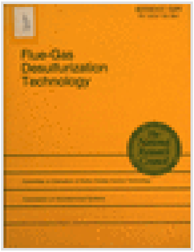

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Prepared by the
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NOTICE

The project that is the subject of this report was approved by the Governing Board of the National Research Council, whose members are drawn from the Councils of the National Academy of Sciences, the National Academy of Engineering, and the Institute of Medicine. The members of the committee responsible for the report were chosen for their special competences and with regard for appropriate balance.

This report has been reviewed by a group other than the authors according to procedures approved by a Report Review Committee consisting of members of the National Academy of Sciences, the National Academy of Engineering, and the Institute of Medicine.

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CHAPTER 1

SUMMARY, CONCLUSIONS, AND RECOMMENDATIONS

SUMMARY

The Clean Air Act Amendments of 1977 include a number of regulations relating to the emission of sulfur oxides, which, because of a dearth of available low-sulfur fuels, require technological methods of emission control.

This study considers the sources of sulfur oxides in the United States as well as the changes expected in the future as a result of the changing energy supply. It examines the available methods for abating sulfur oxides emissions. Because flue-gas desulfurization (FGD) is the only alternative likely to be generally available in the coming decade, the report concentrates on that process. The various scrubbing systems are examined, particularly with regard to commercial experience, side effects, and costs. The costs of alternative FGD systems are assessed, and steps are recommended to enhance the timely development of new and improved commercial systems.

CONCLUSIONS

1. Current U.S. annual sulfur oxide emissions, estimated at 30 million tons per year, are reported to cause adverse environmental effects (see Ref. 5, Chap. 2). The combustion of coal accounts for two-thirds of these emissions. The remaining third is accounted for by the burning of residual oil in utility and industrial boilers, the smelting of nonferrous ores, and other industrial processes.

2. Slightly over half of the U.S. sulfur oxides emissions are generated by electric utilities burning coal. Without controls the projected large increase in coal-burning units would result in a significant increase in emissions, but implementation of present new source performance standards (NSPS) should prevent this increase.

Projected sulfur oxides emissions from nonutility coal-burning boilers will also increase substantially. These sources now represent 5 to 7 percent of U.S. sulfur oxides emissions. Emissions from other sources are not expected to increase significantly.

3. There are technologies other than FGD under development that may offer options for emission control, but they are unlikely to be deployed rapidly enough to obviate the need for FGD in the predictable future.

4. The dominant commercial FGD process is nonregenerable lime/limestone slurry scrubbing. There are over 40 full-scale sulfur oxides scrubbing systems of this type presently in operation on utility boilers in the United States.

5. Although a number of regenerable processes have been investigated on a bench and pilot scale, only two (Wellman-Lord and magnesium oxide) are commercially available. Spray drying FGD technology has recently moved from pilot plant to commercial availability.

6. Reported and projected capital costs for all FGD processes vary from about $40 to $190 per kilowatt (kW), and corresponding FGD revenue requirements vary from 3 to 15 mills/kWh (kilowatt hour). The capital cost at July 1978 prices for a hypothetical limestone slurry scrubber removing 85 percent of the sulfur dioxide (SO_2), to be completed in mid-1980, is estimated to vary from $120/kW for low-sulfur coal to $150/kW for high-sulfur (>2.5 percent S) coal. Corresponding FGD revenue requirements are 8 and 15 mills/kWh. Estimated costs for regenerable processes are similar, but estimated costs for a spray dryer system, not yet commercially tested, are considerably lower.

7. The use of flue-gas scrubbers and other control technologies causes some secondary environmental impacts. Limestone scrubbers cause a boiler derating of up to 5 percent and, depending on plant design, may increase potential emissions of other pollutants. Limestone scrubbers also produce solid wastes in amounts generally less than the amount of ash from the coal. The total land requirement for disposal in ponds or dry impoundments is not significant nationally but may be so locally. Impacts on water need not be serious.

8. A number of lime/limestone scrubbers have been operated successfully on boilers burning low-sulfur (<2.5 percent S) coal over an extended period in the United States, thus meeting the criterion proposed by the National Academy of Sciences in 1970 (see Ref. 3, Chap. 2) for a full-scale demonstration of scrubbing.

Although the successful performance (as measured in terms of availability, operability, or reliability) of two scrubbers on high-sulfur coal offers encouragement for the future, the median performance factor of 60 percent for scrubbers operating on high-sulfur coals in 1978 cannot be considered satisfactory.

Unsatisfactory performance may be inherent in the designs or may be due to improper operation, but it is not possible at this time to separate the two causes.

The assessment of the status of FGD has been complicated by unavailability of enough reliable data from operational systems.

9. Supply factors are not deemed likely to limit the rate of application of scrubbers.

RECOMMENDATIONS

1. The highest priority should be given to improving the reliability of FGD systems for application to high-sulfur coals.

It is imperative that the causes of the unsatisfactory performance of the majority of the scrubbing systems using high-sulfur coal be determined. Such an effort might include a training program for scrubber personnel at the existing plants, trouble-shooting visits, and visits by inspection teams. The results of this program would determine future directions of applications, research, and development. An important goal of this activity should be improved future documentation of performance of all presently operating units.

2. Commercial development of spray drying (dry scrubbing) should continue to be pursued, especially for systems using low-sulfur fuels. The government could contribute by supporting research to provide a firm scientific understanding of the process. Government funds to increase the rate of development of spray drying for boilers using high-sulfur coal can be justified because the possible cost savings may be large.

3. Further development of one, or at the most two, reliable regenerable FGD systems should be pursued both for insurance against high costs for reliable disposable systems using high-sulfur coals and to increase the options available. Attention also should be paid to alternatives, such as fluidized bed combustion or spray drying, that may make second-generation wet-scrubbing systems unnecessary.

CHAPTER 2

INTRODUCTION

AIR POLLUTION AND SULFUR OXIDES

The earliest concerns about air pollution both in the United States and abroad centered about the visible pollutants--smoke and particulates--whose adverse impacts could be observed easily. However, as early as the mid-1930s, sulfur oxides were regarded as undesirable pollutants, and attempts were made to reduce emissions from several power plants in London. The flue gases were scrubbed with alkaline Thames River water in order to improve air quality in and around that city. By the 1950s, several research programs in the United States and Europe had been initiated directed toward devising improved methods for removal of sulfur oxides by flue-gas desulfurization (FGD), or stack scrubbing, including research on regenerable processes.[1] [2]

The rapid expansion in energy demand that occurred starting about 1950 greatly increased the amount of all air pollutants resulting from fuel combustion, and in the 1960s there was renewed interest in stack-gas desulfurization because of environmental concerns in the United States and Japan. The pollutants of concern were particulates, sulfur and nitrogen oxides, carbon monoxide, organic compounds, and trace metals. Because of the increasing concentration of pollutants in the atmosphere in the United States, the Air Quality Act of 1967 became law. Its aim was to set emission limitations on those pollutants--particulates and sulfur and nitrogen oxides--for which adequate information was believed to be available for standards to be set. As a result, in the early 1970s, important applications of FGD for sulfur oxide controls were initiated in the United States.

Because of the widespread occurrence of particulates and sulfur oxides and the large quantities emitted, their control has received the greatest attention by far. Technology for particulate reduction to the levels prescribed in the 1970 Clean Air Act was available when the Act became effective. Methods for the control of sulfur oxides were not so well advanced, and a variety of methods were tested or used to meet the sulfur oxides emission regulations. These included a shift to low-sulfur fuels, precombustion treatment of fuels to reduce the sulfur content to the levels required to meet emission standards, removal of sulfur oxides during combustion, the use of tall stacks to increase dispersion, and postcombustion FGD using a wide variety of processes.

Whereas a large number of FGD processes have been proposed, and a considerable number tested (see Chap. 4), nearly all commercial installations to date have used either lime or limestone as the scrubbing agent. These processes produce a solid waste that must be disposed of. Several other types of commercial FGD processes have been installed that use a mixture of lime and an alkaline compound, such as fly ash, sodium carbonate, magnesium oxide (MgO), or sodium sulfite (Wellman-Lord). The Wellman-Lord and MgO processes produce saleable products, whereas the others create a solid waste that must be disposed of.

Because of the importance of sulfur oxides control, the lack of commercial experience with the control technology, and sharp disagreement over the degree of control needed and the adequacy and reliability of the processes actually being used, the National Academy of Sciences has been involved in a number of studies of sulfur oxides and technology for their control.[3-5] The present study brings up to date the status of sulfur oxides control technology--a matter that has become of much greater concern because of the provisions of the Clean Air Act Amendments of 1977 that require use of continuous emission controls in coal-fired power plants and establishment of revised and more stringent new source performance standards (NSPS).

ENVIRONMENTAL CONSIDERATIONS OF SULFUR OXIDES EMISSIONS

Fuel combustion for steam and electric power generation may result in significant emission of particulates, sulfur oxides, and nitrogen oxides. This report concerns sulfur oxides from combustion, which are primarily sulfur dioxide (SO_2) with 1 to 2 percent sulfur trioxide (SO_3) present.

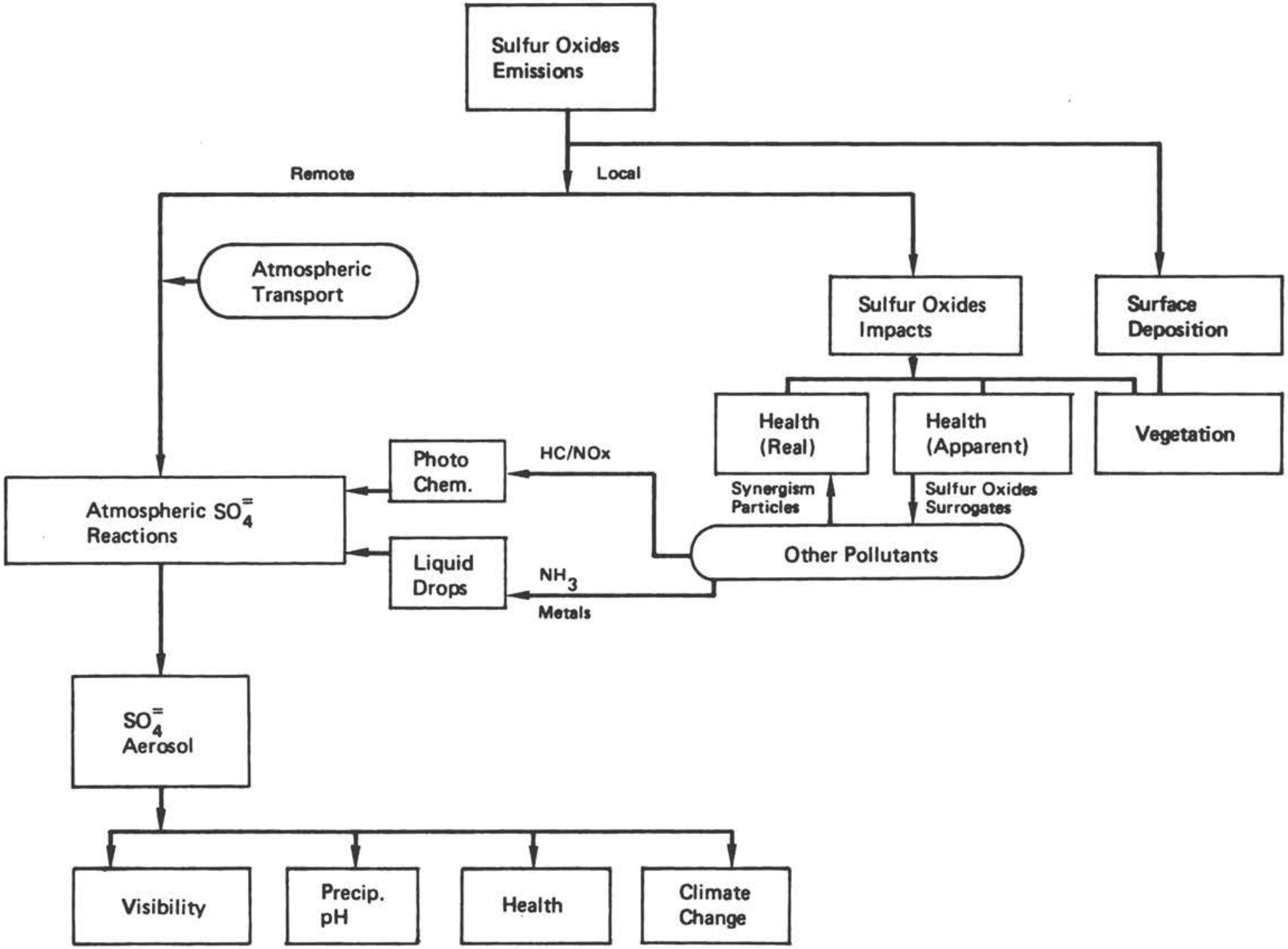
Control of sulfur oxides emissions is warranted because there can be effects from these emissions on the atmosphere both locally and at distances up to several hundred miles. That sulfur oxides can harm the environment when they occur in sufficient quantities has been known for decades in the United States and elsewhere around the world. In part, as a result of the hazards that have been linked to excessive emissions, the first National Ambient Air Quality Criteria issued under the Air Quality Act of 1967 dealt with sulfur oxides. Since the first criteria document was issued in 1969, there has been a considerable increase in knowledge about sulfur oxides as air pollutants. Most important, it is now recognized[5] that there is a family of sulfur compounds, not just SO_2 alone, that must be considered as pollutants.

Figure 2-1 shows the important aspects of the sulfur oxides pollutant system as it is now understood. On the right side of Figure 2-1 are shown the local impacts of sulfur oxide (primarily SO_2) emissions that have been recognized widely for many years. These impacts include health effects and vegetation damage. Health effects in this schematic system are classed as "real" and "apparent." The real effects, sometimes with synergistic assistance from other pollutants, have been widely discussed (e.g., see Ferris[6]). Some of the health effects listed by Ferris and attributed to combined effects of sulfur dioxide and total suspended particles include increased respiratory symptoms in chronic-bronchitis patients and an increase in attacks sustained by asthmatics. Figure 2-1 also shows "apparent" health effects linked to "other pollutants" and a surrogate role for atmospheric sulfur oxides (primarily SO_2) concentrations. This surrogate role is assigned to sulfur oxides because it is difficult to define a single causative agent in a mixture as complex as the urban-pollutant mixture. Sulfur dioxide concentrations have been measured for many years, and, because emissions have been widespread in urban areas, the concentrations have served as a good index of general urban pollutant levels; thus it is not surprising that SO_2 concentrations could be linked to health effects in a surrogate fashion when other harmful pollutants were not identified. Buechley[7] (as quoted by Ferris[6]) used the surrogate concept in discussing mortality studies and SO_2 in the greater New York area.

Vegetation damage from sulfur oxides has been widely recognized in the United States for more than 75 years and still occurs around major emission sources. Figure 2-1 links vegetation to emission through a process of surface deposition in recognition of the mechanism by which sulfur oxides can reach vegetation and the ground surface. This surface deposition phase, sometimes called dry deposition, is being studied in more detail, and it appears that half or more of the SO_2 emitted from a tall stack may be deposited on or absorbed by vegetation or the soil.[8] The fact that this scavenging process is likely to be such a major factor in the total pollutant-sulfur cycle was not widely recognized until extensive power-plant plume studies and transport model calculations were carried out in the mid-1970s.

The left side of Figure 2-1 shows a phase of the pollutant-sulfur cycle that is now recognized as being much more important than it was when the first sulfur oxides criteria document was issued in 1969. This phase is the long-distance atmospheric transport of sulfur oxides during

Figure 2-1. The sulfur oxides pollutant system.



which atmospheric chemical reactions take place to produce a plume dominated by sulfate (SO_4=) aerosol particles rather than by SO_2. This phase of the sulfur-emission cycle has attracted attention because of occurrences of acid rainfall. The Scandinavian acid rain problem is a widely known aspect of long-distance sulfur transport and atmospheric reaction.

In the long-range transport phase there are at least two chemical reactions that are active in the conversion of SO_2 to SO_4=. The liquid droplet process was the first recognized and involves the absorption of SO_2 and NH_3 into fog or cloud droplets where, with catalytic assistance of a metal ion such as iron or manganese, SO_2 is oxidized and then reacts to form ammonium sulfate. The second process is the SO_2 photochemical reaction; it was identified in more recent research on photochemical smog aerosols, which showed that even trace concentrations of SO_2 could enhance the production of smog aerosols. Further study has shown that sulfuric acid is a common product of photochemical or sunlight-driven reactions involving hydrocarbons, nitrogen oxides, and SO_2--all common constituents of urban air pollution. Research has also shown that both ammonium sulfate and sulfuric acid aerosol particles can be identified as components of the atmospheric particulate mass.[5]

The impact of SO_4= aerosols, shown in the lower left portion of Figure 2-1, includes visibility reduction, precipitation acidity (pH), health effects, and potential climate change. Damage to materials from acid corrosion might also be included. Effects on visibility caused by small particles are well documented, and some studies have shown that one-third or more of the particles in the size range of interest are sulfur compounds. Sulfur compounds would thus be expected to have a generally proportionate role in causing any restricted visibility problem in urban areas. Precipitation pH has received considerable attention because effects can occur at downwind distances of hundreds of miles and, in ecologically sensitive areas, important changes in the environment can result. Scandinavia and the northeastern United States are two regions with significant sulfur oxides emissions in sectors upwind from sensitive ecological systems, and there has been widespread and well-publicized discussion of acid rain problems in these areas.[5] Ecological problems caused by precipitation pH may also occur in other areas even though the effects are not so dramatic as in the more sensitive areas.

Health effects from sulfates or sulfuric acid concentrations at levels that might be encountered in the ambient atmosphere must be considered as speculative on the basis of Ferris's summary.[6] There are also little or no adequate concentration or exposure data on which to base an assessment of SO_4= health effects.[5]

The possibility of climate change from sulfur-compound aerosols also depends on the light-scattering effects of these particles and the possible cooling that might occur from high concentrations of these compounds in the future.[9]

In summary, sulfur oxides control programs have traditionally been based on local effects of vegetation damage and postulated health effects. Research evidence, mainly developed since 1970, shows that important pollutant impacts from sulfur oxides emissions can also occur after the atmospheric transport of these materials for many hundreds of miles or several days. This long-range transport poses new considerations for sulfur oxides emission control programs and regulatory agencies.

SULFUR OXIDES AND FEDERAL REGULATIONS

The Clean Air Act Amendments of 1977 include a number of regulations relating either directly or indirectly to the emission of sulfur oxides and other pollutants. Various major provisions of the act include national ambient air quality standards, performance standards for new or modified stationary sources (NSPS), prevention of significant air quality deterioration in areas cleaner than required by federal standards, and methods for cleaning up nonattainment areas.

National Standards

An ambient-air-quality standard establishes the minimum safe concentration of a pollutant in the general air. The 1977 Amendments specified that all areas of the country must meet primary health standards for sulfur oxides by the end of 1982. Secondary standards for protecting general welfare are to be met in a "reasonable" time period.

New Source Performance Standards

On June 11, 1979, the Environmental Protection Agency (EPA) established national performance standards (i.e., maximum allowable pollutant emissions) for new or substantially modified electric utility generating units that have a heat input of 250 million Btu/hour or more. For other stationary sources, which include smaller power plants, ore smelters, cement plants, and oil refineries, performance standards must be set by 1982 for all currently unregulated major source categories. The law requires that all major stationary sources use the best available control technology (BACT) to reduce emissions substantially.

In one particular case--that of coal-fired power plants--the law narrowly defines BACT as the best continuous emission control available. A controversy had arisen before 1970 over the use of dispersion methods (such as tall stacks and cutbacks in operation during adverse weather conditions) instead of emission reduction technology. The 1977 Amendments reaffirmed that dispersion methods alone cannot be used as final compliance measures.

The 1979 regulations for new or substantially modified utility power plants require that emissions for solids or solid-derived fuels (except solvent-refined coal) be limited to 1.2 pounds of SO_2 per million Btu of heat input; a 90 percent reduction is required, except when emissions are less than 0.6 pound of SO_2 per million Btu of input. When SO_2 emissions are less than 0.6 pound per million Btu, a 70 percent reduction in potential emissions is required.

The percentage reduction requirement is to be determined on a continuous basis and will refer to a 30-day rolling average. The percentage reduction is computed on the basis of overall SO_2 removal, including precombustion treatment and removal of sulfur in the ash.

For gaseous and liquid fuels (not derived from solid fuels) the limits for SO_2 emissions are 0.8 pound per million Btu of heat input and 90 percent reduction in potential emissions. The reduction requirement does not apply if SO_2 emissions are less than 0.2 pound of SO_2 per million Btu of heat input.

Anthracite coal is exempt from the percentage reduction requirement but is subject to the maximum emission rate of 1.2 pounds of SO_2 per million Btu of heat input. Other exemptions of various kinds apply to facilities in noncontinental U.S. areas and to resource-recovery facilities.

Solvent-refined coal is subject to the emission limit of 1.2 pounds of SO_2 per million Btu of heat input but requires only an 85 percent removal of SO_2 on a 24-hour/day basis. Commercial demonstration plants of solvent-refined coal will be permitted an 80 percent removal requirement.

Prevention of Significant Deterioration

The 1977 Amendments specified that sulfur oxide emissions cannot cause an increase over the baseline concentration of sulfur oxides in air in which the air is cleaner than the ambient standards. There is a system of maximum allowable increases, with the smallest increase allowed in Class I areas, more in Class II, and the most in Class III; however, no area may exceed the national ambient standards. Mandatory Class I areas include those international parks, national memorial parks, national wilderness areas greater than 5,000 acres, and national parks of more than 6,000 acres in existence at the time of the legislation. All other areas are initially designated Class II. Certain federal areas may be redesignated Class I; states have the authority either to upgrade other areas to Class I or to downgrade them to Class III. However, certain federal areas of 10,000 acres or more may not be redesignated as Class III.

The law does not rule out growth in cleaner-than-standard areas but requires major new sources to get a preconstruction permit, for which a modeling study must be carried out at the applicant's expense showing the projected impact of the new-source emissions on the air quality of the area.

Nonattainment Areas

For areas where ambient air quality exceeds the standards, the 1977 Amendments provide for an offset policy. Before new sources of emissions are permitted, action must be taken to more than offset the new emissions by reducing existing ones. The objective is to continue reducing a nonattainment area's emissions until standards are achieved but to allow some growth of less-polluting industries in the interim.

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CHAPTER 3

SOURCES OF SULFUR OXIDES EMISSIONS AND THEIR CONTROL

SOURCES OF SULFUR OXIDES EMISSIONS

The total output of sulfur oxides (primarily SO_2) emissions in the United States has been estimated at about 30 million tons per year for recent years (Table 3-1).[1] [2] Most sulfur oxides pollution is produced by the burning of sulfur-bearing fossil fuels (coal and residual oil) and by the processing of sulfur-bearing minerals to recover nonferrous metals. Other sulfur oxides pollution sources include a variety of processes that are unimportant as far as total uncontrolled sulfur oxides pollution is concerned. Most are small-volume emitters, such as sulfuric acid plants and sulfur recovery units in refineries, and are controllable by using available control technology.

Combustion of Coal in Boilers

Coal is burned in electric utility boilers, in industrial boilers generating electricity or process steam, and in industrial or commercial boilers used to heat water or raise steam for space heating. The balance of the coal used is for steelmaking, for direct process heat in cement and lime kilns, and for other miscellaneous uses not important nationally from the standpoint of sulfur oxides pollution.

Boilers consumed over 430 million tons (the equivalent of 10.0×10^{15} Btu) of the 592 million tons of coal shipped for use within the United States in 1975.[3] This represents about 44 percent of the fuel used annually for boiler firing. The balance comes from gas (32 percent), residual oil (19 percent), distillate oil (about 5 percent), and small amounts of other fuels that are mainly waste products. Table 3-2 gives data for coal-fired boilers, showing consuming sector, estimates for fuel consumption, and estimates for sulfur oxides emissions for each class.

Table 3-1. Estimated annual emissions of sulfur oxides in the United States.

Source	Sulfur Oxides (10^6 tons/year)
Combustion of coal in boilers	18-20
Combustion of residual oil in boilers	3-4
Smelting of nonferrous ores	2-3
Other industrial processes	1-2

Table 3-2. Fuel consumption and sulfur oxides emissions for coal-fired boilers in the United States (1975).

Consuming Sector	Estimated Number of Units	Annual Coal Consumption (10^{15} Btu)	Estimated Sulfur Oxides Emissions (10^6 tons/year)
Utility	1,500	9.31	16.3
Industrial-commercial	150,000 to 200,000	1.10	1.8

Table 3-3. Fuel consumption and sulfur oxides emissions for residual-oil-fired boilers in the United States (1975).

Consuming Sector	Estimated Number of Units	Annual Residual-Oil Consumption (10^{15} Btu)	Estimated Sulfur Oxides Emissions (10^6 tons/year)
Utility	1,000	2.50	1.5
Industrial-commercial	300,000 to 400,000	1.76	1.3

Combustion of Residual Oil in Boilers

Residual oil is utilized for the same applications as coal. Boilers fired with residual oil consume 4.3 × 10^{15} Btu/year compared with 10.0 × 10^{15} Btu/year in coal-fired boilers. Almost 80 percent of the estimated 895 million barrels of residual oil consumed in 1975 was fired in boilers.[4] The remainder was used for direct process heat, fuel for seagoing ships, and miscellaneous purposes. Table 3-3 gives statistics for residual-oil-fired boilers to compare with Table 3-2 for coal-fired boilers. Although coal- and oil-fired boilers are used in the same applications, they have distinctly different patterns with respect to the size and number of units. The significance of these differences is discussed further in the section of this chapter on the nature of the sulfur oxides problem.

Smelting of Nonferrous Ores

Sulfur oxides emissions from the smelting of nonferrous ores come mainly from the production of copper, lead, and zinc. Some discharges are associated with the production of other nonferrous metals, but the amounts are insignificant as far as their contribution to national pollution levels is concerned.

The 2 to 3 million tons of sulfur oxides emitted in the production of primary copper, lead, and zinc occur in discharges from processes that employ pyrometallurgical techniques to roast, smelt, and refine metal sulfide ores. The roasting and smelting operations involve the separation of impure metals from sulfur ore concentrates. Most of the sulfur and other volatile impurities (including trace-metal compounds of arsenic, cadmium, and other metals) are liberated in these steps. The refining steps that take place at higher temperatures eliminate the balance of the sulfur and other impurities to produce high-purity metals.

The emissions from smelters are significantly different from those discharged by boilers burning fossil fuels. The emission streams containing sulfur oxides are extremely variable as far as temperature, volume of the emission streams, concentration of sulfur oxides, and amounts of cocontaminants are concerned. Further, the number of processing sites is small, consisting of around 40 plants made up of a wide variety of operations, including roasting, smelting, and sintering.

NATURE OF THE SULFUR OXIDES PROBLEM

The three major sources of sulfur oxides pollution include several subcategories that represent basically different problems as far as present and projected control technology needs are concerned. As already indicated, combustion of coal and oil and metal recovery all produce emissions that are basically different. This difference is due to variations in composition of the feed materials that are volatized or oxidized and discharged in the waste streams. In addition, the size of the sources (which is relatable to amounts of pollution discharged and stack height) influences both the economic feasibility of control and the probability of exposure of human beings or the environment to high concentrations of pollution. Finally, the different categories present dissimilar problems with respect to potential for future pollution.

Combustion of Coal

Most sulfur oxides pollution from boiler operation is generated by burning of coal in boilers with heat input rates in excess of 250 × 10^6 Btu/hour. These boilers are subject to NSPS. About two-thirds of this pollution comes from coal burned in electric utility boilers alone. The importance of coal burning in the production of electricity is illustrated by Table 3-4, which gives U.S. generating capacity by major category.[5]

The potential for future sulfur oxides pollution from combustion of coal in electric utility boilers is shown in Figure 3-1.[3] These curves assume a 5.2 percent growth rate for coal and residual-oil burning, which is consistent with predictions of the Federal Power Commission for all power generation. The upper curve shows the sulfur oxides that would be discharged from coal-fired power plants if no emission controls were used beyond those being applied in 1975. The second highest curve shows the estimated emissions that will occur if NSPS of 1.2 pounds of SO_2 per million Btu generated are met by all new boilers coming into use between 1975 and 1990. The next to the lowest curve shows the estimated emissions that will be produced if all new boilers achieve 90 percent control of sulfur oxides. The lowest curve shows the level of discharge from boilers in operation in 1975 that continue to operate in future years, assuming that none of the 1975 boilers is retired before 1981 and that after 1981 the same proportion of boilers that were in and out of compliance in 1975 would be retired.

Some important conclusions for coal-fired utility boilers are suggested by Figure 3-1. First, large increases in emissions would be experienced if controls are not applied. Second, meeting NSPS will keep emissions from increasing significantly (provided that the growth in coal burning does not substantially exceed the 5.2 percent per year that was assumed for the projection), even if existing

Figure 3-1. Projected sulfur oxides emissions for coal-fired power plants.

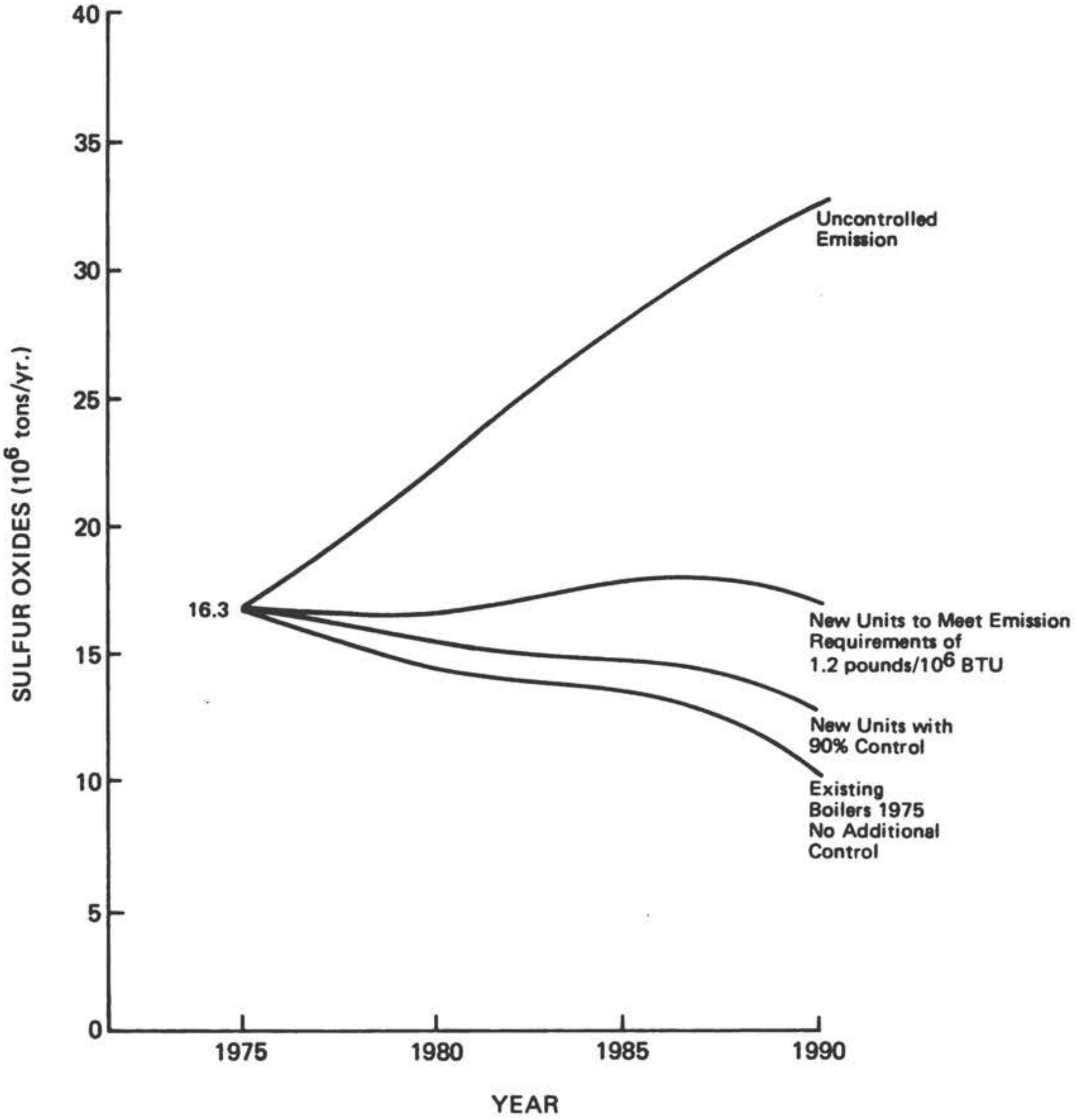

Table 3-4. Electrical generating capacity of the United States (1975).

Source	Megawatts	Percent
Coal-fired boilers	196,000	39
Oil-fired boilers	72,000	14
Gas-fired boilers	89,000	18
Nuclear	41,000	8
Hydroelectric	58,000	11
Other	53,000	10
Total	509,000	100

plants are not brought into compliance. Third, the benefits possible if more stringent controls are met may not be cost effective, although the reduction appears to be significant. Finally, boilers in operation in 1975 are likely still to be significant sources of pollution in 1990 and beyond.

The emissions from coal-fired boilers present problems that in some important respects are distinctly different from those presented by combustion of oil, which is more widely used in smaller boilers, or the smelting of nonferrous ores. The volumes to be treated are greater, and concentrations of pollutant to be removed are lower. For a 1,000-MW boiler burning coal containing 2.5 percent sulfur, about 1.7 million scfm containing about 0.2 percent SO_2 would be generated. Sulfur oxides control on this scale presents problems that are radically different from those associated with smelters or the smaller boilers that tend to be used with residual oil combustion.

At present, methods that can be used for control of sulfur oxides from coal combustion include physical coal cleaning for removal of some of the sulfur before combustion and FGD processes that scrub the combustion gases. Physical coal cleaning is effective for certain coals and, where it is applicable, is the cheapest way to remove sulfur. Unfortunately, the characteristics of U.S. coals are such that physical coal cleaning cannot be used except as a supplemental technique to meet projected standards.[6] Production of low-sulfur boiler fuels from coal by using a number of different processes is under study. Fluidized bed combustion systems that are designed to retain the sulfur in a fluidized bed of limestone are under development. Unfortunately, it does not appear, as will be discussed later in this chapter, that any of the advanced systems will be available for widespread application in the near future; hence, widespread use of FGD systems alone or in combination with physically cleaned coal seems to be likely for the next 10 to 20 years.

About 10 percent of the total sulfur oxides from coal combustion is produced by boilers in industrial or commercial service. The discharges from the large industrial boilers with tall stacks will be similar to those from utility boilers, which are generally contributors to remote, rather than local, pollution. The smaller boilers that are predominant in nonutility service may produce quite significant local pollution because they employ short stacks and are likely to be located in urban areas. At present most nonutility boilers burn gas, distillate oil, or residual oil. As the cost of these fuels increases, and restrictions are applied to their use, a substantial increase in the number of coal-fired boilers used in this service is expected to take place.

The sulfur oxides regulations for small industrial installations have not yet been promulgated, but for many of these facilities the use of the stack scrubbing methods currently employed by the electric utilities will be impractical. Physical coal cleaning may be useful in helping to minimize pollution from small boilers, but the amount of control that would be possible may not be adequate. Alternative FGD technology, such as spray drying and clear-solution scrubbing, may be more acceptable at small commercial installations. These types of processes might offer reduced operating and maintenance costs and greatly simplify solid-waste disposal practices for these smaller coal-burning installations. Atmospheric fluid bed combustion may offer an alternative solution. Too little attention has been given to this potential problem in view of the announced national policy of shifting industrial consumption of fuel from oil and gas to coal.

Combustion of Oil

Future sulfur oxides emissions resulting from the burning of residual oil as boiler fuel are difficult to predict. At present, the oil-fired electric utility capacity is about 72,000 MW. Much of the residual oil that is burned contains 1 percent or less sulfur, and the weighted average is about 1.6 percent for nonutility boilers and 1.0 percent for utility boilers. The amount of sulfur oxides emitted by utility boilers was an estimated 1.5 million tons in 1975. An additional 1.3 million tons were generated by combustion of residual oil in other types of boilers. The pressure to restrict the use of oil and increase the amount of coal burned in boilers may cause a gradual reduction in the amount of sulfur oxides generated by the burning of residual oil, but the decreases are not expected to be great. For example, normal retirement of boilers would reduce emissions from oil-fired utility boilers from 1.5 million tons in 1975 to about 1.3 million tons in 1990 if no new oil-fired boilers are built. However, a faster than normal retirement should occur because of the investment tax credits for conversion from oil to coal contained in the Energy Tax Act of 1978. On the other hand, the projected increases in consumption of petroleum products seem likely to generate increasing quantities of residual oil that cannot be economically processed to produce gasoline, distillate oil, or other high-quality products. It appears reasonable, therefore, to assume that some residual-oil burning will continue during the balance of this century.

The problems presented by pollution from burning of residual oil differ from those associated with coal combustion in several respects. First, as indicated earlier, the boilers are generally smaller and tend to be located in urban areas where discharges are emitted at low levels. The potential for local impact is therefore great. Second, sulfur oxides are emitted along with finely divided particulates, a large fraction of which are in the respirable range. This is likely to increase the potential for adverse health impacts from sulfur oxides. In addition, the particulates contain trace metal compounds and carbonaceous materials that may present serious problems in their own right.[7]

Sulfur oxides emissions from residual-oil-fired boilers can also be reduced by desulfurizing the oil before combustion. Unfortunately, the degree to which available technology can be applied is limited by the characteristics of the crude oil from which the residual oil is derived. Those crude oils high in impurities produce residues that are difficult to process into low-sulfur fuels. Whereas many residual oil fuels are being desulfurized to some degree now, we may be reaching the practical limits as far as this approach to sulfur oxides pollution control is concerned.

Smelting of Nonferrous Ores

Problems associated with discharges of sulfur oxides from copper, lead, and zinc production are in most respects unlike those associated with combustion of coal and residual oil. In smelting, sulfur oxides are discharged from many different kinds of equipment in varying quantities and concentrations with a wide variety of cocontaminants, which can include substantial amounts of trace-metal compounds. Whereas only a small number of facilities are involved (about 40 smelters and refineries), each tends to present unique problems in pollution control.

Most smelters are located in sparsely populated areas, but some are not. Emissions of trace-metal compounds, which may be the most serious pollutant discharged from smelters,[8] vary widely in quantity because of differences in the ore concentrate being processed. In some locations where SO_2 concentrations are high, emissions can be and are being controlled by conversion of SO_2 to sulfuric acid in contact-acid plants. About 1.2 million tons of SO_2 were converted to acid in 1975. This is probably less than one-third of that generated. Unfortunately, this approach is economically feasible only in areas where SO_2 concentrations are above about 6 percent and markets are available for the acid that is produced. In addition, prescrubbing of the gaseous discharge, a step that is necessary to remove trace metal compounds before the gases enter the acid plant, generates contaminated water that must be dealt with. FGD processes have not been applied to tail-gas cleaning in copper, lead, and zinc facilities in the United States, but a number of such plants are in operation in Japan.

METHODS OF SULFUR OXIDES CONTROL

General compliance with sulfur oxides emissions regulations for combustion processes relied, when regulations were first imposed, on burning low-sulfur fuels. However, processes and equipment to remove sulfur from fossil fuels before, during, and after combustion have been developed, and others are still being developed. Fuel oil is now being desulfurized to bring high-sulfur oils into compliance. Coal cleaning can remove a portion of the pyritic sulfur, and processes for gasification and liquefaction of coal to produce clean fuels are being actively pursued.

The substitution of low-sulfur compliance fuel is only a short-term solution because of economic factors. Low-sulfur oil is in short supply, and this has resulted in increased prices. Further, low-sulfur coal that will meet the 1979 NSPS is generally not available. Thus the longer term control of sulfur oxides emissions will have to rely on removal of the sulfur before, during, or after combustion of sulfur-bearing fuels.

Desulfurization Before Combustion

Desulfurization of natural gas and petroleum products has been practiced for years to meet fuel standards. Residual oils are most difficult to treat because they contain metals that are deposited and poison the catalysts that are used for desulfurization. However, under the pressure of sulfur oxides emission limitations, processes have been developed.

Coal washing or beneficiation to reduce ash has been a regular practice of the coal industry for many years. In general, about 40 to 60 percent of the total sulfur in Appalachian coals is in the form of pyrites, as is roughly 35 percent of the sulfur in western coals. Coal-cleaning methods can remove about 50 to 70 percent of these inorganic sulfides. The low-sulfur coals in the West contain a smaller proportion of inorganic sulfur and do not benefit so greatly from cleaning. Thus conventional coal-cleaning methods alone are not sufficiently effective to meet air pollution control requirements at all plants. However, mechanical coal cleaning can often reduce the sulfur content of the coal so that emission standards at some older plants subject to state implementation plans can be met. Naturally occurring low-sulfur coals can also serve the same purpose. A combination of coal cleaning and stack scrubbing may be the most effective and lowest cost method of meeting emission standards at certain plants.

A number of different chemical processes to treat coal have been tested with the objective of removing greater amounts of sulfur from the coal than can be achieved by coal washing. None of these has yet been commercialized because of unsolved technical problems and high costs.

Desulfurization of coal beyond that attainable by conventional coal-cleaning methods has been the subject of considerable research effort for over 15 years, with only partial success achieved to date. Coal will dissolve in a number of organic solvents, particularly high-molecular-weight, ring-structure compounds. Some of the tars and oils produced during the carbonization or distillation of bituminous coal can also act as solvents. Research is continuing on methods to disperse or dissolve coal in liquids, to filter off the ash and undissolved material, and to reconstitute the coal by separating it from the liquid solvents, which are then recycled. The purified solid coal has a considerably lower ash and sulfur content than the original coal. The processes have not yet been commercialized because of difficult problems in solid-liquid separation and the high cost of producing the clean coal.

Other processes are under study in which the coal is treated with gases, such as hydrogen and carbon monoxide, under pressure. In these instances gaseous sulfur compounds are formed by the reaction of the hydrogen and carbon monoxides with the sulfur in the coal and are removed from the coal. None of these processes has been successful so far because of problems of bringing the gas into contact with the coal efficiently, the large volume of gas that must be handled, and unfavorable reaction kinetics at temperatures that do not decompose the coal and reduce its heating value.

Sulfur-free gaseous and liquid fuel can be made from coal. At the end of the 19th century, coal was used to produce gas for illumination, cooking, and heating. However, electricity replaced gas for lighting early in the 20th century. Following World War II, the fuel-gas industry switched from gas manufactured from coal to natural gas when gas pipelines were installed that could transmit the gas from the gas fields to the large consuming markets. By 1960 essentially no coal was being gasified in the United States, although gas from coal continued to be produced abroad for residential and process heating and to make synthesis gas, a chemical feedstock.

Early gasifiers used air and steam to produce a gas having a heating value of between 125 and 150 Btu/scf and consisting primarily of carbon monoxide, hydrogen, and the nitrogen from the air. Cyclic gasification processes could produce a higher quality gas of up to 300 Btu/scf. Improvements in recent years have involved the use of oxygen in place of air and operation at high pressure to produce a lower cost gas with heating values between 200 and 450 Btu/scf.

Current efforts to gasify coal include both modification of existing processes and the development of new processes.[9] Gasification studies have been directed toward making a clean gas with a heating value of about 150 Btu/scf for direct use in combined-cycle electric power generation or making synthetic pipeline-quality gas with a heating value of 1000 Btu/scf. Although air can be used (in place of oxygen) in making low-Btu gas, for high-heating-value synthetic gas it is necessary to use oxygen as the oxidant, clean the raw product gas, and then methanate the gas to obtain the high heating value desired. For both low- and high-Btu gas, H_2S and particulate matter are removed from the gas. To date the use of these processes for air pollution control appears to be more costly than the use of processes that scrub combustion gases.

The growing shortage of petroleum, and the facts that liquids may be transported and stored at low cost and are indispensable as a fuel in transportation, have provided the main justification for continued research in coal liquefaction. Much of the early work on coal liquefaction was done in Germany and England before and during World War II. There are two types of processes: Fischer-Tropsch synthesis and coal hydrogenation. Because it involves gasification followed by liquid hydrocarbon synthesis, the Fischer-Tropsch process is inherently more costly than other means of removing sulfur. A variety of coal hydrogenation processes are under study. These low-sulfur fuels made from coal (solids, liquids, or gases) can be used by both small (commercial and small industrial) and large (utility and large industrial) users. Because of the high costs involved none of these offers immediate prospects of being competitive with FGD stack gas scrubbers at the large installations where stack scrubbers can be used economically.[10] However, for smaller fuel users, use of clean fuels made from coal may be the lowest cost method of meeting environmental standards.

Removal During Combustion

The removal of sulfur during combustion may be accomplished by using a fluidized bed of limestone or by using processes in which sulfur-bearing fuel is injected into a molten bath of salts or metals, where the sulfur in the fuel reacts with the bath materials, which are then regenerated. The molten carbonate and iron processes that use the latter approach appear less promising than fluidized bed combustion.

Atmospheric fluidized bed combustion (FBC) is used in waste disposal and industrial and process steam generation and is under development for coal conversion and combustion. Pilot studies are providing design data for a full-scale demonstration of industrial, commercial, and utility applications of atmospheric FBC with limestone removal of sulfur. Applications of FBC may be available for commercial and industrial boilers in the early 1980s. Indications are that costs are comparable with those of present FGD processes.[11] Larger volumes of limestone are required, but dry disposal should be less difficult than the disposal of sludge from wet processes. The larger, more complex units needed for electric power generation by utilities will require additional demonstration, which will delay the application of FBC in such units, perhaps to the end of the 1980s.

Pressurized FBC, which may be lower in cost when used with combined cycles for generating electricity, requires additional research and development before the first prototype can be built, and a commercial plant cannot be expected before 1990.

STATUS OF ALTERNATIVES TO FLUE-GAS DESULFURIZATION

FGD stack scrubbing is generally too costly to be used in the very small commercial and industrial boilers since the successful use of a scrubber requires operators, extensive maintenance, and means for the disposal of the semisolid waste that is produced. Scrubbers have been installed on fewer than 100 medium-sized industrial and commercial boilers, and these installations usually use some form of clear solution sodium scrubbing. For most small fuel users to meet environmental standards at reasonable costs, other means will have to be devised. These methods include the use of clean solid, liquid, or gaseous fuels made from coal or of atmospheric fluidized bed combustors.

Methods to produce clean fuels from coal that will be particularly valuable to the smaller fuel users are available, but their costs are now high. As a result, extensive research on improved processes is under way.[11] [12] Atmospheric FBC that should also be particularly useful to the users of small quantities of coal is being investigated. Either clean fuels made from coal or atmospheric fluidized bed combustors, or both, could be available in the 1980s if their pollution regulation requires increased control of sulfur oxides emissions for nonutility boilers.

On the other hand, the large industrial and utility coal consumers are expected to continue to use pulverized coal and scrubbers for the predictable future because alternative energy sources and fuel systems for generating electricity are not yet sufficiently advanced to be used commercially.

Atmospheric FBC, pressurized FBC, gasification (low and medium Btu), and liquefaction all can be used to produce a clean fuel from coal. All these systems except atmospheric FBC can be used in a combined gas-turbine, steam-turbine power plant. Such electric generating plants offer the best prospects for having their existing technical problems solved in the near future and may provide increased efficiency at acceptable costs. With a turbine inlet temperature of 1370 to 1650°C, a combined-cycle electric power generating efficiency of over 50 percent (based on the heating value of the clean-coal-derived liquid fuel as delivered) can be achieved. The inefficiency of the off-site fuel plant for conversion of coal to gases or liquids would reduce the coal-to-electricity efficiency level to approximately 30 to 40 percent, depending on how clean the liquids are that are produced. If an integrated low-Btu gasifier is employed as the fuel supply system, coal-to-electricity efficiencies are estimated to be about 40 to 44 percent with turbine inlet temperatures of 1370 to 1650°C. High-temperature gas turbines and a high-temperature gas clean-up system are the high-priority items for development.

Another variation of the combined gas-turbine, steam-turbine system features the direct combustion of coal in a pressurized fluidized bed. The fluidized bed can be operated at high excess air as a combustor for a gas turbine or at low excess air with heat extracted from the bed by steam or air tubes within the bed. The energy extracted from the bed in the latter case is introduced into the steam turbine or gas turbine cycle. Even with gas-turbine inlet temperatures of 870 to 980°C, the efficiency levels are expected to be close to 40 percent because these systems operate directly on coal. However, the products of coal combustion must be cleaned at high temperature (870 to 980°C) to the tolerance level of a gas turbine. Because of uncertainties with respect to equipment costs, the overall economics of these systems remain to be established.

There has been, and likely will continue to be, steady progress in advanced air cooling of turbine blades, leading to increases in turbine inlet temperatures. By 1985, one can expect the introduction of new cooling technology and new materials technology to have resulted in production of gas turbines that can operate at much higher temperatures than those available today. These machines will be continually improved into the 1990s and beyond, but their use may exacerbate the nitrogen oxide problem.

Although these alternative technologies to FGD appear to be promising, for the next decade, or even longer, FGD will continue to be widely employed.

RATE OF APPLICATION OF SCRUBBERS

In the data shown in Figure 3-1, the growth rate in the use of coal in utility power plants is assumed to be 5.2 percent per year. The historical rate of construction of fossil fuel power plants has been greater than this projected rate for the future. Application of FGD equipment to conventional power plants increases plant equipment and costs between 10 and 20 percent. Thus, even with the 1979 NSPS requirement of including scrubbers, equipment suppliers and construction companies would appear to have sufficient capability to build needed new plants.

One area of concern, discussed in Chapter 4, is uncertainty about the performance of scrubbers on units burning coal containing more than 2.5 percent sulfur. Once this uncertainty is resolved, the rate of application of scrubbers will not be limited by supply factors.

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CHAPTER 4

FLUE-GAS DESULFURIZATION TECHNOLOGY AND PROCESSES

DESULFURIZATION PROCESSES

More than 100 processes and/or systems have received some level of consideration for use in removing the sulfur from flue gases. However, only three or four of the process concepts are now commercially important in the United States. These processes all use aqueous scrubbing with disposal of a waste product or with regeneration of the scrubbing agent to produce marketable sulfuric acid or elemental sulfur. Dry processes have not yet received any significant degree of commercial acceptance, although several types are now being introduced commercially.

Throwaway Processes

The most generally accepted approach to flue-gas desulfurization is aqueous scrubbing with the production of $CaSO_3$-$CaSO_4$ solids. This process generally is known as throwaway scrubbing. Limestone ($CaCO_3$) or lime (CaO) reacts with the flue gas in an aqueous system to produce $CaSO_3$. Because most waste gases contain oxygen, the solids will also contain variable quantities of $CaSO_4$.

Intentional air oxidation of the solids produced has been practiced in Japan in order to produce marketable gypsum, and in the United States it has been tested with a view to improving the disposal characteristics of the solids. Generally, in the United States the $CaSO_3$-$CaSO_4$ or $CaSO_4$ solids are disposed of in ponds or landfills. The disposal of this solid waste in an acceptable manner is one of the most significant problems of throwaway scrubbing.

Slurry Scrubbing. Slurry scrubbing is the dominant commercial FGD process. The general concept is shown in Figure 4-1. It includes a scrubber, a recycle tank, and a device for liquid-solid separation.

Figure 4-1. Throwaway slurry scrubbing.

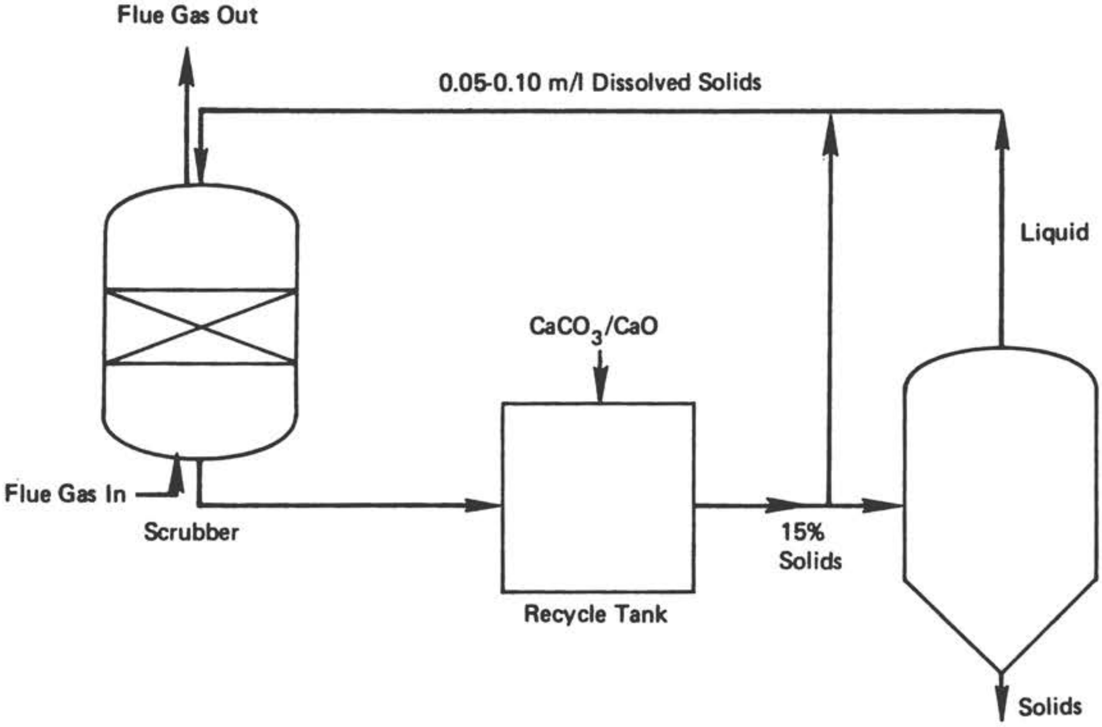
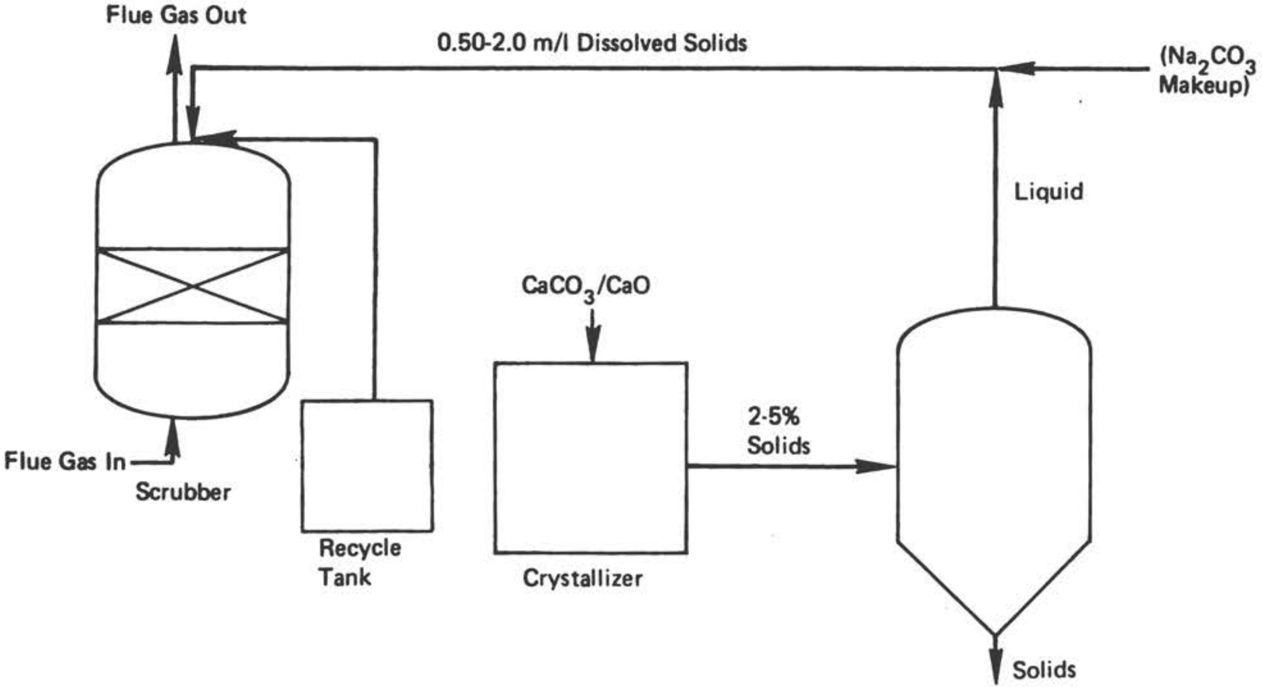


Figure 4-2. Dual alkali throwaway scrubbing.



Typically, the scrubber operates at the adiabatic saturation temperature (50-60°C for most flue gas) and atmospheric pressure. Clean gas from the scrubber is usually reheated to 75-90°C by hot-air injection or indirect exchange with steam to allow for adequate plume dispersion and to protect downstream equipment from corrosion by acidic condensate. A number of scrubber types have been used, including sprays, venturis, turbulent beds of solid or hollow spheres, modified sieve trays, and open eggcrate packing.

The recycle tank is usually a simple stirred tank or several tanks in series. Slurry is recycled to the scrubber, with a small portion, containing 10 to 15 percent (by weight) suspended solids, withdrawn for liquid-solid separation. Clarifiers, filters, centrifuges, and settling ponds have all been used for liquid-solid separation.

The design of this type of system is constrained primarily by the need to avoid $CaSO_3$ and $CaSO_4$ scaling in the scrubber. To control $CaSO_4$ scaling, a combination of crystallizer residence time and $CaSO_4$ solids concentration is used to desupersaturate the scrubber feed. The liquid's circulation rate must also be adequate to prevent excessive $CaSO_4$ supersaturation at the scrubber exit. $CaSO_3$ scaling is prevented by limiting the amount of unreacted $CaCO_3$ or CaO solid that is returned to the scrubber.

If the amount of sulfate in the solids is less than 15 to 20 percent of the total sulfate plus sulfite, $CaSO_4$ will crystallize in solid solution with $CaSO_3$, rather than crystallizing as gypsum ($CaSO_4 \bullet 2H_2O$), its usual form.[2 3] As a result, the constraints on crystallizer design and liquid circulation rate can be relaxed without the occurrence of gypsum scaling.

Soluble additives, such as MgO, Na_2CO_3, and organic acids, have been used to enhance the mass transfer performance of slurry scrubbers.[2 4-6] Air oxidation has been used to upgrade the waste solids (because gypsum is easier to dewater than $CaSO_3$).[7 8]

Air oxidation, limestone dissolution, and gypsum crystallization all take place within the scrubber vessel in the Chiyoda Thoroughbred 121 system, which uses a sparger (gas-phase-dispersed) contactor as the scrubber instead of the liquid-phase-dispersed contactors described above. The Chiyoda system has been operated at a 23-MW prototype test unit on a medium-sulfur coal-fired utility boiler in the United States.

Clear-Solution Scrubbing. Clear-solution scrubbing avoids many of the problems associated with slurry scrubbing.[1] One such process is shown in Figure 4-2. This dual alkali process absorbs SO_2 in a clear solution of sodium sulfite (Na_2SO_3) to produce sodium bisulfite ($NaHSO_3$). The scrubbing solution is regenerated by lime or limestone with the resulting crystallization of $CaSO_3$ solids.[9-11]

If less than 15 to 20 percent of the SO_2 is oxidized in the scrubber system, $CaSO_4$ is precipitated in solid solution with the $CaSO_3$.[12] Otherwise, the sulfate must be removed as Na_2SO_4 solids or solution, although some Na_2SO_4 can be regenerated with CaO to yield gypsum.

The $CaSO_3$-$CaSO_4$ solids are separated from the scrubbing solution by clarification followed by filtration or centrifugation. The filter cake is washed with makeup water to retain soluble sodium in the scrubbing system and thereby minimize sodium makeup.

The clear-solution dual alkali technology is now being commercialized because it is more efficient and may be more reliable than slurry scrubbing. However, the liquid-solid separation system is more complex, and only lime has been used successfully as the alkali source.

Another approach to clear-solution scrubbing is represented by the Dowa process.[13] Sulfur dioxide is absorbed in an aqueous solution of basic aluminum sulfate buffered at pH 3 to 4. After every pass through the scrubbing system, the solution is oxidized by air to convert the dissolved SO_2 to sulfate. A slipstream from the scrubber loop is neutralized by lime or limestone, with a resultant crystallization of gypsum, which is separated by a centrifuge. This process has been commercialized in Japan, and there are plans to begin testing it in the United States in 1980 at the TVA Shawnee Power Plant.

Dry Scrubbing. Dry scrubbing processes that utilize reactive solids (generally lime, sodium carbonate, or sodium bicarbonate) have been studied for a number of years. Early efforts, where lime or limestone was injected directly into the gas stream, gave low efficiencies and poor utilization of reactant. Sodium compounds gave better efficiency and utilization but were costly and resulted in formation of soluble solid waste that could present environmental problems. Recent technical advances, combined with new air emission standards that require cleaning stack gases with relatively low concentrations of SO_2, have generated renewed interest in dry scrubbing systems.

Several versions of dry scrubbing have emerged. These involve the following:

1. Dry reactant, injected directly into the gas stream for reaction, followed by collection and further reaction on

a fabric filter or collection in an electrostatic precipitator. This process is being installed on full-scale equipment.

2. Pelletizing coal with powdered limestone prior to combustion so that reaction can take place during combustion, in the flue gas, and during the dust collection process. This process has shown promise on pilot-scale equipment.

3. Spray drying, utilizing a spray dryer to contact Na_2CO_3 solution or CaO slurry with the stack gas. The solution or slurry is completely evaporated (no liquid is present at the outlet) and the dry solids are collected by a fabric filter or electrostatic precipitator. As a result, the use of corrosion-resistant materials and liquid recirculation is generally not required and the reheat requirement is minimized. This process is being installed on full-scale equipment.

It is expected that this technology will be limited to stack gases with low levels of SO_2 (less than 1000 ppm). At higher SO_2 concentrations, lime scrubbing systems have been unable to achieve 90 percent SO_2 removal; Na_2CO_3 becomes prohibitively expensive and environmentally unacceptable because of the large amount of alkali consumed and soluble salt waste produced.

Regenerable Scrubbing Processes

Regenerable processes remove SO_2 from flue gas and convert it to marketable products, such as elemental sulfur, sulfuric acid, and liquid sulfur dioxide. Such systems are environmentally attractive because they minimize greatly the production of waste products. Economically, these systems are potentially attractive because they avoid the costs of alkali makeup and solid waste disposal. In practice, the energy required for processing and the complexity of the processing usually make these processes more expensive than throwaway scrubbing. As a result, there are now only a few applications of regenerable processes in the United States, although there continues to be an active interest in developing such processes. Regenerable processes are more commonly used in Japan because waste disposal is more of a problem there than in the United States.

As long as most facilities continue to use throwaway FGD systems, there will be adequate markets for the sulfur and sulfuric acid produced in regenerable processes in the United States.[14] [15] Sulfur is the preferred product because it is easily stored and inexpensively transported. If there are no markets, sulfur is also an acceptable waste product, since it can be stored easily. However, production of

Table 4-1. Regenerable scrubbing processes.

Generic Name	Process Operation	Product
Thermal regeneration		
Wellman-Lord[16,17]	Na_2SO_3 solution; evaporative crystallization	95% SO_2
Steam stripping[18,19]	Acid/base buffer or nonvolatile aldehyde	95% SO_2
MgO[20-23]	$MgO/MgSO_3$ slurry; centrifuge, dry, and calcine	15% SO_2
ZnO[6]	ZnO/Na_2SO_3 solution; centrifuge, dry, and calcine	95% SO_2
Acid decomposition of bisulfate		
Stone and Webster/Ionics[25]	NaOH solution; electrolytic prod. of $NaOH/H_2SO_4$	95% SO_2
Ammonium bisulfate[32,33]	$(NH_4)_2SO_3$ solution; thermal decomp. of $(NH_4)_2SO_4$ to NH_3 and NH_4HSO_4	95% SO_2
H_2S regeneration to S[34,53]		
Citrate[35,36]	Sodium citrate buffer	S
Aquaclaus[37,38]	Sodium phosphate buffer	S
NH_3-IFP[38,39]	$(NH_4)_2SO_3$ solution; evaporative decomp.; aqueous reaction of H_2S with SO_2	S
CO regeneration		
Consol[40]	K_2SO_3 solution reaction with CO	50% H_2S
Sulfoxel	Na_2SO_3 solution reaction with CO	S
High T reduction		
Kel-S[38,41]	$CaCO_3$ slurry; reaction with coal to CaS; carbonation	H_2S
Aqueous carbonate[42,43]	Na_2CO_3 solution; reduction of molten Na_2SO_4 and Na_2SO_3 with coal to make Na_2S; carbonation	H_2S
RESOX[38,46]	Reduction of SO_2, etc.	S

sulfur from SO_2 requires the use of a reducing agent, usually H_2 made from methane. As a result, it is usually more economical to produce sulfuric acid, rather than sulfur, even though sulfuric acid can be three times as costly to transport. There are only limited existing markets for liquid SO_2, but if a large source of SO_2 can be developed, SO_2 has the potential to be substituted for elemental sulfur in the production of sulfuric acid.

A large number of regenerable scrubbing processes have been proposed and partially developed, as shown in Table 4-1. Only the Wellman-Lord and MgO processes are now used commercially. The federal government is currently cofunding large-scale demonstrations (100 MW) of the Wellman-Lord, citrate, and aqueous carbonate processes, and there are active pilot plant and laboratory development programs of the steam stripping, RESOX, and Kel-S processes.

Wellman-Lord Process. The Wellman-Lord process (Figure 4-3) is the only regenerable system currently being used in the United States.[16 17] In this process, SO_2 is absorbed in a concentrated aqueous solution of sodium sulfite (Na_2SO_3) to produce sodium bisulfite ($NaHSO_3$). The scrubbing solution is regenerated by crystallization of Na_2SO_3 in a single- or double-effect evaporator. Water is condensed from the vapor to leave concentrated (95 percent) SO_2 gas. The Na_2SO_3 solids are redissolved and recycled to the absorber. The concentrated SO_2 is converted to sulfur by reaction with methane[44] or to sulfuric acid by reaction with air. When the process is used to treat tail gas from sulfuric acid or sulfur recovery plants, the concentrated SO_2 is recycled to the front end of the plant.

With most waste gases, prescrubbing is necessary to remove residual particulates, HCl, and SO_3. In the absorber, oxygen present in the flue gas converts some sulfite to sulfate. Typically this sulfate must be removed from the absorbent solution by the selective crystallization of sodium sulfate. The evaporative crystallizer must be operated below 100°C to prevent excessive disproportionation of bisulfite to sulfate and thiosulfate.

The Wellman-Lord process was first tested in 1970 on tail gas from a sulfuric acid plant in Paulsboro, New Jersey. There followed several applications on tail gas from sulfur recovery plants in the United States and Japan and on flue gas from oil-fired boilers in Japan. The first application to a coal-fired boiler was made in 1977 in the United States.

Magnesium Oxide Process. The MgO process has been tested in the United States, but no commercial units are currently operating.[20] As shown in Figure 4-4, SO_2 is absorbed in a slurry of $MgSO_3$. Makeup MgO is added to the

Figure 4-3. Wellman-Lord process.

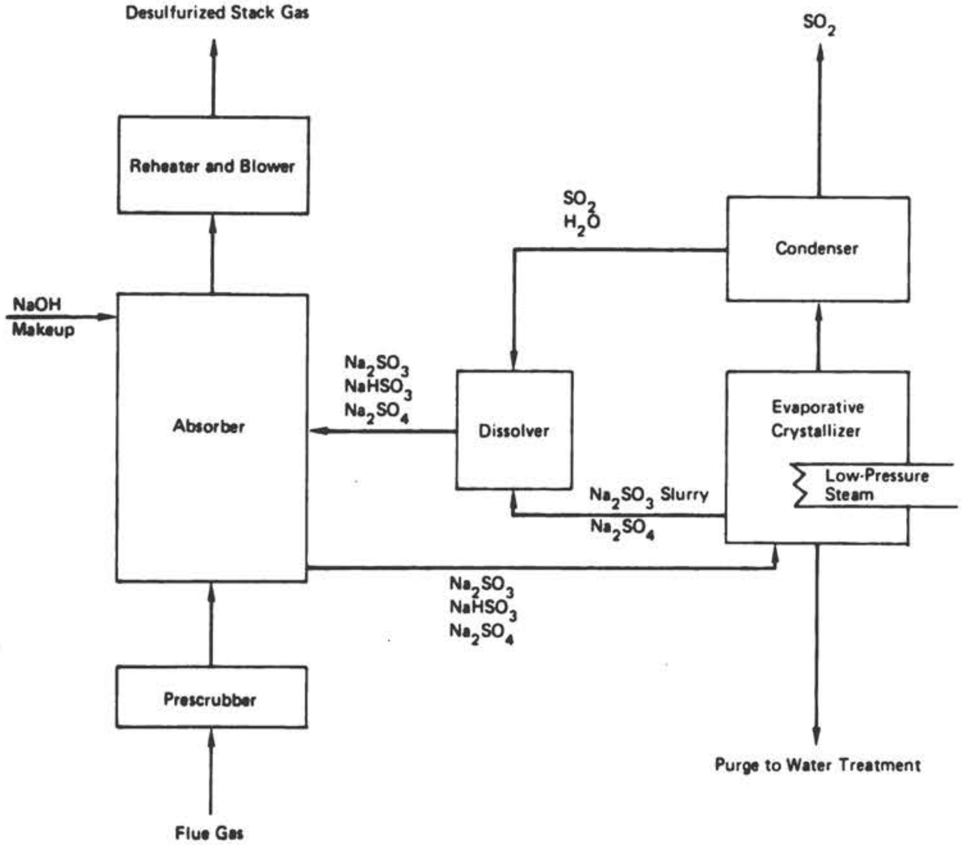
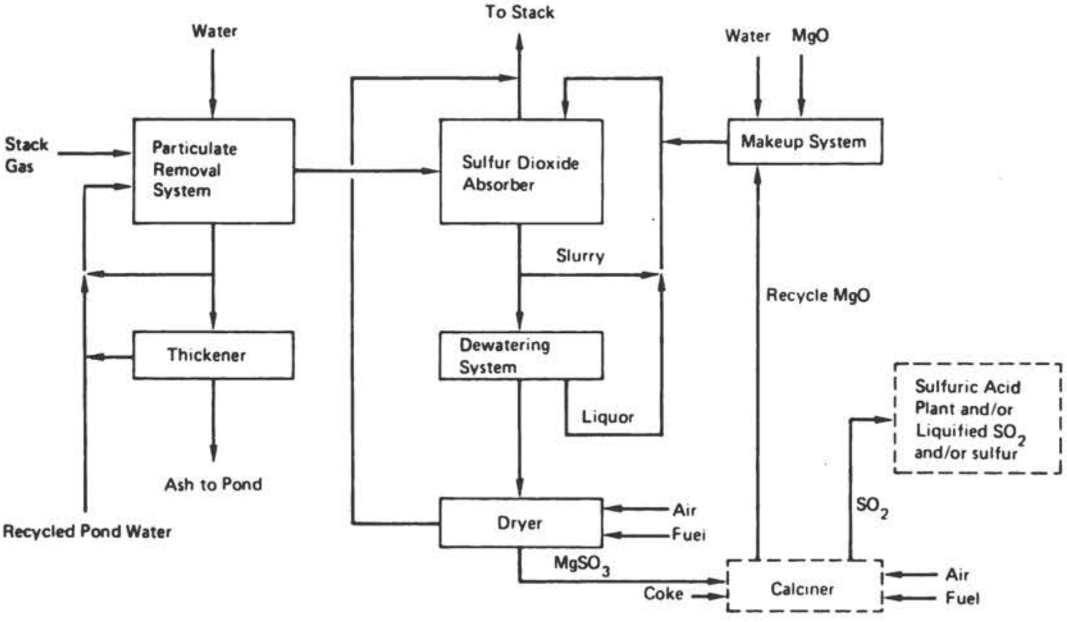


Figure 4-4. Magnesium oxide scrubbing.



recirculating slurry to produce $MgSO_3$; $MgSO_3 \bullet 3H_2O$ or $MgSO_3 \bullet 6H_2O$ solids are separated by a centrifuge and dried to remove entrained water and water of hydration. The anhydrous $MgSO_3$ is shipped to a sulfuric acid plant where it is converted to MgO and SO_2 at 815-1090°C by direct-fired heating in a rotary or fluidized bed calciner. The gas stream is cleaned and used as a source of SO_2 for sulfuric acid production. The MgO solids are shipped back to the scrubber site.

The process was tested on stack gas from an oil-fired boiler at Boston Edison in 1972-1974.[21] It has also been tested on stack gas from coal-fired boilers at Potomac Electric Power Company[22] and Philadelphia Electric Company.[23] In all three cases there were problems with solids handling and with coordination between the scrubbing and regeneration facilities. However, the process appears to be basically sound and is awaiting application in an economically attractive situation.

Dry Processes

Dry processes avoid saturating the flue gas. A number of such systems have been partially developed, as shown in Table 4-2. None of them has been used commercially in the United States, however, primarily because of the capital cost required for handling fixed or moving beds of solids.

Carbon absorption has been extensively tested on large units in Japan, Germany, and the United States. Catalytic oxidation was tested in a 100-MW unit in the United States. CuO absorption with H_2 regeneration has been used in Japan and tested briefly in the United States. Both CuO adsorption and several activated-carbon processes have the potential for removing some nitrogen oxides along with the sulfur oxides, if ammonia is added.

WET SCRUBBING EQUIPMENT

Wet scrubbing using lime or limestone is the predominant technology used in the United States and Japan, which are the two nations using most of the postcombustion sulfur oxides cleanup systems. The basic element of these wet-process systems is the absorber in which the flue gas is placed in contact with the scrubbing medium.

Although FGD systems come in many sizes, shapes, and configurations, primary consideration has been given to four general types: venturi systems with or without spray towers (Figure 4-5), turbulent contact absorbers (Figure 4-6), packed or tray-type absorbers (Figure 4-7), and horizontal systems (Figure 4-8).

Table 4-2. Dry processes.

Generic Name	Process Operation	Product
Carbon adsorption		
Water wash[45]	Absorption at 150° C; regenerate to dilute H_2SO_4; $CaCO_3$ neutralization	$CaSO_4$
Thermal[45-47]	Absorption at 150° C; desorption at 300-600° C	10-20% SO_2
Reducing gas[48]	Absorption at 150° C; desorption at 300-600° C with H_2	S
CuO adsorption[49,50]	Adsorption on CuO at 350° C; desorption by H_2 at 350° C	30-90% SO_2
Catalytic oxidation[51]	Catalytic oxidation at 450° C; absorption in H_2SO_4 at 150° C	85% H_2SO_4
Activated Na_2CO_3[52]	Absorption by nahcolite or trona at 150° C	Na_2SO_4
Dry limestone[53]	Adsorption by $CaCO_3$ or dolomite at 600-1000° C	$CaSO_4$
Molten carbonate[54]	Absorption in molten Li, Na, K_2CO_3 at 400° C; reaction with coke at 700° C; carbonation	H_2S
MnO_2[45]	Absorption by MnO_2 at 150° C; aqueous oxidation; NH_3 neutralization	$(NH_4)_2SO_4$

Figure 4-5. Schematic of venturi system and spray tower.

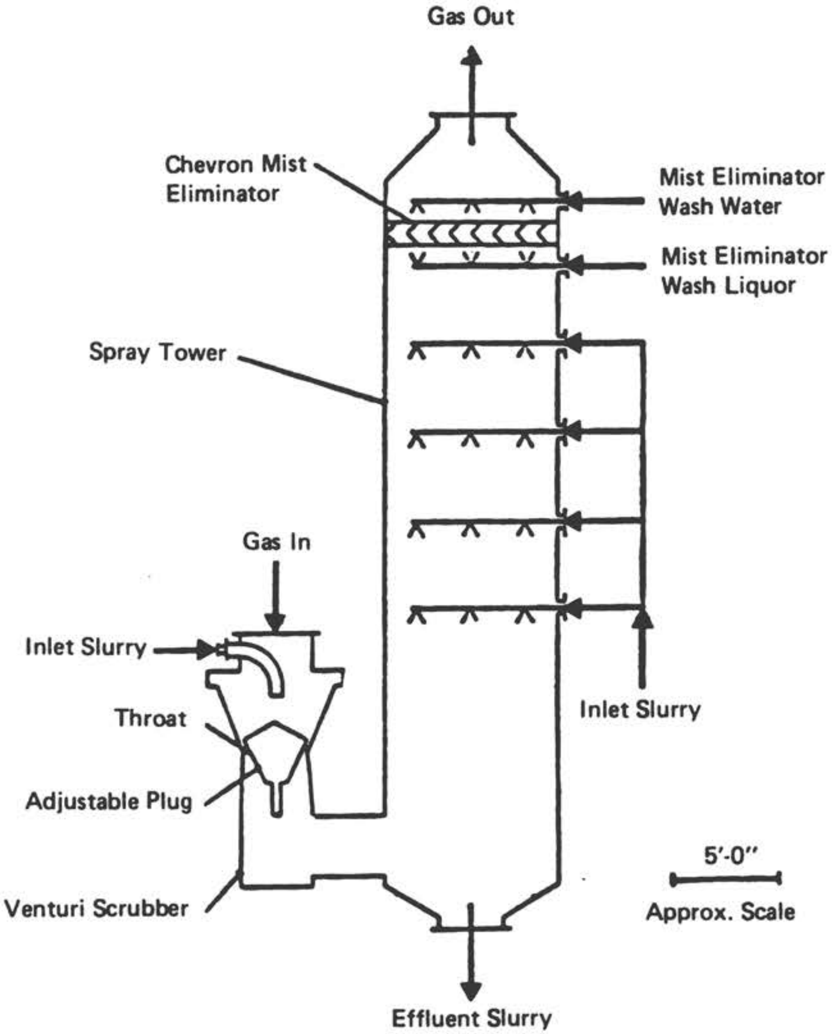


Figure 4-6. Schematic of three-bed turbulent contact absorber system.

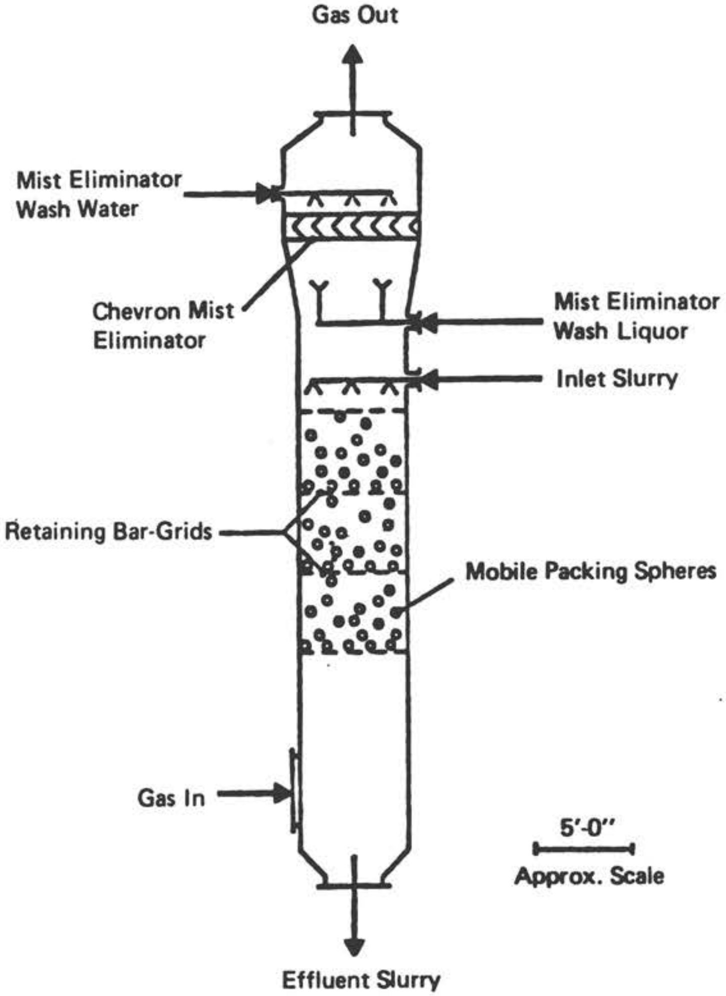


Figure 4-7. Packed absorber.

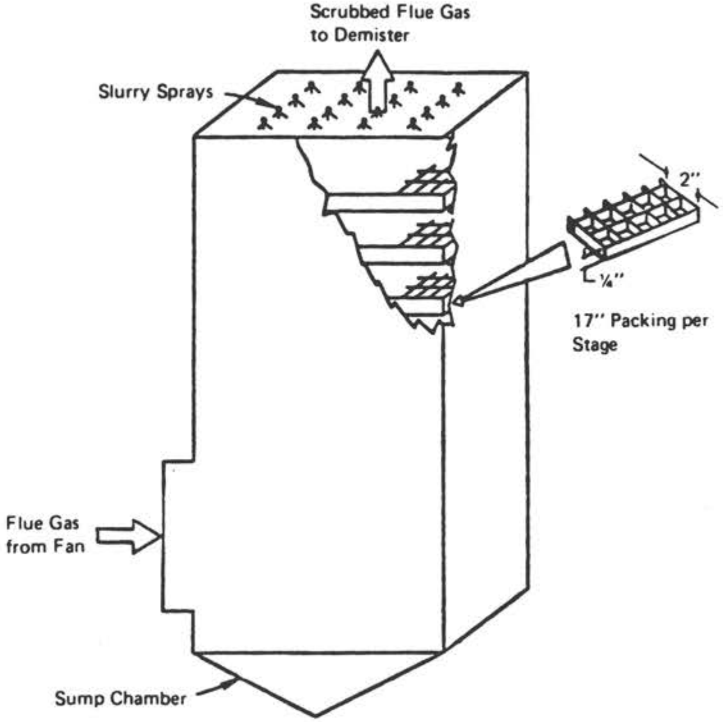
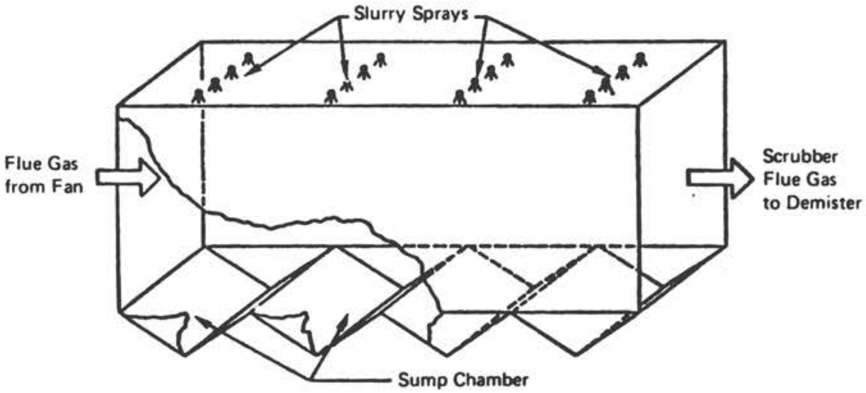


Figure 4-8. Horizontal scrubber.



The first three of these units use a vertical configuration and vertical countercurrent flows of flue gases and scrubbing media. The fourth involves horizontal flow of the flue gases and vertical flow of the scrubbing medium.

Each general type of FGD process has its advantages, but operational difficulties have also been encountered with each. Three major equipment-related problem areas have been identified[24] in lime and limestone scrubbing; these are mist elimination, materials of construction, and the need for a better understanding of process chemistry and its relation to system design. This is discussed in more detail in Chapter 6.

COMMERCIAL STATUS OF FLUE-GAS DESULFURIZATION TECHNOLOGY

The status of FGD systems for the U.S. electric utility industry as of November 1978 is given in Table 4-3.[26] There are 46 operational units, and an additional 98 units are planned or under construction. Table 4-4 gives the distribution of FGD systems on utility boilers by chemical processes. Lime or limestone slurry scrubbing processes account for 88 percent of the total. Wellman-Lord, MgO, and dual alkali processes each account for 2 to 4 percent of the total.

Table 4-5 gives the FGD plants operational in Japan as of December 1978.[27] The total installed FGD capacity in Japan is equal to 26,000 MW, or 50 percent higher than that in the United States, although about half of this capacity is on nonutility boilers.

A description of the individual FGD units in operation in the United States and a discussion of their efficiency and reliability are given in Chapter 6. Although existing FGD installations are dominated by lime and limestone systems, others are under development and expected to become commercially available in the future. The reliability, efficiency, and operating problems of these new processes are still not known.

CROSS-MEDIA IMPACTS OF FLUE-GAS CLEANING PROCESSES[56]

Air pollution control technology produces cross-media environmental impacts from the solids in the coal, from the FGD wastes, from the increased air pollution created by boiler derating, and from changes in the nature of the pollutants emitted.

The Resource Conservation and Recovery Act of 1976 (RCRA) is designed to regulate all solid-waste disposal to

Table 4-3. Number and capacity of U.S. utility FGD systems.

Status	Number of Units	Capacity (MW)
Operational	46	16,054
Under construction	43	17,297
Planned		
Contract awarded	20	10,690
Letter of intent signed	3	1,960
Requesting or evaluating bids	5	3,100
Considering FGD	27	13,406
Total	144	62,507

Table 4-4. Distribution of FGD systems by chemical process.

	FGD Capacity (MW)		
Process	Operational	Under Construction	Planned
Limestone[a]	8,734	8,687	10,848
Lime[b,c]	6,070	6,029	3,482
Lime/limestone	20	330	330
Sodium carbonate	375	509	0
MgO	120	0	1,326
Wellman-Lord	735	180	940
Dual alkali	0	1,102	0
Aqueous carbonate[d]	0	400	100
Citrate[e]	0	60	0
Total[f]	16,054	17,297	17,026

[a] Includes alkaline-fly-ash-limestone and limestone-slurry configurations.

[b] Includes alkaline-fly-ash-lime and lime-slurry configurations.

[c] Includes nonregenerable dry-collection and nonregenerable wet scrubbing configurations.

[d] Includes nonregenerable dry collection and regenerable configurations.

[e] This system is being installed at St. Joseph Minerals' G. F. Wheaton Plant and is listed as a utility FGD system because the plant is connected by a 25-MW interchange to the Duquesne Light Company.

[f] Because the processes for all planned systems are not known, the totals in this table are less than those in Table 4-3.

Table 4-5. FGD plants in Japan operational at end of 1978.

Plant Constructor	Wet Lime/Limestone		Indirect Lime/Limestone		H_2SO_4S, $(NH_4)_2SO_4$		Na_2SO_3, Na_2SO_4		Total	
	No. of Plants	Nm^3/hour[a]	No. of Plants	Nm^3/hour[a]	No. of Plants	Nm^3/hour[a]	No. of Plants	Nm^3/hour[a]	No. of Plants	Nm^3/hour[a]
Mitsubishi Heavy Industries (MHI)	34	19 020					3	292	37	19 312
Ishikawajima Heavy Industries (IHI)	17	4 445					79	4 351	96	8 796
Hitachi, Ltd.	13	6 940[b]			2	590	15	603	30	8 133
Mitsubishi Kakoki (MKK)	2	256			13	6 478[c]	41	913	56	7 647
Kawasaki Heavy Industries	4	756	6	5 450			7	256	17	6 462
Tsukishima Kikai (TSK)	1		4	398	1	88	40	4 042	46	4 528
Chiyoda Chemical Engineering and Construction			15	4 585					15	4 585
Oji Koei							57	4 280	57	4 280
Sumitomo Metal-Fujikasui	7	3 954					6	270	13	4 224
Kurabo Engineering			5	603	1	18	106	3 751	112	4 372
Mitsui Miike-Chemico	4	2 744			1	500			5	3 244
Ebara Manufacturing			11	1 914			10	1 167	21	3 081
Kobe Steel	6	2 475							6	2 475
Nippon Kokan (NKK)	3	245	1	150	2	1 990	6	62	12	2 447
Kureha Chemical							8	1 431	8	1 431
Showa Denko							5	1 372	5	1 372
Cadelius							8	1 291	8	1 291
Sumitomo (SCEO)-Wellman					6	1 288			6	1 288
Nippon Steel	2	1 200							2	1 200
Mitsui Metal Engineering	4	1 006			2	130			6	1 136
Dowa Engineering			8	666					8	666
JGC	1	330			1	125			2	455
Ube Industries					2	220			2	220
Niigata Engineering			1	185					1	185
Mitsui Engineering							1	160	1	160
Total	98	43 371	51	13 951	31	11 427	392	24 241	572	93 150

[a] Nm^3/hour = normal cubic meters per hour; 1000 Nm^3/hour = 0.27 nw equivalent gas capacity.

[b] Babcock-Hitachi.

[c] Wellman-NKK.

prevent pollution and minimize health risks. It is intended to abolish open dumps, require permits for all hazardous-waste deposits, and impose requirements for solid-waste disposal. Hazardous wastes are those that contribute to illness or pose hazards to either health or the environment.

The basic regulations to implement this act have not yet been adopted, but the facility generating the waste will be required to determine, by test, whether the waste is hazardous and, if it is, must keep strict records and be accountable for the materials for 20 years.

Electric utility fly ash and solid wastes generated by flue-gas desulfurization are to be classified initially as special large-volume hazardous wastes, which will have interim facility standards. Costs of disposal under these circumstances are estimated to be about 88 cents per million Btu, compared with 31 cents per million Btu using current utility prices.[55] No final decision has been made on how coal ash or FGD solid wastes will eventually be classified, but if for some plants they are classified as hazardous wastes, disposal costs could be increased by a factor of 10 or more.

Technology and Production of Wastes

Coal-fired utility and industrial boilers generate two types of coal ash--fly ash and bottom ash. Depending on the way in which the boiler is fired and on the fusion temperature of the ash, as much as 70 to 95 percent of the ash may be carried out of the boiler with the flue gas as fly ash, the remainder being removed as bottom ash. Total coal-ash production by electric utilities is expected to reach 72 million tons/year (including over 45 million tons/year of fly ash) by 1980,[25] and industrial boilers are expected to increase this amount by 10 to 15 percent.

As noted above, nonrecovery throwaway FGD systems comprise 90 percent of the utility FGD commitments, and most of them generate a solid waste; the remainder generate a liquid waste.

The quantities of coal ash and FGD wastes produced depend primarily on the ash and sulfur contents of the coal, the applicable air emission regulations, the type of FGD system employed, and the operating conditions of both the FGD system and the boiler. To meet NSPS of 1.2 pounds of SO_2 per million Btu, a typical utility boiler operating at a 70 percent load factor can produce annually between 100 and 500 short tons of dry, ash-free solid waste per megawatt of capacity from the scrubber and from one to two times as much ash. The total quantity of coal ash and FGD waste is expected to be 80 million tons or more (dry basis) by 1980.

Characterization of Wastes

Coal Ash. The chemical composition of coal ash (bottom ash and fly ash) varies widely in concentrations of both major and minor constituents. The principal factor affecting the variation of the composition is the variability in the mineralogy of the coal; however, differences in composition can also exist between fly ash and bottom ash generated from the same coal. Regardless of the type of ash (either fly ash or bottom ash), more than 80 percent of its total weight is usually made up of silica, alumina, iron oxide, and calcium salts. As much as 20 percent of fly ash can be water soluble, so the potential exists for release of contaminants through leaching.

Coal also contains a number of trace elements. Concentrations of trace elements tend to be highest in eastern coals (Appalachian) and lowest in western coals.[29] On the average, only four elements--arsenic, boron, chlorine, and selenium--are present in coals in concentrations much above the average concentration in the earth's crust.

Although the major constituents of bottom ash and fly ash are generally similar, there may be a substantial enrichment of a number of trace elements in the fly ash (antimony, selenium, and lead) as compared with bottom ash.[30] A few of the elements originally present in coal (notably sulfur, mercury, and chlorine) enter the gas stream in some types of combustion equipment and leave the boiler as gaseous species that are not collected downstream in dry-ash collection equipment; however, these may be collected in wet FGD systems used for particulate and/or sulfur oxides control.

FGD Wastes. FGD waste characteristics, particularly the chemical composition, may vary over extremely wide ranges. The principal constituents in solid wastes from most nonrecovery FGD systems are calcium-sulfur salts (present as calcium sulfite and/or calcium sulfate), although significant quantities of calcium carbonate, unreacted lime, inerts (inorganic compounds not oxidized or otherwise reacted), and/or fly ash can also be present. The ratio of calcium sulfite and calcium sulfate (the latter present as $CaSO_4 \cdot 1/2\ H_2O$ or as gypsum, $CaSO_4 \cdot 2\ H_2O$) will depend on the extent to which oxidation occurs within the system.

Combined fly ash and FGD wastes are referred to by the generic term, flue-gas cleaning (FGC) wastes. Fly ash will be a principal constituent of FGC wastes only if the scrubber serves as a particulate control device in addition to removing sulfur oxides or if separately collected fly ash is admixed with the FGD wastes. The amounts of inerts and unreacted raw materials (lime and/or limestone) will depend on system stoichiometry.

FGD waste solids carry with them occluded or free liquor (10 to 90 percent, depending on the amount of dewatering) that contains a wide variety of dissolved substances ranging from trace amounts of various heavy metals to substantial quantities of commonly occurring species such as sodium, calcium, magnesium, chloride, and sulfate. In general, the concentrations of different chemical species in solution will be dictated either by equilibrium solubilities (as in the case of most calcium salts) or, for the most highly soluble species, by the rate at which they enter the FGD system.

The levels of trace elements in FGC wastes depend primarily on four factors:

- Levels of trace constituents in the coal relative to its sulfur content;
- Presence and levels of trace elements in FGD-process additives and makeup water;
- Amount of ash, if any, collected with or admixed with the FGD wastes; and
- Efficiency of the scrubber system in capturing volatile trace constituents.

Data from the analysis of wastes produced by direct lime and limestone wet-scrubbing systems indicate that most of the trace elements in FGC wastes result from the presence of fly ash.[30] Tables 4-6 and 4-7 give the ranges of concentrations of trace elements and soluble chemical species measured in samples of ash-rich wastes and waste liquors.

Waste liquors from once-through sodium scrubbing usually consist primarily of sodium sulfate, chloride, and sulfite (if not oxidized to sulfate as a part of the system operation) at total dissolved solids levels up to 30 percent by weight. The waste may also contain appreciable quantities of fly ash when the system is used for simultaneous sulfur oxides and particulate control.

Disposal Options and Regulatory Factors

At present, coal ash and FGC wastes are disposed of exclusively on land. The three principal disposal methods are wet ponding, dry impoundment, and mine disposal.

Table 4-6. Typical concentrations of trace elements in FGC wastes.

Element	Concentration Ranges (ppm)	Median Concentration (ppm)[a]	Number of Observations	Range of Trace Element Measured in Coal (ppm)
Arsenic	3.4-63	33	9	3-60
Beryllium	0.62-11	3.2	8	0.08-20
Cadmium	0.7-350	4.0	9	—
Chromium	3.5-34	16	8	2.5-100
Copper	1.5-47	14	9	1-100
Lead	1.0-55	14	9	3-35
Manganese	11-120	63	5	—
Mercury	0.02-6.0	1	9	0.01-30
Nickel	6.7-27	17	5	—
Selenium	0.2-19	7	9	0.5-30
Zinc	9.8-118	57	5	0.9-600

[a] Values as reported.
Source: R. R. Lunt et al.[31]

Wet Ponding. Wet ponding usually involves discharge of FGC waste slurries (either directly from the scrubber or after thickening) to a diked containment area where waste solids settle out and supernatant liquor is discharged or recycled to the FGC system. This is a common method used for temporary storage or ultimate disposal of FGC wastes. Evaporation-settling ponds are also used for disposal of liquid wastes from once-through sodium scrubbing systems. In some cases, solid wastes are pretreated before discharge by addition of chemicals to stabilize the wastes, resulting in a hardened material of reduced permeability.

Dry Impoundment. In dry impoundment, moist dewatered solid wastes, usually admixed with dry fly ash, are deposited on a graded site and compacted. Dry impoundment is being used increasingly, frequently in conjunction with stabilization processes, for minimizing the environmental impact of waste disposal. Stabilization, as now practiced, usually involves admixing filtered or centrifuged wastes with dry fly ash and a small amount of lime, which improves the ultimate structural stability and reduces the leaching potential (through reduced permeability and possibly some insolubilization of soluble species).

Disposal in Mines. Mine disposal is potentially attractive because the same transport system that brings the

Table 4-7. Typical concentrations of chemical species in FGD sludge liquors and elutriates.

	Eastern Coals			Western Coals		
Species	Range in Liquor (ppm)	Median (ppm)	Number of Observations	Range in Liquor (ppm)	Median (ppm)	Number of Observations
Antimony	0.46-1.6	1.2	4	0.09-0.22	0.16	2
Arsenic	<0.004-1.8	0.020	15	<0.004-0.2	0.009	7
Beryllium	<0.0005-0.05	0.014	16	0.0006-0.14	0.013	7
Boron	41	41	1	8.0	8.0	1
Cadmium	0.004-0.1	0.023	11	0.011-0.044	0.032	7
Calcium	470-2,600	700	15	240-∼45,000	720	6
Chromium	0.001-0.5	0.020	15	0.024-0.4	0.08	7
Cobalt	<0.002-0.1	0.35	3	0.1-0.17	0.14	2
Copper	0.002-0.4	0.015	15	0.002-0.6	0.20	7
Iron	0.02-0.1	0.026	5	0.42-8.1	4.3	2
Lead	0.002-0.55	0.12	15	0.0014-0.37	0.016	7
Manganese	<0.01-9.0	0.17	8	0.007-2.5	0.74	6
Mercury	0.0009-0.07	0.001	10	<0.01-0.07	<0.01	7
Molybdenum	5.3	5.3	1	0.91	0.91	1
Nickel	0.03-0.91	0.13	11	0.005-1.5	0.09	6
Selenium	<0.005-2.7	0.11	14	<0.001-2.2	0.14	7
Sodium	36-20,000[a]	118	6	1,650-∼9,000[a]	—	2
Zinc	0.01-27	0.046	15	0.028-0.88	0.18	7
Chloride	470-5,000	2,300	9	1,700-43,000[b]	—	2
Fluoride	1.4-70	3.2	9	0.7-3.0	1.5	3
Sulfate	720-30,000[a]	2,100	13	2,100-18,500[a]	3,700	7
TDS	2,500-70,000[a]	7,000	—	5,000-95,000[b]	12,000	3
pH	7.1-12.8	—	—	2.8-10.2	—	3

[a] Levels of soluble sodium salts in dual-alkali sludge (filter cake) depend strongly on the degree of cake wash. The highest levels shown reflect single measurements on an unwashed dual-alkali filter cake.

[b] Levels of soluble chloride components in sludges are dependent on the chloride-to-sulfur ratio in the coal. The highest levels shown are single measurements for a Western limestone scrubbing system operating in a closed loop using cooling-tower blowdown for process makeup water.

Source: R. R. Lunt et al.[31]

coal to the power plant can be used to transport the wastes to the mine. It also eliminates the need for large tracts of new land for disposal. Placement of FGC wastes in mines may also be beneficial in that it fills voids left from coal extraction. In general, active surface mines are considered to be the most attractive sites.[31] In surface mines, dewatered wastes mixed with fly ash or otherwise stabilized could be placed either in the pit bottom before replacement of overburden or in the overburden spoil banks before reclamation.

Ocean Disposal. In areas where no mines are available and disposal sites for land impoundments are scarce, ocean disposal may be a technically feasible alternative. It is now being jointly studied by EPA, DOE, and EPRI.

Regulatory Factors. The disposal of FGC waste and coal ash is and will continue to be subject to federal and state regulations. The key legal framework concerning environmental impact on land is the Resource Conservation and Recovery Act, which provides sufficient statutory basis for preventing significant adverse health and environmental impacts. However, much of the development and implementation of specific regulations lies ahead.

Cross-Media Impact Issues

Potential environmental impacts of FGC systems are dependent on a multiplicity of factors and their complex interrelationships, so that impacts tend to be site specific and cannot be easily generalized. Therefore, an examination of cross-media impacts outside the context of a specific application of FGC technology can only address the potential environmental impact issues. The following discussion identifies the principal cross-media environmental issues related to air, water, and land impacts.

Air Quality Impacts. The FGC system is a control measure designed to reduce facility emissions, but it can produce other air quality effects. These may be divided into three categories: changes in facility emission levels, changes in pollutant distribution, and fugitive emissions from waste disposal.

The application of commercially available FGD technology for sulfur oxides control causes a boiler derating of 3 to 5 percent of its generating capacity because of the consumption of power and steam (for reheat) by the FGD system. A resultant equivalent increase in emissions of nitrogen oxides would be expected because of the extra coal combustion required to provide this heat and energy. The impact on the amount of particulate emissions depends on plant design, as does the amount of nitrogen oxides, since some of the oxides are removed by the scrubber.

Another complicated consideration is the extent to which FGD systems might influence the formation and emission of fine particulate sulfates. The overall reduction in sulfur oxides emissions resulting from FGD system operation would be expected to reduce the overall potential for sulfate formation by SO_2 oxidation. However, a wet scrubber system will also change the humidity in the immediate vicinity and might change the levels of trace metals in the emission plume. Both of these factors have been considered important in the oxidation of SO_2 to sulfate, but data to evaluate the significance, if any, of these combined changes are not currently available.

Data to permit evaluation of the significance of changes in pollutant distribution resulting from FGC system operations are lacking. However, FGD system operations might be expected to influence the extent of both wet and dry deposition of various pollutants in the vicinity of a power plant.

Water-Related Impacts. Water-related impacts can be broken down into two categories, point source and nonpoint source.

Point Sources. Potential point-source impacts stem from the discharge of noncontact cooling and seal water from FGC systems as well as from the discharge of any process liquor. The primary effect of noncontact water on water quality is in terms of sensible heat and oil and grease. The quantity of noncontact cooling water is relatively small in comparison with other plant waste streams, and these discharges would normally be treated along with other plant wastewater and/or be recycled for reuse either in the FGC system or elsewhere in the plant.

Direct discharges of process liquors from solid-waste disposal operations could occur in the form of supernatants from wet impoundments. The other types of point-source impact for process water discharge from FGD systems are from liquid-waste-producing nonrecovery systems and from prescrubber blowdown from recovery systems. The only widely applied FGD system that produces liquid waste involves once-through sodium scrubbing using some form of soda ash, caustic, or impure brine. The waste liquor, which usually amounts to about 0.5 to 1.5 gpm per megawatt of capacity for high-sulfur coal systems, can be discharged to evaporation ponds or wastewater treatment systems. If fly ash is present, the wastes are usually discharged to a settling pond before subsequent treatment or disposal. For large-scale systems, evaporation ponds are generally used.

Prescrubber blowdown from recovery systems is usually small in volume, generally 0.1 to 0.2 gpm per megawatt of capacity. However, the blowdown can be quite acidic ($pH < 2.0$) and can contain up to a few thousand parts per million of dissolved solids, as much as 5 to 10 percent suspended solids (fly ash and calcium-sulfur salts), and numerous trace metals (as cited earlier). The waste stream would normally be neutralized and solids removed as a part of the FGC system operation. The clarified, neutralized liquor would then be either mixed with other plant effluents or further treated.

Nonpoint Sources. The solid wastes generated by FGC systems have the potential to affect water quality, especially in conjunction with their disposal. The potential impact mechanisms of principal interest for all land-based disposal options are leachate and runoff.

The wet-ponding disposal method has maximum potential for leaching of constituents because of the constant intimate contact with water. The extent of leaching depends on the permeability of the wastes and underlying soil, surface runoff, and other factors. To reduce the potential for transport of contaminants into groundwater, ponds can be constructed in areas with low-permeability soils or can be lined with clay.

Major soluble contaminants of importance in FGC wastes are the sulfates, sulfites, and chlorides. For certain dry-sorbent systems using sodium alkalis, overall waste solubility (sodium availability, in particular) could have important adverse impact potential in disposal environments close to usable freshwater resources. Sodium may also be important in leachate or runoff from impoundments of wastes from sodium carbonate scrubbing systems. Stabilization processes have been applied to the wastes from wet FGC systems to achieve reductions in permeability and the rates of leaching of major species. However, runoff (and, to a degree, leachate) quality may still require attention on a site-specific basis in the disposal of stabilized FGC wastes, especially during their placement.

FGC wastes can exhibit relatively high trace-metal levels. From the standpoint of water quality impacts, the presence and availability of metals such as As, B, Se, Cd, Ni, and Zn can be of importance in the leachate and/or runoff from FGC waste-disposal areas or in the ocean disposal of such wastes.

Land-Related Impacts. Geologic and soil-related impacts are associated with the stability of the FGC wastes that are disposed of. Physical instability is a potential problem for all FGC wastes, including stabilized wastes in all types of land disposal. Important considerations are design factors affecting disposal site configurations, stability of underlying materials, erosion potential, and climatic considerations including freeze-thaw conditions.

Instability problems can be ameliorated by compaction methods using dry impoundments and disposal in mines.

Impact on land used for waste disposal is another important environmental factor. A typical 1000-MW power plant requires over a 30-year plant life an estimated 160 to 280 hectares (400 to 700 acres) for disposal of ash and FGD wastes when piled to a height of 20 to 30 feet. This refers to the excavated area proper; actual land commitment, including access roads and buffer zones, may be much larger. However, in terms of national or regional land use, the total land requirements for FGC waste disposal are not significant. If all the coal ash and FGD wastes are deposited by dry-disposal methods to a depth of 10 m (32.8 feet), the total cumulative land commitment (excavated area only) for these wastes will be 5580 hectares (13,750 acres) by 1985 and 19,600 hectares (48,150 acres) by 2000. However, the land required in a given locality could require modifications of land use planning and practices on a site-specific basis.

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CHAPTER 5

COSTS OF FLUE-GAS DESULFURIZATION*

COSTS REPORTED IN THE LITERATURE

The costs of FGD reported in the literature give a very wide range of values. A review of selected published information[1-9] indicates that the capital costs can range from $42 to $183 per kW of installed FGD capacity. This compares to a total plant cost of $700 to $900 per kW. The operating revenue requirements reflect this wide range of capital charges and range from 3 to 9 mills per kWh. This compares to a levelized cost of power generation of about 45 to 50 mills per kWh.

The wide variability in costs from different literature sources stems from differences in

- Scope of the facilities included in the estimate, including boundary limits and amount of redundancy in equipment;
- Degree of conservatism employed by the estimator for processes in differing stages of development;
- Factual economic information, such as dependability of component pricing, selection of the time framework, and treatment of escalation display of costs; and

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*This chapter and Appendix A are based on a draft report, "Economic and Design Factors for Flue Gas Desulfurization Technology," made available to the committee by the Electric Power Research Institute (EPRI), Palo Alto, California. The report, when completed, will be published by EPRI as Project RP 1180-9. Use of the report herein does not imply endorsement of the concepts, methods, and terminology it contains. It should be noted that the various cost calculations used by EPRI and repeated here were made before the May 25, 1979, revisions to the NSPS were issued by the U.S. Environmental Protection Agency under the Clean Air Act Amendments of 1977.

- Purposes of the estimate and level of effort expended.

Table 5-1 summarizes the eight published capital cost estimates for some eleven of the more promising FGD processes. Table 5-2 gives data on actual installed capital costs for seven plants, three of which use limestone, two lime, and two alkaline ash. Revenue requirements are summarized in Table 5-3 for four study estimates; these ranged from 2.3 to 8.7 mills/kWh. For the four operating plants, the costs were between 5.6 and 9.5 mills/kWh when capital charges were included.

A number of earlier attempts were made to correlate the cost of FGD systems with plant size,[10-12] with sulfur content of the coal,[11, 12] and with efficiency of SO_2 removal,[11] but these still showed large variations among plants. The cost estimates used by many of these investigators for individual parts of the FGD system are given elsewhere.[5, 13, 14]

Any improvement in estimate consistency will require not only an accurate definition of scope of equipment and operations to be included but also consistent treatment and presentation of the way in which such items as fees, royalties, interest during construction, and land are to be treated.

UNIFORM COST ESTIMATE COMPARISONS FOR FGD PROCESSES

In order to place the estimates of different FGD systems on a more uniform basis, a standard estimating procedure was developed and used for eight systems. Appendix A gives a complete description of the method and the items included in the capital and operating costs. The plants were normalized for size, coal heating value, sulfur in the flue gas and sulfur removal, date of the estimate, and location. In addition, the capacity factor, heat rate, excess air, ash content, and ash flow to the scrubber were adjusted to the same value for each system. All plants were required to reduce sulfur oxides by 85 percent, with maximum allowable emissions of 1.2 pounds of SO_2 per million Btu. A description of each of the waste disposal methods for the processes is given, since a variety of disposal methods will be used depending on the process selected. The scope of facilities, including engineering costs, project costs, labor costs, owners' costs (royalty allowance, inventory, initial chemicals, etc.), and the year of the estimate were all reduced to a uniform estimate. The cost estimates correspond to a mid-1980 plant startup and mid-1978 dollars.

Table 5-1. Estimated capital costs for new FGD installations.

				Capital Cost (dollars/kW)										
Source of Estimate	Estimate Date	Plant Size, MW	Percent Sulfur in Coal	Lime	Limestone	Wellman-Lord	Integrated Catalytic Oxidation	Magnesia	A/I Aqueous Carbonate	Bergbau-Ferchung	Chiyoda	Double Alkali	Dowa	Sodium Carbonate
TVA[a]	1974	1 x 500	3.5	52	46	62	76	52						
PEDCo[b]	1975	1 x 500	0.6-3.5		53-58	67-90								
SRI[c]	1976	1 x 500	3.7		151	236								
Bechtel[d]	1976	2 x 500	0.48-4.6	89-137	103-127									
Interagency[e]	1979	1 x 500	3.5		96	112	142	104	110	80		102	96	65
Battelle TVA[f]	1979	1 x 500	3.5		97									
Battelle PEDCo A[g]	1980	1 x 1,000	3.5	115										
Battelle PEDCo B[g]	1980	1 x 500	3.5		134									
Battelle United Engrs.[h]	1980	1 x 1,2329	3.6	56										

Sources: [a]McGlamery and Torstrick[3]; [b]PEDCo[5]; [c]Oliver and Van Scoy[2]; [d]EPRI[4]; [e]Stern et al.[1]; [f]Bloom et al.[6]; [g]Laseke[8]; [h]Aul et al.[7]

Table 5-2. Actual capital costs for new FGD installations.

Plant	Plant Size, MW	Percent Sulfur in Coal	Process	Time Period	Capital Costs, Dollars/kW
La Cygne	820	5	Limestone	1971-1978	64
Bruce Mansfield	3 x 825	4.7	Lime	1974-1977	183
Colstrip	2 x 360	0.6	Alkaline Ash	Through 1977	84
Sherburne County	2 x 720	0.8	Alkaline Ash	Through 1977	42
Martin Lake	750	1.0	Limestone		100
South West	194	3.5-4.0	Limestone	Through 1977	77
Conesville	410	4.5	Lime	1976	38

Source: Bloom et al.[6]

Table 5-3. Estimated and actual revenue requirements for new FGD installations.

					Revenue Requirement (miles/kWh)									
Source	Plant	Plant Size, MW	Percent Sulfur in Coal	Base Year	Alkaline Ash	Lime	Limestone	Wellman-Lord	Integrated Catalytic Oxidation	Magnesia	A/I Aqueous Carbonate	Chiyoda	Double Alkali	Dowa
TVA[a]		1 x 500	3.5	1975		2.8	2.3	4.2	3.5	2.8				
PEDCo[b]		1 x 500	0.6-3.5	1975			3.1-3.7	3.6-4.7						
SRI[c]		1 x 500	3.7	1976			6.0	8.7						
Interagency[d]		1 x 500	3.5	1980										
Battelle	La Cygne	1 x 820	5.0	1977			4.3	5.9	3.7	4.3	4.1	1.5	4.6	4.2
Battelle	Bruce Mansfield	1 x 825	4.7	1977			1.7[e]							
Battelle	Sherburne County	2 x 720	0.8	1977		9.5								
Battelle	Conesville	1 x 410	4.5	1976	1.1[e]	5.6								

Sources: [a]McGlamery and Torstrick[3]; [b]PEDCo[5]; [c]Oliver and Van Scoy[2]; [d]Stern et al.[1]

[e]Excludes capital charges.

With the estimates normalized in this fashion it is possible to compare the eight different FGD processes on a common basis.

The type of normalization of cost estimating procedures used in this report should result in much better comparisons among the competing processes with respect to overall costs, energy requirements, capital costs of control equipment, and other important variables. However, it does not necessarily result in a better estimate of absolute costs.

In a comparison of the 1975 TVA capital cost estimate for a limestone scrubbing system with the one in this report, after adjusting the TVA estimate to the 1978 dollars used in this report, the capital cost was $71/kW for the TVA estimate and $158/kW for this report. It was possible, by a careful analysis of the two reports, to explain all but $6/kW of this difference, but this does not permit any conclusion about which of the estimates is closer to what actual costs will be.

The FGD annual revenue requirements given in this report are also higher than others cited in the literature. However, for reasons given in the first section of this chapter and reported in Tables 5-1, 5-2, and 5-3, the range of cost estimates in the literature is wide. For example, the range of "adjusted" costs[1] reported for 1978 for all operating limestone scrubbing plants is 2.58 to 6.56 mills/kWh (a range of 2.5 times) with an average adjusted cost of 4.5 mills/kWh.[2] For all operating lime scrubbers the average of adjusted costs was 4.35 to 8.68 mills/kWh with an average adjusted cost of 6.6 mills/kWh (all in 1977 dollars). This compares with the limestone scrubbing costs in this report of 12.1 mills/kWh for high-sulfur coals and 8.0 mills/kWh for low-sulfur coals and lime scrubbing costs of 13.3 and 7.7 mills/kWh repectively (1978 dollars).

There are a number of reasons why one would expect the average reported adjusted average operating costs to be lower than those estimated in this report. For example, those costs are reported in 1977 rather than 1978 dollars, all the operating plants were constructed in a period when the 1978 inflation effects were much lower, and most operators would probably not include many of the cost items specified and included in the cost methodology used in this report.

Even allowing for all these uncertainties, it appears that the absolute levels of scrubbing costs reported below are higher than those of plants in operation and of cost estimates reported in other publications. This, however, does not seriously affect the use of these estimates for making comparisons among the costs for different process types--the real purpose of this chapter.

Capital-Cost Estimates

The estimated capital costs are shown in Figure 5-1, in which the capital investments are broken down by process capital, general facilities, and owner's cost. Process capital includes cost of all on-site FGD facilities, including all direct and indirect construction costs. General facilities include all FGD-related facilities, engineering design, fees, services, and contingencies. The owner's costs include royalties, inventories, chemicals, land required, and interest during construction.

For all processes, process capital is more than 50 percent of total costs, with general facilities normally somewhat more than half of the balance. In all cases, total capital costs with low-sulfur coal are significantly lower than with high-sulfur coal. For the assumptions used in these estimates, the lowest capital costs with high-sulfur coals for processes that will meet the 1979 NSPS were for the lime slurry scrubbing process. With low-sulfur coals the lowest capital costs were for the spray-dryer, fabric filter process, with the lime slurry process being the next lowest capital-cost process.

Projected costs for the absorption-steam stripping-RESOX (ASR) process are shown in Figure 5-1 and subsequent figures for both current and improved technology resulting from a successful R&D program. With high-sulfur coal, the capital cost of the improved ASR and Wellman-Lord regenerable processes are about $180/kW each.

Operation and Maintenance Costs

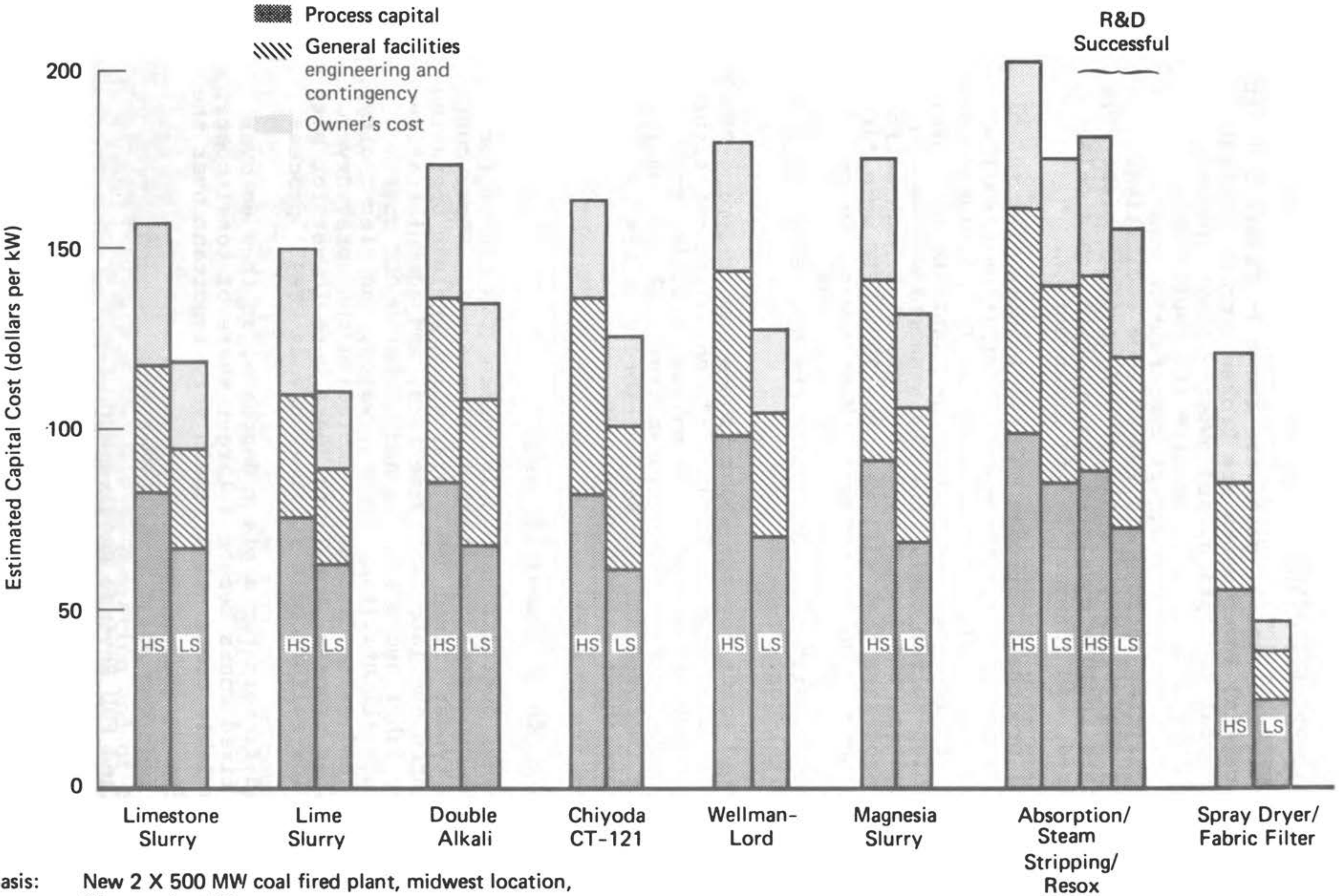
First-year operation and maintenance (O&M) costs for each of the processes are shown in Figure 5-2. These costs are of two types: fixed O&M costs, which include operating labor, maintenance labor and materials, and administrative-supervisory labor and services; and variable O&M costs, which include all utilities (steam, water, and electricity), chemicals, and waste disposal. Excluding the spray dryer, fabric filter process, total O&M costs were lowest for both high- and low-sulfur coals for the Chiyoda CT-121 process.

As load factors for a plant decrease, as they do over time, the fixed costs become a larger share of total costs, but the variable costs still remain very important over the plant life.

Levelized FGD Revenue Requirement

Figure 5-3 shows an estimate of the levelized FGD revenue requirement expressed in mills/kWh for a 30-year

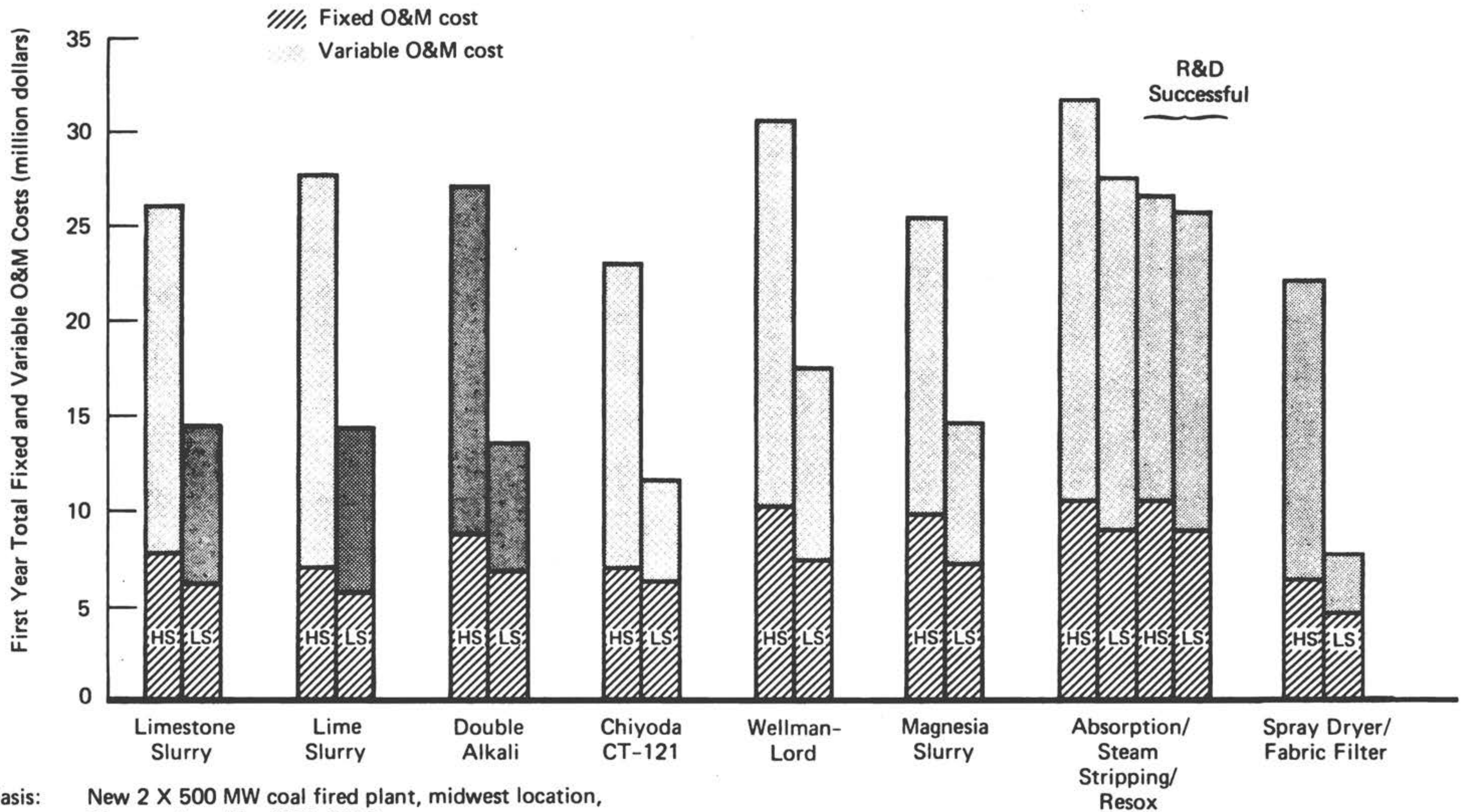
Figure 5-1. Flue-gas desulfurization estimated capital cost.



Basis: New 2 X 500 MW coal fired plant, midwest location,
30 year plant life
Mid 1980 plant startup
High sulfur coal - 4.0% sulfur (avg)
Low sulfur coal - 0.48% sulfur (avg)
Capacity factor 70%, 6132 hrs/yr
85% SO_2 removal

HS = High sulfur coal
LS = Low sulfur coal

Figure 5-2. Flue-gas desulfurization first-year operation and maintenance costs.



Basis: New 2 X 500 MW coal fired plant, midwest location,
30 year plant life, 1979-2008
Mid 1980 plant startup
High sulfur coal - 4.0% sulfur (avg)
Low sulfur coal - 0.48% sulfur (avg)
Capacity factor 70%, 6132 hrs/yr
85% SO_2 removal

HS = High sulfur coal
LS = Low sulfur coal

plant life for each of the eight FGD systems. The levelized revenue requirement is a measure of the present value of future revenue requirements over the life of the plant, including the effect of inflation. The four elements of cost considered are plant investment, owner's cost, fixed O&M cost, and variable O&M cost. Owner's costs are a small portion of total costs for all processes. Fixed O&M costs are somewhat larger but still generally less than 25 percent of total cost. Variable O&M costs are the major element of the levelized 30-year FGD revenue requirement, followed by capital charges for plant investment.

With high-sulfur coals, the spray-dryer, fabric-filter process (if it can be used successfully) appears to have the lowest cost, with a levelized 30-year FGD revenue requirement of 10 to 12 mills/kWh; the Chiyoda process appears to have the next lowest cost. The regenerable Wellman-Lord and improved ASR processes, which recover elemental sulfur, are estimated to cost about 13 mills/kWh with high-sulfur coals and 9 and 12 mills/kWh respectively with low-sulfur coals. With low-sulfur coals, the spray-dryer, fabric-filter process appears to have the lowest cost, at about 4 mills/kWh, followed by Chiyoda CT-121 at about 7 mills per kWh. The favorable position of spray drying may be due to the limited experience with this process.

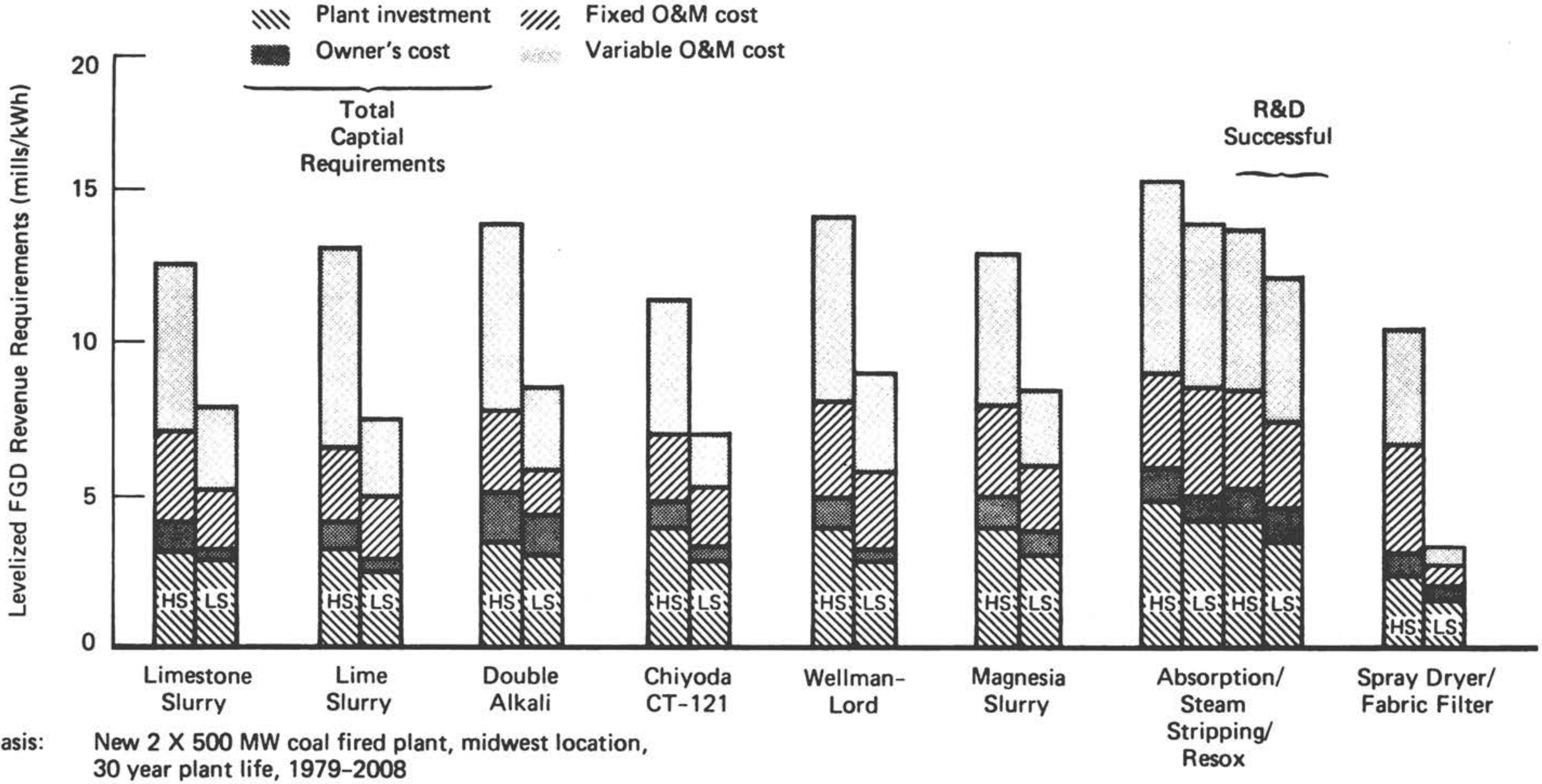
Energy Consumption

The energy consumption for each of the eight FGD processes considered is shown in Figure 5-4. The lowest consumption is with the spray-dryer, fabric-filter process, which currently appears to be feasible only for low-sulfur coals. No reheat is assumed, but full-scale experience with this process may show that reheat is required. Except for the ASR process, energy requirements are much lower with low-sulfur than with high-sulfur coals. Wet throwaway processes are from one-half to one-fourth as energy intensive as regeneration processes, with the most energy-intensive process being the ASR process. Improvements resulting from research and development are expected to reduce steam consumption of the latter process by 30 to 60 percent, significantly reducing energy consumption, as shown in Figure 5-4.

Energy Intensity

The energy requirements to remove 1 pound of SO_2 from flue gases for each of the processes are shown in Figure 5-5. Low-sulfur coals are much more energy intensive per pound of sulfur removed than high-sulfur coals for all processes that are able to use both types of coal. Figure

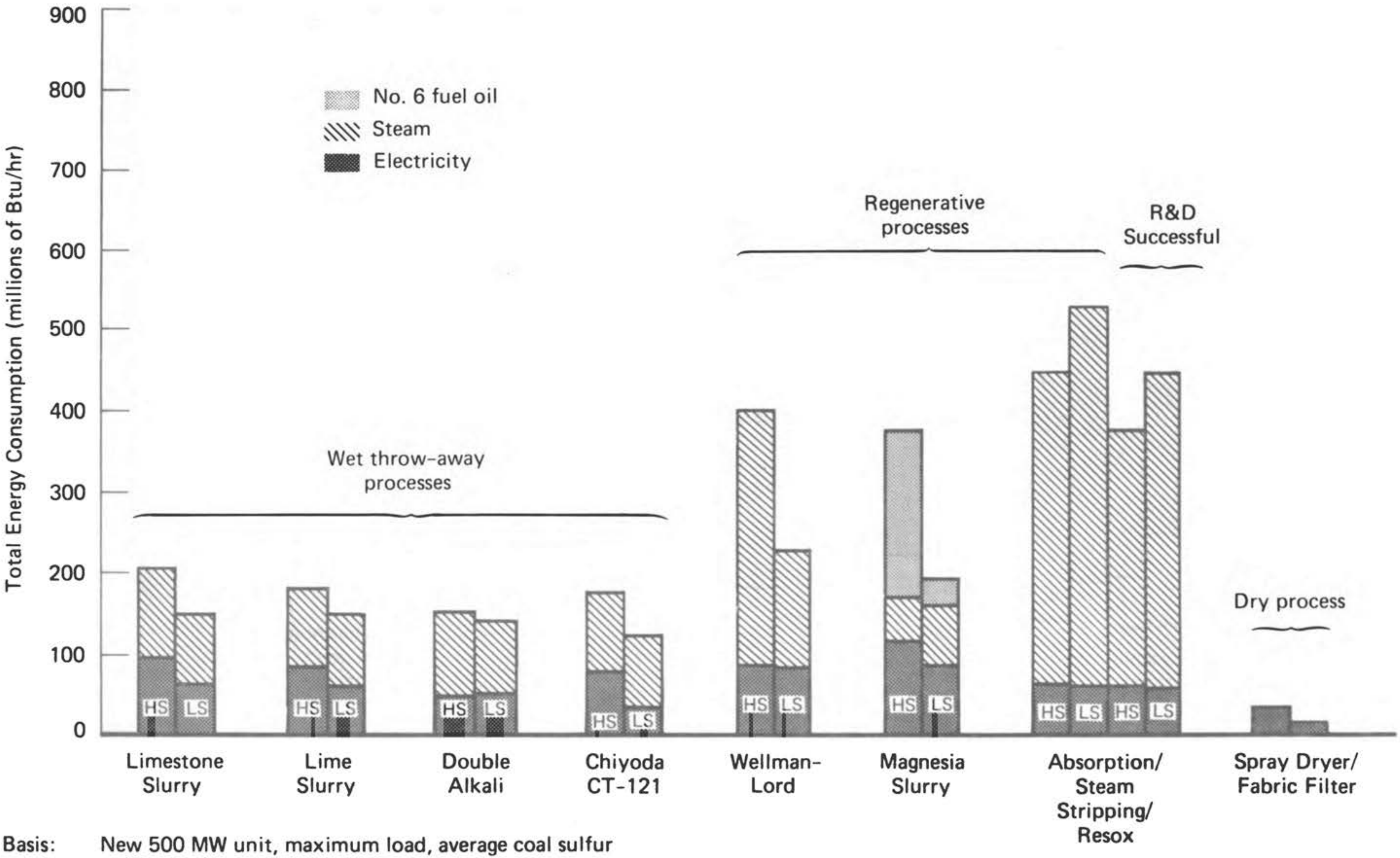
Figure 5-3. Levelized FGD revenue requirements, 30-year life (1979-2008).



Basis: New 2 X 500 MW coal fired plant, midwest location,
30 year plant life, 1979–2008
Mid 1980 plant startup
High sulfur coal - 4.0% sulfur (avg)
Low sulfur coal - 0.48% sulfur (avg)
Capacity factor 70%, 6132 hrs/yr
85% SO_2 removal

HS = High sulfur coal
LS = Low sulfur coal

Figure 5-4. Flue-gas desulfurization total energy consumption.



Basis: New 500 MW unit, maximum load, average coal sulfur
High sulfur coal: 4% S, 85% SO_2 removal
Low sulfur coal: .48% S, 83% SO_2 removal
No. 6 fuel oil: HHV = 150,000 Btu/gal.

5-5 shows that the energy consumption per pound of sulfur removed differs less among the four wet throwaway processes than among the regenerable processes.

Analysis of the individual energy input for each wet throwaway process with both types of coal indicates that the bulk of the electrical energy is used for fan power and absorbent pumping, both of which are related to gas flow volume. The other energy input, steam, is used entirely for flue-gas reheat in all cases. (In climates in which freezing can occur, some steam is used for heating the tanks.) Because the flue-gas densities and reheat-temperature differentials for both the high- and low-sulfur cases are comparable, this energy input is also a function of gas volume.

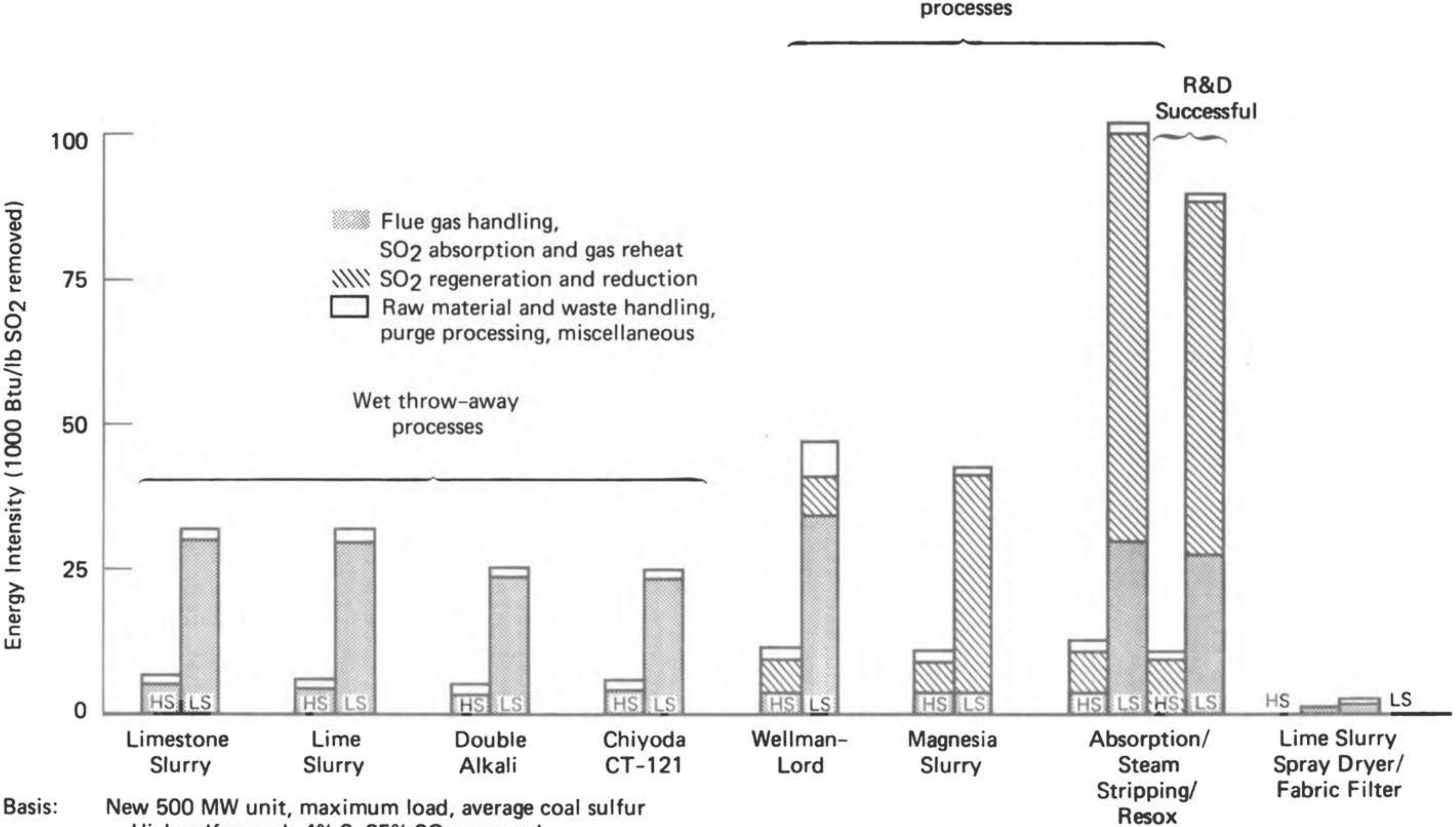
Thus it may be concluded that, for wet throwaway FGD processes employing flue-gas reheat, total energy consumption is determined primarily by gas volume and is only marginally influenced by total sulfur oxides removal requirements. It is for this reason that low-sulfur applications are relatively more energy intensive than high-sulfur applications for a given generating unit size and heat rate.

The general characteristics of the wet throwaway processes indicate that the total excess combustion air and total air in-leakage in the boiler draft system can have a significant effect on actual total FGD energy consumption. It also appears that there may be a basic level of energy consumption associated with the absorption of SO_2 by slurries of calcium compounds. Comparison of the relative energy intensities of the Chiyoda CT-121 and limestone slurry processes suggests that the Chiyoda absorption-vessel design and chemistry reduce the energy input required for absorption when limestone slurry is used as the absorbent.

The total energy consumptions for all regenerative-process cases are substantially higher than for the throwaway process cases because of the energy required to regenerate and reduce the absorbed SO_2. However, the differences between the requirements of the high- and low-sulfur cases are large, with the heat demands of the regeneration and reduction sections accounting for the bulk of both the total consumption and the difference for each process. The Wellman-Lord and magnesia slurry processes show somewhat reduced differences in energy intensities for the high- and low-sulfur cases. This is largely because the energy demands of the regeneration and reduction sections are determined primarily by sulfur oxides removal rate rather than by flue-gas flow rate.

In contrast to all the other processes examined, the total energy consumption of the absorption-steam-stripping

Figure 5-5. Flue-gas desulfurization energy intensity.



Basis: New 500 MW unit, maximum load, average coal sulfur
High sulfur coal: 4% S, 85% SO_2 removal
Low sulfur coal: .48% S, 83% SO_2 removal

HS = High sulfur coal
LS = Low sulfur coal

process with low-sulfur coal is much higher than with high-sulfur coal. The reason is that the specific steam consumption (pounds of steam per pound of SO_2 regenerated) of the stripping process increases as the sulfur loading of the absorbent liquor decreases. This results in an eightfold difference in energy intensities between high- and low-sulfur coal and a total energy consumption for the low-sulfur case that would probably eliminate the absorption-steam-stripping process from consideration for any power plant using low-sulfur coals.

The spray-dryer, fabric-filter process, because it employs neither recirculating absorbents nor flue-gas reheat, requires the lowest total energy input and therefore the lowest energy intensity of all of the low-sulfur cases examined.

Effect of Sulfur Content

To illustrate how the sulfur content of coal might affect costs, those items of cost expected to be most sensitive to the sulfur content of the coal were isolated and analyzed. The results of these analyses are shown in Figures 5-6, 5-7, and 5-8, which respectively show plots of total capital costs, operating costs, and levelized FGD revenue requirements against the sulfur content of coal. The data plotted in these figures use the cost with low-sulfur coal as a base and adjust this cost for changes to those portions of the system that are most sensitive to sulfur content. Thus, these plots do not represent costs with the use of high-sulfur, high-Btu coal but indicate only the effect of sulfur content on costs.

The slope of the line on the figures indicates the sensitivity of any particular process to sulfur content. For capital costs (Figure 5-6), this ranges from $6.05/kW/percent sulfur for the spray dryer, fabric filter process to $17.33/kW/percent sulfur for the Wellman-Lord process, indicating a much greater sensitivity of capital costs to sulfur content for the latter process. For operating costs (Figure 5-7), the range is from $2.8 million/year/percent sulfur (first-year costs) for the steam stripping/RESOX process to $5.6 million/year/percent sulfur for the Wellman-Lord process.

Generally those systems that show more sensitivity to sulfur content in capital costs show less sensitivity in the operating costs. Thus levelized FGD revenue requirements (Figure 5-8) show a range of 1.2 to 2.2 mills/kWh/percent sulfur. However, even those systems that show the most sensitivity to sulfur content may still be cheaper in overall costs than a system that is less sensitive to sulfur content.

Figure 5-6. Total capital requirements, sensitivity to sulfur content, mid-1980 plant startup.

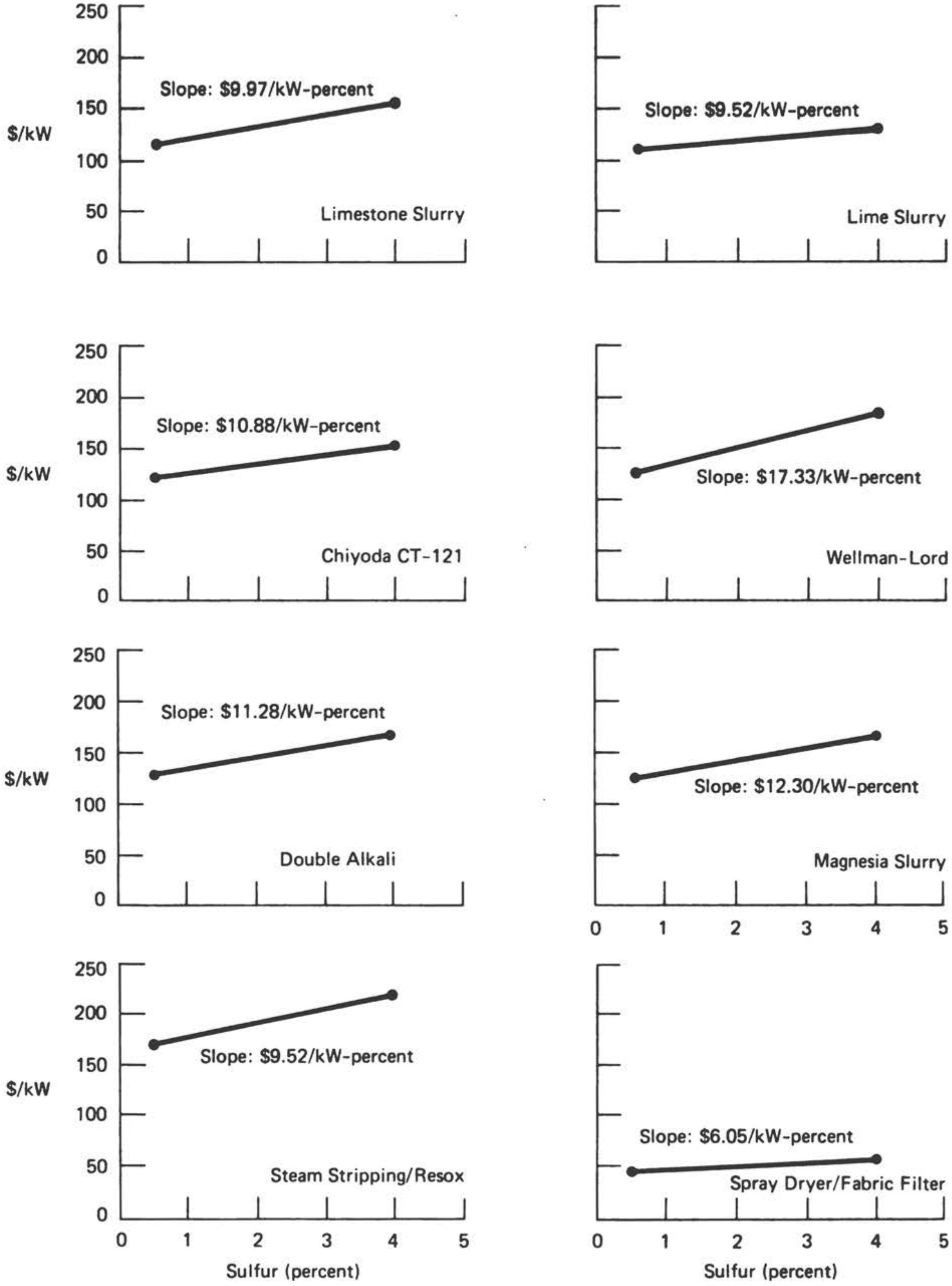


Figure 5-7. First-year total fixed and variable operation and maintenance costs, sensitivity to sulfur content, mid-1978 dollars.

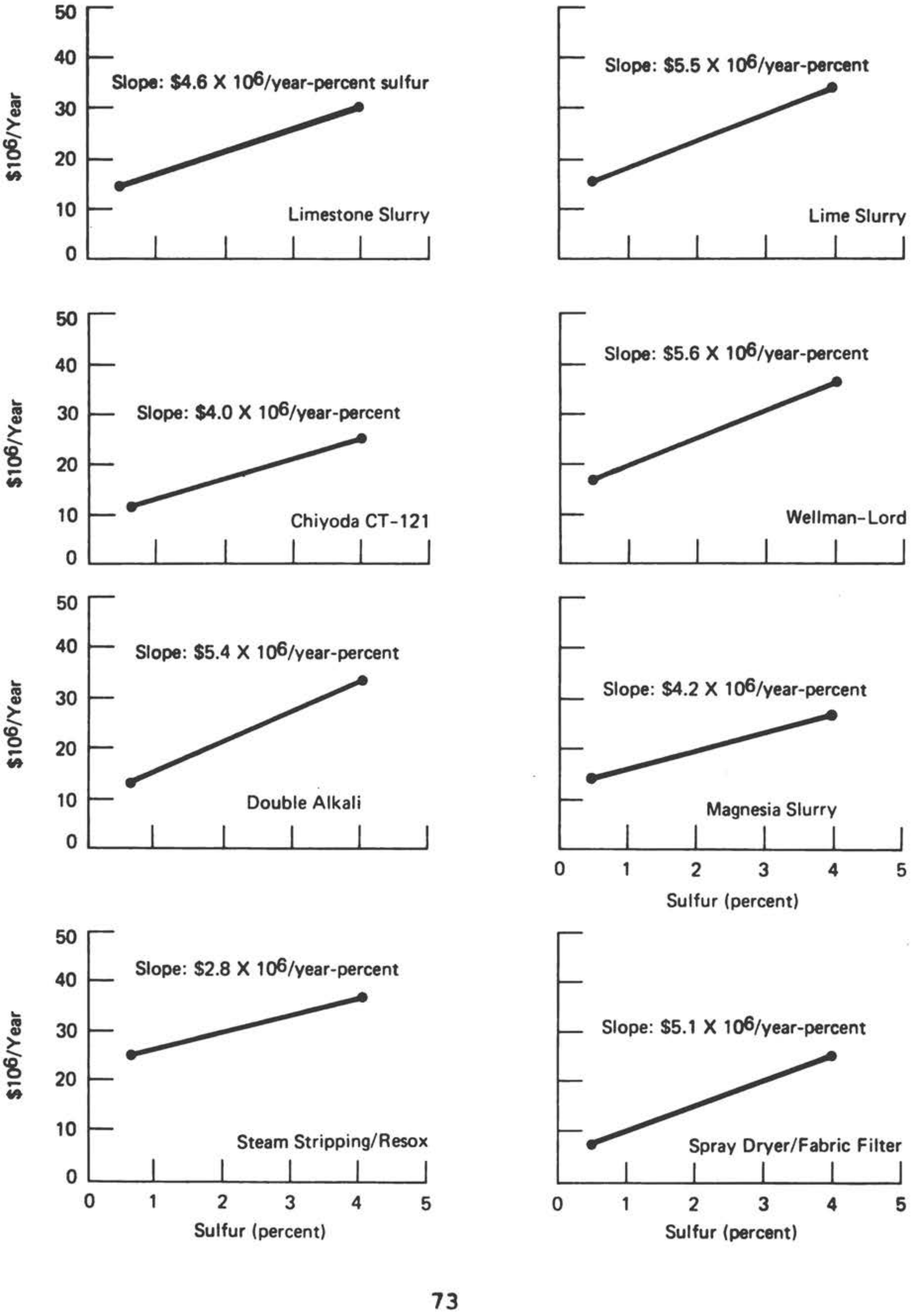


Figure 5-8. Levelized FGD revenue requirements, sensitivity to sulfur content, 30-year life (1970-2008).

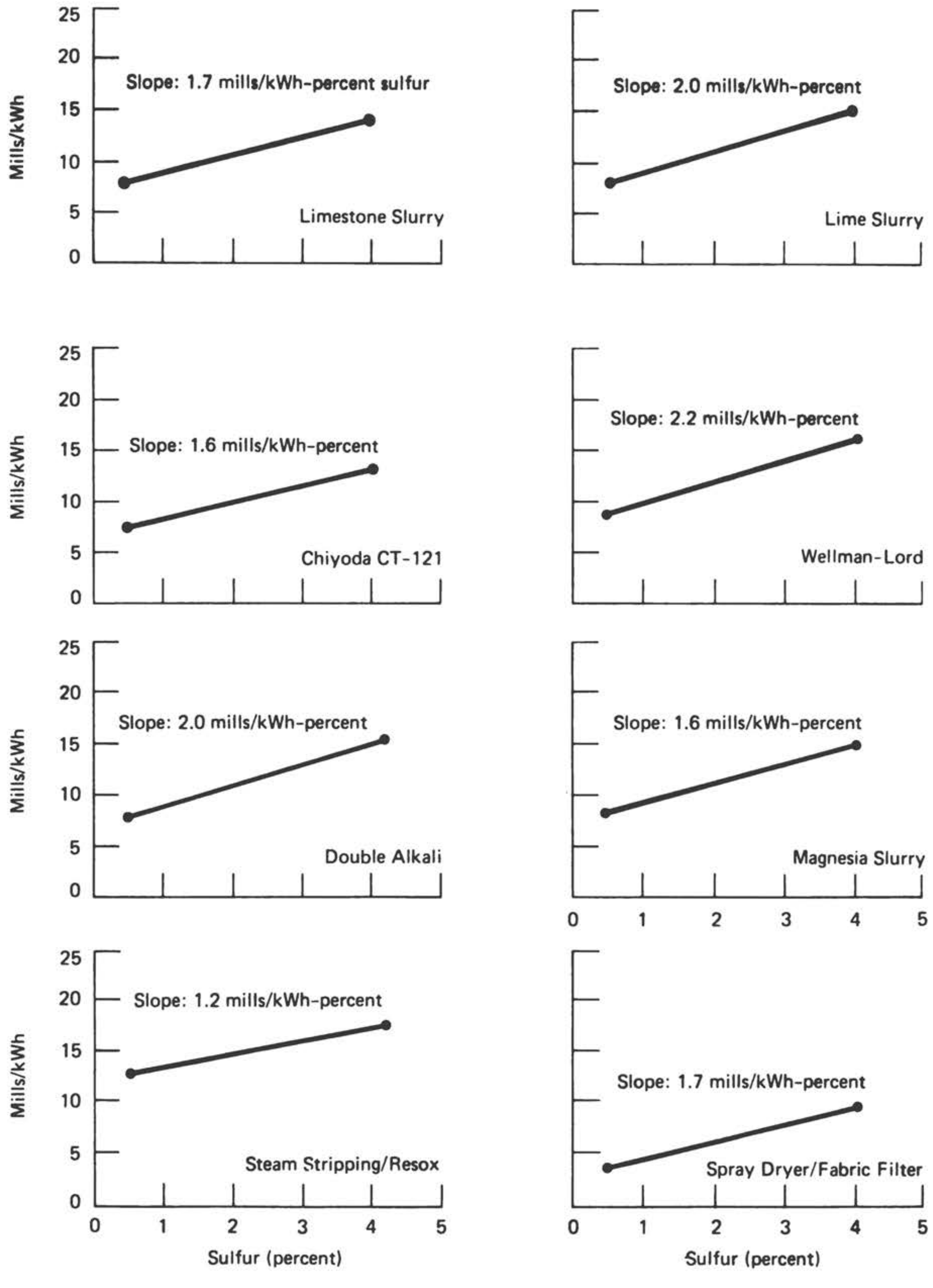


Figure 5-9. Levelized FGD revenue requirements, sensitivity to utility costs, 30-year life (1979-2008).

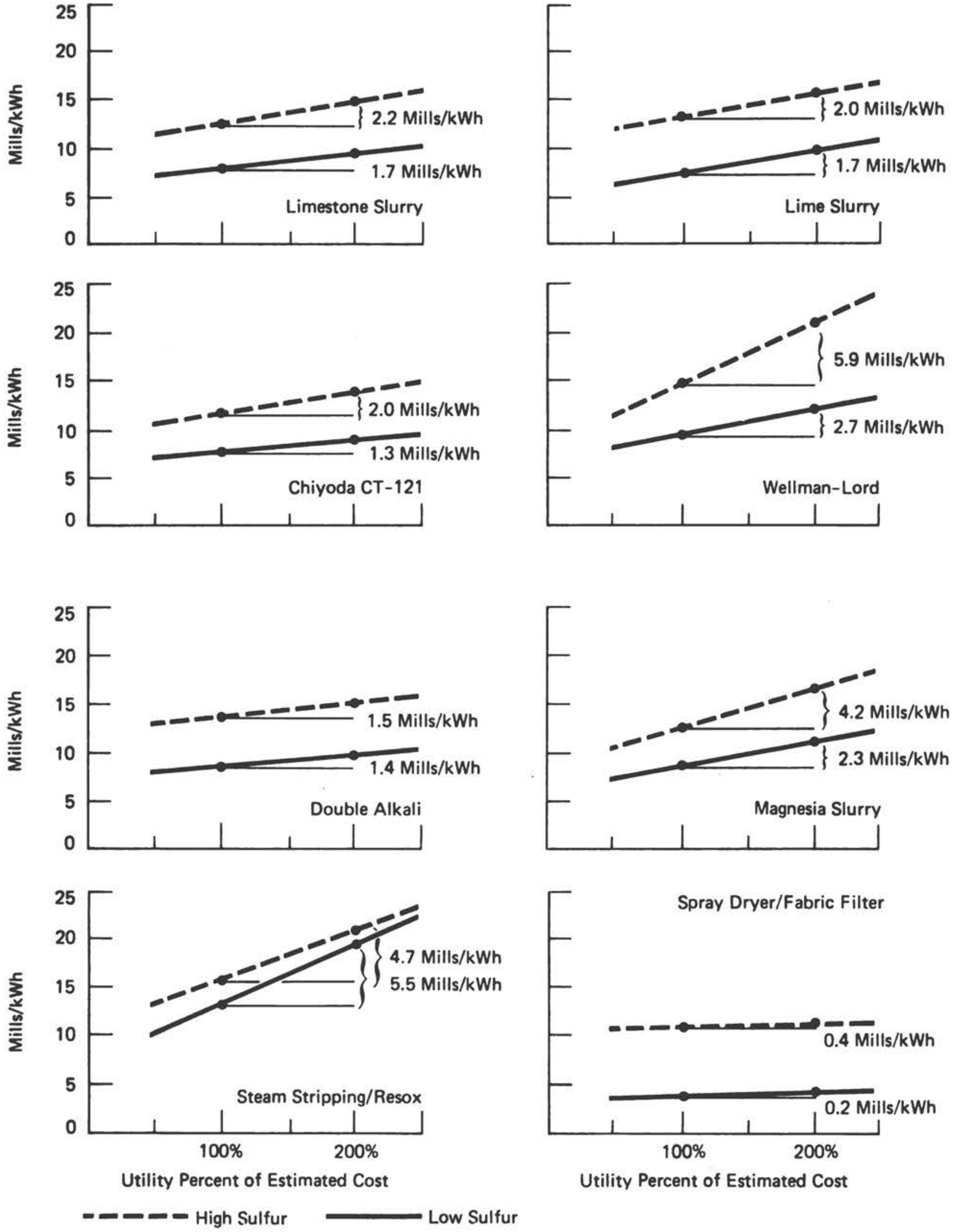


Figure 5-10. Levelized FGD revenue requirements, sensitivity to chemical costs, 30-year life (1979-2008).

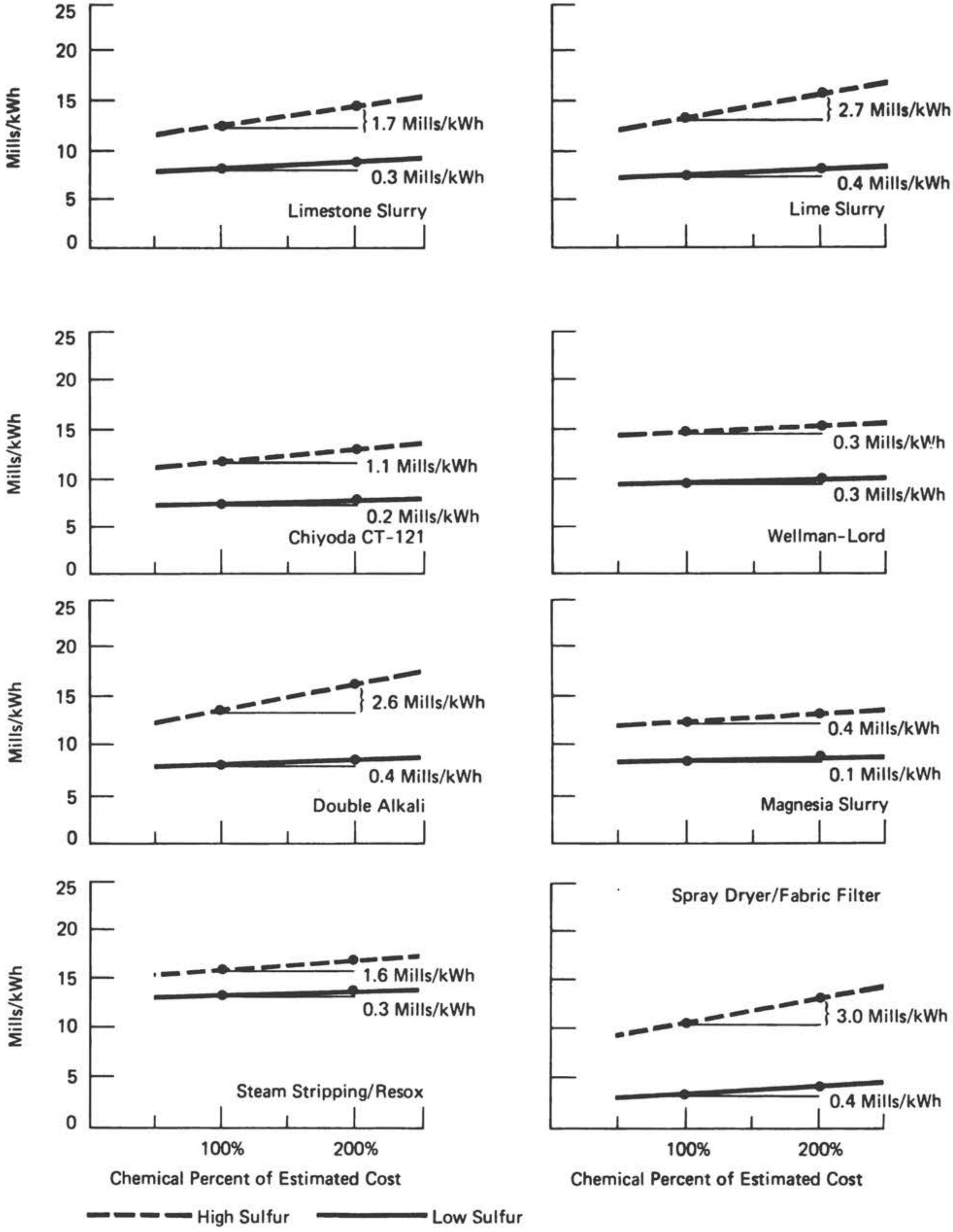


Table 5-4. Effect of utility and chemical costs.

Process	Utilities		Chemicals	
	Percent of Levelized FGD Costs	Utility Cost, Mills/KWh[a]	Percent of Levelized FGD Costs	Chemical Cost, Mills/KWh[a]
High-sulfur coals				
Limestone slurry	17	2.2	16	2.0
Lime slurry	16	2.1	23	3.0
Chiyoda CT-121	16	1.9	11	1.3
Double-alkali process	11	1.5	24	3.2
Wellman-Lord	40	5.9	3	0.4
Magnesium slurry	33	4.2	4	0.5
Steam-stripping-RESOX	29	4.6	12	1.9
Spray dryer, fabric filter	4	0.4	32	3.3
Low-sulfur coals				
Limestone slurry	21	1.7	5	0.4
Lime slurry	22	1.7	8	0.6
Chiyoda CT-121	18	1.3	7	0.6
Double-alkali process	17	1.4	3	0.2
Wellman-Lord	31	2.8	4	0.4
Magnesium slurry	28	2.4	1	0.1
Steam stripping-RESOX	40	5.4	3	0.4
Spray dryer, fabric filter	5	0.2	14	0.5

[a] 30-year levelized costs.

Effect of Utility and Chemical Costs

A similar analysis of costs for utilities and for chemicals (reagents) was made. The effect of variations in sulfur content on operating costs for utilities on total FGD revenue requirements is shown in Figure 5-9, and the effect of chemical costs on revenue requirements is shown in Figure 5-10. In these figures the slope of the line shows the effect that an increase in the cost of utilities or chemicals would have if the costs were increased to 200 percent of the value used in the study.

Analysis of these figures indicates that, in most instances, at the level of pricing in the study, the cost of utilities has a larger impact on FGD revenue requirements than does the cost of chemicals. This is particularly true with low-sulfur coals and for regenerative processes.

The interplay of these effects is shown in Table 5-4, which gives the utility and chemicals costs for each process and the percentage of total FGD revenue requirements that the utility or chemical costs constitute in each process. With high-sulfur coals, utility costs of sulfur oxides scrubbing range from 4 to 40 percent of the FGD revenue requirements, whereas with low-sulfur coals the range is 5 to 40 percent. For chemicals, the cost range is 3 to 32 percent with high-sulfur coals and 1 to 14 percent with low-sulfur coals. From this, one can see that doubling either utility or chemical costs for a limestone high-sulfur slurry process would have about equivalent impact, whereas doubling the chemical costs on the Wellman-Lord high-sulfur or low-sulfur process would not have nearly the impact of doubling utility costs.

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CHAPTER 6

PERFORMANCE OF FLUE-GAS DESULFURIZATION

Because scrubbers generally function close to design efficiencies when in operation, the issue of primary concern has been scrubber dependability. A number of commercial FGD systems have been in operation long enough that the experience gained should permit conclusions to be drawn regarding the dependability of the systems' operation. However, although there is agreement on some of the facts that have emerged, there remain wide differences of opinion on others, even when the same data are evaluated by different experts.

In July 1978 there were 35 full-scale FGD systems in operation in the United States,[1] but of these only 22 units have sufficiently detailed operational records to permit analyzing the data in depth. Table 6-1 lists these 22 major FGD installations and gives the design removal efficiencies for them. Other studies of these data have been made and reported elsewhere.[2] [3] Also given in Table 6-1 are data for eight additional plants that have come into operation more recently; they are also included in Figures 6-4 and 6-5.

Unfortunately, although the total number of years of scrubber operating time is large, the large number of variables that must be considered in evaluating the dependability of the systems makes it difficult to generalize the operating results. In most cases each system and site has unique characteristics that make comparisons difficult. The different plants use coals with widely varying sulfur and chloride contents, a variety of scrubbing agents, and different-sized scrubbers, each with different designs. In addition, the plants have dissimilarities in the average and variable capacity factors over which the FGD systems operate and wide differences in maintenance practices.

The large number of variables that characterize commercial FGD systems and the wide range of opinions about what is meant by the terms "dependability" or "reliability" have made comparisons among the systems equally difficult. The apparent failures at some commercial FGD plants have led many people in the utility industry to question whether FGD

Table 6-1. Identification of plants used in figures.[a]

No.	Name and Unit	Utility	MW	Start-up	Process	Sulfur Content of Coal (%)	SO_2 Design Removal Efficiency (%)
1	Will County	Commonwealth Edison	84	4/74	Limestone	4	—
2	Mystic	Boston Edison	150	4/72	Magnesium oxide	2.5 (oil)	—
3	Hawthorne 4	Kansas City Power and Light	100	8/72	Lime	0.5-3.5	70
4	Hawthorne 3	Kansas City Power and Light	140	11/72	Lime	0.5-3.5	70
5	La Cygne 1	Kansas City Power and Light	820	2/73	Limestone	5	80
6	Paddys Run 6	Louisville Gas and Electric	65	6/73	Lime	3.5	90
7	Cholla 1	Arizona Public Service	115	10/73	Limestone	0.44-1.0	59
8	Reid Gardner 2	Nevada Power	125	4/74	Sodium carbonate	0.5	90
9	Reid Gardner 1	Nevada Power	125	4/74	Sodium carbonate	0.5	90
10	Scholz 1A	Gulf Power	23	8/78	Limestone CT 121	3	90
11	Scholz 1B, 2B	Gulf Power	23	8/78	Limestone	2.5	90
12	Green River 1, 2, 3	Kentucky Utilities	64	9/75	Lime	3.8	80
13	Coalstrip 1	Montana Power	360	11/75	Lime/alkaline fly ash	0.8	60
14	Sherburne 1	Northern States Power	710	3/76	Limestone	0.8	50
15	Bruce Mansfield 1	Pennsylvania Power and Light	825	4/76	Lime	4.7	92
16	Cane Run 4	Louisville Gas and Electric	178	8/76	Lime	3.5	85
17	Coalstrip 2	Montana Power	360	7/76	Lime/alkaline fly ash	0.8	60
18	Reid Gardner 3	Nevada Power	125	7/76	Sodium carbonate	0.5	85
19	Conesville 5	Columbus and Southern Ohio Electric	400	1/77	Lime	4.5	89
20	Sherburne 2	Northern States Power	710	4/77	Limestone	0.8	50
21	Widows Creek 8	Tennessee Valley Authority	550	5/77	Limestone	3.75	80
22	Bruce Mansfield 2	Tennessee Power and Light	825	7/77	Lime	4.5	92
	Huntington 1	Utah Power and Light	415	5/78	Lime	0.5	80
	Milton R. Young 2	Minnesota Power Coop	450	9/77	Lime/alkaline fly ash	0.7	85
	Cane Run 5	Louisville Gas and Electric	183	12/77	Lime	3.75	85
	Conesville 6	Columbus and Southern Ohio Electric	400	4/78	Lime	4.67	89
	Southwest 1	Springfield City Utilities	200	4/77	Limestone	3.5	80
	Dean H. Mitchell 11	Northern Indiana Public Service	115	11/76	Wellman-Lord/Allied Chemical	3.5	90
	Duck Creek 1	Central Illinois Light	400	7/78	Limestone	3.3	85

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[a] No specific measurements are included in this report concerning plant SO_2 removal efficiencies. Most plants investigated have, in fact, made one or more stack gas sampling measurements to verify the design performance specifications. Practically, however, it has been found that mass balance requirements imposed by the chemistry of each process set very tight limits on the variability of the composition of the flue gas and slurry components. Thus, small deviations in either direction from the SO_2 design removal parameters will cause the scrubber to become inoperative.

currently is a proven technology. Others, however, point to the successful operation of some installations as evidence that FGD systems can now be operated reliably.

PERFORMANCE DEFINITIONS

The debate over the status of the dependability of the FGD units now in operation has been confused by the variety of terms used (sometimes interchangeably) to measure FGD performance. The following are the most frequently used terms and their usual definitions:

Availability: Hours the FGD system is available for operation divided by hours in the period (PEDCo).

Operability 1: Hours the FGD system was operated divided by boiler operating hours in the period (PEDCo).

Operability 2: Hours the FGD system is available for operation divided by boiler operating hours in the period (EPRI).

Reliability: Hours the FGD system operated divided by hours it was called on to operate (PEDCo).

Utilization: Hours the FGD system was operated divided by hours in the period (PEDCo).

Each of these indices of performance may be best suited for evaluating various parameters, but unless they are defined accurately and used consistently, interpretation of operating data being evaluated may be distorted. For example, for the following conditions,

Hours in period = 100

Hours boiler operated = 90

Hours FGD operated = 60

Hours FGD available to be operated = 75

Hours FGD called on to be operated = 65

the indices would have these values:

Availability, 75

Operability 1, 66

Operability 2, 83

Reliability, 92

Utilization, 60

Unfortunately, the reported data on different plants have used all these indices, so it is not possible to use a single index in the discussions that follow. In some of the figures used in this chapter, e.g., Figures 6-2 and 6-3, it was necessary to use several of the indices interchangeably; thus a wider spread of the data results than if a common index could have been used.

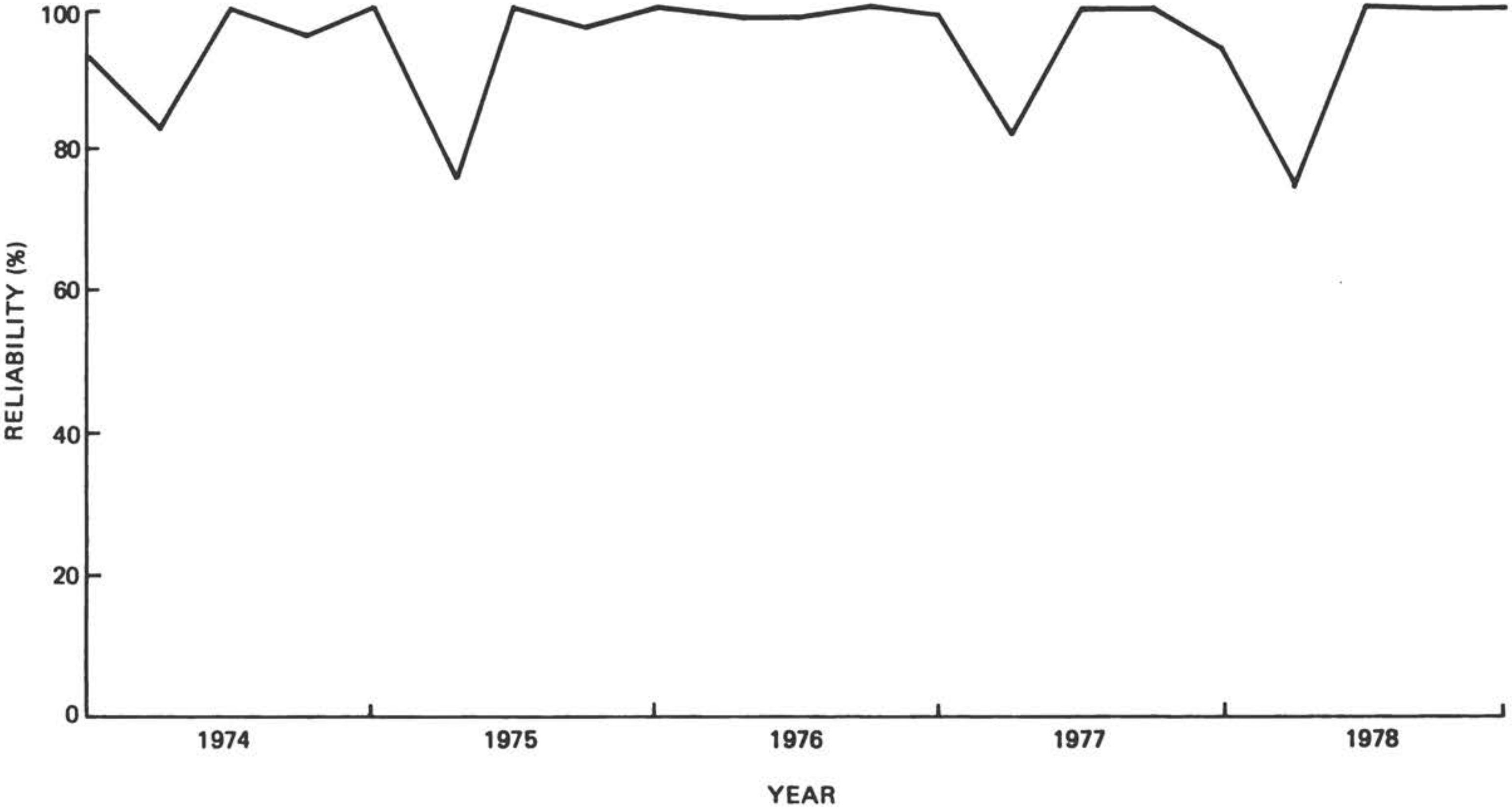
PERFORMANCE AS A FUNCTION OF SULFUR CONTENT

The coals used in the 22 scrubber installations in Table 6-1 have sulfur contents ranging from 0.5 percent (Reid Gardner 1, 2, and 3) to 5.0 percent (La Cygne 1). Examination of the operating data and discussions between some committee members and the engineers responsible for operating the FGD systems lead to the conclusion that the systems have been more dependable for low-sulfur coals than for high-sulfur coals. This conclusion is consistent with the National Academy of Sciences report to the Senate Committee on Public Works,[4] which stated:

> For power plants that burn low-sulfur (less than 1 percent sulfur) coal, either lime or limestone scrubbing is the most effective method now available for reducing emissions of sulfur dioxide in flue gases. Emissions of sulfur dioxide from such sources can be reduced by at least 90 percent with these methods. Successful operation has been demonstrated on commercial scale modules of 115 MW for lime scrubbing and 175 MW for limestone scrubbing.

Experience with FGD systems since that report was issued has verified this conclusion. Much larger systems have now been operated, and for much longer periods, using a variety of coals, limes, and limestones. Figure 6-1 shows the FGD system performance in a utility using low-sulfur coal and limestone FGD over a 5-year period. Except for occasional periods, the reliability of that particular FGD unit has been over 95 percent. It has been pointed out, however,[8] that the Cholla 1 facility operates with coal seldom exceeding 0.8 percent sulfur and that the limestone fixed packing scrubber would be inapplicable to higher sulfur coals. Also, the unit operates in an open-loop mode, so dissolved solids are not returned to the system, as would be required in most locations in the United States.

Figure 6-1. Reliability history of Cholla 1, Arizona Public Service Company (average sulfur content of coal 0.5 percent).



The generally favorable experiences at plants using low-sulfur coal may be attributed, in part, to designs that required only low efficiences for sulfur oxides removal. Other reasons for the favorable experiences may be the ability to use a low stoichiometric excess of limestone to reduce mist-eliminator plugging, a diminished make-per-pass to reduce scaling, and a high level of oxidation of $CaSO_4$, which also helps control scale formation. In other plants using low-sulfur coal, such as those of Montana Power and Northern States Power, the alkaline nature of the coal ash appears to have had a beneficial effect on FGD performance, even though the simultaneous removal of ash and sulfur oxides normally leads to poorer scrubber performance.

Figure 6-2 shows the cumulative average performance of scrubber installations using coal with less than 1.0 percent sulfur as a function of the year in which the system was installed. Except for two earlier sodium carbonate systems, performance has been consistently good, although the data base is insufficient to determine any trend with time.

Figure 6-3 shows the performance at 14 plants using FGD units on high-sulfur coals as a function of the time when the plant was installed. Of the three plants using limestone FGD, only La Cygne (point 5 in Figure 6-3) has had successful experience with a high-sulfur coal. From this figure it would also appear that for high-sulfur coals there has been no improvement in performance in commercial installations using all types of scrubbing agents since about 1973 or 1974.

However, because of the wide scatter of the individual points of Figure 6-3, great care must be used in their interpretation. Plants 6 and 22, which used lime FGD, had somewhat higher than average performance, whereas plant 19, also using lime, had a poor performance. Plant 21, using limestone, also had a poor performance. Plants 1, 2, 10, and 11 are no longer being operated (plant 2 also used high-sulfur oil, not coal, as a fuel), and plants 3 and 4 used lime as the scrubbing agent. The earliest four plants using high-sulfur coals had very low dependability. The data base for plants installed at a later date is still insufficient to permit determination of a statistically significant trend with time, but dependability with high-sulfur coals continues to remain much lower than with low-sulfur coals.

Additional data on seven newer installations have recently become available (based on an unpublished PEDCo report, 1979). The plant characteristics are given at the bottom of Table 6-1. In Figures 6-4 and 6-5, the annual average performance is plotted versus year, as compared to the cumulative average performance plotted in previous figures. Figure 6-4 shows the most recent performance experience with low-sulfur coals and Figure 6-5 gives the

Figure 6-2. FGD performance for 8 plants using coal with less than 1.0 percent sulfur content.

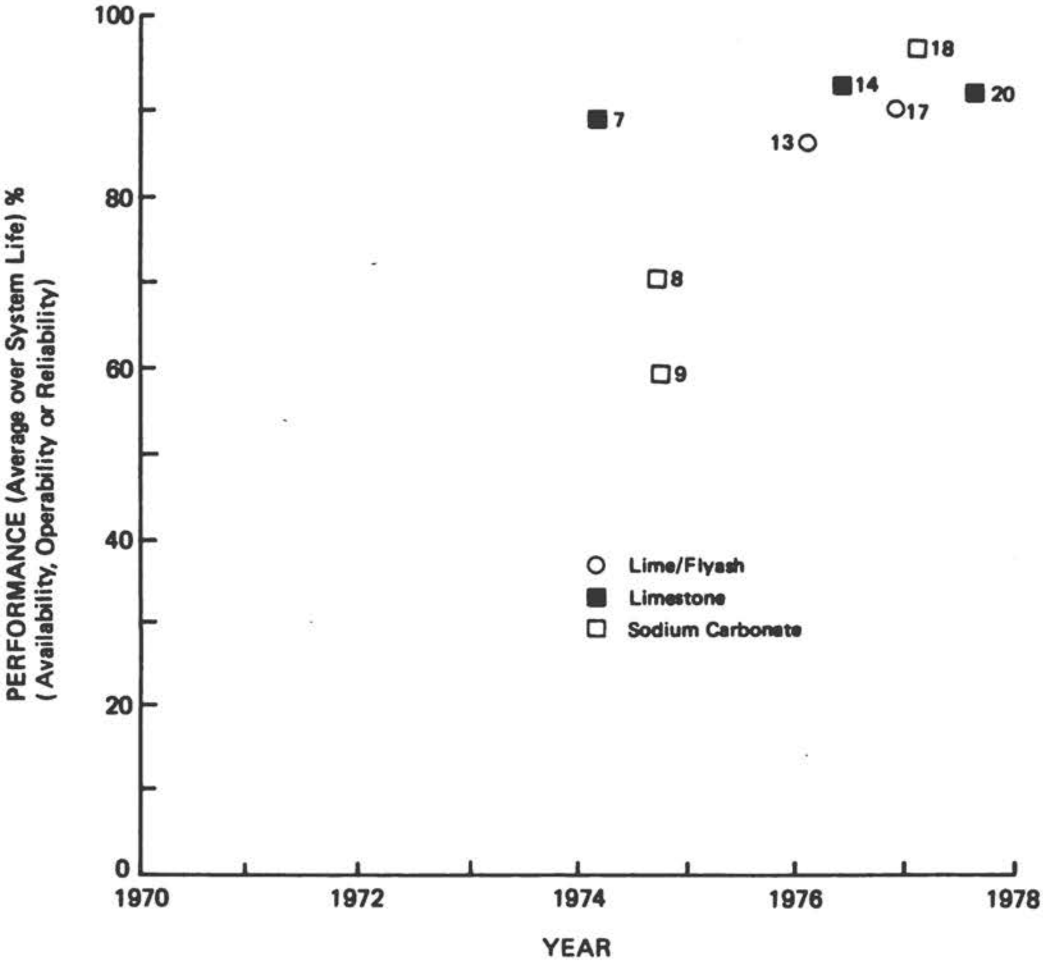
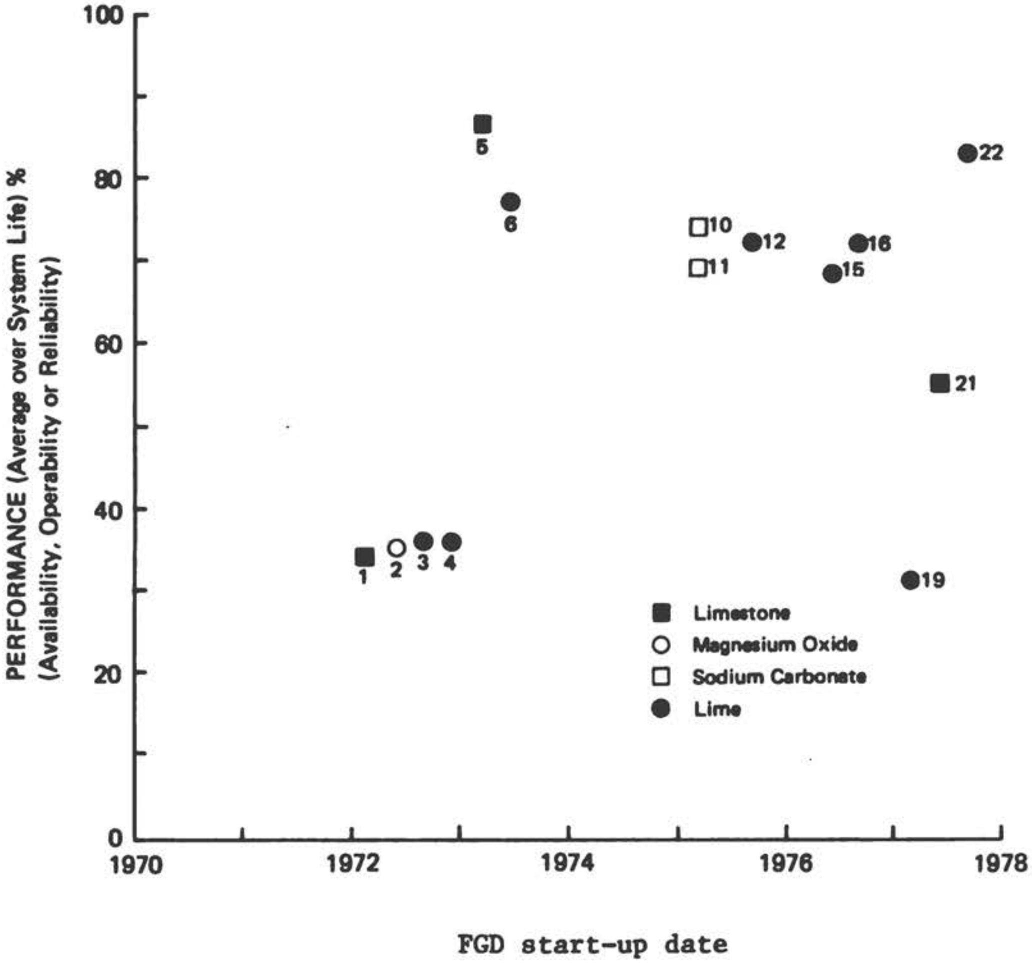


Figure 6-3. FGD performance for 14 plants using coal with more than 2.5 percent sulfur content.



same data for high-sulfur coals. Except for one new plant, Milton R. Young, all the plants using low-sulfur coal had performances that ranged from over 80 percent to 95 percent or more, with performance of these plants generally improving over time.

With high-sulfur coals (Figure 6-5*) the picture that emerges is more ambiguous. In 1978 the plant performances ranged from 30 percent to over 95 percent, with a median around 60 percent. One limestone and one lime scrubber each had performances greater than 90 percent, highly satisfactory, and an additional lime scrubber performed at a level of 80 percent. Two of these three scrubbers were started recently, but three other new scrubbers had unsatisfactory performances.

It is also noted that over their lifetimes the performance of half of the scrubbers have improved and half have deteriorated. Thus the latest data for high-sulfur coal scrubbers confirm the earlier findings that dependability is still much lower than for low-sulfur coal scrubbers; but the successful performances of two scrubbers and the marginally successful performance of one additional scrubber offer encouragement for the future of scrubbing high-sulfur coals. Figure 6-5 shows initial data on the Wellman-Lord System (Dean H. Mitchell). While some reliability information is available at present, the

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*In comparing the data of Figures 6-5 and 6-3, it will be seen that plants 2, 6, 10, and 11 of Figure 6-3 are not shown in Figure 6-5. The reasons given by PEDCo for excluding these plants from the comparison of Figure 6-5 depend in each case on the specific plant. Plant 2 differs from other plants in Figure 6-5 in that high-sulfur oil was used as a fuel. Plant 6 was not plotted because it was used very intensively as a test facility to investigate, for example, the effects of such reagent substitutions as carbide lime. Plant 6 was also reported to operate under conditions where demand for electric power was light. Although the unit was operated for 9 months in 1973, it was operated for a total of only 15 months during 1974 through 1976. After 1976, no further data were available. For the periods the unit was in service, the operabilities were reported to be 52, 82, 98, and 100 percent. Thus, although important data were obtained from plant 6, their inclusion in the study of Figure 6-5 was of marginal value. Plants selected for inclusion in Figure 6-5 more nearly approximate base load conditions than does plant 6. Plants 10 and 11 were not included in Figure 6-5 because these facilities are very small (23 MW), were primarily constructed as a test bed or prototype, and have not accumulated enough hours in service recently to warrant inclusion in Figure 6-5.

Figure 6-4. Annual average scrubber performance for low-sulfur coal operations.

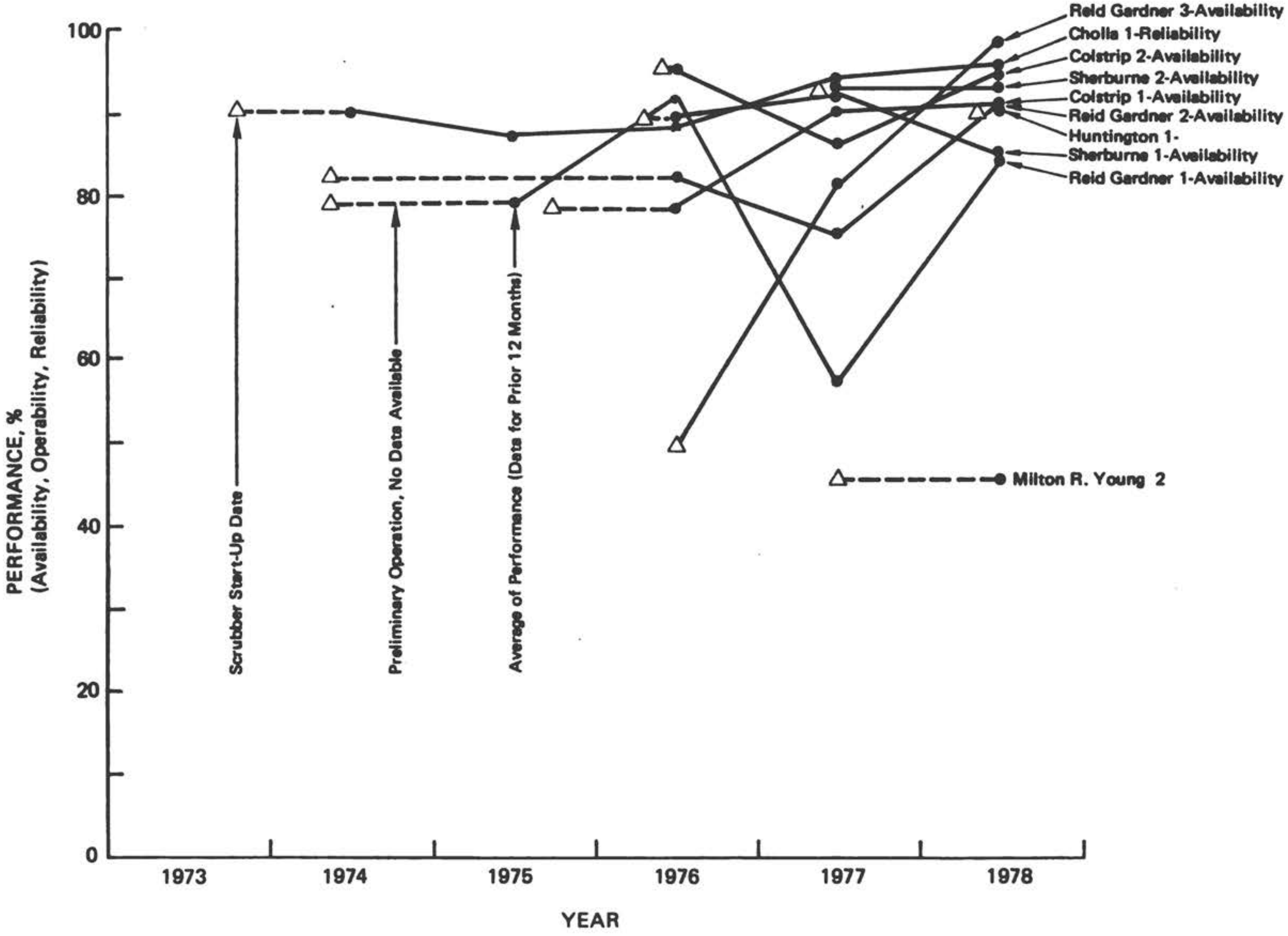
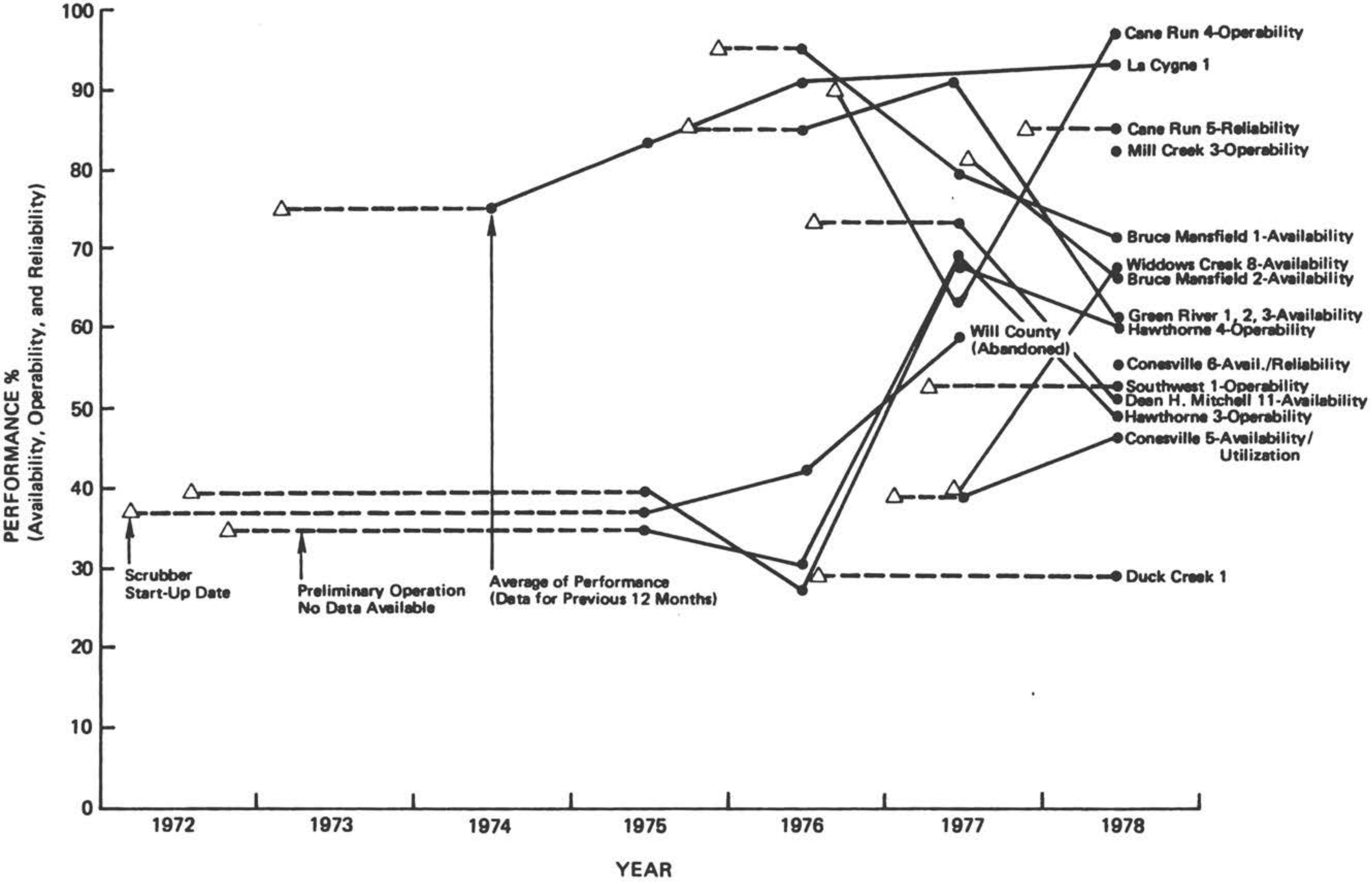


Figure 6-5. Annual average scrubber performance for high-sulfur coal operations.



performance of this first full-scale system producing elemental sulfur cannot as yet be assessed.

Month-by-month performance factors for a 2.0 percent sulfur coal-fired utility boiler in Japan were obtained recently.[5] However, not enough data are yet available to make a plot comparable to Figures 6-2 and 6-4. The data that are available suggest that the performance of Japanese plants is similar or possibly superior to that of plants in the United States having equivalent sulfur in their coals. No experience is available in Japan for comparison with the higher sulfur coals of the U.S. plants in Figures 6-3 and 6-5.

FACTORS AFFECTING PERFORMANCE

Nearly all the commercial FGD experience in large plants involves the use of lime or limestone as the scrubbing agent, so the following discussion covers only these two systems. However, because of differences in plant size, plant design, sulfur content of the coal, chemical characteristics of the limestone, and required removal efficiencies for sulfur oxides, direct comparisons of performance among the different plants are difficult to make.

There are a number of physical and nonphysical factors affecting FGD performance, and these are discussed below.

Chemical Control Problems

Because the fuels and materials (coal, lime, limestone, steel, rubber linings, stack linings) vary widely in composition from one plant to another, process control concentration levels, such as those for pH (a critical parameter), have to be determined in part by trial and error in full-scale operation. This inability to maintain sensitive control of process pH often leads to chemical difficulties, such as plugging and scaling, which may cause extensive mechanical failures. Many of the reported mechanical failures probably should be viewed as a failure to control the process chemistry adequately.

With lime and limestone as absorbents, it has been empirically determined that variations in process pH should be held to within a few tenths, i.e., the pH range should be 7.5 to 8.0 for lime and 5.8 to 6.2 for limestone respectively, at critical points within the process streams.[6] [7] Other experience with similar systems indicates that present automatic process controls and process instrumentation are not sufficiently reliable to enable a commercial FGD unit to operate efficiently at high sulfur oxides concentrations without extensive intervention by operating personnel. A description of such continuous maintenance procedures is found elsewhere.[7] Operating experience shows that attempts to operate a FGD system without such extensive maintenance result in significantly lowered reliability.

Mass transfer additives can make system control easier by relaxing constraints based on SO_2 removal. For example, high $CaCO_3$ stoichiometry can be required to produce sufficient SO_2 removal but will usually result in $CaSO_3$ scaling. Recent tests have reported that the use of adipic acid permits sufficient SO_2 removal at a lower $CaCO_3$ stoichiometry.[9] [10] Additives may add a degree of freedom to system control, although the environmental impacts of sludge disposal remain to be determined.

Design Problems

Early FGD installations were deficient in that there was only a limited amount of redundancy in the equipment, so that failure of a single part of the plant could cause the entire system to malfunction. These early designs also did not make allowance for the frequency of maintenance that proved necessary in certain critical areas; for example, in some early systems pH probes and pressure taps were almost inaccessible after installation. Even now, although certain components specified for FGD systems operate trouble-free in other applications, their performance in FGD systems has generally been less than satisfactory; examples are control dampers, vessel lines, slurry pump impellers, and mist eliminators.

Vendor and Utility Inexperience

The first plants were designed and constructed with little experimental data on smaller-scale plants because it was believed that FGD units could be constructed using the experience gained in other industries in which a particular constituent must be removed from a gas stream. Experience, however, has shown that a wide variety of unexpected problems were encountered. These included unexpected chemical reactions whose by-products had very low saturation levels, resulting in scaling and pluggage of scrubber internals; high mist loadings; higher than expected energy, water, and reagent consumption; and operating problems caused by the need for higher solids content in slurries than had been anticipated.

Utilities had little or no operating experience with chemical plants of this type and no knowledge about how such plants should be designed so that they could be integrated into the conventional equipment in an electric generating plant.

Scaling

Lack of understanding of the chemistry of the FGD process has caused serious problems of scale formation in some parts of the system. Although better control of the pH has resulted in reduced scale formation, plugging continues to be a problem in mist eliminators, in the scrubber (particularly with packed beds), in spray nozzles, and in spray pump seals. In several operating systems the inability to eliminate scaling has prevented achieving good pH control and reliable operation. Scale formation leads to sensor malfunction, which results in instabilities in the FGD chemistry, which lead to scale formation, which is followed by further sensor malfunction, and so on.

FGD systems that have tried to collect particulates while simultaneously removing sulfur oxides have encountered excessive scale formation, which is probably due to the catalytic effects of fly ash on the sulfite-to-sulfate reaction.[4] Removal of fly ash before the scrubber by the use of either an electrostatic precipitator or a baghouse increases system reliability by reducing $CaSO_4$ deposition.

Corrosion and Erosion

Erosion of the first-stage compartment and of walls above the water level has occurred in some FGD systems. Corrosion is due mainly to the existence of sulfurous and sulfuric acids or to high chloride concentrations in some parts of the FGD system. There are a number of varieties of corrosion: general corrosion, pitting, crevice corrosion, intergranular corrosion, and stress-corrosion cracking. Methods to reduce the occurrence of corrosion consist mainly of designs that keep the corrosive environments isolated and of proper selection of construction materials. For example, the prescrubber, which is a small vessel, can be used to concentrate the chlorides and can be made of corrosion-resistant materials. However, the acid waste stream from this prescrubber can constitute a disposal problem.

For operation of the balance of the plant during upset conditions in the scrubber, safe, efficient, and reliable dampers are required. However, dampers, which are used to control hot flue-gas flows under bypass conditions, have been subject to intense corrosion and erosion in a large number of installations, primarily because of the settling of corrosion fly ash in quiescent zones when the dampers are closed.

Mist Eliminators

Mist eliminators are used for removing the excess moisture from the gas stream leaving the FGD system in order to prevent downstream deposition and corrosion problems and to minimize reheat energy requirements. In many installations, particularly in limestone systems, the mist eliminators have been a continual operating problem. They have been subject to deposit accumulations that have resulted in excessive pressure drops across the mist eliminators. At the Shawnee pilot plant the use of low limestone stoichiometry and routine water washing has increased operating reliability. On the other hand, if the fresh water required for this washing exceeds the makeup water requirement for the FGD system, an additional disposal problem is created.

Absorbers

The simplest absorber design is the spray tower, which generally gives satisfactory performance over long periods without deposit formation because the design is such that there are few places in the interior in which solids can be deposited. However, spray towers require higher liquid-to-gas ratios than towers with packing of various kinds. Packed towers, however, tend to scale and plug, and thus require a much higher degree of control and maintenance. The use of prequenchers before the SO_2 absorber minimizes the potential for buildup of mud-like deposits and/or scale at the slurry-gas interface. There is also a trend away from the use of venturi designs because the short liquid-gas contact time results in low SO_2 absorption.

Although the spray towers have greater dependability, the mass transfer limitations permit them to be used at satisfactory SO_2 removal rates only with low- and medium-sulfur coals. Use of high-sulfur coals in spray towers requires a higher slurry circulation rate or more than one stage of absorption or both. A higher slurry circulation rate implies also the need for increased height for the spray zone, more efficient mist elimination, and more erosion-resistant slurry pumps.

Reheaters

The use of reheat has become a major feature of most of the recent FGD systems to improve plume dispersion and decrease plume visiblity and tank corrosion. Problems of corrosion of booster fans, ductwork, and stack liners occur unless the cooled gases are reheated above the temperatures that prevent condensation and deposition from the gas stream.

Most in-line reheat systems have been subject to corrosion problems and plugging on the tubes. Even the more exotic materials of construction have corroded, but many of these problems could be minimized if mist-eliminator efficiency were increased and better cleaning techniques for the tubes (soot blowers) were used. Problems with in-line reheaters have been avoided by using direct-fired or hot-air systems.

IMPROVING PERFORMANCE

If high system reliability is to be achieved, each type of process and plant location needs to be examined carefully, particularly from the standpoint of the reactants to be employed and material variability with time. Specifically, the process selection procedure needs to include chemical and mechanical analysis of the coal or oil fuel, the chemical absorbent composition specification, and the chemical composition of the scrubbing water.

The results of full-scale operating experience show that extensive in-house engineering competence, particularly chemical, mechanical, and materials knowledge, is required by the user both in process and site selection and in plant operation. Experience also shows plainly that the successful operation of FGD systems has not yet been reduced to the simplicity of operation of many other components of modern technology. This is because of the effects of the variations in the extremely sensitive chemical balance of the processes. These effects have been well documented; e.g., in one plant (La Cygne),[6] process-control pH is held carefully between 5.6 and 5.8. Variations outside this range are demonstrated to cause major scaling or corrosion problems. Because the FGD systems are ancillary to power production, the variation input is directly proportional to the power load factor. Changes in the demand for electrical power then must be directly related to changes in reactant feed levels--and, if possible, anticipated.

Although the operating range of pH at the La Cygne plant has been optimized through experimental development, pH is not necessarily controlled within the identical range elsewhere--the underlying reason being connected with process reactant differences.

Although FGD reliability with low-sulfur coals has improved over time, FGD performance with high-sulfur coals is still not generally satisfactory. One exception is the full-scale limestone process at La Cygne, which has demonstrated consistent performance of approximately 90 percent since overcoming start-up problems in 1973 and 1974. Reports of the detailed methods used to solve operating problems are available.[6] [7] Site selection was based on locally available coal, water, and limestone. Coal is delivered by trucks, and water is obtained from a 2600-acre reservoir on the site. Fly ash and spent slurry are pumped to a 160-acre settling pond. After settling, some clear makeup water is pumped back from the pond into the system. A full-load stack-emissions test on August 26, 1977, showed that SO_2-removal efficiency averaged 77 percent and particulate emissions met EPA requirements. It is important to recognize that the ambient air measured at the La Cygne Ambient Monitoring System met the National Air Standard.

The La Cygne FGD operation has encountered its greatest difficulty with corrosion of carbon steel in the ducts, damper fans, housing, and stack liners. Because of the very high sulfur concentration in La Cygne coal (5.39 percent), acid attack becomes severe during periods when for any reason an outage, or cold period, occurs. To rectify this problem and others, La Cygne has undertaken a well-defined maintenance schedule. The schedule requires one of the eight scrubber modules to be taken out of service each night under systematic rotation. A maintenance crew then undertakes a complete checkout of all module components, including cleaning the reheater pluggage and nozzles and removing the accumulation in the sump. Loose rubber from linings is also removed, and the induced draft fan blades are cleaned. La Cygne has reduced the time to inspect and clean a module to 6 hours. Occasionally, the hard gypsum scale is removed manually with sledge hammers.

La Cygne also has installed 316L stainless steel in areas of primary scale formation such as the sieve trays and mist eliminators. This has reduced scale adherence as well as the effects of corrosion. Type 316L stainless steel has been used throughout the FGD system from the venturi throat to beyond the reheaters. The two exceptions to the use of 316L steel were the glass-reinforced polyester chevron mist eliminators and the 304 stainless steel used in the reheater tubes.

Pitting, corrosion, and cracking from chloride stress occurred originally in the reheat-tube supports. This problem was rectified by replacing 304 with 316L stainless steel. An improvement also occurred when, during cleaning, the stainless steel reheat tubes were kept at a temperature above the acid dew point. The high temperature prevents the accumulation of acid during the cleaning process, thus reducing corrosion. Corrosion attack on the fans has been reduced by using various epoxy paints. Recently, epoxy paint (Plastic 4005) has been used as a coating on the carbon steel in the stack liner. Areas especially sensitive to corrosion are being clad with Inconel 625 stainless steel.

Plugging of the module components has been found to require constant attention. The areas of special difficulty are the sieve trays, walls, predemister sieve trays, mist eliminators, and reheat tubes. Soft deposits of leaflike masses of calcium sulfite, as well as fly ash and calcium carbonate, are found. La Cygne removes accumulations of this sort with freshwater sprays. Controlling the pH so that excursions higher than about 5.8 are prevented reduces the chemical conditions that encourage the formation of calcium sulfate.

Because the main control of the reactant feed rate in a lime or limestone scrubber occurs through a determination of the pH at one or more points in the system, a dependable pH sensor is crucial to the success of the process. It has been well demonstrated that one or more instrument technicians need to be assigned full time to the task of making rapid and accurate measurements of pH. A description of problems involved in measurements of pH as well as a description of the location within a given system most suitable for pH measurement is available.[8] The importance of making accurate and frequent measurements of pH at many points within the active areas of the system cannot be overstated. Improper readings of pH can lead to imbalanced reagent feed rates, resulting in a series of cascading errors.

It is important to examine whether there are inherent reasons why such favorable results as have been obtained with high-sulfur and high-ash coals at La Cygne cannot be obtained routinely in the future under different conditions. For example, do the operating conditions, materials, etc., differ in a significant way at La Cygne from those at other plants in which such dependability has not been obtained? It has been suggested that the La Cygne operation has a relatively low boiler-capacity factor that is not characteristic of new base-load power production plants and that the discharged liquor in the La Cygne pond has been diluted so frequently that the dissolved salt content in the FGD loop has never built up to its steady-state value. Also, the sulfur oxides emissions rate at La Cygne, although meeting the local requirement, is 2.0 pounds per million Btu, a value higher than the recently established NSPS. On the other hand, the large amounts of ash and sulfur in the coal are both removed in the scrubber without use of an electrostatic precipitator. This type of operation would be expected to cause serious operational problems, but it has not.

Many difficulties remain to be solved at plants using high-sulfur coals, but there is optimism on the part of the committee that many of the operating problems can be solved.

Although scale formation still remains a problem at some plants, more knowledge about its causes has been developed, so at new units it should be preventable. Formation of difficult-to-remove scales can be controlled to some extent by monitoring and controlling pH levels to 5.8 to 6.2 for limestone and to 7.5 to 8.0 for lime. Scale formation can also be controlled by the coprecipitation of calcium sulfate and calcium sulfite. This is achieved by maintaining a maximum oxidation in the slurry circuit of 16 percent or by the addition of seed crystals, which provide nucleation sites for the precipitation of calcium sulfate.

Experience with existing lime and limestone FGD systems has indicated that redundancy in scrubbers and ancillary equipment will lead to significant increases in reliability. Another factor that should increase scrubber dependability is that the new units are being operated under base-load conditions, rather than conditions with large variations in flow rate and composition, and this leads to more stable conditions. Moreover, the new FGD units will generally be designed for coal from a single source. This also will result in the system's being used under conditions in which no large variations are needed in reagent feed rates. Other operating conditions that lead to lower dependability of the system also will be improved.

The increased operating experience by the staffs of the electric utilities also should lead to more reliable operation. FGD is a new type of process for electric utilities that have little experience with chemical processes of any kind. Improved training of operators in chemical and mechanical procedures specific to FGD should be a prime requirement. Experience gained with the first systems should permit more dependable system operations. Employment of chemical engineers familiar with gas-liquid systems should also improve operations.

Chemical-engineering processes, such as those used for FGD, often require constant monitoring in order to ensure reliable operation, and operating personnel assigned to FGD facilities have not appreciated this need. Only after repeated shutdowns because of poor maintenance have improved maintenance practices been introduced. An operations and maintenance regimen for a given unit should be established and rigidly followed.

RESEARCH AND DEVELOPMENT NEEDS

Although a research and development plan cannot be fully developed until all of the causes of the unsatisfactory results of lime or limestone scrubbing of high-sulfur coal are determined, a number of R&D needs can be identified at this time.

Lime and Limestone Chemistry

Fundamental Physical and Chemical Phenonema. SO_2 absorption into lime or limestone slurries is a complicated combination of vapor-liquid-solid equilibria, gas-liquid mass transfer with chemical reaction, and solids dissolution and crystallization. The chemistry is variable because of variations in coal chloride and sulfur content and in components that affect oxidation of sulfite. Some work has been done toward understanding and modeling this complex process. A more complete model could be used to improve reliability and performance by permitting better design and operation. Better understanding would also quantify the effective use of additives, such as MgO and adipic acid.

Plugging and Scaling. The accumulation of slurry solids and scale formation by precipitation of solids from solution contribute in a major way to the operating problems experienced in wet-scrubber operation. Design features and operating conditions are required that will minimize these problems. Their achievement will be aided by a better understanding of the chemistry of wet scrubbing.

Materials. An evaluation of the material failures in the present facilities should be used as a basis for a materials development program.

Energy Consumption. The energy consumption of scrubbers is not insignificant. It should be possible to reduce this consumption by careful design. Particular attention should be paid to methods of reducing the amount of stack gas reheat and developing systems that have lower pressure drops to reduce pumping power.

Auxiliary Components. Many of the operating problems of scrubbers are related to problems with auxiliary components such as pumps, mist eliminators, nozzles, and dampers. A program to increase the reliability of these components and to specify the amount of redundancy required would be of value.

Instrumentation and Control. Operation and control of scrubbers would be aided by continuous, reliable measurements of the SO_2 concentration entering and leaving the scrubber. The development of accurate, reliable instrumentation to effect this is needed; pH meters that need less frequent maintenance also would be of value.

Sludge Disposal. The thixotropic nature of calcium sulfite sludge, with its structural instability, presents handling, dewatering, disposal, and potential leaching problems. Improved methods for fixing and decreasing the solubility of the sludge are needed. The use of forced oxidation deserves more attention, because calcium sulfate crystals are much easier to dewater.

Regenerable Systems

Additional full-scale demonstration of the two most advanced regenerable processes, Wellman-Lord and MgO scrubbing, should be carried out since this will be necessary before their commercial acceptance.

Spray Drying FGD

Understanding of the chemistry and mass transfer occurring in the spray-drying process would offer long-term benefits. There could be a significant cost saving if the process could be adapted to use with high-sulfur coal. Issues that need to be addressed before this FGD approach can see wide commercial acceptance are the potential problems in scaling up from pilot plant to a full-size module, SO_2 removal versus alkali stoichiometry, control capabilities, how to choose the dry sorbent collection device, the maximum sulfur content of the coal that can be handled effectively, and the leachate potential of the dry spent absorbent.

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APPENDIX

UNIFORM METHOD OF ESTIMATING FLUE-GAS DESULFURIZATION COSTS

Cost analyses are prepared for different purposes and often represent widely different levels of effort. For example, cost comparisons of double-alkali and lime or limestone processes might exclude flue gas reheat, sludge disposal, and particulate removal as being common to all systems. These items would be required, however, for comparison of dissimilar processes, such as A/I aqueous carbonate with Wellman-Lord or with limestone. Rigorous development of all costs attributable to sulfur oxides abatement at different removal levels is therefore useful in regulatory studies.

For these reasons and others, there is no unique methodology that will ensure consistency in FGD system cost estimates. What can be used, however, is a comprehensive checklist of capital and operating costs to be included in the estimate.

An outline for such a standard method of presentation of cost data is given in Table A-1 for capital cost estimates and in Table A-2 for operating and maintenance costs. In the balance of this Appendix, the method used to compare published cost estimates on a common basis is given.

NORMALIZATION OF SELECTED PUBLISHED COST ESTIMATES

Certain inconsistencies in the reported estimates were normalized to a common basis with respect to the following factors:

- Unit size,
- Coal heating value,
- Sulfur in flue gas,
- Sulfur removal, and

Table A-1. Process outline for projected capital requirements.

Basis
Unit:
Capacity factor:
Coal:
Pricing level:

Item	$/kW
Raw-material receiving and storage	
Feed preparation and storage	
Flue-gas treatment	
Waste separation	
Waste disposal	
SO_2 regeneration	
Flue-gas supply	
SO_2 reduction	
Product storage	
Total process capital	
General facilities	
Engineering and home office fees	
Project contingency	
Process contingency	
Total plant investment	
Royalty allowance	
Preproduction cost	
Inventory and initial chemicals	
Interest during construction	
Land	
Total capital requirement	

Table A-2. Process outline for projected first-year operating cost.

Basis
Unit:
Capacity factor:
Coal:
Pricing level:

Item	Unit	Unit Rate ($)	Annual Quantity	Annual Cost ($ ×1000)
Operating labor	Man-hour			
Maintenance labor				
Maintenance material				
Administration and support				
Total fixed O&M cost				
Utilities				
Steam	MW/Btu			
Water	Mgal			
Electricity	kWh			
Chemicals				
Limestone	Ton			
Lime	Ton			
Other				
Other consumables				
Water disposal	Ton			
Total variable O&M cost				
Total first-year operating cost				

- Time of estimate.

These parameters were apparent from the published reports used, and corrections to a common base could be made easily.

No attempt was made to normalize the available data for engineering design conservatism, estimating procedures, various developmental stages, and component pricing.

Where the commercially developed processes, such as the limestone or lime slurry and the Wellman-Lord, were used, the resulting spread in the estimates, as might be expected, was narrower than for less-developed processes. This is shown in Table A-3.

Table A-4 gives the normalized total capital requirements in dollars per kilowatt for the selected reports.

Description of FGD Processes for Which Cost Estimates Were Made

Cost estimates on a common basis were made for each of eight different FGD processes. The processes and their distinguishing characteristics are as follows:

Process	Distinguishing Characteristics
Limestone slurry	Wet calcium scrubbing, landfill disposal of stabilized sludge.
Lime slurry	Wet calcium scrubbing, landfill disposal of stabilized sludge.
Double alkali	Wet sodium scrubbing, absorbent regeneration with lime, landfill disposal of stabilized sludge.
Chiyoda Thoroughbred 121	Wet calcium scrubbing, integral forced oxidation of sulfite to gypsum, landfill disposal of gypsum.
Wellman-Lord	Wet sodium scrubbing, SO_2 regeneration with steam, reduction of SO_2 to elemental sulfur by catalytic conversion using natural gas.
Magnesia slurry	Wet magnesium scrubbing, SO_2 regeneration by calcination,

Table A-3. Range of costs.

Process	Range ($/kW)	Percent Spread Around Mean
Limestone	68-107	28
Lime	60-115	28
Wellman-Lord	80-99	12
Double-alkali	79-152	46
Magnesia	70-146	54

Table A-4. Normalized capital requirements ($/kW).

Process	TVA	SRI	PEDCo	IAg.	Chiyoda
Limestone-slurry	68.4	97.1	106.8	82.0	—
Lime-slurry	60.0	—	115.4	77.5	—
Double-alkali	79.1	—	151.9	—	—
Chiyoda 121	—	—	—	—	54.7
Wellman-Lord	79.6	87.9	99.2	95.2	—
Magnesia-slurry	69.6	—	146	98.6	—
Absorption-steam stripping	—	—	—	—	—
Spray dryer-fabric filter	—	—	—	—	—

Basis: 500-MW newly constructed power plant; coal heating value 12,000 Btu/lb; 4 percent sulfur (avg.); SO_2 removal, 90 percent; fly ash, 80 percent; sulfur in SO_2, 100 percent; estimate, mid-1978.

	reduction of SO_2 to sulfuric acid using catalytic conversion.
Absorption-steam stripping-RESOX	Wet sodium citrate scrubbing, SO_2 regeneration by steam stripping, reduction of SO_2 to sulfur using anthracite.
Spray-dryer, fabric filter	Dry sodium carbonate or lime absorption, simultaneous fly ash removal, landfill disposal of soluble salts with fly ash.

The first seven processes involve absorption of SO_2 from flue gas by contact with aqueous solutions or slurries of calcium, sodium, or magnesium compounds. The first three of these processes produce sludges of calcium salts, which are dewatered and stabilized before disposal. The fourth process produces a high-quality gypsum, which is dewatered and trucked to landfill without further treatment. The last three of these seven processes regenerate the absorbent alkali and produce an SO_2 stream, which is converted to either sulfur or sulfuric acid.

The spray-dryer, fabric-filter process provides a basis for comparison of the costs of a simple dry FGD process with the seven selected wet processes. Costs for dry-process systems currently being developed may be less than for wet systems, but so far the dry-process systems appear to be feasible only for low-sulfur coal.

In addition, an alternate absorption-steam stripping-RESOX (ASR) case was evaluated, assuming expected capital cost and steam consumption savings that would result from ongoing research and development on alternate scrubbing reagents, improved heat exchanger and RESOX reactor designs, and use of bituminous coal as the RESOX reductant.

POWER-PLANT CHARACTERISTICS USED IN ESTIMATES

The data are based on a new two-unit coal-fired plant producing 1000 MW (net) of power. The plant is assumed to be located in the vicinity of Kenosha, Wisconsin, at an elevation of 600 feet above sea level.

Estimates were made for operation on both a high-sulfur Illinois coal and a low-sulfur Wyoming coal. All the major parameters used in the calculations are given in Table A-5.

Unit operating data are presented only for the full-load (MCR) condition. Although some losses in boiler efficiency can be expected at reduced load, and auxiliary power

Table A-5. Generating-unit operating data.

Item	Eastern Coal	Western Coal
Plant net output (MW)	1,000	1,000
Number of units	2	2
Net output per unit (MW)	500	500
Gross turbine-generator output, MCR (MW)	540	530
Capacity factor (percent)	70	70
Net heat rate (Btu/kWh)	9,986	10,293
Heat input to boiler, MCR (10^6 Btu/hour)	4,993	5,146
Coal burn rate, MCR (tons/hour)	247	321
Total excess air (percent)	42	42
Flue-gas flow rate (10^6 lb/hour)	5,952	6,327
Flue-gas flow rate (10^3 scfm)	1,328	1,437
Total ash as fly ash (percent)	80	80
Fly ash production rate (tons/hour)	31.6	16.4
Required precipitator efficiency (percent)	99.8	99.5
Fly ash to FGD system (lb/hour)	150	154

requirements will not be reduced in precise proportion to unit load, variations in the net coal firing rate and the corresponding flue gas flow rate are normally within a fraction of a percent of the variation in unit load. In order to simplify the evaluation, annual average material flows and utility consumptions are based on full-load gas flow conditions at average coal sulfur. The annual totals thus calculated are then reduced by the specified plant-capacity factor for calculation of annual costs.

In all cases the model plant design includes particulate-removal devices to control total particulate emissions to 0.03 lb/10^6 Btu heat input to the boiler, as required by the proposed September 1978 NSPS for control of particulate emissions. In the cases in which wet FGD processes are used, electrostatic precipitators are assumed to be installed upstream of the FGD systems. The required precipitation efficiencies and the resulting fly ash loadings at the FGD system inlets are given in Table A-5.

In the case of the spray-dryer, fabric filter process, the fly ash and products of the SO_2 absorption reaction are removed from the flue gas in the baghouse.

SYSTEM CHARACTERISTICS

In all cases, the FGD systems are designed to control SO_2 emissions to the limits of the proposed September 1978 NSPS for control of SO_2 emissions. These limits are given in Table A-6. The resulting SO_2 removal rates are given in Table A-7.

If emissions exceed 1.2 lb/10^6 Btu at 85 percent removal, removal efficiency must be increased to limit emissions to 1.2 lb/10^6 Btu. If 85 percent removal would reduce emissions to less than 0.2 lb/10^6 Btu, removal efficiency may be reduced to result in 0.2 lb/10^6 Btu emissions.

The SO_2 standards listed in Table A-6 are defined by the 1978 proposed NSPS as 24-hour averages. The designs of the model FGD systems evaluated in this report include SO_2 removal capability beyond that required when firing coal of average sulfur content to accommodate variations in the sulfur content of the coal being fired during any given 24-hour period of operation.

The design of the FGD systems is based on controlling instantaneous SO_2 emissions to the levels listed in Table A-6 when firing coals of the maximum sulfur contents specified. Coals of the specified maximum sulfur contents may therefore be fired continuously without violating the proposed NSPS. This design approach alone ensures

Table A-6. NSPS for control of sulfur oxides emissions.[a]

Category	Amount
Required reduction of generating-unit emissions	85 percent
Maximum allowable emission	1.2 lb $SO_2/10^6$ Btu
Maximum controlled emission required	0.2 lb $SO_2/10^6$ Btu

[a] As proposed in September 1978.

Table A-7. FGD system performance data.

Item	Eastern Coal	Western Coal
Total coal sulfur converted to SO_2 (percent)	100	100
Design condition (MCR, maximum sulfur)		
SO_2 production rate (lb/hour)	45,000	12,833
Required SO_2 removal rate (lb/hour)	39,490	10,190
Required removal efficiency (percent)	87	85
Total SO_2 emission (lb/10^6 Btu)	1.20	0.51
Average condition (MCR, average sulfur)		
SO_2 production rate (lb/hour)	39,550	6,160
Required SO_2 removal rate (lb/hour)	33,620	5,130
Required removal efficiency (percent)	85	83
Total SO_2 emission (lb/10^6 Btu)	1.19	0.20

compliance when the sulfur contents of the coals being fired rise above the long-term averages.

An additional conservatism is incorporated into the design by the assumption that 100 percent of the sulfur in each type of coal is converted to SO_2. This is in contrast with the assumptions of earlier evaluations, supported by recent reports on combustion characteristics of various coals, that indicate that 5 to 10 percent of the total coal sulfur will be contained in the ash. The assumption of 100 percent conversion of sulfur to SO_2 in effect results in a 5 to 10 percent margin in the FGD systems' capacities to remove sulfur oxides from the flue gas.

In the event of extreme excursions of coal sulfur content, each system includes an installed spare absorption train that could be brought into operation to provide an additional 25 to 33 percent flue-gas treatment capability.

To meet the apparent intent of the proposed NSPS for control of sulfur oxides emissions, each FGD system will include one complete installed spare flue-gas handling train. Bypass ducts capable of handling 100 percent of the generating unit design gas flow are provided around the flue-gas treatment sections (prescrubbers and absorbers or spray dryer reaction chambers) to permit full-power operation of the generating units during FGD system failure and simultaneous shortfall in system-wide generating capacity.

WASTE DISPOSAL

In the cases in which the lime or limestone slurry and double-alkali processes are used, the design includes partial dewatering of the calcium sulfite-sulfate effluent slurries in thickeners. The thickener underflow streams are dewatered to 50 percent solids in rotary drum vacuum filters. The resulting filter cake is blended with fly ash and a small amount of dry lime to produce a truckable mixture. The dewatered, stabilized sludge is trucked 10 miles from the plant site to a landfill area.

In the case in which the Chiyoda CT-121 process is used, the gypsum slurry produced in the absorption tank is centrifuged to produce a relatively dry cake. The gypsum cake is trucked 10 miles from the plant site to a landfill area.

The spray-dryer, fabric-filter FGD system is unique in this report in that it involves the disposal of a dry waste consisting of fly ash and water-soluble sodium salts. It is assumed that the waste solids are trucked to a disposal site 10 miles from the power plant and deposited in a clay-lined excavation. As the waste material is accumulated it is periodically capped with impermeable clay to prevent incursion of rain and surface water, which could cause leaching of the sodium salts.

ECONOMIC PREMISES

Projected capital requirements and first-year operating cost can be calculated and comparative economic analyses presented for each process for operation using coals with different sulfur contents.

The bases and qualifications for the economic evaluations in this study are summarized below.

Basis of Estimate

Estimates are based on cost information obtained from published reports, the process vendors, Bechtel's in-house resources, and data contained in the Electric Power Research Institute's Economic Premises for Electric Power Generating Plants as amended in September 1978 (Table A-8).

Table A-8. Source of information used in evaluating process.

Process	Information Source
Limestone slurry	Bechtel, UOP
Lime slurry	Bechtel, UOP
Double alkali	Envirotech, EPA report 1/78
Chiyoda 121	Chiyoda International
Wellman-Lord	Davy Powergas, Allied Chemical
Magnesia slurry	Bechtel, Philadelphia Electric Co.
Absorption-steam stripping-RESOX	Flakt, Foster Wheeler
Spray-dryer, fabric-filter	Bechtel

Table A-9. FGD process facilities: uniform plant section breakdown.

Area	Plant Section	Limestone	Lime	Double-Alkali	Chiyoda CT-121	Wellman-Lord	MgO Slurry	Absorption-Steam Stripping	Spray Dryer
1	Raw material Receiving and storage	X	X	X	X	X	X	X	X
2	Feed preparation and storage	X	X	X	X	X	X	X	X
3	Flue-gas treatment	X	X	X	X	X	X	X	X
4	Flue-gas reheat	X	X	X	X	X	X		
5	Waste separation	X	X	X	X				
6	Waste disposal	X	X	X	X				
7	Flue-gas supply	X	X	X	X	X	X	X	X
8	Purge treatment					X	X	X	X
9	SO_2 regeneration					X	X	X	
10	SO_2 reduction					X	X	X	
11	Product storage					X	X	X	
12	Precipitator credit								X
	Total process facilities	X	X	X	X	X	X	X	X

Estimates are prepared in a uniform manner according to a standard evaluation method published by EPRI to provide consistent economic comparisons and a model for the power industry. Vendor information, adjusted to fit the model plant parameters presented, was coordinated with the respective process vendors for their review and information.

A uniform scope breakdown presented in the standard evaluation method for all FGD process systems is given in Table A-9.

General Facilities. General facilities consist of a pro rata share of the costs of railroad, paved roads, parking lot, walkways, landscaping, laboratory, storm sewers, office, lockers, maintenance shops, fencing, security systems, sanitary facilities, fire and service water, and temporary construction facilities.

For this study, the total cost of these facilities was set to be equal to 12.5 percent of the total process capital for each FGD process.

Engineering Costs. Engineering costs include all design, administration, project management, procurement, and contractors' fees and are assumed to be equal to 12.5 percent of the total process capital for each FGD process.

Project Contingency. Project contingency is the amount of money, man-hours, and time that must be included in an estimate and schedule in order to provide for uncertainties in quantity, pricing, productivity, activity, duration, and timing that lie within the defined scope of the project, to reflect a desired level of confidence.

A 10 percent contingency was applied to limestone, lime, and Wellman-Lord systems, since the cost estimates were based on actual labor rates and quotations for equipment.

A 15 percent contingency was applied to the other five systems, which have not been defined or detailed beyond the flow-diagram level.

Process Contingency. A process contingency is applied to new technology in an effort to quantify the uncertainty in cost of equipment that is not available commercially.

Table A-10 was prepared following the guidelines of EPRI's Economic Premises. This table summarizes the contingencies established for each FGD process. Each process was separately evaluated for its status of technological development, and the appropriate level of contingency was applied to each section. For instance, in the case of the ASR process, there was no contingency applied to the raw-material-receiving, feed-preparation, or

Table A-10. Project and process contingencies.

Process	Project Contingency (percent)	Process Contingency High-Sulfur Coal (percent)	 Low-Sulfur Coal (percent)
Limestone slurry	10	5	5
Lime slurry	10	5	5
Double alkali	15	9	15
Chiyoda Thoroughbred 121	15	14	15
Wellman-Lord	10	9	9
Magnesia slurry	15	11	10
Absorption-steam stripping-RESOX	15	20	20
Spray-dryer, fabric-filter	15	20	13

reheat sections, as these are well developed and commercially available. A 25 percent contingency was used for the absorber section to reflect the design development of this process and equipment.

Exclusions. Cost projections in this study exclude all particulate removal equipment and their installations.

In the case of the spray-dryer, fabric-filter system, particulate removal is combined with SO_2 removal. The SO_2 removal process is therefore credited with costs of an equivalent electrostatic precipitator for fly ash removal to bring its costs to a common basis with the other processes evaluated.

Owner's Cost. Owner's cost, including royalty allowance, preproduction cost, inventory, initial chemicals, interest during construction, and land, has been estimated following the guidelines of EPRI's Economic Premises for application to FGD Systems.

Project Schedule

For the purposes of this study, schedule durations for engineering, procurement, and construction are assumed to be the same for each process. Schedules for actual plants may differ.

All estimates are based on a project schedule of 58 months from start of engineering to commercial operation of the first unit and 70 months to commercial operation of the second unit. The center of gravity for the project is July 1, 1978. Construction is scheduled on a standard work week with casual overtime included but without scheduled overtime. Plant startup is July 1, 1980.

The estimates assume current material lead times and availability of personnel with the required skills.

Labor Costs

The capital cost estimates reflect the cost of labor at the plant locations in Kenosha, Wisconsin.

The operation and maintenance cost estimates reflect the current operating labor cost in EPRI's *Economic Premises*.

The estimates include no incentives to attract and hold skilled labor because the assumed site is near a major population center.

Price Level

All estimates, including equipment, materials, freight, labor, engineering, and other home-office services, are at July 1, 1978, price levels.