale atmospheric utility boilers should be demonstrated by 1979-1980; operation of the pressurized pilot plant should be completed by 1982. Commercial availability of the atmospheric unit is projected in the time frame of 1981-1982. Vendor capacity should be at least as great as that for conventional units since fluidized-bed boilers are amenable to a greater degree of shop fabrication.

Effectiveness--Bench-scale and pilot-scale data indicate sulfur dioxide removal efficiencies of 90 to 95 percent. Fluidized-bed combustion should also be reliable since changes in the type of fuel burned in the boiler do not affect the removal of sulfur dioxide.

Applicability--Fluidized-bed boilers may have slightly broader application than conventional boilers due to low environmental impacts and potential to use a wide range of fuels. These units are principally applicable to new installations, although some limited specialized retrofit applications are being considered.

Environmental impact--Environmental impacts of fluidized-bed units are positive in terms of sulfur dioxide, nitrogen oxides, and particulate emissions. Nitrogen dioxide emissions can be controlled to 0.2 pound per million Btu, well below the New Source Performance Standard of 0.7 pound per million Btu. Preliminary indications show that particulate emissions are more coarse, and therefore are easier to collect. Emissions of carbon monoxide and hydrocarbons are also low.

Energy impact--The fluidized-bed boilers should generate power at least as efficiently as conventional power boilers with scrubbers. Table 4-6 presents comparative estimates of overall thermal efficiencies.(5)

Table 4-6. THERMAL EFFICIENCY OF FLUIDIZED-BED BOILERS
(percent)

| Boiler type | First generation | Second generation |
|---|---|---|
| Fluidized bed | | |
| Atmospheric | 36 | 40 |
| Pressurized | 38 | 47 |
| Conventional and stack gas scrubber | 37 | 37 |

Cost of compliance--Fluidized-bed boilers may offer a lower cost alternative to conventional boilers. Current estimates indicate that fluidized-bed boiler systems offer an installed capital cost saving of 15 to 20 percent over conventional boilers with stack gas scrubbing. Table 4-7 details comparative operating costs for fluidized-bed and conventional boilers at a 635-MW plant using 4.3 percent sulfur coal and operating at a load factor of 70 percent.(5) To summarize, the increment in cost of a fluidized-bed system over a new noncontrolled conventional coal-fired system, and hence the incremental cost of compliance, would be 2.5 to 3.0 mills/kWh, which would be competitive with flue-gas desulfurization at 2.5 to 4.0 mills/kWh.

NONCONTINUOUS STRATEGIES

Noncontinuous compliance strategies rely on the dispersion capacity of the air to meet ambient air quality standards. When meteorological conditions cause a reduction in assimilative capacity, noncontinuous strategies

Table 4-7. COMPARATIVE OPERATING COSTS FOR CONVENTIONAL AND FLUIDIZED-BED COAL-FIRED POWER PLANTS

(mills/kWh)

| Cost category | Conventional boiler, once-through | Atmospheric-pressure fluidized-bed boiler: Regenerative | Atmospheric-pressure fluidized-bed boiler: Once-through | Pressurized fluidized-bed boiler, combined cycle: Regenerative | Pressurized fluidized-bed boiler, combined cycle: Once-through |
|---|---|---|---|---|---|
| Fixed charges | 10.45 | 9.88 | 9.32 | 8.74 | 8.37 |
| Fuel | 8.20 | 9.18 | 8.58 | 8.68 | 8.06 |
| Dolomite or limestone | 0.10 | 0.05 | 0.29 | 0.12 | 0.52 |
| Operating and maintenance | 0.99 | 0.86 | 0.67 | 0.90 | 0.71 |
| Total | 19.74 | 19.97 | 18.86 | 18.44 | 17.66 |

call for reducing emission rates of the source. Emission rates are varied through fuel switching and load shifting. Tall stacks, which are normally incorporated into load shifting or fuel switching "supplementary control systems" are used to enhance the dispersion of pollutants.

The basic elements of a noncontinuous control system are air quality monitoring, meteorological data, scheduled emission rates, a predictive air quality model, and the necessary means to vary emissions. The monitoring network is used as an indication of a potential air quality problem period, as a source of data input to the model, and as a check on the effectiveness of the strategy. The model also uses other inputs to predict periods in which emission rates should be varied. The reliability of these elements largely determines the effectiveness of the noncontinuous control alternative. In the discussion, "effectiveness" of these alternatives refers to the effectiveness in assuring that ambient air quality standards are not violated.

Fuel Switching

Fuel switching requires a utility to provide for storage and firing of an alternative low-sulfur fuel. The alternative fuel would be used when the monitoring instrumentation and/or the predictive model indicated that air quality standards would be violated under normal fuel operation.

Commercial Availability--All of the necessary components of a fuel switching program are currently available. A certain amount of lead time, usually 1 to 2 years, is required to set up the monitoring network and to develop and refine the model. Changes in storage and handling facilities could require 1.5 to 2.5 years, depending on the magnitude of modification required.

Effectiveness--The effectiveness of fuel switching as a control strategy is largely determined by the reliability of the prediction mechanism. System reliability is dependent upon the accuracy of meteorological and emissions forecasting, as well as air quality modeling. Control reliability can be improved through the inclusion of a safety factor in the air quality threshold value for initiating fuel switching. Control reliability would also be expected to improve as the predictive model is refined through operating experience. Table 4-8 presents data on the operating experience of the Tennessee Valley Authority's Paradise steam plant.

The time required to switch fuels, varying from 20 minutes for a dual-fired plant with divided bunkers to 3 hours for a plant with no capability to bypass coal already in the bunkers, also plays a role in effectiveness. In general, noncontinuous strategies are most effective in attaining the 24-hour primary standard because of this time requirement. These methods have been approximately 90 percent effective in meeting the 3-hour secondary standard.(6,7)

Table 4-8. RELIABILITY OF NONCONTINUOUS CONTROL SYSTEM AT THE TENNESSEE VALLEY AUTHORITY'S PARADISE STEAM PLANT IN PROTECTING 3-HOUR AND 24-HOUR AMBIENT AIR QUALITY STANDARDS[a]

| Time period | Violations of 3-hour secondary standard (0.5 ppm)[b] | Violations, 24-hour primary standard (0.14 ppm)[b] |
|---|---|---|
| Before control (1/1/68 to 9/18/69) | 10 | 8 |
| After control (9/19/69 to 3/31/74) | 4 | 0 |

[a]Based on Tennessee Valley Authority and Environmental Protection Agency data.

[b]At any of the 14 sulfur dioxide air quality monitors around the plant.

Applicability--Although fuel switching is technically applicable to a wide range of plants, application is limited by operational and practical environmental considerations. Prolonged use of low-sulfur coal over 6 hours in boilers designed for high-sulfur coal reduces precipitator performance and increases particulate emissions. Increased slagging and decreased generator capacity are also potential problems. However, interim use of low-sulfur oil does not create these problems.

Practical enforcement considerations may dictate that fuel switching be used on isolated plants so that the source of air quality violations is identifiable. In addition, fuel switching is not applicable to a rough terrain that is not conducive to dispersion. Fuel switching is most readily applicable to dual-fired plants due to the absence of need for boiler and fuel-feed modifications and to the reduced time required for the switching.

Environmental Impact--The use of low-sulfur coal in boilers burning high-sulfur coal can cause increased particulate emissions and ash production. This impact is negligible for control periods of less than 6 hours; the small amount of increased ash does not create a disposal problem.

A more serious potential problem is the contribution of noncontinuous systems to levels of suspended sulfate while they are burning high-sulfur fuels. Some of the sulfur dioxide and hydrogen sulfide emitted is converted to sulfate, and Environmental Protection Agency assessments show that existing sulfate concentrations in some areas of the country may adversely affect human health. However, national ambient air quality standards for acid sulfate aerosol have not been set. For the present, continuous control of sulfur dioxide emissions is thought to be the best approach to sulfate control, but additional research is needed to determine an optimal approach. EPA believes, however, that a number of isolated power plants can use supplementary control systems, which require additional emission reduction on an intermittent basis, as an interim strategy for a number of years without increasing the risk to public health.

Energy Impact--The most significant energy impacts of this alternative are transportation and use of the low-sulfur fuel. In general, intermittent use of low-sulfur fuel represents an efficient use of a scarce and energy-intensive fuel.

Cost of Compliance--The cost of a fuel-switching program includes capital expenditures for installation, operating expenses, and extra surveillance and enforcement costs to the control agency. Capital costs for a 750-MW boiler are estimated at $16/kW. While operating costs would vary considerably among installations, a reasonable annualized cost estimate might be 0.5 to 1.0 mills/kWh. If low-sulfur oil is the auxiliary fuel, an additional cost of boiler conversion and storage facilities would be necessary for a coal-fired plant not equipped to burn low-sulfur oil. This cost would range from $12/kW to $40/kW for large and small units, respectively.

Load Shifting

Load shifting is a procedure that reduces the rate of emissions from a specific plant by shifting scheduled generation to another plant on an interconnected electrical transmission system. This system is similar in concept and operation to the fuel-switching system.

Commercial Availability--The components of a load-shifting program correspond to fuel-switching requirements and are commercially available. Lead time to develop the predictive system is also similar. Additional system capacity could be required, and transmission lines may need to be constructed. Time requirements vary from 1 to 4 years according to the magnitude of the modification and institutional arrangements necessary. It is currently common practice to use load shifting for other reasons, such as forced outages.

Effectiveness--Problems with the reliability of the predictive mechanism are parallel for load shifting and fuel switching. In addition, allowances must be made in the transmission system and generating reserve for concurrent load reductions and/or frequent shift requirements. The reliability can be increased by incorporating the additional potential to switch fuels or use tall stacks. Emission reduction from load shifting may require from 30 minutes to 2 hours to accomplish.

Applicability--Load shifting is generally more suitable on a system with a greater number of generating units for a given installed capacity; in the event of forced outage, a small amount of capacity is out of service at one time. This method is also less applicable to locations where numerous plants were built in close proximity or locations where a large percentage of total capacity is subject to areawide air pollution episodes.

Environmental Impact--Environmental impacts of load shifting may be greater than those of fuel switching because of the necessary acreage for transmission line construction and because of possible construction requirements for additional generation units. Other environmental impacts parallel those mentioned under fuel switching.

Energy Impact--Energy requirements will vary depending upon the units involved in the load shift and upon transmission system losses. Additional energy input requirements are not considered to be a problem.

Cost of Compliance--The cost of a load-shifting operation varies with the number of generating plants whose loads must be shifted. The principal components of this cost are program development, additional reserve generating capacity, addition of transmission capacity, and displaced power cost. Program development is estimated at $200,000 to $600,000. Additional reserve capacity costs, depending on the type and size of unit, are from $80 to $100/kW less than the average cost of original capacity. Transmission costs are $200,000 per gigawatt (1000 MW) per mile at an operating cost of $200 per mile. The cost of displaced power is about $500 per hour. This figure assumes a load shift of 100 MW with a cost difference of 5 mills/kWh.

Tall Stacks

A stack whose physical height exceeds that required to eliminate the effects of local terrain on plume rise is classified as a tall stack. These stacks are designed to prevent high ground-level pollutant concentrations in the vicinity of the source, and can considerably alter the dispersive characteristics of the plume.

Commercial Availability--The current annual construction rate is 10 to 20 per year. Complete construction requires 4 to 5 months, and neither manpower nor materials are currently constraints to construction.

Effectiveness--While tall stacks are effective in reducing the severity and number of excess pollutant concentrations near the source, they distribute emissions over a larger area and add to the overall pollutant burden. Load switching in combination with tall stacks yields increased availability of generators, but as indicated earlier, it is difficult to define accurate criteria for determining when load switching should occur. Tall stacks do present the advantage of 100 percent availability. Both of the discussions below also include issues that limit the effectiveness of this approach.

Applicability--The number, height, size, and distribution of both terrain and buildings that affect dispersion determine the applicability of tall stacks. In addition, other considerations, such as structural requirements in earthquake-prone areas or height restrictions in airport flight patterns, are practical limits.

Environmental Impacts--While tall stacks may generally prevent high ground-level pollutant concentrations, there are meteorological circumstances that inhibit their effectiveness. Atmospheric inversions frequently limit upward dispersion even when emission occurs at a high level; tall stacks provide no control mechanism for such occurrences. Persistent wind direction can also cause long-term impact on a limited area. The sulfate problem is also of concern with tall stacks because such stacks disperse sulfur oxide emissions over a larger area rather than reducing atmospheric emissions.

Energy Impact--Tall stacks require no additional energy expenditure and, due to additional draft provided, may reduce the plant's overall energy requirement.

Cost of Compliance--Costs of tall stacks are figured in terms of thousands of dollars per foot of stack height. Current costs range from $3500 to $7000/foot, depending on company and construction method. A 1000-foot stack would probably cost roughly $6 million. The amortized cost for a large boiler would run approximately 0.15 to 0.30 mills/kWh.

ENERGY RECOVERY FROM SOLID WASTES

In 1973, about 135 million tons of solid waste per year were generated by residential and commercial sources in the United States. About 70 to 80 percent of that waste was combustible and convertible to energy.

Not all waste is available for energy recovery. Because energy recovery systems must be large enough to achieve enconomies of scale, energy recovery appears feasible only in more densely populated areas, such as Standard Metropolitan Statistical Areas. If energy recovery had been practiced in all such areas in 1973, the equivalent of almost 425,000 barrels of oil per day (bbl/day) could have been saved. This is a significant amount of energy. For example, 425,000 bbl/day is equivalent to 10 percent of all the coal used by electric utilities in 1973 and is enough energy to light every home and office in the nation. More significantly, solid waste can satisfy large percentages of the energy needs of individual users, such as industrial plants, thereby reducing dependence on fossil fuels.

Based on energy recovery systems planned or under development at the present time, it is projected that by 1980 energy recovery systems should be operating in almost 30 cities and counties and recovering the equivalent of 40,000 bbl/day, assuming continuation of current levels of Federal financial and technical assistance. With greatly expanded levels of Federal assistance, this projection could be as high as 236,000 bbl/day. The following discussion covers energy recovery systems that are available or under development, associated environmental impacts, and the economic issues.

Availability of Technology

Solid waste disposal systems must be operationally reliable and involve a minimum of technical risk. Furthermore, such systems must operate at a reasonable cost without degrading the environment. Risk and reliability are usually evaluated through examination of existing full-size systems in actual operation. Although no technology is presently risk-free, two energy recovery methods are commonly considered "commercially available." Other, and possibly better, methods are presently being developed and are projected to become commercially available throughout the 1977 to 1982 time period.

Available Methods--The methods commercially available include: (1) the generation of steam (for district heating and cooling or for industrial processing) in a waterwall incinerator fueled solely by unprocessed solid waste and (2) the use of prepared (shredded and classified) solid waste as a supplement to pulverized coal in electric utility boilers. There are many existing waterwall incinerators in the United States, and new steam generation systems are being built in Nashville, Tennessee (district heating and cooling) and in Saugus, Massachusetts (industrial process steam). The use of prepared solid waste as a supplementary boiler fuel is being demonstrated in St. Louis, Missouri with demonstration grant support from the Environmental Protection Agency and with the cooperation of and additional funding by the Union Electric Company. Several other supplementary fuel systems are being implemented by communities across the country, including Chicago, Illinois; Bridgeport, Connecticut; Ames, Iowa; Wilmington, Delaware (with Environmental Protection Agency demonstration grant support); and Monroe County, New York (Rochester area).

These methods are defined as commercially available because they have been demonstrated in large-scale facilities and because private industry is offering these technologies for sale. Waterwall incinerators are already in widespread use in this country. While there is little risk of technical failure, the long-term reliability of these systems has not yet been established. Solid waste has been used as a supplement to coal or oil in steam or electric boilers in Europe for about 20 years. However, the practice is relatively new in the United States, because, unlike European boilers, most steam-electric boilers in the United States fire fuels in suspension, requiring that solid waste be processed before it is fired as a supplementary fuel in the boiler. The St. Louis project has provided the only experience with this technology. While several other cities are implementing similar systems, to date there has been relatively little experience in this area. Consequently, until more systems are built, there will still be some risk associated with implementing such energy recovery systems.

Developing Technology--Other, and possibly better, methods are presently being developed. Pyrolysis, which converts solid waste into gaseous or liquid fuels, is being demonstrated with Environmental Protection Agency demonstration grant support in Baltimore, Maryland, and San Diego County, California, and, without agency grant support, in South Charleston, West Virginia. These systems are expected to become fully operational during the 1975 to 1977 time period and commercially available during the 1977 to 1980 period.

In addition to pyrolysis, the production of methane gas through controlled biological decomposition (anaerobic digestion) of solid waste is about to be performed at pilot-plant scale. Commercial implementation of this technology is projected for the 1980 to 1982 period.

## Environmental Impact

The impact on the environment of implementing systems to recover energy and materials from solid waste can be assessed in two areas:

1. Avoidance of solid waste disposal impacts.

2. Environmental impact of energy recovery facilities.

Solid Waste Disposal--Communities in the United States usually process and dispose of waste in the following ways:

1. Open dumping of solid waste on the land is the most prevalent and cheapest method used in the United States. Open dumps cause pollution of ground water through leachate and air pollution through open burning. In addition, dumps are notorious as breeding grounds for disease carrying vectors.

2. Conventional incineration can reduce the volume of municipal solid waste for disposal by as much as 90 percent. However, residue is frequently put in open dumps and not disposed of properly. Most incinerators were built before today's air quality standards were implemented; consequently, they are unable to meet the requirements of the Clean Air Act of 1970. New incinerators can meet air quality standards but are very expensive in the absence of revenues from steam sales to offset costs.

3. Acceptable land disposal of solid waste involves dumping of raw, baled, or shredded waste in a manner that safeguards against adverse environmental and health effects. Operation is relatively inexpensive.

Waste management is a choice between two options: disposal (in the three forms described) or recycling. If the wastes cannot be returned to the economy, they must go back into the environment, the consequences of which are still only vaguely understood. Land deposition of wastes exposes them to natural mechanisms. Rain soaks into disposal sites until, like a saturated sponge, the site can hold no more. At that point, leachate develops and, loaded with pollutants picked up from the waste, it percolates through the soil toward groundwater acquifers (the drinking water of nearly half the population) or runs off into rivers and lakes.

Where precipitation rates and groundwater tables are high, leachate formation presents a potentially serious problem. Too little is known today about the ability of soil to purify leachate before or after it reaches acquifers; it is known that wells have been polluted by leachate. Typical leachate contains chemicals and minerals in concentrations too high for drinking water.

Conventional sanitary landfilling techniques minimize the impact of leachate generation. In some areas, however, more control may be needed, including leachate collection and treatment (techniques are not well developed). But the most disturbing fact is that, of the nation's 17,000 to 20,000 disposal sites, only a handful qualify as sanitary landfills in a true sense, where site selection, operation, and monitoring all contribute to acceptable land disposal practices. Methane gas migration from land disposal sites, sublimation of toxic chemicals into the atmosphere, and open burning of wastes are other examples of environmental degradation from poor solid waste disposal practices.

Although land disposal will always be necessary, energy recovery, when combined with recovery of recyclable materials, can reduce disposal requirements up to 90 percent and can have a significant role in reducing the pollution from inadequate disposal practices.

<u>Energy Recovery Facilities</u>--The environmental impact of energy recovery facilities will vary with different energy recovery systems, which can be analyzed in two parts: feedstock preparation and energy conversion. Feedstock preparation refers to the handling (receiving, conveying, and storage) and processing (shredding, pulping, and classification) that prepares the waste for energy conversion. Energy conversion refers to the chemical process (combustion, pyrolysis, or biodecomposition) that converts the waste into energy.

<u>Feedstock preparation</u>--Feedstock preparation involves receiving, size reduction (shredding or pulping), classification, and storage facilities. Potential emissions to the air, water, and land, including noise and odor, are similar to other light industry and can be controlled by relatively simple techniques. The most significant emissions are: (1) dust emitted to the air from cyclone separators, (2) water-borne contaminants resulting from wash-down of waste-handling areas, (3) noise from delivery truck traffic and from processing equipment, and (4) odors. These emissions are controlled, respectively, by dust collectors, filters and discharge to sanitary sewers, selective routing of trucks and enclosures for equipment, and enclosures for all areas handling waste.

<u>Energy conversion</u>--There are four predominant types of energy conversion units: (1) waterwall incinerators, (2) power plant boilers, (3) pyrolysis reactors, and (4) anaerobic digestors for production of methane gas. Waterwall incinerators are subject to, and can be designed to meet, New Source Performance Standards. The other types of units are not now subject to such standards or have not been tested for compliance at full scale.

Power plant boilers firing solid waste in combination with fossil fuels are not now subject to New Source Performance Standards. The standards under development for such facilities will not constitute an impediment to the increased use of solid waste as a fuel. Emission tests have been conducted at one location to date, Union Electric Company's Meramec Plant, where solid waste is burned with coal as part of the Environmental Protection Agency's solid waste energy recovery demonstration grant to the city of St. Louis. The tests indicate that:

1. Particulate emissions increased slightly when solid waste was fired with coal, probably because of decreases in the efficiency of the electrostatic precipitator. There was no discernible change in particle size or resistivity. Decrease in precipitator performance may result from increases in gas velocity and changes in precipitator electrical conditions (spark rate).

2. Gaseous emissions (sulfur oxides, nitrogen oxides, hydrogen chloride, and mercury vapor) were not significantly affected by combined firing of waste and coal.

3. Uncontrolled particulate emissions per cubic foot of exhaust gas were not changed by combined firing; however, total uncontrolled particulate emissions did increase because of increases in the gas flow rate.

4. Additional air pollution testing is required to complete the characterization of particulate emissions resulting from combined firing.

Additional tests will be conducted in late 1974 and early 1975. The test results will be available in the spring of 1975. If preliminary indications of increased particulate emissions are confirmed, an increase in the capacity of the pollution control devices will be required.

Pyrolysis reactors were developed to convert waste to energy using little or no ambient (excess) air, thus minimizing or precluding any discharge of gases to the environment. Test of pilot-scale systems indicate that New Source Performance Standards can be met; all full-scale systems will be required to meet the standards for incinerators.

Anaerobic digestors have not been developed on a scale large enough to test the potential air and water emissions. Based upon laboratory experience, however, air emissions appear to be negligible, and water emissions appear to be controllable.

Economics of Energy Recovery

Energy recovery must compete with the three other processing and disposal methods mentioned earlier: open dumping, conventional incineration, and sanitary landfilling. Capital investment would be $15 to $30 million for a plant designed to process 1000 tons of solid waste per day. Operating costs ($10 to $15/ton, including amortization) can be offset by revenue from sale of energy and materials ($4 to $12/ton) and by disposal fees. Thus, for a reasonable capital investment, energy recovery can compete economically with other environmentally sound disposal methods.

Already some communities, especially densely populated areas, have estimated that energy recovery would cost less than their present disposal method. Moreover, trends in relative economics favor energy recovery, as indicated by the following considerations:

1. Enforcement of land disposal regulations by State and local governments is expected to become more vigorous. This will tend to eliminate open dumping and to increase the cost of land disposal.

2. Increasing land costs and citizen opposition to land disposal in urban areas will tend to push landfills farther from centers of waste generation, thus necessitating additional transportation, an increased cost.

3. Rising costs of energy and materials will increase the potential for revenues from an energy recovery system.

4. Installing air pollution control equipment on incinerators appears to be very costly. Very few incinerators have been upgraded or built in the past 10 years.

5. Innovations in technology are expected to make available systems less expensive and to result in more economical alternatives.

Even where energy recovery does cost more than land disposal, economic cost is not the only consideration. Several communities have already elected to pay more for energy recovery than their current disposal costs because it represents a positive step in the direction of environmental protection and resource conservation.

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# CHAPTER 5

## FACTORS AFFECTING COMPLIANCE

The review of the status of compliance with environmental regulations of coal-fired power plants that is given in Chapter 3 of this report is based on announced changes in fuel requirements and on a projected rate of construction of new facilities. A number of other factors could affect compliance, however, including possible conversions of power plants from oil to coal, decreased demand for electricity through 1980, nonutility demands for coal, and curtailments in allotments of natural gas. These issues are discussed below, largely in qualitative terms.

This section of the report also covers the various allocation authorities of Federal agencies that must coordinate energy resources and demands with environmental needs. This brief discussion covers the nature of these authorities and their use and issues related to the new authorities provided by the Energy Supply and Environmental Coordination Act.

### CONVERSIONS FROM OIL TO COAL BY ELECTRIC UTILITY PLANTS

The Federal Power Commission has estimated that plants having 24,000 megawatts of steam electric generation capacity had converted from coal to oil by the end of 1974. These plants presently account for nearly 40 percent of the heavy oil consumption by electric utilities in the United States. Many of these plants, which are located largely on the east coast, had converted because of the availability of low-cost, imported oil. Restrictions on the sulfur content of fuels issued pursuant to local laws and the Clean Air Act have provided major incentives in recent years for plants to switch from coal to oil.

Two factors of recent origin will probably tend to reverse this trend toward the use of oil. One factor is the sharp rise in oil prices over the last few years from $3 per barrel for residual oil to $10 to $12 per barrel. This price shift will create strong economic incentive for plants to switch back to coal. The second factor is the passage of the Energy Supply and Environmental Coordination Act, which authorizes the Federal Energy Administration to prohibit the use of oil and natural gas as the primary energy sources for electric utility plants.

Although the number of plants that may switch back to the use of coal is unknown at this time, these plants clearly constitute a potentially significant addition to the demand for coal. Since these units are exempted from New Source Performance Standards by Section 119 (d) (5) of the Clean Air Act, they would have to comply with State Implementation Plan regulations not later than January 1, 1979. The maximum potential impact of their reversion to coal would amount to additional coal demands of 40 to 50 million tons per year by 1980 if all plants went back to the use of coal. The range, 40 to 50 million tons, reflects different degrees of utilization of the power-generating capacity of the reconverted plants.

Shifting these plants back to coal will create new demands for low-sulfur coal and sulfur removal equipment, inasmuch as the majority of these plants are located in regions having more restrictive regulations on the sulfur content of fuels than those that affect most existing coal-fired plants. The maximum demand for low-sulfur coal would occur if all reconverting plants relied upon the use of low-sulfur coal rather than flue-gas desulfurization to meet emission limitations. To illustrate this maximum demand for low-sulfur coal, the respective capacities of reconverted plants (24,000 megawatts total) were classified by currently applicable State Implementation Plans to determine the allowable sulfur content of the coal that would be needed. The results are shown in Table 5-1.

Table 5-1. ESTIMATED COAL DEMAND BY SULFUR CONTENT FOR STEAM ELECTRIC POWER PLANTS RECONVERTING FROM OIL

| Sulfur content of coal, percent sulfur by weight | Amount of coal, million tons/year | Percent of total |
|---|---|---|
| < 0.7 | 21.6 | 43.2 |
| 0.7 to 1.5 | 21.8 | 43.6 |
| 1.5 to 3.0 | 5.4 | 10.8 |
| >3.0 | 1.2 | 2.4 |
| | 50 | 100 |

The actual demand for low-sulfur coal will undoubtedly be less than shown in Table 5-1, however, for two reasons:

1. Plants that face the most stringent sulfur regulations in order to be in compliance may not convert to coal at all.

2. Use of sulfur removal equipment will permit the use of higher-sulfur Appalachian coal.

Although neither the overall quantity nor quality of coal required for the conversion of some of these plants can yet be accurately predicted, reversion to use of coal by a significant number of these plants, especially by plants governed by stringent sulfur regulations, would add to the demands for low-sulfur coal and for sulfur removal equipment.

## COAL REQUIREMENTS IN NONUTILITY SECTORS

Rising oil prices and the lack of availability of natural gas is likely to boost the use of coal by 1980 in industries that consume large amounts of fuel. Table 5-2 illustrates the uses of coal in 1973.

Table 5-2. COAL DEMAND IN 1973 BY SECTOR

| Use | Millions of tons | Percent of total |
|---|---|---|
| Electric power plants | 388 | 63.2 |
| Coke plants | 94 | 15.3 |
| Industries (other than coke plants) and retail sales | 79 | 12.9 |
| Export sales | 53 | 8.6 |
| Total | 614 | 100.0 |

Of the total demand, 24 percent was largely for low-sulfur, metallurgical coal for use in the steel industry or for export. Only 13 percent, or roughly 80 million tons, was steam coal used by industrial and commercial establishments.

The most recent projection of nonutility demand for coal was made by the Federal Energy Administration in their Project Independence Blueprint. In that study, the projected increase in nonutility demands was only 15 million tons by 1980; however, this estimate would appear to be too low.

Coal for export is expected to remain roughly at present levels. Demand by the steel industry for coking coal depends on the rate at which output is expanded, the amount of energy conserved in blast furnace operations, and whether the past trend toward substitution of oil and natural gas for coke will be reversed. A rough estimate of coking coal demand may be derived by assuming that it grows at the same pace as steel output, which is forecast by the American Iron and Steel Institute to increase 2.5 percent per annum. Coking coal needs would then grow to 112 million tons by 1980, which is 18 million tons more than was used in 1973 (Table 5-2).

Combustion uses of coal amounted to 79 million tons in 1973, which reflects a continuing decrease resulting from economic factors and environmental restrictions. Whether these industrial and commercial users will need more coal in the future is purely conjectural. Industrial uses provide another area in which reconversion to coal could result in a substantial increase by 1980 in the demand for coal. A recent estimate indicated that combustion coal demands could increase by as much as 28 million tons by 1985 if industrial boilers that once used coal were to use coal again. As in the case of utility boilers, this potential will not fully be realized because of economic and environmental constraints.

Although precise estimates of nonutility coal demand cannot be made, it is important to recognize that the 37 percent of coal supplies used for nonutility consumers (Table 5-2) tends to be very low in sulfur content. Sixty-five percent of nonutility demands is largely in the form of metallurgical quality coal, which must also be very low in sulfur content. In addition, industrial and commercial uses of steam coal tend to be subject to stiff sulfur restrictions.

Thus, nonutility uses of coal constitute a potentially important source of demands on the nation's capacity to provide low-sulfur coal. Because industrial boilers are generally too small to be outfitted economically with flue-gas desulfurization systems, these nonutility demands gain added significance. Therefore, added demands by these nonutility consumers will tend to increase the consumption of low-sulfur coal.

## COAL REQUIREMENTS FOR THE ELECTRIC UTILITY INDUSTRY

Chapter 3 of this report reviewed the status of compliance with regulations issued pursuant to the Clean Air Act that are in force through 1980. However, coal requirements for utilities depend initially on the rate of growth in electricity demand, the rate of installation of nuclear electricity-generating capacity, the availability and price of natural gas and oil, and the availability and price of coal. The interplay of these factors will determine the actual demand for coal by electric power plants.

### Impact of Changes in Demand for Electricity

Generation of electric power has historically grown at a rate of approximately 7 percent per annum. The most recent estimate by the Technical Advisory Committee to the Federal Power Commission projected a demand for electricity equal to 3245 billion kilowatt hours (kWh) in 1980 compared with the 1973 demand of 1844 billion kWh. Recent experience suggests, however, that these forecasts were much too high. Based on nearly complete data for 1974, the Federal Power Commission estimates that power generation in 1974 was about 0.6 percent less than in 1973. If power growth resumes its historical growth pattern in 1975, power generation will be 2855 billion kWh by 1980. No one yet knows the impact skyrocketing energy prices will have on the demand for electricity. Should the conservation ethic continue to prevail, then demand for electricity could be even lower by 1980. This could lead to a slower rate of growth in coal demand by electric power plants.

### Impact of Expansion of Nuclear Power Plant Capacity

Several years ago, experts predicted a rapid expansion of nuclear capacity by 1980. It was anticipated that 125,000 megawatts of nuclear capacity would be operating at a baseload level of 80 percent of capacity by 1980. Instead, the Atomic Energy Commission is now projecting a probable level of 69,000 megawatts of nuclear capacity in 1980. Furthermore, operating problems have plagued existing installations so that projected 1980 levels of power production are 55 to 57 percent of capacity, instead of 80 percent.

A number of policy measures are now being considered that would reinstate time tables for delayed construction of nuclear plants, which would boost capacity to over 100,000 megawatts by 1980. Operating performance of nuclear power plants is also expected to improve. These measures could increase power from nuclear generation in 1980 by 220 billion kWh. A great deal of any expansion that occurs in power generation by nuclear plants will probably replace power generation from coal-fired plants. The recent Project Independence Blueprint analysis by the Federal Energy Administration indicated that expanded use of nuclear fuels to generate power would largely displace coal. This would reduce the load on existing coal-fired plants and would apply pressure to delay construction of some new coal-fired plants. It is clear that expanded nuclear-fueled power plants will not simply replace oil-fired power plants since many nuclear power plants would be part of utility systems that do not rely on oil. Recent estimates by the Federal Power Commission indicate that at least half of the potential 30,600 megawatts of nuclear capacity that might be accelerated to become operational by 1980 is located in utility systems that do not use oil.

One factor that would militate against expansion of nuclear power-generating capacity is the serious financial situation faced by many utility systems. The slower growth in demand for electricity (discussed in the previous section) jeopardizes future utility earnings and makes it difficult for utilities to meet existing debt service commitments. Thus, utilities are tending to delay large financial outlays for new electricity-generating capacity, especially for nuclear-fueled capacity with its much higher capital costs. This has led some utilities to choose coal-fired capacity, which is cheaper and more reliable. These actions will stimulate the demand for coal and increase requirements for low-sulfur coal and sulfur removal equipment.

## Impact of Natural Gas Shortages

Natural gas is a premium fuel that has accounted for roughly 22 percent of the energy used by the electric utility industry. However, the regulated pricing system for natural gas has led to declining production rates. It is anticipated that natural gas supplies available to the utility industry will decline during the 1970's. Under the current gas curtailment system, utilities are the lowest-priority customers for this premium fuel and thus will feel the brunt of supply shortages. Even if prices were to be deregulated and/or leasing of natural-gas-rich offshore tracts speeded up, it is doubtful that new supplies would be sufficient to offset the declining trend until the early 1980's. Gas consumption by utilities is already dropping at an alarming rate, having declined from about 4 trillion cubic feet in 1972 to an estimated 3.3 trillion cubic feet in 1974. Forecasts by the utilities and by government agencies indicate that further declines in natural gas usage to 2.2 to 2.5 trillion cubic feet by 1980 can be anticipated.

The lack of availability of natural gas, even to maintain existing power plant capacity, will lead to efforts by the utilities to shift power loads to other fuels, especially coal and nuclear fuels. This shift could accelerate the construction of new coal-fired plants (which have to meet New Source Performance Standards) and will certainly tend to raise capacity utilization factors (and coal usage) in existing coal-fired power plants.

If the shortage in natural gas is as serious as the forecasts would indicate, this shift to coal could result in significant increases in sulfur and particulate emission loadings in localized areas that are hard hit by natural gas curtailments. It is important to recognize that the sulfur regulations adopted by the States and approved by the Environmental Protection Agency in 1971-1972 were predicated upon increased usage of natural gas. Substitution of coal for gas can lead to significant increases in emissions, thus jeopardizing the effectiveness of the environmental regulations in achieving ambient air quality goals. As curtailments occur, the Environmental Protection Agency will have to reevaluate the adequacy of the regulations, especially those for sulfur.

## USE OF ALLOCATION AUTHORITIES: EMERGENCY PETROLEUM ALLOCATION ACT AND ENERGY SUPPLY AND ENVIRONMENTAL COORDINATION ACT

### Oil Allocations

There are three authorities through which the environmental impacts of oil shortages can be addressed. The Emergency Petroleum Allocation Act authorizes the Federal Energy Administration to allocate oil by its quality characteristics, such as sulfur content. To our knowledge, this authority has never been used explicitly by the Federal Energy Administration. However, during the Arab oil embargo, the Environmental Protection Agency and the Federal Energy Administration established a system by which to monitor the sulfur content of oil delivered to utilities, providing a basis for allocations by sulfur content if necessary. When viewed in conjunction with reduced fuel usage during the embargo, the greater use of fuels with higher sulfur content did not seriously jeopardize air quality.

The Federal Energy Administration in April 1974 issued Section 215 of its regulations under the Emergency Petroleum Allocation Act, which prohibits coal-fired sources from converting to oil unless health standards will be jeopardized or undue economic hardships will occur as a result of continued use of coal. Exceptions may be granted only when suitable alternative fuels are not available and a State certifies that the use of petroleum is essential to meet health standards. This regulation continues to be, along with Section 119 of the Clean Air Act, a regulatory check on the energy implications of compliance with the Clean Air Act.

Fuel allocation authority has been granted under the Energy Supply and Environmental Coordination Act to minimize harmful environmental effects of fuel combustion. Insofar as this authority relates to oil allocation, it provides a mechanism through which the Environmental Protection Agency could initiate allocations on the basis of the sulfur content of oil. It also makes explicit (and provides a further legal basis for) the authority of the Federal Energy Administration to exercise its existing authorities under the Energy Supply and Environmental Coordination Act to allocate oil on the basis of sulfur content.

This allocation authority would be used in the event of another fuel-oil crisis to ensure that areas with poor air quality do not become the dumping ground for poor-quality imported fuel oil. This authority obviously must be adapted to the existing oil distribution system. Residual oil would probably be the most important fuel to reallocate by sulfur content should such reallocation become necessary. From a logistical standpoint it will also be the most practicable since 90 percent of the heavy oil used on the east coast is imported and, therefore, can be reallocated by diverting oil tankers.

Coal Allocations, Fuel Exchanges, and Control Equipment Deliveries

New authorities relating to coal were provided by the Congress in the Energy Supply and Environmental Coordination Act. These relate to fuel exchange orders for coal, authority delegated to the Federal Energy Administration for coal allocation, and discretionary authority to set priorities for deliveries by manufacturers of sulfur removal equipment.

It is clear that reallocation of coal would be far more complicated and difficult than similar actions for petroleum products, as the following reasons illustrate:

1. Coal mines are normally opened on the basis of long-term contracts for most of the expected production. If coal is reallocated, these contracts will become problematic and will have to be broken or transferred.

2. Coal supply systems are far more inflexible than oil supply systems. It will be logistically difficult to redirect supplies.

3. Access to information from coal suppliers will be more difficult to obtain than from oil suppliers because of the multiplicity of producing companies.

4. Differences in coal quality are far more important than differences in oil quality, for coal gives rise to multiple pollutants and has many combustion properties that vary significantly.

If exchange orders were invoked to minimize environmental problems resulting from coal conversion, logistical problems would be minimized if the swap were made with a nearby plant, preferably owned by the same utility company to minimize force majeure problems. Unfortunately, most of the plants capable of fuel switching are in the Northeast where relatively little coal is now being used.

The Environmental Protection Agency does not presently believe that its discretionary authority to set priorities for the delivery of sulfur removal equipment should be used. In order to assure that the national ambient air quality standards for sulfur dioxide are attained in an expeditious manner commensurate with the availability of low-sulfur coal and flue-gas desulfurization systems, the Environmental Protection Agency is concentrating its enforcement efforts on power plants in violation of the primary standards. As shown in Chapter 3, approximately 150 million tons of coal is expected to be consumed by plants that are involved in litigation or that will not be in compliance with State Implementation Plan requirements for sulfur dioxide by the specified attainment dates. Of this total, the Environmental Protection Agency has so far identified about 90 plants, having a total capacity of about 68,000 megawatts, that probably do not meet primary standards. Two-thirds of these plants, with total coal-fired electricity-generating capacity of about 50,000 megawatts, will need to reduce sulfur dioxide emissions substantially, by means of flue-gas desulfurization or the use of low-sulfur coal. The rest of the plants can attain the standards by using coal having moderate sulfur content or by using techniques such as coal washing or blending.

## USE OF ENFORCEMENT AUTHORITY: CLEAN AIR ACT

Exercising its authority under Section 113 of the Clean Air Act, the Environmental Protection Agency intends to issue enforcement orders that include schedules for achieving compliance in an expeditious but reasonable time. In some cases, these orders may run beyond the attainment dates specified in the applicable State Implementation Plans if earlier compliance is not possible, with adequate interim requirements to minimize the adverse effects on human health of the extended period of noncompliance. Earlier this year the Administrator submitted proposals for revising the Clean Air Act that included a provision which clarifies the authority of the Environmental Protection Agency to issue enforcement orders extending beyond the approved attainment dates. In implementing enforcement policy, the Agency is attempting, to the maximum extent possible, to allow for the time actually required to comply, including considerations of control system design and lead times and the capacity of manufacturers to supply flue-gas desulfurization systems. The relative impact of the power plants on air quality is also taken into account. Plants that will come into compliance by switching to low-sulfur coal without plant modifications will normally be given less time than plants using flue-gas desulfurization systems. If flue-gas desulfurization is the compliance technique, adequate time is allowed for the utility to phase-in the scrubbers on each unit. In the case of a second generation system with which there has been little operating experience, the Agency will allow adequate time at the front end of the schedule for the company to gain the experience required with a prototype unit before installing the additional units.

A good example of this approach can be seen in the consent agreement signed between the Environmental Protection Agency and the Philadelphia Electric Company for the installation of magnesium oxide scrubbers at the company's Cromby plant, Unit 1, and its Eddystone plant, Units 1 and 2. The magnesium oxide system, which generates products used in the manufacture of sulfuric acid, has not been widely used on coal-fired power plants, and at the time the order was signed it was determined that the company needed time to gain experience with the adaption of the system to boiler operation. For this reason, the compliance schedule allows for the phasing-in of the scrubbers in two major stages. During the first phase of the schedule, the company is to complete the installation of the flue-gas desulfurization system already begun at Eddystone, Unit 1, and it is to be in compliance by March 1, 1975. On or before June 1, 1975, the company is to submit an evaluation of the performance of the system to the Environmental Protection Agency.

During the second phase of the schedule, the company is to initiate design procedures for installation of the additional flue-gas desulfurization systems required at Eddystone, Unit 1, and for sulfur oxide and particulate control systems for Eddystone, Unit 2, and Cromby, Unit 1. Detailed plans of these systems are to be submitted to the Environmental Protection Agency by August 15, 1975. The company is to place purchase orders or contracts for major component parts of the phase-two control equipment by September 15, 1975. The company is to operate Eddystone, Units 1 and 2, and Cromby, Unit 1, in compliance by May 1, 1978. Provisions are included for reducing the impact on air quality of these plants during episodes of high air pollution and for periodically reporting to the Environmental Protection Agency on the progress being made in meeting the compliance plan. The Agency believes that this agreement adequately assures achievement of air quality goals while taking into account the practical considerations of installing flue-gas desulfurization systems.

If State Implementation Plan requirements for particular plants are more stringent than required to meet the primary standards for sulfur dioxide, it is the Agency's policy generally to include schedules in enforcement orders that allow for more time at the beginning of the schedule than is given to plants that contribute to concentrations in excess of the standards. This allows States time to consider revising their implementation plans and helps assure, as well, that priority plants can get low-sulfur coal or flue-gas desulfurization systems.

The Environmental Protection Agency believes that this approach is adequate at the present time for dealing with compliance problems arising out of delays in obtaining flue-gas desulfurization equipment. At the present time the capacity of scrubber vendors to supply control equipment generally exceeds the demand for these systems by the utility industry and the Environmental Protection Agency believes that there is no need to restrict orders for new systems by establishing a rigid system of priorities. Even with an increase in enforcement activities, it is the judgment of the Agency that a reversal of this situation in the near future is unlikely, especially since over half of the power plants identified by the Agency for priority enforcement actions are involved in litigation challenging the Agency's approval of applicable State Implementation Plans, or are under State Implementation Plans that are being revised, thereby hampering the Agency's ability to initiate enforcement actions.

The situation obviously could change in the longer run, however, as these particular enforcement impediments are resolved and also as new power plants become operational; but probably the greatest factor that will cause an increased demand for flue-gas desulfurization equipment is the number of plants mandated to convert from petroleum products or natural gas pursuant to Section 2 of the Energy Supply and Environmental Coordination Act. Since no conversion orders have been issued to date, the effect of this Act on availability of flue-gas desulfurization equipment is not yet clear. However, flue-gas desulfurization could be required on perhaps as much as 10,000 to 15,000 megawatts of capacity if these plants converted back to coal.

In assuring that these plants achieve compliance in accordance with the requirements of Section 119(c) of the Clean Air Act, the Environmental Protection Agency has authority pursuant to Section 119(e) to establish priorities under which manufacturers of continuous emission-reduction systems would be required to provide such systems first to plants in Air Quality Control Regions in which the national primary ambient air quality standards have not yet been achieved. This authority is to be used only if it is found to be necessary in carrying out the requirements of Section 119(c). The Environmental Protection Agency considers the use of such allocation authority as highly undesirable because it causes serious dislocations in the control system market and, therefore, the Agency will not use this authority unless it is absolutely clear that there are no other alternatives. There are a number of ways in which the authority under this Section could be implemented should the need arise. At one extreme, the Agency could designate by rule specific Air Quality Control Regions that would receive priority for obtaining flue-gas desulfurization systems. Control system manufacturers would then be prohibited from selling such systems to all other existing plants until the control needs of plants within these priority Regions were satisfied. In order to prevent such a priority designation from blocking attainment of primary standards in Air Quality Control Regions not affected by implementation of Section 2 of the Energy Supply and Environmental Coordination Act, the Agency would also have to designate the Regions containing power plants that are already on coal and that contribute concentrations in excess of primary standards. This massive Federal intervention into relationships between control system manufacturers and utilities is the least acceptable approach to achieving compliance since it would severely restrict the market for flue-gas desulfurization systems and thus would destroy the manufacturer's incentive to advance the technology.

A more acceptable but still undesirable approach would be to give priority to plants on a case-by-case basis upon receipt by the Environmental Protection Agency of a request from a utility for such a designation. Utilities would not be eligible to apply for such priority designation before demonstrating good faith in attempting to procure appropriate control systems on their own. While this approach would not be as restrictive as that of designating priority Air Quality Control Regions in anticipation of control-system shortages, the Agency still considers this to be an excessive measure that is to be used only after all alternatives have failed.

It is important to recognize that any priority-setting system would be extremely difficult to implement for three reasons. The first is the difficulty of developing a plant-by-plant priority list. Second, neither the Environmental Protection Agency nor the State environmental agencies have any direct control over the demand for flue-gas desulfurization systems. Under the Clean Air Act, all polluting sources are allowed to choose the most cost-effective way to comply with emission limitations. Although it can take enforcement action, the Environmental Protection Agency cannot dictate the method of compliance. It is difficult to see how an allocation authority, which controls only the supply of flue-gas desulfurization equipment and not the demand for such control equipment, would work. Finally, allocating control equipment is quite different from allocating oil. Fuel oil is a fairly homogeneous product, whereas flue-gas desulfurization systems can be differentiated by types of process, cost, vendor sources, and reliability. How would an allocation scheme that allowed utilities the choice of vendor ensure equity among the dozen suppliers of flue-gas desulfurization systems? For example, will one vendor who can supply flue-gas desulfurization equipment in 1977 object when a utility is assigned a different vendor to install a system in 1979? These are only illustrative examples of the complexities involved in invoking the priority-setting authority granted to the Environmental Protection Agency under the Energy Supply and Environmental Coordination Act.

At the present time, therefore, the Environmental Protection Agency does not anticipate using the authority granted in Section 119(e) of the Clean Air Act and has not developed regulations for its implementation. If it becomes clear, as the provisions of the Energy Supply and Environmental Coordination Act are carried out, that some form of a priority-setting procedure is required, the Environmental Protection Agency will provide ample notification of its intentions to use this authority well in advance of actually initiating such procedures.

## TECHNICAL APPENDIX A: STATUS OF LOW- AND INTERMEDIATE-Btu RESIDUAL OIL AND COAL GASIFICATION SYSTEMS

The status of low- and intermediate-Btu coal gasification systems as of mid-1974 is given in this appendix. Eight types of process are covered: (1) moving bed/dry ash, (2) moving bed/slagging, (3) fluid bed/dry ash, (4) fluidized bed/agglomerating ash, (5) entrained flow, (6) entrained flow/slagging, (7) molten bath, and (8) underground gasification. Paragraph headings indicate the developer of the system and, in parentheses, the current status of the system.

### MOVING BED/DRY ASH

Lurgi (Commercially Available)--Because the maximum size of the gasifier is limited, several gasifier units must be operated in parallel. Older models accepted only noncaking coals, but a modified version has been tested successfully with caking coals.

Wellman-Galusha (Commercially Available)--The standard gasifier accepts only anthracite or coke, but an agitator model that also accepts bituminous coal is available.

U.S. Bureau of Mines (Operational, Pilot)--A 1200-lb/hr pilot developmental unit is in operation in Morgantown, W. Va. The Office of Coal Research and the Tennessee Valley Authority plan to install two or more commercial-size gasifiers designed on the basis of this unit. Tests indicate that it can accept strongly caking coals.

Gegas/General Electric (Operational and Design, Pilot)--A 50-lb/hr unit has been in operation since 1971, and a 1200-lb/hr pilot developmental unit is in the design stage. General Electric hopes to develop a unique coal extrusion process for feeding coal to the gasifier, and is also developing membrane systems for gas clean-up. The process will be used to produce low-Btu gas for power plants.

Kellogg (Under Construction, Pilot)--A 4-ton/hr pilot should be operational in mid-1975 in Houston, Texas.

### MOVING BED/SLAGGING

Thyssen-Galocsy (Defunct, Pilot)--A 40-ton/day pilot plant was operated in Germany in 1943-1944. Work was interrupted by World War II and not resumed.

### FLUID BED/DRY ASH

Winkler (Commercially Available)--Atmospheric pressure processes in commercial use for some time. System is being modified by Davy Powergas for high-pressure operation.

Synthane/U.S. Bureau of Mines (Under Construction, Pilot)--Construction of this 3-ton/hr pilot unit in Bruceton, Pa., is expected to be completed in January 1975. Studies with a 40-lb/hr gasifier indicate the process can accept any U.S. coal.

$CO_2$ Acceptor/Consolidated Coal (Operational, Pilot)--A 1.5-ton/hr pilot unit has been in operation since 1972 in Rapid City, S.D. It can only accept lignite and subbituminous coal. Problems with refractory failure and plugging of acceptor lines experienced during startup seem to be solved.

Exxon Oil Company (Under Construction, Pilot)--This 20-ton/hr pilot, under construction in Baytown, Texas, will be used to produce intermediate-Btu gas for upgrading to synthetic natural gas.

Hydrocarbons Research, Inc. (Commercially Available)--This 10-ton/day unit was first operated in 1958 in Trenton, N.J., with anthracite. It was modified in 1972 to accept bituminous coal.

COGAS/Cogas Development Company (Operational, Pilots)--A 4-ton/hr pilot has been in operation since March 1974 in Leatherhead, England, and a 400-lb/hr pilot has been in operation since May 1974 in Plainsboro, N.J. The process will be used to produce intermediate-Btu gas for upgrading to synthetic natural gas.

Bituminous Coal Research (Developmental, Bench Scale and Pilot)--A $2,575,000, 50-month contract with the Office of Coal Research covers bench-scale and pilot experimental development unit work that will provide the basis for design of a pilot plant. The process will be used to produce low-Btu gas for power plants.

FLUIDIZED BED/AGGLOMERATING ASH

U-Gas/IGT (Design, Pilot)--Funds are being sought for construction of the 10-ton/hr pilot plant that has been designed. Present studies are being made with a 4-foot-diameter gasifier. The primary purpose of the process is to provide low-Btu gas for power plants.

Westinghouse (Under Construction, Pilot)--A 1200-lb/hr pilot developmental unit is mechanically complete in Waltz Mill, Pa. First hot tests were expected in January 1975. If significant success is achieved with this unit, a decision could be made to go directly to a full-size pilot integrated with a combined cycle plant (120 MW).

Battelle-Union Carbide (Under Construction, Pilot)--A 1200-lb/hr pilot developmental unit was expected to be completed in the first quarter of 1975 in West Jefferson, Ohio.

ENTRAINED FLOW

Bigas/Bituminous Coal Research (Under Construction, Pilot)--This 5-ton/hr pilot is expected to be completed in early 1975 in Homer City, Pa.

Combustion Engineering (Design, Pilot)--A contract is presently being negotiated for construction of a 5-ton/hr pilot. Very little information is available at this time. Process will be used to produce low-Btu fuel for power plants.

Foster-Wheeler (Design, Pilot)--Construction of this 50-ton/hr pilot was scheduled to begin in the fourth quarter of 1974. In phase I, the pilot will provide low-Btu gas for modified existing boilers. In phase II (early 1978), the gas will fuel a combined cycle plant.

Garret Flash Pyrolysis/Garret Research and Development Company (Proposed, Pilot; Operational, Bench Scale)--Support is being sought for a 10-ton/hr pilot plant. A bench-scale unit (50 lb/hr) has been in operation since January 1973.

ENTRAINED FLOW/SLAGGING

Koppers-Totzek (Commercially Available)--There are many commercial installations in Europe and Asia.

Texaco Oil Company (Defunct)--Texaco has had previous pilot plant experience with this process, and a semicommercial unit was in operation for a number of years.

Babcock and Wilcox-DuPont (Defunct)--A 17-ton/hr commercial unit was operated for about 1 year in the early fifties by DuPont at Belle, W.Va. The unit has since been dismantled.

MOLTEN BATH

Applied Technology Corp. (Operational, Bench Scale)--Studies with a molten iron bath have involved a 25-inch-inside-diameter induction furnace to simulate the gasifier (4000-lb capacity).

M. W. Kellogg Company (Operational, Bench Scale)--A pilot developmental unit employing molten salt is planned and preliminary flow sheets and cost estimates have been made.

Atomics International (Bench Scale)--This process, also employing molten salt, will be used to produce low-Btu fuel for power plants.

UNDERGROUND GASIFICATION

Pilot-scale tests of this process are being conducted in Hanna, Wyo.

# TECHNICAL APPENDIX B: OPERATING SUMMARY FOR FLUE-GAS DESULFURIZATION SYSTEMS

This appendix presents a summary of the operational history of flue-gas desulfurization (FGD) systems through October 1974. Paragraph headings indicate utility and unit names and, in parentheses, unit capacity. Unless otherwise specified, the units are coal-fired.

Arizona Public Service, Cholla No. 1 (115 MW)--Since startup in October 1973, the FGD system availability has been consistently above 90 percent. There have been a few mechanical problems, the most persistent being vibration in the reheater section.

Boston Edison, Mystic No. 6 (150 MW, oil)--For 1973, reported scrubber availability ranged from 73 percent in August to 13 percent in December. The decreasing availability was due to deterioration and subsequent overhaul of the process equipment. Recent (1974) availability figures are: March, 87 percent; April, 81 percent; May, 57 percent; and June, 80 percent. This system has been down, with no immediate plans for restarting, since the EPA demonstration program was completed. Boston Edison is evaluating the data collected during the demonstration period to determine the course of future action.

Commonwealth Edison, Will County No. 1 (167 MW)--Availability of Module A has increased in the past several months. It was 72 percent in April, 93 percent in May, 54 percent in June, 95 percent in July, 91 percent in August, and 85 percent in September. Module B has been removed from service until all necessary modifications are made to Module A to permit reliable operation.

Duquesne Light, Phillips Section (410 MW)--At present, only flue gas from Boilers 2, 3, and 4 (about 40 percent of the station capacity) is treated because fly ash from the inefficient precipitators overloads the clarifiers. Operating hours for Modules 1 through 4 between March 17 and June 30, 1974 were 1756, 762, 815, and 1707, respectively. The plant tries to run Modules 1 and 4 continuously. The outage hours for these units is primarily for inspections.

General Motors, Parma Plant (32 MW)--System availability has been essentially 100 percent since April 1974. However, the availability figure has little meaning since only two of the four modules were operating at any time because of low demand.

Illinois Power, Wood River (110 MW)--The unit operated only 700 hours during the past 2 years. Primary reason for the downtime was the delay in converting the reheaters from natural gas to fuel oil firing. The unit was scheduled to restart in late November 1974.

Kansas City Power and Light, Hawthorn No. 3 (140 MW)--The FGD system has undergone several major modifications. Availability has since increased from 30 percent in 1973 to as high as 70 percent recently. Plant operators were on strike between July and October 1, 1974, and during that time the FGD system was down. The system was restarted on October 1st.

Kansas City Power and Light, Hawthorn No. 4 (110 MW)--This unit was converted from furnace injection to tail-end scrubbing. The plant has experienced more problems with this unit (both mechanical and chemical in nature) than with Unit 3. The operation can be characterized as "fair."

Kansas City Power and Light, LaCygne (820 MW)--Initial problems included fan deposits, demister and nozzle plugging, reheater failure, and screen plugging. Many of the original problems were attributed to poor pH control. Recently the unit has had about 80 percent availability and there are no outstanding problems. However, it is necessary to remove each module from service once a week to clean out accumulated solids.

Kansas City Power and Light, Lawrence No. 4 (125 MW)--The system has undergone a number of process modifications. At present, the system is capable of sustained operation, although sulfur dioxide removal efficiency is limited to only 75 percent and the demisters must be washed daily (automatic washing). Manual washing of the demisters is required every 2 weeks. The unit is badly corroded and will be replaced by a new electrostatic precipitator and FGD system in 1977.

Kansas City Power and Light, Lawrence No. 5 (400 MW)--This unit has encountered many of the same process problems as Unit 4. In addition, there is poor gas flow distribution between the eight modules and within each module; measures are being taken to correct the distribution. The boiler burns natural gas whenever it is available, so it is difficult to assess FGD system availability.

Louisville Gas and Electric, Paddy's Run (65 MW)--FGD system availability is near 100 percent. However, since the system is installed on a peaking boiler there are many occasions when the boiler's run is too short to justify startup of the FGD system.

Southern California Edison, Mohave No. 2 (160 MW)--This is an experimental unit. It has operated quite successfully with an availability above 80 percent.

Nevada Power, Reid Gardner No. 1 and No. 2 (125 MW each)--These two FGD systems started up in March 1974 and have had an availability of over 90 percent when there was sufficient trona (impure form of sodium carbonate). The lack of trona has limited the operation of the units. Each system has operated only 900 hours since April 1974.

Potomac Electric and Power, Dickerson No. 3 (100 MW)--There is no record of the FGD system's availability for the period prior to August 1974 since the unit was down frequently for process modification, equipment repairs, etc. Availability since August is about 34 percent.