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ENVIRONMENTAL CONTROL IMPLICATIONS OF GENERATING ELECTRIC POWER FROM COAL

TECHNOLOGY STATUS REPORT VOLUME II

ENVIRONMENTAL CONTROL-
COAL UTILIZATION PROGRAM

ARGONNE NATIONAL LABORATORY

PREPARED FOR
DIVISION OF ENVIRONMENTAL CONTROL TECHNOLOGY
U. S. ENERGY RESEARCH AND DEVELOPMENT ADMINISTRATION

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ENVIRONMENTAL CONTROL IMPLICATIONS
OF GENERATING ELECTRIC POWER FROM COAL

TECHNOLOGY STATUS REPORT

Volume II

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FOREWORD

A continuing assessment of "Environmental Control Implications of Generating Electric Power from Coal" is being carried out for the Division of Environmental Control Technology in the ERDA Office of Environment and Safety by Argonne National Laboratory and a number of subcontractor companies. This report is the first in a series of reports to be issued under the program and represents efforts from inception of the program in March, 1976 through December, 1976. The primary emphasis in this initial report is on the characterization and evaluation of existing and near-term technologies for coal utilization. Environmental regulations and the health effects of pollutants are also reviewed.

Volume I of the report is a condensation of the technology descriptions and evaluations. It also includes recommendations for research and development activities identified by the study thus far, and an executive summary. Reference citations have been omitted from this volume in the interest of brevity and readability.

Volume II of the report contains much more extensive and detailed technology descriptions and evaluations. The appropriate reference citations are included to identify source materials, with a list of references presented at the end of each major topic.

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TABLE OF CONTENTS

	<u>Page</u>
ABSTRACT	1
1 INTRODUCTION	1
1.1 THE ERDA PROGRAM ON ASSESSMENT OF ENVIRONMENTAL CONTROL TECHNOLOGY FOR POWER GENERATION FROM COAL	1
1.2 CONTENT AND ORGANIZATION OF REPORT	4
1.3 FUTURE WORK ON THE PROGRAM	5
2 ENVIRONMENTAL REGULATIONS	7
2.1 AIR QUALITY REGULATIONS	7
2.1.1 Ambient Air Quality Standards	9
2.1.2 Emission Standards	16
2.1.3 Regulatory Developments	34
2.2 WATER QUALITY REGULATIONS	39
2.3 REFERENCES	44
3 HEALTH EFFECTS	45
3.1 SUMMARY	45
3.1.1 Statement of Purpose	46
3.2 "HEALTH" DEFINED	47
3.2.1 The Measurement of "Health"	47
3.2.2 The Study of Health Effects	47
3.3 HEALTH EFFECTS ASSOCIATED WITH AIR POLLUTION FROM COAL USE . .	48
3.3.1 Physiological Effects	48
3.3.2 Clinical Conditions Resulting from the Physiological Effects	49
3.4 HEALTH EFFECTS ASSOCIATED WITH SPECIFIC POLLUTANTS	51
3.4.1 Sulfur Dioxide	51
3.4.2 Oxides of Nitrogen	53
3.4.3 Ozone	54
3.4.4 Hydrocarbons	55
3.4.5 Carbon Monoxide	57
3.4.6 Particulates	57
3.5 REFERENCES	61
4 CONTROL TECHNOLOGIES FOR CONVENTIONAL POWER PLANTS	64
4.1 FLUE GAS DESULFURIZATION SYSTEMS	64
4.1.1 Summary	64
4.1.2 Introduction	65
4.1.3 Technology Description	66

TABLE OF CONTENTS (Cont'd)

	<u>Page</u>
4.1.4 Reliability of Operational FGD	82
4.1.5 Secondary Environmental Impacts of FGD	92
4.1.6 Costs of FGD	93
4.1.7 Anticipated Deployment of FGD	99
4.1.8 Conclusions and Recommendations	101
4.1.9 References	102
4.2 PARTICULATE CONTROL TECHNOLOGY	104
4.2.1 Summary	104
4.2.2 Introduction	105
4.2.3 Technology Descriptions	106
4.2.4 Advanced Concepts	134
4.2.5 High-Temperature, High-Pressure Particulate Removal	137
4.2.6 Sampling and Measurement Techniques	138
4.2.7 References	142
4.3 NITROGEN OXIDES CONTROL	144
4.3.1 Summary	144
4.3.2 Introduction	146
4.3.3 Formation of Nitrogen Oxides	150
4.3.4 Combustion Modification for NO _x Emission Control	153
4.3.5 Flue Gas Treatment	160
4.3.6 Secondary Environmental Impacts	162
4.3.7 Conclusions	163
4.3.8 References	164
4.4 DISPOSAL OF SOLID AND LIQUID WASTES	166
4.4.1 Summary	166
4.4.2 Fly Ash and Bottom Ash	169
4.4.3 Flue Gas Desulfurization Wastes	186
4.4.4 Wastewater Effluent Control	203
4.4.5 References	211
5 CONVENTIONAL POWER PLANTS USING CLEANED COAL OR LOW SULFUR COAL	216
5.1 COAL PREPARATION AND COMBUSTION OF CLEANED COAL	216
5.1.1 Summary	216
5.1.2 Introduction	217
5.1.3 Status of Coal Preparation and Cleaning Technology	218
5.1.4 Constraints in Preparation of United States Coals	250
5.1.5 Recommendations and Conclusions	259
5.1.6 References	261
5.2 USE OF LOW SULFUR COAL	267
5.2.1 Introduction	267
5.2.2 Minemouth Price of Coal	268
5.2.3 Price Premiums for Low Sulfur Coal	270
5.2.4 Transportation Costs	272
5.2.5 Total Delivered Price	274

TABLE OF CONTENTS (Cont'd)

	<u>Page</u>
5.2.6 Constraints on the Extraction and Distribution of Coal	274
5.2.7 Constraints on Utilization	284
5.2.8 References	301
6 FLUIDIZED-BED COMBUSTION	303
6.1 SUMMARY	303
6.2 INTRODUCTION	305
6.2.1 Need for Fluidized-bed Combustion	305
6.2.2 Background	306
6.3 TECHNOLOGY DESCRIPTION	309
6.3.1 Atmospheric Fluidized-bed Combustion	311
6.3.2 Pressurized Fluidized-bed Combustion	312
6.3.3 Differences between AFBC and PFBC	313
6.3.4 Status of the Technology	314
6.3.5 Efficiency	319
6.3.6 Possible Add-On Control Technology	320
6.4 CONTROL OF POLLUTANT EMISSIONS	320
6.4.1 Sulfur Dioxide	321
6.4.2 Oxides of Nitrogen	328
6.4.3 Particulate Emissions	332
6.4.4 Trace Elements	337
6.4.5 Hydrocarbon Emissions	340
6.4.6 Other Forms and Sources of Pollutants	340
6.5 MANAGEMENT OF FBC SOLID WASTES	340
6.5.1 Introduction	340
6.5.2 Magnitude and Nature of the Problem	341
6.5.3 Disposal Modes	343
6.5.4 Utilization Alternatives	343
6.5.5 Regeneration	346
6.5.6 Limestone and Dolomite: Availability and Secondary Pollution	347
6.6 IMPLEMENTATION	347
6.6.1 Costs Compared to Regular Combustion with Flue-gas Desulfurization	347
6.6.2 Time Frame for Availability	350
6.6.3 Areas of Applicability	351
6.6.4 Possibility of Retrofit	352
6.6.5 Barriers to Implementation	352
6.7 REFERENCES	353
APPENDICES	358
APPENDIX A. STATE AMBIENT AIR QUALITY STANDARDS	359
APPENDIX B. COAL MARKET MODEL	397

TABLE OF CONTENTS (Cont'd)

	<u>Page</u>
B.1 Choice of Regions	397
B.2 Regional Demand	400
B.3 Coal Supply Functions	401
B.4 Transportation Costs	407
B.5 Future Rail Rates	411
B.6 Rail-Barge Costs	411
B.7 Model Description	416
APPENDIX C. MODEL PLANT UNDER CONSIDERATION FOR THE ASSESSMENT OF TECHNICAL PROBLEMS ASSOCIATED WITH THE BURNING OF LOW SULFUR WESTERN COAL	420

LIST OF FIGURES

<u>No.</u>	<u>Title</u>	<u>Page</u>
2.1	Coal Reserves in the U.S.	20
4.1	Schematic of Venturi Scrubber and Spray Tower Test Facility at the TVA Shawnee Plant	70
4.2	Typical Process Flow Diagram for Venturi/Spray Tower System . .	74
4.3	Operability of the FGD Systems at the Cholla Station of Arizona Public Service, and the LaCygne Station of Kansas City Power and Light; Examples of Best Performance on Plants Using Low and High Sulfur Coals	86
4.4	Operability of the FGD Systems at the Reid Gardner Station of Nevada Power Company	87
4.5	Operability of the FGD Systems at the Scholz Station of Gulf Power Company and the Paddy's Run Station of Louisville Gas and Electric	90
4.6	Range of Estimated Costs for Limestone Scrubbing	94
4.7	Inlet and Outlet Cumulative Mass Loadings for a Precipitator with an Overall Efficiency of 99.6%	109
4.8	Measured Fractional Efficiencies for a Cold-Side Electrostatic Precipitator with the Operating Parameters as Indicated, Installed on a Pulverized Coal Boiler	110
4.9	Computed ESP Performance Curves at 5, 20 and 40 nA/cm ²	112
4.10	Variation of Fly Ash Resistivity with Temperature and Coal Sulfur Content	114
4.11	Measured Fractional Efficiencies for a Hot-Side Electrostatic Precipitator with the Operating Parameters as Indicated, Installed on a Pulverized Coal Boiler	115
4.12	Total NO _x Emitted from Stationary Sources in the U.S.	147
4.13	Uncontrolled NO _x Emissions vs. Coal Nitrogen Content	151

LIST OF FIGURES (Cont'd)

<u>No.</u>	<u>Title</u>	<u>Page</u>
4.14	Typical Coal-Fired Utility Boiler	154
4.15	Reuse of Ash Sluicing Water in Coal-Fired Power Plants	210
5.1	Schematic Flow Diagram of Closed Circuit Coal Preparation Plant	219
5.2	Comparison of 1985 Delivered Prices of Low Sulfur Coal	275
5.3	Heat Loss Due to Moisture in Coal for Fuel Temperature of 120°F	294
5.4	Pulverizer Output as a Function of Coal Grindability Index and Calorific Value	295
6.1	Schematic Diagram of the Three Fluidized-bed Combustion Systems Showing the General Energy-Conversion Cycles	310
6.2	Atmospheric Fluidized-Bed Power Plant	316
6.3	Pressurized Fluidized-Bed Power Plant	317
6.4	Effect of Ca/S Mole Ratio on Sulfur Retention	327
6.5	Effect of Temperature on Sulfur Retention	327
B.1	Demand Regions and Centroids	398
B.2	Coal Producing Areas	399

LIST OF TABLES

<u>No.</u>	<u>Title</u>	<u>Page</u>
2.1	National Ambient Air Quality Standards	10
2.2	Stringency of State Air Quality Standards Compared to NAAQS	11
2.3	Federal New Source Performance Standards for Coal-Fired Power Plants	19
2.4	New England Coal Air Quality Analysis for Sulfur	22
2.5	Middle Atlantic Coal Air Quality Analysis for Sulfur	24
2.6	South Atlantic Coal Air Quality Analysis for Sulfur	25
2.7	East North-Central Coal Air Quality Analysis for Sulfur	27
2.8	East South-Central Coal Air Quality Analysis for Sulfur	28
2.9	West North-Central Coal Air Quality Analysis for Sulfur	29
2.10	West South-Central Coal Air Quality Analysis for Sulfur	31
2.11	Mountain Coal Air Quality Analysis for Sulfur	32
2.12	Pacific Coal Air Quality Analysis for Sulfur	33
2.13	Comparison of EPA, Senate, and House Versions of Significant Deterioration Regulations	36

LIST OF TABLES (Cont'd)

<u>No.</u>	<u>Title</u>	<u>Page</u>
2.14	Summary of Effluent Limitations Guidelines and Standards for Pollutants Other Than Heat from Steam Electric Power Generating Plants	40
2.15	Chemical Wastes Control and Treatment Technology	41
4.1	Operational FGD, June 1976	68
4.2	Comparison of Typical Sludge Dewatering Properties	77
4.3	FGD Installations in the West	84
4.4	FGD Installations in the East	88
4.5	Effect of Variations on Capital Cost of FGD	96
4.6	Revenue Requirement Comparisons of Throwaway and Regenerable FGD Systems	98
4.7	Number and Total MWe of FGD Systems	100
4.8	FGD Planned in the East and West	100
4.9	Performance Data for Fabric Filters on Coal-fired Boilers . . .	123
4.10	Installation, Operation and Maintenance Costs, Sunbury Station	125
4.11	Estimated Capital Cost for the Nucla Baghouse Installation as of October 1974	127
4.12	Erected Costs for Baghouses and Precipitators	128
4.13	Summary of Operating Particulate Scrubbers	131
4.14	Installed Costs for Scrubbers	132
4.15	Summary of Total NO _x Emissions from Fuel Combustion Sources . .	148
4.16	Summary of Combustion Modification Techniques for Control of NO _x Emissions from Coal-Fired Utility Boilers	156
4.17	Megatons of Coal Ash Collected in the U.S.	171
4.18	Major Chemical Constituents of Fly Ash and Bottom Ash from the Southwestern Pennsylvania Region	172
4.19	Concentrations of Selected Trace Elements in Coal and Ash at TVA's Allen Steam Plant	173
4.20	Equilibrium Concentrations of Trace Elements in Coal Ash Leachate	176
4.21	Commercial Utilization of Ash in the U.S. in 1975	181
4.22	Composition of Sludges from Operating SO ₂ Scrubbers	188
4.23	Range of Concentration of Constituents in Scrubber Liquors . .	191
4.24	Classes of Various Waste Water Sources	204
4.25	Typical Chemical Wastes From a Coal-Fired Powerplant	205
4.26	Flow Rates for Chemical Wastes	206

LIST OF TABLES (Cont'd)

<u>No.</u>	<u>Title</u>	<u>Page</u>
5.1	Basic Unit Operations in Coal Preparation	224
5.2	Preparation Plant Capital and Operating Costs	242
5.3	Comparative Coal Costs for a Utility Utilizing Cleaned Coal and Run-of-Mine Coal from the Same Mine	244
5.4	Potential Capacities and Operating Costs of Commercially Available Continuous SO _x Controls	248
5.5	Capital Costs for Commercially Available Continuous SO _x Control Technologies	249
5.6	Composite Product Analyses for Prepared U.S. Coals	252
5.7	Enhancement of Coal Quality by Beneficiation	253
5.8	Environmental Pollutants Resulting from Operation of a Typical Coal Preparation Plant	256
5.9	Coal Production Costs for Marginal Mines in 1985	270
5.10	Low Sulfur Coal Price Premiums	272
5.11	Mining Equipment Additions: Surface, 1975-1980	277
5.12	Mining Equipment Additions: Surface, 1980-1985	277
5.13	Mining Equipment Additions: Underground 1975-1980	278
5.14	Mining Equipment Additions: Underground 1980-1985	278
5.15	Classification of Coals by Rank	285
5.16	Seventeen Selected U.S. Coals Arranged in Order of ASTM Classification	286
5.17	Design Parameters of Coal and Coal Ash	290
5.18	General Areas of Savings and Costs for Dried and Oiled Coal . .	292
5.19	Ash Characteristics of Four Different Coals	297
6.1	Fluidized-bed Combustion Facilities	318
6.2	Plant Comparisons	319
6.3	Mass Balance for Trace Elements in Fluidized-bed Combustion of Coal--Comparison of Exxon and ANL Results	339
6.4	Projected Emissions of Trace Elements from Conventional and Fluidized-bed Combustors Expressed as a Percentage of the Element Entering the System	339
6.5	Typical Spent FBC Sorbent Composition	342
6.6	Economic Comparison of 600-MWe Plants	348
6.7	Comparison of Advanced Steam Plants Using Different Furnace Types	349

LIST OF TABLES (Cont'd)

<u>No.</u>	<u>Title</u>	<u>Page</u>
A.1	Applicable State Ambient Air Quality Standards	360
A.2	Summary of State Implementation Plan Regulations	363
A.3	Particulate Emission Regulations for Fuel Combustion Sources . .	365
A.4	SO ₂ Emission Regulations for Fuel Combustion Sources	375
A.5	NO _x Emission Regulations for Coal-Fired Fuel Combustion Sources	392
B.1	Estimated Geological Characteristics of Marginal Deep Mines in 1985	404
B.2	Estimated Geological Characteristics of Marginal Strip Mines in 1985	404
B.3	Mining Cost Adjustment Factors for Key Variables	406
B.4	Rates for Shipment of Coal by Unit Train	410
B.5	Transport Costs via Inland Waterways	414
B.6	Differences Between Rail and Rail-Barge Costs	414
B.7	Comparison in 1985 of All-Rail and Rail-Barge Costs to Great Lakes Demand Centers	416

*ENVIRONMENTAL CONTROL IMPLICATIONS
OF GENERATING ELECTRIC POWER FROM COAL*

ABSTRACT

This is the first in a series of reports evaluating environmental control technologies applicable to the coal-to-electricity process. The technologies are described and evaluated from an engineering and cost perspective based upon the best available information obtained from utility experience and development work in progress. Environmental control regulations and the health effects of pollutants are also reviewed.

Emphasis is placed primarily upon technologies that are now in use. For SO₂ control, these include the use of low sulfur coal, cleaned coal, or flue-gas desulfurization systems. Electrostatic precipitators and fabric filters used for the control of particulate matter are analyzed, and combustion modifications for NO_x control are described. In each area, advanced technologies still in the development stage are described briefly and evaluated on the basis of current knowledge.

Fluidized-bed combustion (FBC) is a near-term technology that is discussed extensively in the report. The potential for control of SO₂ and NO_x emissions by use of FBC is analyzed, as are the resulting solid waste disposal problems, cost estimates, and its potential applicability to electric utility systems.

The report is divided into two volumes. Volume II presents the detailed technology analyses complete with reference citations. This same material is given in condensed form in Volume I, although the references are omitted. A brief executive summary is also given in Volume I.

1 INTRODUCTION

*1.1 THE ERDA PROGRAM ON ASSESSMENT OF ENVIRONMENTAL CONTROL TECHNOLOGY
FOR POWER GENERATION FROM COAL*

In March of this year a program was begun at Argonne to evaluate technologies for controlling the environmental impacts of processes for generating electric power from coal. The program is being carried out for ERDA's Division of Environmental Control Technology as part of its effort to assess the effectiveness of methods for controlling pollutant emissions from energy extraction, conversion, and utilization processes being developed by ERDA.

The control technologies considered in the Argonne program include conventional coal combustion processes with add-on stack-gas cleaning, processes that involve the production and use of a cleaned or solvent-refined coal, and processes such as fluidized-bed coal combustion and low-Btu gasification/combustion in which the combustion and pollutant removal operations are combined. Methods for controlling environmental impacts associated specifically with the mining and transporting of coal are not covered in this work, but are being addressed in other ERDA programs at Argonne and elsewhere.

The focus of this program is the preparation of a series of comparative engineering assessments, based on performance, costs, and availability, of alternative processes for abatement of environmental impacts from coal utilization for power generation. It is intended that these assessments be based on available information obtained from all relevant technology development work in progress and that they be kept current as new information becomes available. Coal-to-electricity technologies have, of course, been subjected to a considerable investigation already and are being evaluated in several current studies. Consequently, it seems appropriate to state at the outset the reasons for carrying out yet another study. First, ERDA is required to review the status of environmental control technologies for power generation and to develop independent positions on their technical and economic feasibility. This program is to provide information and recommendations for that effort. In addition, there are important differences in emphasis and approach between the present assessment study and others. In particular, there appears to be no other effort to compare all current and near-term control technologies for coal utilization on an in-depth engineering and cost basis. Such comparative evaluations of the alternative control technologies for coal utilization can be expected to be of considerable value in the selection of control systems for new power plants, and in planning development and demonstration programs for improved control technologies. Also there is apparently no other program that provides for a continuing effort to maintain a current file of information on control technologies for coal-to-electricity processes, as this program does. Because of this it should be possible to follow progress in technology development work and trends in overall performance of control systems, and to anticipate effects of changes in emission regulations on control technology requirements more readily.

The evaluation of the performance of control system options is to take account of all potential direct and indirect environmental impacts of coal utilization. Direct impacts that are considered include emission of atmospheric pollutants, such as particulates, sulfur oxides, nitrogen oxides, hydrocarbons, and the trace elements in coal; pollutants in process wastewater, including polyaromatic hydrocarbons and trace metals; and groundwater contamination by infiltration of pollutants from landfill burial of waste ash, coal fines, and scrubber sludge. Examples of indirect impacts are pollutant emissions from the production of process materials such as limestone used in scrubbers and fluidized-bed combustion units and from the production of steam, electricity, and other utilities used to operate the process or its control systems. The control technologies are to be evaluated in the context of existing and anticipated emissions regulations for coal-fired power plants. The regulations themselves are to be appraised in the light of the cost penalties that they impose on the electric utility sector and of information about the health and ecological effects produced by environmental disturbances from power plants. The program also includes monitoring of investigations of health and ecological effects of all pollutants from each technology. It is not intended, however, that the program is to undertake any new research on health or ecological effects of pollutants from coal utilization processes, nor will it provide any new data on these effects.

The information on pollutant emissions and other disturbances associated with the various control options for coal utilization processes are then to be used for comprehensive assessments of their present and future usefulness. These assessments are to take account of all factors that may affect their potential for utilization. In addition to their environmental impacts, these factors include the time frame for availability of demonstrated technology, capital and operating costs, overall energy efficiency, operating reliability, adaptability of existing facilities for retrofit or modifications, and potential for improved control efficiency. Consideration is also to be given to the availability of needed hardware, manpower, materials, and transportation facilities. The assessments are to give attention to the important site-specific factors associated with the technologies.

To be able to make comparisons among a number of complex alternatives involving a large number of factors, it is necessary to make use of a systematic procedure for bringing these factors together on a common basis and weighing them in accordance with appropriate criteria. Considerable attention must be given to the selection and development of the criteria for comparison and a suitable procedure for carrying out necessary information handling and analysis. These activities have been major components of the work to date, and will continue to be so during the next year. It is planned that the first comprehensive comparative evaluation of the control technology alternatives will be made in the latter half of FY 1977.

1.2 CONTENT AND ORGANIZATION OF REPORT

The principal activity of the Argonne staff during the first six months of the program has been the compilation of current information on the performance and costs of conventional combustion/stack gas cleaning systems, coal preparation processes, use of low sulfur western coal as a sulfur emission control strategy, and fluidized-bed combustion technology. The purpose of this report is to discuss the current status of each of these technologies and to provide a preliminary evaluation of their apparent potential for meeting environmental protection requirements in a cost-effective manner. The intention here is to present neither detailed descriptions of these technologies nor comprehensive analyses of their relative strengths and limitations. However, it is intended that the currently available information on all of the important environmental control issues associated with each technology be discussed and that areas where needed information is lacking be identified.

The order of presentation of the report is as follows. In Chapter 2 the current environmental protection regulations, both federal and state, pertaining to power plants are described. These include ambient air quality standards and stack gas emission regulations for air pollutants as well as water quality and effluent discharge regulations. The current understanding of the health effects of coal combustion pollutants is summarized in Chapter 3. The pollutants covered include sulfur oxides, nitrogen oxides, particulates including fines and trace elements, and carcinogenic hydrocarbons.

Chapter 4 contains a discussion of conventional combustion processes with stack gas cleaning for control of pollutant emissions. The discussion covers the current status of lime/limestone scrubber technology and other flue gas desulfurization systems of both throwaway and regenerable types. Control of particulate emissions in power plant stack gases by means of electrostatic precipitators and other devices is included, as is nitrogen oxides emission control by combustion modification techniques and stack gas cleaning. Disposal/utilization of waste solids and control of water effluents associated with these technologies are also addressed. Control of sulfur emissions from coal combustion by means of coal pretreatment (washing and cleaning) and coal selection (low sulfur coal) is described in Chapter 5. Finally, the potential of fluidized-bed combustion for utility application, and remaining problems, are discussed in Chapter 6.

The material presented herein has been obtained from a large number of sources including reports available in the open literature, direct communication with equipment vendors and architect/engineering firms, and private consultants. Wherever appropriate, the sources of information have been cited by referral to a list of references found at the end of each chapter or major subsection. The Argonne staff assumes responsibility, of course, for the accuracy of all other statements, as well as the conclusions and recommendations that are given.

1.3 FUTURE WORK ON THE PROGRAM

During the coming year work will continue to compile and evaluate information needed for the assessment of the combustion processes and control technologies covered in this report. Two developing technologies, production/combustion of solvent refined coal and low Btu coal gasification/combined cycle generation, will be added to the program. It is planned that this work will be carried out primarily by private companies and a number of consultants under contract to Argonne to contribute their expertise to the program. Four subcontractors have already begun work on the program, and at least four more subcontract programs are planned. It is our intention to make extensive use of qualified experts for the information required in the assessments of these technologies.

During the last half of the year the comparative evaluation of the currently available environmental control options for coal combustion will be initiated by the Argonne staff using the information on the technologies developed by subcontractors and consultants. This assessment will cover all of the environmental control issues associated with conventional combustion and stack gas cleaning, the use of low sulfur coal and cleaned coal, and combinations of these options. A report describing these issues and the relative advantages and disadvantages of the control technology options will be issued at the end of the year in December 1977.

2 ENVIRONMENTAL REGULATIONS

Coal-fired power plants have been the subject of extensive environmental regulations because of their significant contribution to environmental emissions. The principal areas of concern have been air quality, thermal discharge, and water quality. The objective of this chapter is to outline the current regulatory framework in which coal-fired power plants must operate. The discussion is limited to regulations pertaining to air and water quality; thermal discharge problems are not included within the scope of this program and, hence, are not covered in this summary.

2.1 AIR QUALITY REGULATIONS

The air quality management process in the U.S. relies on a multifaceted approach as prescribed in the Clean Air Act of 1970. There are basically five mechanisms for the control of air pollution:

1. National Ambient Air Quality Standards (NAAQSs), which are to be attained on a regional basis through State Implementation Plans (SIPs) (Sections 109 and 110).
2. Standards of Performance for New Stationary Sources, which reflect the degree of emission limitation achievable through the application of the best system of emission reduction which has been adequately demonstrated, taking into account the cost of achieving such reduction (Section 111).
3. National Emissions Standards for Hazardous Air Pollutants (NESHAP) for stationary source controls of pollutants that may cause serious health effects (Section 112).
4. Emission Standards for Moving Sources, which are required by the Clean Air Act to reduce mobile source emissions at least below a given level (Sections 202, 211, and 231).
5. Abatement by Means of Conference (Section 115) and Emergency Powers (Section 303), which are lesser-used options.

Coal-fired power plants are most significantly affected by the first two mechanisms. The concept of setting an ambient air quality standard stems from the desire to protect the public health and welfare from the damaging effects of pollutants in the atmosphere. The air quality standard is expressed as a maximum allowable pollutant concentration limit and is linked to studies that demonstrate threshold values at which health and/or welfare effects become apparent. The new source performance standard has an

entirely different focus in that it requires the use of the best form of emission control technology for new sources. In some cases the new source standard requires emission reductions greater than those needed to attain the ambient air quality standards.

These two approaches, although markedly different in their focus, are complementary. The approaches differ in the division of administrative responsibility among the various federal, state, and local pollution control agencies. Under the ambient air quality standard approach, the federal government, through the Environmental Protection Agency (EPA), is charged with the responsibility of reviewing the potential health and welfare impacts of various pollutants, developing criteria documents outlining these impacts, and setting National Ambient Air Quality Standards (NAAQSs). Once a NAAQS has been set, each state is charged with the responsibility of developing a State Implementation Plan (SIP) that describes what steps will be taken to attain the standards. In the event that a state fails to develop an acceptable SIP, the EPA can develop and promulgate its own plan for the state.

Under the new source standard approach, the EPA is charged with the responsibility of periodically reviewing various pollutant emission source categories to determine the best emission control technology, considering cost, and to develop a New Source Performance Standard (NSPS) that reflects that level of emission control. This standard then applies to all new and modified sources of that category. Unless states specifically request delegation of authority, the enforcement of NSPSs lies in the jurisdiction of the EPA.

Since the initial development of control regulations through the NAAQS/SIP and NSPS mechanisms, many issues have been raised as to their application to coal-fired power plants. For example, some states have chosen to develop their SIPs to a level that exceeds federal NAAQS and NSPS requirements. Other states have used approximate analyses of questionable validity (necessitated in many instances by a lack of resources and tight timetables) to develop their control regulations. These policies have led to charges of regulation "overkill," especially for power plants. It has been argued that the regulations have created a demand for clean fuels (i.e., low sulfur coal, oil) that cannot be met without substantial

cost penalties. It is not the intent of this section to discuss all of the issues in detail, but rather to summarize the regulations as they currently exist and to identify the problem areas that have been most frequently discussed.

2.1.1 Ambient Air Quality Standards

To date the EPA has promulgated National Ambient Air Quality Standards for six pollutants, often referred to as criteria pollutants because each has an associated criteria document prepared for it that outlines the justification for the standard.¹⁻⁶ The standards are listed in Table 2.1. The variations in averaging time reflect the different effects of each pollutant. Annual average standards for particulates, SO₂, and NO₂ were designed to protect against long-term effects of relatively low concentration levels. The 24-hour and shorter-period standards were designed to protect against acute effects resulting from exposure to high concentrations for short periods of time.

The distinction between primary and secondary standards for particulates and SO₂ was made to account for variations in the type of effect of the pollutant. Primary standards are designed to protect public health. Secondary standards are designed to protect public welfare (e.g., materials damage, vegetation and animal damage, etc.). Most of the current efforts have been aimed at attainment of the primary standards, which was originally targeted for mid-1975. Increasing emphasis will be placed on secondary standard attainment as more of the Air Quality Control Regions are brought into compliance with the primary standards.

In the course of developing a State Implementation Plan to meet the NAAQSs, each state had the option to adopt ambient air quality standards of its own. In most cases, states simply adopted the NAAQS. In some cases, states adopted air quality standards more stringent than the NAAQSs in all or a portion of the state. (There was no point in a state's adopting less stringent standards, since the federal requirements would then supersede the state requirements.) Table 2.2 summarizes the state ambient air quality standards relative to the NAAQSs for total suspended particulates (TSP), SO₂, and NO₂, the pollutants of primary concern for coal-fired power plants. A total of 13 states have particulate standards more stringent than the

Table 2.1 National Ambient Air Quality Standards

Pollutant	Concentrations in $\mu\text{g}/\text{m}^3$				
	Averaging Time ^a				
	1-hr	3-hr	8-hr	24-hr	1-yr
Particulates					
Primary				260	75 (G) ^b
Secondary				150	60 ^d (G)
SO ₂					
Primary				365	80 (A) ^c
Secondary		1300			
CO	40 ^e		10 ^e		
Hydrocarbons		160 ^f			
Oxidants	160				
NO ₂					100 (A)

^aAll averages less than 1 year are not to be exceeded more than once per year.

^b(G) Geometric average.

^c(A) Arithmetic average.

^dIntended as a guide to meeting the 24-hr secondary standard (40CFR50).

^eCO concentrations measured in mg/m^3 .

^f6 a.m. to 9 a.m. only. The hydrocarbon standard is intended as a guide to achieving the oxidant standard.

Table 2.2 Stringency of State Air Quality Standards Compared to NAAQS

State	State Ambient Air Quality Standards								
	State Air Quality Standards Equivalent to NAAQS			State Air Quality Standards More Stringent than NAAQSa					
				In a Portion of the State			Throughout the State		
	TSP	SO ₂	NO ₂	TSP	SO ₂	NO ₂	TSP	SO ₂	NO ₂
<u>REGION I</u>									
Connecticut	X		X					X ^b	
Maine			X						
Massachusetts	X	X	X				X	X	
New Hampshire	X		X					X ^b	
Rhode Island			X				X	X	
Vermont			X				X	X	
<u>REGION II</u>									
New Jersey	X	X	X						
New York			X	X				X	
Puerto Rico	X	X	X						
Virgin Islands	X	X	X						
<u>REGION III</u>									
Delaware			X				X	X	
Dist. of Columbia			X				X	X	
Maryland			X				X	X	
Pennsylvania	X	X	X						
Virginia	X	X	X						
West Virginia	X		X					X ^b	

Table 2.2 (Contd.)

State Ambient Air Quality Standards									
State	State Air Quality Standards Equivalent to NAAQS			State Air Quality Standards More Stringent than NAAQS ^a					
				In a Portion of the State			Throughout the State		
	TSP	SO ₂	NO ₂	TSP	SO ₂	NO ₂	TSP	SO ₂	NO ₂
<u>REGION IV</u>									
Alabama	X	X	X						
Florida			X	X				x ^b	
Georgia	X		X					X	
Kentucky	X		X					x ^c	
Mississippi	X		X					x ^b	
North Carolina	X							x ^b	X
South Carolina	X	X	X						
Tennessee	X		X					x ^c	
<u>REGION V</u>									
Illinois	X	X	X						
Indiana	X		X					x ^b	
Michigan	X	X	X						
Minnesota	X		X					X	
Ohio	X		X					X	
Wisconsin	X		X					x ^b	
<u>REGION VI</u>									
Arkansas	X	X	X						
Louisiana	X		X					x ^b	
New Mexico			X				X	x ^b	
Oklahoma	X	X	X						
Texas	X	X	X						

Table 2.2 (Contd.)

State Ambient Air Quality Standards									
State	State Air Quality Standards Equivalent to NAAQS			State Air Quality Standards More Stringent than NAAQS ^a					
				In a Portion of the State			Throughout the State		
	TSP	SO ₂	NO ₂	TSP	SO ₂	NO ₂	TSP	SO ₂	NO ₂
<u>REGION VII</u>									
Iowa	X	X	X						
Kansas	X	X	X						
Missouri	X		X		X				
Nebraska	X	X	X						
<u>REGION VIII</u>									
Colorado			X	X				X	
Montana	X		X					X ^b	
North Dakota	X							X ^b	X
South Dakota	X							X ^b	X
Utah	X	X	X						
Wyoming	X		X					X ^b	
<u>REGION IX</u>									
Amer. Samoa	X	X	X						
Arizona	X		X					X	
California			X				X	X ^b	
Guam	X		X					X ^b	
Hawaii							X	X	X
Nevada			X				X	X ^c	

Table 2.2 (Contd.)

State Ambient Air Quality Standards									
State	State Air Quality Standards Equivalent to NAAQS			State Air Quality Standards More Stringent than NAAQS ^a					
				In a Portion of the State			Throughout the State		
	TSP	SO ₂	NO ₂	TSP	SO ₂	NO ₂	TSP	SO ₂	NO ₂
<u>REGION X</u>									
Alaska	X		X					x ^b	
Idaho	X	X	X						
Oregon	X		X					x ^b	
Washington	X		X					X	

^aState standards were rated more stringent than the NAAQSs if, *for the same averaging times*, they required either a lesser average value or fewer periods above a specified concentration or if the state had standards for averaging times other than those used in the NAAQSs. States with either no standards or less stringent standards were rated as having standards equivalent to the NAAQSs, since in these cases the NAAQSs would apply. This table also treats the annual average secondary TSP "guidelines" in the NAAQS as a standard to which the state standards are compared.

^bState retains 24-hr and annual SO₂ standards equivalent to original SO₂ secondary NAAQS and guidelines that have been rescinded at the federal level.

^cState retains annual SO₂ standards equivalent to original SO₂ secondary NAAQS that has been rescinded at the federal level.

NAAQS in all or part of the state. Thirty-six states have SO₂ air quality standards more stringent than the NAAQS. It is emphasized that of these 36, 20 have standards that are the same as the original federal secondary annual and 24-hr standards for SO₂, which have since been rescinded. In most cases, the states had adopted the federal standards when they were first issued but have not yet taken action to rescind them in accordance with federal practice. None of the states appear to be actively pursuing the attainment of these old standards.

Table A.1 gives the actual values of the state ambient air quality standards.* Only five states show regional variation in their ambient standards. Almost one-quarter of the states have standards specifying average times different from those used in the NAAQS. Standards for TSP and SO₂ have been adopted by almost all states, but over a quarter have not adopted NO₂ standards. Greater variation exists between SO₂ standards for various states than between TSP standards.

The tabulated values show that most states adopted ambient air quality standards either equivalent to or very close to the federal ambient standards in effect at the time of adoption. Some notable exceptions are Florida, which has SO₂ standards in the Miami area that are an order of magnitude more stringent than the NAAQS; Colorado, which has both TSP and SO₂ standards one-half to one-third of the NAAQSs in parts of the state; Georgia, which has a very stringent annual SO₂ standard (43 µg/m³); and Hawaii, which has very stringent SO₂ standards for all averaging times.

The ambient air quality standards establish a value of pollutant concentration above which adverse public health and welfare effects are expected to appear. These have been subject to much debate and criticism, the most recent being aimed at the epidemiological studies that were used to develop the SO₂ standards. Several groups have charged that the data do not justify the current standards and have suggested that serious consideration be given to relaxing the standards. The National Air Pollution Criteria Advisory Committee has recommended that EPA review all the criteria documents for possible revision.

*Table A.1 is included in Appendix A at the end of the report.

Despite all the criticism and controversy, the NAAQSS have withstood court tests, and the primary efforts in SIP development have been aimed at meeting these standards. In our judgement any revision of the existing standards would be several years away if at all. The possibility does exist, however, for additional NAAQSS to be promulgated. A recent court decision has ordered EPA to develop an ambient standard for lead. There are still some litigation proceedings underway, but the lead standard could be promulgated as early as 12-18 months hence. Also, there has been some discussion on the development of a short-term NO₂ standard (the current standard is an annual average) as a result of evidence indicating possible adverse health effects. This prospect is entering the preliminary evaluation phase and no definitive timetable has yet been announced. Other potential ambient standards that have been discussed, but which must be considered as beyond the 18-mo timeframe with respect to their impact on coal-fired power plants, are a total sulfur compound standard to control sulfate formation, a fine particulate standard (currently considered unlikely), and trace metal standards.

2.1.2 Emission Standards

One of the principal mechanisms used in the State Implementation Plans to attain the NAAQSS is the setting of emission limits on the sources that are contributing to ambient air quality problems. The primary question to be answered is the correspondence between emission limit and the desired ambient air quality. The technique of dispersion modeling has been applied most frequently to answer this question for power plants. The model, usually of the Gaussian-plume formulation, relates the emission rate, physical plant characteristics (e.g., stack height, exit velocity, etc.), and the meteorological conditions to estimate the power plant's contribution to air pollutant concentrations. By varying the emission limit for the plant in the model, it is possible to determine the level of control that is needed to bring the air quality into acceptable limits.

Although the technique appears straightforward, numerous debates, discussions, and lawsuits have arisen with regard to the reasonableness of state emission limits. Some arguments have centered on the validity of the modeling approach used. Some have revolved around a state's use of the "example region" approach in which its worst areas were used to develop

regulations applicable throughout the state. Yet other controversies have focused on the lack of any consideration of the availability of control technology or clean fuel, and/or the economic reasonableness of the regulations.

Issues have been raised regarding the use of intermittent (or supplementary) control systems, in which clean fuels would be burned only during periods of poor atmospheric ventilation, or the use of tall stacks to meet air quality requirements. EPA has issued criteria for the use of SCS⁷ as an acceptable control technique. These include: (1) each source must demonstrate that adequate constant emission reduction techniques are not available, (2) techniques that are available must be applied to achieve maximum practicable emission reductions prior to SCS implementation, (3) a dispersion model must be used to estimate maximum pollutant concentrations, (4) the operator must be willing to accept full legal responsibility for maintaining the NAAQS throughout the area that is significantly influenced by the source, and (5) each source must support and participate in a research and development effort to develop permanent control systems. There are only a few sources that would be capable of meeting all the criteria; therefore, SCS use is extremely limited. For tall stacks, EPA policy has been that credit will be allowed only for a stack that meets the criterion of "good engineering design." This means a height sufficient to prevent plume downwash and severe localized problems. Further increases in stack height will not be considered in determining the needed level of emission control.

In all these situations the principal point of contention has been the link between emission rate and air quality. The debate has been concerned with whether or not the emission limit accurately reflects the air quality conditions. In this regard, there has been much more controversy over emission limits than over the ambient air quality standards.

It is extremely difficult to tabulate state emission regulations in a uniform way due to the large diversity of regulation form and applicability. Power plant regulations are generally part of an overall fuel combustion source regulation. Table A.2* summarizes the regulations in terms

*Table A.2 is included in Appendix A at the end of the report.

of the units in which the emission limits are expressed. For particulate control, 45 out of the 48 states considered here, plus the District of Columbia, rely on an emission limit expressed in pounds of particulates per million Btu of heat input for at least part of the control program. Only four states (Michigan, Arkansas, Oregon, and Washington) do not rely at all on this type of regulation and use instead grain loading, pounds of particulates per 1000 pounds of exhaust gas, pounds per hour, or ground-level concentration as the regulatory mechanism. In addition, some of the other states use these other control mechanisms in tandem with the Btu-based regulation.

From a regulatory standpoint, the Btu-based mechanism provides the most flexible approach to dealing with a wide size range in sources. The pounds per hour limit can effectively limit power plant size and the ground-level concentration regulation can be extremely difficult to enforce.

For sulfur oxide control, the most widely used mechanism is again, the pounds of pollutant (expressed either as SO₂ or sulfur) per million Btu of heat input. Thirty-three states use it in their regulations with 19 using it exclusively. A substantial number (18) use fuel sulfur content regulations with nine relying on this mechanism alone. Six states (Virginia, West Virginia, Arkansas, Louisiana, Colorado, and Wyoming) use neither mechanism and employ air quality measurements, stack gas concentration, or pounds per hour controls.

The fuel sulfur content regulations are in general more constricting since they often do not allow for stack-gas cleaning as a compliance method. In analogy to the particulate regulations, the pounds-per-hour limits can restrict the size of a facility.

Table A.3* gives the actual value of the particulate emission regulations for various sizes of fuel combustion sources. These size criteria are not necessarily a part of the regulation, and the table is designed to show only what value of the standard would apply to each size. In terms of equivalent power plant capacity, the 250x10⁶-Btu/hr facility is roughly equivalent to 25 MWe. Table A.4* gives the value of the SO₂ emission regulations and/or the fuel sulfur content regulation. Table A.5* gives the NO_x emission regulations.

*Tables A.3, A.4, and A.5 are included in Appendix A at the end of the report

In contrast to the SIP development of regulations that are tied to ambient air quality requirements, federal New Source Performance Standards (NSPSs) are based on the use of the best available control technology considering cost. Table 2.3 gives the NSPSs promulgated for coal-fired power plants.

Table 2.3 Federal New Source Performance Standards for Coal-Fired Power Plants^a

Pollutant	Allowable Emissions (lb/10 ⁶ Btu heat input) ^b
Particulates	0.1
SO ₂	1.2
NO _x ^c	0.7

^aGreater than 250x10⁶ Btu/hour heat input.

^bMaximum 2-hr average.

^cExpressed as NO₂ equivalent.

In all states that have emission regulations less stringent than NSPSs, the federal standards apply. Where the state standards are more stringent, the source must comply with state requirements. Also, although NSPSs are not directly tied to ambient air quality standards, it is not an acceptable argument for a facility to claim compliance with a NSPS if it causes violations of the NAAQS. In a sense the NSPS represents an upper limit on emissions, and it is recognized that some facilities may have to control to better than NSPS levels to meet the NAAQS requirements.

Of significance to the development of coal-fired generation capability is a comparison of the state regulations to the federal requirements. State regulations that are more stringent than federal could conceivably discourage the location of coal-fired power plants. This is especially true in the case of sulfur oxide emission regulations since control is more difficult to achieve. An estimate of how these differences could affect coal utilization can be made by comparing the requirements placed on coal-fired power plants by state regulations to federal regulations. Figure 2.1 shows the location of coal fields in the U.S. The figure shows that the coal fields can be viewed as existing in basically three geographical areas. Eastern or Appalachian coal lies along a broad strip stretching from Pennsylvania, through Ohio, West Virginia, Kentucky,

Fig. 2.1 Coal Reserves in the U.S.

Tennessee, and into Alabama. Midwestern coal lies principally in Illinois, Indiana, Iowa, and Missouri, with some in Arkansas, Oklahoma, and Texas. Western coal lies primarily along the Rocky Mountains, extending from Montana, North Dakota, Idaho, Wyoming, Colorado, and Utah, to Arizona and New Mexico. There are small pockets of coal deposits elsewhere, but these three major areas constitute the largest resources and involve the biggest issues in the use of coal for electricity generation. The following discussions review the impact of state and federal regulations on coal use in each of nine regions of the country. The review is confined to coal now being used in each region. It is based on a recent power plant siting study conducted at Argonne.⁸

2.1.2.1 New England

Table 2.4 summarizes the air quality constraints on the currently used coal in New England. The coal from the Northern West Virginia and Panhandle areas (Districts 3 and 6) does not meet fuel sulfur content restrictions in Connecticut, Maine, Vermont, and the Berkshire AQCR in Massachusetts. Where it could be permitted by emission limit regulations, it would require significant flue gas desulfurization (FGD) removal efficiencies to conform to federal NSPS or to the state regulations. Therefore, continued widespread use of this coal would require substantial utility commitment to scrubber utilization. Only the coal from the Southern No. 1 (District 7) area comes close to meeting all the state requirements without FGD, although it would still be banned from Connecticut and the core cities of the Boston AQCR. None of this coal is currently used by utilities, most probably because of its relatively high price.

By virtue of its sulfur regulations, the State of Connecticut has banned the use of coal. There is virtually no 0.5% sulfur coal in any of the eastern and midwestern fields. Vermont has come close to doing the same with a 1% sulfur restriction, although a revision is under consideration.

The average utility coal would not meet regulatory requirements in any state without significant FGD.

Table 2.4 New England Coal Air Quality Analysis for Sulfur

			Regulation Constraint on Coal Use ^a						
State			Regulation	Coal from Producing District					Average Utility Coal
			%S or S/H ^b	1	2	3&6	7	8	
	Coal Currently in Use	%S S/H ^b NSPS ^a		2.0 2.84 58	1.7 2.48 52	2.8 4.04 70	0.7 0.96 -	1.0 1.42 16	3.0 4.24 72
CT	Statewide		0.5%	No	No	No	No	No	No
ME	Statewide		2.5%	Yes	Yes	No	Yes	Yes	No
	Inside Portland AQCR		1.5%	No	No	No	Yes	Yes	No
MA	Statewide		1.1	61	56	73	-	23	74
	Boston AQCR		2.4-0.56	15-80	3-77	41-86	0-42	0-61	43-87
	Berkshire AQCR		2.2%	Yes	Yes	No	Yes	Yes	No
NH ^c	Existing Sources		5.6-4.0	-	-	-	-	-	0-6
	New Sources		3.0-2.0	0-30	26-50	-	-	-	29-53
RI	Statewide		1.1	61	56	73	-	23	74
VT ^d	Statewide		1.0%	No	No	No	Yes	Yes	No

^aNumerical entries for each state and the NSPS indicate SO₂ removal efficiency required for compliance with regulation. Entry of "Yes" or "No" indicates compliance with fuel sulfur content regulation. In all cases federal NSPSs supercede less stringent state regulations for sources greater than 250x10⁶ Btu/hr heat input.

^blb SO₂/10⁶ Btu heat input.

^cState regulation actually written in terms of lb S/MM Btu.

^dA change to permit 2.0% sulfur has been proposed.

2.1.2.2 *Middle Atlantic*

The air quality constraints on coal utilization for the Middle Atlantic region are summarized in Table 2.5. Only the Southern No. 1 (District 7) and the Utah (District 20) coals are capable of meeting the federal NSPS without FGD systems. New Jersey regulations effectively prohibit the use of all of the coal currently being brought into the region, with the exception of Southern No. 1 (District 7) and Southern No. 2 (District 8) coal, which may be used in selected counties. New York and Pennsylvania both have regions that can use most of the coal without FGD, regions that require only moderate FGD removal efficiencies, and regions that require significant FGD removal to ensure compliance. Some of the required removal efficiencies in New York City and selected air basins in Pennsylvania are near the current state of the art for FGD systems (i.e., 80-90%) and may, in effect, exclude these coals from use in these areas. The average utility coal can be used in most parts of New York and Pennsylvania with no FGD required. It cannot be used in New Jersey or in Philadelphia and requires significant FGD for use in air basins and selected areas in New York.

2.1.2.3 *South Atlantic*

Table 2.6 gives the air quality constraints for South Atlantic region coal. The Southern No. 2 (District 8) coal, which is the most widely used, can be burned everywhere in the region, except the District of Columbia, with little or no FGD requirements. The high sulfur coals from Ohio (District 4), Western Kentucky (District 9), Illinois (District 10), and Indiana (District 11) require significant FGD removal efficiencies to comply with the federal NSPS or some of the more stringent state regulations, but none require greater than 80% removal, which is within current technology. Delaware, the District of Columbia, and Maryland have the most restrictive regulations by virtue of their sulfur-content limitations. None of the coal currently used in the region meets the District of Columbia's requirements. The average utility coal can meet the requirements of all the states, assuming only moderate FGD removal efficiencies, with the exception of Delaware and the District of Columbia.

Table 2.5 Middle Atlantic Coal Air Quality Analysis for Sulfur

			Regulation Constraint on Coal Use ^a								
State			Regulation	Coal from Producing District						Average Utility Coal	
			%S or S/H ^b	1	2	3&6	4	7	8	20	
	Coal Currently in Use	%S S/H ^b NSPS ^a		2.0	1.7	2.8	3.4	0.7	1.0	0.7	2.33
				2.84	2.48	4.04	5.36	0.96	1.42	1.04	3.68
			1.2	58	52	70	78	-	16	-	67
NJ	Statewide		0.2%	No	No	No	No	No	No	No	No
	Selected Counties		1.0% or 1.5	No	No	No	No	Yes	Yes	Yes	No
NY ^c	Statewide		5.0-3.8	-	-	0-6	7-29	-	-	-	-
	Erie and Niagara Cos.		3.4-1.2	0-58	0-52	16-70	37-78	-	0-16	-	8-67
	Selected Towns in Suffolk Co.		1.2	58	52	70	78	-	16	-	67
	New York City and selected counties		0.4	86	84	90	93	58	72	62	89
PA	Statewide		4.0	-	-	1	25	-	-	-	-
	Air Basins		3.0-0.6	0-79	0-76	26-85	44-89	0-38	0-58	0-42	18-84
	Philadelphia		0.3%	No	No	No	No	No	No	No	No

^aNumerical entries for each state and the NSPS indicate SO₂ removal efficiency required for compliance with regulation. Entry of "Yes" or "No" indicates compliance with fuel sulfur content regulation. In all cases federal NSPSs supercede less stringent state regulations for sources greater than 250x10⁶ Btu/hr heat input.

^blb SO₂/10⁶ Btu heat input.

^cState regulation actually written in terms of lb S/10⁶ Btu.

Table 2.6 South Atlantic Coal Air Quality Analysis for Sulfur

		Regulation Constraint on Coal Use ^a												
		Regulation	Coal from Producing District											Average
State		%S or S/H ^b	1	2	3&6	4	7	8	9	10	11	13	Utility Coal	
	Coal Currently in Use	%S S/H ^b NSPS ^a	2.0 2.84 58	1.7 2.48 52	2.8 4.04 70	3.4 5.36 78	0.7 0.96 -	1.0 1.42 16	4.1 6.41 81	3.2 5.37 78	3.4 5.60 79	1.4 1.99 40	1.93 3.08 61	
DE	New Castle Co.	1.0%	No	No	No	No	Yes	Yes	No	No	No	No	No	
DC	All Sources	0.5%	No	No	No	No	No	No	No	No	No	No	No	
FL	Existing Sources	1.5	47	40	63	72	-	-	77	72	73	25	51	
	New Sources	1.2	58	52	70	78	-	16	81	78	79	40	61	
GA	Existing Sources	3.0%	Yes	Yes	Yes	No	Yes	Yes	No	No	No	Yes	Yes	
	New Sources	1.2	58	52	70	78	-	16	81	78	79	40	61	
MD	Statewide	1.0%	No	No	No	No	Yes	Yes	No	No	No	No	No	
NC	Existing Sources	2.3	19	7	43	57	-	-	64	57	59	-	25	
	New Sources	1.6	44	35	60	70	-	-	75	70	71	20	48	
SC	Class III Cos.	3.5	-	-	13	35	-	-	45	35	38	-	-	
	Class I&II Cos.	3.5-2.3	0-19	0-7	13-43	35-57	-	-	45-64	35-57	38-59	-	0.25	
VA	Statewide	2.64	7	-	35	51	-	-	59	51	53	-	14	
	National Capital AQCR	1.06	63	57	74	80	-	25	83	80	81	47	66	
WV	Priority III AQCRs	3.2	-	-	21	40	-	-	50	40	43	-	-	
	Priority I&II AQCRs	2.7	5	-	33	50	-	-	58	50	52	-	12	
	Kanawha Valley AQCR	1.6	44	35	60	70	-	-	45	35	38	-	-	

^aNumerical entries for each state and the NSPS indicate SO₂ removal efficiency required for compliance with regulation. Entry of "Yes" or "No" indicates compliance with fuel sulfur content regulation. In all cases federal NSPSs supercede less stringent state regulations for sources greater than 250x10⁶ Btu/hr heat input.

^blb SO₂/10⁶ Btu heat input.

^cState regulation actually written in terms of lb S/10⁶ Btu.

2.1.2.4 *East North-Central*

Table 2.7 summarizes the air quality evaluation for the East North-Central region. The federal NSPS poses an equal or more stringent requirement than state regulations in Illinois, Indiana, Wisconsin, and parts of Ohio. Michigan's sulfur regulation inhibits the use of much of the existing coal, and Ohio's most restrictive regulations require the use of the lower sulfur coals to avoid extensive FGD requirements.

The East North-Central states have been the subject of many studies regarding the marketability of western coal. It has been shown that they currently represent the most easterly of potential markets for western coal, and their dependence on coal for electric generation makes them a strong potential customer. At the same time, they have somewhat less restrictive state air pollution control regulations than do other regions, relying instead on federal NSPSs to provide control of new, large, fossil-fuel power plants. All these factors put these states in one of the most flexible positions regarding fuel choice.

2.1.2.5 *East South-Central*

Table 2.8 summarizes the air quality analysis for coal utilization in the East South-Central states. Federal NSPSs are the most stringent limits applied anywhere in the region. The Southern No. 2 (District 8) and the Southeastern (District 13) coals can be used by utilities with little or no FGD. The high sulfur coals require FGD but with removal efficiencies that are within current technological limits.

It can be inferred that the regulatory requirements of the states in this region have not created a strong demand for western coal. The lack of convenient transportation links between western coal fields and this region has likewise inhibited the marketability of western coal.

2.1.2.6 *West North-Central*

Table 2.9 gives the air quality analysis for coal shipped into the West North-Central states. Federal NSPSs are the most stringent regulations throughout the region with the exception of percent-sulfur restrictions in parts of the St. Louis AQCR and in the Minneapolis-St. Paul AQCR. All

Table 2.7 East North-Central Coal Air Quality Analysis for Sulfur

			Regulation Constraint on Coal Use ^a													Average Utility Coal	
State		Regulation	Coal from Producing District														
		%S or S/H ^b	1	2	3&6	4	7	8	9	10	11	14	17	19	22&23		
	Coal Currently in Use	%S S/H ^b NSPS ^a	1.2	2.0 2.84 58	1.7 2.48 52	2.8 4.04 70	3.4 5.36 78	0.7 0.96 -	1.0 1.42 16	4.1 6.41 81	3.2 5.37 78	3.4 5.60 79	1.5 2.06 42	0.6 0.99 -	0.5 0.98 -	1.0 1.95 38	3.13 5.37 78
IL	Statewide	6.0		-	-	-	-	-	-	6	-	-	-	-	-	-	-
	Major Metropolitan Areas	1.8		37	27	55	66	-	-	72	66	68	13	-	-	8	66
	New Sources	1.2		58	52	70	78	-	16	81	78	79	42	-	-	38	78
IN	Existing Sources	6.0-1.2		0-58	0-52	0-70	0-78	-	0-16	6-81	0-78	0-79	0-42	-	-	0-38	0-78
	New Sources	1.2		58	52	70	78	-	16	81	78	79	42	-	-	38	78
MI	Statewide	1.5%-2.0%		Yes	Yes	No	No	Yes	Yes	No	No	No	Yes	Yes	Yes	Yes	No
	Wayne Co.	0.5%-1.25%		No	No	No	No	Yes	Yes	No	No	No	No	Yes	Yes	Yes	No
OH ^c	County Dependent	6.8-0.6		0-79	0-76	0-85	0-89	0-38	0-58	0-91	0-89	0-89	0-71	0-39	0-39	0-69	0-89
WI	New Sources	1.2		58	52	70	78	-	16	81	78	79	42	-	-	38	78

^aNumerical entries for each state and the NSPS indicate SO₂ removal efficiency required for compliance with regulation. Entry of "Yes" or "No" indicates compliance with fuel sulfur content regulation. In all cases federal NSPSs supercede less stringent state regulations for sources greater than 250x10⁶ Btu/hr heat input.

^blb SO₂/10⁶ Btu heat input.

^cOhio regulations based on EPA proposal.

Table 2.8 East South-Central Coal Air Quality Analysis for Sulfur

			Regulation Constraint on Coal Use ^a									
State		Regulation	Coal from Producing District								Average Utility Coal	
		%S or S/H ^b	3&6	7	8	9	10	11	13	15		
	Coal Currently in Use	%S S/H ^b NSPS ^a		2.8 4.04 70	0.7 0.96 -	1.0 1.42 16	4.1 6.41 81	3.2 5.37 78	3.4 5.60 79	1.4 1.99 40	5.0 8.29 86	3.11 5.31 77
AL	Priority II&III AQCRs	4.0	1	-	-	38	26	29	-	52	25	
	Priority I AQCRs & Jefferson Co.	1.8	55	-	-	72	66	68	10	78	66	
KY	Priority III AQCRs	4.0-3.5	1-13	-	-	38-45	26-35	29-38	-	52-58	25-34	
	Priority II AQCRs	4.0-2.0	1-50	-	-	38-69	26-53	29-64	-	52-76	25-62	
	Priority I AQCRs & all new sources	4.0-1.2	1-70	-	0-16	38-81	26-78	29-79	0-40	52-86	25-77	
MS	Statewide	4.8	-	-	-	25	11	14	-	42	10	
	New & modified sources < 250x10 ⁶ Btu/hr	2.4	41	-	-	63	55	57	-	71	55	
TN	Existing Sources											
	Class III Cos.	4.0	1	-	-	38	26	29	-	52	25	
	Class II Cos.	3.0-1.2	25-70	-	0-16	53-81	44-78	46-79	0-40	64-86	44-77	
	Class I Cos.	1.6-1.2	60-70	-	0-16	75-81	70-78	71-79	20-40	81-86	70-77	
	New Sources	1.2	70	-	16	81	78	79	40	86	77	

^aNumerical entries for each state and the NSPS indicate SO₂ removal efficiency required for compliance with regulation. Entry of "Yes or "No" indicates compliance with fuel sulfur content regulation. In all cases federal NSPSs supercede less stringent state regulations for sources greater than 250x10⁶ Btu/hr heat input.

^b1b SO₂/10⁶ Btu heat input.

Table 2.9 West North-Central Coal Air Quality Analysis for Sulfur

State			Regulation Constraint on Coal Use ^a																Average Utility Coal	
			Regulation %S or S/H ^b	Coal from Producing District																
				3&6	4	7	8	9	10	11	12	13	14	15	17	19	21	22&23		
	Coal Currently in Use	%S S/H ^b NSPS ^a	2.8 4.04 70	3.4 5.36 78	0.7 0.96 -	1.0 1.42 16	4.1 6.41 81	3.2 5.37 78	3.4 5.60 79	3.5 6.75 82	1.4 1.99 40	1.5 2.06 42	5.0 8.29 86	0.6 0.99 -	0.5 0.48 -	0.7 1.89 36	1.0 1.95 38	2.73 5.21 77		
IA	Statewide	5.0	-	7	-	-	22	7	11	26	-	-	40	-	-	-	-	4		
KS	Statewide	3.0	26	44	-	-	53	44	46	56	-	-	64	-	-	-	-	42		
MN	Statewide	2.0%	No	No	Yes	Yes	No	No	No	No	Yes	Yes	No	Yes	Yes	Yes	Yes	No		
	Minneapolis~St. Paul AQCR	1.5%	No	No	Yes	Yes	No	No	No	No	Yes	Yes	No	Yes	Yes	Yes	Yes	No		
MO	Statewide	1000 lb SO ₂ /hr for selected sources																		
	St. Louis AQCR																			
	<2000 x 10 ⁵ Btu/hr	2.0%	No	No	Yes	Yes	No	No	No	No	Yes	Yes	No	Yes	Yes	Yes	Yes	No		
	>2000 x 10 ⁵ Btu/hr	2.3	43	57	-	-	64	57	59	66	-	-	72	-	-	-	-	56		
NE	Statewide	2.5	38	53	-	-	61	53	55	63	-	-	70	-	-	-	-	52		
ND	Statewide	3.0	26	44	-	-	53	44	46	56	-	-	64	-	-	-	-	42		
SD	Statewide	3.0	26	44	-	-	53	44	46	56	-	-	64	-	-	-	-	42		

^aNumerical entries for each state and the NSPS indicate SO₂ removal efficiency required for compliance with regulation. Entry of "Yes" or "No" indicates compliance with fuel sulfur content regulation. In all cases federal NSPSs supercede less stringent state regulations for sources greater than 250x10⁶ Btu/hr heat input.

^blb SO₂/ 10⁶ Btu heat input.

of the western coals are well within these restrictions, however. FGD requirements imposed by other state regulations are well within current technology. These regulatory requirements are another factor contributing to the smaller demand for western coal in this region.

2.1.2.7 West South-Central

Table 2.10 gives the air quality analysis of the coal for this region. Arkansas regulations require that air quality standards be met at the plant boundary. This is not easily translatable into an emission limit or sulfur-content restriction. Texas and Oklahoma have regulations less stringent than the federal NSPS, although stack gas SO₂ concentration limits also apply. Concentration limits constitute the entire Louisiana regulation.

2.1.2.8 Mountain

Table 2.11 summarizes the air quality analysis for the Mountain region. Virtually all of the coal can meet the federal NSPS with minimal or no FGD systems. However, Arizona, Nevada, New Mexico, and Wyoming have emission limits more stringent than the NSPS and hence impose FGD requirements with the low sulfur coal. In Wyoming and portions of Nevada, these requirements are pushing the state of the art of FGD by requiring in excess of 80% removal efficiency.

In some respects, the regulatory pattern in the Mountain states appears unusual. These states are not heavily industrialized and have some of the most stringent emission regulations in the country. The low sulfur coal that abounds in the region can easily be used in other regions with little or no FGD requirements; yet there are significant requirements imposed by the "home state" regulations. In this coal-rich region, more than one-third of the heat input to fossil-fired generators is derived from oil and gas. This may, in part, be explained by the structure of the regulations.

2.1.2.9 Pacific

Table 2.12 gives the coal air quality analysis for the Pacific region. It shows the federal NSPS to be more stringent than state regulations. There is very little restriction on the coal currently being used.

Table 2.10 West South-Central Air Quality Analysis for Sulfur

			Regulation Constraint on Coal Use ^a						
State			Regulation	Coal from Producing District					Average Utility Coal
			%S or S/H ^b	7	8	13	14	15	
	Coal Currently in Use	%S S/H ^b NSPS ^a		0.7	1.0	1.4	1.5	5.0	5.10
				0.96	1.42	1.99	2.06	8.29	8.71
		1.2		-	16	40	42	86	86
AR	Statewide		Ambient air quality standard						
LA	Statewide		2000 ppm in flue gas						
OK ^c	Statewide		2.0	-	-	-	3	76	77
TX ^d	Statewide		3.0	-	-	-	-	64	66

^aNumerical entries for each state and the NSPS indicate SO₂ removal efficiency required for compliance with regulation. Entry of "Yes" or "No" indicates compliance with fuel sulfur content regulation. In all cases federal NSPSs supercede less stringent state regulations for sources greater than 250x10⁶ Btu/hr input.

^b1b SO₂/10⁶ Btu heat input.

^cState regulation; not part of SIP. SIP regulation is in form of stack-gas SO₂ concentration limits.

^dAdditional ground-level concentration limits also part of the SIP.

Table 2.11 Mountain Coal Air Quality Analysis for Sulfur

State	Regulation Constraint on Coal Use ^a												Average Utility Coal
	Regulation. %S or S/H ^b	Coal from Producing District											
		1	7	8	14	16	17	13	19	20	22&23		
	Coal Currently in Use	%S S/H ^b NSPS ^a	2.0 2.84 58	0.7 0.96 -	1.0 1.42 16	1.5 2.06 42	0.5 0.98 -	0.6 0.99 -	0.5 0.91 -	0.5 0.98 -	0.7 1.04 -	1.0 1.95 38	0.52 1.03 -
AZ	Existing Sources New Sources	1.0 0.8	65 72	- 17	30 44	51 61	- 18	- 19	- 12	- 18	4 23	49 59	3 22
CO	Statewide	150-500 ppm in flue gas											
ID	Statewide	1.0%	No	Yes	Yes	No	Yes	Yes	Yes	Yes	Yes	Yes	Yes
MT	Statewide	2.0	34	-	-	3	-	-	-	-	-	-	-
NV	Statewide Clark Co. Washoe Co. for sources <250x10 ⁶ Btu/hr	1.4-0.21 0.15 1.0%	51-91 95	0-78 84	1-85 89	32-90 93	0-79 85	0-79 85	0-77 84	0-79 85	0-80 86	28-89 92	0-80 85
NM	Existing sources in AQCR 012 Existing sources in AQCR 014 ^c & all new sources	1.0 0.34	65 88	- 65	30 76	51 83	- 65	- 66	- 63	- 65	4 67	49 83	3 67
UT	Existing sources	1.0%	No	Yes	Yes	No	Yes	Yes	Yes	Yes	Yes	Yes	Yes
WY	Existing sources New sources	1.2-0.3 0.2	58-89 93	0-69 79	16-79 86	42-85 90	0-69 80	0-70 80	0-67 78	0-69 80	0-71 81	35-85 90	0-71 81

^aNumerical entries for each state and the NSPS indicate SO₂ removal efficiency required for compliance with regulation. Entry of "Yes" or "No" indicates compliance with fuel sulfur content regulation. In all cases federal NSPSs supercede less stringent state regulations for sources greater than 250x10⁶ Btu/hr heat input.

^blb SO₂/10⁶ Btu/hr heat input.

^cDoes not include Four Corners and San Juan plants that have 1b SO₂/hr regulations.

Table 2.12 Pacific Coal Air Quality Analysis for Sulfur

			Regulation Constraint on Coal Use ^a					
State		Regulation	Coal from Producing District				Average Utility Coal	
			%S or S/H ^b	17	19	20		22&23
	Coal Currently in Use	%S S/H ^b NSPS ^a	1.2	0.6 0.99 -	0.5 0.98 -	0.7 1.04 -	1.0 1.95 38	0.70 1.76 32
CAC ^c	Statewide	0.5%		No	Yes	No	No	No
OR ^d	Existing sources	1.0%		Yes	Yes	Yes	Yes	Yes
	New sources	1.6-1.2		-	-	-	18-38	9-32
WA	Statewide	1000-2000 ppm in flue gas						
	Northwest							
	Air Pollution							
	Control Authority	1.5		-	-	-	23	15

^aNumerical entries for each state and the NSPS indicate SO₂ removal efficiency required for compliance with regulation. Entry of "Yes" or "No" indicates compliance with fuel sulfur content regulation. In all cases federal NSPSs supercede less stringent state regulations for sources greater than 250 MM Btu/hr heat input.

^bSO₂ /MM Btu heat input.

^cFlue-gas SO₂ concentration limits also apply in selected areas.

^dFlue-gas SO₂ concentration of 1000 ppm in Portland AQCR.

2.1.3 Regulatory Developments

Several developments in the regulatory process are currently underway that could have significant impacts on the future utilization of coal-fired generators. The two that will be discussed here are the air quality maintenance planning process and the proposed prevention of significant deterioration amendments to the Clean Air Act.

The air quality maintenance planning process is an extension of the NAAQS/SIP program. Recently published regulations⁹ require states to extend their SIPs to include the effects of growth and development in areas that could potentially have difficulty in maintaining the NAAQSSs over a 10-yr planning horizon. The significance of this program on power plant development was demonstrated in a recent study on plant siting⁸. About 30,000 MW of new coal-fired generating capacity (roughly 1/4 of the total new coal capacity through 1984) is scheduled for location in areas designated as Air Quality Maintenance Areas (AQMAS) for particulates and SO₂. A complete list of AQMAS is available from EPA¹⁰. Since the air quality maintenance planning process incorporates concepts of regional land use planning as well as traditional technological controls as air pollution control mechanisms, this program could conceivably play a significant role in the siting of coal-fired plants as well as in the level of emission control required of these facilities. The air quality maintenance planning effort is currently being pursued by all states having AQMAS. The supporting technical analyses and the regulatory changes to the SIPs are scheduled for completion in the next 1-2 years. This set of revisions will be only the initial phase as the process is conceived as an on-going air quality maintenance effort that will be reviewed at least every five years.

Of potentially more significant impact on coal-fired plants are the proposed amendments to the Clean Air Act that require the prevention of significant deterioration (PSD) of air quality in areas currently meeting the secondary NAAQSSs. The development of this type of regulatory effort resulted from a suit brought by the Sierra Club against EPA in which the court decided that the intent of the Clean Air Act was to have EPA exercise some control over the air quality in clean air areas. EPA published a set of PSD regulations¹¹ and simultaneously requested that Congress clarify its intent on the significant deterioration issue. To date, both houses of

Congress have developed versions of PSD regulations that are variations of the EPA-promulgated regulations. The regulations were not voted on prior to Congressional recess but will most likely come up for a vote early in the next session.

All three versions of the PSD regulations rely on the designation of various areas of the country according to the allowable air pollutant concentration increments resulting from growth and development. Class I designations would be reserved for areas that are intended to remain pristine. National parks and wildernesses, scenic areas, and other such areas would fall into the Class I designation. Only very small increments in pollutant concentrations would be permitted. Class II designations would apply to areas where a moderate growth in concentrations could be tolerated as the region grew. Class III designations would be reserved for areas where maximum growth was planned for. The air quality would be permitted to move all the way up to the secondary standards. The states would have the option of determining the classifications. Table 2.13 summarizes the three versions of the regulation. The differences can be summarized briefly.¹²

The Senate bill differs from the EPA regulations in two major ways. First, it establishes a limited number (131) of mandatory Class I areas which constitute 1.3% of the total U.S. land area including national parks, (33 areas), international parks (1 area), national wilderness areas (96 areas) and national memorial parks (1 area). Secondly, it eliminates Class III, but keeps the same increments for Class I and II and a ceiling of the National Ambient Air Quality Standards.

In addition, the Senate bill allows deterioration up to the levels of Class II within the mandatory Class I areas by development locating adjacent to those areas unless the federal land manager, the governor of an adjacent affected state, or the EPA administrator can demonstrate to the state that the proposed source would cause an adverse impact on air quality values within the Class I boundaries. In this event the state would require the proposed source to demonstrate that it would not violate the Class I increments. Conversely, if the federal land manager can demonstrate that adverse air quality effects will occur below the Class I increments, he may request the state to deny a permit to the source even if the source will

Table 2.13 Comparison of EPA, Senate, and House Versions of
Significant Deterioration Regulations

Pollutant	Allowable Concentration Increments by Area Type ^a (µg/m ³)								
	EPA Regulations			Senate Version		House Version			
	Class I	Class II	Class III	Class I	Class II	Class I	Class II	Class III	
Sulfur Dioxide									
Annual	2	15	80	2	15	1.6	20	40	
24-hr	5	100	365	5	100	7.3	91	183	
3-hr	25	700	1300	25	700	26	325	650	
Total Suspended Particulates									
Annual	5	10	75	5	10	7.5	19	38	
24-hr	10	30	150	10	30	15	38	75	

^aAbove existing levels.

not violate the Class I increments. Thus, the Senate approach allows states the maximum flexibility in determining the distance any source would have to locate away from a Class I area. Either the Class II or Class I increment could apply depending on the case-by-case determination of whether an adverse impact on air quality values would occur.

The Senate bill takes an approach similar to EPA's preconstruction review requirements for new major sources. Only 28 specified major industrial source categories are subject to the preconstruction review. In the Senate bill, only these specified major sources are required to be counted against the increment. Extractive industries, such as strip mining, are not covered by the requirements of the Senate bill. The Senate bill establishes the existing EPA New Source Performance Standards (NSPSs) as the floor for best available control technology. However, states are free to set more stringent emission limitations on a case-by-case basis in order to provide more flexibility for future growth and development within the allowable increments. In order to make a determination of "best available control technology", states must consider economic, energy and environmental costs. Once an emission limitation is set, the owner of a source may select a variety of methods to meet the limitation. Methods of continuous emission control include use of low sulfur fuels, techniques such as desulfurization of fuels, flue-gas cleaning, and more effective combustion engineering.

The House bill also differs from the EPA regulations in several major ways. It establishes a limited number (98) of mandatory Class I areas which constitute 1.1% of the total U.S. land area including certain national parks (35 areas) and national wilderness areas (63 areas), and it develops an alternative approach for establishing the permissible increase in pollution in each class. The House increments are established as follows: (1) Class I - 2% of the lowest national standard for all pollutants except particulates, which is set at 10% of the lowest national standard; (2) Class II - 25% of the lowest national standard for all pollutants; and (3) Class III - 50% of the lowest national standard for all pollutants. In addition, the allowable ceiling which may not be exceeded in any area is the secondary standard (existing law) or 90% of the primary standard, whichever is lower. The Class II increments are very similar to EPA's increments; the Class III increments are approximately one-half of EPA's increments.

The House bill defines a major emitting source as any stationary source of air pollutants which directly emits, or has the design capacity to emit, one hundred tons per year of any pollutant for which National Ambient Air Quality Standards are established. All these sources are subject to a new-source review program. EPA is required to evaluate existing New Source Performance Standards (NSPSs) and to revise them to reflect the degree of emission reduction achievable through the application of the best technological system of continuous emission reduction, taking into account cost, health, environmental and energy requirements. The House bill states that no credit will be given for stack heights greater than good engineering practice (as defined by regulations promulgated by the administrator of EPA). For purposes of the House bill, good engineering practice means the height necessary to insure that emissions from the stack do not result in excessive concentrations of any pollutant in the immediate vicinity of the source as a result of atmospheric down-wash, eddies, and wakes which may be created by the source itself, nearby structures, or nearby terrain obstacles. The House bill does not allow any EPA role in state reclassification decisions concerning any federal or non-federal lands as long as the state meets specified procedural requirements and does not attempt to reclassify federal lands that may not be reclassified (i.e., mandatory Class I areas). The House bill also eliminates any EPA or federal land manager authority over any classification or reclassification of any federal lands.

The potential impact of the PSD regulations on coal-fired power plants is very large. Any moderate-to-large-size facility can conceivably create pollutant concentration increments in excess of the PSD requirements without even considering the effects of other nearby sources. These would be strong forces influencing the size and siting of new power plants. A significant number of studies of the significant deterioration issue have been conducted by a wide variety of organizations. These include the Environmental Protection Agency, Federal Energy Administration, Office of Management and Budget, White House Energy Resources Council, Electric Utility Industry Clean Air Coordinating Committee, General Electric Company, U.S. Chamber of Commerce, and the Edison Electric Institute among others. The studies are so numerous that the Department of Commerce has prepared an annotated bibliography of the various reports. Many of the studies

reach opposing conclusions and there are only a few points of common agreement: (1) Class I areas present a major obstacle to growth, (2) industry capital costs will increase as a result of prevention of significant deterioration regulations, (3) facility size, emission control technology, and siting will be influenced by the regulations, and (4) future growth will be restricted by the elimination of Class III areas.

2.2 WATER QUALITY REGULATIONS

The Environmental Protection Agency has developed effluent limitation guidelines and new source performance standards for wastewater discharges from steam electric power generating plants as outlined in Table 2.14, which is taken from an Environmental Protection Agency development document.¹³ These regulations fall into two categories: (1) best practicable control technology currently available (BPCTCA), and (2) best available technology economically achievable (BATEA). These standards must be met by July 1, 1977 and July 1, 1983 respectively. It should be noted that with technologies designated as BPCTCA or BATEA, terms such as "best practicable" or "best available" do not limit the choice to a single process. Any technology that meets the stated effluent limitations may be used. Table 2.15 summarizes the major water pollutants from coal-fired power plants, their sources, and current applicable treatment technologies. Although the information in this table is several years old, it is expected that the relative costs and capabilities of the treatment technologies have not changed significantly. The current investigations of treatment methods described in Chapter 4 will provide updated and more complete information on the performance of these systems.

Other regulations that affect the discharge of wastewater from power plants include receiving-water quality standards, pretreatment standards, limitations for toxic substances, drinking-water standards, and specific state and local standards.¹⁴

Table 2.14 Summary of Effluent Limitations Guidelines and Standards for Pollutants Other Than Heat from Steam Electric Power Generating Plants¹³

Source	Pollutant Parameter	Effluent Limitations ^a		
		BPCTCA (1977)	BATEA (1983)	New Sources
Nonrecirculating cooling water	Free Available chlorine		0.2 (C.5 max) ^b	
	Total residual chlorine		b	
Cooling tower blowdown	Free available chlorine		0.2 (C.5 max) ^b	-
	Total residual chlorine		b	
	Chromium, total	No limitation	0.2 (0.2 max)	-
	Zinc, total	"	1.0 (1.0 max)	-
	Total phosphorus (as P)	"	5.0 (5.0 max)	-
	Corrosion inhibiting materials other than Cr, Zn, and P	"	Case-by-case	-
	All corrosion inhibiting materials	"	-	No discharge
Ash transport	Total suspended solids	30 (100 max)	-	-
	Oil and grease	15 (20 max)	-	-
Bottom ash transport	Total suspended solids	-	2.4 (8.0 max)	1.5 (5.0 max)
	Oil and grease	-	1.2 (1.6 max)	0.75 (1.0 max)
Fly ash transport	Total suspended solids	-	20 (100 max)	No discharge
	Oil and grease	-	15 (20 max)	No discharge
Low-volume wastes				
Boiler Blowdown	Total suspended solids		30 (100 max)	
	Oil and grease		15 (20 max)	
	Copper, total		1.0 (1.0 max)	
	Iron, total		1.0 (1.0 max)	
Metal equipment cleaning wastes	Total suspended solids		30 (100 max)	
	Oil and grease		15 (20 max)	
	Copper, total		1.0 (1.0 max)	
	Iron, total		1.0 (1.0 max)	
Others, except sanitary wastes and radwastes	Total suspended solids		30 (100 max)	
	Oil and grease		15 (20 max)	
Rainfall runoff from materials storage piles and construction activities	Total suspended solids		No to exceed 50 mg/L	
Rainfall runoff from other sources ^c	All pollutant parameters		No limitation	
Sanitary wastes and radwastes	All pollutant parameters		No limitation	
All sources	Polychlorinated biphenyls		No discharge	
	pH value ^d		Within the range 6.0-9.0 at all times	

^aNote: Numbers are concentrations, mg/L, except for pH values. Effluent limitations, except for pH and rainfall runoff, are quantities of pollutants to be determined by multiplying the concentration indicated times the flow of water from the corresponding source. Effluent limitations are averages of daily values for 30 consecutive days (maximum values for any one day are determined from the numbers in parentheses), except for pH and rainfall runoff. In the event that waste streams from various sources are combined for treatment or discharge, the quantity of each pollutant attributable to each waste water source shall not exceed the limitation for that source. No limitations are prescribed for sources/pollutants not specified in this table.

^bNote: Neither free available chlorine nor total residual chlorine may be discharged from any unit for more than two hours (aggregate) in any one day and not more than one unit in any plant may discharge free available chlorine or total residual chlorine at any one time. Exceptions to be made, on a case-by-case basis, if discharger demonstrates that limitations must be exceeded in order for the cooling system to operate efficiently.

^cNote: ...and from facilities designed, constructed and operated to treat the volume of material storage runoff and runoff from construction activities that is associated with a 10-yr, 24-hr rainfall event.

^dNote: From all sources except nonrecirculating cooling water, rainfall runoff from sources other than materials storage piles and construction activities^c, sanitary wastes and radwastes.

Table 2.15 Chemical Wastes Control and Treatment Technology^{1 3}

Pollutant Parameter	Control and/or Treatment Technology	Effluent Reduction Achievable	Industry Usage	Costs	
				Capital	Operating
<u>Common:</u> pH	Neutralization with chemicals	Neutral pH	Common	\$10-20,000 (tanks, feeder, etc.)	\$3-30,000 (chemicals, labor, etc.)
Dissolved Solids	1. Concentration and evaporation	Complete removal	Not generally in use - desalinization technology	\$250,000-\$1,660,000 costs are significantly less in areas where evaporation ponds are feasible.	\$150,000-\$450,000 costs are significantly less in areas where evaporation ponds are feasible.
	2. Reverse osmosis	50-95%	Not in use - desalinization technology	50-80 c/1000 gal. total cost.	
	3. Distillation	60-90%	Not in use - desalinization technology	80-150 c/1000 gal. total cost.	
Suspended Solids	1. Sedimentation	90-95%	Extensive	\$1000-\$20,000 MW based on 500 gpd/MW	1-20c/1000 gallons
	2. Chemical coagulation and precipitation	95-99%	Moderate	\$10,000-\$35,000 MW based on 500 gpd/MW	1-20c/1000 gallons
	3. Filtration	95%	Not generally practiced-water treatment technology.	\$7,000-\$30,000 MW based on 500 gpd/MW	1-20c/1000 gallons
<u>Specific:</u> Phosphate (Blowdown, Chemical Cleaning, Floor & Yard Drains, Plant Laboratory & Sampling)	1. Chemical coagulation and precipitation		Not generally practiced-water treatment technology.	\$10,000-\$35,000 MW based on 500 gpd/MW	1-20c/1000 gallons
	2. Deep well disposal	Ultimate disposal	not practiced	Costs extremely variable-dependent primarily on geologic conditions.	
Iron (Water Treatment, Chemical Cleaning, Coal Ash Handling, Coal Pile Drainage)	1. Oxidation, chemical coagulation & precipitation	Removal to 0.1 mg/l	Limited usage	\$150-4,000x10 ³	10-100c/1000 gallons
	2. Deep well disposal	-----	As described above	-----	
Copper (Once-through Condenser Cooling)	1. Replace condenser tubes with stainless steel or titanium.	Elimination of discharge.	Done in several plants where tubes have eroded or corroded-not done for environmental reasons.	Prohibitively expensive-would not be done except where retubing is required for process reasons.	No incremental operating cost.
Copper (Blowdown, Chemical Cleaning)	1. Chemical coagulation and precipitation	Removal to 0.1 mg/l	Limited usage	\$100-\$9,000/1000 gpd capacity	10-350c/1000 gallons
	2. Ion exchange	Removal to 0.1 mg/l	Not practiced	\$400-\$1200/1000 gpd capacity	31-81c/1000 gallons
	3. Deep well disposal	-----	As described above	-----	
Mercury (Coal Ash Handling & Coal Pile Drainage)	1. Reduction & precipitation	Removal to 0.3 mg/l	Limited usage	\$700/1000 gpd	7-27c/1000 gallons
	2. Ion exchange	Removal to 0.1 mg/l	Not practiced	\$18,000-\$22,000/1000 gpd	\$1/1000 gallons
	3. Adsorption	Removal to 50 µg/l	Not practiced	\$5000-\$50,000/1000 gpd	\$0.50-\$2/lb. Mercury removed

Table 2.15 (Cont'd)

Pollutant Parameter	Control and/or Treatment Technology	Effluent Reduction Achievable	Industry Usage	Costs	
				Capital	Operating
Vanadium (Chemical Cleaning)	1. H ₂ S treatment precipitation	Removal of low concentrations difficult to achieve	Not practiced	Cost	data not available
	2. Ion exchange		Not practiced	Cost	data not available
Vanadium (Oil Ash Handling)	1. Convert to dry collection	Ultimate Disposal	Practiced in several plants	Cost	data not available
	2. Total recycle with blowdown & precipitation	Complete recycle of liquid	Not generally practiced	Cost	data not available
Chlorine (Once-through Condenser Cooling)	1. Control of residual Cl ₂ with automatic instrumentation	Control to 0.2 mg/l	Limited usage in the industry-technology from sewage treatment practiced in some plants-all systems are not capable of being converted to mechanical cleaning.	\$5,000	Negligible
	2. Utilize mechanical cleaning	Eliminates Cl ₂ discharge		No cost data available	
Chlorine (Recirculating)	1. Control of residual Cl ₂ with automatic instrumentation	-----As described above-----			
	2. Reduction of Cl ₂ with sodium bisulfite	Below detectable limits	Being installed in a new nuclear facility; however excess NaHSO ₃ is discharged	No cost data available	
Aluminum/Zinc (Water Treatment, Chemical Cleaning, Coal Ash Handling, Coal Pile Drainage)	1. Chemical precipitation	Removal to 1.0 mg/l	Limited usage	\$500-\$3000/1000 gpd	10-180¢/1000 gallons
	2. Ion exchange	Similar to copper			
	3. Deep well disposal	-----As described above-----			
Oil (Chemical Cleaning, Ash Handling, Floor & Yard Drains)	1. Oil-water separator (sedimentation with skimming)	Removal to 15 mg/l	Common usage	\$1,500-\$15,000 based on 500 gal/MW 25-400 MW range	No data
	2. Air flotation	Removal to 10 mg/l	Limited usage	\$5,000-\$50,000	No data
Phenols (Ash Handling, Coal Pile Drainage, Floor & Yard Drains)	1. Biological treatment	Removal to 1 mg/l	Not practiced in the industry.	\$150-\$2800/1000 gpd	22¢/1000 gallons
	2. Ozone treatment	Removal to <0.01 mg/l	Not practiced in the industry	No data	No data
	3. Activated carbon	Removal to <0.01 mg/l	Not practiced in the industry.	\$50-\$350/1000 gpd	4¢-15¢/1000 gallons
Sulfate/Sulfite (Water Treatment, Chemical Cleaning, Ash Handling, Coal Pile Drainage, SO ₂ Removal)	Ion exchange (sulfate) Oxidation & ion exchange (sulfite)	75-95%	Not practiced in the industry.	Total cost of \$2,00/1000 gallons	
Ammonia (Water Treatment, Blowdown, Chemical Cleaning, Closed Cooling Water Systems)	1. Stripping	50-90%	Not practiced; several installations in sewage treatment	Total cost - 3¢/1000 gallons	
	2. Biological nitrification	Removal to 2 mg/l	Not practiced for these waste streams	No data available	
	3. Ion exchange	80-95%	Not practiced	Total cost - 10¢/1000 gallons	

Table 2.15 (Cont'd)

Pollutant Parameter	Control and/or Treatment Technology	Effluent Reduction Achievable	Industry Usage	Costs	
				Capital	Operating
Oxidizing Agents (Chemical Cleaning)	Neutralization with reducing agent and precipitation where necessary.	Neutral pH & 95% removal	Limited usage	No data available	
BOD/COD (Sanitary Wastes)	Biological treatment	85-95%	Common practice	\$25,000-\$35,000	Negligible
COD (Water Treatment, Chemical Cleaning)	1. Chemical oxidation	85-95%	Limited usage	No data available	
	2. Aeration	85-95%	Not practiced	No data available	
	3. Biological	85-95%	Not practiced	No data available	
Fluoride (Chemical Cleaning)	Chemical precipitation	Removal to 1 mg/l	Limited usage	Total cost - 10-50¢/1000 gallons	
Boron (Low Level Radwastes)	Ion exchange	Removal to 1 mg/l	Not generally practiced - radioactive material would concentrate on ion exchange resin requiring inclusion in solid radwaste disposal system.	No data available	

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3 HEALTH EFFECTS

3.1 SUMMARY

The utilization of coal for power production has become a major consideration as an alternative for oil and nuclear systems. Although this resource is abundant relative to other forms of fossil fuel, coal's combustion effluents have the potential for serious adverse effects on human health. To evaluate this potential, descriptions of both the effluents and the exposed population are required.¹

Health effects analysis is basically a matter of determining dose and estimating response.² Physiological and pathological responses in a population exposed to the airborne insults from coal will reflect the individual's susceptibility and the duration or history of exposure. There will always be individuals who have severe short-term reactions to any increased level of a contaminant. Subgroups such as young children, the aged, and the infirm are especially sensitive to the impact of increased concentrations of respiratory irritants and other poisons.³ The short-term adverse effects from coal combustion will be manifest in these subgroups as an increased incidence of respiratory disease and premature death. Chronic exposure to coal combustion effluents may result in an increased incidence of respiratory disease and cancer in the total population.

Combustion products of coal contain a variety of constituents. Oxides of carbon, sulfur, and nitrogen are present as gases, while volatile organics and inorganics exist as vapors, and particulates from ash are abundant and distributed in a wide range of particle diameters. The amounts of these products are dependent on the type of coal, the process of combustion, and the efficiency of control devices. Estimation of dose from these airborne effluents requires knowledge of their chemical and physical nature.

For gaseous effluents, dose estimation from emission rate is a relatively straightforward procedure. This is not as true for vapor phase products and particulates. The dose from these products is more a function

of inhaled particle size than a mass. Respirable-size particles ($.01-1\ \mu\text{m}$ in diameter) are able to pass the upper respiratory clearance mechanisms and enter the lower respiratory areas, remaining there for extended periods of time. The respirable particles, by absorption, can also serve as carriers for volatile combustion products. Through this mechanism the actual dose inhaled may be considerably greater than in the emission rate from the stack. Therefore, it is necessary to consider volatility of the chemical species, absorptivity of the particles, and hygroscopicity of both.

All of the above factors must be considered in estimating dose-response. Before the health effects of combustion effluents can be predicted or estimated, we must know the following parameters about these effluents:

1. Emission rate.
2. Physical and chemical state.
3. Atmospheric transport parameters including the chemical or physical changes.
4. Specific toxic qualities and known or presumed detrimental effects upon human health.

From these, in turn, can be computed the concentration of effluents to which people are actually exposed, and the level of effects to be anticipated.

3.1.1 Statement of Purpose

The purpose of this chapter is to present a review of known information on the adverse health effects related to coal combustion. The assumption is made that qualitative effects from uncontrolled combustion will not significantly differ from those of controlled coal use. Such an assumption does not imply equality of quantitative responses. Through the control of emissions the portion of an exposed population exhibiting adverse responses will be considerably reduced. Also, the overall severity of the effects will in all likelihood be reduced.

3.2 "HEALTH" DEFINED

3.2.1 *The Measurement of "Health"*

The distinction between good health and poor health is not sharp. The health status of individuals can range along a continuum from perfect physical condition to moderate illness to imminent death. The level of ill health that can be considered a serious economic or medical problem varies according to the age and occupation of the person considered. A case of influenza, for example, which might be considered a mild annoyance in a high school student, could be cause for alarm in an elderly person with a heart condition.

Nevertheless, an objective definition of health is needed. The one most commonly used, because it is most easily measured, is mortality. There are more useful measures of the health status of a population which are far less readily available. These are the incidence of disease (the rate at which unaffected persons develop a given disease per unit time) and disease prevalence (the proportion of the population suffering the given disease at any time).

The characteristics of the population under study are important aspects of the expected health status. Even under the best of circumstances, the risk of death is always relatively high at birth, reaches a minimum around ages 10-15, and increases roughly exponentially thereafter. Females tend to live longer than males, and smokers tend to die earlier than non-smokers. A variety of social and economic factors also influence mortality rates, and in some cases these factors vary markedly among easily identifiable racial and ethnic groups. Therefore, it is important that age, sex, and race be controlled in any health effects measurement scheme.

3.2.2 *The Study of Health Effects*

The health effects of an environmental stress or noxious agent in humans are often hard to study. For ethical reasons, it is usually impossible to study in man, under controlled experimental conditions, substances suspected of leading to lethal or permanently harmful outcomes. As a consequence, the results of animal experimentation, with all of the implied problems of interspecific variation, are nevertheless a major source of data. Thus, we are often in possession of excellent dose-response data for substances in animals not directly applicable to humans.

On the other hand, when data come from human studies, we often find that they derive from cases in which the dose and duration of exposure (especially the former) and indeed the composition of the toxic substance being studied are not well defined. Thus while the nature of the effects may be well described for humans, quantitative dose-response relationships may remain obscure, since the circumstances of exposure may be unknown. This problem is particularly acute in the case of long-term or latent effects in which the history of exposure over a 10-20 yr period must be estimated.

3.3 HEALTH EFFECTS ASSOCIATED WITH AIR POLLUTION FROM COAL USE

Most of the effluents from current modes of coal utilization that have a direct impact on human health are found in the stack emissions from coal-burning facilities, and hence appear as airborne pollutants. These characteristically have four major types of health impacts.

3.3.1 *Physiological Effects*

3.3.1.1 *Irritation*

In this case, the challenge from the pollutant has the effect of causing an inflammatory reaction in the affected organs. Inflammation is designed as a defense mechanism by which the body rejects foreign materials. It is characteristically seen as a local reaction, for example around a wound, where the effect will be to wall off and later destroy invading pathogens and/or other foreign material that cannot be removed by any other means. Paradoxically, when an inflammatory response occurs over a wide area, it may have a deleterious effect. Because of the tissue damage it induces, it may be more deleterious than the challenge or foreign material that stimulated the reaction. The result may interfere with other immunological mechanisms to the point where susceptibility to attack by pathogenic organisms is actually enhanced.⁴

3.3.1.2 *Direct Toxicity*

The pollutant causes direct damage to the cells with which it comes in contact. This usually results when the agent interferes with the metabolism of the cell, by either inactivating key enzymes, being metabolized into unneeded products, or otherwise disrupting normal cell function. In

general, substances with toxic effects will also stimulate inflammation, but the response is not always in proportion to the challenge. Inflammation usually occurs at the site of contact and toxic effects may show up anywhere in the body after absorption.

3.3.1.3 Carcinogenesis

The pollutant and/or its metabolic by-products stimulate the development of tumors after some latent period which may range from a few years to several decades. The tumor may develop as a result of an accumulation of gene mutations or chromosome aberrations due to biochemical reactions between the genetic material of the cell and the carcinogen or its metabolites.

3.3.1.4 Physical Synergism - Lung Clearance

An additional class of effects occur in the respiratory system, which, while not directly harmful in and of themselves, can potentiate the ones described above. The mechanisms for clearing noxious substances from the lungs may be reduced in effectiveness, thereby increasing the residence time of effluents in the lung. This usually results either from a reduction in ciliary action in the bronchial tree, or from a thickening of the protective layer of mucus which interferes with the ciliary action moving foreign particles out of the lung.

3.3.2 Clinical Conditions Resulting from the Physiological Effects

The responses listed above may have different outcomes, depending upon the age and condition of the victim, the nature of the noxious agent, and the duration of exposure. The clinical manifestations typically observed among persons exposed to airborne pollutants are described in the following sections.

3.3.2.1 Acute Respiratory Disease

Inflammation of pulmonary tissue and the general debility produced by toxic effects make both the upper and lower respiratory tract more subject to infection. Thus the incidence of influenza, pneumonia, colds, and other acute pulmonary diseases tends to be elevated in exposed populations.

Acute asthma attacks can be induced in susceptible persons by respired irritants. The severity of an attack, whether pollutant-induced or not, can be markedly increased by the synergistic relationships that have been found between the body's response to histamines, which are released in the initial phase of an asthma attack, and the prior exposure to other irritants.

3.3.2.2 Chronic Respiratory Disease

Prolonged exposure to irritants and toxins has been shown to lead to irreversible damage to lung tissue. Emphysema and chronic bronchitis have been shown to develop in a variety of experimental animals exposed to low levels of the common pollutants. These are also the characteristic effects of chronic pulmonary injury in man and are seen, for example, after prolonged use of tobacco. Early inflammatory responses have been shown to lead to the development of various pneumoconioses (silicosis, asbestosis, etc.) when certain kinds of irritant particles are introduced.

3.3.2.3 Aggravation of Pre-existing Conditions

A person already in poor health from a condition such as chronic respiratory or cardiovascular disease, whether originally caused by the pollutants in question or not, is at much higher risk of suffering an acute or fatal episode when exposed to airborne irritants.

3.3.2.4 Neoplastic Diseases

Exposure to carcinogens of the kinds found among coal combustion products usually leads to neoplasia or cancer in the site or organ of deposition. Cancers of the respiratory and alimentary tracts are therefore most likely to be associated with coal effluents. However, metabolic transport and transformation has the potential for causing cancer in other organs as well. Cancers of the bladder, central nervous system, and hematopoietic tissues, for example, have all been associated with organic effluents having structures analogous to those seen in coal.

3.4 HEALTH EFFECTS ASSOCIATED WITH SPECIFIC POLLUTANTS

The effluents produced from coal combustion are a heterogeneous group; this section breaks them down and tries to summarize what is known about the components of interest.

3.4.1 Sulfur Dioxide (SO_2)

SO_2 was one of the earliest suspected toxic agents in air pollution episodes and has therefore been studied extensively. In the pure state, it is a colorless gas with a slight acrid odor. In concentrations over $56 \mu\text{g}/\text{m}^3$, it is largely absorbed in the upper respiratory tract (URT) with only 2-10% reaching the pulmonary region. At concentrations of $2-5 \mu\text{g}/\text{m}^3$, 90-98.8% of what is inhaled reaches the terminal bronchioles and alveoli. Thus the effective dose received by the most sensitive parts of the respiratory system does not decrease linearly with decreasing atmospheric concentration. It has not been shown to produce serious direct effects in the pure state in humans in the concentrations which would ordinarily be expected in areas of heavy coal utilization (i.e., $7-35 \mu\text{g}/\text{m}^3$), although levels above 0.25 ppm are usually associated with adverse health effects in epidemiological studies.⁵

3.4.1.1 Irritant Effects ^{6,7,5,8}

In humans, initial exposure to concentrations of SO_2 which might be realistically encountered produces a temporary vasoconstriction which lasts about 10-20 minutes in a previously unexposed subject, with measurable reduction in the elasticity of the lung lasting for somewhat longer periods of time. Subjects exposed over several days show slight changes in lung capacity and pulmonary resistance, levels of various enzymes, and blood chemistry. There appears to be a habituation effect, in that a person with one or more days prior exposure to low levels of SO_2 does not react as severely to a subsequently higher dose as does one who has not. In even the worst-case realistic dose range, the irritant effect is mild, and tends to decrease with habituation.

3.4.1.2 *Co-irritant Effects*

SO₂ has been found in some studies to interact with other irritants to both enhance and ameliorate their effects. Experimental rats habituated to sulfur dioxide, for example, will not react as strongly to a subsequent dose of nitrogen dioxide as one without such prior exposure. Indications of a synergism have been found in studies involving ozone (O₃) and histamine wherein prior exposure to SO₂ will result in more severe reactions to those irritants.

SO₂ can be absorbed on the surfaces of otherwise benign particulates, which markedly enhances the irritant effect. It is not known whether this results from the longer residence time of the SO₂ in the area of the particle deposition or from an enhancement of the irritant effect of the particle itself.⁹

3.4.1.3 *Carcinogenic Effects*

SO₂ passes readily through cell membranes, and once in an aqueous medium, such as cell cytoplasm, can form a number of free radicals and ions, notably sulfite, bisulfite, and SO₂⁻. Although the first two can be quite toxic, there is a well developed enzyme system that rapidly neutralizes and removes these ions. The risk associated with these ions is therefore quite low for most people. The SO₂⁻ radical, however, is a relatively long-lived species with an affinity for breaking disulfide (S-S) bonds,¹⁰ which makes it a potential cause of gene mutations and possibly a long-term carcinogen.

3.4.1.4 *Co-carcinogenic Effects*

One experiment using rats showed that prior exposure to SO₂ facilitated the induction of lung tumors by benz(a)pyrene administered by aerosol. In fact, in this particular experiment benz(a)pyrene did not appear carcinogenic in the absence of SO₂.⁵

3.4.1.5 *Effects on Lung Clearing*

SO₂ in short-term doses (30 µg/m³ for rats) temporarily suppresses the action of ciliated cells lining the bronchial passages and a similar response has been observed in humans. Ciliated cells are responsible for

removing particulates and other debris from the lungs. Reduction of their action may increase the residence time of alien substances. Long-term doses at 15-25 $\mu\text{g}/\text{m}^3$ did not have this effect, but instead resulted in thickening of the protective mucus layer over the cilia, which inhibits their ability to move the debris and therefore has in the long run an effect similar to that seen following acute exposure.⁵

3.4.2 *Oxides of Nitrogen*

Nitrogen oxides (NO_x) are produced by both the oxidation of organically bound nitrogen in coal and the secondary oxidation of atmospheric nitrogen during the combustion of coal and most other hydrocarbons, especially at temperatures greater than 2800°F. The two most important species are nitric oxide (NO) and nitrogen dioxide (also known as Nitrogen Peroxide) (NO_2). Nitric oxide is an unstable species which oxidizes readily to NO_2 . Nitrogen oxides are also important in the generation and regulation of ozone levels and in the production of organic components of photochemical smog. The species most commonly found in the atmosphere is NO_2 , the component discussed below.

3.4.2.1 *Irritant Effect*

NO_2 is a strong irritant. Rats experimentally exposed to as little as 0.5 ppm showed signs of acute inflammatory response after only four hours of exposure. Chronic exposure of experimental animals to levels insufficient to produce evidence of acute inflammation were nonetheless sufficient to produce irreversible emphysema-like lesions. Human experiments at 5-ppm levels have shown evidence of inflammation as measured by diminished lung compliance, but unlike SO_2 the effects seem to be delayed one-half to one hour after the onset of exposure. As with SO_2 and O_3 , there is a protective habituation effect to the effects of acute inflammation. It must be emphasized, however, that the protective effects of habituation do not necessarily apply to effects other than acute inflammation. In fact, in the opinion of many researchers the reverse is true, that the mechanism of habituation to the acute inflammatory response may be part of the effect of chronic toxicity.

3.4.2.2 *Co-irritant Effect*

See 3.4.1.2

3.4.2.3 *Carcinogenic Effect*

Nitric oxide in aqueous solution can form nitrite (NO_2^-) ion, which in the presence of suitable organic amide bases can form nitrosamines, which in turn are highly potent carcinogens.¹¹ The possibility exists, therefore, of a carcinogenic effect both in the lung and the stomach as the result of swallowed particulates. Although there are suggestive relationships between stomach cancer and air pollution¹² in some localities, there is little verification of this hypothesis available as yet.

3.4.2.4 *Co-carcinogenic Effect*

Experiments showing enhancement of benz(a)pyrene carcinogenesis following prior exposure to NO_2 are in progress, but the results have not yet been published.

3.4.2.5 *Lung-clearance Effect*

NO_2 seems to reduce ciliary action in the same fashion as SO_2 .

3.4.3 *Ozone⁵*

Ozone appears as the result of secondary reactions following combustion. It is a highly reactive trimeric molecule of oxygen.

3.4.3.1 *Irritant Effect*

Ozone is among the stronger of the simple inorganic gaseous irritants.

3.4.3.2 *Co-irritant Effects*

The relationships between ozone and other irritants are many and varied. They show a habituation effect. However, prior exposure to ozone produces cross tolerances to a much greater spectrum of irritants than is the case with most of the other noxious agents. When exposure to ozone and other irritants is simultaneous, the effect is usually additive or syner-

gistic. Prior exposure to substances containing disulfide groups or sulphydryl groups tends to be protective against the acute response.

3.4.3.3 *Carcinogenic Effects*

Ozone at long term exposure levels of one ppm has been shown to be carcinogenic in susceptible strains of mice.⁵ Its capacity for reacting with disulfide and sulhydryl groups, and for forming other free radicals, gives it the capacity for mutagenic activity--a characteristic of many carcinogens. Beyond the mouse experiments, however, there is little experimental verification of this facet of O₃ response.

3.4.3.4 *Direct Toxic Effects*

Ozone is very active biochemically, and has been shown to cause premature aging in some experimental animals. This effect develops despite the fact that most mammals, including man, have a very well developed enzyme system (superoxide dismutase) for removing and denaturing O₃ and other active peroxides.

3.4.4 *Hydrocarbons*

Coal has no unique structure. It is generally viewed as a network of aromatic carbon compounds interspersed with various heterocyclic compounds. The potential exists therefore for the formation of a wide variety of organic effluents, especially during transient operating conditions that permit incomplete combustion.

Many of the products of coal decomposition are equivalent to the advanced stages of pyrene synthesis. At temperatures on the order of 900°C, the predominant reactions are ring closures, condensation, and aromatization reactions.¹³ The main products tend to be polynuclear ring compounds. Products from low temperature pyrolysis might be expected to be encountered during periods of startup and shutdown. These compounds would tend to be single aromatic rings or heterocyclic compounds with alkyl side chains.

The consequences of inhalation of hydrocarbons are complex because the inhaled substances are always in mixtures. This intermingling of compounds makes it virtually impossible to incriminate any single material as

the agent in the causation of pathologic changes. However, in experimental situations a number of organic compounds arising from the combustion or processing of coal have been identified as either known or "suspect" carcinogens, and others as strong eye and lung irritants.

3.4.4.1 *Irritant Effects*

The products of incomplete coal combustion include aliphatic and aromatic hydrocarbons, aldehydes, and ketones. Of the aldehydes, formaldehyde and acrolein are recognized as the two most common hydrocarbon irritants. These compounds are easily absorbed across the mucous membranes of the conjunctivae and alveoli. Their initial actions are to produce tears (lacrimation) or sneezing (sternutation).¹⁴ Other effects associated with inhalation of these products include rhinorrhea, cough, sore throat, and a sense of substernal oppression. Irritation from formaldehyde is apparent to most people at concentrations of 2-3 ppm. The same reactions from acrolein are associated with concentrations of less than 1 ppm.¹⁵

The intensity of acute and chronic inflammatory reactions will depend on the specific toxicological properties of the pollutant. The olefins or unsaturated aldehydes produce more noticeable irritation than do saturated aldehydes. Their toxicity increases with the addition of a double bond and decreases with increasing molecular weight.

Where a hydrocarbon is absorbed in the respiratory tract depends upon the pollutant's water solubility. Highly water-soluble products tend to be absorbed in the nasal, buccal, nasopharyngeal, and laryngotracheal regions. The higher molecular weight, less soluble compounds are able to penetrate deeply into the lungs.

Photochemical reaction products can be considered as secondary products of coal combustion. These compounds result from the interaction with ultraviolet radiation and the oxidation of effluent hydrocarbons. Ozone and the PAN series are examples of this group. Photooxidation is also a pathway for aldehyde formation.¹⁵ The PAN series, peroxyacetylnitrate (PAN), peroxybenzoylnitrate (PBZN) and its homologues, are potentially more toxic than the aldehydes. However, due to their high reactivity and resultant short lifetimes, the extent to which the PANs are directly responsible for irritant effects is uncertain.

3.4.4.2 *Carcinogenic Effects*

Among the products of coal combustion, the most serious potential for carcinogenic effects appears related to the polycyclic compounds. Polycyclic aromatics and aza-arenes derived from the benz(a)anthracene skeleton have been shown to contain a number of strong carcinogenic agents.¹⁶ The most widely studied compound of these groups is benz(a)pyrene.¹⁷ This compound has been clearly established as a causative factor in skin and lung cancers in experimental animals.

3.4.5 *Carbon Monoxide*

Carbon Monoxide (CO) may be produced during incomplete combustion of coal, and is therefore most likely to appear when a concerted effort is being made to control NO_x emissions.

3.4.5.1 *Direct Toxic Effect*

CO is best known for its affinity for hemoglobin, combining to form carboxyhemoglobin (COHb), which has a very long residence time in the blood. The victim suffers asphyxiation. At COHb levels >1.3% in the blood for over eight hours, persons with stable coronary artery disease (angina pectoris) may start to note increased frequency and duration of symptoms; at blood levels of 1.9% excess deaths may occur among people with pre-existing cardiovascular disease.¹⁸

The effects at lower levels among otherwise healthy persons is not well defined.

3.4.6 *Particulates (Including Trace Elements)*

A significant portion, approximately 10% of the mass, of the combustion products from coal is in the form of particulates. Microscopic solid particles and liquid droplets result from the processes that take place during and after combustion. Although the size range given for atmospheric particulates extends from about 0.005 to 500 μm , the particulates from coal combustion appear in a more limited size range. These products tend to be found in the 0.01-10 micrometer range of equivalent aerodynamic diameters. Because this range neatly brackets the size defined for respirable particles,

the coal combustion particulates pose a significant potential for adverse human health effects.

Mechanical procedures can reduce the coal itself or the ash to particles on the order of several micrometers in diameter. During combustion the constituents of coal can vaporize and later condense, or a fine ash can be produced such that particles of 0.1-1 μm are created. Partial combustion can result in the formation of soot particles 0.01-1 μm in diameter. The energy available from combustion can also be responsible for the formation of condensation nuclei of 0.01 μm in diameter. The processes stated above give rise to primary particulates, the results of direct interactions during combustion. Secondary particulates can be formed from the post-combustion interactions of gaseous products and sunlight. The sulfates, nitrates, and hydrocarbons usually result from photochemical reactions. The size range associated with these particles is 0.01-1 μm .¹⁹

Virtually all of the naturally occurring elements can be found as contaminants in coal. The emission of these constituents is dependent on their chemical form prior to combustion and on their volatility.²⁰

Most elements in coal, exclusive of carbon, come in the form of aluminosilicates, inorganic sulfides, and organic complexes. During combustion, the sulfides and organic compounds are decomposed to produce SO_2 and a number of oxides and other chemical species of varying volatility. The aluminosilicates, on the other hand, have very high vaporization temperatures, and tend therefore to survive more or less intact as fly ash and slag.¹³

Many of the elements and compounds that volatilize and adsorb on particulates are known to have adverse effects on human health,²¹ and one of the most interesting of these is SO_2 , which has been discussed in Section 3.4.1. When adsorbed on such surfaces, SO_2 is in many cases transformed into SO_3 and the sulfate ion far more readily than when it is in the gaseous state, and in the presence of high humidity (and possibly hygroscopic particles) may form aerosols of sulfuric acid or other acid sulfates. Particles containing vanadium are particularly likely to catalyze this reaction.

3.4.6.1 *Mechanisms of Action*

The effects that particulate emissions can have on human health are determined by three factors: (1) the composition of the particulates, (2) their size, and (3) the amount of time they spend in contact with sensitive tissues.

The lungs constitute the major route of entry for toxic airborne particulates. The probability of particle deposition and the anatomical position of the respiratory system in which deposition occurs is primarily a function of particle size. Those less than about $0.01\ \mu\text{m}$ in diameter tend to behave like gases, and are generally not deposited at all. Particles with a diameter of 0.01 to around $1\ \mu\text{m}$ are predominantly deposited in the alveolar or pulmonary region, while larger particles show a greater tendency to deposit in the nasopharyngeal and tracheobronchial regions.

Most airways are lined with ciliated and mucus-secreting cells that trap impacted particles and move them, aided by the cough reflex, to the pharynx from where they are swallowed or expectorated. The extraction of many toxic substances from such particles is inhibited by the mucus layer in the bronchial tree and may therefore take place in the stomach, where their residence time is relatively short. There have been studies, however, which show a positive correlation between particulate concentrations in air and stomach cancer.¹²

The surface of the alveoli must be kept clear of deposited matter to allow for efficient gas exchange. Phagocytosis by alveolar macrophage cells is the principal clearance mechanism of this area. Insoluble particles or aerosol droplets are engulfed by alveolar macrophage cell. The cell and particle may then migrate either to the ciliated epithelium of the terminal bronchioles, there to be swept out of the system by muco-ciliary action, or pass through the alveolar membrane and enter the lymphatic system. If the deposited particle is soluble in the tissue fluid on the surface of the alveoli, it can be readily absorbed into the bloodstream.

The rate at which particles are cleared from the pulmonary areas is variable. For particles that are engulfed by macrophage cells and carried to the ciliated epithelium or lymphatic system, the residence half-life is two to six weeks. If the macrophage does not succeed immediately in clearing

the foreign particle, it may become sequestered in the lung. In this case the residence half-life rises to several months or years and the clearance rate will depend upon particle solubility.

A cytotoxic material can influence its own rate of clearance in several ways. Such a substance can damage or destroy the phagocyte, thereby directly reducing macrophage action. Tissue reaction to a sequestered particle can result in the progressive segregation of the foreign body behind a mass of fibrous material, making removal more difficult. The formation of the silicotic nodule is an example of the latter type of reaction.²²

3.4.6.2 *Physiological Effects*

The toxic effect produced by respirable particles depends on the chemical species that they contain. Small particles are generally more toxic than large ones. The submicron fly ash particle presents a double threat to human health. Not only does this particle reach the pulmonary region of the lung and remain there for extended periods of time, but it also has the capability of delivering relatively high concentrations of some of the effluents as the result of surface adsorption (see Section 3.4.6.1). A detailed breakdown of the known effects that might be attributed to each of the individual components would tend to be repetitive. We therefore present only a brief list of the major effects that can be anticipated and the important contributors in each.

Irritant Effect

Because they can absorb SO₂ and other irritant gases and vapors, respirable particulates have the ability to magnify their effects by holding high concentrations of these irritants in close proximity to sensitive tissues for protracted periods of time.

The sulfate ion, which is often associated with small particles and aerosols, appears to be a far more potent irritant than any of the others discussed here. This is probably due in part to the fact that the ion forms a very strong and reactive acid and also to the fact that it is so strongly associated with particulates.⁵

The cations associated with the sulfates are important mediators of

irritant potency.⁹ Pure sulfuric acid (H_2SO_4) and ferric ammonium sulfate ($\text{FeNH}_4(\text{SO}_4)$) are the most potent forms. Other ions tend to be weaker in proportion to their acidity.

Most particles that contain silica can, if they become permanently sequestered in the lung, induce various forms of fibrotic lung disease, such as silicosis, pneumoconiosis, etc.⁸ In the amounts that are likely to be produced by power plants, however, this effect is likely to be unimportant.

Carcinogenic Effect

Particulates act as carriers of many trace elements and hydrocarbons in the effluent stream. Nickel (in the form of nickel carbonyl), chromium, (especially in the form of chromic trioxide), beryllium, and arsenic have been implicated as carcinogens. In the organic particulates, many contain the known carcinogen benz(a)pyrene and its relatives.

Direct Toxic Effects

Lead, tellurium, mercury, arsenic, selenium, cadmium, nickel, chromium, and vanadium are all known to be highly toxic,²⁴ with many exhibiting a special propensity for cellular deposition and retention. These elements are capable of interfering with and disrupting the function of the central nervous system and other organ systems of the body unrelated to the respiratory system.

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4 CONTROL TECHNOLOGIES FOR CONVENTIONAL POWER PLANTS

4.1 FLUE GAS DESULFURIZATION (FGD) SYSTEMS

4.1.1 Summary

In July 1976, 27 FGD systems ranging in size from 10 MWe to 835 MWe were reported to be operating on utility boilers in the U.S. The installed capacity, 5573 MWe, was close to 3% of the 200,000 MWe of coal-fired generating capacity, but the number of FGD systems actually operating reliably on larger (>100 MWe) power plants was small. There is some indication that reliability is improving as operating experience increases, and additional improvement may be expected as FGD units incorporating newer design concepts come on line. At the present time, however, performance corresponding to commercial availability (which may be defined as reliable operation on 100 MWe for a minimum of one year) has been achieved only in two cases; only during the past year, and by dint of an intensive maintenance program, has it been achieved on a unit burning coal of high sulfur content.

Close to 85% of currently installed FGD systems, and more than 90% of installations now planned to be operating in 1980, utilize lime/limestone scrubbing and yield sludges that present a major disposal problem. So far no regenerable FGD system that yields a marketable product has been satisfactorily demonstrated in this country. Demonstrations of regenerable FGD that are about to get underway (for the Wellman-Lord process) or have been planned (for the Citrate and the Aqueous Carbonate process) are not likely to have any impact before 1985.

FGD installations planned by the utilities for operation by 1980 total 32,210 MWe. However, it is unlikely that this level will be reached since process selection for some 5000 MWe has not yet occurred and lead times for FGD installations can easily be four years or more. Only one-half, 16,300 MWe, of the planned installations will burn high sulfur (>1% S) coal from mines east of the Mississippi, the remainder will be used in the West to meet state regulations that are more strict than the NSPS. In 1975, 176 million tons of the 410 million tons of coal burned by the utilities in the U.S. did not comply with regulations; 93% of the non-complying coal was burned east of the Mississippi in utility boilers with a generating capacity of about 80,000 MWe. Planned installation of FGD east of the Miss-

Mississippi by 1980 is only one-fifth of that needed to correct non-compliance. Unless efforts are made to accelerate deployment of FGD systems, or to accelerate the development of other near-term technologies for clean use of coal, the continued production of coal currently being mined in the East and Midwest will be jeopardized.

4.1.2 *Introduction*

Flue gas desulfurization (FGD) is the generic term used to denote processes for chemical or physical removal of sulfur dioxide from flue gas, usually by means of a gas scrubbing operation. Since scrubbers are capable of continuously and efficiently reducing SO₂ emissions, FGD is one of the options available to the utilities for complying with New Source Performance Standards (NSPSs) while continuing to burn high sulfur coal, or for complying with more strict state regulations that cannot be met by burning low sulfur coal. FGD, in fact, is the only option currently available.

The issues revolving around FGD utilization are quite controversial. To some extent the appropriateness of the National Ambient Air Quality Standard (NAAQS) for SO₂ has been questioned on the grounds that SO₂ may be merely a surrogate for other pollutants, but the major controversy has been on the issue of "stacks vs. scrubbers."¹ With respect to the NAAQS for SO₂, it has been noted earlier in Section 3.4 of this report that pure SO₂ at concentrations near the primary NAAQS is relatively harmless, but that combinations of SO₂ with other pollutants and oxidation products of SO₂ in the form of sulfate particulates and sulfuric acid aerosols may be a cause of serious health problems. Definitive information on these effects may not be available for several years. In view of historical precedents and worldwide trends, however, a relaxation of the NAAQS for SO₂ appears highly unlikely. Indeed, the imposition of additional regulations, specifically for particulate sulfates, is a distinct possibility. If this should occur, the control capability of current FGD processes might prove to be inadequate and use of a clean fuel, such as low-Btu gas, may be required.

The issue of tall stacks versus scrubbers has been argued both in the press and in the courts. The most heated arguments between EPA and the utilities have occurred in four areas:

1. Need for continuous emission control.
2. Reliability of FGD units.
3. Disposal practices for FGD wastes.
4. Costs.

Only the first of these issues will be discussed at this point; the reliability and costs of FGD and problems associated with the disposal of FGD wastes are discussed below in Subsections 4.1.4 and 4.1.6 and in Section 4.4, respectively.

The need for continuous reduction of SO₂ emissions to maintain satisfactory air quality was questioned long before EPA and the Clean Air Act came into existence. In England and the TVA, after early experiences with FGD, decisions were made to erect tall stacks and to rely on good dispersion to reduce ambient levels of SO₂. Additional control features aimed at reducing plant emissions under adverse meteorological conditions were later adopted. These supplementary control systems (SCS) have become extremely sophisticated: the most advanced incorporate multistation SO₂ monitoring, measurement of atmospheric conditions at more than one height, weather forecasting, dispersion modeling, and computerized plant operations such as load or fuel switching.^{2,3} The EPA, however, has interpreted the language of the Clean Air Act to mean that NAAQSs must be met by continuous emission reduction, and the recent refusal of the U.S. Supreme Court to hear the Big Rivers case⁴ has supported the EPA interpretation. The authority of the EPA to prescribe continuous emission control is permissive rather than obligatory under the present law however, and the agency has indicated that limited use of SCS, where it is reliable and enforceable, may be permitted until 1985.

4.1.3 *Technology Description*

More than 50 FGD processes have been proposed and developed to a varying degree. As an aid in discussing them, it has become customary to categorize the processes as wet or dry and, additionally, as regenerable or nonregenerable. Most of the FGD processes developed to date fall into the *wet* category and involve a scrubbing operation in which the SO₂ in the flue gas is absorbed into a circulating aqueous solution or slurry containing

an appropriate immobilizing reagent, usually alkaline in nature. For economic reasons, use of lime or limestone slurries has been most common, but magnesium oxide, alkali carbonates, and ammonia have also been used. In some of the newer processes, the absorbing solution is buffered with citrate, phosphate, or acetate. One of the major Japanese processes uses dilute sulfuric acid as the absorbent, the SO_2 being immobilized by oxidation and converted to gypsum for removal from the system.

In *dry* processes, flue gas is passed over a solid capable of efficiently adsorbing the SO_2 , reacting with it, or catalyzing its oxidization to SO_3 . Activated carbon, copper and manganese oxides, and vanadium-oxide catalysts are among the solids that have been used.

The term *regenerable* was originally applied to FGD processes that include a step in which the absorbed SO_2 is re-evolved with regeneration of absorbing capacity of the liquid or solution. The evolved (concentrated) SO_2 stream is subsequently converted to a marketable product such as sulfur or sulfuric acid. Nowadays, regenerable is used more loosely to refer to any process yielding a potentially marketable product. Correspondingly, the term nonregenerable is now applied to processes in which the spent sorbent is discarded.

4.1.3.1 Scope

For practical reasons, discussion in this report will be limited to those 12 FGD processes that appear to have the greatest potential for near-term commercialization in the U.S. Eight of the 12 were classified as being in operation on 10-MWe or larger plants in June 1976; the number of units and the capacity installed for each process are shown in Table 4.1. All of these processes are of the wet scrubbing type. The first five listed, lime and limestone scrubbing, the double alkali process, alkaline ash, and sodium carbonate scrubbing are nonregenerable, or throwaway, processes. They account for 24 of the 27 units and for 5410 MWe, or more than 95% of the 5573 MWe installed. Lime and limestone scrubbing alone account for 84% of the total. Wastes from these throwaway processes can be a serious problem. Those from lime/limestone scrubbing and from the double alkali process as well, are calcium sulfite/calcium sulfate sludges that are difficult to dewater and may require chemical fixation for satisfactory disposal. Wastes from sodium

carbonate scrubbing are soluble and can only be disposed of in an arid climate. The process is therefore restricted to western locations; the alkaline ash process, which is only possible with some western coals, is similarly restricted. The three remaining processes listed in Table 4.1, as well as the four other processes to be considered are all in the regenerable category. The magnesium oxide scrubbing process, in which commercial grade sulfuric acid is produced via an off-site calcining operation, was operated earlier in the U.S. at two sites that are now inactive. The FW-BF (Foster Wheeler-Bergbau Forschung) and Chiyoda 101 installations are demonstrations of technology developed, respectively, in Germany and Japan. The FW-BF process uses activated carbon as the adsorbent and yields sulfur as the product. The Chiyoda 101 process uses dilute sulfuric acid as the sorbent and produces gypsum. A 115-MWe demonstration of the sulfur-producing Wellman-Lord process is scheduled to start up late in 1976, and commercial-scale demonstrations are planned in the U.S. for the Citrate process and the Aqueous Carbonate process (ACP), both of which are wet processes yielding sulfur. A demonstration of the Cat-Ox process, which produces sulfuric acid, was underway, but has been indefinitely postponed.

Table 4.1 Operational FGD, June 1976^a

Process	No. of Units	MWe
Limestone	11	2674
Lime	8	2074
Double Alkali	2	52
Alkaline Ash	1	360
Sodium Carbonate	2	250
Magnesium Oxide	1	120
FW-BF	1	20
Chiyoda-101	1	23
TOTAL	27	5573

^aDerived from information in the May-June 1976 report on the *Status of Flue Gas Desulfurization Systems in the United States*, prepared by PEDCo-Environmental Specialists, Inc., under EPA contract.

4.1.3.2 Design Considerations in Wet FGD

The problems that have been encountered in this country with FGD operations and that have slowed their development pace, as well, are mainly mechanical ones associated with corrosion and erosion, and particularly with plugging and scaling.^{5,6} It is appropriate, therefore, to consider these problems in terms of scrubber design alternatives before discussing process details. The gas train in a wet scrubbing operation typically consists of two stages of scrubbing followed by a mist eliminator, provision for stack-gas reheat, and a fan to overcome the pressure drop across the system, which may be as much as 20 in. of water. The energy expended in overcoming the pressure drop and in reheat of the gas is common to all wet FGD processes and may account for 2-3% of plant output in terms of steam or electricity. Additional energy expended for handling of solids and liquids, and for the recovery/reduction of SO₂ in regenerable processes, results in overall energy penalties in FGD ranging from 4-10% depending on process type.

Use of a venturi scrubber in combination with a spray tower for the two scrubbing stages, as shown in Figure 4.1, is becoming increasingly common. In the first of the two scrub stages, the flue gas is cooled from the normal discharge temperature of 300°F to about 150°F and particulates, if present, are removed. Combining the particulate removal with SO₂ removal offers obvious economies, but installation of an electrostatic precipitator for prior removal of particulates is not uncommon, particularly at the present state of FGD development. This makes it possible to operate the boiler when the scrubber is down, provides *dry* fly ash for addition to wet FGD wastes, and lessens erosion problems.

In the second scrub stage, where absorption of SO₂ is important, a variety of designs is possible. Venturi scrubbers can be used when the absorptivity of the solution/slurry is high, but it is more common to use a design that provides for better contact between gas and liquid. Earlier, when emphasis was on the efficiency of absorption, there was a tendency to employ designs that maximized gas-liquid interface areas. Fixed beds of marbles or mobile beds of hollow polymeric spheres (similar to ping-pong balls) were commonly used. Severe problems were encountered as a result of scaling and plugging of the numerous interstices of these units. The current trend is to minimize the internal hardware in scrubbers to decrease the

Fig. 4.1 Schematic of Venturi Scrubber and Spray Tower Test Facility at the TVA Shawnee Plant

likelihood of these problems and to facilitate maintenance. The use of spray towers, which offer the additional advantages of low pressure drop and excellent turndown capability, is one of the more attractive approaches.

After the flue gas exits from the scrubber, entrained aerosol droplets must be removed to prevent deposition of the solids they contain on downstream equipment, such as induced draft fans or reheaters. The mist eliminator is perhaps the most critical component of a scrubber system and has been termed its "Achilles' heel." Most of those used in commercial FGD systems are of the zigzag "chevron" baffle design. Trade-offs between mist removal and pressure drop are important in system design, and the range of linear gas velocities below which impingement is inefficient and above which breakthrough occurs is limited. It might be noted here that it is the linear gas velocity through the scrubber and mist eliminator that determines the size of the system; for a typical velocity of 10 ft/sec, a cross sectional area of 800 sq ft (20 ft x 40 ft) is needed for gas flow of 480,000 acfm, corresponding to 150 MWe. Practical considerations lead to modularization at this size.

Since breakthrough can lead to a variety of serious problems, even including higher than permissible particulate emissions, it is of utmost importance to minimize the buildup of solid accumulations on the demister surfaces. Plugging of the demister, in fact, has been one of the major sources of FGD problems.⁵ The provisions made for washing it are critical, particularly in lime/limestone scrubbing where the solids content in the scrubbing liquor is high. If the scrubber is operated in the closed-loop mode (no discharge of water from the system), the quantity of fresh water available to the system is limited to the water lost by saturation of the flue gas and by retention in the solid wastes. Since the use of fresh make-up water for this purpose is desirable but limited, the design of the washing system and the configuration or orientation of the mist eliminators becomes very important. Horizontal mist eliminators are very convenient to use with vertical scrubbers and, consequently, have been widely used. The problem is that the gas rises vertically and the liquid droplets tend to stay suspended on the eliminator plates, which in turn promotes scaling. A possible solution to the problem is to use a vertical moisture eliminator in which the gas travels horizontally and the droplets can flow unhindered

down the eliminator plates. The disadvantage of the design is the necessity of a separate elimination chamber at added capital expense, unless a horizontal scrubber is used. A 170-MWe horizontal scrubber has performed very well in a recent test program (with low sulfur coal) at the Mohave Station of Southern California Edison in Nevada, and is currently undergoing additional evaluation at Four Corners, New Mexico. With support by EPA and EPRI, TVA is conducting tests with high sulfur coal on a 1-MWe unit. If results of these tests are favorable, there may well be a strong move toward horizontal scrubbers.

The flue gas is cooled to a temperature close to the dew point in passing through the scrubber and can cause serious corrosion by condensation on fans, duct work, and dampers unless it is reheated. Reheating is also needed to restore plume buoyancy (but there is not complete agreement on the amount of reheat needed under various conditions). The insertion of steam tubes into the flue gas stream has been considered to be the most economical method for reheat, but it has led to serious corrosion problems. As a result of these problems, it is becoming popular to use indirect heat by blending externally heated air with the flue gas to achieve the desired temperature. This method is less efficient and more costly, but it is very reliable and reduces maintenance costs.

Scrubber booster fans have also had their share of problems, chiefly because of corrosion and imbalance created by solids deposition. They appear to operate more reliably when they are dry; forced draft fans and induced draft fans installed downstream from the reheater have been substantially more trouble-free.⁶

So far in this discussion, attention has been focused on the gas train, but serious problems of corrosion and erosion, particularly in pumps and nozzles in the liquor loop, have also surfaced.⁸ Solutions to these problems are gradually being found. Use of low carbon (L)-high molybdenum stainless steels and of improved protective coatings (including rubber linings and fiberglass reinforced plastic (FRP) pipe) have been effective in reducing corrosion. Without exception, however, these more stringent material requirements have substantially increased costs. Additional costs, in the form of added process control and equipment alteration, will accrue as improvements suggested by the studies of process chemistry to be discussed below are brought into practice.

4.1.3.3 Process Features

Because lime and limestone (L/LS) scrubbing are so predominant in both present and planned FGD installations, and because recent research has indicated that substantial improvements in process operations are possible, they will receive the greatest attention in this section. Only brief descriptions and an indication of current status in the U.S. will be provided for the less-developed processes.

Lime/Limestone Scrubbing

Lime and limestone scrubbing are very similar in most respects, but there are a few differences that have an important impact on unit operations and process chemistry. A flowsheet for a lime scrubbing system, shown in Fig. 4.2, might apply equally well to limestone scrubbing. In each case a slurry of the alkaline reagent (CaO or CaCO_3 , 5-10% solids) is added to a hold tank fed by the spent scrubber liquor and a slip stream is withdrawn to a solids handling stage (thickener, centrifuge, and/or filter) where waste solids are separated for disposal and clarified liquor is returned to the scrubber system. To a large extent, however, the similarity ends at this point. In the case of lime, the reaction with the SO_2 -rich scrubber liquor is quite rapid. Care, in fact, must be taken to avoid addition of excess lime; in this event the pH of the liquor entering the scrubber from the hold tank would be too high and would lead to formation of scale by direct reaction of CO_2 and SO_2 in the flue gas. In the case of lime scrubbing, therefore, the circulating slurry is primarily one of calcium sulfite (along with a small amount of calcium sulfate formed by oxidation). Typically, about 3% of the slurry dissolves in passing through the scrubber, and the pH changes from ~ 8.0 to ~ 6.0 as SO_2 is absorbed.

In limestone scrubbing, on the other hand, the reaction of the added limestone with the SO_2 -rich scrubber liquor is considerably slower. Inevitably, therefore, the recirculating slurry, as well as the slip stream removed for separation of solids, contains excess unreacted limestone.⁹ The amount of excess limestone needed has decreased from 50% or more, in former times, to less than 20%, as more has been learned about process chemistry. Because of slower reaction in the hold tank, the recirculating slurry enters the scrubber at an appreciably lower pH (~ 6.0) and, buffered by the limestone

Fig. 4.2 Typical Process Flow Diagram for Venturi/Spray Tower System

present, does not change greatly (exit pH ~ 5.2). The pH difference between lime and limestone scrubbing has at least two important consequences. At the lower pH of limestone scrubbing the removal of SO_2 is less efficient and oxidation of sulfite to sulfate is more extensive (up to 20%) because sulfite is more soluble at the lower pH and available for oxidation for a longer time.¹⁰ The latter effect assumes considerable importance because calcium sulfate solutions have a strong tendency to become supersaturated and to lead to scaling problems when supersaturation exceeds a certain level (35%). Until only two years ago it was thought that L/LS scrubbers operated in a closed-loop mode were inevitably saturated with respect to sulfate. More recent experiments in the TVA test program, however, have shown that operation in the unsaturated mode is possible and have established conditions for controlling it.¹¹ Unsaturated operation, in addition to eliminating the potential for scaling of scrubber internals, can greatly increase the amount of clarified liquor available for mist eliminator washing. Unsaturated operation appears to be made possible by the fact that the sulfate can be purged, without crystallization, as a "solid solution" in the precipitated calcium sulfite. Conditions that favor the purging of the sulfate, such as the increased solubility of sulfite and sulfate in the presence of Mg^{++} , should facilitate unsaturated operation, and indeed this has been found to be the case. In a 10-wk test at the Phillips Station of the Duquesne Light Company, it was found that the use of lime enriched with 8-10% magnesia eliminated scaling to the extent that previous scale was removed and, concurrently, increased the efficiency of SO_2 absorption sufficiently to permit use of a single scrub stage.¹² Advocacy of unsaturated operation is not unanimous however; there are other FGD experts who claim that the increased solubility of sulfite will lead to increased oxidation and that it may be difficult, with typical variations in SO_2 levels, to avoid becoming supersaturated. Note that Cl^- ions, which decrease the solubility of calcium salts, will have an effect opposite to that of magnesium and tend to promote supersaturation. If anything is obvious, it is that the reactions of SO_2 with lime and limestone are not as simple as they would appear at first, and that much remains to be learned about the detailed chemistry of the system and the most effective way to avoid scaling.

Before leaving the subject, however, two additional studies of importance that have resulted from the EPA-TVA program should be cited. In studies

aimed at improving limestone utilization by operation at low pH, Borgwardt¹³ has found that the kinetics of limestone dissolution/SO₂ precipitation can be accelerated by using three or four hold tanks in series (2-4 min residence time in each) to simulate tubular flow of the scrubber effluent. Under these conditions, and with tower pressure drop increased to 12-in. H₂O, high SO₂ removal efficiency (90%) and high limestone utilization (94%) were obtained in a single-loop scrubber. It seems likely that this technique will be incorporated into forthcoming designs, possibly at the expense of increased capital costs. Under conditions of increased utilization of limestone it is possible to maintain low pH while oxidizing sulfite, and thus attempt to increase the sulfate content of the product and to improve its dewatering characteristics. Unfortunately, it was not possible to achieve the desired goal of 80% solids.¹³ Note in this regard that extensive (80%) oxidation of sulfite to sulfate occurs naturally when L/LS scrubbing is applied to low sulfur coals because of the higher ratio of oxygen to sulfite.

A major problem with L/LS scrubbing is the production of large quantities of CaSO₃·0.5 H₂O/CaSO₄·2H₂O sludge that is difficult to dewater because of the nature of the calcium sulfite crystals. To facilitate its disposal the sludge is usually mixed with the fly ash, but dewatering to the extent needed for use as landfill is still not possible. Table 4.2 shows typical values for sludges with high calcium sulfite content as produced from a high sulfur eastern coal and for a sludge with high calcium sulfate content as produced from a low sulfur western coal.¹⁴ It may be noted that the sludge in the latter case can be dewatered more effectively.

The quantities of sludge produced per kWh will depend of course on the sulfur and ash content of the coal, the mole ratio of lime additive to sulfur, the efficiency of SO₂ removal, the degree of oxidation to sulfate, and the moisture content of the sludge. In a typical case, where coal containing 3.0% S and 12.0% ash is burned in a power plant that uses 0.88 lb coal/kWh and removes 85% of the SO₂, the quantities of dry calcium solids produced correspond to 0.10 lb/kWh for lime scrubbing and 0.12 lb/kWh for limestone scrubbing (1.2 stoichiometry).¹⁴ The quantity of ash produced from the coal, 0.11 lb/kWh, is similar. The combined weight of ash and calcium solids (averaged) is 0.22 lb/kWh, one-fourth that of the coal; at 50% solids, which is typical, the wet weight is half that of the coal. Under

Table 4.2 Comparison of Typical Sludge Dewatering Properties^{1,4}

Sludge Type	Approximate Degree of Dewatering, percent solids		Approximate Percent Solids for Optimum Compaction
	Settling	Filtration	
High $\text{CaSO}_3 \cdot 1/2\text{H}_2\text{O}$ (low fly ash)	30-35	50	80
High $\text{CaSO}_3 \cdot 1/2\text{H}_2\text{O}$ (high fly ash)	35-40	55-60	80
High $\text{CaSO}_4 \cdot 2\text{H}_2\text{O}$ (low fly ash)	60-65	80	90

the conditions specified, a 1000-MWe power plant operated at a load factor of 73% would consume 2.8 million tons of coal per year and produce 1.4 million tons of wet sludge. There is a growing feeling that chemical fixation of the sludge will be required, not merely to improve its physical properties but also to decrease the likelihood of problems arising from leaching. The disposal of FGD wastes is discussed more fully in Section 4.4.

Double Alkali Process

In the double alkali process the SO_2 is absorbed in a circulating solution of sodium alkali (containing sodium sulfite, sodium hydroxide, and sodium sulfate formed by oxidation). The scrubber effluent is then treated with limestone and lime to regenerate the alkali. Limestone is suitable to regenerate alkali from sodium sulfite, but lime is required in the case of sodium sulfate. The calcium sulfite and sulfate formed in the regeneration are separated, usually by vacuum filtration with washing to remove most of the soluble salts, and discarded. Typically, the sludge contains 50-60% solids and 2-3% soluble sodium salts. Its physical characteristics are similar to those of L/LS sludges.

One of the more important advantages of the double alkali process is that better than 90% removal efficiencies for SO_2 are readily attainable. In addition, utilization of L/LS is high, 95-98%, and scaling problems are decreased (although not completely eliminated).

The double alkali process is well established in Japan where 15 units are operating on industrial boilers. Two units have been installed on coal-fired industrial boilers in the U.S.; a 25-MWe unit went into operation in late 1974 and a 50-MWe unit began operating in late 1975. Satisfactory operation is claimed in both cases. A 20-MWe demonstration unit is operating on a coal-fired utility boiler and two larger installations are planned. These are discussed in Section 4.1.4.

Lime/Alkaline Fly Ash

The alkaline ash process is an outgrowth of the observation that wet scrubbers installed in the western U.S. for particulate removal also removed appreciable amounts of SO_2 from the flue gas. The removal occurs because of the inherent alkalinity (mostly calcium base) of the fly ash produced from western coals. The alkali content in western coal ash can range from 10 to 50%.¹⁵ For a coal containing 0.7% sulfur and 7.5% ash, of which 20% is alkali, the total alkali is equivalent to 1.2 stoichiometry. Lime addition in such a case is primarily for control of pH. Only one unit, the Colstrip Station of Montana Power, is cited as using lime/alkaline ash FGD, but other units, such as the Valmont No. 5 Station of Public Service of Colorado and the Sherburne No. 1 Station of Northern States Power, also utilize the alkalinity of the ash.

Sodium Carbonate Scrubbing

The salient feature of this "process" is that the spent absorbent, containing soluble sodium sulfite and sulfate, is discarded. This practice is acceptable only in an extremely arid climate. Two units at the Reid Gardner Station of the Nevada Power Co. are operating in this way and one further installation is planned there. Soda ash has been used in scrubbing, but use of trona to be obtained from a dry lake in California is planned.

Magnesium Oxide Scrubbing

In this process, the SO_2 in particulate-free flue gas is absorbed in a circulating slurry of magnesium oxide. Solids in the spent liquor ($\text{MgSO}_3 \cdot 3\text{H}_2\text{O}$, $\text{MgSO}_3 \cdot 7\text{H}_2\text{O}$, and $\text{MgSO}_4 \cdot 7\text{H}_2\text{O}$ formed by oxidation) are removed by centrifugation and dried. The solids are heated at 1040°C in the presence

of carbon (char) to regenerate magnesium oxide and evolve a stream of SO_2 sufficiently concentrated for use in the manufacture of sulfuric acid. Economic considerations dictate that the FGD solids generated at the utility be shipped to a sulfuric acid plant for regeneration.

The process was earlier demonstrated on an oil-fired boiler at the Mystic Station of Boston Edison (with support by the EPA) and on a coal-fired boiler at the Dickerson Station of Potomac Electric Power. Regeneration of the product in both cases was carried out at a chemical company in Rhode Island. Moderately satisfactory operation was eventually achieved at the Mystic Station, but losses of magnesium oxide were high (about 10%) and the number of regeneration cycles never exceeded five. Substantial improvement in both areas is required for acceptable commercial operation. Operation of the coal-fired Dickerson Station was never very satisfactory and is best described as a learning experience. The FGD units at both of these sites are now inactive.

A magnesium oxide scrubbing unit installed at the Eddystone Station of Philadelphia Electric is currently being used only for particulate collection.

Wellman-Lord Process

In this process, SO_2 in particulate-free flue gas is absorbed in a circulating solution of sodium sulfite (and sodium sulfate formed by its oxidation). The SO_2 is recovered by thermal stripping in an evaporative crystallizer, and a bleed stream (about 6%) of sodium sulfate is withdrawn for discard. The concentrated (90%) stream of SO_2 can be condensed, oxidized to sulfuric acid, or converted to elemental sulfur. In the EPA-supported demonstration at the 115-MWe Mitchell Station of Northern Indiana Public Service expected to start up in July 1976, the SO_2 will be reduced to sulfur with natural gas. Construction has recently begun on two additional installations at the San Juan No. 1 and No. 2 stations, 375 MWe and 340 MWe respectively, of the Public Service Co. of New Mexico.

Chiyoda 101 Process

In this Japanese process the SO_2 is absorbed in dilute (2-5%) sulfuric acid containing iron salts to catalyze oxidation. The oxidation is

completed in a separate tower through which a flow of air is maintained. A slip stream of acid is withdrawn and treated with limestone to precipitate gypsum. The scrubber and the oxidizer in this process are appreciably larger than scrubbers used in other FGD processes and larger pumps must be used for the high liquid/gas ratio that is required.

Citrate Process

In the Citrate process developed by the Bureau of Mines, SO_2 in cooled ($45\text{--}65^\circ\text{C}$) and cleaned flue gas is absorbed in a buffered solution containing sodium citrate, citric acid and sodium thiosulfate. Absorbed SO_2 is reacted with H_2S at about 65°C and atmospheric pressure to precipitate elemental sulfur and regenerate the solution for recycle. The sulfur is separated by oil flotation and melting. The H_2S for the reduction is made by reacting two-thirds of the recovered sulfur with natural gas and steam. Since thiosulfate ion depresses oxidation of bisulfite, only small amounts of sodium sulfate (which must be removed in a bleed stream) are formed. The process has most recently been operated on a lead smelter at Bunker Hill, Idaho. Under a \$12.7 million cost-sharing agreement between the Bureau of Mines and St. Joe Minerals Corporation, the Citrate process will be demonstrated at the company's George F. Wheaton plant in Monaca, Pennsylvania.¹⁶

Aqueous Carbonate Process (ACP)

In this process the SO_2 is absorbed by aqueous sodium carbonate in a spray dryer. The dry solids are mixed with carbon (char or coal) and are blown by air into molten sodium carbonate (1000°C) where reduction to sodium sulfide occurs. The reduction mixture is quenched, filtered, and carbonated (with off-gas from the reducer) to evolve hydrogen sulfide. The sodium carbonate solution is recycled and H_2S is converted to sulfur in a Claus reactor. The various steps of the process have been tested only separately. Eight New York state utilities and the EPA have initiated a 4-yr (\$22 million) test of the process at the 100-MWe, coal-fired Huntley station of Niagara Mohawk.¹⁷

Catalytic Oxidation (Cat-Ox)

In this dry process, flue gas from which particulates have been effectively removed is passed at 450°C through a vanadium pentoxide catalyst bed to oxidize the SO₂ to SO₃. The gas is then cooled (220°C) and the SO₃ is absorbed in a circulating stream of (80%) H₂SO₄. In a new installation, a hot electrostatic precipitator (outlet 450°C) would be used, and heat would be recovered by installing the air preheater of the boiler after the catalyst bed. Retrofit of the process to an existing unit requires extensive modifications and duct work and is not considered to be practical. A demonstration of the process, supported by the EPA, was attempted in a retrofit installation at the 110-MWe Wood River Station of the Illinois Power Co. The system started up in 1972, but because of numerous problems, not all of which were related to the process itself, never reached the stage of satisfactory operation. The program has been indefinitely postponed and its future is uncertain.

The process offers some advantage in that the operations are simple, labor requirements are low, and gas reheat is not required. A major drawback is that limited market for the low-grade sulfuric acid product could seriously limit siting possibilities.

Activated Carbon (FW-BF)

In this process, SO₂ in the flue gas (at 150°C) is adsorbed on char, where in the presence of air and moisture it is converted to sulfuric acid, which is strongly retained in the interior pore system of the char pellets. (Oxides of nitrogen are also adsorbed to some extent). As it becomes saturated, char is removed and heated (in an inert atmosphere) to 650°C by mixing it with sand at 800°C. Under these conditions the sulfuric acid is reduced to SO₂, the nitrogen oxides dissociate, and some char is oxidized to carbon dioxide. In the sulfur recovery section, the (concentrated) SO₂ is passed through a vessel containing crushed coal at 700-800°C, where it is reduced to sulfur. Gaseous sulfur is condensed from the effluent and the tail gas is recycled for removal of residual SO₂.

A 23-MWe demonstration of the FW-BF process, based on activated carbon adsorption, started up in February, 1976. Problems involving

front-end high-temperature excursions and plugging of the condenser in the sulfur recovery section were encountered. In May, 1976, because of mechanical problems and depletion of char supply, the decision was made to prematurely terminate the test program.*

4.1.4 *Reliability of Operational FGD*

The electric utilities maintain that the reliability of FGD units should be comparable to that of utility boilers. The operating availability for conventional boilers has varied from 82% for units of 600 MWe and larger to almost 94% for newer units of 100 MWe or less.¹⁸ In Japan, where about 20,000 MWe of FGD is currently installed (mainly on oil-fired boilers), the reliability of FGD units has reached or exceeded these levels.¹⁹ The operation of FGD on coal-fired boilers in the U.S. has not yet achieved this level of reliability. Recent reports suggest that reliability of FGD is continuing to improve as operating experience accumulates, but that it clearly has not reached the state where trouble-free operation of a new FGD unit can be expected.²⁰

A definition of "reliability" would clearly be useful at this point, and it is unfortunate that one satisfactory to everyone concerned has not been developed. Several parameters have been proposed for the purpose and have received some degree of acceptance, but none of them in itself is completely satisfactory.²¹ Their definitions and limitations will be presented here to avoid repetition later. The four parameters frequently used are:

1. *Availability*: hours FGD available/total period hours.
Objection--hours of FGD use not indicated.
Result --can overemphasize FGD viability.
2. *Reliability*: hours FGD operated/hours called upon.
Objection--no unequivocal definition of "called upon".
3. *Operability*: hours FGD operated/hours boiler operated.
Objection--hours boiler use not indicated.
Result --an on-stream factor without much meaning.

*Reported in May-June 1976 report on the *Status of Flue Gas Desulfurization Systems in the United States*, op.cit.

4. *Utilization:* hours FGD used/total period hours.
 Objection--boiler outages lower value.
 Result --can penalize FGD evaluation.

Used together, the last two parameters might be satisfactory, but to date few results have been reported in this way.

In Table 4.1 FGD installations were grouped according to process. In discussing the performance and potential applicability of FGD, it is more appropriate to use a different classification, distinguishing between units using low sulfur western coal and those using eastern coals of higher sulfur content. To a very large extent this also results in a geographical classification, as west or east of the Mississippi. Although this approach is not traditional, it is a natural one because there are major differences in the nature and objectives of FGD in the two cases. In the West, FGD is generally used either to meet emission limitations that are more strict than the NSPS or as an adjunct to particulate removal, utilizing the alkalinity of ash in the coal. High efficiency for SO₂ removal is not always needed, and process operations are favored by the low inlet SO₂ concentrations and, in many locations, by the aridity of the climate. Practices that lead to successful operation in the West generally cannot be transferred to the more demanding conditions of FGD in the East. It is not purely coincidental that the first example of "commercially available" FGD, i.e., operation at 80% reliability on 100-MWe for a year, was with low sulfur coal at the Cholla Station of Arizona Public Service.²²

4.1.4.1 *Status of FGD in the West*

The FGD units at western locations that were considered to be active at midyear are shown in Table 4.3, which also lists the process employed, the sulfur content of the coal burned, and the date of initial operation.* There are nine units installed on 2170 MWe and all of them are of the throw-away variety.

*Information leading to the classification of the FGD units and to the statements about their 1976 performance in this section and the following one have been obtained from the January-February, March-April, and May-June 1976 reports on the *Status of Flue Gas Desulfurization Systems in the United States* issued by PEDCo - Environmental.

Table 4.3 FGD Installations in the West

Utility & Location	Station & Scrubber Size (MWe)	Reagent	Percent S in Fuel	Start-up Date
Arizona Public Service Joseph City, Arizona	Cholla No. 1 115 MWe	Limestone	0.5	1/74
Arizona Public Service Farmington, New Mexico	Four Corners #5A 160 MWe	Lime	0.7	2/76
Kansas Power & Light Lawrence, Kansas	Lawrence No. 4 125 MWe	Lime injection	0.5	12/68
Kansas Power & Light Lawrence, Kansas	Lawrence No. 5 400 MWe	Lime injection	0.5	11/71
Montana Power Co. Colstrip, Montana	Colstrip No. 1 360 MWe	Lime/Ash	0.8	10/75
Nevada Power Moapa, Nevada	Reid Gardner No. 1 125 MWe	Sodium Carbonate	0.5-1.0	4/74
Nevada Power Moapa, Nevada	Reid Gardner No. 2 125 MWe	Sodium Carbonate	0.5-1.0	4/74
Northern States Power Becker, Minnesota	Sherburne No. 1 710 MWe	Limestone	0.8	3/76
Public Service Colorado Boulder, Colorado	Valmont No. 5 50 MWe	Limestone	0.7	10/74

Data on the performance of these units during 1976 are available for only three units, the aforementioned 115-MWe Cholla station and the two 125-MWe Reid Gardner Stations of Nevada Power. The three were reported to be on line in January and February but no specific figures for performance were reported. The Cholla station reported *reliability* in April, May, and June to be 98%, 88%, and 52%, respectively. The lower value in June reflects routine shutdown for midyear inspection and maintenance, and there is thus little change from the 86% *reliability* achieved in the last eight months of 1975. The Reid Gardner No. 1 station reported *availability* in March and April to be 99% and 15% respectively. The unit was down because of turbine overhaul in May and June. The Reid Gardner No. 2 station reported values of *availability* to be 70%, 86%, and 99% in March, April, and June. Presumably it was down in May. The current performance of these three stations is not significantly different from the levels of performance in 1975, shown in Figs. 4.3 and 4.4.

Only brief mention of the remaining six units is justified. The Four Corners Station has been retrofitted with the horizontal scrubber previously tested successfully at Mohave Station of Southern California Edison. The unit started up in mid-February, but a boiler overhaul was begun in April. The two Lawrence units, originally designed for lime injection, are considered to be obsolete and will ultimately be replaced. Even if available, a report on performance would thus not be meaningful. The Montana Power Co. has supplied no information on the Colstrip No. 1 station other than to say it is operating at full capacity. The newly installed Sherburne No. 1 unit is still undergoing shakedown and modification. The Valmont No. 5 Station, in which experimental SO₂ control was incorporated into existing particulate removal facilities, has not operated this year.

Until data on the performance of the newer units at the Colstrip and Sherburne Stations is forthcoming, an assessment of FGD in the West (which would have to be based on the performance of one or two units) is of dubious value.

4.1.4.2 Status of FGD Units in the East

The status of 15 FGD units considered to be active at locations east of the Mississippi is shown in Table 4.4. The two 10-MWe test units

Fig. 4.3 Operability of the FGD Systems at the Cholla Station of Arizona Public Service, and the LaCygne Station of Kansas City Power and Light; Examples of Best Performance on Plants Using Low and High Sulfur Coals.

Fig. 4.4 Operability of the FGD Systems at the Reid Gardner Station of Nevada Power Company.

Table 4.4 FGD Installations in the East^a

Utility & Location	Station & Scrubber Size, MWe	Reagent	Percent S in Fuel	Start up Date
Commonwealth Edison Joliet, Illinois	Will County No. 1 167 MWe	Limestone	1-3.5	2/72
Duquesne Light Elrama, Pennsylvania	Elrama 510 MWe	Lime	1-2.8	10/75
Duquesne Light Wireton, Pennsylvania	Phillips Nos. 1-4 410 MWe	Lime	1-2.8	7/73
General Motors Parma, Ohio	Parma No. 1 32 MWe	Double Alkali	2.5	3/74
Gulf Power Sneads, Florida	Scholz No. 1A 20 MWe	Double Alkali	3.0	2/75
Gulf Power Sneads, Florida	Scholz No. 1B, 2B 23 MWe	H ₂ SO ₄	3.0	3/75
Gulf Power Sneads, Florida	Scholz No. 2A 20 MWe	Activated Carbon	3.0	2/76
Kansas City P & L Kansas City, Missouri	Hawthorne No. 3 140 MWe	Lime injection	3.5	11/72
Kansas City P & L Kansas City, Missouri	Hawthorne No. 4 100 MWe	Limestone	3.5	8/72
Kansas City P & L La Cygne, Kansas	La Cygne No. 1 820 MWe	Limestone	5.0	2/73
Kentucky Utilities Lexington, Kentucky	Green River Nos. 1-2 64 MWe	Lime	3.8	10/75
Louisville, Gas & Elec. Louisville, Kentucky	Paddy's Run No. 6 65 MWe	Lime	3.0	4/73
Pennsylvania Power Shippingport, Pa.	Bruce Mansfield No. 1 835 MWe	Lime	4.3	4/76
Philadelphia Electric Eddystone, Pa.	Eddystone No. 1 120 MWe	Magnesium Oxide	2.5	11/74
Rickenbacker AFB Columbus, Ohio	Rickenbacker 20 MWe	Lime	3.6	3/76

^aExcluding two 10-MWe TVA test modules at the Shawnee plant and the 37-MWe system at the oil-fired Stock Island Station of the Key West Utility Board.

operated by TVA at their Shawnee plant and the 37-MWe, oil-fired unit at Stock Island (inactive for some time) have not been included in this list. Twelve of the 15 units, controlling 3108 MWe, or more than 90% of the total 3346 MWe, are based on L/LS scrubbing. There is somewhat more information available on these units than in the case of western FGD units, but not a great deal more.

Four of the 15 were only minimally active. The Eddystone Station of Philadelphia Electric, which is equipped for magnesium oxide scrubbing, has operated only for particulate removal this year. The Hawthorne Stations of Kansas City Power and Light, like those of the Lawrence Station discussed in the previous section, were designed for lime injection and require extensive modifications; reliable performance has never been achieved on these units since their installation in 1972. The regenerable, activated carbon, process at the Scholz No. 2A Station of Gulf Power must also be considered inoperable; after a brief period of operation following startup in February the demonstration program was indefinitely postponed.

Of the 11 more active units, six employed lime scrubbing. The Paddy's Run No. 6 station, often cited for its reliability, continued its record. Operability (on-stream time) of 100% was reported for January, May, and June, but the system was not used during the intervening months. It must be recognized, however, that this is a peaking unit and does not see much use under ordinary circumstances. The sporadic operation is graphically displayed in Fig. 4.5. A test program to investigate both reliability and sludge disposal at Paddy's Run has been sponsored by the EPA and is now underway. The only other encouraging note in lime scrubbing is the performance of the 64-MWe Green River Station of Kentucky Utilities, which started up only late last year but has achieved high availability *and* utilization in the past four months. Performance of the larger 410-MWe Phillips Station has been reported to be only about 67%. It has had difficulty operating without using magnesia enriched lime and an open water loop.¹² Its younger "twin," the Elrama Station, is still undergoing testing. The remaining two lime scrubbers, the 20-MWe "Bacho" unit at Rickenbacker Air Force Base and the 835-MWe unit at the Bruce Mansfield Station of Pennsylvania Power, are still in shakedown.

Fig. 4.5 Operability of the FGD Systems at the Scholz Station of Gulf Power Company and the Paddy's Run Station of Louisville Gas and Electric

The limestone unit at the 820-MWe La Cygne Station of Kansas City Power and Light is still the only FGD unit in the East that has operated reliably for extended periods. Although down in April it reported availabilities greater than 90% for March, May and June. This status may be compared with past performance, and with performance of the Cholla Station, in Fig. 4.3. It is clear that an extremely important factor in the successful operation of this unit is the determined effort to make it work and the degree of commitment to that end. There are seven scrubbing trains on the system, and it has been the practice to take one out of service each night, on a rotational basis, for cleaning. More than 50 people, or one-fourth of the plant personnel, are employed in operating and maintaining the FGD system. The cleaning operations result in derating of the plant from 820 MWe to 700 MWe; addition of an eighth scrubber train to restore full output on a continuous basis is planned. In view of the dedication to making the operation a success, it is ironic that the plant does not meet NSPSs with the present source of coal (5.39% S, 9421 Btu/lb). The 80% removal of SO₂ and the 98.2% removal of particulates leave residual emissions (2.28 lb and 0.18 lb per 10⁶ Btu respectively) almost twice those of the NSPSs. A virtual twin of this unit, the Will County Station of Commonwealth Edison, continues to have problems and was essentially unavailable for all but one month of this year.

The three remaining FGD units are small demonstration units testing newer processes. The Chiyoda 101 process, a 23-MWe system which had been operating with high reliability at the Scholz Station of Gulf Power as shown in Fig. 4.5, has been out of operation to repair fire-damaged components. The double alkali process is being tested at the Parma Station of General Motors and the Scholz Station of Gulf Power. The latter program is being supported by EPA and EPRI. The Parma plant has had its share of problems in the past but has reported figures of 80-90% for availability and operability in the past three months. Performance of the double alkali unit at Scholz continues to be about as variable as it has been in the past (see Fig. 4.5).

A definite trend toward use of the double alkali process instead of direct L/LS scrubbing appears to be underway. Central Illinois Light will install a double alkali unit on their 575-MWe Newton No. 1 Station and EPA

is contributing to a demonstration on the 277-MWe Cane Run No. 6 Station of Louisville Gas and Electric. The process does not eliminate the problems associated with waste disposal in L/LS scrubbing, but it does alleviate problems of plugging and scaling.

In looking at the overall picture of FGD in the East one notes that there are relatively few recent encouraging developments. Before the year is out, however, six new units are to come on line, including the long delayed Wellman-Lord regenerable process. The prospects for deployment of FGD in the early 1980s will depend to a considerable extent on the performance of these systems.

4.1.5 Secondary Environmental Impacts of FGD

Concerns about the overall energy consumption and environmental impacts accompanying the use of FGD have been expressed on a number of occasions too numerous for citation. These effects are commonly called secondary environmental effects, but it is clear that there can be no completely unequivocal definition of where "secondary" begins and ends. The major concern about environmental effects in FGD has been that of satisfactory disposal of FGD wastes. That concern is addressed later, along with the disposal of solid wastes derived from particulate control, in Section 4.4. Further consideration of secondary impacts in this section will be restricted to the energy consumption and pollutant emissions that result from the production of process inputs (chemicals) and from direct process operations.

As to process inputs, and considering the gamut of processes that are operational or to be demonstrated, it can quickly be concluded that the major operation with potentially significant environmental impacts is the calcining of limestone. It can be calculated from engineering data that calcining the limestone needed for FGD of a coal containing 3.5% sulfur requires input of energy equivalent to 1.6% of the coal and produces particulate emissions corresponding to 0.2 lb per 10^6 Btu of coal burned. This is above the NSPS and ultimately will require control. The 1.6% energy penalty obviously becomes hidden in operating expense as a higher cost for lime than for limestone.

As to process operations, indirect effects can be favorable or otherwise. The favorable effects are those on atmospheric emissions; wet scrubbers are efficient particulate removing devices; a small amount of NO_x removal also occurs via absorption in the alkaline scrubbing agents, and some reduction of trace metal and organic emissions is possible. The unfavorable effects are due to the pollutants emitted in generating the energy required to operate the various FGD processes. Calculated values⁵ for the energy consumption vary from 4% for L/LS scrubbing to more than 9% for regenerable sodium scrubbing. Clearly then the operation of an FGD process to remove SO_2 can increase NO_x and particulate emissions by 4-9%, but if the incremental power required is generated in a controlled plant, it seems more appropriate to regard the extra energy requirements as an added capital or operating expense rather than as a significant source of pollutants.

4.1.6. *Costs of FGD*

The costs of FGD have been a subject of very heated debate over the years. The arguments were completely futile in most cases since they did not specify the basis for the costs, which depend greatly on process and site variables. Time factors could also have contributed to differences in opinions since FGD costs have increased steadily from year to year, not only because of escalation, but also because of changes in design, equipment, and materials of construction that were made to increase reliability. Estimates made by TVA indicate, as shown in Fig. 4.6, that FGD costs have more than doubled over the past five years with increases attributable to inflation and to refinements being 65% and 45% respectively.^{24,25} Present estimates, which are based on considerable operating experience and are not likely to be affected greatly by additional process changes, should provide more accurate predictions of system costs. Variations in estimates that may be encountered now are more likely to reflect site-specific factors, i.e., different requirements at different locations.

4.1.6.1 *Factors that Affect FGD Costs*

There are a number of variables that can have an important effect on costs of FGD systems. These include the size of the unit, the FGD process selected, the sulfur content of the fuel, provisions for particulate control

Fig. 4.6 Range of Estimated Costs for Limestone Scrubbing

and for redundancy, and whether it is a new or retrofit installation. Some indication of the direction and magnitude of these effects on capital costs is provided in Table 4.5, which shows the percentage change in \$/kWe costs caused by variations from the base case (new 500-MWe installation, limestone process, 3.5% S in fuel, wet particulate collection included, only pumps spared). Assumption of a base case cost of \$100/kWe makes analysis of the effects very simple, although cost estimates discussed below indicate that a figure of \$85/kWe for the base case may be more realistic. Only a few general comments on the table will be made. It is clear that costs decrease significantly as unit size increases even though scrubbers are installed as modules. The savings result from economies of scale in solids handling and disposal costs. The appreciably higher capital cost of the regenerable sodium process as compared to L/LS FGD is attributable to the additional equipment necessary for the regeneration step. The capital costs of other regenerable processes are also expected to be higher than those for limestone scrubbing. The expenditure of energy in the regeneration step can also result in higher operating costs. The increase in capital costs with increase in sulfur content results from the need for larger/additional solids handling and disposal facilities. Operating costs will also increase with sulfur content, since additional limestone is needed. Effects of sulfur content on capital and operating costs of regenerable processes are similar. The addition of an electrostatic precipitator for dry particulate collection is an extra cost option that is frequently purchased with FGD, as noted earlier, because it permits boiler operation when the scrubber is down. The installation of an extra scrubbing train falls in much the same category; both are a form of insurance against unreliability. The incremental costs of a retrofit installation can be substantial. Since the unit must also be depreciated over fewer years and operate with a lower load factor, annualized costs can escalate rapidly. Costs for a limestone scrubber fitted to a plant with a remaining life of 15 years and a load factor of 0.3 have been calculated to be double those when the plant has a remaining life of 30 years and a load factor of 0.7.²⁶

4.1.6.2 *Estimates of FGD Costs*

There has been a major effort in recent years to quantify cost effects of process variables so that FGD costs can be compared on a common basis.

Table 4.5 Effect of Variations on Capital Cost of FGD^a

Factor	Base Case	Variation	Percentage Change in \$/kWe Costs
Size	500 MWe	200 MWe, 1000 MWe	+30, -25
Process	Limestone	Lime, Sodium	-10, +25
Sulfur	3.5%	2%, 5%	-10, +10
Particulate Control	Included	Electrostatic Precipitator	+25
Extra Gas Train	500 MWe	250 MW, 1000 MW	+40, -10
Retrofit	New Unit	Average, Difficult	+25, +50

^aDerived from information in Refs. 24 and 26

TVA has published a thorough and highly detailed cost study of five leading FGD processes. In addition to L/LS, the magnesium oxide, sodium, and Cat-Ox regenerable processes are covered.²⁴ An update of this study has recently appeared.²⁵ A model plant study for limestone and sodium scrubbing has also been reported,²⁶ and the model has been used to interpret data from an Edison Electric Institute survey of actual utility installations.²¹

Agreement in the three cases on the cost of L/LS scrubbing is remarkably good. Adjusted costs reported by 19 utilities, based on 1975 dollars, ranged from \$50 to \$88 per kWe, and averaged \$70 per kWe. Costs (1975 dollars) developed by the model fall between \$53 and \$81 per kWe, depending upon the parameters selected. The cost estimates reported by TVA, in terms of mid-1977 dollars, range from \$51 to \$88 per kWe, as shown in Fig. 4.6.

The cost reported in the TVA study for a new 500-MWe unit burning 3.5% S coal, corresponding to the base case in Sec. 4.1.6.1, is \$68.4 per kWe. Some of the assumptions made for the purpose of the study, however, (such as proven system, experienced design and construction team, no overtime, 3-yr program--no delay, and 5% escalation) are just not appropriate at the present time. It has also been recognized that the updated economics do not reflect any recent changes in process technology that may result from the innovations in chemistry and design that were discussed earlier. Both factors will increase the estimated cost, but it is very difficult to put a precise figure on the increase. Because a 10% increase in cost might easily be anticipated if any one of the above mentioned assumptions were not currently valid, an increase of 25% in the estimated cost, to about \$85 per kWe, may not be unreasonable. Annualized costs, increased correspondingly from those shown in Table 4.6, are about 5 mills/kWh.

A comparison of annualized costs (1978 dollars) for throwaway and regenerable FGD systems, including by-product credits and sludge disposal costs, as developed in the TVA study, is shown in Table 4.6. In view of what has just been said about the estimated costs of limestone FGD, and in view of the even greater uncertainties regarding costs of the less developed regenerable processes, the absolute values in this table must be regarded with at least some reservation. It is important, however, to recognize the possibility that regenerable processes will become cost effective as the requirements and costs for environmentally acceptable disposal of limestone

Table 4.6 Revenue Requirement Comparisons of Throwaway
and Regenerable FGD Systems^a

Process	By-product (tons)	Annual Revenue Requirements (mills/kWh)		
		Base Costs ^b	Includes By-Product Credit ^c	With Sludge Fixation ^d
Limestone	206,000 ^c	3.41	-	4.01
Lime	175,000 ^e	3.65	-	4.15
Magnesia	110,400 ^f	4.02	3.23	-
Cat-Ox	137,400 ^g	3.65	3.04	-
Sodium	32,700 ^h	5.37	4.99	-

a New coal-fired 500-MWe unit, 3.5% S coal, 7000 hr/yr.

b 1978 basis.

c 100% sulfuric acid at \$25/ton, 80% acid at \$16/ton, sulfur at \$45/long ton (\$40.18/ton).

d Assuming sludge fixation service fee by contract treating sludge in utility's pond at \$10/ton of 100% solids.

e 100% solids.

f 100% H₂SO₄.

g 80% H₂SO₄.

h Elemental sulfur.

wastes increase, as they inevitably will. The importance, therefore, of satisfactory demonstrations of more promising regenerable processes cannot be overemphasized. To the extent that the estimates in Table 4.6 are valid, well conceived and executed demonstrations of the Cat-Ox process and of magnesium oxide scrubbing would appear to be of high priority.

4.1.7 Anticipated Deployment of FGD

Since March 1974, bimonthly reports on the status of FGD installations in the U.S. have been issued by PEDCo-Environmental, Inc., under EPA contract. The summary table of the latest report, indicating status as of July 1976, is reproduced here as Table 4.7. It details the number and MWe of FGD units that are operational, under construction, or in various stages of planning, and indicates that a total of 113 FGD systems are to be installed on 42,735 MWe of utility boilers. The bottom line figures of an earlier (July, 1975) summary table have been cited by the EPA and referred to as being more than halfway toward the goal of 90,000 MWe of scrubber control that the EPA estimated will be needed to meet 1980 sulfur oxide standards.²⁷ In the absence of any qualifications, there is a strong tendency to assume that FGD is well on the way to achieving this goal; one that most would define as permitting continued use of the country's high sulfur coal without adverse environmental effects.

A totally different picture emerges when the same data on planned FGD installations are regrouped according to date of expected operation and location of coal supply. This picture, in Table 4.8, shows that only 32,210 MWe are planned for operation by 1980. (Even this level of installation may not be achieved since selection of a process has still not been made for close to 5000 MWe of the planned units and lead times for FGD installation can easily be four years or more.) More importantly, at least as far as continued use of the current mix of U.S. coal production is concerned, the picture shows that only half of this FGD, 16,308 MWe, is planned for installation east of the Mississippi with operation on high sulfur coal.

According to a staff report of the Federal Power Commission, 176.2 million tons of the 410 million tons of coal burned by the electric utilities in 1975 did not comply with emission regulations and 93% of the non-complying coal, or 164 million tons, was burned (and presumably mined) east of the

Table 4.7 Number and Total MWe of FGD Systems

Status	No. of units	MWe
Operational	27	5,573
Under Construction	23	8,727
Planning		
Contract awarded	18	8,855
Letter of intent	5	1,047
Requesting/evaluating bids	6	3,500
Considering only FGD systems	34	15,033
Total	113	42,735

Table 4.8 FGD Planned in the East and West

Year	East			West		
	No. of units	MWe	Cumulative MWe	No. of units	MWe	Cumulative MWe
1976 ^a	24	4,576	4,576	11	2,655	2,655
1977	8	3,443	8,019	10	5,506	8,161
1978	12	3,522	11,541	5	2,618	10,779
1979	7	3,542	15,083	6	2,973	13,752
1980	2	1,225	16,308	4	2,150	15,902
Beyond	<u>8</u>	<u>1,225</u>	19,358	<u>16</u>	<u>7,475</u>	23,377
TOTAL	61	19,358		52	23,377	

^aIncluding previous installations.

Mississippi.²⁸ This latter amount of coal corresponds to about 80,000 MWe of generating capacity (at the average load factor of 0.5), five times the amount of FGD planned for installation east of the Mississippi through 1980. Stated in another way, more than 120 million tons per year of coal currently mined east of the Mississippi will still be non-complying in 1980 at the planned rate of FGD installation. The performance of FGD systems now operating provides little basis for assuming accelerated deployment of FGD in the early 1980s. Indeed, to the extent that utility plans are reflected by the coal mining industry, it appears that use of low sulfur coal is currently preferred over FGD. Recent mine expansion plans call for additions to annual steam-coal capacity through 1986 of 275 million tons in the West and 148 million tons in the East. Since eastern additions must be discounted by about 15 million tons annually to allow for replacement of depleted capacity there will be little or no net increase in eastern production.²⁹ The continued production and use of eastern and midwestern coals is an essential element in the national energy picture. It will be jeopardized unless the deployment of FGD and/or the development of emerging technologies for clean use of coal are accelerated.

4.1.8 Conclusions and Recommendations

Recent reports on the performance of the 27 FGD systems (5573 MWe) currently operating indicate that reliability comparable to that of utility boilers has been achieved in only a few cases. Analysis of planned installations reveals that FGD systems expected to be operating on high sulfur coal in 1980 total 16,000 MWe, only one-fifth of the amount currently needed to permit continued use of the 164 million tons of non-complying coal burned in 1975 by utilities east of the Mississippi. An additional 16,000 MWe of FGD is expected to be operating with coal that is already low in sulfur but unable to meet regulations in some of the western states. More than 90% of the 32,000 MWe planned for installation by 1980 will utilize lime or limestone scrubbing and thus produce sludges that are difficult to dewater and present serious disposal problems. Installation of regenerable FGD processes is not expected to be significant in the near term, since no regenerable process has been satisfactorily demonstrated so far in this country.

The FGD program of the EPA does address problems in lime/limestone scrubbing and waste disposal, and also includes demonstrations of some regenerable FGD processes. Demonstrations of magnesium oxide scrubbing and catalytic oxidation processes initiated earlier should also be satisfactorily completed so that a final decision concerning their suitability for commercialization can be reached.

In view of the large gap between FGD planned and that needed for high sulfur coal, there is a clear need to accelerate deployment of FGD systems and to accelerate development of technologies for clean use of coal that have the greatest potential for early application. Even with maximum effort, however, interim use of supplemental control systems may be necessary to utilize the high sulfur coal in the most environmentally acceptable way.

4.1.9 References

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4.2 PARTICULATE CONTROL TECHNOLOGY

4.2.1 Summary

For many years utilities have been using electrostatic precipitation (ESP) for collection of particulates and have been gradually increasing the efficiency of collection. About three-fourths of all power plants, and an even higher fraction of large plants, are equipped with ESP. With modern dry-bottom pulverized-coal-fired furnaces that typically discharge 80% of the mineral matter in the coal as fly ash, collection efficiencies higher than 99% are required to meet the NSPS. Such efficiencies are readily attainable by ESP for the eastern and midwestern steam coals that have been used so predominantly by the utilities. The increasing use of low sulfur coals to meet SO₂ standards, however, has introduced problems in particulate collection because these coals produce fly ash that has a high electrical resistivity and is difficult to collect by ESP. In addition, the possibility that regulations will be imposed on emissions of fine (<2 µm in diameter) particulates is a growing concern since the efficiency of ESP reaches a minimum in the submicron region at about 0.5 µm.

Some utilities burning low sulfur western coal have circumvented the problem of high resistivity ash by installing wet scrubbers to remove particulates, either alone or in conjunction with SO₂ removal. Satisfactory removal efficiencies have been obtained, but at the expense of energy penalties of up to 3-5% to overcome the high pressure drop (up to 20 in. water gauge) at which the scrubbers normally operate. In addition, problems with scaling and solids deposition have reduced the availability of scrubbers and increased plant outages and maintenance costs. Disposal of the wet sludges has added to costs for control of water pollution.

Other utilities using low sulfur coal have installed, or are planning to install, fabric filters for removal of fly ash. Fabric filters (baghouses) have been extensively used in industry and are known to have the capability

of removing more than 99% of particulates, independent of their resistivity and largely independent of their size. Use of fabric filters on power plants was previously limited by the short lifetimes of bags exposed to flue gas, but fabrics of woven glass fibers with a polymer coating are now providing lifetimes up to three years. The reduced costs for maintenance and replacement of bags are making fabric filters more competitive with ESP, and a number of major installations are now planned.

The use of flue gas additives to enhance collection of high resistivity particulates by ESP is another area of active interest and several different approaches to improving precipitator performance are being developed. Advanced concepts for particulate collection, such as pre-charging, wet ESP, and charged droplet scrubbing are also being developed and tested at the pilot plant scale.

Removal of particulates from high temperature and pressure gases, such as those in pressurized fluidized-bed combustion and MHD, is at present being investigated only on the laboratory or pilot plant scale. Efforts are being made to improve the efficiency of cyclone collectors for fine particulates, to develop panel-bed, metal, and ceramic filters, and to extend the range of conditions under which ESP can be applied. Some approaches show promise but still need to be demonstrated under more rigorous conditions and on a larger scale.

The mounting interest in fine particulates has underlined the need for additional development of methods and procedures for the collection, fractional sizing, and quantitative measurement of submicron particulates. A number of new techniques for determination of mass emissions are being investigated, and continuous monitors for particle-size distribution are under development.

4.2.2 Introduction

The increasing use of low sulfur coal for electricity generation and the increasing attention being directed to fine particulate emissions are forcing the utilities to reexamine traditional practices for particulate control by electrostatic precipitation (ESP) and to consider alternative control technologies. The objectives of this report are to provide an assessment of the current status of technology for control of particulate

emissions on coal-electricity processes, and to identify areas where additional information, research, or development is needed. The focus of the assessment is on commercially available technology and on the relationships between effectiveness and cost. Available technology is considered to include wet scrubbing and fabric filtration as well as ESP, even though they have not been used extensively thus far. In addition to cost and effectiveness, the assessment will take into consideration other factors, such as problems in operation and maintenance, energy penalties, secondary environmental impacts, and constraints to application.

Advanced concepts for particulate control in conventional power plants and high temperature/high pressure particulate control for advanced power systems will also be evaluated, but in lesser detail and primarily to assess their potential usefulness. The applicability and limitations of techniques for the sampling and measurement of fine particulates will be discussed and programs in particulate control technology currently being sponsored by EPA, ERDA, and other organizations will be identified.

4.2.3 Technology Descriptions

4.2.3.1 Electrostatic Precipitators

Operating Principles

In electrostatic precipitators, the force required to separate particulate matter from the gas stream results from an electric charge on the particles and the electric field generated within the precipitator. Charging of the particles takes place by the attachment of ions generated by an electrical corona. The process of corona generation involves the application of a high DC voltage between a small-radius wire and a cylindrical or plate electrode.

The particle-charging process varies, depending upon the size of the particles being charged. Large particles intercept the electric field lines and become charged by ions that travel along these lines. This process is called field charging or ion bombardment. Ions are also subject to random thermal motion and can collide with particles even though they are not driven by electrical forces. Charging by this process is termed diffusion charging,

and is the predominant charging mode for particles smaller than about 0.2 μm in diameter. Field charging predominates for particles larger than about 1.0 μm in diameter, and both mechanisms contribute to the charging of particles in the intermediate size range.

The rate of particle charging is related primarily to the number of ions present in the interelectrode region, which is related in turn to the precipitator current. When current is not limited by other factors, charging of large particles takes place rapidly, reaching 90% of the saturation charge within a fraction of a second. Smaller particles generally charge at a slower rate, as do large particles if the current is lower.

Collection of the dust is governed by the combination of forces acting on the particles. The turbulence of the gas flow tends to keep the particles distributed uniformly within the interelectrode region, whereas the electrical forces tend to cause the particles to move toward the collection electrode. In the boundary layer adjacent to the electrode where the gas flow is laminar, the electrical forces are large compared to the aerodynamic forces and result in the collection of particles on the electrode.

The collection of dust in a precipitator is thus related to the probability that a particle will enter the boundary region. For particles charged by ion bombardment, the probability of collection (η) has been related to the collection plate area (A), the volumetric gas flowrate (V), and a parameter called the particle migration velocity (w) in an equation (4-1) derived by Deutsch.¹

$$\eta = 1 - e^{-(A/V)w} \quad (4-1)$$

The migration velocity, or terminal velocity of a particle when aerodynamic drag and electrical forces are equal, varies directly with the particle diameter and the electrical fields and inversely with the gas viscosity. The Deutsch equation applies strictly to a single particle size and does not take diffusion charging into account, but it has been shown to predict collection efficiency rather precisely when properly applied. It should be noted that in the above equation an increase in plate area, a decrease in volumetric flowrate (or velocity of gases), and an increase in particle migration velocity would increase collection efficiency exponentially.

Once collected, the dust must be removed from the collection surface. The most common system is the dry collection of dust and the subsequent removal by rapping the collection electrodes. The rapping process and the subsequent falling of the dust into the hoppers result in some reentrainment of the dust and the system must be properly designed to prevent this reentrainment from becoming excessive. Dust deposited in the hoppers is removed by either a pneumatic or hydraulic system through valves, or by other means so as to prevent air inflow or gas discharge to the removal system.

Factors Affecting Precipitator Performance

The performance of an electrostatic precipitator is inherently dependent upon the size of the incoming fly ash and upon its electrical resistivity. The resistivity in turn is dependent upon the composition of the coal and the temperature of precipitator operation.

The size and quantity of fly ash produced from a given coal varies with the type of boiler in which it is burned. In modern pulverized-coal boilers typically about 80% of the mineral matter in the coal is entrained as fly ash with a mass-weighted median diameter of 10-20 μm . The median for particles entering the precipitator is shifted to smaller sizes if a mechanical collector precedes the precipitator.

The size distributions of entering and exiting particles for a specific precipitator installation having an overall collection efficiency of 99.6% are shown in Fig. 4.7, and the fractional collection efficiency as a function of particle size is shown in Fig. 4.8.² The observed decrease in collection efficiency with decrease in particle size from 5 μm to ~ 0.5 μm is attributable to decreased charging by ion bombardment (or to a decrease in migration velocity in the Deutsch equation). The increased collection efficiency below 0.5 μm is attributable to the increasing importance of diffusion charging. The minimum in collection efficiency for particles in the region of 0.5 μm diameter is typical for precipitators, and occurs because particles of this size are not charged efficiently by either mechanism. It is apparent that a large fraction of smaller fly ash particles would result in a lower overall precipitator efficiency. A second consequence is that the achievement of increasingly higher overall efficiencies

Fig. 4.7 Inlet and Outlet Cumulative Mass Loadings for a Precipitator with an Overall Efficiency of 99.6%

Fig. 4.8 Measured Fractional Efficiencies for a Cold-Side Electrostatic Precipitator with the Operating Parameters as Indicated, Installed on a Pulverized Coal Boiler

requires the collection of increasingly greater portions of the fine particles. This has the effect of requiring a proportionately larger increase in precipitator size to increase efficiency from 99.0 to 99.9% as compared to an increase from 90 to 99%.

The resistivity of the fly ash being collected has a major effect on the electrical characteristics, and hence the performance, of a precipitator. The physical arrangement of the electrodes requires that the corona current pass through the collected dust layer. The voltage drop across this dust layer is determined by the resistivity of the dust, the current density, and the thickness of the dust layer. When the precipitated dust has low electrical resistivity, the current is limited only by electrical breakdown of the gases within the interelectrode region and current densities of 50-60 nA/cm² or perhaps higher are possible.

If dust resistivity is moderately high ($\sim 5 \times 10^{10}$ ohm-cm), the electric field within the dust layer can exceed the electrical breakdown conditions for currents in the range of 20-30 nA/cm². When breakdown occurs in the dust layer, a spark is propagated to the corona electrode. Precipitator operation is limited to spark rates of around 50-100/min in each electrical section. Current densities as low as 5 nA/cm² are found in precipitators collecting dust with high resistivity ($> 1 \times 10^{12}$ ohm-cm).

The influence of current densities on collection efficiency as a function of precipitator size is shown in Fig. 4.9. It may be noted that to achieve comparable efficiency a precipitator operating at a current density of 5 nA/cm² would require twice the collecting area as one operating at 20 nA/cm².

Fly ash resistivity depends not only upon the composition of the coal but also upon the temperature. Precipitators commonly have been installed after the air preheater and operate with flue gas temperatures in the neighborhood of 300°F. Under these conditions the resistivity of the fly ash is established by surface conduction and is sensitive to the presence of small quantities of SO₃, sodium oxide, and other hydrophilic species, as well as to the partial pressure of water vapor.³ The sulfur content of the coal has a major effect on ash resistivity in cold-side precipitators because a fraction of the sulfur, typically about 1%, is converted to SO₃.

Fig. 4.9 Computed ESP Performance Curves at 5, 20 and 40 nA/cm^2

during combustion. The dependence of fly ash resistivity on the sulfur content of coals and on the temperature of the flue gas is shown in Fig. 4.10.³ It is evident from these data that use of a coal sufficiently low in sulfur to meet the SO₂ NSPS will produce fly ash that, at temperatures near 300°F, has 100 times the resistivity of ash produced from coal of the average type (2.3%S) burned by the utilities. As discussed earlier and shown in Fig. 4.9, this can necessitate doubling the size and cost of a cold-side precipitator in order to maintain the same efficiency.

Hot-side Electrostatic Precipitation

An alternative approach, indicated by the temperature dependence in Fig. 4.10, is to increase the operating temperature of the precipitator. At higher temperatures, where surface conduction becomes unimportant, the resistivity of ash is determined by its bulk chemical composition and is virtually independent of the sulfur content of the coal. More importantly, the absolute value of the ash resistivity at temperatures in the range of 700-800°F can be 1000-fold lower than that at 300°F for a low sulfur coal. A precipitator operating at the higher temperature can achieve the same efficiency with little more than half the collection area despite the increased gas volume (√1.5-fold). The operating parameters and fractional collection efficiencies of a hot-side electrostatic precipitator with an overall efficiency of 99.3% are shown in Fig. 4.11.²

The higher temperatures can be realized by installing the precipitator before, rather than after, the air preheater. This presents no significant problems in a new installation, but it can involve major modifications and be economically impractical in a retrofit situation. There are other pros and cons to the use of hot-side ESP, such as lower land requirements, better ash handling characteristics, higher energy penalties, smaller differences between onset and breakdown voltages, and more stringent materials requirements, but the overall balance appears to be favorable since use of hot-side ESP for low sulfur coal applications is increasing.

The performance of hot and cold precipitators is affected not only by fly ash size and resistivity, but also by a number of design factors related to gas flow. The reentrainment of collected dust and the leakage of dust around the electrified regions and through the ash hoppers can have

Fig. 4.10 Variation of Fly Ash Resistivity with Temperature and Coal Sulfur Content

Fig. 4.11 Measured Fractional Efficiencies for a Hot-Side Electrostatic Precipitator with the Operating Parameters as Indicated, Installed on a Pulverized Coal Boiler

a significant effect on overall efficiency. Recent studies of reentrainment indicate that 25-40% of the total emissions from a precipitator is reentrained dust.^{4,5} Reentrainment can occur in a variety of ways. Dust being precipitated can strike the dust layer with sufficient velocity to dislodge additional particles. Rapping of the plates can cause dust to be propelled into the gas stream and falling of dust into the hopper can result in reentrainment of dust already removed. Reentrained dust always consists of agglomerates of individual particles, so the redispersed dust is more readily collected than would be indicated by the sizes of the discrete particles. Dust reentrained from the first field is readily collected in subsequent fields. The reentrained dust appearing at a precipitator outlet is principally that resulting from reentrainment of dust collected in the last field. Gas leakage results from the necessity for maintaining clearance above and below the electrodes and from loss through the hopper. The influence of gas leakage and reentrainment are reduced considerably by proper baffling and proper design of rapping gear.

Another factor influencing electrostatic precipitator efficiency is the uniformity of gas flow. As a standard, the Industrial Gas Cleaning Institute has recommended that the gas entering a precipitator should be such that 85% of the local velocities should be within 25% of the mean and the local velocity should not differ from the mean by more than $\pm 40\%$.

Flue Gas Additives

One approach to improving the performance of electrostatic precipitators on existing plants is through the use of flue gas additives. The additives, which include SO_3 , NH_3 , triethylamine and a number of proprietary products, serve in various ways to reduce the resistivity of the fly ash or to increase its agglomeration.

One of the most common difficulties with electrostatic precipitators is high resistivity ash resulting from a change in fuel or from failure to properly assess the resistivity characteristics of the ash in the design phase. Such problems can be overcome through the use of flue gas additives to reduce the ash resistivity.

As already noted, a consequence of burning a low sulfur coal to avoid excessive emissions of sulfur dioxide is that the concentration of sulfur

trioxide in flue gas is also lowered and the problem of excessive ash resistivity is incurred. One way to overcome this problem is to add sulfur trioxide from an external source (vapor from anhydrous sulfur trioxide or sulfuric acid).⁶ Alternative sources being used more frequently are sulfur dioxide, vaporized and passed over a catalytic oxidizer in the presence of air, or elemental sulfur, burned to sulfur dioxide and then finally converted to sulfur trioxide in a catalytic oxidizer.

Although ammonia is not a naturally occurring component of flue gas, it is sometimes added in place of sulfur trioxide to treat ash from low sulfur coal.⁶ One useful effect of ammonia addition is an improvement in the electrical properties of the gas stream within a precipitator. After addition, ammonia reacts with normally occurring sulfur trioxide and water vapor to form a fume of ammonium sulfate.⁷ The fume particles are then electrically charged, and the added quantity of charged particulates increases the electrical field through a space-charge effect. Another useful effect of ammonia addition is to lower reentrainment losses of collected ash. This effect is probably the consequence of increased cohesive forces between the ash particles, which lead to larger aggregates that are less likely to be reentrained.

Another conditioning mechanism, claimed for triethylamine as an additive, is increased agglomeration of ash particles *before* they are collected. Other additives are intended to catalyze oxidation of naturally occurring sulfur dioxide to sulfur trioxide.

Additives that are on the market are being continually diversified. Much needs to be learned about both the chemical compositions of the proprietary formulations and the mechanisms of their operation, not only to predict when the different additives can be effective, but also to obtain a broader understanding of precipitator problems that can be solved with chemical additives.

Operating Problems and Reliability

Electrostatic precipitators that are properly designed, installed and maintained usually do not require service between regularly scheduled plant shutdowns.

What operational problems that are encountered fall within several categories. The most prevalent problem with some installations is corona electrode failure. Several causes of corona electrode failure have been identified. These are: (1) localized excessive sparking due to sharp protrusions or edges at the collection electrode; (2) misalignment of the electrode structure due to foundation shifts, improper erection practice, or failure to allow for thermal expansion; (3) swinging of the electrodes; and (4) corrosion. Failures of all types of electrode structures have been experienced but they are more prevalent on the wire-weight types.

A second problem is overloading or malfunctioning of the ash removal system. Ash buildup in the hoppers can lift the weights, causing electrodes to short out or arc through the ash forming fused masses that must be manually removed. Ash buildup in the flues and ducts is another type of problem that can cause poor performance due to a change in the gas flow distribution.

Insulator problems can occur in some instances if moisture condenses on them or if they become contaminated. Electrical tracking can reduce the effectiveness of operation and result in cracking of the insulator.

Other problems that must be considered are: (1) binding or other malfunction of the rappers, (2) distortion or rupture of the shell, and (3) air leakage.

Secondary Environmental Impacts

There is some concern that the amount of sulfur trioxide or sulfuric acid that is added to the flue gas as a conditioning agent may contribute to the air pollution burden. Sulfur trioxide is used in concentrations up to 20 ppm of stack gas. If as much as 5 ppm escapes being absorbed on the fly ash and is emitted as sulfuric acid, the emission level would be 0.01 g/ft^3 , about one-fifth of the NSPS for total particulates.

Introduction of metals into the flue gas stream to act as catalysts for oxidizing sulfur dioxide to sulfur trioxide may also be identified as a potential health hazard.

There is not sufficient information available at this time to indicate the seriousness of these concerns.

Energy Requirements

One of the advantages of electrostatic precipitators is the relatively low energy required to achieve the desired level of cleaning. Pressure drops across a precipitator are typically of the order of 0.5-1.0 in. water gauge. The power (P) required to move a volume of gas against a pressure drop is:

$$P = \frac{746 \ v \ p}{6356 \ \eta}$$

where:

v = gas volume, cfm,

p = pressure drop, in. water gauge, and

η = combined fan and motor efficiency, about 50%.

For a precipitator installed on a 500-MW plant producing 1.75×10^6 acfm of gas, the energy required would be 308 kW. Electrical requirements for achieving a 99% collection efficiency would be 1180 kW. The total power requirements would be 1488 kW or about 0.30% of the total plant capacity.

Costs

Costs of electrostatic precipitators for coal-fired boilers are related to plate area, degree of sectionalization, and local requirements for duct work. The most recent data available from the Industrial Gas Cleaning Institute indicate that in 1969 flange-to-flange precipitator costs were approximately \$5.00/ft² of collecting area.⁸ Installed costs were approximately double this value, and retrofit costs were as high as 3.5 times the flange-to-flange costs. If a specific collection area of 400 ft²/1000 acfm and a gas flow to power production ratio of 3500 acfm/MW are assumed, the \$5.00/ft² cost value converts to \$7.00/kW. Total costs, based on 6000 hours per year and adjusted for inflation, are estimated to be about 1 mill/kWh.

Retrofitting

Retrofitting an installation with an electrostatic precipitator can present problems because of the physical size of the precipitator. The problem is most severe if the precipitator is installed ahead of the air heater, where there is generally less space available. Very few such installations have been made.

Even in a cold-side installation, it is sometimes necessary to design the precipitator with taller plates than usual, to use a chevron configuration, or a stacked precipitator arrangement.

Research Under Way

Electrostatic precipitator research supported by EPA includes studies of fly ash resistivity. The research consists of laboratory measurements in environments of water and sulfur dioxide in concentrations in the ranges normally encountered in the emissions from electric power boilers. Efforts are being made to correlate fly ash resistivity with coal composition. The correlation can then be used to develop quantitative relationships between coal composition and maximum useful precipitator current, as well as relationships between theoretical migration velocities and current densities for the range of ash particle sizes encountered in power boilers.

Research supported by EPRI includes the following subjects:

1. *Conditioning.* This work is on the mechanisms of flue gas conditioning (contract with Southern Research Institute).
2. *Reliability and operating costs.* This is a study to identify some of the factors influencing these items. The frequency and causes of electrode failure are being studied. Studies are also being made of some of the causes of precipitator shell failure, especially in hot-side installations (contract with Southern Research Institute).
3. Evaluation of electrostatic precipitators for collection of fine particles and trace elements (contract with Meteorology Research, Inc.).

4.2.3.2 Fabric Filters

Operating Principles and Equipment

Fabric filters, usually in the form of baghouses, have been used for many years to remove dusts from industrial process gases or gaseous emissions, notably from cement kilns and metallurgical operations. They have also been installed on a number of small power boilers. However, it is only within the past few years that they have been considered for removing fly ash from large electric utility boilers burning coal.

In the filtration of stack gases, as in many other applications of fabric filters, the fabric is formed into a vertically hung tube or sleeve

closed at the top. The stack gas is drawn through the bag and the collected dust forms a loosely deposited cake on the inside. Periodically the flue gas flow is turned off and the dust is removed from the fabric by agitation, partial bag collapse, air backflow, or reverse air jet. The filter is thus regenerated and prepared to resume filtering. The collected dust falls into a hopper, from which it is carried away for disposal.

Fabrics of different constructions (e.g., woven, felted, or knitted) and a wide variety of yarn sizes, twists and fabric finishes are available for various applications. Cotton and wool fabrics or felts are used, as well as synthetic fabrics based on acrylic polymers or polyamides (e.g., Nomex). At the present time, glass fibers have been found more suitable than natural or synthetic fibers in withstanding the combined action of sulfur oxides and heat in baghouses on power boilers burning coal.

The type of fabric that has given best service on power boilers is woven glass fiber. It is coated with graphite and fluorocarbon polymers that act as lubricants to reduce abrasion of the yarns against themselves, especially during the regeneration of the filter, and thus extend filter life. However, bags made from polyester are being successfully used in Australia to remove fly ash from the effluents of power boilers.

Fabric filters collect particles by impaction (including interception) and diffusion, perhaps aided by electrostatic forces. Recent studies of filter performance by an EPA contractor have produced improved mathematical models for filter action. Earlier models of collection efficiency for filters were based on arrays of cylinders as the collectors. The new models represent the woven fabric as an array of pores before the dust cake is formed. This concept leads to a nonlinear model for filter drag (pressure drop) that fits the experimental data more closely than the previous linear-drag models.⁹

Fabric filters have an advantage over electrostatic precipitators in that their collection efficiency is not affected by the chemical composition of the fly ash, nor is it as sensitive to particle size. A previous disadvantage was that maintenance costs were significantly higher, largely due to the need or practice of replacing bags after service of one year or less. Recent experience, however, indicates that bags can be operated for three years or more. The use of fabric filters is thus becoming more attractive in

the light of the trend toward use of low sulfur coal producing high-resistivity fly ash that is difficult to collect, or requires increased power for collection, in an electrostatic precipitator.

Representative Installations

Some specifications and performance data for fabric filter installations on coal-fired boilers are presented in Table 4.9.¹⁰ For assessing the present status of fabric filter technology the two most important installations are the Sunbury Station of Pennsylvania Power and Light Co. and the Nucla Station of Colorado Ute Association. They are the only units for which much data on fractional collection efficiencies have been obtained. Both plants burn a low sulfur coal and both are relatively small.

*Sunbury Station.*¹¹ The fuel burned is a mixture of anthracite silt, bituminous coal, and petroleum coke; the mixture has a high ash content and a low sulfur content. Electrostatic precipitators that were installed originally were inefficient in cleaning the gas, evidently because of the high ash and low sulfur contents of the fuel.

Four identical pulverized coal boilers provide steam for two 87.5 MWe turbines. Each boiler produces about 225,000 acfm of flue gas at 325°F and has a separate baghouse containing 1,260 bags 12 in. in diameter and 30 ft in length. The bags are made of woven glass fiber with a Teflon-base finish. The active air-to-cloth filter ratio (based on 7 of the 8 compartments being in service) is 2.067:1 cfm/ft², and the filtering velocity is 2 ft/min. The pressure drop through the baghouse is about 2.5-in. water gauge.

The inlet grain loading is about 2 gr/ft³, and the outlet loading is about 0.017 gr/ft³; the average overall mass collection efficiency is thus 99.2%. The fractional collection efficiency over the range of particle sizes for which an impactor gives valid data (down to 0.1 μm) increases slightly with decreasing particle size, from 99.5% at a particle diameter of 10 μm to 99.8% at 5 μm, and then drops to 99% at 0.1 μm.

Table 4.10 gives some details of the construction and operating costs of the baghouses.

Table 4.9 Performance Data for Fabric Filters on Coal-fired Boilers¹⁰

No.	Installation and Test Period	Boiler Type	Fuel and (sulfur content) (wt. % S)	Flue Gas		Fabric Filter					
				Flow rate (ACFM)	Temp. (°F)	Type	Life (yr)	Eff. (%)	ΔP (in. H ₂ O)	Velocity (ft/min)	Drag ^b Type Baghouse ^c
1.	Carborundum Industrial Boiler 1968-1975	Spreader Stoker	Coal (NA ^c)	10,000	375	Glass and Nomex	NA	NA	3.0	3.0	1.0 RA
2.	PSE and GNJ ^d Mercer Station July 1965-1966	Pulverized	Coal + 20% Coke (NA)	21,600	270	F.G. ^e	NA	NA	5.0	5.0	1.0 RA
3.	Chemical Process Boiler	NA	Coal (0.81)	1,500	312	F.G.	NA	98.5	4.0	3.5	1.14 MS
4.	Australian Boiler 1956	NA	Coal (NA)	Pilot Plant	<250	NA	NA	NA	4.0	3.5	1.14 NA
5.	Midwest Utility (Pilot Plant) 1967-1969	Pulverized	Coal (0.6-2.9)	2,880	250	NA	>2	99.8	4.0	4.0	1.0 MS
6.	Wheelabrator (Pilot Plant) 1971-1972	NA	Coal (2.0)	NA	NA	f	f	98.5	<4.0	7.5	0.53 PJ
7.	Colorado UTE Nucla Station 1973-Present	Spreader Stoker	Coal (0.78)	86,240	310	F.G. Graphite Silicon Coated	NA	99.6 to 99.9	4.2	3.1	1.35 RA & MS
8.	Pennsylvania Power and Light Company Sunbury, Pa. 1973-Present	Pulverized	Anthracite & Coke 15-35% (1.3)	225,000	325	F.G. Teflon Coated	2.5	99.0 to 99.8	2.5	2	1.25 RA

Table 4.9 (Cont'd)

No.	Installation and Test Period	Boiler Type	Fuel and (sulfur content) (wt. % S)	Flue Gas		Fabric Filter					
				Flow rate (ACFM)	Temp. (°F)	Type	Life (Years)	Eff. (%)	ΔP (in. H ₂ O)	Velocity (ft/min)	Type Baghouse ^c
9.	Kerr, Ind. Concord, N.C. 1972-1974	Spreader Stoker	Coal (0.7)	11,000	300	A ^B		98.2	2.0	3.2	0.63
						A		98.5	4.0	6.1	0.66
						A		97.1	7.0	8.8	0.89
						B		98.2	1.0	5.4	0.19
						B		96.0	3.0	8.5	0.35
						B		95.1	7.0	14	0.50
						C	NA	96.6	0.8	3.3	0.24
						C		97.3	4.2	6.1	0.69
						C		97.8	5.6	8.7	0.76
						D		98.8	2.2	3.4	0.65
						D		97.6	5.6	8.7	0.76
						D		96.9	5.3	8.9	0.60
10.	Amalgamated Sugar Co. 1973-Present	Stoker	Coal (0.6)	92,000	300	F.G.	NA	NA	5.5	3.56	1.83
11.	Dupont (Parkersburg, W. Va.) 1974-Present	Stoker	Coal (2.5)	Variable	350	Teflon and Glass	NA	NA	2.0 to 3.0	4.0	0.5 to 0.75
12.	Haner Dye & Finishing 1975-Present	Stoker	Coal (0.8)	75,000	310	F.G.	0.75	NA	4.0	6.0	0.61
				40,000	310	26 oz.	0.16	NA	5.0	6.0	1.0
13.	Harrison Radiator Div., C.M. 1974-Present	Stoker	Coal (0.75)	62,000	400	Nomex with Lime	NA	NA	4	4.5	0.89
				76,000	400				4	4.5	0.73
14.	Pa. Power & Light Co., Holtwood, Pa. 1975	Pulverized	Coal (1.8)	200,000	360	Glass	NA	NA	4.5	2.42	1.86

^aRA-Reverse Air; PJ-Pulse Jet; MS-Mechanical Shaker. ^bFilter drag = $\frac{\text{Pressure drop}}{\text{air-cloth ratio}}$. ^cData not available. ^dPublic Service Electric & Gas Company of New Jersey.

^eFiber glass. ^fPolyester and Nomex tested for less than 24 hr & Pulsglass for greater than 2000 hr. ^gA-Gore-Tex/Nomex
B-Teflon Felt
C-Dralon-T
D-Nomex

Table 4.10 Installation, Operation and Maintenance Costs, Sunbury Station

Bag Filter Installation

<u>Expenditure Description</u>	<u>Total cost(\$)</u>
Western Precipitator Contract (4 Baghouses)	\$3,201,700
Structures & Improvements	372,100
Land & Land Rights	1,500
Boiler Plant Equipment (Ash Removal Equipment and Precipitator Modifications)	1,190,000
Accessory Electrical Equipment	72,000
Overhead	662,800
Total Construction Cost	\$5,500,100

Estimated Operating & Maintenance Cost^a

(@ \$12/manhour)

<u>Cost Description</u>	<u>Cost</u>		
	<u>1973</u>	<u>1974</u>	<u>1975</u>
Collapse Fan Power Consumption	\$18,600	\$18,600	\$18,600
Air Compressor Power Consumption	3,000	3,000	3,000
Instrument Department Labor	950	950	1,800
Mechanical Maintenance Labor	2,130	5,840	15,678
Electrical Maintenance Labor	7,410	3,800	6,000
Construction Department Labor	3,950	2,350	2,000
Complete Bag Replacement			
Material (\$48,000/baghouse)		48,000	96,000
Labor (\$11,000/baghouse)		11,000	22,000
Total Cost	\$36,040	\$93,540	\$165,078

^aCost of power consumption for the ID fan not included.

*Nucla Station.*¹² At this station, there are three 13-MW generators, each with a stoker-fired traveling-grate boiler with fly ash re-injection. The fuel is western coal containing, on average, 14% ash and 0.7% sulfur.

A separate baghouse is used for each boiler. Each baghouse contains 672 graphite-silicon-coated glass fiber bags 8 in. in diameter and 264 in. in length, with a total cloth area of 30,964 ft²/baghouse. The design air-to-cloth ratio is 2.79:1. Bags are cleaned by a combination of gentle mechanical shaking and reverse air flow. The pressure drop through the baghouse is about 4.2-in. water gauge.

Measurements of fractional collection efficiency with impactors, diffusion equipment, and a condensation nuclei counter showed the Nucla baghouses to have a collection efficiency of >99% on a mass basis for particles down to $\sim 1 \mu\text{m}$ and a collection efficiency >99% on a number basis for particles between 0.5 μm and 0.0025 μm . The mean mass efficiency for all particle sizes was 99.84%.

Costs

Some details of the construction and operating costs for the 402-MWe Sunbury Station are shown in Table 4.10. Capital costs for the 39-MWe Nucla Station are shown in Table 4.11. The total installed costs correspond to \$30/kW for the Sunbury Station and to \$67/kW for the smaller Nucla Station. In both cases, however, the costs include some items not normally considered in cost comparisons. The \$16/kW cost for the baghouse collectors at the Nucla Station are somewhat less than one-fourth of the total cost.

Operating and maintenance costs for the Sunbury Station in 1975, when bags were replaced in two of the four baghouses, correspond (at a load factor of 0.7) to 0.16 mills/kWh. Note, however, that this figure does not include the cost of power to overcome the 2.5 in. pressure drop; the 0.27% energy penalty for this would add about 0.06 mills/kWh to the operating costs. Total annualized costs for the Sunbury Station (1976 basis) are estimated to be 1.4 mills/kWh. This is comparable with the total annualized costs estimated for an electrostatic precipitator designed for use with a coal of the type burned at Sunbury.

Table 4.11 Estimated Capital Cost for the Nucla Baghouse Installation
as of October 1974

Item	Costs	Percent
Baghouse Collectors	\$ 631,168	24.23
Ash System	86,332	3.31
Miscellaneous Equipment and Materials	219,083	8.41
Painting	61,000	2.34
General Construction	1,193,080	45.80
Engineering (Consultant)	294,383	11.30
C-U Project Manager Cost	120,000	4.61
Total	<u>\$2,605,046</u>	<u>100.00</u>

Note: Installations are reportedly being made on two new plants of 1150- and 350-MW capacity. Information on the design of these installations is not yet available.

Table 4.12 Erected Costs for Baghouses and Precipitators

Fuel Sulfur (%)	Erected Cost ^a (\$/kW)		
	Baghouse 99.9% Eff.	ESP 99.5% Eff.	ESP 99.9% Eff.
0.75	13.40	17.00	21.30
1.75	13.40	12.50	16.00
2.75	13.40	11.00	12.20

^a 500 MWe, flange to flange, 1976 dollars.

In Table 4.12 erected costs for a baghouse of 99.9% efficiency are compared with costs for electrostatic precipitators of comparable efficiency as a function of sulfur content in the coal being burned. The estimates indicate that for power plants using low sulfur coal (<1% S), baghouses offer higher collection efficiency at lower cost.

Retrofitting

Retrofitting baghouses in utility installations may present more problems than electrostatic precipitators because they are bulky. At the Sunbury Station, the baghouses were installed on top of electrostatic precipitators that had been used previously. The precipitators were gutted and used as structural supports for the baghouses.

Research Under Way

Research supported by EPA on the use of fabric filters includes studies on the Nucla baghouse under a contract with GCA/Technology Division.

4.2.3.3 Wet Scrubbers

Scrubber Types and Operating Principles

Scrubbers have been widely used for collecting industrial dusts, notably in metallurgical plants, and they have been installed within the past few years in electric utility power plants for the removal of sulfur dioxide and fly ash. Most of the installations are designed for removal of

sulfur dioxide, and there seems to be a very recent trend to use dry collectors (a high-efficiency mechanical collector or an electrostatic precipitator) to remove fly ash ahead of a scrubber for sulfur dioxide, instead of using a scrubber to remove both sulfur dioxide and fly ash.

The types of scrubbers most extensively used for removing fly ash in electric utility power plants are the gas-atomized spray type (e.g., the venturi scrubber) and the mobile-bed type.

The mechanisms for collection of fly ash by scrubbers involve inertial impaction of fly ash particles for those larger than about $1\text{ }\mu\text{m}$ in diameter, interception of particles with diameters of the same order of magnitude as the diameters of the collecting droplets, and diffusion for those smaller than about $0.1\text{ }\mu\text{m}$. In the particle-size range of $0.1\text{--}1.0\text{ }\mu\text{m}$, all three mechanisms are active. Condensation of water vapor and other secondary effects such as thermophoresis (movement of the particle opposite to a temperature gradient in the gas) may also be involved in particle collection.

As in the case of fabric filters, it has been possible to derive useful semi-empirical mathematical models of scrubber action, but again the complexity of the problem and the lack of experimental data have hindered the development of theoretical models of performance. Calvert has developed relationships between collection efficiency, dust-particle size, and size distribution for various scrubber designs and operating conditions.¹³

Scrubbers have the disadvantage of a large pressure drop (thus requiring more energy than electrostatic precipitators) for efficient collection of fine particles. They also introduce the necessity of handling a wet fly ash slurry and recirculating the scrubber liquid. Scaling, corrosion, plugging, and mist entrainment in the effluent gas are troublesome problems.

There are 13 electric utility power boilers in the United States, in sizes ranging from 58 to 350 MW, with operating wet scrubbers for collection of fly ash. Most of the installations are retrofitted, the scrubbers having been installed in series with mechanical collectors or electrostatic precipitators. Usually, the power boilers burn low-sulfur coal, and the electrostatic precipitators that had originally been installed were not collecting the high-resistivity fly ash with the expected efficiency.

Representative Installations

Information is available on the performance of fly ash scrubbers at the following installations:

1. Valmont, Cherokee, and Arapahoe Stations; Public Service Co. of Colorado; turbulent contact absorbers (TCA) with mobile-bed packing.
2. Dave Johnson Station; Pacific Power & Light Co.; venturi scrubber.
3. Four Corners Station; Arizona Public Service Co.; venturi scrubber.
4. Clay Boswell and Aurora Stations; Minnesota Power and Light Co.; high pressure spray system.
5. Holtwood Station; Pennsylvania Power & Light Co.; venturi scrubber.

Table 4.13 shows some of the operating information on these installations.¹⁴

The information available on these scrubbers indicates that in general they remove fly ash efficiently. However, there is not much experimental data on the fractional collection efficiencies of wet scrubbers. Some of the recent published information was obtained on the TCA scrubber at the Cherokee Power Station.^{15,16} It indicates that the collection efficiency reaches a minimum at a particle diameter of about 0.5 μm , i.e., in the same particle-size range in which fabric filters and electrostatic precipitators also show the lowest collection efficiency. On an overall mass basis, the scrubber appeared to operate at the design particulate removal efficiency of 95%. Entrainment of mist interfered with accurate measurements of the submicron particles in the effluent; comparisons with other collection data are not warranted.

Costs

Some data obtained in 1973 on installed costs of scrubbers for fly ash are given in Table 4.14.

The Dave Johnston Plant Unit 4 scrubber comprises three parallel single-stage venturis, each capable of treating about 500,000 acfm of flue gas. Labor for the operation of the scrubber was estimated to be somewhat less than one man per shift, and maintenance labor to be 3-5 men on three 8-hr shifts.

Table 4.13 Summary of Operating Particulate Scrubbers

Plant	Scrubber Capacity (MW)	Scrubber Type	Availability (%)	Removal Efficiency (%)		Liquid/Gas (gal/1000 acf)	Pressure (in.WG)	Treated Gas Flow
				Part.	SO ₂			
Colorado P.S.								
Arapahoe	100	3-Stage TCA ^a	86	96	45	54.2	10-18	299,000 SCFM
Cherokee	600	3-Stage TCA	55-95	97	20	55.9	10-18	302,000-897,000 SCFM
Valmont	100	3-Stage TCA	76	96	45	58.3	10-18	299,000 ACFM
Pacific P&L								
D. Johnston	330	Venturi	N/A	99	40	13	15	1,500,000 ACFM (270°F)
Minnesota P&L								
C. Boswell	350	High Pressure Spray	N/A	99	20	8	4	1,300,000 ACFM (254°F)
Aurora	116	High Pressure Spray	N/A	98	20	8	4	291,160 ACFM (340°F)
Arizona P.S.								
Four Corners	575	Venturi	80	99.2	30	9	28	814,000-1,030,000 ACFM (340°F)
Penn. P&L								
Holtwood	75	Venturi	90-95	99	20	12.5	5-6	209,000 SCFM

^aTurbulent Contact Absorber

Units 1, 2, and 3 at the Four Corners Station of the Arizona Public Service Co. are equipped with single-stage venturists. Units 1 and 2 are 175 MW each, and Unit 3 is 225 MW. Each unit has two scrubber modules. Each module on Units 1 and 2 is capable of treating 400,000 acfm at 340°F. The modules for Unit 3 are slightly larger. The total design gas flow for all three generating units is 2,658 acfm. Operating labor was estimated to be 21,600 man-hr/yr for all 3 units, with an additional 12,000 man-hr/yr for maintenance.

Information obtained subsequently in the study of particulate collection efficiency quoted above^{15,16} showed that the annual operating cost in 1973-1974 was \$495,000, based on 75% availability. For a gas flow rate of 610,000 acfm, the operating cost was \$0.81/acfm.

Operating Problems

Mobile-bed scrubbers for removing fly ash have been plagued by a variety of maintenance problems, such as breakage of the plastic spheres used as contactors. However, the most serious problems have been with scale and solids formation.

Table 4.14 Installed Costs for Scrubbers^a

Plant	Installed Cost (\$)	Capacity (MW)	Installed Cost (\$/kW)
Colorado P.S.			
Arapahoe Unit 4	4.0×10^6	100	40.0
Cherokee Unit 1	3.2×10^6	100	32.0
Cherokee Unit 3	3.9×10^6	165	23.6
Cherokee Unit 4	10.4×10^6	350	29.7
Pacific P&L			
Dave Johnston Unit 4	8.0×10^6	360	22.0
Arizona P.S.			
3 Units	39.0×10^6	575	52.0

^a1973 data.

Heavy formation of calcium sulfate scale has been noted as the chief cause of downtime on one installation of this kind of scrubber. The scale accumulates and hardens in regions of low flow rates. Scale formation has also been a problem with venturi scrubbers, in which it has built up in the venturi throat, broken off, and plugged lines.

There has been some success in controlling scale deposition (as distinct from scale formation) by water treatment, e.g., by the addition of lime.

The absorption of sulfur dioxide in the scrubber liquor is significant if the fly ash is alkaline. The chemical composition of the water used also plays a part in the scale formation, which should therefore be less of a problem if softer water is used. However, some scaling has been observed in one plant using an acid water.

Operating problems such as those caused by scaling and plugging have reduced the availability of the equipment (the proportion of time that the equipment is operating) to levels that in some instances are marginally acceptable (70-80%). Studies by EPA and utilities that have been evaluating scrubbers for fly-ash collection indicate that in new installations, the utilities are switching to fabric filters or electrostatic precipitators. If sulfur dioxide must also be removed from the flue gas, the trend is to install an electrostatic precipitator (or an efficient mechanical collector) ahead of a sulfur dioxide scrubber.

Secondary Environmental Impacts

The disposal of the fly ash slurry and recovery of water from it is a problem, in view of the large amounts of soluble and partly soluble inorganic compounds it contains. See Section 4.4 for further details about sludge disposal.

Retrofitting

Retrofitting scrubbers in utility installations should present few problems; they are more compact than electrostatic precipitators or bag-houses.

Research Under Way

Research supported by EPA includes:

1. The development of methods for predicting scrubber performance.
2. The measurement of fractional collection efficiencies of scrubbers.
3. The evaluation of new scrubber designs.
4. The study of condensation and flux forces in scrubber action.

4.2.4 Advanced Concepts

Because they are relatively further developed, the advanced concepts for collection of particulate matter that are of primary interest to this review are: (1) precharging of particles being collected, (2) charged-droplet scrubbing, (3) wet electrostatic precipitation, and (4) packed-bed filtration.

4.2.4.1 Precharging of Particles

As noted above, electrostatic precipitator performance in collecting fly ash is profoundly affected by its resistivity. If the resistivity is greater than 10^{10} ohm-cm, as is the case for fly ash from some low-sulfur coals, a rapid decrease in performance is observed as back-corona and spark-over begin to limit the allowable current density.

Therefore, precipitators with precharging sections have been proposed for the collection of such high resistivity materials. The charging section can have an electrode geometry designed to provide stable corona and to avoid back corona and sparkover. The second stage can employ an electrode geometry to avoid corona and to provide for maximum collection. Design, construction, and testing of a pilot-scale (500-1000 acfm) charger has been carried out at Southern Research Institute for the EPA. This research is being continued with: (1) the determination, by means of a theoretical and very limited experimental program, of the optimum electrode configuration for a high-current-density particle charger, (2) a study to determine the feasibility of high-current-density charging of high-resistivity dusts, and (3) a pilot-scale (1000-3000 acfm) experimental program to determine the feasibility of the charging system for fine-particle collection. Development of a precharging system is also being funded by EPRI and field trials have been conducted at the John Sevier Plant of TVA on a pilot-scale precipitator. Details of the

precharger configuration have not been published nor have test results from the pilot-scale studies. Plans are under way for full-scale trials in the event the pilot-scale tests indicate promise.

4.2.4.2 Charged-Droplet Scrubbing

The use of electrostatic forces for improving the action of wet scrubbers is being studied by several investigators on laboratory and small pilot-plant scales.

Melcher (Massachusetts Institute of Technology) has conducted basic laboratory research under EPA sponsorship on the critical time constants governing the performance of charged-droplet scrubbers.¹⁷

Pilat (University of Washington) has demonstrated that the collection of fine particles by water droplets in a spray scrubber can be substantially increased by electrostatically charging the droplets and particles to opposite polarities. Studies are being conducted in a 1000-acfm pilot plant.¹⁸

The applicability of charged-droplet scrubbing to the removal of fine particles is also being studied by the TRW Systems Group, under a contract with the EPA.¹⁹ In the TRW Charged Droplet Scrubber, water droplets are highly charged by electro-hydrodynamic spraying. An externally imposed electric field is used both to form the charged droplets and to move them through the scrubber, producing a high droplet velocity relative to the uncharged particles being collected.

Charged-droplet scrubbing is expected to be useful in the collection of particles in the 0.1-1.0 μm size range, because electrical interactions are more effective in this range than the collection mechanisms of diffusion and impaction that operate in the usual wet scrubber.

The EPA supports several other projects for research on new concepts for particle collection, based on the augmentation of filtration or scrubbing by electrical forces, at Battelle Northwest, Carnegie-Mellon University, and the University of Illinois.

4.2.4.3 Wet Electrostatic Precipitation

Wet electrostatic precipitators, which have been used for many years for the collection of the fine particles from metallurgical furnaces, are

now being considered for control of fly ash and sulfur dioxide emissions from coal-fired power plants.

In a wet precipitator, the wire-plate design of a conventional dry electrostatic precipitator is modified by the addition of spray nozzles or weirs that irrigate the collection electrodes. The results of experiments at Southern Research Institute indicate performance comparable to that obtained with dry electrostatic precipitators collecting fly ash under favorable electrical conditions. The experiments also indicate that fine particle collection efficiencies in wet electrostatic precipitators can be estimated from the same theoretical relationships that apply to dry precipitators. Therefore, when fly ash electrical resistivity limits the allowable current density in a dry electrostatic precipitator, it follows that substantial plate area reductions may be obtained by wet operation. Formation of deposits on the electrodes during wet operation is a potentially serious problem as is corrosion of the electrode materials.²⁰

4.2.4.4 Gravel-bed Filtration

Gravel-bed filters, in which the gas is passed through a bed of solid granules, are used in cement manufacturing for control of dust. The only reliable measurements on collection efficiency, which were made during 1976, indicate that such a filter performed as well as a wet scrubber in collecting fine particles in the emissions from a Portland cement cooler, with a power consumption slightly higher than that of a venturi scrubber having the same collection efficiency.²¹ Gravel-bed filters have not yet been evaluated for collection of fly ash. Research is continuing on evaluation of the application of gravel-bed filters to collection of fly ash by EPRI.

The panel-bed filter, which operates somewhat similarly, is being developed by Squires at the City College of New York for control of fly ash in fluidized-bed combustion of coal.²² The dust-laden gas is passed in a horizontal direction through a bed of granules contained in a tall narrow panel. The results that have been obtained so far indicate that these filters are promising for controlling emissions of submicron particles at a relatively low energy cost. However, the data on fractional collection efficiency needs to be expanded to obtain a more reliable assessment of the device.

4.2.5 High-Temperature, High-Pressure Particulate Removal

Several processes have been recently reviewed by Midwest Research Institute²³ for their potential application to the removal of particulate matter in hot combustion gases under pressure. Examples of the operating conditions that must be considered are magnetohydrodynamic power systems, which operate up to about 1250°C; coal-gas turbines, operating up to similar temperatures; and coal gasification processes such as the Lurgi gasifier, which is operated at pressures up to 30 atmospheres at temperatures up to 900°C.

The types of equipment that can be considered for these applications include mechanical collectors (cyclones), granular (or gravel) bed filters, electrostatic precipitators, fabric filters, and molten-salt scrubbers. The characteristics of these types of collectors and their suitability for use under the conditions mentioned above vary widely.

Mechanical collectors such as cyclones would operate under the conditions specified but are inefficient in collecting fine particles (those with diameters less than several microns).

Granular-bed filters appear to have the capability of operating under the desired conditions and of efficiently collecting fine particles. They are being studied for hot gas cleaning by EPRI and others.

Electrostatic precipitators have the capability of efficient collection of fine particles, but high temperature and pressure are likely to affect their operation and design, and their suitability for this use has yet to be demonstrated.

Molten-salt scrubbers should be efficient in collecting fine particles and they also offer the possibility of removing sulfur dioxide. Entrainment of particles from dispersion of the absorbent may be a problem. Scrubbers are being developed for these applications.

Fabric filters are also capable of efficient collection, and filters made of metal or ceramic fibers have already been tested in cleaning metallurgical gases. Regeneration of the filter, i.e., removing the collected dust, can be a problem.

Extensive analyses have been made of the fundamental forces involved in the removal of particles from gas streams and how they respond to high temperature and pressure. These analyses indicate that high pressure reduces the effectiveness of particle collection processes and that high temperatures also have a deleterious effect on the collection of large particles. However, the collection of small particles ($\leq 0.5 \mu\text{m}$) may be aided by an increase in temperature, because of the increased diffusivity and coagulation or agglomeration. Nevertheless, the overall result appears to be a loss in collection efficiency with increased temperature and pressure.²⁴

The lack of some specific and critical information, or techniques, is already apparent. Specific needs encompass: (1) better techniques for generating and sampling aerosols at high temperatures and pressures; (2) the effects of these conditions on particle mobility, electrical corona, and electrical charging of particles; (3) effects of filter parameters, such as filter diameter or granule dimensions, on filter performance; and (4) suitable construction materials.

4.2.6 *Sampling and Measurement Techniques*

The data required for determining the efficiency of control devices in collecting fly ash are obtained by sampling flue gas and measuring the physical and chemical properties of the ash. Only within the past few years have adequate sampling and analytical techniques become available, and even these techniques are continually being evaluated and improved. There is still no complete agreement among those who use the techniques with regard to the interpretation of some of the results.

The relevant techniques are those used to measure the mass and particle-size distribution of fly ash collected by sampling the flue gas upstream and downstream of the pollution control device. In the methods used at present, mass is measured by weighing. The particle sizing techniques employ inertial impaction, light scattering, diffusion, and electrical mobility of the particles for their characterization.²⁵ The applicability of these techniques and some of the problems involved in their use on power plant stacks are discussed below, as are some improved techniques under development by EPA and others.

4.2.6.1 *Techniques Used at Present*

Particulate Mass Concentration

Mass concentrations of particulate matter in flue gas are measured by drawing a sample of gas through a probe and filter and weighing the collected material. This is the basis of EPA Method 5, the manual test method that is used in determining compliance with federal regulations. There is some difference of opinion as to how the results should be interpreted, especially with regard to condensation of vapors in the probe and filter box. Some investigators making performance tests of control devices on emission sources prefer to use a sampling train that differs from that used in Method 5 in that the filter for trapping particulate matter is located in the stack instead of outside the stack at the end of the sampling probe. Thus, condensation of vapors in the probe and filter box is avoided. Another advantage of the alternative system is that the particles are trapped before they enter the probe, from which they may not be adequately recovered despite the probe washing procedure specified in Method 5.

There is an increasing need for improved techniques for sampling particulate matter in flue gas downstream from wet scrubbers. Problems are encountered due to the presence of acid mist and the water-saturated condition of the flue gas.

The only instrumental method that is used for routine measurement or monitoring of mass emissions is the opacity monitor or transmissometer, which is commercially available, and which has been demonstrated to be useable in power plant stacks. Opacity is only an indirect measure of mass and must be related to it empirically for any specific installation.

Particulate Size and Size Distribution

These techniques may be classed according to the physical mechanism that is used to obtain the data: (1) inertial, (2) optical, (3) diffusional, and (4) electrical. In their present state of development, instruments employing these techniques are used to complement each other in covering the particle-size range below 10 μm . Inertial devices are used for the larger particle sizes. Diffusional and electrical instruments are best suited for the smaller sizes, and optical counting equipment covers the intermediate sizes.

Inertia. Particles are collected on an impingement surface because of their inertia, and the collected particles are removed and weighed. In a cascade impactor, the sampled gas is drawn over a series of impingement stages, each operating at a higher impingement velocity than the previous stage. Thus progressively finer particles are deposited on the stages as the gas passes through the impactor. Cascade impactors are used in the particle-size range of 0.5-10.0 μm . Efforts are under way to develop inertial sizing devices with extended size ranges and with automatic, real-time, readouts of the particle size information, but to date no such device has been used successfully in an industrial flue gas atmosphere.

In most plants, the impactors can be inserted directly into the stack, and probe losses can be avoided. Even so, impactors are subject to considerable loss of material in the inlet nozzle and on internal surfaces. There is often poor correlation of mass loadings obtained with impactors with the values obtained with EPA Method 5. The extent of deposition in the impactor is related to particle size and can contribute significantly to errors in the measurement of the particle-size distribution. Chemical reaction of the deposited particles or collection substrate with constituents of the flue gas, such as SO_2 , can also lead to erroneous results.

Cyclones have been used less than impactors for fine-particle measurements because they are bulkier, and the size-cut points are not as sharp. However, they have the ability to collect samples of large sizes for subsequent analysis.

Optical Particle Counting. Optical counters for single particles have been used to some extent in tests made on stack emissions in connection with determining the fractional collection efficiency of control devices. The type used in these tests covers the particle-size range from 0.3-2.0 μm .

Particle Diffusivity. For particles with diameters $<0.5 \mu\text{m}$, diffusivity is size-dependent and under controlled conditions can be used to measure particle size. Though the application to emissions is still in the development stage, diffusion techniques have already been shown to provide useful measurements. Diffusivity measurements are made with diffusion batteries, with condensation nuclei counters used for measuring number concentrations of particles at the inlet and outlet of the battery.

Electrical Mobility. The measurement of electrical mobility of a particle bearing a known electrical charge can be used for the determination of particle size.

This type of instrument is being evaluated in field tests, with measurements in parallel with diffusional tests. It has the advantage of rapid acquisition of data and can become the standard method of sizing sub-micron particles (down to 0.01 μm or below) if the field tests show it to be accurate and reliable. Problems with extracting the sample, conditioning it, and delivering it to the instrument, which are associated with the extremely small particle size being measured, probably are more troublesome than any operating problems of the instrument itself.

4.2.6.2 *Techniques Being Developed*

Mass Emissions

Other methods that are being considered for monitoring mass emissions include the following, which are for the most part still in the development stage.

Light Scattering by Suspended Particles. Designs for measuring forward scattering that have been investigated so far require rather complicated optics. Instrumentation that measures back-scattered light in-stack is already commercially available. The light source is a light-emitting diode incorporated into a probe inserted in the stack.

Deposition of Electric Charge on an Electrometer Sensor by Impinging Particles (the Triboelectric Effect). This technique has been used both in-stack and on extracted samples. Better results are obtained on sources that emit particles relatively uniform in size and charge. Probe losses have been a problem. Some instruments using this approach are already on the market.

Attenuation of Beta Radiation by Deposited Particulate Matter. This technique requires an extractive system in which some kind of filter is used to collect the sample. The interfacing equipment that has been used so far is mechanically complicated and requires excessive maintenance. Probe losses have also been a problem.

Change in Vibrational Frequency of a Quartz Crystal on Deposition of Particles (Piezoelectric Microbalance). This method is subject to probe losses and loss of sample because the particles do not adhere to the surface after deposition. It is subject to interference from gas and moisture. Commercial devices based on this method have been used for monitoring low concentrations of particles in ambient air, but the applicability of the method for monitoring stack gases remains to be demonstrated.

Particle Size and Size Distribution

Equipment for continuous monitoring of the particle-size distribution of particulate emissions is still in the research stage.

The development of continuous monitors for particle-size distributions based on cascade impactors combined with automatic read-out mechanisms for rapid and continuous measurements in the stack is being carried out by EPA as well as by equipment manufacturers. The most practical read-out technique appears to be the attenuation of beta radiation by the collected particles. Alternatively, changes in the vibrational frequency of a quartz crystal in an impactor may be used. Multiple-angle light scattering is also being investigated.

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4.3 NITROGEN OXIDES CONTROL

4.3.1 Summary

Combustion modification and flue gas treatment are two approaches applicable to conventional combustion processes for control of nitrogen oxides (NO_x) emissions. The former suppresses the formation of the NO_x in the furnace through the alteration of combustion conditions, and the latter destroys the NO_x after it has formed. Major emphasis in the United States has been on combustion modification, since it is the less costly way of complying with current federal emission regulations.

NO_x formed in combustion processes originates from two sources: (1) oxidation of molecular nitrogen in the combustion air via a thermal process

to form "thermal NO_x "; and (2) conversion of nitrogen chemically bound in the fuel to "fuel NO_x ". The relative contributions of these two sources have a very important bearing on the effectiveness of different combustion-modification techniques. For pulverized coal firing, bench-scale studies have shown that the fuel NO_x can be responsible for more than 75% of the total NO_x production, suggesting that combustion-modification techniques that suppress only thermal NO_x (e.g., water injection) will not be able to achieve sufficient reduction of NO_x produced in coal-fired boilers. Combustion-modification techniques that have been actively investigated in coal-fired utility boilers, therefore, include only low excess air (LEA) firing, staged combustion, flue gas recirculation (FGR), combinations of these techniques, and new burner designs.

LEA firing, staged combustion, and a combination of these two techniques have been successfully demonstrated in field units. These techniques have the lowest costs of any NO_x control method, and have been installed in existing units and incorporated into the design of new units. However, their impacts on boiler reliability and maintenance still have not been fully resolved. The best firing combination, tangential firing in conjunction with LEA and staged combustion, can achieve NO_x concentration reductions to levels of 250–300 ppm. The FGR method has been found to be less effective than LEA firing and staged combustion in coal-fired utility boilers; this ineffectiveness, along with its high costs, makes the FGR an unattractive method for coal-fired boilers. Significant advances have been made in new burner designs. The Babcock and Wilcox dual-register burner has been demonstrated capable of reducing NO_x emissions by 50%, and an experimental burner has been identified that can reduce NO_x emissions to as low as 150 ppm. In the long run, advanced burners will probably replace the practice of external combustion modification and achieve NO_x levels considerably below that of present-day burners.

To date, flue gas treatment is capable of achieving the greatest reduction in NO_x emissions and a number of potential flue gas denitrification processes exist. However, no commercially demonstrated process for reducing NO_x emissions from coal-fired utility boilers is currently available. Owing to its high cost, this approach is only being envisioned as an "add-on" method to supplement combustion modification, if and when higher removal efficiencies for NO_x become necessary.

4.3.2 Introduction

Nitrogen oxides (NO_x) are currently emitted in the United States at a rate in excess of 20 million tons per year.¹ About half of the total man-made NO_x emissions are attributed to stationary combustion sources, while a little less than one-half are associated with mobile sources. A recently completed EPA-sponsored survey of 1972 NO_x emissions from stationary combustion sources (Fig. 4.12 and Table 4.15) has shown that, of the 11,665,000 tons of NO_x emissions from the stationary sources, coal-fired utility boilers contributed 32.5% of the total.²

Nitrogen oxides emitted by combustion sources are predominantly in the form of nitric oxide (NO) with the balance, usually less than 5%, in the form of nitrogen dioxide (NO_2). The oxides are formed by the fixation of molecular nitrogen in combustion air at high (greater than 3300°F) flame temperatures (thermal NO_x) and by the oxidation of chemically bound nitrogen in the fuel (fuel NO_x). The relative contributions of the thermal and fuel NO_x depend on the combustor design and operating conditions, as well as on the nitrogen content of the fuel.

Nitric oxide is a relatively harmless gas, but it is rapidly converted to toxic nitrogen dioxide in the atmosphere. As detailed in Chapter 3, NO_2 is: (1) potentially hazardous to human respiratory systems, (2) an important constituent in the formation of photochemical smog, and (3) involved in the complex chemistry of irritative peroxyacetylnitrate (PAN). Consequently, oxides of nitrogen are among the atmospheric pollutants for which the EPA has enacted regulatory standards. As pointed out in Chapter 2, the EPA's New Source Performance Standards limit NO_x emissions from a coal-fired boiler to the equivalent of 0.7 lb of NO_2 per million Btu of heat input (maximum 2-hr average), which corresponds to an NO_2 concentration of ~ 525 ppm (by volume, 3% excess oxygen, dry basis) in the stack gas.

There are several possible approaches to controlling the emission of NO_x from coal-fired power plants, including (1) modification of combustion conditions, (2) flue gas treatment, and (3) fluidized-bed combustion. Fluidized-bed combustion technology is discussed in Chapter 6.

Fig. 4.12 Total NO_x Emitted from Stationary Sources in the U.S. (1972)²

Table 4.15 Summary of Total NO_x Emissions from Fuel Combustion Sources (1972)²

Source	NO _x Production, 10 ⁶ tons/yr (percent of total)			Totals by Source	Cumulative Percentage
	Gas	Oil	Coal		
Utility Boilers	1.114(9.55)	0.768(6.58)	3.788(32.47)	5.670(48.61)	48.61
I.C. Engines					
Reciprocating	1.873(16.06)	0.316(2.71)	-	2.189(18.77)	67.38
Gas Turbines	0.172(1.47)	0.119(1.02)	-	0.291(2.49)	69.87
Industrial Boilers	0.495(4.24)	1.098(9.41)	0.515(4.41)	2.108(18.07)	87.94
Commercial/Residential Heating	0.3308(2.84)	0.467(4.00)	0.029(0.25)	0.8268(7.09)	95.03
Process Heating	0.1855(1.59)	0.149(1.28)	0.0553(0.47)	0.3902(3.35)	98.38
Non-Combustion	-	-	-	0.149(1.28)	99.66
Incineration	-	-	-	0.041(0.35)	100
Totals by Fuel	4.1703(35.75)	2.9174(25.01)	4.3873(37.61)	11.665(100)	

The formation of NO_x is rate controlled and, in contrast to the formation of sulfur oxides, is dominated by combustion conditions. Consequently, combustion modifications have been found to be an effective technique for NO_x control. The basis of this approach is to alter conditions in the primary flame zone so as to suppress the formation of NO_x . Control development is therefore closely related to specific equipment design.

Flue gas treatment, on the other hand, is used to control or reduce the quantity of NO_x after it has been formed in the furnace. This approach, currently being actively investigated in Japan, is believed to hold promise for specialized cases where high NO_x concentrations are present or where very low levels of NO_x emissions are required.

The EPA has recently awarded a contract to the Aerotherm Division of the Acurex Corporation to perform a detailed environmental assessment and systems analysis of the effectiveness of combustion modifications in the control of NO_x emissions from stationary combustion sources. The EPA is also planning a detailed state-of-the-art assessment for NO_x control by flue gas treatment. In the EPRI program for NO_x control, KVB Engineering is evaluating homogeneous chemical destruction of NO_x in a reducing atmosphere, and Arizona Public Service is assessing the environmental and operational aspects of the application of combustion modification technology to western coal firing.

It is possible that the EPA will soon impose much stricter regulations for NO_x control on stationary sources in general and on utility boilers in particular. This action is being contemplated because of the inability of the automobile industry to meet automotive NO_x standards specified by the Clean Air Act without unacceptable fuel economy penalties. NO_x emissions of 200 ppm for 1980 and 100 ppm for 1985 are currently being considered as R & D goals by the EPA for coal-fired utility boilers. These levels are well beyond the capabilities of current combustion modification technology, which can do no better than 250 to 300 ppm. To meet such standards, a considerable increase in efforts to develop better combustion modification technology and flue gas treatment will be required.

4.3.3 Formation of Nitrogen Oxides

The formation of nitrogen oxides (NO_x) in fuel combustion processes is briefly reviewed in the following sections, and the major factors affecting the formation are summarized.

4.3.3.1 Thermal Fixation of Atmospheric Nitrogen

In all high-temperature combustion processes using air as the oxidant, the combination of molecular nitrogen and oxygen in the air results in the formation of nitric oxide (NO). Although NO does dissociate at lower temperatures, the decomposition rate is so slow that, once formed, the NO concentration remains essentially constant as heat is removed from the combustion gases. As the combustion gases cool, a small amount of NO is further oxidized to nitrogen dioxide (NO_2). The mixture of these two species is conveniently referred to as NO_x .

The formation of thermal NO is generally accepted to be determined by highly temperature-dependent chemical reactions, the so called Zeldovich reactions.^{3,4} The rate of formation is significant (more than 50 ppm) only at high temperatures (greater than 3300°F) and doubles for every increase in flame temperature of about 70°F .¹ Except in a small region near the flame zone in which a greater than equilibrium concentration of oxygen atoms is found, the rate of NO formation is proportional to the square root of the oxygen concentration, and thus increases with increasing oxygen concentration.

4.3.3.2 Oxidation of Fuel Nitrogen

In addition to thermal NO_x , some fuel-bound nitrogen is also converted to NO during combustion. Tests on carefully controlled laboratory-scale units have shown that the fraction of chemically bound nitrogen in coal transformed to NO_x is typically 15-40%, corresponding to concentrations of 375 to 1000 ppm for coals containing 1.4 wt% N.^{5,6} The higher conversion efficiencies are attained when the nitrogen content is low or when the combustion mixture is lean (high excess air).^{1,7} Figure 4.13 shows NO_x emissions from uncontrolled combustors as a function of nitrogen content in the coals burned.

LEGEND :

	<u>COAL TYPE</u>	<u>BOILER TYPE</u>	<u>REFERENCE</u>
◇	BITUMINOUS	TANGENTIAL	21
◆	SUB-BITUMINOUS	TANGENTIAL	21
○	BITUMINOUS	OPPOSED WALL	27
□	BITUMINOUS	LABORATORY	7, 9
■	SUB-BITUMINOUS	LABORATORY	7, 9
△	BITUMINOUS	PILOT-SCALE	14, 15
◻	BITUMINOUS	FRONT WALL	10, 11
◻	BITUMINOUS	OPPOSED WALL	10, 11

Fig. 4.13 Uncontrolled NO_x Emissions vs. Coal Nitrogen Content

The reaction mechanisms by which fuel nitrogen is converted to nitrogen oxides are not so clearcut as are reactions for the fixation of atmospheric nitrogen. It has been found that the conversion of fuel nitrogen to NO_x can occur at a much lower flame temperature than the conversion of atmospheric nitrogen. Furthermore, the conversion efficiency increases markedly with increased oxidizing conditions in the flame but is only a weak function of flame temperature over a wide temperature range.^{7,8} A number of investigators have recently found evidence that the conversion of chemically bound nitrogen in pulverized coal to NO_x can be responsible for more than 75% of the total NO_x produced under conditions representative of normal operation.^{7,8,9}

4.3.3.3 Factors Affecting NO_x Emissions from Coal-fired Boilers

Based on the evidence cited above and other information obtained from measurements on operating furnaces, it can be concluded that the major factors affecting the formation of NO_x in coal combustion processes are:

1. Combustion temperature. The rate of thermal NO_x formation is highly dependent upon the peak combustion temperatures, becoming significant (>50 ppm) only at temperatures greater than 3300°F and doubling for every increase in flame temperature of 70°F.
2. Air/coal ratio. The formation of both thermal and fuel NO_x is dependent upon the amount of air supplied with the coal; higher air/coal ratios favor higher NO_x production (see Section 4.3.4.1).
3. Heat release and removal. Low heat-release rates and high heat-removal rates reduce thermal NO_x formation because low peak temperatures and shorter residence times at high temperatures are achieved.
4. Mixing of fuel, air and combustion products. Distribution of the fuel and air so as to achieve most of the combustion under fuel-rich conditions reduces both fuel and thermal NO_x formation. Slow diffusion of the fuel and air streams also reduces total NO_x production. Internal recirculation, or backmixing of combustion products into the primary combustion zone, dilutes both the fuel and air, lowers the flame temperature, and thereby results in less NO_x formation.
5. Fuel nitrogen content. The nitrogen content of most U.S. coals is 1-2% by weight.⁴ The higher the nitrogen content, the greater will be the NO_x production (Fig. 4.13). The percentage conversion, however, decreases with increasing nitrogen content. For a given nitrogen content, the amount of NO_x formed per million Btu increases as the heating value of the coal decreases.

4.3.4 Combustion Modification for NO_x Emission Control

The most frequently used method for burning coal in utility boilers today is by pulverized-coal firing (Fig. 4.14). The coal is powdered in a pulverizing mill into extremely fine particles which are mixed with heated primary air from the air preheater. The mixture of coal fines and primary air is blown into the furnace through burner ports directly into the combustion zone. Once inside, the coal fines are quickly ignited at the temperature in the combustion zone. Almost simultaneously the volatile matter and moisture are released, and the volatile gases and fixed carbon ignite. The hot combustion products then flow across the boiler tubes, which provide the surface required to transfer much of the heat. The still hot combustion products (about 500 to 600°F) from the boiler are directed through another heat exchanger, called an economizer, and the air preheater before reaching the stack temperature.

The combustion modification approach is based on the premise that NO_x can be substantially reduced by alteration of the conditions under which the fuels burn. Working from an understanding of NO_x formation chemistry, investigators have formulated a number of control techniques. Methods for controlling thermal NO_x , based on the reduction of the peak temperature in the combustion zone, include low excess air (LEA) firing, staged combustion, flue gas recirculation (FGR), reduced air preheat, and water injection. Techniques for controlling fuel NO_x are based on the reduction of oxygen availability in the combustion zone, and include LEA firing, staged combustion, and FGR. In addition, pilot plant and field studies have demonstrated that changes in burner design are also able to reduce significantly the formation of both fuel and thermal NO_x through aerodynamically influencing the local recirculation rate and oxygen concentration in the flame.

Since fuel NO_x can be a major contributor to total NO_x emissions in coal combustion processes, it is generally believed that control techniques that suppress only thermal NO_x will not be able to achieve sufficient reductions of NO_x produced in coal-fired utility boilers. Therefore, development of NO_x control methods for coal-fired boilers has been concentrated on techniques that simultaneously reduce the formation of both thermal and fuel NO_x . These include LEA firing, staged combustion, FGR, and new burner designs.

Fig. 4.14 Typical Coal-Fired Utility Boiler
(Courtesy of Babcock and Wilcox)

Table 4.16 summarizes the status of these techniques and combinations of techniques for NO_x emission control in coal-fired boilers. Also listed in the table are typical values of the NO_x levels achievable and the control effectiveness of these techniques for the two major firing modes, tangential firing and wall firing. The references cited in the table provide the background for the discussion in the following five subsections.

Information regarding NO_x emission control in vertical and turbo coal-fired utility boilers through combustion modifications is sparse, hence reliable values of controlled NO_x emission levels are difficult to establish. For cyclone boilers the NO_x emissions are so high (>1,000 ppm) that the NSPS for NO_x (~525 ppm) cannot be met by employing combustion modifications only.

4.3.4.1. Low Excess Air (LEA) Firing

LEA firing is one of the most widely applied combustion-modification techniques for NO_x control. By reducing the availability of oxygen at the burners, both thermal and fuel NO_x can be reduced significantly.

Maximum combustion efficiency for coal normally requires 20-30% more air than the stoichiometric amount, depending on the boiler type and the properties of the coal burned. Field studies have shown that, if the excess air is reduced by 10% (e.g., to 15% from 25%), NO_x emissions will generally be reduced about 20%. This relationship varies only slightly with boiler type.

However, as the excess air level decreases, the concentrations of other pollutants such as CO, hydrocarbons, and particulates increase. The lowest level of excess air at which a combustion process will operate without unacceptable adverse effects is highly dependent on the boiler type and coal characteristics. Furthermore, with certain eastern coals having low ash-fusion temperatures, the localized reducing conditions in the lower furnace that occur with LEA firing can cause accelerated wall-tube corrosion and ash slagging. In addition, control devices are required to distribute the coal evenly to all burners served by the same pulverizer in order to prevent operation of burners at fuel-rich (reducing) conditions.

Table 4.16 Summary of Combustion Modification Techniques for Control of NO_x Emissions from Coal-Fired Utility Boilers^a

Technique	Principle of Operation	NO _x Emission Level NO ₂ basis, 3% O ₂ ^b	NO _x Control Effectiveness ^c	Limitations	Applications	References
Low Excess Air Firing (LEA)	Reduces oxygen level in primary flame zone and suppresses thermal and fuel NO _x	Wall firing 450-600 ppm Tangential 350-450 ppm	20 to 30% ^d	Unburned hydrocarbons; CO emissions at low level of excess air; increased fouling	Routine use in utility boilers	10 to 25
Staged Combustion (SC)	Biased firing or overfire air ports reduces oxygen level in primary flame zone (first stage)	Wall firing 350-450 ppm Tangential 250-350 ppm	30 to 45%	Fouling of convective section; poor first stage ignition; soot formation; load reduction	Retrofit of existing boilers and design of new units	10 to 26
LEA Plus SC	Combination of the above two	Wall firing 350-400 ppm Tangential 250-300 ppm	40 to 50%	Limitations with SC plus corrosion on wall tubes	Retrofit of existing boilers and design of new units	10 to 26
Flue Gas Recirculation (FGR)	Recycled flue gas reduces the temperature and oxygen concentration of flame zone	Wall firing 500-700 ppm	10 to 20%	Limited effectiveness in coal-fired boilers	None expected for coal-fired boilers	8, 14-17, 22, 23, 26
New Burner Designs	Controlled mixing of fuel and air to suppress fuel and thermal NO _x	Wall firing 350-450 ppm	40 to 50%	Unknown	Under development	27 to 29

^aThe New Source Performance Standard for NO_x emissions by coal-fired utility boilers is 0.7 lb NO₂ per million Btu of heat input, which corresponds to an NO₂ concentration of 2525 ppm.

^bNO_x emission levels reported as NO₂, based on 3% excess O₂. Values cited are nominal for average unit capacity and operating conditions; the range of available data is much wider than the values listed.

^cExpressed as functional reduction relative to baseline NO_x emission levels of 500-900 ppm for wall-fired utility boilers and 400-600 ppm for tangential-fired boilers.

^dFor reduction of 10 to 15% in excess air.

Nevertheless, firing with low levels of excess air is typically the first technique deployed in a control program and is normally included even when other control techniques are used. The lowest excess air level achievable in combination with other techniques, such as staged combustion, is usually higher than when LEA is the only control employed.

4.3.4.2 *Staged Combustion*

After LEA, a logical next step is to optimize the distribution of the air in the furnace, i.e., between primary air (through the burners) and later additions. Staged combustion, taking advantage of both low flame temperatures and low oxygen concentration, has been found to be a very effective technique for reducing the formation of both thermal and fuel NO_x . In this approach biased (off-stoichiometric) burner firing or overfire air ports are used to control the mixing of the fuel and the combustion air. The resulting fuel-rich regions in the primary flame zone are cooled through radiative heat transfer before the whole combustion is completed with the remaining combustion air. Thus, although the overall fuel-air mixture is near stoichiometric (that is, low excess air), the primary NO_x -forming region of the flame is operated with less than the stoichiometric amount of air.

The effectiveness of NO_x control by staged combustion is highly dependent on the fuel/air stoichiometry in the burners of the primary stage. Studies have shown that this technique is capable of reducing NO_x emissions from coal-fired utility boilers by as much as 45%. The extent of NO_x reduction is limited only by poor flame stability, convective section fouling, and excessive formation of unburned hydrocarbons. However, recent studies in wall-firing utility boilers by TVA^{24,25} have shown that severe corrosion of wall tubes may occur in locally reducing regions that result from staged combustion. In addition, the number of available burners, the limited capacity for varying the fuel rate to individual burners, and the availability of overfire air ports for air addition above the burners place constraints on the use of staged combustion in retrofit applications. Nevertheless, staged combustion has been regarded as the most successful method for NO_x control, and overfire air systems have been included in the design of new coal-fired boilers to meet current NO_x emission standards.

4.3.4.3 *Flue Gas Recirculation (FGR)*

FGR is a technique in which a portion of the flue gases produced is recycled back to the combustion zone. The control of NO_x by this technique results from two factors: (1) the temperature of the flame zone is reduced by the returning cool flue gases, and (2) the concentration of oxygen available for NO_x formation is also reduced. Of these, the temperature effect is generally accepted to be the more important.

Information regarding the effectiveness of NO_x reduction by FGR in coal-fired utility boilers is scarce and inconclusive. Thompson et al.²⁶ reported that the use of 15% gas recirculation produced only a 13-17% reduction in NO_x on a 560-MWc boiler. Pilot-plant studies by Armento and Sage,^{14,17} and Pershing et al.⁹ gave similar results. However, some pilot plant results^{6,22,23} did show that NO_x reductions of 35-40% were achieved with 25-30% flue gas recirculation. Additional emissions of CO or hydrocarbons were not detected in any of these investigations.

In general, FGR is considered to be less effective as an NO_x control method than is LEA firing or staged combustion. Furthermore, the high installation cost of ducting and the energy penalty (~0.5%) attributed to recirculation fans make this method rather unsuitable for coal-fired boilers.²⁶

4.3.4.4 *New Burner Designs*

Advanced burner design is an alternate approach to reducing formation of both thermal and fuel NO_x by means of controlled mixing of the fuel and air. With modified burner designs, the basic NO_x control principles underlying the staged combustion and FGR techniques can be incorporated internally in the furnace, thereby avoiding some of the operational problems normally associated with these techniques.

The potential for major reductions in NO_x emissions by the modification of burner designs has been established both in full-scale tests²⁷ and on experimental burners.^{28,29} Tests of the dual-register burner developed by Babcock and Wilcox at the Southern Electric Generating Company's E. C. Gaston steam plant demonstrated a 50% reduction in NO_x emissions compared to the burners originally installed (365 vs. 725 ppm).²⁷ Operating units equipped with this type of burner will be going into service this year.

Through the use of multiple concentric fuel and air ports, which apparently provide delayed mixing or a form of staging, NO_x emissions as low as 150 ppm ($\sim 17\%$ of "normal") have been reported for an experimental coal-fired burner.²⁸ A full-scale facility now under construction will make possible the testing of these concepts at full scale and in multiple burner arrays.

In the long run improved burner design will probably replace the practice of external combustion modification and achieve NO_x levels considerably below that of present-day burners.

4.3.4.5 Combination of NO_x Control Techniques

The techniques of LEA firing, staged combustion, and FGR can, in principle, be utilized in combination to control NO_x emissions. Undoubtedly, the most powerful of these combinations is the use of staged combustion patterns in conjunction with LEA firing. In this mode of operation, the combustion of the bulk of the fuel occurs under reducing conditions that affect the formation of both thermal and fuel NO_x .

Although full-scale tests have proven that the combination of LEA firing and staged combustion can achieve lower NO_x emissions than obtainable with either technique alone, the total reduction of NO_x is not equal to the sum of the reductions obtained separately. The effectiveness of any combination of techniques must therefore be evaluated for the integrated system. Also, test programs will be required to define operational and safety limitations.

FGR has also been combined with staged combustion on a full-scale coal-fired utility boiler in an attempt to attain lower NO_x emissions.²⁶ The addition of up to 20% gas recirculation to staged combustion produced about a 6-10% further reduction in NO_x emissions.

4.3.4.6 Costs of NO_x Combustion Control

The most recent data on the economics of combustion modification technologies are those reported by Combustion Engineering, Inc.³⁰ for new and existing tangential, coal-fired, utility boilers. Overfire air, FGR to the secondary air ducts, and FGR to the primary air system are among the methods

considered. The cost of LEA firing was not investigated, since there is generally no significant additional cost for new units or units in good condition. However, older units could require modifications to the windbox in various ways, including addition of division plates, separate dampers and operators, air register operators, fuel valving, instrumentation for fuel and air flow, and automatic combustion controls. The EPA has subsequently estimated the investment costs for LEA firing on existing coal-fired utility boilers requiring modifications.²

The results reported in these two studies can be summarized as follows:

1. LEA firing and overfire air systems are the lowest cost methods for reducing NO_x emission levels on both new and existing units. For a 500-MWe utility boiler, the former results in an additional capital cost of 0.55 \$/kWe (in 1974 dollars) for an existing unit; the additional capital costs for the latter method are 0.50 \$/kWe (in 1973 dollars) for an existing unit and 0.14 \$/kWe for a new unit. There is no significant operating cost (less than 0.01 mills/kWe) for either of these methods.
2. FGR either to the windbox (secondary air) or to the coal pulverizer (primary air) requires greater capital expenditures than either LEA firing or overfire air, and also increases operating costs because of additional required fan power. In existing units the necessity to reduce unit capacity to maintain acceptable gas velocities could result in a 10-20% decrease in plant capacity.
3. In general, the capital cost of any of the control methods for an existing unit is approximately twice that for a new unit.

4.3.5 Flue Gas Treatment

Flue gas treatment is an alternate method for control of NO_x emissions. This method of control is applied after the NO_x has formed, and can be used either by itself or following combustion modifications. Because of the high cost associated with this approach, only a small effort has been devoted to it in the United States. Faced with more stringent emission standards, Japanese industry has been much more interested in the flue-gas-treatment approach, and has several major pilot plants in operation and full-scale plants under construction.³¹

Flue-gas-treatment methods can be grouped into four broad classes.

They are:

1. Chemical absorption, involving oxidation of NO_x to NO_2 , followed by scrubbing with an aqueous acid or alkaline solution to remove the NO_2 .
2. Physical adsorption, involving removal of NO_x by solids such as char or copper oxide.
3. Catalytic processes, including decomposition of NO_x , selective reduction of NO_x by NH_3 , and simultaneous removal of NO_x and SO_x .
4. Non-catalytic processes, principally selective reduction of NO_x to N_2 by NH_3 or other reducing agents.

4.3.5.1 Potential NO_x Flue-gas-treatment Processes

To date, there is no fully developed flue-gas-treatment process for controlling NO_x emissions from coal-fired boilers. Several potentially promising processes do exist, but these have not as yet been adequately demonstrated on a coal-fired boiler. Many of these processes remove NO_x and SO_x simultaneously.

1. The Shell/UOP CuO adsorption process,^{32,33} in addition to removing SO_2 , has been found to remove approximately 60-70% of the NO_x present as well. This process is being commercially applied on a 40-MWe, oil-fired boiler in Japan, and is being piloted in the U. S. on a test flue gas stream corresponding to that of a 0.6-MWe, coal-fired boiler.³³
2. The Bergbau-Forschung/Foster-Wheeler process³⁴ utilizes a char adsorption system for simultaneous removal of SO_2 and about 50% of the NO_x . A pilot plant add-on unit (coal-fired boiler) was in operation in West Germany from 1968 to 1970.^{34,35} A demonstration unit has been built for Gulf Power Company in Chattahoochee, Florida.³⁴ After a brief period of operation the test program was indefinitely postponed.
3. In the Chiyoda Thoroughbred 102 process both SO_x and NO_x are removed after the NO_x is oxidized to NO_2 with ozone in an absorber containing an aqueous sodium sulfite solution. A similar process by Fuji Kasui uses chlorine dioxide instead of ozone for the oxidation step. NO_x removal levels of 60-90% appear possible with these processes.
4. The Kawasaki Magnesium process uses magnesium scrubbing and lime addition for simultaneous removal of SO_x and NO_x . A pilot plant with a capacity of treating the flue gas from a coal-fired boiler with a capacity equivalent to ~1.7 MWe has been operated in Japan since 1975.³¹

5. The Exxon Thermal DeNO_x process uses NH₃ at 1300 to 1900°F to selectively reduce about 70% of the NO_x. This process has been demonstrated in Japan on full-scale, gas- and oil-fired boilers, but no information on coal-fired boilers is currently available.

A number of SO₂ wet scrubbing processes (e.g., lime/limestone and sodium carbonate) have also been shown to remove a small fraction (generally less than 10%) of the NO_x in utility boiler flue gases. These processes have little promise as primary flue-gas-treatment systems for NO_x control.

4.3.5.2 *Cost of NO_x Flue-gas-treatment*

Since all of the flue-gas treatment processes for NO_x control discussed above are still in the development stage, definitive cost information is not available. The costs of wet scrubbing processes using ozone as the oxidation agent are expected to be high, because the production of ozone is energy intensive and requires expensive equipment. The cost of ozone for treating flue gas containing 200-300 ppm NO has been estimated to be about 2 mills/kWh.³¹ For dry processes such as The Exxon Thermal DeNO_x process, the use of NH₃ as the reduction agent can lead to high operating costs (>1 mill/kWh) for control of flue gases having high NO_x concentrations (>500 ppm). In general the costs of NO_x control by flue-gas-treatment processes appear comparable to those for FGD processes, which are at least a factor of ten higher than the costs of combustion-modification techniques. Consequently, these processes are expected to find little use in the United States unless and until NO_x emission regulations are made considerably more stringent.

4.3.6 *Secondary Environmental Impacts*

Emission control techniques used for one pollutant can sometimes result in increased emissions of other pollutants. Such secondary environmental impacts are expected to be minimal in the combustion modification approach to control of NO_x. Field tests have shown that, with proper system design and operation, emissions of secondary pollutants such as CO and hydrocarbons can be maintained below regulated levels while achieving the NSPS for NO_x. Since there are no energy penalties associated with the favored techniques (LEA and SC), emissions of other fuel-derived pollutants, such as SO₂, are not increased.

Potential secondary problems of emissions resulting from NO_x flue gas treatment include ammonia, ozone or other oxidants, wastewater contaminants such as nitrates, sulfates or nitric acid, and possible pollutants associated with the production of NH_3 or ozone. The severity of these problems is uncertain, since all of these processes are still under development.

4.3.7 *Conclusions*

Combustion modification and flue gas treatment are two approaches that can be applied to conventional fuel-combustion processes for NO_x control. Major emphasis in the United States has been on the former approach, since it is the less costly way of complying with current federal emission regulations. For coal-fired utility boilers combustion-modification techniques that have been actively investigated include LEA firing, staged combustion, FGR, combinations of these techniques, and new burner designs.

LEA firing, staged combustion, and the combination of these two techniques also have the lowest investment and operating costs of any NO_x control method. However, their impacts on boiler reliability and maintenance still have not been fully eliminated, even though these techniques have been incorporated into the design of new units and installed in existing units. The state-of-the-art technology, tangential firing in conjunction with low excess air and staged combustion, can achieve reductions of NO_x concentrations to levels of 250-300 ppm.

FGR has been found to be less effective than LEA firing and staged combustion in coal-fired utility boilers. This ineffectiveness, in combination with its high costs, makes FGR an unattractive method for coal-fired utility boilers. For control of NO_x emissions from gas- or oil-fired utility boilers, however, this method has considerable potential.

Significant advances have been made in new burner designs. Full-scale tests have indicated that the Babcock and Wilcox dual-register burner is capable of reducing NO_x emissions by 50%, and laboratory results from an experimental burner have shown that NO_x emissions can be reduced to 150 ppm from about 900 ppm. Currently, advanced burner designs have been recognized as the simplest and most economical approach to NO_x emission control.

The costs for removal of NO_x from flue gases are generally an order of magnitude higher than those associated with reducing NO_x formation through alteration of combustion conditions. Consequently, less attention has been placed on the flue-gas-treatment approach. Although several potential flue-gas-treatment processes exist, no commercially demonstrated process for reducing NO_x emissions from coal-fired utility boilers is currently available.

However, at this time flue-gas treatment is capable of achieving the greatest reductions in NO_x emissions. This approach is therefore being considered as an "add-on" method to supplement combustion modification if and when higher removal efficiencies for NO_x are called for.

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4.4 DISPOSAL OF SOLID AND LIQUID WASTES

4.4.1 Summary

The increased use of coal for power generation will result in increased land requirements for the disposal of ash and sulfur abatement wastes as well as increased potential for contamination of water supplies.

Annual production of ash by the electric utilities is already approaching 60 million tons. Despite intensive efforts to increase utilization of

ash in the construction industry and for soil stabilization, more than 80% of the ash produced at the present time is merely ponded or used as landfill.

The major environmental problem in ash disposal is that the quantities of trace metals and dissolved solids in leachates and runoff from the disposal sites can exceed water quality criteria, sometimes by an order of magnitude. Attenuation of the leachate contents by percolation through soil is expected to provide substantial protection against contamination of aquifers by trace elements in some cases, but attenuation of some elements, such as selenium and boron, is known to be ineffective. In most cases, therefore, it will be necessary to install and maintain a suitable system of subsurface and trench drains to reduce the possibility of ground water contamination. Some control measures are already being employed by most utilities.

Land requirements for disposal of the ash from power plants are also significant. About 120 acres, ponded to a depth of 30 feet, are required for disposal of the 5 million tons of ash that might be accumulated by a 1000-MWe coal-fired power plant during its lifetime. Until recently ash ponds were merely abandoned, but reclamation is clearly desirable and will be required in most cases. Gradual development of a suitable vegetative cover should be possible if the landsite is carefully selected and the landfill is properly protected against erosion.

The use of lime or limestone scrubbing to control sulfur-oxide emissions from power plants adds a new dimension to waste disposal problems and dramatically increases land requirements and costs. The calcium solids produced in the scrubbing operation weigh close to five times as much as the sulfur in the coal and, additionally, exhibit a strong tendency to retain water. Fly ash is commonly collected with the scrubber solids or added afterwards to increase the solids content, but even then the mixtures cannot be dewatered by settling or filtration to the extent required to support equipment or structures. For a plant burning coal with 3% sulfur and 12% ash, the sludge/fly ash mixtures will typically retain an equal weight of water and require more than three times the amount of land for disposal than would ash alone. Leachates and runoff from the disposal ponds, like those from ash ponds, can result in contamination of water supplies with trace elements and dissolved solids. The problem is a serious one

because lime/limestone scrubbers are currently scheduled to be installed on 25,000 MWe of generating capacity by 1980, and could be required on all coal-fired power plants by legislation now pending.

In most of the FGD systems now operating, the sludge is discharged to an excavated pond without further treatment, but several options for mitigating the water-pollution or land-use aspects of disposal are available or under investigation. Leaching can be controlled by installation of an impervious liner in the pond. Clay liners, at a cost of about \$5/kW, are being installed in a few of the newer FGD systems. Other barriers, including heavy duty plastics at costs up to \$40/kW, are also being investigated, but the long term integrity of any liner remains an uncertainty.

A second approach that addresses both the permeability and the physical instability of the sludges is that of chemical stabilization. A number of recipes involving the addition of lime or cement have been concocted by the utilities, and proprietary additives are offered by several companies. After curing for a month or more, stabilized sludges exhibit permeabilities in the range of 10^{-6} cm/sec and compressive strengths of 300-400 psi. Sludges at five of the operating FGD systems are being stabilized. In the most ambitious project (the Bruce Mansfield plant of Pennsylvania Power Co.), thickened slurry is mixed with the stabilizing agent and pumped seven miles to a disposal area formed by constructing a 450-ft dam in a large ravine. The costs of stabilization and disposal are not well established, but a recent estimate equivalent to 0.9 to 1.4 mills/kWh indicates that they can contribute significantly to total FGD costs.

An alternative approach to waste disposal that is actively being investigated and shows promise involves oxidation of the spent (ash-free) scrubber liquor to convert the calcium sulfite to calcium sulfate. Since gypsum can be satisfactorily dewatered and disposed of, environmental problems would be eliminated if complete oxidation can be achieved.

Power plant liquid wastes that require control include blowdown and equipment cleaning wastes. Cooling tower blowdown water typically contains high concentrations of suspended and dissolved solids, and sometimes significant amounts of residual chlorine. Chromium, zinc, phosphate, or other corrosion inhibitors and biocides may also be found. The best available

treatment is lime-soda softening followed by reuse as makeup water. Boiler blowdown can be treated similarly.

Equipment cleaning waste originates mainly from boiler and boiler tube cleaning, and contains high levels of toxic chemicals. It appears that the necessary treatment steps will include pH adjustment, precipitation, sedimentation, filtration, ion exchange or reverse osmosis, and ammonia removal.

4.4.2 Fly Ash and Bottom Ash

4.4.2.1 Introduction

All coal-fired boilers produce ash in amounts depending on the inorganic mineral (ash) content of the coal being burned. This by-product has value as a utilizable raw material, but unfortunately only a minor fraction is marketed. The balance must be disposed of in a manner that will do the least environmental damage to the atmosphere, land, and water and will be at the same time reasonable in cost.

As the use of coal for electric power generation increases, so also will the annual production of ash -- for which utilities will need to find purchasers or else safe methods and sites for dumping. Added to this is the possibility, even likelihood, that more stringent regulations may require control measures to be instituted for reducing the environmental impact of the several hundred million tons of ash that were stockpiled (dumped) during the past several decades when pollution problems were of lesser priority.

Disposal of ash by landfill (the time-honored method) involves potential problems of pollution of surface and subsurface water. Leaching tests on ash samples from existing power plants suggest that runoff and seepage from ash dumps may exceed established water quality criteria with respect to concentrations of various chemical species, including toxic trace elements. Other problems associated with disposal by landfill are structural stability, wind erosion, and the unsightliness of the ash pile. Utilities are well aware of these problems; they and various other private and public institutions are developing and/or installing control technology to minimize or resolve them.

A great deal of R&D has been performed to investigate various end uses for ash. Significant beneficial uses have been developed, many of them of large-tonnage potential.

This section of the report assesses the current status of the disposal problem and the direction and promise of R&D designed to alleviate it. The report also assesses the current status, as well as progress and outlook, for utilization. Where appropriate, areas requiring further information, R&D, and/or assessment are identified.

4.4.2.2 Magnitude and Nature of the Problem

Quantities Expected

The amount of ash depends, of course, on the ash content of the coal, the amount of coal burned, and the efficiency of the ash collection devices.

Coals vary considerably in ash content. For example, coal burned at five utility stations was found to range from 10 to 25% ash.¹ As indicated in Table 4.17, the current average ash content of coal burned by utilities is about 15% by weight.

Greater efficiency of coal cleaning lowers the ash content considerably, but this is not expected to have a significant impact on the national ash-disposal burden within the next 5-10 years.

More than 90% of the coal currently used by electric utilities is burned in pulverized-coal boilers. In such boilers 70-80% of the ash is produced in the form of fly ash, which is carried out of the combustor in the flue gases and is separated from these gases by electrostatic and/or mechanical collectors. The remainder of the ash drops to the bottom of the furnace as bottom ash or slag. The amounts of each type of ash produced in the U.S. during several recent years are listed in Table 4.17. It is noted that the percentage of ash collected as fly ash has risen from 65% in 1971 to 71% in 1975.

As emission regulations were tightened in recent years, utilities installed more efficient ash collection devices. At one time an efficiency of 95% was considered satisfactory, but regulations now require 99% or higher.² It is conceivable that growing concern over the health hazards

associated with the emission of very fine particulates could lead to requirements for collecting 99.9% or more of the fly ash. Although this would add but little to the total bulk of ashes collected, it could exacerbate some of the ecological and pollution problems associated with disposal/utilization.³

Characteristics of Ash

The identities and concentration ranges of major chemical constituents in samples of fly ash and bottom ash from the region of southwestern Pennsylvania are listed in Table 4.18. The chemical compounds that are most abundant in the ash are the oxides of silicon, aluminum, and iron. Although a rather wide concentration range is indicated for each major constituent, the ranges listed for fly ash rather closely resemble those listed for bottom ash.⁴

Table 4.19 shows concentrations of selected trace elements in the coal, bottom ash, and fly ash at the R.A. Allen Steam Plant of the TVA in Memphis, Tennessee. The coal burned at this plant is a mix of coals from southern Illinois and western Kentucky containing about 12% ash (dry basis), and the boilers are of the cyclone-fed type. Analyses were performed on samples of fly ash obtained both upstream and downstream from the electrostatic precipitators.

Table 4.17 Megatons of Coal Ash Collected in the U.S.^a

Type	Year					
	1971	1973	1974	1975	1980 ^b	1985 ^c
Fly Ash	27.7	34.6	40.4	42.3		
Bottom Ash	10.1	10.7	14.3	13.1		
Boiler Slag	<u>5.0</u>	<u>4.0</u>	<u>4.8</u>	<u>4.6</u>		
Total	42.8	49.3	59.5	60.0	75.0	120.0
Coal Consumed	-	-	390	403		
Calculated Average Ash Content	-	-	15.3%	14.9%		

^aCompiled by National Ash Association and Edison Electric Institute.

^bProjection by R.E. Morrison, American Electric Power Services Co.

^cProjection based on expected doubling in coal-fired power generation, 1975-1985.²

Table 4.18 Major Chemical Constituents of Fly Ash and Bottom Ash from the Southwestern Pennsylvania Region ^a

Constituent	Fly Ash (% by Weight)	Bottom Ash (% by Weight)
Sulfur Trioxide	0.01-4.50	0.01-1.0
Phosphorus Pentoxide	0.01-0.50	0.01-0.4
Silica	20.1-46.0	19.4-48.9
Iron Oxide	7.6-32.9	11.7-40.0
Aluminum Oxide	17.4-40.7	18.9-36.2
Calcium Oxide	0.1-6.1	0.01-4.2
Magnesium Oxide	0.4-1.2	0.5-0.9
Sodium Oxide	0.3-0.8	0.2-0.8
Potassium Oxide	1.2-2.4	1.7-2.8
Titanium Oxide	1.3-2.0	1.3-1.8

^aA.M. DiGioia et al., cited by Ref. 4.

Of the trace elements measured, eight (As, Cd, Cu, Ga, Pb, Sb, Se, and Zn) were more concentrated (6- to 100-fold) in the fly ash than in the bottom ash, and tended to be more concentrated (4- to 5-fold) in the (presumably more finely divided) fly ash discharged up the stack than in that collected by the precipitator. Thirteen trace elements (Ba, Ce, Co, Eu, Hf, La, Mn, Rb, Sc, Sm, Sr, Ta, and Th) showed little preferential partitioning between the bottom ash and the collected or discharged fly ash. The elements Cr, Cs, Ni, U, and V showed behavior intermediate between the above groups. Mass balance calculations indicated that some of the Se, most of the Hg, and probably most of the Cl and Br went up the stack in the gaseous state.⁵

Hulett et al., also have studied fly ash from TVA's Allen Steam Plant.⁶ They found that particle compositions vary with particle size, and that the interior of a particle has a different composition than the surface. Iron and aluminum tend to concentrate in the interior, while sulfur (occurring as sulfate) seems to concentrate on the surface.

Fly ash agglomerate contains hollow spheres (cenospheres), which themselves are packed with smaller cenospheres that are in turn also packed with spheres 1 μ m or less in diameter.⁷ These systems of cenospheres are called plerospheres. The formation of the aluminosilicate plerospheres probably results from rapid differential heating of the noncombustible coal fraction and subsequent evolution of gas from thermal decomposition and dehydration.

Table 4.19 Concentrations of Selected Trace Elements in Coal and Ash at TVA's Allen Steam Plant ^a

Element	Element Concentration (ppm)			
	Coal ^b	Bottom ash	Inlet fly ash ^c	Outlet fly ash ^d
As	4.45	18	110	440
Ba	65	500	465	750
Br	3.7	2	~4	
Cd	0.47	1.1	8.0	51
Ce	8.2	84	84	120
Cl	914	<100	<200	
Co	2.9	20.8	39	65
Cr	18	152	300	900
Cs	1.1	7.7	13	27
Cu	8.3	20	140	
Eu	0.1	1.1	1.3	1.3
Ga	4.5	5	81	
Hf	0.4	4.6	4.1	5.0
Hg	0.122	0.028	0.050	
La	3.8	42	40	42
Mn	33.8	295	298	430
Ni	16	85	207	
Pb	4.9	6.2	80	650
Rb	15.5	102	155	190
Sb	0.5	0.64	12	55
Sc	2.2	20.8	26	36
Se	2.2	0.08	25	88
Sm	1.0	8.2	10.5	9
Sr	23	170	250	
Ta	0.11	0.95	1.4	1.8
Th	2.1	15	20	26
U	2.18	14.9	30.1	
V	28.5	260	440	1180
Zn	46	100	740	5900

^aAdapted from Ref. 5.

^bMixture of coals from southern Ill. and western Ky. Ash content ~12%.

^cCollected upstream from electrostatic precipitator.

^dCollected downstream from electrostatic precipitator.

Microcrystals observed on the surface of the cenospheres appear to contain high concentrations of calcium and sulfur (probably CaSO_4 or its dihydrate). It is suggested that these microcrystals are probably formed by the leaching of metal oxides in the ash by condensed sulfuric acid. In connection with health hazards associated with inhalation of fine particulates, these microcrystals may, because of their increased surface area and potentially toxic chemical composition, have biological implications more critical than expected for the cenosphere material.⁷

The significance of the compositions and properties of the various components of ash will be discussed in subsequent sections on disposal and utilization. Suffice it to say here that the disposal technology chosen and the hoped-for end use will need to be based on specific chemical and physical characteristics of the ash produced at each site.

4.4.2.3 Ash Disposal Technology

The principal means of ash disposal in the electric utility industry is a landfill operation that involves dumping the ashes into shallow ponds or lagoons, usually on the site of the plant where the ashes are produced. This practice can result in serious degradation of the land if the filled lagoons are not subsequently reclaimed or the contents sold for industrial utilization.

Reclamation has not been practiced much in the past, but with increasing concern for the environment greater care will have to be given to site selection, to management of the landfill, including monitoring for potential water pollution, and to functional and aesthetic restoration of the dump after it is filled.

Pollution from Ash Dumps

Leaching by percolation of rain, melted snow, or surface runoff represents the greatest pollution threat posed by ash dumps. In fact, it is a threat wherever ashes are exposed to rain or surface water. However, ash that is hauled away and put to use in embankments, road and base construction, and the like (where it is spread or mixed with soil, sand, gravel, and/or stabilized by cementitious reactions) will yield a leachate that is less apt

to be saturated and is more readily attenuated by the underlying or adjoining soil. Moreover, in such applications, the elements being leached will probably be exhausted in some reasonably short time.

Table 4.20 compares the equilibrium concentrations of various trace elements in ash leachates from five different power plants with the various water quality standards.¹ Concentrations that exceed one or more of the standards are encircled in the table. Note that the concentrations of As, Ba, B, Cr, Hg, Mo, and Se exceeded one or more of the water quality criteria at one or more of the power plants. The pH of the leachates studied ranged from 8.2 to 12.5.

The leachability of a given species in the ash will be determined largely by its solubility. Generally about 2-5% of fly ash is water-soluble.⁸ The resulting solution is usually alkaline due to the effect of free lime, although some ashes, especially from eastern coals, produce acidic leachates. These acidic liquors often exceed stream criteria with respect to sulfate, total iron, zinc, lead, cadmium, and manganese, but they are usually acceptable with respect to copper.

Aside from solubility, another factor influencing the leachability of ash is the possibility that some of the solubles may become fixed by participation in a pozzolanic reaction.⁹

The engineer in charge at an ash dump has recourse to several options to reduce potential contamination of groundwater by leachate. Among these are:

1. Excluding, intercepting or diverting all or part of the surface flow and subsurface water.
2. Maintaining a suitable system of subsurface and trench drains.¹⁰

Attenuation of the leachate contents by percolation through soil is expected in many cases to provide substantial protection against trace elements reaching an aquifer.¹ Laboratory attenuation (percolation) data obtained on soils at utility stations indicate that after 10 years of continuous flow, the level of chromium and selenium (at soil depths of 30-50 ft) would still be 95% less than it is in the original ash leachate. Boron and arsenic were also significantly sorbed by the same soil.

Table 4.20 Equilibrium Concentrations of Trace Elements in Coal Ash Leachate¹

	Station Number					Water Quality Criteria ^a		
	1	2	3	4	5	Surface Water FWPCA (mg/l)	Irrigation FWPCA (mg/l)	Public Water Supply Intake EPA (mg/l)
Bottom Ash (wt %)	20	20	20	50	100			
Precipitator Ash (wt %)	80	80	80	50	--			
pH	12.5	9.5	12.2	12.0	8.2			
Element (ppm)								
Sb	.006	.013	.033	.022	.0087	--	--	--
As	<.002	.084	.015	.072	.006	0.05	1.0	0.1
Ba	.40	<.3	<.3	<.3	<.3	1.0	--	--
Be	.003	.00064	.0007	.001	.00026	--	--	--
B	.03	16.3	.21	1.1	.048	1.0	0.75	1.0
Cd	<.001	.0025	<.01	<.001	.0011	0.01	0.005	0.01
Cr	<.001	.21	.11	1.0	.014	0.05	5.0	0.05
F	2.3	1.4	2.0	17.3	1.4	--	--	--
Ge	<.01	<.01	<.01	<.01	<.01	--	--	--
Hg	.0006	.0005	.015	.0003	.0003	--	--	0.002
Pb	.0068	.0027	.024	.0043	.0063	0.05	5.0	0.05
Mn	<.002	<.002	<.002	<.002	<.002	0.05	2.0	--
Mo	.047	.052	.05	.69	.010	--	0.005	--
Ni	<.05	.015	.025	<.05	.046	--	0.5	--
Se	.009	.0005	.033	.47	<.0005	0.01	0.05	0.01
V	<.1	<.1	<.1	<.2	<.1	--	10.0	--
Zn	.038	.025	.19	.005	.0175	5.0	5.0	5.0
Cu	<.005	.031	.092	.013	.015	1.0	0.2	1.0

^aFWPCA = Federal Water Pollution Control Administration.

The EPA is funding a TVA study that will: (1) assess the effect of pH adjustment on the leaching of ash dumps, (2) define sampling and analytical procedures for effective monitoring of ash dumps, (3) characterize and quantify the effects of coal ash leachate on groundwater quality, and (4) study fly-ash handling systems and methods of disposal, utilization, and treatment. ERDA has indicated that leaching from ash dumps will continue to be of interest.¹²

Controlling Erosion of Ash dumps

The following guidelines have been given for protecting ash dumps from erosion and liquefaction:⁹

1. Control internal erosion by making use of a properly designed drainage and filter system to ensure that fine material is not carried off by seepage water.
2. Control external erosion by providing a suitable vegetative cover on the downstream slope and slope protection on the upstream slope. Adequate spillway or runoff diversion capacity should be provided and maintained.
3. Control liquefaction by good compacting and proper drainage.

On the downstream slope it would be sufficient to cover the compacted ash with gravel and topsoil, followed by seeding with a close-turfing grass. The upstream slope can be protected against erosion by a protective blanket consisting of an impervious clay-shale layer on a rock-fill layer, or else a fine-rock layer.

Ash deposited in lagoons may pose a dust hazard as the material dries out. The small, hollow cenospheres have a low density and are susceptible to wind erosion. Proper compaction of the ash helps to prevent this. Also, in some instances, the ash tends to form a skin that, if undisturbed, protects it against blowing. Spraying the surface with polymer emulsions is also effective in preventing wind erosion. Long-term control is best achieved by establishing a suitable vegetative cover.¹³

Reclamation of Ash Piles

Ash does not readily support plant growth. This is due partly to lack of the necessary nutrients (a need that can be supplied by application of fertilizers) and partly to the presence of inhibiting elements such as boron. Yet natural colonization of an ash surface by vegetation often takes place. The first plant to appear is usually a moss, which can cover a moist ash surface within six months and which effectively binds together the ash particles to inhibit erosion. A common weed is usually the next colonizer to appear, and this can be followed by a range of other plants.¹³

Tests on ash piles have shown that boron may be 20 times as available in fresh ash as it is in a normal soil. Chemical treatments for removing the excess boron proved to be too expensive. Fortunately, various useful plant species tolerate ash conditions. The clover family is, in general, quite tolerant. Some grasses, particularly rye grasses, are tolerant. Of the arable crops, those of the beet and cabbage families do well. Sugar beets, fodder beets, and mangels benefit from the boron in the ash, provided it is not too high. Considerable success has been obtained with rye and wheat on a field scale, and (at a later stage) even with the relatively intolerant barley.¹³ Of course, if the ash can be covered with topsoil to a depth of perhaps 12 inches, then a great range of crops can be grown on the site. However, cost usually makes this tactic impractical.

A variety of trees (alder, honey locust, spruce, poplar, and willow) are tolerant to ash conditions, but their growth is not sufficiently vigorous to sustain commercial timber production. A number of shrubs can also be grown on ashes. Thus it should be possible to landscape an ash disposal site with these tolerant species.¹⁴

Other Methods of Ash Disposal

Direct deposition of ashes in underground mines is a possible disposal option. Filling of deep mines with power plant ash has been used as a mine subsidence prevention technique.⁸ The feasibility of this approach is currently being investigated by the Bureau of Mines for disposal of lime/lime-stone scrubber sludges.

Another possible method of ash disposal that is partly dumping and partly beneficial use would be the utilization of ashes in the rehabilitation

of areas which have been desecrated by strip mining, quarrying, and the like. It has been suggested that in these cases the cost of ash disposal could be shared by the utilities and other organizations (presumably the original desecrators, land developers, or local governments).⁹

Conclusions

Subject to the findings of ongoing R&D, it seems reasonable to conclude at this time that while disposal of ash continues to pose an environmental problem, the problem is not much worse than other waste disposal situations and is one that can be managed by careful monitoring and by optimum employment of currently available technology.

4.4.2.4 Utilization of Ash Wastes

Commercial use of ashes is an attractive alternative to disposal by dumping or landfill. First, it represents a means of alleviating the ecological impact resulting from disposal of ashes in lagoons or land sites. Second, to the extent that the ashes are sold or given away to be put to some practical use, it reduces disposal costs. Third, there are technical as well as economic advantages to the user who utilizes ash as a raw material, e.g., for structural compositions, pavings, etc.

Industry, governmental agencies, universities, and other nonprofit institutions have over the years conducted and/or sponsored extensive investigations aimed at developing and perfecting various beneficial end uses for coal ash. As noted in the following pages, these efforts have borne fruit.

For the past 10 years, the National Ash Association has fostered development of markets for power plant ash and promoted its use for new applications. The NAA is a trade association sponsored by 30 of the electric utility companies of the nation, some coal companies and the National Coal Association, some university faculty members, and an impressive number of industrial firms active in utilizing ash and/or doing research on its uses.

If full usage of ash does not eventually become a reality, it will not be for lack of effort by organizations such as the NAA, the Bureau of Mines, Dept of Transportation, the EPA, and various state and local governmental agencies, as well as commercial ash-utilization firms.

Extent of Utilization

European countries utilized a major fraction of their national production of fly ash in 1971 (79% in the Federal Republic of Germany, 65% in France, 54% in the United Kingdom, 44% in Belgium, and 44% in Poland).³

In contrast, U.S. utilization in the past three years was only 14-17%. However, it is encouraging to note the growth in actual tonnage of ash consumed in beneficial end uses. The tonnage utilized in 1975 was over three times that utilized in 1966 (9.8 compared to 3.1 million tons), even though the percent utilization showed only a modest increase (from 12.1 to 16.4%). Thus as the production of ash expands over the next few years, a greater tonnage may be utilized -- but not necessarily a higher percentage.

As seen from the data in Table 4.21, specific end uses can be identified for about 45% of the fly ash utilized, 48% of the bottom ash, and 80% of the boiler slag; the balance in each instance is identified either as "ash removed from plant sites at no cost to utility" or as "ash utilized from disposal sites after disposal costs." However, all these categories represent ash for which the utilities are no longer responsible and which no longer poses a disposal problem for them.

The bulk of the ash sold in the U.S. is marketed by a relatively few companies specializing in the promotion and sales of ash -- or by utility companies that have their own active sales organizations.³ Collins¹⁵ suggests that tax reductions, increased subsidies, or reduced transportation costs might be used as incentives for the expanded use of recyclable materials such as fly ash.

The Markets

The construction industry currently consumes the largest amount of fly ash. As Table 4.21 shows, one of the main markets for ash is its use as a component in portland cement compositions. Another is its use for soil stabilization and in pavements. Blast grit and roof granules constitute another substantial market.

Table 4.21 Commercial Utilization of Ash in the U.S. in 1975^a
(Kilotons)

Use	Fly Ash	Bottom Ash	Boiler Slag
Type 1-P Cement	225	70	36
Partial Substitute for Cement	945	-	-
Lightweight Aggregate	90	35	-
Stabilization & Roads	450	525	72
Filler in Asphalt Mix	135	-	-
Ice Control	-	280	54
Blast Grit & Roof Granules	-	420	864
Misc.	180	350	414
Ash Removal at no Cost to Utility ^b	1,080	875	270
Ash Utilized ^b from Disposal Sites	<u>1,395</u>	<u>945</u>	<u>90</u>
1975 Total Utilized	4,500	3,500	1,800

^aCompiled by the National Ash Association and Edison Electric Institute.

^bSpecific end use not known.

Cement and Concrete. Blended cements are usually made by inter-grinding cement clinker with industrial by-products such as fly ash or granulated blast-furnace slag. Fly ash is attractive for this purpose because it is widely produced in large amounts and in a form that is usually immediately suitable for the purpose.

Research by the Bureau of Reclamation showed that replacement of 15-30% of cement in normal density concrete by fly ash improves sulfate resistance of test specimens by an average of 50-100%¹⁶ and prevents or greatly retards corrosion of the reinforcing steel.¹⁷ During the last 20 years at least 50 dams, or locks and dams, were built that employed fly ash in the concrete used in their construction. For example, the Dworshak Dam in Idaho required 7.5 million cubic yards of concrete that consumed 250,000 tons of fly ash.¹⁸

There are several economic and ecological advantages in utilizing fly ash as a substitute for part of the cement used in concrete construction.

1. Cost. Where the delivered price of cement is about \$30/ton, fly ash will cost \$6-\$7/ton.
2. Convenience. It takes less pouring time and less finishing time than does standard concrete.¹⁹
3. Conservation. There is a considerable saving in energy (1,300 kWh/ton for cement vs. nominal kWh/ton for waste fly ash).²⁰ The savings are almost directly proportional to the degree of ash substitution.²¹
4. Expands production. Plant capacity is extended with practically no investment in new facilities.

Aggregates for Lightweight Concrete. A considerable quantity of fly ash was utilized in 1975 for producing lightweight concrete, and this use is expected to expand rapidly. Its resistance to freezing and thawing makes lightweight aggregate prepared from sintered fly ash more valuable to road-builders and to the concrete construction industry.²² The sintered ash is produced by heating pelleted fly ash at about 2300°F. Incidentally, carbon impurities (unburnt coal and soot) in the fly ash act as fuel to supply part of the heat. Pelleting is necessary to control dust emissions during the sintering.

Lime- and Cement-stabilized Fly-Ash Pavements. The use of lime/fly-ash aggregate (LFA) and lime/cement/fly-ash aggregate (LCFA) mixtures in pavement construction has increased substantially during recent years. During 1971, nearly 2 million tons of LFA materials were placed in the United States, with over 1 million tons placed in the Chicago area alone. Perhaps the largest job utilizing LFA and LCFA materials was the construction in 1967 of the Newark Airport. More than 2 million tons of LFA and LCFA were used as base materials for the runway and taxiway systems serving jumbo jets. Five years later the pavements were observed to be in excellent condition.

Asphalt Pavements. In general, power plant aggregates (ash and slag) can be successfully used in asphaltic compositions.²³ The advantages of fly ash as mineral filler in asphalt paving are lower cost, acceptable size, gradation without processing, and superior resistance to water.¹⁹

Road Fill. The light weight of fly ash makes it extremely attractive as road fill, especially when embankments have to be constructed over poor ground, such as alluvial clay or silt, where excessive weight might cause settlement beyond allowable limits and, in the worst case, could produce a complete failure of the subsoil.

The wet weight of fly ash per compacted cubic yard is between 0.9 and 1.1 tons, depending on the source and moisture content of the material. This compares very favorably with the weight of traditional filling material.²²

Slag as Anti-skid Agent. Boiler slag has been used with some success in West Virginia in deslicking applications. The dramatic reduction shown in the reported accident data before and after deslicking is evidence of the anti-skid characteristic of this mixture.²⁴

Sand-Blasting Grit. Significant amounts of bottom ash and boiler slag are being used for this purpose.²⁵

Load-bearing Fill. Because of its high load-bearing capacity, fly ash is often used as load-bearing structural fill for industrial buildings, schools, etc. Its light weight and self-hardening properties make fly ash an ideal construction raft for building development over poor ground.

Settlement is reduced to a minimum; the hardened fly-ash raft forms a monolithic structure that can then bridge weak spots in the subgrade and thus reduce differential settlement.²²

Recently, the Central Illinois Light Company blended 400,000 cubic yards of weak loess clayey-silt soil with 3% lime and 5% fly ash to provide a base on which to place a 7-foot-thick concrete slab to support the boiler and turbine generator of a 400-MWe power plant.²⁴

Brick. Extensive R&D has been conducted on fly-ash brick by the Coal Research Bureau of West Virginia University (CRB/WVU) -- an effort that was crowned by commercial success. A fly-ash brick plant designed to produce 35 million bricks yearly, using a process developed at the CRB/WVU, is operating at Edmonton, Alberta. The demand for fired products from fly ash has led to the construction of a second plant for the manufacture of paving tile. Further expansion is reportedly being considered for this plant. However, efforts to expand the use of fly ash in the manufacture of ceramic brick in the U.S. have not resulted in consumption of substantial quantities.

Miscellaneous Uses. Other actual or potential uses for fly ash, bottom ash, and/or boiler slag are:

1. As an agricultural soil amendment.
2. As a component of grout.
3. In production of mineral wool.
4. As a filler or extender in a variety of materials.
5. For extinguishing burning spoil piles.
6. As a source of chemicals (sulfur, alumina, iron oxide, etc.).

R&D. A number of federal government agencies have initiated research programs to investigate possible uses of various wastes in construction. For example, the Federal Highway Administration has sponsored programs investigating sulfate wastes, fly ash, and bottom ash. EPA has funded research on the combined use of fly ash and coal waste as base-course material and an evaluation of various processes to stabilize chemical sludges. The Bureau of Mines research program is aimed at developing new and improved ways (some of which utilize ash) to stabilize, reclaim, or utilize mineral wastes.

The Federal Energy Administration has funded an investigation of the engineering properties of concrete mixes made from low-percentage blended cements using various types of fly ashes, slags, and cement-kiln dusts. ERDA is studying the economic and energy-saving aspects of increased use of blended cements.

Impact of Flue Gas Desulfurization and Fluidized-bed Combustion

Where coal-fired power plants are equipped with *FGD* scrubber systems employing lime or limestone, the disposal of ashes is usually linked with disposal of the spent sorbent (sulfited and sulfated stone). As pointed out in Section 4.4.3.2, the scrubber effluents can contain varying amounts of fly ash, and additional fly ash is sometimes added to improve the rate of drainage of excess water from the waste sludge, and also to improve its physical strength. In fact, most fixation recipes designed to stabilize and solidify the partially dewatered sludges utilize fly ash for its pozzolanic (cement forming) properties.

Ashes produced by an *FBC* unit are apt to be "contaminated" with some spent sorbent, which consists mainly of calcium sulfate, lime and limestone (plus some magnesia in the case of dolomite). Such contamination may for some end uses be beneficial (e.g., landfill revegetation, reclamation, base-course paving), while in other end uses it would probably be harmful (e.g., concrete, concrete block, cement, etc.). For example, ASTM C618 limits the SO_3 (sulfate) content of fly ashes for use in concrete to 5%. Furthermore, *FBC* ashes may cause "unsoundness" because of their content of CaO and MgO . These compounds will slowly hydrate after the cement paste matrix has hardened. The products of the hydration have significantly larger volumes than the initial compounds. These increases in volume result in internal stresses that may eventually cause total disruption of the hardened cement.

Pollution Accompanying the Utilization of Ashes

Dust. Control of dust will always be necessary wherever dry fly ash is handled. Hauling waste ash, even dampened fly ash, in open-bodied dump trucks will not be tolerated much longer. Tank trucks would minimize the dust problem.²⁶

Dust is a threat in the sintering of fly ash for use in synthetic aggregates. However, this nuisance can be controlled by spraying with water; by adjustment of flow, pressure, and moisture; and by dust collection systems.¹⁹

Leaching. The leaching of compositions containing ash may not be a serious problem, because the ash is either well diluted with soil or other ingredients that may attenuate the more harmful components of the leachate, or the ash is stabilized (rendered less soluble and/or unavailable) by cementitious reactions. However, the leaching aspect certainly needs to be more fully investigated.

4.4.3 *Flue Gas Desulfurization (FGD) Wastes*

4.4.3.1 *Introduction*

Lime/limestone scrubbers have been selected for a large fraction of installed and planned FGD systems. They are scheduled to be installed on 5500 MWe of capacity by the end of 1976, and on more than 30,000 MWe of capacity by the end of 1980.²⁷ Large quantities of watery wastes will be generated in the operation of these scrubbers, and their disposal presents major problems with respect to land use and water quality. The raw sludges usually cannot be dewatered sufficiently to support people or equipment and must be disposed of by ponding. Reclamation of the disposal ponds may be impossible unless the wastes can be permanently stabilized by chemical fixation. In addition, overflow and leaching from the ponds can contaminate water supplies with soluble species present in the waste liquor and the settled solids.

The objectives of this report are: (1) to define the physical and chemical characteristics of the wastes and the magnitude of the disposal problem, (2) to assess the environmental acceptability and costs of available and developing technology for disposal or utilization, and (3) to identify information gaps and needed research or development.

1.4.3.2 Characterization of FGD Wastes

One aspect of lime/limestone scrubber wastes that importantly affects disposal/treatment options is their diversity. There is no such entity as a typical sludge. All of the sludges contain calcium sulfite ($\text{CaSO}_3 \cdot \frac{1}{2}\text{H}_2\text{O}$) and calcium sulfate ($\text{CaSO}_4 \cdot 2\text{H}_2\text{O}$) as principal components, and some also contain unreacted limestone (CaCO_3) and/or fly ash, but the proportions of the solids vary widely.²⁸ The predominant species can be either calcium sulfite or the sulfate depending upon the sulfur content of the fuel and the mass transfer characteristics of the FGD systems.²⁹ Oxidation of the sulfite to sulfate is more extensive at low inlet concentrations of SO_2 where the slurries are subjected to more recirculation and aeration before being discharged.

The degree of oxidation in the FGD system is quite important because the dewatering characteristics of the sludges are determined largely by their calcium sulfite content.³⁰ $\text{CaSO}_3 \cdot \frac{1}{2}\text{H}_2\text{O}$ tends to crystallize in the form of small platelets that entrap water and make it difficult to remove by physical means. $\text{CaSO}_4 \cdot 2\text{H}_2\text{O}$, on the other hand, forms large blocky crystals that are more readily dewatered. Wastes in which the calcium sulfate predominates therefore present fewer problems in disposal.

Bulk Components

Due to the pattern of FGD usage in the East and the West (Section 4.1) and to the sulfur contents of the respective coals, the sludges tend to fall into two broad categories. Sulfate-rich sludges (>70% oxidation) are typical in applications to low sulfur (<1% S) coal. Sulfite-rich sludges (<30% oxidation) are the norm in high sulfur (>3% S) systems unless oxidation is deliberately promoted.²⁹ This pattern shows up clearly in Table 4.22 which presents the composition of the sludges produced at selected FGD installations. The unusually low degree of oxidation at Paddy's Run has been ascribed to the presence of an inhibitor in the carbide lime used as sorbent. Table 4.22 also provides some indication of the quantities of fly ash and unreacted limestone that can be present. In most of the installed FGD systems (but not that at Paddy's Run) the bulk of the fly ash is collected in the scrubber system and is discharged with the calcium solids. Conversely, in most of the FGD systems under construction or planned the fly ash will be collected by an upstream electrostatic precipitator.³¹ In addition to simplifying scrubber operations, this makes it possible to add dry fly ash

Table 4.22 Composition of Sludges from Operating SO₂ Scrubbers

Facility	Coal (%S)	<u>Weight Percent, Dry Basis</u>				Solids Content ^a (wt %)
		CaSO ₃ ·½H ₂ O	CaSO ₄ ·2H ₂ O	CaCO ₃	Ash	
Paddy's Run	3.5-4.0	94	2	0	4	40
La Cygne	5.3	40	15	30	15	35
Shawnee	2.9	40	10	10	40	45
Cholla	0.4-1.0	15	22	3	60	50
Lawrence	0.5	10	40	5	45	50

^aDewatering by filtration at Paddy's Run, by ponding at other facilities.

to the separately dewatered calcium solids and thus reduce the ultimate moisture content of the waste and the quantity of additive required for fixation.

Water Content

The lime/limestone slurries withdrawn from the reaction tank usually have a solids content of about 10%. In some cases they are pumped directly to the settling pond, but usually they are routed to a clarifier for preliminary dewatering. This not only reduces the acreage required for the pond, but can also increase the solids content of the slurry to a point where chemical treatment is practical. Flocculants are sometimes added to increase the rate of settling and decrease the size of the clarifier, but they do not significantly increase the solids content of the underflow.²⁹ In a number of the more recent FGD installations the clarifier underflow is further dewatered by centrifugation or vacuum filtration to facilitate chemical stabilization.

The degree of dewatering achieved by these steps depends upon the composition of the wastes.³⁰ Sulfite sludges can be dewatered in a thickener to 35-45% solids, and settling will not significantly increase the solids content. Sulfate sludges can be dewatered to 45-55% in a thickener and to 60-65% solids by settling. Centrifugation or vacuum filtration can increase the solids content to 50-55% for sulfite sludges and to 75% for a sulfate sludge. The presence of significant amounts of fly ash slightly alters the dewatering characteristics, increasing the solids content of sulfite sludges, but decreasing the solids content of sulfate sludges.

Still lower moisture contents can be achieved thermally in kiln or thermal disc dryers.³² Under these conditions air voids are created within the solids, and the volume of the wastes can be reduced by compaction. Rewatering of solids dried thermally or by filtration occurs if they are exposed to moisture.³⁰

Trace Components

The chemical characterization of FGD wastes must also include the dissolved species in the scrubber liquors that constitute the residual moisture in the sludges. It is important to recognize that the occlusion of

scrubber liquor in the sludge is the only way to purge dissolved solids from the FGD system when it is operated with a closed water loop (without a discharge stream or an increase in circulating volume). It follows that the concentrations of soluble species in the scrubber liquors will be higher if less liquid is removed with the solids, as in a low sulfur system or by more effective dewatering.³⁰

The concentration ranges of some species in FGD effluents taken under closed-loop conditions from the Shawnee Plant of TVA, the Cholla station of Arizona Public Service, and the Phillips Station of Duquesne Light are shown in relation to Public Water Supply Intake criteria in Table 4.23. The concentrations of several elements (arsenic, boron, cadmium, chromium, lead, mercury, and selenium) are seen to exceed the water quality criteria, in some cases by more than an order of magnitude. The chemical oxygen demand (COD), total dissolved solids (TDS), and the high levels of sulfate, chloride, calcium, and magnesium are additional sources of potential pollution.³⁴ A developing trend toward use of lime enriched with magnesia adds to the problems.

Physical Properties of Untreated Wastes

The physical properties of untreated FGD wastes, such as viscosity, load bearing strength, bulk density, permeability, and porosity, are determined largely by their moisture content.³⁰

The viscosity of slurries containing 30-50% solids, as in clarifier underflows, is sufficiently low (≤ 20 poise) that they can be pumped.³⁵ At the Bruce Mansfield plant of Pennsylvania Power Company thickener underflow containing 30% solids is mixed with a fixative and pumped seven miles to the disposal site, a 1400 acre impoundment formed by constructing a 480-ft dam in a large ravine.³² Wastes with a solids content greater than 50% are generally very difficult to pump.³⁴

The load bearing characteristics of untreated lime/limestone wastes are strongly dependent upon their moisture content.³⁰ Sludges with a solids content of 50-60% are thixotropic, reliquifying when subjected to vibration or stress. At 65% solids they will support personnel (5-10 psi), and at 70% solids they will support heavy equipment and light construction (> 25 psi). A filtered sulfate sludge, at 75% solids, is thus capable of being used as landfill if it is compacted and otherwise protected from exposure to water.³⁰

Table 4.23 Range of Concentration of Constituents
in Scrubber Liquors³³

Constituent	Range of Concentration (mg/l)			EPA Public Water Supply Intake Criteria 1973
Aluminum (Al)	0.03	to	0.3	
Antimony (Sb)	0.09	to	2.3	
Arsenic (As)	< 0.004	to	0.3	0.1
Beryllium (Be)	0.002	to	0.14	
Boron (B)	8.	to	46.	
Cadmium (Cd)	0.004	to	0.11	0.01
Calcium (Ca)	520.	to	3000.	
Chromium (Cr)	0.01	to	0.5	0.05
Cobalt (Co)	0.10	to	0.7	
Copper (Cu)	< 0.002	to	0.2	1.0
Iron (Fe)	0.02	to	8.1	
Lead (Pb)	0.01	to	0.4	0.05
Magnesium (Mg)	3.0	to	2750.	
Manganese (Mn)	0.09	to	2.5	
Mercury (Hg)	0.0004	to	0.07	0.002
Molybdenum (Mo)	0.91	to	6.3	
Nickel (Ni)	0.05	to	1.5	
Potassium (K)	5.9	to	32.	
Selenium (Se)	< 0.001	to	2.2	0.01
Silicon (si)	0.2	to	3.3	
Silver (Ag)	0.005	to	0.6	
Sodium (Na)	14.0	to	2400.	
Tin (Sn)	3.1	to	3.5	
Vanadium (V)	< 0.001	to	0.67	
Zinc (Zn)	0.01	to	0.35	5.0
Chloride (Cl)	420.	to	4800.	250.
Fluoride (F)	0.07	to	10.	
Sulfite (SO ₃)	0.8	to	3500.	
Sulfate (SO ₄)	720.	to	10,000.	250.
Total Dissolved Solids (TDS)	3200.	to	15,000.	
Chemical Oxygen Demand (COD)	60.	to	390.	
pH	3.0	to	10.7	5-9

The dry bulk densities of untreated wastes range from 0.75 to 1.0 g/cm³ (47-63 pcf). Wet bulk densities vary with dewatering practice, from 1.45 g/cm³ (90 pcf) for a settled sludge with 50% solids to 1.65 g/cm³ (103 pcf) for a filtered sludge with 65% solids.³⁵ The porosity can vary from 48 to 75%.

Permeability of untreated sludge is approximately 10⁻⁴ to 10⁻⁵ cm/sec (10-100 ft/yr), similar to that of ponded fly ash. The settled sludge thus offers little resistance to the migration of dissolved solids to underlying soil.³⁵

4.4.3.3 Chemical Treatment of FGD Wastes

The quality of lime/limestone scrubber wastes can be improved in two distinct ways, by oxidation to gypsum or by chemical stablization.³²

Oxidation

In Japan, where FGD-derived gypsum is marketable, efforts have been concentrated on oxidation. Most of the FGD systems in use there have been designed or modified so as to produce gypsum.³⁶ In some systems the precipitated calcium sulfite/sulfate mixtures are forcibly oxidized, whereas in others the oxidation step has been integrated into the FGD process and occurs prior to precipitation of the calcium-sulfur product.

In the U.S., where it is unlikely that significant amounts of FGD-derived gypsum could be marketed in competition with the natural product, oxidation of scrubber wastes has received little attention. None of the commercial FGD systems in the U.S. features deliberate oxidation, but a demonstration of the gypsum-producing Chiyoda 101 process that was developed in Japan is underway on a 20-MWe scale at the Scholz station of the Gulf Power Company.³⁷ Forced oxidation of lime/limestone scrubber effluents is being investigated at the pilot plant level by EPA and at the Shawnee Test Facility by TVA.³⁸ Even if FGD-gypsum cannot be sold or otherwise utilized, its production could prove to be a cost effective approach to environmentally acceptable disposal of FGD wastes.³²

Fixation

Most of the efforts in the U.S. to improve the quality of the wastes have involved chemical fixation.³² A number of processes have been developed

for increasing the load bearing strength of the sludges and decreasing their permeability and tendency to rewater. Proprietary formulations and/or fixation services are marketed by several firms and some recipes have appeared in the open literature.

The fixation processes operate in different ways, utilizing fly ash, lime, silicates, and/or polyvalent metal ions to form low grade concretes.³⁹ In general, the objective is to solidify the sludges by promoting pozzolanic and other cementitious reactions between lime compounds in the additives, alumina/silica in the fly ash, and calcium-sulfur compounds in the sludge.

Some of the fixation techniques can be applied to thickener underflows containing as little as 30% solids, but additional dewatering decreases the amount of additive required and increases the strength of the product.²⁹ For sludges with a moisture content of 50-60%, the quantity of additive required is usually 5-10% by weight of the dry sludge solids.³⁹ The fixation of vacuum-filtered lime and limestone wastes by addition of 3-5% lime and various quantities of fly ash has been reported recently.²⁹ The solidification of the wastes generally occurs over a period of time that varies with the nature of the fixation process and the ambient temperature.⁴⁰ In some cases a month or more is required for curing.

Representative of the recipes that have been published are two that have been used by Commonwealth Edison Company at its Will County plant:

1. Addition of 100 lb portland cement plus 400 lb fly ash per ton of dry sludge solids.
2. Addition of 200 lb lime plus 400 lb fly ash per ton of dry sludge solids.

At present, the latter recipe is being used and solidified wastes from the disposal pond are being transported, at a cost to the utility of \$2.35/ton, to an offsite landfill approved by the EPA.^{32,41} A systematic study of stabilization with lime and fly ash was recently carried out by Combustion Engineering, Inc. to characterize the load bearing properties of lime and limestone sludges that had been dewatered by vacuum filtration and treated with 3-5% lime and varying quantities of fly ash.²⁹

Properties of Treated FGD Wastes

Information on the physical and chemical properties of treated FGD wastes is being compiled in a number of EPA-sponsored programs.⁴² Field

evaluations of sludges treated by the Chemfix, Dravo, and IU Conversion Systems (IUCS) processes are being conducted at Shawanee by TVA/Aerospace.⁴³ Field and laboratory evaluations of stabilized and unstabilized sludges are also being carried out at Paddy's Run by Louisville Gas and Electric and Combustion Engineering, Inc.⁴² At the U.S. Army Engineering Waterways Experiment Station (WES) physical and chemical analyses are being performed on sludges from three different FGD processes treated in each case by five different fixation processes.⁴⁴

Preliminary results obtained in these studies indicate a marked variation in properties of the treated sludges with the nature of the fixation process.³⁵ Compressive strengths observed in field studies of the treated sludges ranged from 25 psi to 400 psi, much lower than values obtained in controlled laboratory tests, but at least adequate for the support of heavy equipment. The porosity in some cases was reduced significantly, to 35-55%, while other processes produced a solid with a virtually unchanged porosity of 70-75%. The permeability of the treated sludge was reduced by less than a factor of two in some cases, but by several orders of magnitude in others.³⁵

Weathering such as freezing and thawing has been reported to break up the structure of some treated wastes.⁴⁴ The permeability of several treated wastes that were mechanically fractured and powdered to simulate extensive weathering exhibited permeability values approximately the same as for untreated wastes. Fracturing (but not powdering) and compacting resulted in about one order of magnitude reduction of permeability relative to the powdered condition.³⁵

Leaching studies indicated that fixation reduced the concentration of dissolved solids in the first pore volume of leachate by about 50%.³⁵ After passage of 3-5 pore volumes, concentrations of dissolved solids in leachates of treated sludges were about 25-50% of those observed for untreated sludges and remained constant, reflecting the solubility of bulk components, chiefly gypsum. The effects of chemical treatment on immobilizing trace elements was not discernible; in certain cases the fixatives appeared to be contributing trace metals to the leachate.

4.4.3.4 Quantities of FGD Wastes

The amount of sludge produced at a power plant equipped with lime/limestone scrubbers is determined by the amount and sulfur content of the coal burned, the fraction of SO_2 removed, the degree of oxidation of the calcium sulfite, and the amounts of unreacted sorbent, fly ash, and residual moisture that are present.

It can be readily calculated that the weight of dry calcium solids produced by a limestone scrubber operating with a 20% excess of sorbent (96% purity) and a removal efficiency of 85% will range from 4.1 to 5.2 times the weight of sulfur in the coal depending upon the degree of oxidation. For 20% oxidation, as typical of a high sulfur system, the weight percent of dry calcium solids will be about 4.3 times the percentage of sulfur in the coal. (A lime scrubber operating with a stoichiometric amount of sorbent and a removal efficiency of 90% will produce about 10% less calcium solids). Limestone scrubbing applied under these conditions to a coal containing 3% S and 12% ash would thus yield calcium solids with a dry weight 13% that of the coal. If all of the ash was incorporated and the sludge settled to 50% solids, the weight of dry FGD solids would be 25% that of the coal, and the wet sludge would weigh half as much as the coal. With a wet bulk density of 90 lb/ft^3 , the sludge produced from one ton of coal would occupy 11 ft^3 .³⁰

The yearly production of sludge from a typical 1000-MWe plant (34% efficiency with FGD) and the land requirements for disposal by ponding are calculated to be as follows:

Basis

Power plant: 1000 MWe, 6000 hr/yr, 10,000 Btu/kWh.

Coal: 3% S, 12% Ash, 10,000 Btu/lb.

Process-

Limestone: 85% SO_2 removal, 1.2 Ca/S removed

Lime: 90% SO_2 removal, 1.0 Ca/S removed

<u>Process</u>	<u>Wastes, 10^3 ton/yr</u>			<u>Land</u> <u>(acre-ft/yr)</u>
	<u>Ca Solids/Ash</u> <u>Dry</u>	<u>Total</u> <u>Dry</u>	<u>Total</u> <u>Wet</u>	
Limestone	390/360	750	1500	770
Lime	350/360	710	1420	725

If this plant operates for 30 years at an average load factor of 0.5, disposal of the accumulated wastes by ponding to a depth of 30 ft would require 560 acres (0.875 mi^2). This requirement, close to four times the area needed to pond ash alone, could limit the availability of suitable sites, particularly in the East.

About 25,000 MWe of new generating capacity equipped for lime/limestone scrubbing is scheduled for installation by 1980, but about 14,000 MWe of the total will use low sulfur coal and produce correspondingly smaller quantities of wastes. At that time FGD wastes will be accumulating at a rate greater than 20 million ton/yr and about $10\text{--}15 \text{ mi}^2$ of land will be required for their disposal. If FGD systems are required on all coal-fired power plants built in the 1980's, and if lime/limestone scrubbers are used on a large fraction of the plants, an additional 50 mi^2 of land would be required for waste disposal.

4.4.3.5 Waste Disposal Technology

Ponding

The utilities have traditionally disposed of fly ash by ponding, using landfill operations only when on-site disposal was impractical.³¹ In the absence of any applicable federal guidelines or regulations, they have adopted similar practices for the disposal of FGD wastes. At all but two of the 20 lime/limestone installations operating in 1976 the wastes are ponded. In most cases the sludges are not chemically treated and the ponds have not been lined with impervious material.³² Six utilities with 13 power stations (5205 MWe equivalent) have reported plans to chemically treat the wastes prior to disposal. Six stations (2180 MWe) are scheduled to be operating in 1976 and seven others have made definite commitments to begin by 1979.³⁵

There are two major environmental concerns in the ponding of FGD wastes: (1) the water pollution potential associated with soluble species in the waste liquor and solid phases, and (2) the land degradation associated with physically unstable waste solids.³⁴ As noted earlier, in Table 4.23, the concentrations of some components in scrubber liquors can exceed water quality criteria by more than an order of magnitude.³³ These potentially harmful substances can be introduced into water supplies by overflow from the disposal pond or by percolation through the settled solids into the soil.

Runoff. At most of the FGD installations, clarified liquor from the thickener and/or the settling pond is returned to the scrubber. Overflow from the pond is not uncommon however, because most of the systems operate with an open water loop.³² The amount of fresh water used to irrigate the mist eliminator sufficiently to keep it from plugging usually far exceeds the quantity of water lost from the system by evaporation and by occlusion within the FGD solids. The copious use of fresh water also facilitates scrubber operation by limiting the build-up of dissolved solids, such as chloride ion, which have an adverse effect on process chemistry and materials of construction.⁴⁵ In the obvious trade-off between the technical and the environmental performance of FGD systems, operational considerations have prevailed thus far. If closed-loop operation is unattainable, a water treatment system will be required for the discharge. This would, of course, add to the overall cost and energy consumption of the FGD system.

Leaching. Contamination of groundwater supplies by leaching is also a definite threat because of the permeability of the wastes. Untreated wastes, with permeabilities in the range 10^{-4} - 10^{-5} cm/sec (10-100 ft/yr), offer little resistance to flow of scrubber liquor to the pond floor.³⁵ During the active life of the pond, while sludge is continually being deposited and there is supernatant scrubber liquor, the concentrations of leachate components will approach their concentrations in steady state scrubber liquor. If the wastes are still physically unstable and cannot be protected from exposure to rainfall when operations cease, leaching will continue. Although the concentration of trace sludge components in the leachates will gradually decrease, those of major components will remain constant. The possibility therefore exists for infiltration of substantial quantities of bulk and trace components of scrubber liquors into the underlying soil.

The rate of migration from the pond of trace components in the leachates can be slowed by the retentive characteristics of some soils, but it is known that some substances, such as boron and selenium, are not attenuated effectively by soil.³⁰ Adverse effects on the quality of surface and ground water have not been detected thus far, but the limited time and extent of investigation provide little assurance.³² Because effects might take long to appear and, by the same token, be long lasting, disposal of wastes in a pond without an impervious liner cannot be regarded as an environmentally

acceptable practice.³⁰ It should also be emphasized that fixation of the sludge does not eliminate the need for a pond liner unless the treatment is one that reduces the permeability of the solids to 10^{-6} cm/sec or less.

Pond Liners. Although the need to control leaching is recognized, in the absence of specific requirements for use of impervious pond liners they have been installed at only two of the commercial-scale FGD systems.³² In both cases the ponds were lined with a 12-18 in. layer of clay, which has a permeability of 10^{-7} - 10^{-8} cm/sec. Numerous artificial liners have been proposed, including both flexible films of rubber or various plastics and non-flexible liners such as asphalt, cement or even stabilized FGD wastes.³⁰ The useful lifetimes of potential liners, which are determined by the aging characteristics of the material and by chemical interactions with the sludge and soil, are a matter of concern. Flexible liners are generally guaranteed for 20-25 years, and nonflexible liners are expected to have a somewhat longer life, but long-term service data for sludge containment are not yet available for either type of liner.³⁰ An evaluation of potential lining materials by exposing them to FGD wastes, liquors, and leachates for a 2-yr period is being carried out under EPA sponsorship at the U.S. Army Engineer Waterways Experiment Station.³⁵

Landfill

The second major problem with ponding of FGD wastes is the potential loss of land use and value. If the wastes remain unstable and impossible to cover, the pond can be a permanent eyesore and hazard with respect to both safety and leaching. Fixation of the wastes prior to ponding can eliminate these problems, even if the treatment is one that does not greatly reduce leaching during the active life of the pond. By covering the stabilized wastes with a protective layer of clay and soil and establishing a vegetative cover further leaching can be minimized and the disposal site can be reclaimed.

The major advantage of fixation, however, lies in the possibility of eliminating long-term ponding and potential problems from leaching. By successively filling a number of small ponds that will accommodate the volume of sludge produced during the period of time required for curing, stabilized

sludge can be removed periodically or continuously for transport to an offsite landfill or to create an onsite monument to pollution control. (The equivalent of the Great Pyramid of Egypt could be constructed from the wastes of the 1000-MWe plant described earlier in less than 3 yrs). With proper management of the operations, pollution by erosion or leaching can be essentially eliminated.

This approach is being used or planned at three of the commercial-scale FGD installations.³⁵ At the Phillips and Elrama stations of Duquesne Light treated wastes are being transported to an offsite landfill; at the Conesville plant of Columbus and Southern Ohio Electric, construction of a tiered mound of stabilized wastes is planned.

Alternatives for Disposal

Alternatives to ponding and landfill for the disposal of FGD wastes are being evaluated by the A.D. Little Co. in a program sponsored by EPA.^{34,42} Technical, environmental, and economic factors associated with the disposal of untreated and chemically treated wastes in the ocean and in deep and surface coal mines are being assessed. Preliminary conclusions are that active eastern and midwestern room and pillar mines and midwestern strip mines show the most promise.³⁴ The acceptability of ocean disposal is somewhat uncertain. The disposal of treated FGD wastes in underground coal mines as a means of preventing subsidence is being investigated by Radian under a Bureau of Mines contract.³⁴

Disposal Costs

The costs for disposal of scrubber wastes are not well defined, but available information indicates that they can contribute significantly to overall FGD costs. The cost estimates are customarily expressed in terms of dollars per ton of dry solids, and to relate these to electricity costs it is necessary to know both the sulfur content of the coal and the ash content of the wastes.

Reported costs vary widely, even for comparable treatment. Commonwealth Edison Co. has reported costs of \$19/ton dry solids (including \$2.35/ton for removal from the site) for fixation and disposal at the Will County

station, but these costs may be higher than normal because of the intermittent operation of the FGD system at this installation.⁴¹ A cost of \$12-14/ton dry solids has been reported for fixation and off-site disposal by Duquesne Light.⁴⁶ Costs of \$8-16/ton solids have been estimated by a vendor of fixation services.⁴⁷

Engineering cost estimates for disposal in lined ponds and for land-filling of chemically treated FGD wastes have been made by Aerospace.³⁵ Their estimates are based on a 1000-MWe power plant burning coal with 3% sulfur and 12% ash and operating for 30 years at an average load factor of 50% (cf. Section 4.4.3.4).

Total costs for chemical treatment and disposal at a site five miles distant are estimated to range, in 1975 dollars, from \$7.30-11.40/ton of dry solids (including fly ash) for the three commercial fixation processes that were evaluated. These costs correspond to incremental electricity costs of 0.9-1.4 mills/kWh.

Costs for disposal of untreated wastes in lined ponds, not including the costs of reclamation, are about 75% of those for chemical treatment and landfill. For liners made of PVC-20 and Hypalon-30, which represent a reasonable range of liner costs, the disposal costs of dry solids are estimated to be \$5.70-7.80/ton, equivalent to 0.7-1.0 mills/kWh.

4.4.3.6 Utilization of FGD Wastes

Commercial utilization of lime/limestone scrubber wastes is a possible alternative to disposal. A number of uses in agriculture and the construction industry have been proposed and investigated.

Agricultural Use

The use of lime/limestone wastes as a filler material and source of sulfur in granular fertilizers is being investigated at the pilot-plant scale by TVA in the Interagency Energy-Environment Program.³⁵ In addition to process development the program includes field tests, economic/marketing studies, and comparison of trace element contents with those of conventional fertilizers.

The use of natural gypsum as a calcium source for peanuts is fairly well established in the U.S., and the growth of peanuts and soybeans in mixtures of soil and Chiyoda-produced gypsum is being evaluated at the University of Florida Agricultural Center, Quincy, Florida.³⁵ Early results indicate the feasibility of applying up to 20 tons of the gypsum per acre.

Industrial Use

The use of FGD waste as an ingredient in road-base and paving materials, artificial aggregates, and lightweight concretes has been investigated by a number of federal and private research centers.

Inclusion of scrubber sludge in conventional lime/fly ash/aggregate pozzolans appears to result in increased early strength and greater final strength.⁴⁸ Synthetic aggregates made from lime, fly ash, and scrubber sludge have also been tested as substitutes for natural aggregate in paving mixtures. They appear to be useful for road-base construction, but not suitable for wearing surfaces.⁴⁷

The use of FGD-derived gypsum in portland cement manufacture is being evaluated by the South Carolina Public Service Authority and a manufacturing facility.³⁵ A detailed assessment of by-product gypsum production and market potential for wallboard production is being conducted by TVA in the inter-agency program.³⁵

The Kel-S process of Pullman Kellogg and a proprietary TRW process for conversion of FGD wastes to elemental sulfur are being evaluated.³⁵

Outlook for Utilization

Major deterrents to utilization of lime/limestone scrubber wastes are their variable physical and chemical properties, high transportation costs, dewatering requirements for many applications, and their inability to compete economically with other materials.⁴⁹ Although some applications appear to be technically and economically feasible, the potential usage is so limited that only a small fraction of the expected sludge production could be marketed. At least for the near term, disposal of wastes by ponding or landfill will continue to be the major alternatives.⁴⁹

4.4.3.7 *Conclusions and Recommendations*

Sludge disposal is generally regarded as the major remaining problem in lime/limestone scrubbing.⁴⁵ The options available in the U.S. are limited to ponding for raw sludge and to ponding or landfill in the case of chemically stabilized wastes. (Oxidation of the sludge to gypsum in order to facilitate utilization or disposal by landfill is extensively utilized in Japan, but the technology has not yet been demonstrated in the U.S.)

Environmentally acceptable disposal of scrubber wastes, by ponding or landfill, requires the elimination or control of leaching and of overflow/runoff, and preferably should permit eventual reclamation of the disposal site. Neither the capability of achieving these objectives nor the magnitude of the associated costs have been adequately established.

In principle, leaching can be controlled either by depositing the wastes in an impervious container or by sufficiently reducing their permeability. However, the lifetimes of proposed impervious liners in contact with sludge and soil are not known, and the ability of the chemical fixation processes to effect a sufficient and permanent decrease in permeability is uncertain.

Overflow from waste disposal ponds can be eliminated by operating the FGD system with a closed water-loop. Closed-loop operation is expected to have adverse effects on process chemistry and materials of construction, but there is no basis for evaluating the magnitude of these effects since experience with closed-loop operation of commercial FGD systems is extremely limited. The only available alternative to closed-loop operation, and at the expense of increased capital and operating costs, is to install a water treatment system to process any discharge.

In view of the imminence of waste disposal at a greatly increased scale, there is an urgent need for a vigorous R&D program to resolve these questions.

4.4.4 WASTEWATER EFFLUENT CONTROL

4.4.4.1 Introduction

Until recently, wastewater streams from coal-fired power plants were largely ignored, except where they interfered with plant operation. But with more stringent effluent limitations going into effect (ultimately approaching the goal of zero discharge), waste streams are now being scrutinized. Several studies are underway to characterize various wastes and new efforts are being made to maximize water reuse. This shift in emphasis from once-through water systems to water recycle/reuse is reflected in current research, publications, and conferences.

In order to better familiarize the reader with the range of wastewater streams emanating from conventional coal-fired power plants, Tables 4.24 through 4.26 have been adapted from an EPA development document.⁵⁰ Table 4.24 ranks wastewater flows by relative volume, while Table 4.25 indicates typical concentrations of major pollutants. Table 4.26 gives both reported data and typical ranges for flow rates and volumes of chemical wastes. For the purpose of this report, liquid effluents will be divided into three general categories:

1. Blowdown and equipment-cleaning waste.
2. Solids-handling water.
3. Coal-cleaning effluents.

Sanitary waste generated by plant personnel is not specifically included as it is low in volume and not a serious treatment problem. It is either discharged to the municipal wastewater treatment plant or processed on-site in a package plant; both usually employ conventional biological treatments.

The first step in dealing effectively with any waste stream is a thorough analysis of its constituents. However, a recent literature survey by the TVA indicates that only cooling tower and boiler blowdown have been thoroughly examined.⁵¹ Even these are not of a consistent composition; they were found to vary at different sites, depending upon the make-up water character, fuel type, system type, thermal efficiency, and cycles of system operation. There may even be a seasonal pattern to waste composition within a system due to a change in the source of make-up water during dry periods.

Table 4.24 Classes of Various Waste Water Sources⁵⁰

Class	Source
High Volume	Nonrecirculating main condenser cooling water
Intermediate Volume	Nonrecirculating house service water Blowdown from recirculating main cooling water system Nonrecirculating ash sluicing systems Nonrecirculating wet-scrubber air pollution control systems
Low Volume	Clarifier water treatment Softening water treatment Evaporator water treatment Ion exchange water treatment Reverse osmosis water treatment Condensate treatment Boiler blowdown Boiler tube cleaning Boiler fireside cleaning Air preheater cleaning Stack cleaning Miscellaneous equipment cleaning Recirculating ash sluicing systems Recirculating wet-scrubber air pollution control systems Intake screen backwash Laboratory and sampling streams Cooling tower basin cleaning Rad wastes Sanitary system Recirculating house service water Floor drainage Miscellaneous streams
Rainfall Runoff	Coal pile drainage Yard and roof drainage Construction activities

Table 4.25 Typical Chemical Wastes From a Coal-Fired Powerplant⁵⁰

Waste Stream	Flow (gpd/MW)	Typical Concentrations of Major Pollutants ^a (mg/l)				
		TSS	Iron	Copper	Sulfate	Hardness
Ion exchange	88	46	-	-	2085	-
Boiler blowdown	52	25	-	-	-	-
Boiler cleaning	0.25	127	2100	380	-	520
Boiler fireside cleaning	4.44	582	142	-	1650	4661
Air preheater cleaning	11.7	1882	1610	-	1130	3700
Miscellaneous cleaning	1.11	1000 ^b	-	-	-	-
Laboratory operations	10	100 ^b	-	-	-	-
Floor drains	30	100 ^b	-	-	-	-
Recirculating bottom ash sluicing blowdown	400	1000 ^b	-	-	-	-
Ash pond overflow (once- through fly ash)	5000	60	-	-	510	244
Coal pile drainage	- ^c	864	-	-	6880	1025

^aBased on the average of available data.

^bAssumed values.

^cBased on 0.02 acres/MW coal pile and 40 in. of rainfall per year,
the flow is calculated to be 59,500 gpd for a 1000 MW plant.

Table 4.26 Flow Rates for Chemical Wastes⁵⁰

Waste Stream	Reported Data		Typical Flow or Volume	Basis	Remarks
	Waste Flow or Volume	Frequency			
Condenser Cooling Water					
Once-Through	-	-	500-1500 gpm/MW	-	Flow reported in FPC Form 67
Recirculating	20-7200 x 10 ³ gpd	-	Varies from 0.3% to 4% of circulating water flow	-	Blowdown depends on water quality and varies from 2-20 concentrations
Water Treatment					
Clarification	No discharge				
Softening	No discharge				
Ion Exchange	1-53,300 x 10 ³ gpd	52-365 cycles/yr	-	-	Extremely variable depending on raw water quality
Evaporator	0.1-1060 x 10 ³ gpd	300-365 cycles/yr	-	-	Extremely variable depending on raw water quality
Boiler Blowdown	0.05-1120 x 10 ³ gpd	25-365 cycles/yr	-	-	Flow reported in FPC Form 67
Chemical Cleaning					
Boiler Tubes	3-5 boiler volumes	once/7 mo - once/100 mo	1 boiler vol. per 1-2 hr-boiler draindown time	Frequency-once per 24-30 mo	
Boiler Fireside	24-720 x 10 ³ gal	2-8/yr	300,000 gal	5/yr	
Air Preheater	43-600 x 10 ³ gal	4-12/yr	200,000 gal	6-12/yr	
Misc. Small Equip.	No reported data	-	-	-	
Stack	No reported data	-	-	-	Cleaned infrequently
Cooling Tower Basin	No reported data	-	-	-	Cleaned infrequently
Ash Handling	5-32,000 x 10 ³ gpd	-	-	-	Overflow from ash ponds reported in FPC Form 67
Drainage					
Coal pile	17-27 x 10 ⁶ gal/yr	Dependent upon rainfall	-	Reported data based on 43-60 inches of rain year	Flow dependent upon frequency, duration, and intensity of rainfall
Floor & Yard Drains	No reported data	-	-	-	Flow dependent upon frequency & duration of cleaning and stormwater runoff
Air Pollution Control Devices	No discharge				
Misc. Waste Streams					
Sanitary Wastes	No reported data	-	25-35 gal/capita/day	Personnel: operators-1 per 20-40 MW maintenance-1 per 10-15 MW administrative-1 per 15-25 MW	
Plant Laboratory and Sampling	No reported data	-	-	-	Nominal, variable flow
Intake Screen Backwash	No reported data	-	-	-	Guideline requires collection & removal of debris-flow data not significant
Closed Cooling Systems	No reported data	-	5 gpd	-	-

Recognizing the importance of characterizing these power plant waste streams and their associated variables and dependencies, EPA has initiated several studies along these lines. Associated with these efforts is an additional study of power plant water recycle/reuse to be completed in late 1976 by the Radian Corporation.

4.4.4.2 *Blowdown and Equipment Cleaning Waste*

Cooling towers accumulate mineral deposits due to evaporation and the addition of corrosion inhibitors. It is therefore necessary to discharge, either continuously or intermittently, a fraction of the circulating water (usually in the range of 0.3-1.0% of the flow). This blowdown contains high concentrations of suspended and dissolved solids and sometimes significant amounts of residual chlorine. It may also contain chromium, zinc, phosphate, or other corrosion inhibitors and biocides in excess of effluent standards. A recent study shows the best treatment (technically and economically) of the blowdown to be lime-soda softening (or related chemical precipitation).⁵² The water can then be reused as cooling tower makeup (since make-up water generally requires pretreatment by softening anyway), reused as scrubber makeup, or discharged. Boiler blowdown contains mainly a high level of solids and can be similarly treated. Cooling tower and boiler blowdown are also often used for ash sluicing water, and then evaporated. However, reusing this sluicing water is more economical.

The main source of equipment-cleaning waste is from boiler and boiler tube cleaning. Although this is done only about once every three years, it is a serious problem due to high levels of toxic chemicals. There are two cleaning methods available: circulation and soaking. The circulation method uses acid and neutralization steps, while soaking employs acid, alkaline, and neutralization phases. TVA has surveyed the composition of these wastes at several plants and found the following substances or indices to exceed water quality criteria:

Ammonia	
Phosphorus	
Copper	Acid, alkaline, and
Iron	neutralization wastes
pH	
Suspended solids	

Phenols
Cadmium
Lead
Manganese
Nickel
Zinc

Acid waste

Oil and grease

Some of the EPA effluent guidelines that apply are copper, 1 mg/l; iron, 1 mg/l; oil and grease, 15 mg/l; pH, 6-9; and suspended solids, 30 mg/l. Work is underway at TVA to evaluate treatment alternatives for these equipment cleaning wastes, but it appears that some necessary treatment steps will include pH adjustment, precipitation, sedimentation, filtration, ion exchange or reverse osmosis, and ammonia removal.

4.4.4.3 *Solids Handling Water*

The principal solid wastes emitted from a coal-fired power plant are combustion by-products and flue gas desulfurization (FGD) solids. Combustion by-products can be divided into fly ash and bottom ash. Fly ash is normally collected in hoppers under mechanical collectors and electrostatic precipitators and then sluiced to a settling pond. Bottom ash accumulates beneath the furnace and is periodically flushed out, sent through a clinker grinder, then sluiced to a settling pond. The ash consists of metal oxides, carbon residuals, and trace elements that may be released into the sluicing water. FGD wastes, discharged from the system as slurries containing calcium sulfite, calcium sulfate, and fly ash, are also sluiced to a settling pond in most cases. As with ash ponds, characteristics of the FGD sludge pond effluent depend upon the composition of the solids with which it comes into contact, the source and quantity of water entering the pond, and the operating efficiency of the pond itself. Ponding can accomplish concentration and stabilization of solids, storage, and dust control.

Ash ponds are the receptacle for fly ash and/or bottom ash and may even receive coal pile runoff and coal cleaning waste.⁵³ TVA's figures show the main problems with ash pond effluents are suspended solids and trace elements. Analyses were run on grab samples taken quarterly or weekly from once-through discharges of fly ash, bottom ash, and combined ash ponds at 12 plants during 1973 and 1974. The pH ranged from 3.3 to 12.0, depending upon the sulfur and alkaline metal-oxide contents of the ash (affected in turn

by the source of the coal), the buffering capacity of the sluicing water, and the type of furnace used. The trace elements analyzed by TVA were arsenic, cadmium, chromium, copper, iron, lead, manganese, selenium, and zinc. Samples were also analyzed for mercury, nickel, and silver, but these substances were not found in detectable levels. Lead was found in a detectable amount at only one location.

A large portion of the suspended solids and trace metals in the ash pond effluent can be attributed to the presence of cenospheres. These are low-density, hollow-sphere, gas-filled ash particles that can be present in great enough quantity to form a floating blanket on the pond. Therefore, some means of reducing the accumulation of cenospheres may be one necessary step in the treatment.

Every substance in the effluent, except selenium, exhibits a strong pH dependence; the substance remains in solution or precipitates out, depending upon the pH value. Consequently, an obvious treatment step would be pH adjustment and precipitation. This procedure would probably have no significant effect on selenium, however, and other measures may be necessary. Choice of treatment methods will have a high degree of site specificity, depending principally on the existing pH range.

It is likely that the ash pond effluent will have to be recycled or reused in other ways to meet the EPA BATEA requirements of 1983. A flow chart for a power plant that incorporates both recycle of ash pond effluents and reuse of effluents as FGD scrubber make-up is presented in Fig. 4.15. Note that the ultimate sink for aqueous wastes in this plant is the FGD sludge disposal site. The control of leaching and overflow in the disposal of FGD wastes has been discussed in Section 4.4.3.

4.4.4.4 *Coal-Cleaning Effluents*

The main pollutants resulting from coal cleaning and preparation are suspended solids and a wide variety of trace metals. The impurities present strongly reflect those of the bed from which the coal is extracted.⁵⁴ The majority of coal cleaning and preparation plants are using (or converting to) recirculating water systems. Treatment includes thickeners, filters, or settling ponds in the cycle. Of course, this simply transfers the problem to one of sludge disposal.

There is also a problem with drainage from the refuse pile resulting from the coal washing/preparation. This effluent is very similar in composition to acid mine drainage, and can be treated as such.⁵⁵ The waste may be neutralized with lime, limestone, soda ash, or caustic soda. Again, this transfers the real problem to one of sludge disposal. Battelle's total environmental assessment of an FBC boiler plant will include coal preparation, and therefore may contain the most current and complete analysis of this waste.

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5 CONVENTIONAL POWER PLANTS USING CLEANED COAL OR LOW SULFUR COAL

5.1 COAL PREPARATION AND COMBUSTION OF CLEANED COAL

5.1.1 Summary

Coal preparation is an established commercial operation that upgrades coal quality and assists in the control of a number of environmental problems. The preparation process is used to concentrate the desired carbonaceous coal components, and to remove substantial quantities of water, mineral matter, and sulfur. Thus, a more desirable feed stock for power generation and other forms of coal use is provided. The extent of preparation selected is constrained by product specifications and overall system economics. With some coals the sulfur content can be reduced to meet sulfur emission regulations without the use of flue gas desulfurization (FGD). The potential for preparing coal to meet those regulations varies according to the coal characteristics and the processing technologies employed.

Five levels of coal processing practiced in the U.S. are discussed here. The modes of operation and functions of the several unit operations are described with the aid of process flowsheets.

Present industrial methods can extract from coal various amounts of the mineral impurities and up to about 40-50% of the total sulfur, depending upon its form. Methods under development may extend the sulfur removal to 90% or more. Extraction of nitrogen does not appear imminent, but by removing much of the mineral matter and a portion of the inorganic sulfur, coal can be converted into a relatively clean fuel.

The practicality of coal preparation is highly dependent upon the yields of clean product and the product qualities attainable. The capital and operating costs associated with preparation are discussed in this chapter along with an example of the economic impacts on sulfur emission control for coal-fired steam systems.

Technological constraints are found to be primarily associated with the need to liberate coal components by crushing. Fine-sized coal particles are more difficult and costly to process and handle.

5.1.2 Introduction

Coal produced by present-day mining methods generally contains such significant amounts of mine debris and waste material as to render it undesirable as a feedstock for power plant use without some preparation to convert it into a suitable product. The level of preparation required depends on the kind of power plant to which the coal is destined, the emission regulations, and the overall cost-benefit resulting from its use.

A recent U.S. Bureau of Mines report¹ on coal washability states that only about 14% of a total of 455 coals tested meet the federal New Source Performance Standards (NSPSs) for power generation ($1.2 \text{ lb SO}_2/10^6 \text{ Btu}$). It further estimates that if the coals were cleaned to a 90%-Btu recovery and a 1.5-in. maximum size, about 24% of the coal samples tested would meet the NSPS, 35% would meet a standard of $2.0 \text{ lb SO}_2/10^6 \text{ Btu}$, and approximately 60% would meet $4.0 \text{ lb SO}_2/10^6 \text{ Btu}$.² Since many states have emission standards for power plants as high as $4.0 \text{ lb SO}_2/10^6 \text{ Btu}$, physical preparation could be of considerable value in providing coals for power plants subject to such regulations.

In addition to reducing the sulfur content of coal, there are certain other advantages of coal preparation, including:

1. Production of coal with uniform properties.
2. Development of a series of specified coal properties within wide constraints established by the parent coal characteristics, the available processing technology and equipment, and the overall energy system economics. Coal properties that can be managed by preparation include both physical and chemical characteristics. The physical properties are size consist, handleability, and bulk density. Chemical properties include mineral (ash) content and composition, sulfur content (principally pyrite), moisture content, and calorific content. Implied in the control of these chemical coal properties are such secondary effects as mineral (ash) behavior during and after combustion, volatile matter content, and combustion reaction rates. Environmental implications include oxides of sulfur that may be released to the atmosphere via flue gases and quantities of ash that must be disposed of in landfill operations.
3. Reduction of coal transportation (and other handling) costs from mine to power generating plants.

4. Improved reliability and efficiency of combustion, and lower power plant operating and maintenance costs because of reduced boiler fouling and corrosion.

5.1.3 *Status of Coal Preparation and Cleaning Technology*

5.1.3.1 *Levels of Coal Preparation Practiced in the United States*

Coal is a highly heterogeneous material. The coal properties specified for combustion are basically established by the design and location of the power plant, although costs, energy conservation policies, and environmental regulations may modify these requirements. In general, the higher the degree of beneficiation required, the more complex and costly will be the coal preparation operation. A balance must be achieved between product yield and quality.

The physical processing of coal relies upon the need to liberate physically-compacted coal components (produced by crushing during both mining and beneficiation), to separate component coal particles by size and density, and also to control water content of the processed coal particles. In achieving these processing goals, extensive material handling and auxiliary control concepts must be used. Each coal preparation system is individually engineered and numerous unit operations in many processing combinations may be employed to achieve the desired specifications.

The nature of coal preparation currently practiced or planned in the United States may be generalized into five processing levels. Fig. 5.1 is a schematic flow diagram of a modern closed-circuit coal preparation plant. Only the first four levels are shown. They represent the "maximum" beneficiation concept that present technology can provide. The level of preparation practiced or the extent of cleaning desired will depend of course on the coal feed stock, the utilization specifications, and the prevailing system economics. The fifth level, which is still in the planning stage at the present time, should become operational in 1977.

Following is a brief description for each of these five coal processing levels:

1. *Level One Coal Processing.* This procedure is designed to remove mine debris and some noncombustible impurities. The unit operations typically

FIG. 5.1 Schematic Flow Diagram of Closed Circuit Coal Preparation Plant

include crushing and particle sizing to achieve a uniform saleable product with some improvement in coal heat content, but negligible change in sulfur content. Product yields (material recovery) are generally about 95% or greater.

2. *Level Two Coal Processing.* This procedure represents the minimal processing to create a significant overall quality change. The feed top size is reduced to four or six inches achieving minimal component liberation. Usually only the plus 3/8-in. or plus 1/4-in. particles and those at a relatively high gravity ($>1.5 \text{ g/cm}^3$) are beneficiated. The fine coal is usually neither wetted nor cleaned. This procedure may result in an 80% or greater yield with moderate ash reduction but only slight sulfur reduction.

3. *Level Three Coal Processing.* This level represents many beneficiation efforts applied commercially today. The coarse particles ($>3/8$ in. or $1/4$ in.) and fine particles ($3/8$ in. by 28 mesh) are beneficiated in separate circuits with the slimes (<28 mesh) generally not cleaned. In addition to liberation achieved by top-size reduction (often to 1 in.), middling products are sometimes separated and subjected to further liberation and reprocessing. Separations are seldom made at densities less than 1.40 g/cm^3 . The processing of fines and slimes particles involves complex water quality control circuits, product dewatering, and usually centrifugal as well as thermal drying. Yields are typically about 70-80% with moderate ash and sulfur rejection.

4. *Level Four Coal Processing.* This level represents the current best or most sophisticated practice generally applied for the production of metallurgical coals, but it is also finding increasing use for steam-grade coals. It involves both coarse- and fine-coal treatment as in Level 3, but also includes froth flotation as well as other ancillary devices (such as vacuum filters, thermal and centrifugal drying, etc.) for treatment of sizes generally below 28 mesh. This procedure can be considered commercially the most advanced and sophisticated coal processing in frequent use today. Product yields are generally about 50-70% with considerable sulfur and ash reduction.

5. *Level Five Coal Processing.* This concept, being attempted in 1976³ for the first time, will extend the limit of existing coal preparation technology by using selective crushing and making repeated separations at two

or more densities. The final density separation will be as low as 1.30 g/cm³ in a plant circuit that achieves maximum liberation, resulting in practical elimination of the coarse-coal circuit. This system, which will produce a premium quality clean coal (<0.8% sulfur) in yields of less than 30%, can be economically justified only by development of a usable quality middling product (2.2% sulfur). This multiproduct-stream concept was developed at Homer City to meet current sulfur oxide emission standards for a new power station without flue gas desulfurization. The middling product from this cleaning plant will meet quality specifications for use in existing, older power stations.

Several aspects of these various levels of coal beneficiation result from the following generalities, applicable to essentially all mineral commodities:

1. The beneficiation response is less efficient but also less costly when treating larger particle sizes.
2. Higher quality products result when preparing smaller particle sizes, since particle homogeneity increases with a decrease in particle size.
3. Most coals are beneficiated in water media. With the decrease in particle size and increase in particle surface area, the products (clean coal and refuse alike) contain increasing amounts of water that must be removed to levels of ~6% to achieve acceptable handleability and avoid calorific dilution.
4. The achievement of higher sulfur liberation will unavoidably create levels of very fine particles that are difficult to handle. These *slimes* are costly to process, but must be recovered to provide acceptable process economics and to minimize environmental problems in solids disposal.
5. Unit volume capacity of most coal beneficiation operations decreases with particle size, increasing capital and operating costs.

Material balance flowsheets have recently been described for preparation plants located in the major coal-producing states of West Virginia, Illinois, Indiana, and Pennsylvania.⁴ The coal products from these plants are used for both metallurgical and steam generation purposes. With the recent more restrictive sulfur oxide emission regulations, the preparation of steam coal is moving upward from Levels 1, 2, and 3 to Levels 4 and even 5. If any general trends are evident in these flowsheets they would include:

1. Attainment of higher calorific recovery, even if capital and processing costs are greater, as a result of the increasing costs of mining coal.
2. More intense cleaning to reduce sulfur content to meet stricter product specifications as required by air pollution regulations.
3. More extensive use of thermal dryers (necessitated by the treatment of finer coal) to achieve handleability requirements and to reduce transportation costs of the product coals.
4. More detailed control of the water circuit to meet water pollution regulations that now require closed water circuits. Thickeners and filters are being used to replace settling basins. The increased use of polymeric flocculants in classification, centrifuge, and filter operations is noted.
5. Closer control of all refuse products to aid disposal and minimize potential environmental problems.
6. More extensive processing of minus 3/8-in. particle sizes necessitated by the production of finer sizes by modern mining methods and by crushing in preparation plants to achieve increased component liberation. This concept incorporates the creation of a middlings product that is further crushed and reprocessed to increase recovery. Plant designs seek to minimize inplant size degradation.
7. Increased use of silo storage to maintain product quality and to aid in rapid train loading.
8. Use of tough, low-friction, plastic lining materials in preparation plants to reduce noise, increase handleability, and decrease wear and abrasion.
9. The use of froth flotation is increasing to enhance recovery of the slime sizes, and reduce mineral matter content despite its constraints on pyrite rejection.

These plants frequently use heavy-media vessels (coarse coal) and heavy-media cyclones (fine coal). Some add froth flotation to recover slime products and thermal dryers. Others utilize shaking tables in lieu of heavy-media cyclones. All are typical Level 3 or 4 coal preparation plants, with the exception of two which are Level 2 processes utilizing Baum jigs to treat the total size range.

5.1.3.2 Unit Operations in Present Use in Coal Preparation Plants

A listing by functional type of the basic unit operations utilized in coal preparation operations is given in Table 5.1. Equipment by different manufacturers have varying limitations and advantages, and in some instances multifunction capability.

Following are brief descriptions of some of the unit operations commonly found in coal preparation plants.

Crushing

Crushing is utilized for several functions that affect equipment selection. Among these are: (1) control of top sizes, (2) preparation of special sizes for subsequent processing requirements, (3) component liberation, (4) development of special cleaned coal product sizes, and (5) crushing of refuse for improved disposal control. The general selection criteria include development of appropriate top size, prevention of formation of excessive fines, and control to achieve the desired particle size distribution.

Particle Sizing

Particle sizing is critical in coal preparation. It is used: (1) to separate raw coal into various sizes for marketing, as in Level 1 coal processing, (2) to control size consist of feeds for particular unit operations that are size sensitive, (3) to control product composition and achieve maximum particle recovery during the processing operations, and (4) to prepare final product sizes.

Particle sizing in coal preparation generally incorporates the following types of unit operations: (1) screening, (2) cyclones, and (3) settling techniques.

Screening. This operation can be performed on either dry or wet material, although most preparations use water. Traditionally, screening operations have been limited in their application to larger particle sizes and are still practiced, but with the development of effective and efficient chassis and fine-aperture cloths, they are now being applied to sizes

Table 5.1 Basic Unit Operations in Coal Preparation

Materials HandlingSolids

- Mine car - rail
- Truck
- Belt conveyor
- Skip hoist
- Tramway
- Front-end loaders
- Vertical bucket hoists
- Sluices
- Pipeline
- Trash removal - wood, metal (magnetic devices)
- Feeder

Fluids - water, air, slurries

- Pipes
- Sluices - launderers
- Pumps
- Fans

Preprocess Storage (by mine, mine section, size, source destination)Open Storage

- Discharge capability
- Stackers
- Reclaimers

Enclosed Storage

- Bins
- Silos

Crushing - Develop desired particle sizeMine site - underground or surface mine siteCoal

- Preprocess
 - Breaker feeders
 - Rotary breaker
 - Roll crushers - single
- Process (liberation)
 - Roll crushers - multiple, staged
 - Impactors

Refuse

- Roll crushers
- Jaw crushers

Table 5.1 (Cont'd)

Particulate Sizing - Control size consist to process or product
Screening (8 in. to 1/2 mm)

Stationary
Vibrating - single/multiple deck

Classification

Settling tanks
Drag tanks
Thickeners
Desilters
Cyclones

Gravity SeparationCoarse Sizes (+3/4 in.)

Jigs (Plunger-Baum-Batac)
Heavy media vessels (magnetite, sand, loess, variety of vessel designs)

Fine Sizes

Heavy media cyclones (magnetite)
Shaking tables
Feldspar Jigs - Batac jigs
Air tables

Slimes

Hydro cyclones
Shaking tables
Froth flotation
Classifiers

Media Recovery Systems

Magnetic separators
Screens
Classifiers
Storage - feeders, control

Solid-Fluid Separation (coal and refuse)

Screens (profile, crossflow, sieve bend)
Classifying cyclones
Thickeners - settlers

Dewatering Systems (coal and refuse)Mechanical

Filters (disc, drum, pressure)
Centrifuges
Screens

Thermal Dryers (variety of designs)

as small as 150 mesh (105 μm). In these latter applications, screens are utilized more for particle recovery than for close sizing.

Classification Cyclones. They are used for sizes principally below 1/4 in. They play a critical role in preparation of feeds for subsequent operations, including some product composition control.

Settling Sizing. This concept is used primarily to recover fine solids from water slurries and is seldom applied directly in the coal industry for separation of distinct particle size fractions.

Gravity Separation

Gravity separation is a complex operation that is closely related to particle size. Hence, there are a number of unit operations that are grouped according to the acceptable limitations on their feed size consist.

Jig. The jig is the most widely utilized device to clean coal. Although often considered to be widely applicable to a full range of particle sizes, its separational efficiency decreases with particle sizes below 1/8 in. This decreased efficiency is manifested by an increasing density of separation with decreasing particle size below about 1/8 in. To minimize the tendency for small particles, which are inefficiently separated, to decrease usable unit capacity, the feed to the jig is sometimes dry prescreened to remove the fine sizes. This practice serves several functions:

1. Increases jig capacity for particles that will be effectively cleaned.
2. Prevents wetting of fine particles with the subsequent addition of unit operations for their recovery/drying, if they are not to be washed.
3. The dry fine particles may be processed pneumatically.
4. The fine particles may build up in the jig water circuit tending to increase fluid viscosity and interfere with cleaning response on some occasions.

Some fines in the jig water system may be desirable to increase the jig fluid density (acting as a heavy media). In fact, some systems intentionally crush the jig middling product to create fines and enhance recovery. Such systems are difficult to control and can lead to inferior products. The complex control and removal of fine particles is well illustrated in the cited flowsheets⁴ (described earlier in Sec. 5.1.3.1) that treat a full size range. The jig is also limited in its ability to separate at densities much below 1.50 g/cm^3 and to process feeds that have high levels of near-gravity material. Among the attributes of the jig is its large capacity and the mode of feed introduction. The pre-wet raw coal feed is introduced to the jig by feeder, sluice, or launderer, which permits precise control rates with minimum particle degradation and abrasion. Recent design modifications (Batac) indicate superior performance in ameliorating some of the above mentioned constraints.⁵

Heavy-Media Vessel. The most effective device utilized to separate particles by density is the heavy-media vessel. This system utilizes suspensions of finely-divided magnetite in water that will remain stable without agitation and functions as a true heavy media. The feed coal is introduced into the suspension, followed by sinking of the heavy particles and the continued flotation of lighter particles. The particle retention time in such systems is small (seconds), and they have accordingly high unit capacities. Since the settling rate decreases with particle size, the systems become less effective with particles smaller than $1/4 \text{ in.}$, accordingly the vessel system is generally limited to particles above that size.

The heavy-media suspension must be closely controlled as to magnetite content and to prevent the buildup of coal slimes within the slurry. Although the designs of various manufacturers differ in the mode of removal of the clean coal and the refuse, the basic vessel design is relatively simple. However, the total heavy-media system must incorporate procedures to attain a high recovery of the magnetite for recycle and for the controlled removal of coal fines from the suspension. These objectives are attained by the use of separate drain screens (2-mm parallel slot openings) treating the clean coal and refuse products. The separated suspension flows directly to the heavy media sump for direct recycle to the separating vessel. The drained products are immediately washed on profiled screens to remove residual

magnetite and coal fines, producing a dilute slurry. This rinse step is important because economical processing depends upon keeping magnetite losses to less than 2.0 lb/ton of feed. Efficient operations regularly keep these losses less than 1.0 lb/ton. The magnetite in the dilute slurry must be recovered magnetically (permanent magnetic drums are utilized) and separated from the coal slimes.

The heavy-media systems are capable of making separations at both high (as much as 1.9 g/cm^3) and low densities (1.35 g/cm^3), and of handling feeds with very high levels of near-gravity material (>50%). These systems are relatively nonsensitive to feed rate up to unit capacity, which permits some latitude within the system for variation in feed quantity. The size consist and particle shape of the magnetite are critical system parameters playing a role in controlling the suspension viscosity. Media other than magnetite can be utilized. Examples are sand (Chance Cone System), ferro-silicon clays, loess, and refuse, but each has its pragmatic limitations.

Although systems using magnetite are more precise in the sharpness of their separation between coal and its impurities, they are generally considered more costly to operate because of the cost of media used to maintain density and its recovery for reuse.

Heavy-media Cyclones. Of the various fine coal ($3/4$ in. by 28 mesh) unit operations, heavy-media cyclones and shaking tables prevail. Heavy-media cyclones are the most versatile devices and are perhaps capable of making the sharpest separations at the lowest densities of any solid-solid separational device. They are uniquely simple in design, having no moving parts, have large unit capacities per unit volume occupied by the system, and require the same magnetite recovery system as do heavy-media vessels. A major disadvantage of this device is the necessity to mix the feed coal with the heavy-media suspension and pump the mixture into the cyclone under modest pressure (<20 psi). Accordingly, heavy-media cyclone systems have a number of components that are subject to wear and abrasion, requiring close maintenance. Replaceable liners (rubber, ceramic, etc.) for cyclones are routinely employed. The controllable parameters are suspension density, feed pressure, and cyclone design, such as: (1) cyclone diameter (capacity); (2) cyclone angle; (3) vortex-finder length, diameter, and position; and (4) apex diameter. The design and performance of these units are described in Ref. 6.

Shaking Tables. The shaking table has been widely and effectively used for fine coal cleaning. The top size this device can treat is about 3/4 in. It is not limited to a bottom size and can do some cleaning of finer particle sizes. It is particularly effective in removing fine-size pyrite, since the specific gravity of pyrite is higher in comparison to coal.

Tables have a relatively low unit capacity per unit space occupied (10-15 tons per deck; 10 x 20 ft). Capacity has been enhanced by designing double-and triple-deck tables functioning from a single drive system. However, most table systems incorporate many units that require extensive feed distribution systems as well as launderers to collect the separated products. Although capable of efficient separations, it is difficult to separate particles effectively at densities less than 1.50. The principles utilized in shaking tables involve both hindered settling and flowing film concepts in which the film velocity varies with depth. A table installation avoids the extensive magnetic systems required by heavy-media processes. The process variables include amplitude and frequency of motion, table slope, feed pulp density, cross-flow water rates, and deck ripple design. Particle shape can be a pertinent parameter in this device.

Air Tables. Air tables have seen only limited application although utilized for many years. They are characterized by relatively large unit capacities of 40-45 tons per deck. The space requirements, however, are correspondingly large in order to incorporate the blower system, feed and product handling, and especially the duct work and sizable cyclones necessary to recover (for environmental reasons) the fine, dusty particles that are airborne.

The air tables are incapable of making either sharp separations or processing feeds having high levels of near-gravity materials, or of separating at densities below 1.6. The units must be adjusted to create a high quality product that will result in substantial losses of coal to the middlings product, or alternatively, sacrifice product quality to avoid excessive clean coal losses. Another restriction in the application of this device is the requirement of a relatively low feed-moisture content (<5%). Higher moisture content prevents the proper stratification of individual particles, causing high levels of misplaced material. The moisture constraint

has become increasingly limiting, since deep mine systems are now required to use water sprays during cutting of the coal to meet airborne dust regulations. The use of wetting agents is common to remove fine dust. These are all conditions which make air table feeds unacceptably wet. Some plants use thermally dried raw coal as air table feed, but the practice has not been widely adopted. The overall merit of pneumatic cleaning is to avoid the costly and complex dewatering systems essential to wet processing.

Hydrocyclones. Hydrocyclones (water-only cyclones) are generally used to beneficiate coal slimes, and their use has recently been extended to treat particles larger than 3/4 in. The systems are similar to heavy-media cyclones, but do not use any added heavy media such as magnetite; thus they are less costly to operate. Recent plant results⁷ have shown that the method can remove about 40-75% of pyritic sulfur with the actual recovery generally between 60-84%. The design parameters and operation of hydrocyclones have been described in Refs. 8 and 9.

The limitations of hydrocyclones are that they require large volumes of water and do not have the sharpness of separation possible with heavy-media systems. They would be better adapted to high-density separation (+1.70 specific gravity) or as a rougher separation device.

Froth Flotation. Froth flotation is used in coal preparation as a means to increase recovery of clean coal slimes, to concentrate coal particles from dilute suspensions, and to improve the quality of the float product. It is impractical to float particles much larger than 10 mesh, whereas very small particles ($<20 \mu\text{m}$) have such large reactive surface areas that they consume excessive levels of reagents while losing their surface selectivity.

Froth flotation has shown limited practical capability to reduce pyrite (sulfur) content in fine coals, since sulfides tend to be naturally hydrophobic. A reverse froth flotation concept has been developed¹⁰ in which a conventional first stage flotation concentrate is reprocessed with the addition of other reagents that depress the coal and improve the flotation of pyrite to substantially reduce sulfur content. This process is now under industrial pilot study. Others¹¹ have demonstrated the sensitivity of the many coal components (macerals and minerals) to separation by froth flotation.

Coal froth flotation, as a unit operation, is relatively inexpensive, but the subsequent recovery and dewatering of the extremely fine-sized products does not augur well economically for its wide adoption beyond recovery and beneficiation of existing fine particles.

There has recently been revived interest in processes related to bulk oil flotation (an earlier concept was termed Convertol), but with several modifications. Several were described at the 1976 International Coal Preparation Congress.^{12,13}

Solid-fluid Separation

After the separation of the desired clean coal and refuse products from each other, the particles must be subject to solid-fluid separations from the aqueous processing media and their moisture content reduced to acceptable levels (3-8% is usual). The selection, efficiency, and cost of any of these operations is highly particle-size dependent. For particles larger than 1/2 in., the surface area is sufficiently small that vibrating screens will separate the water and reduce the moisture content satisfactorily.

In the particle-size range between 1/2 in. and 400 mesh, dewatering screens can be applied, although the screen unit area required for particles less than 28 mesh increases so rapidly that it is more practical to subdivide the size range and handle them separately. Similarly, dewatering (classification) cyclones can be applied to this full size range; however, the classification size is controlled primarily by cyclone diameter. Small cyclones (<4-in. diameter) have such limited capacities that their use is impractical, suggesting the use of other approaches. Thickeners and/or settling basins are used to separate particles of less than 28 mesh.

Dewatering System

Products from dewatering screens in a size range of 1/2 in. to 60 mesh will have excessive moisture levels(>8%) that are generally reduced by basket centrifuges (mechanical dryers) to satisfactory levels. These devices tend to create some size degradation and have limited application with friable coals. Finer sizes may be dewatered in solid-bowl centrifuges.

The concentrated fine products from froth flotation cells, classification cyclones, fine-sized dewatering screens, thickeners, and settling basins usually contain water levels approaching 50% by weight. Vacuum-disc filters or pressure filters are used to reduce moisture content to the 20% level.

Dewatered fine products that contain excessive water contents are blended when possible with dryer coarse coal products. If the blending proves impractical, the only alternative is to resort to thermal drying. These devices are expensive and are especially prone to create unacceptable air pollution. Considerable study has been given to the use of steam and/or surface reagents¹⁴ with centrifugation or filtration processes to reduce solids moisture content and to thereby avoid thermal drying.

The relationships between these several solid-fluid separation and dewatering systems, including material balances, have been described by Charmbury.¹⁵

The increasing value of coal and greater plant sophistication demand much higher levels of plant control than has been previously practiced. Essential in this control is frequent sampling. Modern preparation plants incorporate continuous weightometers and automatic samplers. Continuous sampling of a heterogeneous material like coal is complex and expensive. The principles of these sampling operations have been detailed in Ref. 16.

5.1.3.3 Recent Developments in Coal Preparation

Although there has been a recent increase in research on innovative coal preparation procedures, none of them has reached commercial practice and few have been evaluated on even a small, continuous pilot plant test. Most of these concepts have the objective of sulfur reduction. Other studies¹⁷ seek to control organic maceral composition, which is more applicable to coal conversion feed stocks, but the techniques also relate to control of mineral matter composition, an important parameter for steam coals. The reduction of pyrite content may be accompanied by reduction of heavy-metal, trace-element levels.¹⁸ All of these proposed methods are subject to the theoretical limitations established by coal characteristics and technological considerations described previously and by pragmatic limitations of economics

and reliability risk. The high capitalization of preparation plants does not augur well for the rapid adoption of any exotic concept in the existing plants.

The major constraint in present coal desulfurization developments is the necessity of pulverizing the run-of-mine (ROM) coals before treatment to finer-sized (sometimes as small as 200 mesh) particles. Fine-coal processing results in lower unit capacity, generally reduced separation efficiency, reduced yields, greater costs, more difficulty in complying with preparation-associated environmental regulations, and more extensive dewatering systems. The justification, therefore, for the degree of fine grinding required would depend on the pyrite-size distribution (and total sulfur content) in the coal, the pollutant emissions from the process, and the costs related to the extent of cleaning desired.

Physical Separation Methods

Processes Based Only on Gravity Acceleration. The recently developed separation methods based on gravity include:

1. *Humphrey Spiral.* This device has long been used to clean fine coal (both anthracite and bituminous) although never widely adopted due to limited unit capacity and high water volume requirements. Recent studies have confirmed these limitations.¹⁹ The system is also used to beneficiate other minerals, such as iron ore.
2. *Pinched Sluice (Wet Systems).*^{20, 21} This approach is characterized by design simplicity. The feed slurry is introduced at the periphery of an angled pinched sluice to produce stratification (by size and density) with deepening of the stream flow. At the sluice discharge throat, each particle assumes a trajectory subject to gravity. The trajectory stream is separated into product fractions by one or more mechanical splitter blades. The sharpness of separation is a function of the particle trajectory stream dispersion.
3. *Pinched Sluice (Dry Systems) - DryFlo Separator.* This system, developed in England for heavy mineral separations, has been studied for application to fine coals.²² It is unique in its simplicity, and very high unit capacity (>2 tons/hr/ft² of bed area). It has been considered for direct use with feeds with top sizes ranging from 10-200 mesh. By the addition of a heavy media (such as magnetite) the size range can be extended to 1/4-in.

The main advantage of the system (use of air rather than water as the cleaning media) may also be its main constraint. The system must be utilized with free-flowing particles probably requiring moisture contents of less than 5%. Closely controlled feed-size consists are important and dust control may be difficult.

4. *Shaking Tables.* Beyond the capabilities of these proven and applied systems,⁶ two new devices were recently introduced by FMC, Inc.^{23,24} The FMC wet table offered good efficiency at substantially greater capacities (up to 40 tons/hr/deck), and the new dry table appears to be especially effective for processing large particle feeds (>1 in.) of low rank coals.
5. *Fine-coal Jigs.*¹⁸ The Batac jig with the compression chamber under the jig screen has three major United States applications that are in early commercial evaluation. Not only do they offer greater capacity (600 tons/hr) and better separation efficiency at low specific gravity (as low as 1.45 in many instances), but they also utilize extensive electronic control to permit wider variations in jiggling actions. The Batac jig is designed for treatment of both coarse- and fine-coal sizes and its performance in terms of sharpness of separation is high.^{25,26}

Processes Applying Physical Forces in Addition to Gravity. Centrifugal separation of pyrite in the dry state has been described, based upon the Pittsburgh seam in which the pyrite particles are uniquely small.²⁷ Effectiveness of separation increased with limited size fractions that intensified the response to particle density.

A similar concept has been combined with air-swept coal pulverizers prior to powdered coal injection into boilers for pulverized coal firing. In these systems, the harder, larger pyrite particles are rejected after liberation.

Processes Based Upon Induced Particle Charges (Electrophoresis). Recent laboratory studies²⁸ conducted by the Bureau of Mines have demonstrated that pyrite and other mineral impurities can be removed from coal by electrophoresis, but the power-input requirements to the system were deemed uneconomical at present for commercial use.

Processes Based upon Magnetic and Electrostatic Phenomena. Magnetic beneficiation of coal has been considered by numerous investigations over the years. Though slightly paramagnetic, pyrite will respond to only very

intense magnetic fields. Pyrite has a relative force of attraction of 0.23 in contrast to 100.0 for soft iron, 40.18 for magnetite, and 6.69 for pyrrhotite. Fields of such intensity are attainable, but their practical use has not been demonstrated. Also, attempts have been made to increase the magnetic response of pyrite by controlled oxidation and reduction. The theory of the concepts has been described.^{29,30,31}

A recent proposal of a related concept utilizes iron carbonyl vapor to enhance the magnetic response of pyrite. Pyritic sulfur reduction of 90%, accompanied by ash reduction of 9-25% and heat content increases of 25%, have been described.^{32,33}

Electrostatic procedures are based upon variations of electrical conductivity between particles. A charge is induced unidirectionally with subsequent controlled discharge rates. These principles will permit different physical placement of particles having varying compositions. Capacity limitations, the need for moisture control, and close sizing still appear to constrain application of the technique.^{34,35}

Froth Flotation and Related-Phenomena. Processes utilizing froth flotation include the following concepts.

1. The characteristics of one system were detailed in Section 5.1.3.2, including the two-stage process variation being evaluated by the U.S. Bureau of Mines.^{10,18} Pilot plant flotation tests of this variation showed pyritic rejections up to 80% for some coal feeds. Further industrial tests are being planned at a central Pennsylvania preparation plant.
2. The multiple-stage flotation concept has led to the development of the Leeds flotation column, giving a response similar to a distillation column. Units handling 1 ton solids/hr have been described.³⁶
3. Selective Slimes Flocculation³² is being studied by the U.S. Bureau of Mines as a means of improving coal recovery as well as quality.
4. The strong recent interest in oil agglomeration was previously described in Section 5.1.3.2.^{12,13,37} Coal particles may be reconstituted into low-ash and moisture agglomerates. The agglomerate size controls moisture content (larger agglomerates contain less water).

Processes to Reduce Moisture. Several techniques have been developed to assist in controlling the moisture content of cleaned coal. These include:

1. *High Frequency Vibrating Screens.*^{18, 38, 39} The devices, previously cited in Section 5.1.3.2 are used to treat feeds down to 14 mesh, although other media find application down to 400 mesh.
2. *Centrifuges.*^{18, 26} These now-standard devices are offered by many manufacturers and take the vibrating-centrifugal or solid-bowl format. Their performances continue to improve. Wear on the gaskets and replacement cost remain a significant economic consideration.
3. *Vacuum Filters.*^{18, 19, 26} Vacuum-disk filters are routinely used for several preparation plant applications in the United Kingdom, and improved performances are being accomplished, partly by the use of surfactants.⁴⁰ The first major commercial application of the pressure filter in the U.S., as applied to refuse slimes, has been recently announced.⁴¹
4. *Static Thickeners.*¹⁸ Environmental requirements for water quality control have increased the use and led to new designs and improved performance of these long-proven devices. Among the recently improved concepts are the Eis Clarifier^{26, 42, 43} and the Lamella Clarifier,⁴⁴ which handle substantially greater feed rates and improve overflow clarities.
5. *Refuse Combustion.*²⁶ A system to dewater and reduce the volume of refuse slime (as thickener underflow) by self-supporting combustion has been described.⁴⁵ The ash is slagged and pelletized for controlled disposal.

Chemical Separation Methods

Chemical treatment processes must be used to remove organic sulfur from coal, as well as the finely disseminated pyrites and mineral matter that cannot be removed completely or efficiently by physical separation. Several processes that involve leaching crushed or ground coal with aqueous solutions of various chemical agents are under development. Since these processes do not greatly alter the molecular structure of coal, they are potentially more economical and thermally efficient than coal gasification or liquefaction processes. On the other hand, the leaching processes are more involved than presently-used physical separation methods because they generally require the use of finer particle sizes, longer residence times, higher temperatures and pressures, special materials of construction, and

the need to recover and regenerate chemical leachants. Most of the chemical extraction processes suffer, to varying degrees, from slow rates of extraction, incomplete removal of organic sulfur, waste disposal problems, energy losses, and the difficulties of dewatering and handling fine-sized coal. Furthermore, these processes have generally only been demonstrated under controlled laboratory conditions with bench-scale apparatus. Nevertheless, some of these processes offer considerable promise for cleaning steam coals in the future, assuming major problems are solvable. Hence, contending chemical separation methods under development are briefly characterized and their development status reviewed below.

TRW-Meyers Process. The TRW-Meyers process for extracting inorganic sulfur from coal is the subject of a major development effort. Extensive bench-scale tests have shown that the method extracted over 90% of the pyritic sulfur from a number of coal samples from several different regions of the United States, as well as reduced the ash content of the samples from 10 to 30%.^{46,47} These samples were mainly high-volatile bituminous coals from Appalachian and interior coal basins, but they also include a low-volatile bituminous coal from Pennsylvania and a subbituminous coal from Montana.

The principles involved in the TRW-Meyers process are based on the reaction of pyrites with a hot solution of ferric sulfate that oxidizes the pyrites to soluble sulfates and elemental sulfur. After the coal and leach liquor are separated, elemental sulfur is removed from the coal by extraction with an organic solvent or by heating the coal to vaporize the sulfur.^{48,49} The spent leach liquor is regenerated through oxidation with air. A coal top size between 10 and 100 mesh, leaching temperature of 90 to 130°C, and coal residence time of 2 to 4 hr in the leaching unit are regarded as appropriate conditions for a commercial plant.^{46,48,49}

Although the TRW-Meyers process has only been demonstrated in bench-scale equipment, a reactor testing unit (or process development unit) is under construction and will be brought on-stream during 1977.⁴⁹ This unit is a limited pilot plant facility (8 ton/day) which is designed to demonstrate the pyrite extraction step and leach-liquor regeneration step, but not other steps in the process. The TRW-Meyers process produces elemental sulfur as a

by-product and a waste slurry containing iron and sulfur compounds and other inorganic materials extracted from coal. Besides not removing organic sulfur, the process is hampered by a relatively slow rate of pyrite extraction (about 75-90% removal in six hours⁵⁰).

Oxygen Leaching. Several methods have been proposed for leaching coal with hot aqueous solutions containing dissolved oxygen under pressure.⁵¹⁻⁵⁵ Pyrites are oxidized and converted into sulfuric acid and/or water-soluble sulfates that are readily extracted. Laboratory tests conducted at 130°C, with oxygen dissolved in the leaching solution under a pressure of 300 psi, extracted 90% of the pyritic sulfur from -100 mesh Illinois No. 6 bituminous coal in two hours.^{51, 52} Similar results were obtained with semi-anthracite coal and lignite. It was also shown that up to 30 to 40% of the organic sulfur can be removed from bituminous coals either by adding ammonium hydroxide to the leach solution⁵³ or by increasing the temperature above 150°C.⁵⁵ Although various schemes have been proposed for treating the spent leach solution, the most likely procedure involves adding lime to precipitate gypsum and iron oxide or hydroxide.^{51, 53} The precipitate is discarded and the water or aqua ammonia are recycled.

The oxygen leaching process is one of the few methods under development that offers the potential of extracting organic sulfur. However, to do so requires higher temperatures at which some oxidation of the coal takes place with an attendant loss of heating value. Thus a loss of 2-7% of the coal energy has been observed in the case of bituminous coal.⁵⁵ The loss would be greater in the case of lower rank coals.⁵² Development of dissolved-oxygen leaching methods has been confined to small laboratory batch and semi-continuous experiments. However, a bench-scale, continuous-flow reaction system to demonstrate the leaching step is under construction and should be in operation at the Pittsburgh Energy Research Center before the end of 1976.⁵⁵

Battelle Hydrothermal Process. The Battelle Hydrothermal Process utilizes a hot caustic solution to extract sulfur from coal ground so that about 70% passes a 200-mesh screen. The ground coal is leached with a solution containing about 10% sodium hydroxide and 2% calcium hydroxide for up to 30 minutes at a temperature of 225-350°C and under a pressure of

350-2500 psi.⁵⁶ Laboratory tests have shown that the method extricated from 87-99% of the pyritic sulfur and 24-72% of the organic sulfur from coal samples taken from six different mines in Ohio, Kentucky, Pennsylvania, and Illinois.⁵⁷ In addition, a large percentage of a number of potentially toxic or hazardous trace elements were extracted. By further treating the leached coal with dilute acid, much of the mineral matter was also removed. Thus after leaching with caustic and washing with acid, the ash content of the six different coals ranged from 0.7 to 5.3%, whereas before any treatment it ranged from 4.6 to 13.2%. The Hydrothermal Process involves a very complex scheme for regenerating the spent leach solution. Since the hot caustic leach solution is known to cause stress-corrosion cracking of stainless steel, the problem of containing this solution at an elevated pressure is unusually severe and high-nickel alloys may be required. Development of the Hydrothermal Process has reached the mini-plant stage at which the caustic leaching step is being tested in a small continuous-flow reactor.⁵⁸

Treatment with Nitric Acid or Nitrogen Oxides. Nitric acid has been used for a long time to extract pyrites from coal in the ASTM method of analysis.⁵⁹ Yurovskii⁶⁰ also proposed the use of nitric acid for an industrial desulfurization process, and showed in laboratory experiments that essentially all of the pyrite could be removed rapidly from various USSR coals by leaching with hot dilute nitric acid. Thus for 3.5 mm x 0 size coal and a reaction temperature of 90°C, most of the pyritic sulfur could be extracted in 8-15 minutes. The nitric acid also extracted iron, calcium, and magnesium compounds, and to a lesser extent aluminum compounds, so that the ash content of the coal was reduced from 10 to 40%, depending on the source of the coal and its mineral composition. Yurovskii proposed to recover nitrogen oxides evolved during the leaching step to regenerate nitric acid. Available sources of information do not indicate whether an industrial process based on nitric acid has advanced beyond small-scale laboratory experiments in the USSR. Further development of the process could be impeded if coal is nitrated as a result of the treatment.

More recently, Diaz and Guth⁶¹ proposed to treat fine-sized coal particles (ranging from 0.6 to 1.2 mm) in a fluidized-bed reactor with a hot

oxidizing gas mixture of air and nitrogen oxides. Pyrites are oxidized to sulfur dioxide and iron sulfate or sulfite, and in addition, organic sulfides in the coal are oxidized to sulfoxides and sulfones.⁶¹ Subsequent leaching of the solids with a dilute caustic solution extracts the sulfur present as sulfoxides, sulfones, sulfates, and sulfites. The gases issuing from the fluidized-bed reactor are treated to recover sulfur oxides, which are converted into sulfuric acid, and to recover nitrogen oxides which are recycled. When Lower Kittanning coal having an initial total sulfur content of 4.3% (3.6% pyritic and 0.7% organic sulfur) was treated in this manner, a product having a total sulfur content of 0.4% was obtained. Thus, the treatment seems to remove most of the pyritic sulfur and part of the organic sulfur. Laboratory development of the process by KVB Engineering, Inc. is continuing.^{62,63}

Combined Physical and Chemical Cleaning

A process that combined heavy-media separation and chemical leaching was demonstrated in 1956-57 in the USSR with a continuous pilot plant having a capacity of 200-300 kg/hr.⁶⁰ Coal and refuse particles (3 mm x 0) were first separated by a dense solution of ferric sulfate in a centrifugal separator. The recovered float coal was then leached with a hot solution of ferric sulfate and nitric acid. The combined treatment was credited with removing a large part of the inorganic sulfur and ash from a Donets Basin coal. However, it is not known whether the process advanced beyond the pilot-plant stage of development.

Bacteriological Process

The extraction of pyritic sulfur from coal by the action of iron- and/or sulfur-oxidizing bacteria, which are found in acid mine water, has been demonstrated in small-scale experiments. Under controlled laboratory conditions, from 50 to 76% of the pyritic sulfur was extracted from several finely ground (-325 mesh), U.S. bituminous coals after four days of incubation.⁶⁴ The bacteriological oxidation of lump coal in small open piles or in a small bunker has been studied in Czechoslovakia.⁶⁵ In one of the tests, the total sulfur content of brown coal (8 cm x 0) placed in a 1.5 m³ bunker was reduced 44% in two weeks and 56% in eight weeks. Larger-scale tests were

reported to be under way, with the main objective tending toward determining the maximum leaching efficiency achievable by this process in the shortest time.

5.1.3.4 Cost of Coal Preparation and Cost Comparisons Between the Use of Beneficiated Coal and Flue Gas Desulfurization for Sulfur Emission Control in Conventional Combustion

Costs of Coal Preparation

The actual cost of coal preparation processes is dependent primarily upon process yields. The higher the value of the run-of-mine coal, the more critical the yield factor. Historically, when coal could be mined for less than \$5.00/ton and a quality product was required, it was frequently found expedient to discard large fractions of the coals (usually fines that had limited, low-valued markets) to refuse piles. This practice was utilized simply because more coal could be mined less expensively than preparation or utilization of the fines. This situation no longer prevails.

The yield of clean coal attainable will vary with the native coal characteristics, the mining system, and the coal preparation technology employed. The effect of coal characteristics is basically defined by size and washability analyses. The levels of preparation and their unit operations have been detailed in Section 5.1.3.1.

The cost of preparing coal includes operating requirements (labor, power, maintenance, etc.) and amortization of the plant investment. These costs are expressed for three different preparation levels and several plant capacities in Table 5.2.

The cost implications of coal preparation on combustion energy systems are illustrated in Table 5.3 by an example comparing costs of run-of-mine coal to those for two levels of cleaned coal at: (1) the mine site, (2) the generating station (effect of transportation costs), (3) after pulverization at the station (effect of coal hardness), and (4) after combustion (effect of ash disposal costs). This example does not take into account additional benefits associated with the use of prepared coal, such as environmental benefits from reduced emissions of particulates and trace

Table 5.2 Preparation Plant Capital and Operating Costs⁶⁶

<u>Capital Costs^a</u>			
<u>Design Capacity-Clean Coal (tons/yr)</u>	<u>Level 4</u>	<u>Level 3^b</u>	<u>Level 2^b</u>
<u>Eastern Bituminous</u>			
3,000,000	\$25,200,000 ^c	\$11,200,000	\$ 3,200,000
2,000,000	17,500,000	8,100,000	2,500,000
1,000,000	9,000,000	4,350,000	1,500,000
<u>Western Subbituminous-Utility Coal^d</u>			
10,000,000			6,720,000
5,000,000			3,360,000
3,000,000			2,040,000
2,000,000			1,580,000
1,000,000			1,200,000
<u>Cleaning Costs (\$/ton)</u>			
<u>Design Capacity-Clean Coal (tons/yr)</u>			
<u>Eastern Bituminous</u>			
Operating Costs ^e	0.80-1.60	0.30-0.60	0.05
Depreciation-Return on Investment ^f			
3,000,000	2.01-3.01	0.93-1.33	0.59
2,000,000	2.18-3.14	1.01-1.45	0.69
1,000,000	2.25-3.23	1.09-1.56	0.83
Total Cleaning Cost			
3,000,000	2.90-4.61	1.23-1.93	0.64
2,000,000	2.98-4.74	1.31-2.05	0.74
1,000,000	3.05-4.83	1.39-2.16	0.88

Table 5.2 (Cont'd)

<u>Western Subbituminous Coals^g</u>	
Operating Costs	0.05
Depreciation-Return on Investment	0.24 ^h
Total Cleaning Cost	0.29

^aMid-1974 Dollars.

Level 4 - Detailed, elaborate facility (75% recovery).

Level 3 - Removal of liberated mineral matter (75% recovery).

Level 2 - Removal of only gross mineral matter (95% recovery).

^bLevels 2 and 3 in this table are approximately the same as the previously defined Levels 1 and 2, respectively.

^cThe capital costs utilized for cleaning eastern bituminous coals at Level 4 ranged between \$23,000 and \$25,000 per ton of raw feed capacity per hour. The value would increase to an estimated \$40,000 per ton hour if "Best Cleaning Technology Available" were developed (Level 5).

^dOnly Level 1 or 2 is applicable. Lignite - only Level 1 considered necessary.

^eIncludes labor, power, and maintenance - no amortization or return on investment. Thermal drying adds about 25% to capital costs and 30% to operating costs (included in value).

^fRange shown gives depreciation based on 20-yr plant life and 15% return on investment up to a 20-yr plant life and a 20% return on investment.

^gWestern subbituminous coal cleaning - ten million tons per year at Level 2. A 20% return on investment is assumed.

^hValue modified from original reference. Source: H.L. Lovell, Pennsylvania State University, personal communication (1977).

Table 5.3 Comparative Coal Costs for a Utility Utilizing
Cleaned Coal and Run-of-Mine Coal from the Same Mine⁶⁶
(May 1974 data)

Cost Parameter	ROM Coal	Prepared Coal ^a	
		Level 3	Level 4
Value at shipping point			
\$/ton	11.08 ^b	14.46 ^c	18.18 ^d
¢/10 ⁶ Btu	45.3	52.2	63.8
mills/kWh ^e	4.64	5.35	6.54
Value at utility (includes transportation) ^f			
\$/ton	14.87	18.25	21.97
¢/10 ⁶ Btu	60.7	65.9	77.1
mills/kWh	6.23	6.76	7.90
Value as fired (includes coal grinding costs) ^g			
\$/ton	15.11	18.38	22.09
¢/10 ⁶ Btu	61.7	66.4	77.6
mills/kWh	6.33	6.80	7.95
Total fuel costs at utility (includes ash disposal) ^h			
\$/ton	15.60	18.62	22.24
¢/10 ⁶ Btu	63.7	67.2	78.1
mills/kWh	6.53	6.89	8.01
<u>Coal Data</u>			
Material Yield (%)		83.2	73.5
Thermal loss in cleaning (%)		5.85	14.49
Heat Content (Btu/lb)	12,240	13,850	14,240
Ash Content (%)	16.4	7.9	5.1
Sulfur Content (%)	1.70	1.30	0.95

^aAssumed cleaning cost \$1.50/ton of clean coal for Level 3 and \$3.75/ton for Level 4. A constant moisture content for run-of-mine and cleaned coal is assumed. Level 3 in this table is nearly the same as the previously defined Level 2.

^bValue of run-of-mine coal as mined assumed to be \$9.28/ton. Selling price would increase to \$11.08/ton by adding \$1.08/ton for UMWA pension fund. Processing losses require an input of 1.20 tons run-of-mine coal to prepare 1.00 ton of clean coal.

Table 5.3 (Cont'd)

^cBased on central Pennsylvania low-volatile bituminous coal assessed at \$14.46/ton based on average U.S. selling price for utility coal in May 1974. This price was equivalent to 65.8¢/10⁶ Btu, and represents an average calorific content of 11,000 Btu/lb. Source: Federal Power Commission data, *Coal News*, No. 4226, 8/14/74, National Coal Association, Washington, D.C. It is further assumed for this example that the figure of \$14.46/ton includes \$1.80/ton contribution to the UMWA pension fund.

^dValue includes cost of 1.36 tons ROM coal at 73.5% yield at \$9.28/ton (\$12.63) plus cleaning cost of \$3.75/ton of clean coal plus \$1.80/ton UMWA pension fund.

^e1971 U.S. average for coal: 10,252 Btu^e used to generate 1 kWh.

^fAssumed shipping cost \$3.79/ton (for 1973). Source: *Coal Traffic Annual*, 1974 edition, p.27, National Coal Association, Washington, D.C. The cost advantages of storage and handling 20% less coal in cleaned form at the power station have not been included.

^gThe grinding of coal for pulverized firing to 70% minus 200 mesh requires energy consumption which varies with coal hardness. Hardness is usually expressed as Hardgrove Grindability Index. A 55 HGI coal uses 7.9 kWh/ton, a 100 HGI coal uses 4.4 kWh/ton, and a 110 HGI coal uses 4.0 kWh/ton. For these calculations power was charged at 3 cents per kWh. The value for the softer coal was utilized for clean coal while the harder coal value was used for run-of-mine coal. Source: Private communication, Richard Borio, Combustion Engineering, Inc., Windsor, Conn. (Feb. 1975).

^hCalculations based upon \$3.00/ton for ash disposal at the utility.

elements, operational benefits from reduced maintenance, and increased reliability. Most of these factors cannot be satisfactorily quantified until additional information now being compiled on the use of cleaned coal has been evaluated.

There are also several aspects of existing sulfur oxide emission standards to be considered. The Clean Air Act of 1970 established emission standards applicable to new stationary power sources whose construction or modification was initiated after August 1971. These regulations limit emissions to 1.2 lb SO₂/10⁶ Btu fired as a 2-hr average. The State Implementation Plans for existing combustion facilities are based on air basin regions, relate to population centers, and vary with heat input rate (enforcement by mid 1975 with deferrals to 1977). The allowed emission levels range widely, but generally are between 1.2 and 4.0 lb SO₂/10⁶ Btu. The ambient air standards are grouped into primary (health hazard) levels (0.03 ppm SO₂ annual average, 0.14 ppm SO₂ daily maximum, and 500 ppm SO₂ maximum), and secondary (public welfare) levels (0.02 ppm SO₂ annual average and 0.10 ppm SO₂ daily maximum). Currently Congress is considering the "Clean Air Act Amendment of 1976" - HB 10498 and S 3219. Existing law requires continuous control of emissions from all new and most existing capacity power plants by 1980. Thus, time factors become critical, since it is questionable if all continuous emission control technologies will be adequate within the next decade. The real decision may well be one of optimization. The energy choices for the future have recently been detailed by the Energy Research and Development Administration.⁶⁷

Cost Comparisons between the Use of Cleaned Coal (or Low Sulfur Coal) in Contrast to Flue Gas Desulfurization. There are two critical but broad limitations that remain unquantified in considering these two approaches:

1. What is the potentially available supply of existing low sulfur coal and coals capable of being beneficiated to meet sulfur emission requirements? The question involves the location of the coal deposits, generating station locations, the development of new mines and preparation facilities, preparation-energy system economics, and alternative technologies like pressurized fluidized-bed combustion and coal conversion to "clean fuels". Most important however, is the nature of the nation's growing energy and environmental policies.

2. What will be the reliability, actual costs, and environmental impacts of flue gas desulfurization technology as it unfolds in commercial application?

Efforts to quantify these two questions were made by the Commerce Technical Advisory Board Panel on Sulfur Oxide Control Technology in 1975^{66,68,69} when it considered coal-fired electricity generating plants in the northeastern United States. Some of the conclusions of that group are listed in Table 5.4. In terms of the estimated incremental cost range of 4-6 mills/kWh for continuous SO₂ emission controls, the 0.5-2.0 mills/kWh for coal cleaning is quite attractive. The comparative capital costs are shown in Table 5.5.⁶⁸

The advantages of using clean coal are defined and constrained by the availability of adequately washed coal and its cost. Such a fuel does not implicate any major changes in combustion facilities (existing or new) with the potential exception of detailed control of ash behavior in the combustion unit and in control of particulate collection due to reduced particle ionization capability. The use of prepared coal holds potential for improved combustion efficiency.

In contrast, besides the lack of adequate experience, the flue gas desulfurization concept will require major additional capital expenditures, reduced plant efficiencies due to power consumption by the scrubber, further energy expenditures in the production and transportation of scrubber reagents, and a major, costly environmental control problem associated with disposal of scrubber sludges. Even with the advent of reliable regenerative scrubber systems, there must be an economic trade-off.

In those situations where acceptable low sulfur coals are not available or coals cannot be totally cleaned to meet existing sulfur emission regulations, combinations of coal preparation and flue gas desulfurization appear promising and should be carefully reviewed. The removal of pyritic sulfur and mineral matter by washing reduces the amount of SO_x to be removed by flue gas desulfurization, lowers the amount of lime/limestone needed and consequently reduces the resulting sludge and ash with cost advantages in many instances. Specific site, market, and lead time constraints will determine the most economical and practical technology for a given plant.

Table 5.4 Potential Capacities and Operating Costs of Commercially Available Continuous SO_x Controls^{6,8}

Control Technology	Lead Time (Years)	Potential Capacity by 1980	Increase in generating costs (Mills/kWh)
Low Sulfur Coal ^a	3-6	20,000-40,000 MWe	4-7
Coal Cleaning	3-4	200-300 million tons coal per year ^b	0.5-2
Lime/Limestone FGD	4-7	45,000-55,000 MWe	4-6 ^c
-or-			-or-
Lime/Limestone FGD with Coal Cleaning ^d	4-7	Somewhat more than 45,000-55,000 MWe for FGD above	3-5 ^c

^aCoal meeting New Source Performance Standards, i.e., 1.2 lb SO_x/10⁶ Btu.

^bOnly a minor fraction of the product meets existing SO_x emission standards.

^cBased on a new 1000 MWe plant using 3% sulfur northern Appalachian coal, and meeting New Source Performance Standards.

^dUse of the combined strategy instead of FGD alone reduces the sludge disposal and FGD capacities needed, thus increasing the capacity available by 1980.

Table 5.5 Capital Costs for Commercially Available
Continuous SO_x Control Technologies^{a, 6, 8}

Control Technology	Cost to the Utility (\$/kWe)		Cost to the Coal Producer (\$/kWe)
Lime/Limestone FGD	FGD Units	\$54-69	-
	Sludge Disposal	\$10-50 ^b	
	Total	\$64-119	
Lime/Limestone FGD with High Coal Cleaning	FGD Units	\$36-49	\$16-23
	Sludge Disposal	\$ 3-14 ^b	
	Total	\$39-63	
Lime/Limestone FGD with Moderate Coal Cleaning	FGD Units	\$42-54	\$ 7-11
	Sludge Disposal	\$ 4-20 ^b	
	Total	\$46-74	
Low Sulfur Coal ^c	\$5-15		No increment for low over high sulfur coal
Coal Cleaning Only	-		\$ 7-23

^aBased on a new 1000-MWe plant using 3% sulfur northern Appalachian coal and meeting New Source Performance Standards.

^bThe utility may in some instances contract for sludge disposal, lowering its capital investment, while generally raising the operating cost.

^cCoal meeting New Source Performance Standards, i.e., 1.2 lbs. SO_x/10⁶ Btu.

5.1.4 *Constraints in Preparation of United States Coals*

The constraints considered here are independent of coal availability problems (time required for opening functioning new mines and preparation facilities), the availability of coal transportation (rail hopper cars, barges, etc.), and the availability of development capital within the framework of the existing national energy policy. The constraints may be categorized as: (1) in situ coal characteristics, (2) process technology, and (3) environmental control technology.

5.1.4.1 *Technical Constraints to Coal Preparation Occasioned by Coal Characteristics*

Coal characteristics control preparation capability primarily by the coal component particle sizes, properties that vary the difficulty of component liberation, and the relative amounts of near gravity material in a process feed stock. These constraints are related to industrial preparation potential by the principles discussed in Section 5.1.3.1.

Fortunately, significant amounts of the mineral matter occur in larger size components ($>5\text{mm}$) although much exists in smaller units. A great deal of the mineral matter can be liberated as particles with densities greater than 2.0 g/cm^3 and may be readily separated from the coal (Level 1 preparation). Other coal mineral components incorporate high carbonaceous contents (densities between 1.5 and 2.0) and are more difficult to remove (Level 2 preparation). Still other mineral components are very small and highly intermixed with the coal macerals (as in micrinite and fusinite) and can be only partially removed by more intense cleaning (Levels 3, 4, and 5 preparation), where separations are made at lower densities that reflect constraints of near gravity levels, lower recoveries, lower unit capacities, and require more sophisticated preparation flowsheets.

Although sulfur reduction constraints follow trends similar to other coal mineral components, there are distinct differences. Sulfur occurs in coals in two primary forms: organically-bound sulfur and pyrite (marcasite). Organic sulfur is generally considered to be noncontrollable by mechanical cleaning, although there are recent indications that some slight reduction can be achieved by separation of organic-sulfur-rich macerals. The pyritic sulfur content of coals varies greatly from seam to seam (and within seams),

as does the pyrite particle-size distribution. These variations account for the pyritic-sulfur-reduction potential by mechanical washing, which ranges from less than 10 to more than 90%.

In general, those pyritic particles having greater than 28 mesh (600 μm) dimensions can be rejected. Pyrite particles ranging between 40 and 600 μm , though more difficult to liberate and reject, can be removed to the degree afforded by preparation plant sophistication and efficiency. Pyrite particles less than 40 μm , even if liberated, are subject to limited rejection at best.

Some indication of the ash and sulfur reduction potential of U.S. coals by mechanical preparation are shown in Tables 5.6 and 5.7. However, such composite data obviously lacks the detail that can be displayed for individual seam sample data sets.

5.1.4.2 Technical Constraints to Coal Preparation Occasioned by Process Technology

The technical constraints to be described exist basically because of a lack of demonstrated need and because of economics involving excessive long-term financial risks that could not be justified. Mechanical coal preparation processes are low-energy consumption and high-capacity concepts, with some plant capacities exceeding 1500 tons per hour.

As previously described (Section 5.1.3.1 and 5.1.4.1), the basic technical constraints in conventional coal cleaning plants are (1) the inability to reject organic sulfur, (2) the lack of efficient mass separation processes for particle sizes down to 40 μm or less, and (3) the environmental problems associated with dewatering fine particles (Section 5.1.4.3).

Organic Sulfur Reduction

With the lack of sufficient energy to break the molecular bonds, existing mechanical methods are not capable of separating any chemically-bound organic sulfur. Higher energy (and cost) concepts considered in Section 5.1.3.3 have also shown but limited removal potential for organic sulfur. With the extension of these concepts to the "coal conversion" approaches that completely destroy coal structure, as in the manufacture of synthetic gas and liquid fuels, the potentials may well be raised.

Table 5.6 Composite Product Analyses for Prepared U.S. Coals^{a,1}

Region	Cumulative Analyses of Float 1.60 Product						
	Percent		Pyritic Sulfur	Total Sulfur	SO ₂ /10 ⁶ Btu ^b (1b)	Calorific Content (Btu/lb) ^c	SO ₂ removal efficiency required ^d (%)
	Btu Recovery	Ash					
Northern Appalachian	92.5	8.0	0.85	1.86	2.7	13,766	56
Southern Appalachian	96.1	5.1	0.19	0.91	1.3	14,197	8
Alabama	96.4	5.8	0.49	1.16	1.7	14,264	29
Eastern Midwest	94.9	7.5	1.03	2.74	4.2	13,138	71
Western Midwest	91.7	8.3	1.80	3.59	5.5	13,209	78
Western	97.6	6.3	0.10	0.56	0.9	12,779	none
Total United States	93.8	7.5	0.85	2.30	3.0	13,530	60

^aBased upon crushing to 3/8-in. top size and separated at a specific gravity of 1.60.

^bBased upon the moisture-free Btu value for the float coal and assuming all the sulfur is converted to SO₂. Actual emissions will vary depending upon the as-fired coal moisture content and the amount of sulfur that actually goes out the stack as SO₂.

^cThe calorific content (moisture-free basis was used to calculate the SO₂ removal efficiency required).

^dValues may require adjustment to account for the as-fired coal moisture content and the amount of sulfur that actually goes out the stack as SO₂.

Table 5.7 Enhancement of Coal Quality by Beneficiation⁶⁸

Coal Parameters ^c	Coal Characteristics ^a			
	Coal Seam Analysis	As Mined ^b	Level 3 ^d Bene- ficiation	Level 4 Bene- ficiation
Northern Appalachian				
Ash (%)	14.7	17.7	7.4	5.8
Sulfur (%)	3.07	2.98	1.96	1.62
Btu/lb	11,475	11,120	12,821	13,233
1b SO ₂ /10 ⁶ Btu	5.08	5.08	2.90	2.32
Southern Appalachian				
Ash (%)	11.2	14.2	4.3	3.9
Sulfur (%)	0.93	0.90	0.81	0.81
Btu/lb	12,720	12,330	14,030	14,261
1b SO ₂ /10 ⁶ Btu	1.61	1.61	1.10	1.08
Mid-Western (Eastern Block)				
Ash (%)	14.1	17.1	7.0	5.3
Sulfur (%)	3.92	3.80	2.72	2.47
Btu/lb	11,412	11,070	12,714	13,134
1b SO ₂ /10 ⁶ Btu	6.52	6.52	4.06	3.57
Mid-Western (Western Block)				
Ash (%)	14.5	17.5	6.5	5.8
Sulfur (%)	3.72	3.61	2.15	2.06
Btu/lb	11,018	10,680	12,425	12,674
1b SO ₂ /10 ⁶ Btu	6.41	6.41	3.29	3.00

^aBased on information from *Steam Electric Plant Factors*, National Coal Association, Washington, D.C., (1974), and A.W. Deurbrouck, *Sulfur Reduction Potential of the Coals of the United States*, Report of Investigation 7633, U.S. Bureau of Mines (1972).

^bRun-of-mine (ROM) coal. Assumes the ash content is increased by 3% due to inert material added by the mining operation.

^cDry coal analysis.

^dLevel 3 in this table is essentially the same as the Level 2 cleaning defined previously in this report.

Pyritic Sulfur Rejection

Present preparation methods are highly effective in rejection of nearly all liberated pyrite in particle sizes down to 28 mesh. With many coals, particle separation at decreasingly lower densities (<1.60) will reject more pyrite (and ash) with an accompanying loss of coal. The attainment of liberation by crushing to increasingly smaller sizes permits further rejection of pyrite. These potentials vary widely for U.S. coals and have been detailed.¹

However, with the development of smaller particle sizes and use of lower separating densities, the processing necessarily becomes more complex and costly and tends toward less separational efficiencies.

With minus 28 mesh particles, the separational procedures and efficiencies become more nebulous and product-process specific. The pyritic rejection trend is toward decreasing efficiency even if the pyrite is liberated. In many coals, pyrite liberation is not fully attained even at the 40- μ m level. Current preparation technology is now being directed to clean and recover those particles smaller than 28 mesh that exist in the plant feed as a result of mining, or are developed in the plant for size-consist control and liberation of mineral components down to top sizes of 3/8 in. Any plan aimed at exceeding this practice and attaining smaller top sizes to achieve greater liberation would have to establish a new direction in preparation technology, which would encompass both advanced physical and chemical methods. Although there is a need for these methods, much additional research and development would be required.

5.1.4.3 Environmental Constraints to Coal Preparation Occasioned by Commercial Preparation Technology

As a result of more stringent state and federal regulations, the coal preparation industry has, over the years, become increasingly involved with problems of air, water, solid wastes, and noise pollution emissions. Control devices can generally be designed to minimize a specific pollutant emission, yet they may also simply be transferring the problems into the area of disposing of collected wastes or pollutants. The basic environmental constraints associated with coal preparation exist in the identification of emission

sources, the characterization of pollutants emitted from such sources, the identification or design of pollution controls, and finally, the analysis of cost-benefits derived from the installation of these control systems.

Pollutants are emitted from all coal preparation plants. They arise not only from the processing units themselves but also from associated operations related to storage, handling, and transfer of materials within the plants, as well as disposal of refuse produced by coal preparation. The extent of emissions resulting from these operations will depend largely upon the properties (including the extent of moisture present), grades, and level of preparation of the coal being processed; and the types of equipment utilized for the removal of sulfur (pyritic) and other mineral components.

Table 5.8 lists the various sources, pollutants, emissions, and associated control technologies in a typical coal preparation plant. Major sources of pollutant emissions include operations such as coal storage, crushing, conveying, screening, thermal drying, and refuse disposal. Emissions from these various sources, if left uncontrolled, can enter all environmental media. Although design measures can be used to lessen or eliminate many of the pollutants, the most difficult control problems experienced by present coal preparation facilities are: (1) closing of plant's water circuit allowing zero discharge of process water to the surrounding environment,^{70,71} (2) determination of a suitable location for disposal of sludge (generally of sizes <35 mesh) from the wastewater treatment system, (3) prevention of drainage and runoff from coal storage and refuse piles, and (4) development and demonstration of noise control retrofit techniques for existing coal preparation plants.⁷²

With current emphasis continuing to be placed on plants capable of high rates of sulfur removal (often resulting in an increased amount of fine coal to be processed), a balance in the economics of coal preparation must be reached between cleaning efficiency vs. coal recovery and waste treatment. As mentioned in Section 5.1.3.1, plants capable of achieving higher levels of sulfur reduction often employ more sophisticated (and therefore more costly) recovery systems for finer-sized solid particles. Dewatering of these fine solids (either as products or refuse) and their subsequent transport or disposal are generally limited to a few viable alternatives.^{70,73}

Table 5.8 Environmental Pollutants Resulting from Operation of a Typical Coal Preparation Plant

Emission	Sources	Pollutant	Pollution Levels (uncontrolled)	Regulation	Control Technology
Air ⁷⁷⁻⁷⁹	Thermal dryers	NO _x	40-70 ppm	-	none
		SO _x	0-11.2 ppm	-	none
		HC	20-100 ppm	-	none
		CO	<50 ppm	-	none
		Particulates	5-20 gr/dscf	0.031 gr/dscf <2G% opacity	Cyclones, fabric filters, wet scrubbers, etc.
	Crushing, screening, conveying, loading, storage, refuse, disposal, etc.	Dust (particulates)	-	<20% opacity	Enclosed conveyors, silo storage, dust collectors, etc.
	Pneumatic cleaning (air tables)	Particulates	0.16 gr/dscf	0.018 gr/dscf <10% opacity	Cyclones, fabric filters, wet scrubbers, etc.
	Refuse piles (spontaneous combustion) ⁸⁰	SO _x , smoke, particulates, etc.	-	MESA ⁸²	Proper spreading and compacting of refuse at landfill.
Proposed Limitations Based on Best Practicable Control Technology Currently Available					
Water ^{81, 82}	Process water in "closed" circuit preparation plant	pH	7.3-8.1	30-Day Average	Daily Maximum
		Total suspended solids including minerals, fine coal particles, trace elements, etc.	2698-156,400 mg/l	No discharge of process water from plant	No discharge of process water from plant
		Total dissolved solids including minerals, trace elements, salts, etc.	636-2240 mg/l		
		Chemical additives for plant's water clarification system ⁸³	500-1000 mg/l		
					Chemical neutralization and precipitation
					Thickeners, settling ponds, filtration, etc.
					Desalination such as the Sul-bisul and the Modified Desal process ⁸¹
					NA ^b

Table 5.8 (Cont'd)

				Proposed Limitations Based on Best Practicable Control Tech- nology Currently Available		
Emission	Sources	Pollutant	Pollution Levels (uncontrolled)	30-Day Average	Daily Maximum	Control Technology
	Coal storage, refuse piles, and coal pre- paration plant ancillary areas ^c	pH	2.5-8.2	6-9	6-9	Pond lining, chemical fixation, compaction of refuse, excavation and diversion of run- off at disposal site, etc.
		Total suspended solids	12-668 mg/l	35 mg/l	70 mg/l	
		Total dissolved solids	260-15,359 mg/l	-	-	
		Iron, total	0.01-980 mg/l	3.5 mg/l	7.0 mg/l	
		Iron, dissolved	0.01-970 mg/l	0.3 mg/l	0.6 mg/l	
		Manganese, total	0.04-9.17 mg/l	2.0 mg/l	4.0 mg/l	
		Aluminum, total	0.1-69.3 mg/l	-	-	
		Zinc, total	0.01-7.2 mg/l	-	-	
		Nickel, total	0.01-2.6 mg/l	-	-	
		Strontium, total	0.03-9.4 mg/l	-	-	
		Sulfate	68-7508 mg/l	-	-	
		Chloride	3.3-1940 mg/l	-	-	
		Fluoride	0.18-2.2 mg/l	-	-	
		Ammonia	0.09-35 mg/l	-	-	

Table 5.8 (Cont'd)

Emission	Sources	Pollutant	Pollution Levels (uncontrolled)	Regulation Applicable to All Coal Preparation Equipments		Control Technology
				Permissible	Duration	
Noise ^{72, 88, 89}	Car shakeout	NA	110-120 dBA	140 dBA	instantaneous	Replaced by rotary dump, enclosures
				115 dBA	>1/4 hr	
				110 dBA	1/2 hr	
	Chutes (steel), crushers, breakers, pumps (vacuum), fans, and blowers	NA	90-115 dBA	105 dBA	1 hr	Rubber linings, equipment modifications, muffler installations, enclosures
				100 dBA	2 hr	
				95 dBA	4 hr	
				90 dBA	8 hr	
	Screens	NA	95-105 dBA			Equipment modifications, enclosures
	Motors	NA	85-100 dBA			Enclosures
	Picking Tables	NA	90-95 dBA			Replaced by rotary breakers, enclosures

^aMining Enforcement and Safety Administration.

^bNot applicable.

^cData are referred mostly to surface water contamination.

^dAmounts vary depending upon the level of preparation practiced (see Section 5.1.3.1).

The difficulty involved in the handling of these dewatered materials often increases with the increasing percentage of moisture contained in the solids. Although a number of new and existing coal dewatering methods⁷⁴⁻⁷⁶ have been under investigation during recent years, the final selection is governed by the economics of the available methods and can vary significantly according to the plant site and plant type.

5.1.5 Recommendations and Conclusions

With an established national intent to utilize more of its extensive coal reserves in supplying energy demands over the next several decades, and the existing environmental regulations that mitigate against such expanded coal development, coal preparation has been recognized as being one of the many possible means to resolve these contradictory trends for power generation.

The present constraints related to coal preparation are for the most part cost-based. The reduction of both mineral matter (ash) and sulfur content of steam coals is of concern, with emphasis placed upon sulfur rejection. Many coals having sulfur levels that fail to meet air pollution standards can be satisfactorily upgraded through coal preparation. Others that cannot be cleaned to meet these standards can be improved to such levels, which when combined with flue gas desulfurization, may result in a more economical and best all-around choice. The relationships between coal reserve and coal consumption locations and coal preparation potentialities are all site-specific.

The technological limitations to extending the potentialities of coal preparation for sulfur reduction include the process inability to reject organic sulfur, the requirements for intense pyrite liberation, the complexities and inefficiencies of processing minus-28-mesh particles and removing water from them after processing, and difficulty in the transportation of finely-divided coal products.

Coals can be prepared to several levels, depending upon consumer specifications and system economics. More intense cleaning requires greater preparation plant sophistication, results in lower yields, and is more costly. Coal preparation plant facilities are individually designed for a given type of coal, market, and industrial setting.

Coal preparation plants now cost between \$5,000-\$40,000 per ton-hr capacity. The processing costs range from \$0.05 to nearly \$5.00 per ton (including depreciation). In many situations the utilization of the prepared product will result in economic and process advantages that may offset these preparation costs.

From a bus-bar cost range of 17-22 mills/kWh to generate electricity, an incremental cost of 0.5-2.0 mills/kWh is estimated for the use of cleaned coals in contrast to 4-6 mills/kWh when lime/limestone flue gas desulfurization is employed. For those situations where coal preparation alone will not meet SO₂ regulations, the combination of coal cleaning-flue gas scrubbing appears to represent a promising alternative.

It is recommended that the utilization of prepared coal be carefully evaluated for all new and existing electrical generating stations and other coal consumers. In many cases, the use of cleaned coal can have economic and process advantages that should not be overlooked.

Other recommendations for the application of preparation to steam coals are:

1. Technical and economic factors for the use of prepared coals should be assessed for each electrical generating station, because the parameters are highly site-specific.
2. The potential of more intense physical coal preparation (especially sulfur reduction) should be evaluated against alternate control technologies or combinations thereof (e.g., chemical cleaning vs. flue gas desulfurization, fluidized-bed combustion, low-Btu coal gasification/combined cycle, etc.).
3. Analytical studies of the characteristics of U.S. coal seams should continue.
4. Coal preparation research should continue to emphasize development of improved technologies for the cleaning of coals of all sizes less than 1/4 in. These studies should include:
 - Evaluation and development of improved fine-coal dewatering, handling, and drying techniques.
 - Demonstration and operation of improved fine-coal recovery systems.

5. Emphasis in environmental research related to coal preparation should continue to be placed on:
 - The characterization of runoff and drainage of waste-water effluents.
 - The development of improved pollution control technologies on all emissions including noise.
 - The treatment and disposal of fine-coal wastes.
6. Efforts should continue on the optimization of process conditions for the various desulfurization methods under development (especially chemical) and should be expanded to include the assessment of their potential for extracting nitrogen, trace elements, and/or mineral impurities.
7. The economics and feasibility of employing chemical processing for additional beneficiation after physical coal cleaning should be evaluated.

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5.2 USE OF LOW SULFUR COAL

5.2.1 Introduction

In recent years a major shift toward low sulfur coal has occurred among electric utilities. Some of the events contributing toward this shift include delays in nuclear power construction and operation, the national objective of reducing oil imports, and most importantly, the enactment of federal sulfur dioxide emission standards. Since these events are likely to continue to have an important impact on the electric utility sector for at least the next 10 years, low sulfur coal will continue to be an important utility fuel source. This unprecedented demand for low sulfur coal by electric utilities and industrial firms has created considerable uncertainty regarding the availability of this premium fuel and its price. At the center of this problem is the fact that major demand centers are located in the East and Midwest, far from the principal reserves of low sulfur coal in the West.

This section of the report examines the possibilities for expanding low sulfur coal production, the price levels associated with meeting demand, and the constraints on utilization. Mining areas in the Northern Great Plains, Rocky Mountains, and Appalachia are analyzed to determine the cost of new mine output. Transport charges are computed from these mining areas to a number of utility demand centers throughout the nation. The combination of these factors, along with price modifications dictated by competitive market forces, determine the delivered price of low sulfur coal.

Apart from the constraints associated with the production and distribution of low sulfur western coals in the midwestern utility markets, constraints associated with their utilization in boilers designed to burn midwestern coal are also important. Low sulfur western coals generally are of a lower quality than midwestern coals in terms of moisture content, calorific value, and ash characteristics. The three main areas where problems could be encountered while burning such western coals are:

1. Problems associated with stockpiling.
2. Necessary boiler modifications, including modifications to the coal handling systems directly associated with the boiler.
3. Derating of the boiler.

5.2.2 *Minemouth Price of Coal*

Although the cost of production plays a key role in determining the market price of coal, the price received at a given mine is not always related to its own costs of production. Many mines have unit costs that are lower than the prices they can obtain in the market. The mining costs that most accurately match the market price for coal are those of the marginal producers within each producing area. This is essentially explained by the nature of competitive markets such as the coal industry. In a competitive market, all buyers and sellers ask the same price for a given commodity. If, at this market clearing price and output, there happen to be mines with different production costs, the mine with the highest unit cost that can still be covered by the market price (i.e., the "marginal mine") will be the price leader for the area. All other producers in the same market area will receive an equivalent price, but because of their lower costs, earn a surplus profit.

Numerous studies have been done which estimate production costs for representative areas throughout the country.^{1,2} These studies relate surface and underground mining costs to mine size, seam thickness, overburden ratio, and other factors influencing the average cost of mining a ton of coal. Although these studies are very thorough in examining detailed mine inputs and their respective costs, they generally fail to explain why price often deviates from cost. That is to say, why the unit production cost for a "model" mine is often much less than the market price actually received for coal. By adjusting these engineering cost studies to reflect the mining conditions of marginal mines (generally smaller and less productive), one obtains a more reliable relationship between cost and price.

The production costs forecasted for 1985 for each of six major low sulfur mining areas have been calculated as shown in Table 5.9. Coal supply costs were estimated by devising supply curves for each type of coal within representative coal provinces. Representative mining areas were determined after considering the significance and similarity in characteristics of coal deposits. The Appalachian Provinces were divided into northern and southern parts to reduce the large area of the single province (which makes specification of one geographic centroid as a shipping point difficult) and to capture the distributions of coal types in the northern and southern parts. Northern Appalachia has relatively lower reserves of low sulfur coal than Southern Appalachia. Very little low sulfur coal lies between Appalachia and the western supply areas. Therefore, no low sulfur coal supply source was constructed for the Interior coal province.

The large land area contained in the western coal fields and the wide varieties of coal available suggested four major subdivisions: Powder River, Uinta, Hanna, and San Juan. Powder River encompasses the subbituminous Powder River region of Montana and northern Wyoming. Southern Wyoming, which contains coal of a higher heat content than that found in the Powder River area, comprises the Hanna region. The southern Rocky Mountain areas were subdivided into two regions -- Uinta and San Juan. Uinta in this report refers to the subbituminous reserves in northern Colorado and Utah, while the San Juan area covers the subbituminous fields of New Mexico and southern Colorado.

Table 5.9 Coal Production Costs for Marginal Mines in 1985

Region	Mining Area	Cost of Coal at Mine (\$/ton)	Processing and Movement to Railhead (\$/ton)	Cost at Railhead ^a (\$/ton)
Northern Appalachia	Westmoreland Co., PA	23.40	1.38	24.78
Southern Appalachia	Raleigh Co., WV	22.16	1.38	23.54
Powder River	Powder River Co., MT	5.16	.30	5.46
Hanna	Carbon Co., WY	5.90	.30	6.20
Uinta	Carbon Co., UT	14.87	.30	15.17
San Juan	San Juan Co., NM	7.50	.30	7.80

^aThese costs are in constant 1975 dollars. Inflation over the period will cause actual costs in 1985 to be somewhat higher.

The procedure employed to calculate the production costs is detailed below. Some critical assumptions underlying this procedure are:

1. The production costs of the marginal mine will determine the market price in each region.
2. The parameters of seam thickness, mine output, and mine depth affect deep mine costs. Overburden ratio and mine output influence strip mine costs.
3. Capital equipment costs are assumed constant in real terms until 1985. This conclusion assumes no capital shortage developing by 1985.
4. Coal production levels are predicated on meeting 1.1 billion tons of coal by 1985, with 695 million tons going to electric utilities.

5.2.3 Price Premiums for Low Sulfur Coal

The costs cited above are for average quality coal extracted from the marginal mines in each area. Thus, they are equivalent to the average price of coal produced in each region. However, coal low in sulfur content has sold for considerably more than coal with relatively more sulfur, particularly since the passage of the Clean Air Act.

Even though utilities are known to place a considerable premium on low sulfur coal, efforts to obtain an accurate quantitative relationship between price and sulfur content have generally been unsuccessful.* A less formal procedure, therefore, has been used in this report.

Although the exact market premium offered for low sulfur coal is difficult to quantify, this premium should be related in a predictable way to the cost of sulfur control technologies. The premium for low sulfur coal should be no greater than the cost differential between using low sulfur coal directly and using higher sulfur coal with a scrubber. This can be shown in the relationship:

$$S \leq (P + T)_H + C - (P + T)_L$$

where:

S = low sulfur premium,

P = the marginal cost of production,

T = transportation cost,

C = the cost of scrubber technologies, and

L,H = low and high sulfur coal subscripts.

This assumes that the two options are equally reliable and that utilities do not systematically prefer incurring higher fuel costs to the higher capital costs of scrubbers. If production and transportation costs for the two coals were to grow at approximately the same rate, and if the cost of scrubbers either declines or remains constant, then the term S must decline or remain constant in absolute dollar terms. In this analysis it was conservatively assumed that the relative cost of control technologies remains fixed at its 1975 level. Therefore, the 1985 premium for low sulfur coal should be equal to the current price differential.

Federal Power Commission data on contract prices of coal delivered to electric utilities was used to estimate the *current* price premium between low sulfur coal and coal with average sulfur content. These premiums for each of the regions are added to the average value of coal to obtain prices for 1985 as shown in Table 5.10.

*One example of previous efforts is the attempt by Bechtel Corp.³ Their first effort yields a counter-intuitive result -- the price increases with sulfur content. Preliminary work at Argonne has also yielded this perplexing conclusion.

Table 5.10 Low Sulfur Coal Price Premiums

Mining Area	Price Differential Between .75 and 1.75% Sulfur (1975 \$/ton)	Railhead Market (1975 \$/ton)
Westmoreland Co., PA	\$4.00	\$28.78
Raleigh Co., WV	2.00	25.54
Powder River Co., MT	.55	6.01
Carbon Co., WY	.55	6.75
Carbon Co., UT	.55	15.72
San Juan, NM	.55	8.35

Owing to the relative abundance of low sulfur coal in the West, sulfur premiums are not as significant a factor in the market price. In eastern mining areas the price differential between low and high sulfur coal produced locally will be proportional to the differential between the per ton cost of using high sulfur coal with a scrubber and the per ton delivered price of low sulfur coal.

5.2.4 *Transportation Costs*

The principal mode of long-distance low sulfur coal movement is, and will likely continue to be, rail, augmented somewhat by barge shipment. Rail transportation rates for coal are not strictly determined by the distance of the haul. Other cost related variables, such as train size and traffic congestion, also affect rail charges. Furthermore, factors affecting the cost of service are not the only variables influencing cost. Unit train rates are set by a process of bilateral negotiation between the rail company and the customer utility. It has long been held that rail lines isolated from competition receive higher rates than those lines that must compete against barges or other energy sources. Both cost and competitive factors have been considered in the procedure utilized to obtain rail rate estimates that is detailed in Appendix B. The average costs for 1975 used in this analysis were 12 mills per ton mile for shipments originating in the East, 10 mills per ton mile for shipments from the Midwest, and 8.5 mills per ton mile for western shipments. These rates were increased for 1985 by the procedure described in Appendix B.

Another major alternative is to ship coal by a combination of rail and barge. It has been estimated that waterway charges per ton mile are approximately one-half those of an all rail shipment. Yet, water routes are much longer. Therefore, total rail-barge costs may not be cheaper than those for an all rail-route. Estimated rail-barge costs have been compared with those of all rail shipments and are reported in the Appendix. These comparisons reveal that savings are relatively great for utilities which employ the rail-barge mode to ship coal from Appalachia. Although none of the specific demand centers considered here can advantageously utilize the Great Lakes, other points may find rail-barge shipments less expensive than all-rail shipments. Detroit Edison, for example, is presently receiving western coal over the Great Lakes; the city of Buffalo in New York is also considering this alternative. Calculations performed in Appendix B reveal that the rail-Great Lakes mode is quite competitive as far east as Buffalo. Therefore, it appears the penetration of western coal might extend farther east than is usually imagined.

A third significant alternative to rail shipment of western coal is the coal slurry pipeline. Six pipelines have been proposed, and destinations have been specified for five of them. The longest pipeline would extend from Wyoming to Pine Bluff, Arkansas. Two pipelines have been considered from the western coal fields (one originating in Colorado, and the other in Wyoming or Montana) to the Gulf Coast. Two other slurry pipelines have been discussed in connection with supplying western demand areas, one to Oregon and another to Nevada. Of these five, only one or two (for reasons discussed in Section 5.2.6) are likely to be completed by 1985. Therefore, coal slurry pipelines will probably have a minimal effect on transportation patterns and overall transportation rates in 1985.

A controversy exists over the nature of their effect. The railroads emphasize that the pipelines will tend to produce short-term benefits and higher long-run costs than railroads. The railroads foresee a scenario in which they are outbid at present because the pipelines will be able to pass on the economies afforded by heavy volumes under long-term contracts. If this drives railroads out of the market, consumers will be exploited by the newly created pipeline monopolists. An alternative result is also possible. If the pipelines do outbid the railroads and if railroad tariffs presently

contain surplus profits due to an absence of competition, the entrance of the slurry pipelines would lead to an overall decline in transportation rates for coal shipments. It is impossible to tell at this time which scenario will eventuate. In either case, by 1985 the effects will be negligible.

5.2.5 Total Delivered Price

Total delivered prices are derived from a model which selects the optimal (i.e., least cost) configuration of coal movements from six mining areas to the 24 demand points indicated in Fig. 5.2. The numbers on the demand centers indicate the delivered prices from the lowest cost source of low sulfur coal in cents per million Btu. The lowest cost source of low sulfur coal is western coal up to the Ohio/Indiana border if unit train is the only transportation mode employed. As discussed in Appendix B, utilization of the rail-barge mode should lower the delivered price of low sulfur coal to demand centers that can conveniently utilize the inland waterway system or the Great Lakes. The inputs to the model were the cost estimates developed in Sections 5.2.2 through 5.2.4.

5.2.6 Constraints on the Extraction and Distribution of Coal

This section will focus on the impact of constraints on the production and distribution of coal. Constraints usually are reflected in excess demand above what the market will supply at a given price. The task then is to calculate the rise in price required, and the time period necessitated, to bring supply and demand back into equilibrium. However, the disequilibrium can be so severe on occasion that it produces a discrete change in industry ability to meet demand, and the time period of adjustment can be very lengthy. The attempt at present will be to determine whether these disruptive situations are likely. Principal areas of examination will be the equipment and manpower inputs to coal mining, and the rail and water transportation systems.

5.2.6.1 Equipment Constraints

Coal production generally is expected to reach one billion tons per year by 1985. However, because of shortages of some mining equipment, doubts have been raised about the ability of the equipment industry to meet expected demand under these circumstances. The procedure will be to review these areas and to determine the degree of seriousness of the possible shortages.

Fig. 5.2 Comparison of 1985 Delivered Prices of Low Sulfur Coal (Cents per Million Btu)

Presently, several kinds of mining equipment are said to be in short supply. Explosives, mine-roof bolters, loading machines, continuous miners, and walking draglines are prime examples. However, a Mitre study⁴ has concluded that all of these, except walking draglines, are likely to be in surplus by 1980 and 1985 (see Tables 5.11-5.14).^{*} The result of the walking dragline shortage will not be an interruption of coal production. Smaller draglines that have shorter delivery times will alleviate the shortage. However, these less efficient tools will prompt higher mining costs.

5.2.6.2 *Labor Constraints*

Labor is the second potential constraint on mining input. The Mitre study has estimated the demand for labor implied by a 1 billion ton per year production level and compared this with projected supplies of labor. They computed the supply of labor by assuming that workers entered the strip and underground segments of the industry at the average 1969-74 rate. The result was an ample supply of labor for strip mining for all demand scenarios except for the "Accelerated Demand" case in the post-1980 period. Even here the aggregate shortage appears to be only about 6% of the required work force. Nevertheless, serious shortages appear in the underground sector in all demand scenarios (e.g., around 20% in 1985).

The magnitude of this shortage, however, may have been overstated by Mitre since they assume that future labor productivity will remain constant at the 1972 level. In 1972, productivity for underground workers had declined to approximately the 1962 level because of the effects of a new federal safety act and poor worker morale. Poor morale not only hurt productivity on the job, but led to many wildcat strikes. The ill effects of these adverse factors should dissipate, and productivity should receive substantial boosts from three sources: (1) the adoption of longwall mining (a new deep mine process popular in Europe but relatively novel in the U.S.), (2) the continuing development of continuous mining equipment adaptable to thin seams, and (3) new haulage technologies reducing the time needed to hoist coal to

^{*}The assumption underlying this conclusion and the other projections of these tables is that equipment production will increase by 20% per year through 1977, and 5% per year thereafter. The implicit demand figure for the "Business as Usual" forecast is about 1.1 billion tons per year of coal, which is equivalent to the Federal Energy Administration baseline forecast.

Table 5.11 Mining Equipment Additions: Surface, 1975 - 1980^a
(Business as Usual)

Loading Shovels	Stripping Shovels	Draglines	Front-end Loaders	Scrapers	Trucks	Bulldozers	Explosives (tons)
<u>Required</u>							
824 ^a	101	170	772	147	1,042	1,839	4,715 x 10 ³
<u>Availability</u>							
1,474	224	168	1,740	295	1,509	3,190	7,142 x 10 ³
<u>Availability/Required</u>							
1.79	2.22	0.99	2.25	2.01	1.45	1.73	1.51

^aNumber of units

Table 5.12 Mining Equipment Additions: Surface, 1980 - 1985^a
(Business as Usual)

Loading Shovels	Stripping Shovels	Draglines	Front-end Loaders	Scrapers	Trucks	Bulldozers	Explosives (tons)
<u>Required</u>							
852 ^a	108	173	781	151	1,161	1,941	6,940 x 10 ³
<u>Availability</u>							
1,968	300	207	2,460	392	2,015	4,262	9,542 x 10 ³
<u>Availability/Required</u>							
2.31	2.78	1.20	3.15	2.60	1.74	2.20	1.37

^aNumber of units

Table 5.13 Mining Equipment Additions: Underground, 1975 - 1980⁴
(Business as Usual)

Continuous Miners	Loading Machines	Shuttle Cars	Personnel Transport	Roof Bolters	36-in. Conveyors (ft)	48-in. Conveyors (ft)	Longwall Miners
<u>Required</u>							
1,435 ^a	1,490	4,199	1,705	4,832	6,836 x 10 ³	560 x 10 ³	87
<u>Availability</u>							
2,500	1,326	4,345	2,699	10,185	12,026 x 10 ³	736 x 10 ³	133
<u>Availability/Required</u>							
1.74	0.89	1.03	1.58	2.11	1.76	1.31	1.53

^aNumber of units.

Table 5.14 Mining Equipment Additions: Underground, 1980 - 1985⁴
(Business as Usual)

Continuous Miners	Loading Machines	Shuttle Cars	Personnel Transport	Roof Bolters	36-in. Conveyors (ft)	48-in. Conveyors (ft)	Longwall Miners
<u>Required</u>							
1,597 ^a	1,653	4,523	1,863	5,050	7,530 x 10 ³	656 x 10 ³	105
<u>Availability</u>							
3,125	1,770	5,805	3,608	13,610	16,058 x 10 ³	1,703 x 10 ³	178
<u>Availability/Required</u>							
1.96	1.07	1.28	1.94	2.70	2.13	2.60	1.70

^aNumber of units

the surface. Overall, underground miners' productivity could conceivably rise as much as 3.0% per year until 1985. Although this is a substantial departure from the recent trend of absolute productivity declines, it does not equal the average productivity growth from 1948 to 1968 of 5.5% per year.

Actually, an increase of 3% per year from the 1972 level would provide an output per man per day of 15.96 tons in 1985. This figure only barely surpasses the previous high of 15.61 tons in 1969. Furthermore, Mitre's formula for calculating manpower needs (projected production divided by average number of tons mined per man per year) produces a number about 25% more than it is at present for the 1.1-billion-ton coal demand when the new productivity estimate is substituted for the 1972 value. Because the predicted shortfall of labor is 20% in the base case, it appears that critical shortages can be overcome by modest increases in labor-saving technologies. In addition, this whole discussion has assumed that 1969-74 worker entry rates into the coal industry would prevail. However, the higher real wages in the coal industry should induce greater labor force entry. In short, a smooth growth path in coal demand toward the 1.1 billion ton figure by 1985 should not produce any major industry-wide production bottlenecks.

5.2.6.3 Coal Transportation Constraints

Rail and Barge Transportation

In 1975, coal transportation represented more than 25% of all railroad tonnage and likely increases in coal production could raise this percentage. Already, minor shortages of gondolas and open hopper cars exist.* However, these shortages appear to be only short-term problems. Mitre's estimated gondola and hopper car requirements over the 1973-1985 period are about 5% greater than the average yearly production over the 1963-1973 era.**⁴ The railroad car industry has filled larger shortages than presently exist in a short time.

*Some coal operators are presently complaining that they cannot obtain rail cars to transport coal directly from the mine.

**The average rise is small, partially because the capacity per car is expected to rise from 51 to 86 tons.

The overall long-term capacity of the railroads to handle increased coal traffic is a more difficult problem. Although the financing has always been available to acquire needed gondola and hopper cars, this is partially because profits have been invested in this area rather than in track and other roadway equipment. Specifically, in the last 10 years, expenditures for roadways and structures have averaged only 25.5% of total capital expenditures by Class-I roads. It is questionable whether adequate financing for both cars and roadways can be obtained in view of the level of railroad earnings, which currently are only three-quarters of their 1947 levels (after adjusting for inflation).

To add some perspective on this issue, it is necessary to estimate the amount of capital required to restore and upgrade the present system to meet probable increases in coal shipments. The U.S. Railway Association has reported on seven midwestern and northeastern roads comprising about 15% of the nation's total trackage. Two points are worth noting about this study. First, instead of computing average lives of roadbed, existing deterioration has been estimated through direct sampling. Secondly, the study covers an important coal-consuming region with the greatest proportion of dilapidated track. It estimates that approximately \$3.8 billion (in 1974 dollars) is needed to bring roadways and structures up to their best previous level of service. Because no attempt seems to have been made to evaluate main and branch lines separately, this figure probably represents an over-valuation. Perhaps an additional \$1.5 billion dollars will be needed over the 1973-1985 period to finance rolling stock; therefore the capital requirements of this railroad region appear to be substantial.

In fact, it is doubtful that these railroads will be able to generate sufficient earnings to finance these expenditures, even with sizeable increases in utilization of capacity (which probably averages under 30% at present for this area). For the 1963-1973 period, all Class-I roads disbursed about \$15.5 billion for capital projects. The poor financial shape of the eastern roads means that they probably accounted for less than \$2 billion of this total (\$2 billion would be the share if their expenditures were proportional to their share of track mileage).

These figures imply that assistance will have to come through merger with stronger railroads or from the federal government. However, it is difficult to perceive any attraction offered to stronger roads by the weaker roads. In fact, the merger talks, which center around the Missouri Pacific and the Southern railroads (two very profitable railroads), illustrate the tendency for stronger roads to merge to the detriment of the financially weak carriers.

From 1970 to 1975, about \$3.6 billion in federal assistance was earmarked for the railroad industry and about \$1.5 billion was actually committed. Unfortunately, nearly all of the money had been distributed to bankrupt or nearly-bankrupt roads or to Amtrak. However, the Railroad Revitalization and Regulatory Reform Act of 1976 authorized money to rebuild roads with the purpose of building a strong interstate system. If this legislation is implemented literally, it appears that eastern roads will be able to handle future traffic increases. The picture is even more certain for western roads. Their relatively superior earnings record and track maintenance policies bode well for the future. For example, in 1975 Burlington Northern spent about \$15 million on track and other improvements -- an increase of 100% over 1974. Although increased unit train usage will call for heavier tracks and strengthened trestles, sufficient capital should be available.

A question also exists as to whether the waterway system can handle increased coal traffic. In 1973, coal on the river system (rather than on the Great Lakes or tidewater) accounted for 69% of total water freight and 18% of total U.S. coal shipments. Here, however, the situation is different from the railroad problem. The difficulty lies not in restoring a huge system of large capacity to health, but rather in determining the practical capacity of the system itself. Demands in excess of this capacity limit will, for the most part, be met by another mode of transportation. Because of the rise of pleasure boating and various impediments in the locking procedure, the theoretical capacity of a lock is not attainable. The estimated economic capacities of many locks on the Illinois and Ohio Rivers have been surpassed already.⁵ These bottlenecks are potentially serious because Illinois has the largest coal reserve base in the U.S. and because the Ohio River carried about 29% of all river shipments in 1972.

A recent Bureau of Mines Study has attempted to estimate the extent of possible dislocations caused by impediments in the overall coal transportation system. Under their assumptions of rail and barge costs, shippers would move 894.1 million tons by rail in 1985 and 229.7 million tons by river if no constraints existed. However, with practical lockage capacities, tonnages shipped on the river system decreased from 229.7 to 150 million tons. Conversely, railroad traffic increased to 934.8 million tons. Total coal shipments decreased by about 40 million tons.

Although this analysis can serve as a first approximation of the present capacity effects of constraints, it has several shortcomings. For example, no attempt is made to estimate expansion of existing locks or construction of new locks to improve navigability. The Army Corps of Engineers is in charge of constructing locks. Information from the Corps on the Ohio River system indicates that an expanded lock is planned at Gallipolis, and other sites are at least under consideration. Moreover, data provided by the Corps indicate that many new locks are authorized for the Trinity River in eastern Texas which flows through the rich lignite beds now under development. For these reasons, it is reasonable to expect greater coal movements on the river system than the Bureau of Mines study forecasts. Furthermore, there may be indirect aid for the inland system in that the tidewater route from Norfolk, Virginia, to New York City could be expanded in terms of tonnage and in terms of ports of destination. Although this route carried over 5 million tons in 1969 its use dropped to an insignificant level by 1973. It was, therefore, not considered in the Bureau of Mines projections for 1985. Although the inland waterway system will probably be severely taxed in the future, it does not seem likely that traffic diversion into other modes or actual loss of shipments will reach the magnitude forecast by the Bureau of Mines.

Coal Slurry Pipelines

The above paragraphs have indicated that the rail and waterway systems should be able to accommodate a coal demand of 1.1 billion tons in 1985 with only minor dislocations. A development that would facilitate the surmounting of these problems would be the construction of one or more of the proposed coal slurry pipelines. However, it does not seem likely that more than one or two of the six discussed pipelines will be completed by 1985.

Coal slurry pipelines face one general obstacle to fast construction; legislative passage of eminent domain laws. Laws granting eminent domain to the slurry pipelines must be passed so that the pipeline sponsors can acquire needed land,* principally from their chief antagonist, the railroad industry. However, the U.S. Congress will not act upon such a bill until a report on this issue is received (probably by July 1977) from the Office of Technical Assessment. This means that, in view of the concerted railroad lobbying effort, federal legislation will not be forthcoming until at least 1978. The individual states could also pass eminent domain laws. In fact, Utah, West Virginia, Ohio, North Carolina, and North Dakota have done so, and Oklahoma and Texas are contemplating such action. However, it is difficult to imagine all the potentially affected states passing such laws before the Congress can act, especially since many of them lie in semi-arid regions and are concerned about the large water requirements of the coal slurry mixture. Legislative resolution of the eminent domain question by 1978 would mean that slurry pipelines could be completed by 1982 at the earliest because of the three to four year construction period.

Perhaps this is why at most three pipelines of the six considered are targeted for completion by 1985. One will run from southeastern Colorado to the Texas Gulf area and will have a capacity of nine million tons per year. Considering the long-term coal contract commitment of the Texas utilities to western coal and the present interest in an eminent domain law in Texas, this pipeline seems relatively certain to be constructed by 1985. A second likely prospect, in view of the passage of the Utah eminent domain law, is the 10 million ton line from Alton, Utah to southern Nevada. The pipeline from Wyoming to Pinebluff, Arkansas was also originally supposed to be completed by 1985. However, resistance by Arkansas to a clustering of power plants has caused the sponsors to look to feeder branches into other states as a way to support the planned 25 million tons per year capacity. This uncertainty coupled with the absence of a settled legal precedent in Wyoming means that construction by 1985 is unlikely. In the

*In Wyoming, slurry pipeline interests have tried to circumvent the eminent domain requirement by purchasing the subsurface rights to railroad-held land. The legality of this tactic is presently being tested in court. Even if it is upheld, the verdict will most probably be appealed and a final legal outcome is not likely until at least 1978.

aggregate, the two pipelines discussed earlier would add significant capacity to the transportation system, especially since some concern exists about bottlenecks developing on railroad lines leading into the large western mines. Yet, the slurry pipelines existing in 1985 will probably not be of overwhelming importance in terms of total transportation system capacity.

In conclusion, it appears that by 1985 constraints on the production of coal will be largely removed. Problems might develop in the transportation system, but the introduction of some slurry pipeline capacity diminishes the likelihood of this possibility. Both conclusions assume a smooth growth in coal demand to 1.1 billion tons in 1985.

5.2.7 Constraints on Utilization

Apart from the constraints associated with the production and distribution of low sulfur western coals in the midwestern utility market, constraints associated with their utilization in boilers primarily designed to burn midwestern coal have been recognized. Western coals generally are of a lower quality in terms of moisture content, calorific value, and ash characteristics, than midwestern coals. To understand this difference in quality it is important to know how various coals are classified. Table 5.15 shows the ASTM⁶ classification (D388) of coals by rank, i.e., according to their degree of metamorphism, or progressive alteration, in the natural series from lignite to anthracite. It should be noted that older coals are classified by dry, mineral-matter-free fixed carbon, and younger coals by moist, mineral-matter-free calorific value. The reason for using two different criteria is that for anthracitic and low- and medium-volatile bituminous coals, the moist, mineral-matter-free calorific value varies little and for high-volatile bituminous, subbituminous, and lignitic coals, the fixed carbon is nearly the same for all. Table 5.16 lists 17 different U.S. coals in order of ASTM classification.⁷ An examination of the calorific and fixed carbon values shows why the two different criteria mentioned above are used for the ASTM classification. In this table the calculations of fixed carbon content, calorific value, and mineral matter basis were done using the Parr formulae.⁸

The constraints associated with the utilization of low sulfur western coals of the types represented in Table 5.16 by numbers 14, 15, and 17 (the

Table 5.15 Classification of Coals by Rank^a

Class	Group	Fixed Carbon-- Dry, Mineral- Matter-Free Basis (%)		Volatile Matter-- Dry, Mineral- Matter-Free Basis (%)		Calorific Value Limits-- Moist, ^b Mineral-Matter- Free Basis (Btu)		Agglomerating Character
		Equal or Greater Than	Less Than	Greater Than	Equal or Less Than	Equal or Greater Than	Less Than	
I. Anthracite	1. Meta-anthracite	98	-	-	2	-	-	} nonagglomerating
	2. Anthracite	92	98	2	8	-	-	
	3. Semianthracite ^c	86	92	8	14	-	-	
II. Bituminous	1. Low volatile bituminous coal	78	86	14	22	-	-	} commonly agglomerating ^e
	2. Medium volatile bituminous coal	69	78	22	31	-	-	
	3. High volatile A bituminous coal	-	69	31	-	14,000 ^d	-	
	4. High volatile B bituminous coal	-	-	-	-	13,000 ^d	14,000	} agglomerating
	5. High volatile C bituminous coal	-	-	-	-	11,500	13,000	
III. Subbituminous	1. Subbituminous A coal	-	-	-	-	10,500	11,500	} nonagglomerating
	2. Subbituminous B coal	-	-	-	-	9,500	10,500	
	3. Subbituminous C coal	-	-	-	-	8,300	9,500	
IV. Lignite	1. Lignite A	-	-	-	-	6,300	8,300	} nonagglomerating
	2. Lignite B	-	-	-	-	-	6,300	

^aThis classification does not include a few coals, principally nonbanded varieties, which have unusual physical and chemical properties and which come within the limits of fixed carbon or calorific value of the high-volatile bituminous and subbituminous ranks. All of these coals either contain less than 43% dry, mineral-matter-free fixed carbon or have more than 15,500 moist, mineral-free Btu per pound.

^bMoist refers to coal containing its natural inherent moisture but not including visible water on the surface of the coal.

^cIf agglomerating, classify in low-volatile group of the bituminous class.

^dCoals having 69% or more fixed carbon on the dry, mineral-matter-free basis shall be classified according to fixed carbon, regardless of calorific value.

^eIt is recognized that there may be nonagglomerating varieties in these groups of the bituminous class, and there are notable exceptions in high volatile C bituminous group.

Table 5.16 Seventeen Selected U.S. Coals Arranged in Order of ASTM Classification

Coal					Coal Analysis, Fed Moisture Basis ^a						Rank FC ^b	Rank Btu ^c
No.	Class	Group	State	County	M	VM	FC	A	S	Btu		
1	I	1	Penn.	Schuylkill	4.5	1.7	84.1	9.7	0.77	12,745	99.2	14,280
2	I	2	Penn.	Lackawanna	2.5	6.2	79.4	11.9	0.60	12,925	94.1	14,880
3	I	3	Va.	Montgomery	2.0	10.6	67.2	20.2	0.62	11,925	88.7	15,340
4	II	1	W. Va.	McDowell	1.0	16.6	77.3	5.1	0.74	14,715	82.8	15,600
5	II	1	Penn.	Cambria	1.3	17.5	70.9	10.3	1.68	13,800	81.3	15,595
6	II	2	Penn.	Somerset	1.5	20.8	67.5	10.2	1.68	13,720	77.5	15,485
7	II	2	Penn.	Indiana	1.5	23.4	64.9	10.2	2.20	13,800	74.5	15,580
8	II	3	Penn.	Westmoreland	1.5	30.7	56.6	11.2	1.82	13,325	65.8	15,230
9	II	3	Ky.	Pike	2.5	36.7	57.5	3.3	0.70	14,480	61.3	15,040
10	II	3	Ohio	Belmont	3.6	40.0	47.3	9.1	4.00	12,850	55.4	14,380
11	II	4	Ill.	Williamson	5.8	36.2	46.3	11.7	2.70	11,910	57.3	13,710
12	II	4	Utah	Emery	5.2	38.2	50.2	6.4	0.90	12,600	57.3	13,560
13	II	5	Ill.	Vermilion	12.2	38.8	40.0	9.0	3.20	11,340	51.8	12,630
14	III	1	Mont.	Musselshell	14.1	32.2	46.7	7.0	0.43	11,140	59.0	12,075
15	III	2	Wyo.	Sheridan	25.0	30.5	40.8	3.7	0.30	9,345	57.5	9,745
16	III	3	Wyo.	Campbell	31.0	31.4	32.8	4.8	0.55	8,320	51.5	8,790
17	IV	1	N.D.	Mercer	37.0	26.6	32.2	4.2	0.40	7,255	55.2	7,610

^aM = equilibrium moisture, %;

VM = volatile matter, %;

FC = Fixed carbon, %;

A = ash, %;

S = sulfur, %; and

Btu = Btu per lb, high heating value.

Fed Moisture = natural inherent moisture in coal, not including visible water on the surface of the coal.

^bRank FC = dry, mineral-matter-free fixed carbon, %.^cRank Btu = moist, mineral-matter-free Btu per lb.

sulfur content and calorific value of these coals would allow compliance with the federal New Source Performance Standards) can be divided into three groups as follows:

1. Problems associated with stockpiling.
2. Necessary boiler modifications including modification to the coal handling systems directly associated with the boiler.
3. Derating of the boiler.

To get an idea of the magnitude of greater quantities of such coal required to replace bituminous coal, a model plant with a gross generating capacity of 500-MWe will be used. Appendix C gives a very brief description of such a model plant.

5.2.7.1 Stockpiling

Coal-fired electric utility generating stations are designed normally to maintain certain quantities of coal in stockpiles at the generating station to prevent shutdown during interruptions in the coal supply. The quantity of coal maintained in stockpiles depends primarily on the location of the station, the maximum hourly burning rate, the mode of delivery, seasonal variations in coal supply and use or plant capacity, and other factors such as availability of storage space or other storage facilities (concrete silos, etc.). In general, for a mine-mouth plant, large coal stockpiles may be unnecessary unless an impending mine closure for periods greater than that expected under normal conditions has to be taken into consideration. On the other hand, for a plant that depends on a Great Lakes supply route, a stockpile large enough to allow for continuous operation of the station during winter months when such routes are inaccessible may be necessary. This, when added on to a normal stockpile, i.e., coal stored for such possibilities as a railroad or miners strike, may require storage capacity of more than 150 days.

For a generating station presently using midwestern coal and receiving it by unit train, a stockpile to supply enough coal for about 90 days is normally required. For a 500-MWe station, using midwestern coal at the rate of about 214 tons/hr, this normal 90-day supply of coal would amount to 460,000 tons. If the same heat input is to be maintained by burning low sulfur western coal with a calorific value of 8,500 Btu/lb, then the burn

rate would have to be about 264 tons/hr or about 23.4% higher. If this low sulfur coal is received by barge, then a 185-day, on-site coal supply would have to be maintained, at least during the winter season, which would require a stockpile of about 1,170,000 tons. If the same coal is received by unit train then a stockpile of only about 570,000 tons would have to be maintained for a normal 90-day supply.

In terms of land required to store these amounts of coal, for Illinois coal it is 8 to 9 acres; for low sulfur western coal received by rail it is 11 to 12 acres; and for low sulfur western coal received by barge it is some 20 to 25 acres. In cases where land is not available, stacking height may be increased to a certain extent, depending on the existing stacking and reclaiming equipment and other coal handling equipment. It is important to note that western coal is more susceptible to spontaneous combustion than midwestern coal and as the height of the pile increases, compacting and covering operations must be done carefully to exclude oxygen from the pile.

Modifications to the coal reclaiming system may also be necessary to accommodate the increase in the hourly rate of coal to be transferred from the stockpile to the silo. Because it is more expensive to increase the silo volume, more frequent loading of the silo is required. Since most stations normally reclaim for one or two shifts each day, the more frequent loading of the silo can be handled by changing to two or three reclaiming shifts per day. For those stations that already have a three-shift reclaiming operation, equipment modifications are necessary to increase the capacity of the conveyors and/or silo volume.

If coal was being received by rail, the unloading facility may need modification to accommodate additional quantities of coal. Enlarging the unloading facilities can be avoided by acquiring additional rail cars. These rail cars would be stored empty at the station and returned immediately to the mine upon the arrival of each loaded coal train. Thus a longer unloading time, which is required by a smaller unloading facility, does not effect the turnaround time of the coal deliveries since the spare rail cars immediately begin the return trip. For such a situation, larger railroad facilities at the station may be necessary.

Careful planning for accommodation of the modifications to the coal handling system should obviate the need for shutdown of the station. The

boiler may be forced to operate at a lower load until completion of the modifications, but downtime of the station should be minimal.

5.2.7.2 *Boiler Modifications*

A majority of coal-fired boilers presently in operation at electricity generating stations use pulverized coal. For example, in Illinois with 15,932 MWe of generating capacity using coal, 9,303 MWe (58.4%) uses pulverized coal. Boilers at seven generating stations, totalling 1,374-MWe (8.6%), are wet-bottom, pulverized-coal fired, while another 7,929-MWe (49.8%) are dry-bottom, pulverized-coal fired. The remainder, 6,435-MWe (40.4%), are wet-bottom, cyclone-fired boilers. The terms "wet-bottom" and "dry-bottom" refer to the method of ash removal from the boiler. In the case of wet-bottom boilers, the coal ash is removed by tapping in the form of slag or a viscous fluid, and in the case of dry-bottom boilers the ash is removed dry. It should also be noted that conversion of a cyclone-fired boiler to a pulverized-coal-fired boiler or vice versa, and conversion of a wet-bottom boiler to a dry-bottom boiler or vice versa is not possible. Burning of western coal in these three types of boilers will necessitate many modifications to the boiler and ash handling systems if efficient operation is to be maintained. These modifications, including those necessary for the pulverizing and coal-firing equipment (e.g., burners), are further discussed in the following pages.

The fuel characteristics that are taken into consideration during the design of the boiler, to insure efficient operation of the boiler and the ash handling system, are shown in Table 5.17. Changes in any of these characteristics, if not originally designed for, may require modification of the boiler, the boiler operating procedure, and/or derating of the boiler depending upon the cost and feasibility of the modifications. In most cases modifying the operating conditions of the boiler may permit burning coal that does not appreciably differ in characteristics from that originally designed for. However, when the switch is from midwestern bituminous, e.g., Illinois No. 6, to low sulfur western subbituminous coal, certain modifications to the boiler design as well as operating procedures are necessary. In most cases, derating is also required.

Table 5.17 Design Parameters of Coal and Coal Ash⁹

Fuel Characteristics	
<u>Properties of Coal</u>	<u>Properties of coal ash</u>
Physical, including density, hardness, specific heat, thermal expansion, and thermal conductivity.	Determined by the concentration and type of minerals in the coal containing the following elements:
Chemical - behavior during heating, i.e., carbonization, gasification, and combustion.	<ol style="list-style-type: none"> 1. Alkalies 2. Sulfur 3. Chlorine 4. Phosphorus 5. Calcium-Magnesium 6. Iron 7. Silica 8. Alumina
Technological properties:	Technological properties:
<ol style="list-style-type: none"> 1. Proximate analysis 2. Ultimate analysis 3. Free-swelling index 4. Differential thermal analysis 5. Thermogravimetric analysis 6. Effluent gas analysis 7. Grindability 8. Calorific value 9. Sieve analysis 10. Ignitability 11. Abrasiveness 	<ol style="list-style-type: none"> 1. Fusion temperatures 2. Viscosity of slag 3. Surface tension of slag 4. Volatility of constituents in slag 5. Sintering temperature and strength of ash

Moisture Content of Fuel

The three- to four-fold increase in moisture content of low sulfur western coal above that of midwestern coal causes problems both with the pulverizers and the boiler itself. In this section equipment used to dry the coal prior to pulverizing it and problems associated with burning coals with high moisture contents will be discussed. Problems associated with pulverizing high-moisture, low-sulfur western coal will be discussed in the next section.

Removal of part of the surface and inherent moisture from low sulfur western coal is desirable because it increases the net calorific value and provides a product generally superior to the original coal for use in existing boilers. It also reduces shipping costs in proportion to the quantity of moisture removed. The costs and savings associated with drying coal and transporting it to the generating station are given in Table 5.18.

The energy required to dry the coal may, to a certain extent, offset the energy savings realized by transporting less moisture. The heat required to dry coal is proportional to the difference between the initial moisture content and the amount of moisture removed. Tests conducted at the coal drying facility located at Commonwealth Edison Company's Powerton generating station at Pekin, Illinois showed that the amount of heat required to reduce moisture content of Colstrip (Montana) subbituminous coal from 25.5% to 16.2% was about 3.8×10^6 Btu/ton of water removed.¹⁰ This amounts to 353 Btu/lb of coal. However, this is offset by the increase in the calorific value of the coal to about 9,650 Btu/lb, which includes the calorific value of the oil added for dust suppression, resulting in a net energy increase of some 880 Btu/lb of dry coal.

Drying produces a coal that may be dusty and more reactive than run-of-mine coal, thereby increasing the possibilities of spontaneous combustion in transit and storage.¹¹ However, by spraying oil and careful compacting to reduce the oxygen available, this problem can be controlled satisfactorily.

The burning of coals with high moisture contents (up to 40%) in boilers designed to burn coal with moisture contents of less than 10% imposes an additional penalty from increased heat loss in the flue gases.¹² Heat is required to raise the fuel moisture to its boiling temperature, evaporate it, and superheat the vapor to the final flue gas temperature. Therefore, the

Table 5.18 General Areas of Savings and Costs for
Dried and Oiled Coal¹⁰

Savings	Costs
1. Reduced transportation cost.	1. Coal dryer installation, including oiling facility.
2. Less coal loss during transportation.	2. Cost of capital and ensuing revenue requirements.
3. Calorific content credit of oil used for dust control.	3. Cost of dryer operation and maintenance.
4. Reduction of dust in generating station.	4. Cost of oil for dust control.
5. Improved boiler capability and capacity factor.	
6. Improved boiler efficiency and reduced maintenance.	
7. Reduced power requirements.	
8. Improved coal conveying.	

loss is dependent upon the fuel temperature, the moisture content of fuel, and the stack temperature. Figure 5.3 shows the relationship between the heat lost as a percentage of the calorific value of the coal burned (for coals with an initial temperature of 120°F) and the moisture content of the coal for flue gas temperatures ranging from 200 to 700°F. The heat loss also depends on the temperature of the coal being fired and increases with decreasing temperature.

Problems Associated with Pulverizers

Large pulverized-coal-fired boilers normally operate on coal pulverized to a fineness such that about 70% of it passes through a 200 mesh screen, which is about the consistency of talcum powder.¹³ Therefore, the most important factors affecting the selection of pulverizers are the Hardgrove grindability index¹⁴ and the rate of grinding of the coal. To a certain extent, a higher inherent moisture content inhibits grinding because of an increased tendency for the coal to ball up inside the pulverizer. In cases where a coal of low calorific value and high moisture content is to be pulverized in pulverizers originally designed for higher rank coal, larger motors may be required to prevent pulverizer stalling caused by increased quantities of less-free-flowing coal.¹⁴ The coal can be dried in the pulverizer itself, but the amount of moisture removed is limited by the quantity of primary air available and the limited capacity of the pulverizer to handle large air flow rates through it.

Some coals are harder and hence more difficult to pulverize than others. The grindability of a coal is expressed in terms of an index showing its hardness relative to that of standard coals. For a coal which is harder to grind than a reference coal, its grindability index would be lower than that of the reference coal. The ASTM standard method for measuring grindability of coal (D409)¹⁵ specifies the procedure for determining grindability by using four samples standardized especially for this purpose and representing grindability indexes of approximately 40, 60, 80, and 110.

Both the heat content and the grindability index of coal affect the output of the pulverizer as measured in Btu per hour. Figure 5.4 illustrates the effect of reduced calorific value of coal and grindability index on pulverizer capacity.¹⁶ This figure does not show the effect on output of

Fig. 5.3 Heat Loss Due to Moisture in Coal for Fuel Temperature of 120°F

Fig. 5.4 Pulverizer Output as a Function of Coal Grindability Index and Calorific Value (Reproduced by Permission of Combustion Engineering, Inc.)

increased moisture content of the coal being pulverized. Note that a nominal capacity 50 ton/hr pulverizer grinding coal with a grindability index of 55 and calorific value of 11,800 Btu/lb to a fineness such that 70% of it passes through a 200 mesh screen will have a heat output of $1,180 \times 10^6$ Btu/hr. If a coal with a grindability index of 55 and calorific value of 8870 Btu/lb is being ground to the same fineness in the same pulverizer, the heat output would be reduced by 25% to 890×10^6 Btu/hr. For the coal characteristics shown in Appendix C and for a pulverizer capacity of 50 tons/hr, the reduction in heat output would be about 35% if Illinois No. 6 coal was replaced by low sulfur coal. The normal pulverizer capacity of a boiler with a gross generating capacity of 500-MWe and burning Illinois coal with a Hardgrove grindability index of about 63 would be 50-60 tons/hr. For a coal burn rate of 214 tons/hr, such a plant would require four pulverizers operating continuously, or five if one is to be used as a standby. Therefore, converting an existing boiler to low sulfur western coal of the type shown in Appendix C requires the addition of at least two more pulverizers. In case more pulverizers or pulverizing capacity cannot be installed, derating of the boiler may be the only option remaining. In any case, derating may be necessary to a certain extent because of the physical limitations associated with the amount of primary air available for drying the coal in the pulverizers or with burner capacity and furnace volume.

Slagging and Fouling

Table 5.19 gives the various ash characteristics and the composition of ash which are important in the design of a boiler. When coal is burned, some of the ash may form deposits of slag on the furnace walls (slagging) and a portion of the ash that is carried from the furnace by the flue gases may form deposits on the tubes in the gas passes (fouling). Under some conditions these deposits may lead to corrosion of these surfaces. The slagging, fouling, and corrosion in an existing boiler depends to a greater extent on the ash characteristics than on the operating conditions.

Slagging indexes based on the base to acid ratio (B/A) of coal ash, various fusion temperatures, and ash viscosity have been developed.¹⁷ If the B/A ratio of a coal ash ranges between 0.5-1.2 for eastern coals, a good possibility exists that slagging problems may be experienced. The

Table 5.19 Ash Characteristics of Four Different Coals¹⁶

Characteristic and Composition	Illinois No. 6 High Volatile C Bituminous	Penn. Freeport High Volatile A Bituminous	Montana Rosebud Subbit. C	Wyoming Gillette Subbit. C
<u>Ash Fusibility, °F</u>				
I.T. ^a (reducing atm.)	2040	2430	2150	2150
S.T.	2060	2560	2180	2180
H.T.	2170	2670	2220	2220
F.T.	2260	2700	2260	2275
$\Delta T(I.T.-F.T.)$	220	270	110	125
<u>Ash Composition</u>				
SiO ₂	45.6	49.3	38.3	31.4
Al ₂ O ₃	17.6	28.6	14.6	16.2
Fe ₂ O ₃	16.4	0.8	7.6	4.1
CaO	6.6	1.8	17.2	25.0
MgO	0.9	1.1	6.3	4.2
Na ₂ O	0.6	0.6	0.5	1.5
K ₂ O	3.6	2.7	0.3	0.5
TiO ₂	1.2	1.5	1.2	1.1
P ₂ O ₅	0.2	0.5	0.2	1.1
SO ₃	6.2	1.5	13.7	14.8
NAF	<u>1.1</u>	<u>1.6</u>	<u>0.1</u>	<u>0.1</u>
Total	100.0	100.0	100.0	100.0
Base/acid ratio	0.44	0.21	0.59	0.72
Fe ₂ O ₃ /CaO ratio	2.5	6.0	0.44	0.16

^aI.T. = Initial deformation.

S.T. = Softening temperature (see Table II of Ref. 16).

H.T. = Hemispherical softening temperature (see Table II of Ref. 16).

F.T. = Fluid temperature.

slagging index used for subbituminous Montana and Wyoming coals is based on the initial deformation temperature and hemispherical softening temperature (temperature of ash in different stages of deformation or fusion). Therefore, based on the B/A ratio for eastern coals and ash fusion temperatures of western coals, Pennsylvania Freeport coal can be considered to be problem free, Illinois No. 6 coal to be somewhat problematic, and both Montana and Wyoming coals to have high slagging potentials. This slagging problem may be controlled by using boilers designed for coals that generally have a high temperature difference between the initial deformation and fluid temperatures. The lower the difference, the less opportunity exists at a given particle residence time for the ash particles to cool by heat transfer to boiler surfaces, and thereby avoid excessive slag buildup and running slag.¹⁶

The control of slagging problems in a boiler converted from Illinois to western coal was described by Commonwealth Edison Company's Holyoak.¹⁹ The absence of slagging problems is attributed to the nonwetting and non-sticking fine ash produced by western coals. However, the resulting increased heat transfer rate increased the rate of scale buildup on the water side of the heat exchange surfaces, and the acid tube cleaning frequency had to be increased from 5-yr to 3-yr intervals.

The quantity of sodium in the ash may effect the potential of a particular coal for fouling boiler tubes. The Bureau of Mines has studied fouling in a pilot plant test furnace to determine the relative fouling potentials of various coals and to develop a correlation between individual ash constituents of the coal and the rate of fouling.¹⁸ The general conclusion that can be drawn from the data collected is that no fouling occurs for coals with less than 3% sodium oxide in the ash, but as the sodium oxide content increases above 3%, the fouling rate increases proportionately. No definite conclusions can be reached at the present time regarding the potential for fouling by low sulfur western coals. The characteristics of individual coals and specific boiler designs are important factors in determining the extent of fouling to be expected when boilers are converted to low sulfur western coals. The only modification that may be necessary to prevent excessive buildup of ash in boiler tube passes is the installation of extra soot blowers or an increase in the frequency of soot blowing.¹⁹

Problems with Low Sulfur Western Coal Firing and Limitations on Coal-Firing Capacity.

As mentioned earlier, since low sulfur western coal is inherently lower in calorific value and higher in moisture content than midwestern coals, up to 30% more coal must be burned to deliver the same amount of heat input in a boiler originally designed to burn midwestern coal. In pulverized-coal-fired boilers the increased quantity of coal that is required to be burned would necessitate modification of the burners. Coordination of pulverizer and burner operation is very essential to prevent flame-outs and assure proper combustion of the coal being fired.

The differences in coal characteristics may create possible problems in carbon carryover, ignition, and flame propagation. Testing of western coals has indicated that oxidation does occur at relatively low temperatures. Thus these coals would be expected to be easy to ignite and to combust completely.²⁰ Experience at stations burning western coal, however, shows carbon carryover to be a problem, implying that complete combustion does not occur. One explanation for the lack of complete combustion is insufficient capacity or number of burners. Since more coal is being fired, a corresponding increase in burner capacity may be necessary if complete combustion is to be maintained. The higher moisture content of the coal results in combustion occurring at a different temperature than for midwestern coals. This may cause difficulties with ignition when converting to western coals. The ignition problems can normally be resolved, however, after experience with firing the coal is obtained.

In cyclone-fired boilers, one of the more serious problems reported to have been encountered in the burning of low sulfur western coals has been the proper combustion of coal.¹⁹ Of the three western coals tested by Commonwealth Edison (Arch Mineral, Decker, and Colstrip), the Colstrip coal is reported to have presented the most serious problems. This coal is reported to have a calorific value of 8,750 Btu/lb, 20-25% moisture and 10-12% ash. Very high carbon carryover was also reported when these coals were burned. Bursts of carbon carryover were also found to be a problem during load changes. This was attributed to western coal not burning in the cyclone where it should, and being carried over into the furnace where the conditions are not right for complete combustion.

5.2.7.3 Boiler Derating

Holyoak¹⁹ reported that in 1973 there was an average of 3.6% or about 400-MWe reduction in Commonwealth Edison's total fossil-fuel-fired generating capacity because of conversion of some of the boilers to low sulfur western coal. He attributed a good part of this loss, approximately 5-10% of the boiler capacity, to pulverizer capacity limitations. The derating of Unit No. 2 at the Will County Generating Station was described by Holyoak as follows:

On the 173-MWe cyclone target wall-type boiler, a load of 135-MWe is the maximum achievable with Colstrip coal and 155-MWe is the maximum with Decker coal. This boiler went into service in 1955. If maximum loads are exceeded, carbon carryover is so heavy that ash conveying systems cannot handle the resultant quantity of ash. Ash samples showing a heat content of 12,000 Btu/lb have been taken from the air heater hoppers. We have had two serious air heater fires on this type of boiler with extensive outages. One precipitator was gutted while learning to burn these coals.

Derating of boilers at other generating stations has also been reported.²¹ Tennessee Valley Authority conducted tests at the Johnsonville steam plant on the burning of low sulfur Montana coal. The two steam generation units tested were a corner-fired pulverized coal Combustion Engineering boiler designed to produce 1,000,000 lb/hr of steam and a rear-wall-fired pulverized coal Foster Wheeler reheat steam generator of 1,100,000 lb/hr steam capacity. The fuels used in these tests were Montana coals with 27.5% moisture, 1.6% sulfur (dry basis), and a heating value of 7865-9000 Btu/lb (as fired); and Kentucky coals with 10% moisture, 3.3% sulfur (dry basis), and a heating value of 9975-10,416 Btu/lb (as fired).

A 35.5% reduction in generating capacity was observed when burning low sulfur Montana coal in the Foster Wheeler unit as compared to performance with Kentucky coal. With the Combustion Engineering unit, a 15% reduction in generating capacity was observed. The reductions resulted from the inability of the coal feeder-pulverizer-exhauster systems to handle the increased quantity of low-heating-value coal.

The TVA tests also reported that the higher moisture content of Montana coal caused a loss in boiler efficiency due to higher heat loss up the stack (about 2.5% higher loss). The heat loss results from utilization

of boiler heat to supply the latent heat to vaporize the moisture in the coal. The total carbon loss up the stack for Montana coal was found to be lower than for Kentucky coal. Furnace slagging was reduced when Montana coal was burned.

It thus appears that the conversion of existing boilers burning high sulfur midwestern coals to low sulfur western coals is not a simple matter. The difficulties in burning this fuel can be traced to the inherent problems of operating the boiler outside of its designed operating limits. The operating parameters that are affected by coal characteristics are summarized below. These factors must be considered carefully when planning conversion of a power plant to burn western coal.

1. Excessive dusting of coal en route to power plant.
2. Reduced conveyor belt capacity (10-20%).
3. Decreased pulverized output (up to 35%).
4. Loss of boiler efficiency due to increased moisture (up to 30%).
5. Water-side scale buildup due to decreased slagging.
6. Increased fouling with high sodium coal.
7. Decreased electrostatic precipitator efficiency because of the decrease in sulfur trioxide concentration in the flue gases. Detailed discussion regarding this problem is included in Section 4.2.
8. Larger dust handling system requirements within the boiler.
9. Carbon carryover.

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6 FLUIDIZED-BED COMBUSTION

6.1 SUMMARY

When compared to electric utility power plants employing conventional coal combustors plus stack-gas scrubbers, plants using fluidized-bed coal combustors (of either the atmospheric-pressure or pressurized type) are seen as offering significant advantages in cost, operating economy, efficient utilization of coal resources, and environmental protection.

More coal can be burned per unit of volume in a fluidized-bed combustor and less heat-transfer surface is needed. This allows considerable savings in vessel sizing and may also offer the economies of shop, rather than field, fabrication. As a result, estimated capital costs are 10-15% less than for a plant of similar capacity utilizing conventional combustors with stack-gas scrubbing.

Power plants with pressurized fluidized-bed combustors are expected to use gas turbines driven by the hot, high-pressure off gas from the combustor to supplement electrical output from the usual steam turbines. This combined-cycle mode of operation can give energy conversion efficiencies of up to 40% compared to ~35% for power plants with conventional coal-fired boilers and stack-gas scrubbers. Power plants with atmospheric-pressure, fluidized-bed combustors, although lacking the extra electrical output from gas turbines, may still show a slight edge in efficiency over conventional plants with scrubbers. In addition, fluidized-bed combustors are capable of burning high-sulfur and low-rank coals with a wide range of properties, and could probably burn mine tailings and coal-processing residues.

Control of sulfur dioxide emissions from a fluidized-bed combustor is readily achieved by adding crushed limestone or dolomite to the bed along with the coal. The stone reacts chemically with the sulfur dioxide, as the latter is formed in the bed, to form calcium sulfate, a stable solid. By this means upwards of 90% of the sulfur in the coal can be retained in the bed, and present federal standards for sulfur dioxide emission are easily met even when burning very high sulfur coal. However, this results in the production of substantial quantities of spent stone that must be disposed of in an environmentally acceptable manner. Indications are, though, that the quantity of spent stone may be considerably less than the quantity of waste

sludge produced by stack-gas scrubbers at a conventional coal-fired plant with the same electrical output, and that the properties of this spent stone will be more conducive to easy disposal than is the case with the scrubber sludge. Processes now under development for regenerating and reusing the spent stone would significantly reduce this disposal problem and would permit recovery of the sulfur in marketable form. Synthetic sorbents that may be more amenable than limestone and dolomite to regeneration and reuse are also being developed.

Owing, at least in part, to the fact that combustion temperatures in fluidized-bed combustors are much lower than those in conventional coal combustors, power plants using fluidized-bed coal combustors can be expected to emit significantly lower levels of nitrogen oxides. Pressurized plants will do even better than atmospheric-pressure plants in this respect, but neither type should have any difficulty in meeting present federal standards for emission of nitrogen oxides, regardless of the type of coal being burned.

Fluidized-bed coal combustors are inherently prone to emit higher levels of solid particulates than do conventional combustors, but tests made on bench- and pilot-scale facilities indicate that the particulate loading of the stack gas can be brought into compliance with federal emission standards through the use of conventional particulate collection devices. In pressurized combined-cycle installations, however, the particulate loading of the hot gases leaving the combustor may have to be reduced still further to prevent excessive erosion of the gas-turbine blades. The resolution of this problem may require advanced types of high-temperature particulate collectors now under development, and/or turbine materials and designs that are more resistant to erosion.

On the basis of the limited amount of experimental evidence currently available, it is tentatively concluded that coal-fired power plants using fluidized-bed combustors will, in general, produce lower levels of trace-element emissions and less preferential concentration of trace elements in the ultra-fine fraction of flyash particles than is the case with conventional coal-fired plants. These benefits are attributed to the lower combustion temperature and to the presence of limestone or dolomite in the fluidized bed. There is, however, some evidence that there may be no actual reduction in the emissions of certain specific and hazardous trace elements (mercury, for example).

In regard to hydrocarbon emissions, some concern has been expressed that the relatively low combustion temperatures in fluidized beds may actually be conducive to the emission of polynuclear aromatic compounds such as benz-(a)pyrene, a known carcinogen. There are, however, virtually no experimental data concerning such emissions from coal-fired fluidized-bed combustors. Some measurements have been made on the 6-in. Battelle fluidized-bed combustor, but no results are yet available.

Finally, it is believed that effective control of pollution resulting from the preparation, handling, and storage of coal, limestone, and dolomite; from cooling operations and waste-heat disposal; and from water treatment at power plants employing fluidized-bed combustion can be accomplished by practices currently in use at conventional coal-fired utility plants.

It is estimated that full-scale electric utility power plants employing atmospheric-pressure, fluidized-bed combustors could be in commercial operation by the middle to late 1980s, while similar maturation of the pressurized combined-cycle concept could be realized by the mid-1990s.

6.2 INTRODUCTION

Fluidization is a widely accepted technique for bringing about heat and mass transfer in the chemical process industries. As applied to coal combustion, it permits high efficiency and high rates of heat absorption at low combustion temperatures.

A fluidized bed is a column of dense particles suspended in an upward flowing air stream. The velocity of the flow required to suspend the particles is a function of their density and size. Because of the rapidly moving particles, the gas-solid mixture is said to behave like a fluid and the heat transfer between the particles is very good. Thus the temperature distribution through such a bed is reasonably uniform and the heat transfer coefficient is quite high.

6.2.1 Need for Fluidized-bed Combustion (FBC)

Combustion of coal in a fluidized-bed combustor is another technique for burning coal in an ecologically acceptable manner. When coal is burned in such a fluidized bed, the heat released during the burning of the coal is

transferred to the rapidly moving particles, and thence to heat transfer tubes that are placed inside the combustor. The heat is removed from the bed by passing air or steam through the heat transfer tubes. The steam from the tubes is used to generate electricity in a conventional steam-turbine plant.

If the rapidly moving particles consist of limestone (or dolomite), then the sulfur dioxide (SO_2) formed during the burning of the coal is absorbed by the limestone to form solid calcium sulfate that remains in the bed and can be discharged from the combustor separately from the coal ash. During combustion fresh limestone is added continuously to absorb the emitted SO_2 and spent limestone is removed from the bed.

The nitrogen oxide content of the flue gas from the fluidized-bed combustor has been found to be less than that of the conventional steam power plant. This lower value may be due in part to the lower temperature of operation of the fluidized-bed combustor as compared with the conventional pulverized-coal-fired plant.

In the conventional, pulverized-coal power plant, temperatures as high as 3000°F may be reached, whereas the fluidized-bed combustor operates most effectively at $1400\text{--}1800^\circ\text{F}$. Because of the uniform temperature and the excellent heat transfer in the bed, the heat transfer to the steam generation tubes is very good. An added feature of the fluidized-bed combustor is its capability of burning many different types of fuel, including those with low heating value and high ash contents.

6.2.2 Background

The fluidized-bed combustor has been under development for many years, supported by several government agencies. Currently, ERDA is the lead agency in the national R&D program on FBC. The ERDA program is primarily process development oriented, whereas environmental studies are supported mainly by the EPA. The EPA has a comprehensive program underway for the environmental characterization of FBC systems. The goal of this program is to obtain all necessary environmental data over the full range of variables for the FBC process. The EPA program is divided into the areas of environmental assessment and control technology development. GCA/Technology Division has recently completed a preliminary environmental assessment which identified potential pollutants that have not received attention in past experimental work, but

which may be emitted from fluidized-bed combustors. GCA also briefly assessed possible control technology for use on pollutants expected to be emitted in significant quantities.

Battelle has recently been awarded the contract for the primary environmental assessment of FBC. This effort comprises the following tasks: (1) to develop and compile background information on the current status of FBC processes and environmentally related technology, (2) to perform a comprehensive analysis of emissions, (3) to develop environmental objectives for the FBC process, (4) to assess the control technology potential of the process and any proposed supplemental control techniques, (5) to perform the environmental impact analysis of FBC, and (6) to develop the environmental R&D program.

As a part of Task 2 above, but under separate contract, Battelle is developing an approach for the comprehensive analysis of FBC units and is to test the approach by conducting an analysis on the 6-in. I.D. unit at Battelle. Comprehensive analyses are also planned on the pressurized combustor at the British Coal Utilization Research Association; on the 7-ft I.D. pressurized, adiabatic, CPU-400 pilot plant at Combustion Power Company (with assistance by Aerotherm/Acurex Corporation and TRW, Inc.); on the 1-ft I.D., pressurized Miniplant facility at Exxon Research and Engineering Company; and on a variety of other planned FBC units, such as the pressurized Component Test and Integration Unit (CTIU) to be built at Argonne, as these units become available. The Mitre Corporation, as part of the comprehensive analysis effort, is preparing manuals for each of the FBC process variations, indicating alternative sampling and analytical procedures that can be employed for each variation.

Ralph Stone and Company has contracted with EPA to address specifically the question of solid and liquid waste disposal from FBC systems. In addition, TVA, under an interagency agreement with EPA, is studying solid waste processing. In general, these studies involve: (1) characterization of solid and liquid waste materials from variations of the fluidized-bed combustion process; (2) laboratory and field studies to identify important waste disposal parameters, e.g., solid leaching properties and the effect of long-term exposure of solid by-products to the environment; (3) laboratory studies of physical/chemical treatment of solid wastes to reduce the environmental

impact upon disposal; and (4) laboratory and marketing studies of the potential for manufacturing marketable products from solid wastes.

ERDA and the USDA are cooperating in a \$1.7-million, 5-yr study of the use of FBC solid wastes for fertilizer and soil treatment. The project will include analyses of the wastes followed by greenhouse and field studies. The material will also be tested for neutralizing acidity in strip-mined land.

EPA plans to build a small atmospheric-pressure sampling and analytical test rig at Research Triangle Park. Subjects to be studied on the rig include: (1) comprehensive analysis of emissions, (2) testing of alternative sampling and analytical techniques, and (3) investigation of alternative add-on control devices. An additional EPA effort by Dow Chemical is intended to evaluate the effect of system size on emission from FBC systems of all known contaminants, including those for which experimental data may not be available. This information will provide an indication of the experimental scale on which environmental data may have to be obtained in order to enable reliable scale-up to commercial-size systems.

Exxon Research and Engineering Company, with EPA, ERDA, and FEA funding, is carrying out an energy, economic, and environmental assessment for the application of coal-fired fluidized-bed boilers in the industrial sector. This study will result in projections of: (1) the applicability of coal-fired fluidized-bed combustion to industrial boilers; (2) the technical requirements of envisioned industrial fluidized-bed coal boilers; (3) the industrial demand for such boilers; (4) the impact on the national energy situation of application of these boilers; (5) the economic impact of the boilers on the industries employing them and on associated industries supplying the use industries; and (6) the environmental impact of industrial coal-fired, fluidized-bed boiler application. Although not specifically related to power generation, the results of this study should be applicable in that area.

The Tennessee Valley Authority is also conducting a project for EPA to develop conceptual designs and comparative capital and operating costs for an atmospheric-pressure fluidized-bed steam power plant, a pressurized fluidized-bed/combined-cycle power plant, and a conventional coal-fired steam power plant with flue-gas desulfurization. This effort is being carried out

in coordination with the Energy Conversion Alternatives Study (ECAS) being undertaken by the National Aeronautics and Space Administration, the National Science Foundation, and ERDA.

The Electric Power Research Institute (EPRI) has expressed interest in FBC. Projects underway include studies on heat transfer and solids distribution, ways to optimize the heat transfer advantages of tubes submerged in a fluidized bed, and an engineering assessment of available data from a boiler manufacturer's point of view.

Based on quantitative results from this work, design and construction of a 6-ft by 6-ft atmospheric, fluidized-bed combustor are being undertaken by Babcock and Wilcox. The combustor, scheduled for operation in September 1977, will be used to study the large scale mechanics of solids distribution and heat transfer.

6.3 TECHNOLOGY DESCRIPTION

There are three types of fluidized-bed combustors that are usually considered:

1. Atmospheric fluidized-bed combustor.
2. Pressurized fluidized-bed combustor.
3. Adiabatic combustor.

As the name implies, the atmospheric fluidized-bed combustor is operated at atmospheric pressure. The fluidized-bed combustor can also be operated at elevated pressures (10 atmospheres seems most suitable), which leads to smaller equipment size for the same heat output. As the air throughput is increased, more and more of the heat of combustion is removed by the fluidizing gas and less by the submerged heat transfer tubes. When the point is reached that all of the heat of combustion may be removed by the fluidizing gas, the reactor is said to be operating as an adiabatic combustor. This eliminates the need for the submerged heat transfer tubes in the combustor bed. In the adiabatic combustor, the fluidizing gas expands through a gas turbine and the waste heat is recovered in a boiler that drives a steam turbine. In Fig. 6.1, brief schematic diagrams depict the differences in the three types of fluidized-bed combustors.

ATMOSPHERIC FLUIDIZED BED COMBUSTION (1 Atm, 15-25% Excess Air)

PRESSURIZED FLUIDIZED BED COMBUSTION (10 Atm, 15-25% Excess Air)

PRESSURIZED ADIABATIC FLUIDIZED BED COMBUSTION (10 Atm, 300% Excess Air)

Fig. 6.1 Schematic Diagram of the Three Fluidized-bed Combustion Systems Showing the General Energy-Conversion Cycles¹⁴

6.3.1 Atmospheric Fluidized-bed Combustion (AFBC)

In an atmospheric fluidized-bed combustor, the coal is burned in a bed of dolomite or limestone. The heat evolved during the oxidation of the coal is transferred to the dolomite particles and thence to heat transfer tubes immersed in the bed. The sulfur dioxide (SO_2) emitted during the burning of the coal reacts with the dolomite and oxygen to form calcium sulfate (CaSO_4). To maintain the reactivity of the bed to the emitted SO_2 , fresh dolomite must be added periodically or continuously to the combustor and spent dolomite (CaSO_4) must be removed.

The bed is supported on a flat distributor plate with holes or bubble-cap devices distributing the air flow evenly through the bed. The air passes at lineal velocities of 2-15 ft/sec through a bed of particles at temperatures of 1400-2000°F. Coal and sorbent are fed to the bed by pneumatic feeders extending through the air distributor or the sidewalls. From 60-70% of the heat released in burning the fuel is transferred to the water/steam in tubes surrounding and submerged in the bed.

The air and combustion gases passing through the bed promote considerable agitation; particles are thrown from the bed and pass into the free volume above the bed. The bigger and heavier particles fall back and return to the bed, while the smaller and lighter particles are carried along in the gas stream and thus out of the bed. Much of the material removed from the bed in this manner is the residue or ash from the combustion of coal. To keep these particles from reaching the atmosphere, a series of separators is utilized to remove particulates from the gas stream, which then exits up the stack. Because particulate material in the first cyclone separator usually contains some unburned carbon, this material is returned to the fluidized-bed combustor, or more commonly to a separate carbon burnup cell. It has been reported that such particulate material may contain from 5-15% of the added carbon.¹

The process variables for a fluidized bed are interrelated, and changes in any one must be compensated for by changes in some of the others if the same power level is to be maintained. The variables of greatest significance are bed temperature, excess air, particle diameter for the coal and additive, and fluidization requirements (gas velocity).

For the bed temperature, it would be preferable to be at the highest temperature attainable in order to achieve the highest thermodynamic efficiency. However, experimental results have narrowed the range to 1400–1700°F. Below 1400°F, the rate of reaction between the additive and the SO₂ is too low. These experimental results have demonstrated the maximum reactivity to be at approximately 1500–1600°F.^{1,2}

The superficial gas velocity must be sufficiently high to maintain a fluidized bed. In a fluidized bed, a superficial velocity exists at which the heat transfer coefficient of the bed is a maximum.³ The superficial gas velocity must be carefully controlled because performance of the combustor may be affected. For example, under certain conditions increases in the fluidizing velocity result in a decrease in the sulfur retention in the bed.⁴ There are also data to show that the combustion efficiency decreases with the fluidizing velocity⁴ and is impractically low at velocities of 8 ft/sec or greater. These high fluidizing velocities can be accommodated and high carbon utilization attained by returning the unburned carbon to a carbon burnup cell where complete combustion is achieved by reaction at a much higher temperature. Alternatively, to reduce or avoid recycling of carbon, lower fluidizing velocities may be required.³

Excess air helps to reduce the unburned carbon in the fluidized bed. At the same time, excess air tends to increase the nitrogen oxides in the exhaust gas, so that a suitable balance must be chosen.³

The particle diameters for coal and sorbent are important in that finer particles result in better heat transfer and in better reactivity of the stone with SO₂. However, particles that are too fine are elutriated from the bed and must be returned if they contain carbon.

6.3.2 *Pressurized Fluidized-bed Combustion (PFBC)*

The pressurized fluidized-bed combustion process is similar to the atmospheric fluidized-bed combustion process, except that the combustor, filters, and fluidizing gas are under pressure (usually about 10 atmospheres). In a fluidized-bed combustor, as the pressure of the system increases, the density of the fluidizing gas increases. Thus for a given lineal gas velocity at the elevated pressure, more moles of gas will pass in a given time period and thus remove more heat from the fluidized bed. Since both the fuel flow

and heat release rates in the combustor are generally proportional to the mass flow of air, the capacity of a boiler with a given cross section can be increased by increasing the pressure. But in order to produce more steam, more heat transfer surface must be submerged in the bed. For this reason, deeper beds will be required for higher-pressure, fluidized-bed boilers.⁵

Also, because the fluidizing gas is at elevated temperature and pressure, the energy in this gas must be recovered to increase the efficiency of the energy conversion process. To recover the energy, the hot gas at the elevated pressure is passed through a gas turbine and allowed to expand to atmospheric pressure. About 20-25% of the electrical energy produced by a pressurized fluidized-bed combustor is calculated to be produced by the gas turbine.

If a gas turbine is used, it becomes important to remove particulates and corrosive substances such as alkali compounds from the gas stream to minimize corrosion and erosion of the gas turbine blades.

6.3.3 *Differences between AFBC and PFBC*

There are several differences between the AFBC and the PFBC, the first being the obvious one of the operating pressure. With the increase in pressure goes an increase in gas density, so that with the same lineal flow rate the mass of gas flowing is directly proportional to the pressure. The heat release rates in the combustor are generally proportional to the mass flow of air.⁵ At a given lineal velocity, the PFBC has a greater mass flow than does the AFBC, hence requiring a smaller cross-sectional area for the same power output. (Note however, that although the cross-sectional area is smaller, the bed depth must be higher to permit installation of sufficient heat transfer coils to remove the heat of combustion.) This smaller size is conducive to shop fabrication and field assembly, as opposed to field construction for the AFBC. Shop fabrication usually results in a lower capital cost for installed capacity, as well as a reduction in construction time that leads to smaller interest and escalation costs. A small but definite improvement in combustion efficiency also has been observed with PFBC.⁶

Because the fluidizing gas is at 10 atmospheres and elevated temperatures (1400-1700°F), it contains energy that must be recovered by allowing the gas to pass through a gas turbine and expand to atmospheric pressure.

The use of gas turbines puts a very severe demand upon the hot flue gas cleaning system, to minimize the corrosion and/or erosion of the gas turbine blades. Extrapolations from experimental results indicate that a gas turbine (60 MW) can operate with an acceptable erosion level when the incoming gas has a particulate loading of less than 0.012 g/m^3 ($5 \times 10^{-3} \text{ gr/scf}$) of the expanded gas.⁷ These limits are an order of magnitude less than the particulate loading of $0.1 \text{ lb}/10^6 \text{ Btu}$, equivalent to 0.115 g/m^3 ($5 \times 10^{-2} \text{ gr/scf}$), mandated by the Clean Air Act.⁸

It has also been observed that in a pressurized fluidized-bed combustor, the emitted nitrogen oxides are lower than in an atmospheric pressure unit. At 1 atm the NO emissions were ~400 ppm at 1550°F with a fluidizing velocity of 3.5 ft/sec and a Ca/S ratio of 1.5. When the pressure was raised to 8 atm, under the same conditions, the NO concentration in the flue gas was reduced to 200 ppm.⁹ This effect is even more pronounced for the CO in the flue gas, with the CO concentration dropping from over 2000 ppm at 1 atm to 170 ppm at 8 atm pressure. An unequivocal explanation has not been forthcoming. However the reduction of both the NO and CO concentrations with increasing pressure suggests that the following reaction might offer an explanation.³

The reaction as written is a slow homogeneous reaction.¹⁰ Experiments to evaluate this reaction yielded the following conclusions:¹¹

- 1) The reaction was catalyzed by CaO or dolomite and was essentially complete in 0.3 sec at 1600°F.
- 2) Under the same conditions, the presence of 17% CO₂ inhibited the reaction drastically.
- 3) In assessing the effect of pressure upon the reaction, it was reported that in the presence of CO₂, the conversion decreased with increased pressure if the residence time was maintained constant.

Based on these results it is suggested that the presence of CO₂ imposes a kinetic limitation upon the reaction.

6.3.4 Status of the Technology

For fluidized-bed technology, the bulk of the operating experience has been with laboratory and development units. Engineering calculations show

that an approximately 300-MWe pressurized fluidized-bed combustor would consist of four modules in parallel, each module consisting of four fluidized beds positioned one above the other with each bed 5 ft by 7 ft in size (Figs. 6.2 and 6.3). This brief description is presented merely for the purpose of relating full plant scale to the units currently operating. To emphasize this point, a list of the fluidized-bed reactors that have been operated is given in Table 6.1. The bulk of the reactors with long operating experience are in most cases less than 2 ft in diameter, although some larger units are in operation. The Combustion Power Company has a combustor 7 ft in diameter. The British have had several reactors of larger size and are now testing a unit in Scotland with an area of 100 sq ft capable of generating 40,000 lb/hr of steam at 400 psig and 560°F. This unit was commissioned in June 1975, and by December 1975 had accumulated 2000 hours of operation equivalent to about three months of continuous operation.¹²

The utilities desire a power plant that has proven good reliability and availability. However, all of the combustors to date (except for Rivesville) have been concerned with the operation of fluidized-bed combustors, rather than with the generation of electricity. Furthermore, for combined-cycle plants, virtually no public access to performance and reliability data exists for the reliability of the associated continuous-duty gas turbines,¹³ because this information is considered proprietary by the companies involved.

In many industrial processes, major operational problems are not revealed in the bench scale or laboratory models that tend to focus attention on the central equipment item and often overlook the critical importance of the arrangement and design of other elements of the system. By analogy, in developing SO₂ scrubber systems, most emphasis was directed to the operation of the scrubber itself and little attention was given to the location and design of off-the-shelf items such as fans, mist eliminators, and heat exchangers used on other gas cleaning applications. All of the auxiliary items mentioned have caused major problems which could possibly have been revealed and solved in the prototype stage of development.¹³ Thus it appears that to achieve utility acceptance, an orderly scaleup of technology is required so that operating problems related to size will be revealed as early as possible.

Fig. 6.2 Atmospheric Fluidized-Bed Power Plant

Table 6.1 Fluidized-bed Combustion Facilities

Organization	Combustor and Regenerator Size	Pressure (atm)	Gas Velocity (fps)	Temperature (°F)	Status/Purpose
National Coal Board (NCG) and British Coal Utilization Research Association (BCURA)	6" diam. 12" x 12"	1	2-3	1240-1680	1962-73/Combustion
	36" x 18"	1	2-8	1420-1680	
	48" x 24" (36" x 24')	5	2	1470-1745	
	27" diam	1	6-14	1420-1680	
Pope, Evans & Robbins (PER)	12" x 16" (FBC)	1	8-14	1450-2000	1966-75/Combustion and regeneration, development plant
	20" x 6" (FBM)	1	12-15	1600-2050	
	20" x 20" (CBC)	1	12-15	1450-2000	
	28' 8.2" x 12' (Rivesville)	1	9-12	1500	
U.S. Bureau of Mines	18" diam	1	2-3	1450-1650	1966-72/Combustion heat transfer
Consolidation Coal	4" diam	1.5	2-3	1700-1900	1968-70/Combustion and regeneration
CSIRO	9" diam	1	2-7	750-1850	1967-68/Combustion
Argonne National Laboratory	6" diam	1	3-7	1400-1700	1968-75/Combustion, regeneration
	3" and 6" diam	8	2-5	1450-1650	
EXXON R&D	3" diam	1	2-4	1500-2000	1968-75/Combustion, regeneration
	3" diam	10	5	1500-2000	
	12.5" and 5" diam	10	5-10	1700-2000	
Foster-Wheeler	18" diam	1	--	--	Operating/Combustion
Combustion Power	20" diam	1	4-10	1400-1800	1973-75/Combustion (adiabatic)
	7" diam	4	5-10	1400-1800	
	6' diam	5	5-10	1400-1800	
Bergbau-Forschung	16" x 31"	1	4-8	1470-1560	1974-75/Combustion
Lurgi	5" diam	1	>10	2000-2200	1962-70/Fast bed
	40" diam	1	>10	2000-2200	
Battelle-Columbus Laboratories	6" diam	1	1-5	1400-2500	1949/Bloating
	24" diam	1	2-10	1400-1700	1960-75/Combustion
	6" diam	1	3-30	1400-1700	1974-75/Combustion
	36" diam	6	10	2100	1975/Combustion (gasification)

ERDA apparently subscribes to this orderly progression of size, as indicated by the 30-MWe Rivesville plant soon to be in operation. The Administration is also contributing to the 13-MWe pressurized fluidized-bed pilot plant to be built by Curtiss-Wright. In support of these units, Component Test and Integration Units (CTIU) are to be built that will permit experimental evaluation of some of the operating parameters. Additionally, ERDA is now about to issue a request for proposals for the conceptual design of a 200-MWe atmospheric fluidized-bed combustor. The Tennessee Valley Authority (TVA) has announced that it will spend \$4 million on the preliminary design and support studies for a 200-MWe demonstration plant using atmospheric fluidized-bed combustion.

6.3.5 Efficiency

The overall efficiency of a power plant is the amount of energy produced divided by the amount of energy introduced into the plant (for our purposes the total Btu introduced by the combustion of the coal feed to the plant). This efficiency may be broken down into two parts--that of the boiler and that of the remainder of the plant. Another measure of the overall efficiency of a power plant is the heat rate (the number of Btu required to generate one kWh of electricity). For pulverized-coal-fired plants the overall efficiency is measured for operating plants. For fluidized-bed combustors, the reported values for efficiency are calculated values, since no large-scale plants are operating from which such numbers can be obtained.

For AFBC the combustor efficiency has been estimated to be 88.6%,⁷ which should be comparable to the efficiency of the pulverized coal-fired boiler. For the PFBC, the combustor efficiency has been calculated to be 92%.

The three systems, pulverized coal-fired plant, AFBC plant, and the PFBC plant, are compared in the following table.⁵

Table 6.2 Plant Comparisons

	Conventional Plant with SO ₂ Scrubbing	AFBC	PFBC
Plant Heat Rate, Btu/kWh	9230	9550	8970
Efficiency (%)	37	36	38

There is the possibility that the efficiency of the pressurized fluidized-bed plant might be increased to as much as 47%.⁵ This may be accomplished by increasing the gas turbine temperature, lowering the projected heat losses between the boiler and gas turbine and by increasing the turbine operating conditions by increased gas turbine temperature and increasing steam temperature and pressure. It should be pointed out that conventional steam power plants have had problems with higher steam pressures and temperatures, and that these advanced conditions are beyond the capabilities of current utility gas turbine technology. Thus, other than reducing the heat losses between boiler and turbine, the other improvements depend upon technological advances not yet attained.

6.3.6 Possible Add-On Control Technology

There are several possible areas of add-on control technology. One such improvement would be in the capability of removing particulates from the combustion gas stream before reaching the turbine. Two possible alternatives that merit investigation are "hot side" electrostatic precipitators and stone filters.

A second add-on control would be in the regeneration of the sorbent. Work on regeneration is currently being done on the bench scale. Should this preliminary work indicate advantages, environmental or economic, then such a technique could be introduced into the larger plants.

Other techniques that might be considered as add-on technology are the pretreatment of sorbent so as to achieve greater utilization by reduced particle attrition, and the use of additives to the bed to reduce trace-element and alkali-metal emissions.

6.4 CONTROL OF POLLUTANT EMISSIONS

Comprehensive reviews and assessments of the situation in regard to the emission and control of pollutants from the fluidized-bed combustion of coal have appeared in recent reports prepared for the EPA by Westinghouse Research Laboratories⁷ and by GCA Corporation,^{14,15} and for the Electric Power Research Institute (EPRI) by Babcock and Wilcox Company.³ Studies of a similar nature are currently being conducted for the EPA by Battelle-Columbus Laboratories^{16,17} and by Dow Chemical Company.¹⁸

Based on the reported performance of existing laboratory-scale and pilot-scale, coal-fired, fluidized-bed combustion facilities, and taking account of any anticipated effects of scaling up to commercial size, it appears quite likely that fluidized-bed combustion can be developed to provide the electric utilities with a method of burning practically any type of coal in a manner that will comply with present federal standards for emission of sulfur dioxide and nitrogen oxides without the necessity for precombustion treatment of the coal (except for crushing and, possibly, screening) or for any chemical scrubbing of the stack gases. Indications are that the relatively low combustion temperatures and the sulfur sorbent employed in fluidized beds will also tend to reduce the emission of volatile trace elements, compared to levels emitted from conventional coal-fired combustors. Control of particulate emissions from fluidized-bed combustors (particularly from pressurized units) appears to constitute a significant problem. Although virtually no experimental information is available concerning the emission of specific organic pollutants from coal-fired, fluidized-bed combustors, there has been speculation that combustion conditions in the bed may be conducive to enhanced emissions of polynuclear aromatic hydrocarbons such as benz(a)-pyrene, a known carcinogen.

6.4.1 *Sulfur Dioxide*

When coal is burned, virtually all of the sulfur present in the coal is converted to gaseous sulfur dioxide (SO_2). The EPA's New Source Performance Standards (NSPSs) for stationary sources specify that a new coal-burning power plant may emit no more than 1.2 lb of SO_2 per million Btu of combustion heat produced, based on a 2-hr average. Unless at least part of the SO_2 is removed from the combustion gases, this emission standard would necessitate burning coal which contains less than about 0.7% sulfur by weight.

In the case of fluidized-bed combustion, SO_2 emission is suppressed by adding to the bed a nonvolatile, incombustible, solid sorbent (usually crushed limestone or dolomite) that mixes with the coal particles and combines chemically with the SO_2 produced during the burning of the coal. Sulfur dioxide is thereby removed from the combustion gases in situ. Coal and fresh sorbent are usually fed continuously into the bottom of the fluidized-bed, while coal ash and spent (sulfated) sorbent are removed from the bed, also in a continuous manner. Removal of 90% or more of the SO_2 is readily achieved, even when burning high sulfur coal.

6.4.1.1 Sorbents and Their Action

Criteria for selecting a sulfur dioxide sorbent include the following:

1. Effectiveness in removing SO₂.
2. Economical availability.
3. Attrition resistance.
4. Trace-element emission characteristics.
5. Possibility of regeneration and reuse.
6. Suitability of spent sorbent for disposal.

Crushed *limestone* (natural stone containing >80% CaCO₃) is an effective, abundant, and inexpensive SO₂ sorbent for use in *atmospheric-pressure* fluidized-bed combustors. After it is introduced into the bed, the CaCO₃ normally undergoes calcination, and the CaO thus formed combines with SO₂ and excess oxygen to form CaSO₄ according to the reaction:

The calcium sulfate thus formed is a stable solid under the conditions existing in the bed.

Sulfur dioxide can also react directly with uncalcined limestone particles, but not very effectively. Such particles are relatively nonporous, and an impervious layer of CaSO₄ tends to form on the outer surface of the particle, halting the sulfation reaction and resulting in low utilization of the available calcium. However, when calcination occurs, the particle becomes much more porous and develops a large internal surface area which enhances the rate and extent of subsequent sulfation.¹⁹ Thus, for practical purposes, limestone must be calcined in order to be an effective SO₂ sorbent.

In general, calcination of limestone takes place readily in fluidized-bed combustors operating at or near atmospheric pressure but not in combustors operating at pressures of several atmospheres or more.¹⁹ Consequently, limestone has usually been found to be a less effective SO₂ sorbent when used in pressurized fluidized-bed combustors. Some attempts have been made to remedy this ineffectiveness by precalcining the limestone before it is injected into the pressurized combustor, but this stratagem did not seem to give the desired result.⁹ However, efforts along these lines are continuing at Westinghouse and at Exxon.²⁰

Dolomite (a natural stone consisting principally of an approximately equimolar aggregate of the carbonates of calcium and magnesium, and denoted by the formula $\text{CaCO}_3 \cdot \text{MgCO}_3$) is, like limestone, widely abundant and low in cost. Unlike limestone, however, crushed dolomite has been found to be generally quite effective as an SO_2 sorbent in pressurized as well as atmospheric-pressure fluidized-bed combustors. Under the conditions usually existing in a pressurized bed, the MgCO_3 constituent in dolomite is converted to MgO . The solid product thus formed is termed "half-calcined" dolomite. It combines readily with SO_2 and excess oxygen according to the reaction

As indicated, it is believed that the MgO constituent in half-calcined dolomite does not itself react with SO_2 , but rather that its formation greatly increases the porosity and accessible internal surface area of the dolomite particles, thereby facilitating efficient sulfation of the uncalcined CaCO_3 constituent.¹⁹

In a fluidized-bed combustor operating at or near atmospheric pressure, dolomite may be fully calcined to form $\text{CaO} \cdot \text{MgO}$, which can then combine with SO_2 and excess oxygen to form $\text{CaSO}_4 \cdot \text{MgO}$. In this case also, the MgO constituent apparently does not become sulfated.

It has been found experimentally that the SO_2 sorption efficiency both of limestone and of dolomite may vary considerably, depending on the source of the stone and even varying between different shipments of stone from the same source. However, it is generally agreed that for use in pressurized combustors dolomite is superior to limestone, both in terms of pounds of sorbent required per pound of sulfur in the coal and in terms of moles of Ca in the sorbent required per mole of S in the fuel. In atmospheric-pressure combustors dolomite and limestone seem to be about equally effective on a Ca/S mole basis, although on the basis of weight ~80% more dolomite may be required.^{3,19} For atmospheric-pressure applications, the choice between limestone and dolomite might well depend upon considerations of local availability, attrition resistance, and impurity content.

In spite of the economical availability of limestone and dolomite and their proven effectiveness as SO_2 sorbents in fluidized-bed combustors,

efforts have been and are being devoted to assessment and development of alternative sorbents (both natural and synthetic) that might have better characteristics in regard to attrition resistance, freedom from trace element emissions, and possibility of regeneration and reuse of the sorbent and recovery of the captured sulfur, while also possessing high SO₂ sorption capability.

Thus, Jonke et al. made experimental comparisons of the SO₂ sorption effectiveness of limestone, dolomite, calcareous shale, and phosphate rock; waste products such as spent oil shale, brown mud, and red mud; and the oxides of lead, manganese, nickel, copper, zinc, and cobalt. The finding was that limestone and dolomite were about 50% more effective than the brown mud (which contained ~41% CaO by weight) and 5-30 times as effective as any of the other materials tested.²¹

Keairns et al. noted that a large number of metal oxides have been screened for their suitability in removing SO₂ from flue gases, but that the thermodynamic data tabulated for the stability of the corresponding metal sulfates rule out most of the oxides for consideration as sorbents in the fluidized-bed process. Most of the sulfates would be too unstable under the conditions existing in a fluidized-bed combustor. On the other hand, the more stable alkali-metal sulfates would be difficult to regenerate and could pose serious corrosion problems.⁷

Although, as mentioned previously, it is generally believed that the MgO constituent in calcined or half-calcined dolomite does not become sulfated in fluidized-bed combustors operating at pressures of up to 10 atmospheres, recent experiments have suggested that MgO can be used to capture SO₂ from simulated combustion gases at a pressure of 21 atmospheres and a temperature of approximately 1500°F, and that the sulfated product can readily be regenerated for reuse.²² It was also suggested that MgO might possibly be made to serve, perhaps by the use of a suitable catalyst, as an effective SO₂ sorbent at the lower pressures projected for practical designs of pressurized fluidized-bed combustors.

At the request of the EPA, Westinghouse undertook an evaluation of a special alumina-based copper oxide catalyst, NALCO 471, as a potential SO₂ sorbent. It was concluded that this material is unsuitable in that the SO₂ sorption process is ineffective at temperatures as high as those usually encountered in a fluidized-bed combustor.⁷

A more promising synthetic SO_2 sorbent is being studied at Argonne National Laboratory. This material consists of granules of α -alumina impregnated with CaO to the extent of 5-15% by weight.²³ It is reported that the sulfation rate is sufficiently high to make this material useful as an SO_2 sorbent in fluidized-bed combustors, although about twice as much synthetic sorbent as dolomite might be needed. Regeneration of the synthetic sorbent is actually faster than regeneration of dolomite. Preliminary cyclic sulfation and regeneration experiments have shown only negligible loss of reactivity, but the study of this feature has not been completed. Tests performed and reported to date also indicate that this synthetic additive may be significantly more resistant to attrition than is the case for limestone or dolomite. However, it is estimated that the present cost per ton of this synthetic sorbent would be approximately 20 times the cost of limestone or dolomite, so the economic advantage (if any) of employing this synthetic sorbent remains open to question.²⁴

6.4.1.2 *Effect of Calcium-to-Sulfur Mole Ratio*

Aside from the nature and properties of the sorbent, the molar ratio of calcium to sulfur in the feed streams is probably the most important factor in determining the SO_2 emission from a fluidized-bed combustor. As this ratio is increased, the quantity of SO_2 released from the bed is decreased. A useful measure of effectiveness is the *sulfur retention*, defined as the percentage of the sulfur in the coal that is captured and retained by the sorbent. In general, the sulfur retention increases quite rapidly as the Ca/S mole ratio is increased to around 2 or 3, beyond which the sulfur retention seems to approach 100% asymptotically as the Ca/S ratio is increased still further.

Another measure of sorbent effectiveness is *calcium utilization*, defined as the percentage of the calcium in the sorbent that is converted to CaSO_4 . In general, calcium utilization decreases as the Ca/S ratio is increased. Thus at a Ca/S mole ratio of 1.0 the calcium utilization could, in principle, be as high as 100%, while with a Ca/S mole ratio of 2 the maximum possible calcium utilization is only 50%. A practical strategy would seem to involve optimizing calcium utilization by employing only enough sorbent to insure "comfortable" compliance with the SO_2 emission standards. The required amount of sorbent would, of course, depend on the sulfur content of the coal being burned.

Although published results of the Ca/S mole ratio needed to obtain a given degree of sulfur retention have shown variations believed to be related to differences in the design and operation of the combustors as well as in the properties and condition of the coals and sorbents, it can be said that in atmospheric-pressure fluidized-bed combustors sulfur retentions of 90% or higher are typically obtained using either limestone or dolomite at Ca/S mole ratios in the range of 2 to 4. In pressurized systems, these high-percentage retentions are typically obtained at Ca/S mole ratios of 1.5-2 using dolomite as the sorbent, while limestone at the same ratios generally gives a sulfur retention of 70% or less.²⁵ The general behavior is illustrated in Fig. 6.4. This figure points up the fact that dolomite is superior to limestone as the SO₂ sorbent in pressurized combustors and that elevated pressure actually increases the effectiveness of dolomite. Sulfur retention of 90% is enough to permit the burning of 12,000 Btu/lb coal containing 7% sulfur, and the sulfur retention can be pushed still higher if necessary. Thus the present federal emission standard for SO₂ can be met when burning virtually any available coal.

6.4.1.3 Effect of Bed Temperatures

In atmospheric-pressure fluidized-bed combustors using either limestone or dolomite as the SO₂ sorbent, maximum sulfur retention has been found to occur at a bed temperature in the range of 1450-1550°F.^{3,6,26} The reason for the decrease in sulfur retention at higher temperatures remains uncertain. Several possible explanations have been proposed, but most are either inconsistent with some other aspect of the observed behavior of fluidized-bed combustors or else are difficult to verify experimentally. Whatever the reason, the decline in sulfur retention is only moderately abrupt, and a bed temperature of ~1500°F is not necessarily impractical for an atmospheric-pressure fluidized-bed combustor.

Results of tests with pressurized fluidized-bed combustors have shown that sulfur retention usually increases by a modest amount as the bed temperature is raised from around 1450°F to about 1750°F.⁶ Thus, from the standpoint of achieving maximum sulfur retention, the optimum bed temperature for a pressurized combustor would seem to be higher than for an atmospheric-pressure combustor. The effect of bed temperature is illustrated in Fig. 6.5.

Fig. 6.5 Effect of Temperature on Sulfur Retention⁶

Fig. 6.4 Effect of Ca/S Mole Ratio on Sulfur Retention⁶

6.4.1.4 *Effect of Fluidizing-air Velocity*

In both atmospheric-pressure and pressurized fluidized-bed combustors, it has been found that increasing the superficial velocity of the fluidizing air causes a decrease in sulfur retention.^{3,26} This effect is especially pronounced when low Ca/S mole ratios are employed. Several factors may be involved here, but a seemingly plausible explanation would be that with higher air velocities the SO₂ released from the burning coal tends to be swept out of the bed before reacting with sorbent and, moreover, that the finer particles of sorbent tend to be elutriated from the bed before they have time to become sulfated.

6.4.1.5 *Other Factors Affecting Sulfur Retention*

In addition to the effects of sorbent properties, Ca/S mole ratio, pressure, temperature, and fluidizing-air velocity discussed above, it has been shown or suggested that a number of other factors may affect the degree of sulfur retention and sorbent utilization. Some of these factors are:

1. Geometry of the bed (depth, area, freeboard, etc.).
2. Coal properties.
3. Particle size of the coal and the sorbent.
4. Manner of feeding coal and sorbent into the bed.
5. Excess air.
6. Fluidization properties of the bed.
7. Oxidizing and reducing conditions in the bed.
8. Recycling of fine particulates elutriated from the bed.

In view of the obvious complexity of the overall sulfur capture process and the multiplicity of factors that may affect the process (some in ways but poorly understood), Strom et al. have proposed that the design of any fluidized-bed combustor should provide sorbent handling and disposal facilities sized for two or three times the expected sorbent feed rate.³

6.4.2 *Oxides of Nitrogen*

There are, of course, several different known oxides of nitrogen. The generic formula NO_x is commonly employed to denote collectively all such oxides or mixtures thereof. Usually, the NO_x produced during combustion

of fossil fuels is at least 90% nitric oxide (NO) with the remainder in the form of nitrogen dioxide (NO₂). However, the NO is converted to NO₂ after it is released into the atmosphere, and it is NO₂ rather than NO that is directly implicated in the atmospheric pollution effects of nitrogen oxides. For these reasons it is customary to specify emission levels and concentrations of NO_x in terms of the *equivalent* levels or concentrations of NO₂. Thus the EPA's New Source Performance Standards for coal-fired utility boilers limit the NO_x emissions to the equivalent of 0.7 lb of NO₂ per million Btu of heat input. This corresponds to an NO₂ concentration of ~525 ppm in the stack gases.³

During the combustion of coal, nitrogen oxides may be formed both by oxidation (thermal fixation) of nitrogen from the air and by oxidation of nitrogen compounds present in the coal. In conventional combustors operating with combustion temperatures on the order of 3000°F, thermal fixation of atmospheric nitrogen may make a significant contribution to the total NO_x formation. However, in fluidized-bed combustors operating with combustion temperatures of only 1450-1750°F, thermal fixation is greatly reduced, and oxidation of fuel-bound nitrogen accounts for substantially all of the NO_x emitted. This assertion has been confirmed by two types of experiments with fluidized-bed combustors. Thus it was found that replacing the nitrogen in the combustion air with argon produced no measurable reduction in NO_x emission.²¹ On the other hand, it was demonstrated that replacing the coal with a low-nitrogen fuel (natural gas) reduced NO_x emission by ~90%.²⁷

6.4.2.1 NO_x Emission Levels

The average content of chemically-bound nitrogen in domestic coal is approximately 1.0-1.5% by weight.²⁸ Using the lower figure, and assuming a heating value of 12,000 Btu/lb, one would expect an NO_x emission level of ~2.7 lb of NO₂ per 10⁶ Btu if all of the bound nitrogen were converted to NO_x and all of this NO_x were emitted from the combustor. Fortunately, observed NO_x emission levels from fluidized-bed combustors are commonly on the order of only 10-20% of this value. The explanation usually proposed is that essentially all of the fuel-bound nitrogen is indeed oxidized to form NO during the burning of the coal, but that a considerable fraction

of the NO thus formed is reduced to N_2 before it leaves the combustor. The reaction of NO with carbon monoxide (CO), yielding N_2 and CO_2 , has been suggested as a likely mechanism for this reduction. Another proposal is that NO reacts with SO_2 and CaO in the bed to form N_2 and $CaSO_4$.²⁹

Strom et al.³ have collected and analyzed a large mass of published data on *measured* levels of NO_x emissions from atmospheric-pressure fluidized-bed combustors. The 228 values reported ranged from about 0.25 to 1.1 lb NO_2 per 10^6 Btu, with a mean of about 0.47, but only about 10% of the reported values exceeded the EPA standard of 0.7 lb NO_2 per 10^6 Btu.

Henschel²⁵ has stated that atmospheric-pressure fluidized-bed combustors commonly show NO_x emission levels in the range of 0.3 to 0.6 lb NO_2 per 10^6 Btu. As for pressurized fluidized-bed combustors, Henschel reports that pressurized systems with heat-transfer surfaces in the bed (and operated with ~20% excess air) typically give NO_x emission levels in the range of 0.12 to 0.3 lb NO_2 per 10^6 Btu. Although actual data from the so-called *adiabatic* pressurized fluidized-bed combustors (that have no heat-transfer surfaces in the bed and depend upon large amounts of excess air for temperature control) are rather limited, indications are that the NO_x emissions from such units may be higher than from the types mentioned above, but still not in excess of the current EPA emission standard.⁷

6.4.2.2 Factors Affecting NO_x Emission Level

As may be inferred from the preceding paragraph, it is found experimentally that increased *pressure* results in decreased NO_x emission, while increasing the *excess air* supplied to the bed leads to increased NO_x emission. Both of these effects are consistent with the hypothesis that NO reacts with CO to form N_2 and CO_2 , as indicated in reaction (6.1). Increasing the total pressure should drive this reaction to the right, while increasing the excess air would reduce the availability of CO.³

Although nearly all investigators have noted a significant increase in NO_x emission as the *bed temperature* is increased above approximately $1650^\circ F$, the correlation between NO_x emission and bed temperature is less conclusive at lower temperatures. In principle, an increase in NO_x emission with increasing temperature might be expected. For one thing, as temperature is increased the formation of NO by thermal fixation of nitrogen in the air

will make an increasingly significant contribution to the total NO_x formation. Also, one would expect that higher temperatures would result in reduced availability of CO for the chemical reduction of NO.

Jonke et al.²⁶ have reported that tests with a pressurized fluidized-bed combustor using dolomite as the SO_2 sorbent showed that the NO_x emission level increased as the Ca/S mole ratio was increased from 1 to 3, and this increase in NO_x was more pronounced at a bed temperature of 1650°F than at 1450°F . On the other hand, investigators who have run tests with fluidized-bed combustors containing a supposedly inert bed additive such as alumina have usually noted a decrease in NO_x emission when an SO_2 sorbent was injected into the bed.³ From these observations it might be concluded that the presence of *some* amount of SO_2 sorbent serves to reduce NO_x emissions, but that too much sorbent can have the opposite effect. It would seem that the relationships between NO_x emission on the one hand and SO_2 and SO_2 sorbents on the other, as well as the mechanisms responsible for these relationships, are in need of further clarification.

Higher NO_x emissions are obtained with coal containing higher concentrations of chemically bound nitrogen. It is reported, however, that the NO_x emission level increases at a rate that is less than proportional to the nitrogen content of the coal.³

6.4.2.3 Prospects and Reservations

Available data obtained from operation of existing fluidized-bed facilities seem to indicate that the prospects are good for the development of commercial-scale, coal-fired fluidized-bed combustors, both atmospheric-pressure and pressurized, that will have NO_x emission levels well below the present EPA emission standards. There are, however, certain reservations and notes of caution that may be sounded.

It has been reported by Dow Chemical Company that there is no indication of any effect of scale on the level of NO_x emissions from fluidized-bed combustion.¹⁸ It is known however, that NO_x emission levels are affected by constraints on mixing within the bed and by the location and extent of reducing zones in the bed.³ It is conceivable that in a really large combustor the dynamics of the bed might be unfavorable in such respects.

Also, experience with conventional coal combustors has shown that NO_x emission tends to increase along with unit size.³

The NO_x problem may be magnified if a carbon burnup cell is used to fire unburned carbon particles elutriated from the main combustor and thus to increase the overall combustion efficiency of the system. It is estimated that this cell, which would operate at $\sim 2000^\circ\text{F}$ and in which some coal would have to be burned with a high level of excess air, could emit NO_x levels as high as 800 ppm.³ Mixing the effluent gases from such a cell with those from the main combustor may increase the overall NO_x emission level of the system. For example, if 15% of the effluent gas comes from the carbon burnup cell and contains 800 ppm NO_x while the main combustor emits 350 ppm NO_x , the resultant NO_x concentration in the stack will be 418 ppm.

Owing, at least in part, to recent delays and disappointments in developing effective and economical means of reducing NO_x emissions from mobile combustion sources, there is a strong possibility that much stricter NO_x controls on stationary sources (including coal-fired utility boilers) may soon be imposed. A recent publication by the EPA indicating goals for stationary sources is probably indicative of levels of control under consideration. The goals for coal-fired utility boilers specify NO_x emission levels of 200 ppm by 1980 and 100 ppm by 1985. These levels are, respectively, about 60% and 80% less than that permitted by present performance standards.^{3a} If and when more effective control of NO_x emissions from fluidized-bed combustion is required, it has been suggested that potentially useful techniques could include: (1) staged combustion with overfire air and (2) catalytic decomposition of NO , if an effective and economical catalyst can be found.³

6.4.3 *Particulate Emissions*

The control of solid particulate emissions from fluidized-bed combustors constitutes a significant, if not serious, problem. Features inherent in the design and operation of such combustors would certainly seem to be conducive to producing high levels of particulates in the off gases. Among such features are: (1) the presence in the bed of numerous particles of limestone or similar incombustible additive as well as particles of coal,

(2) the upward flow through the bed of fluidizing air and combustion gases that can entrain and elutriate small solid particles, and (3) a combustion temperature that is too low to produce slagging of the coal ash. Slagging is thought to play a role in reducing particulate emissions from conventional coal combustors.

6.4.3.1 *Quantity and Needed Reduction of Particulate Emission*

Published experimental data on actual levels of particulate emissions from existing fluidized-bed combustors are surprisingly sparse. However, Vogel et al.⁹ working with a pressurized combustor of 6-in. diameter observed solids loadings in the flue gas leaving the combustor (before any particulate removal) of from 7 to 39 lb/10⁶ Btu of input heat, depending upon the values of Ca/S mole ratio and fluidizing-gas velocity.* On that basis, a reduction of the flue-gas particulate concentration by some two to three orders of magnitude would appear to be required to meet the EPA's New Source Performance Standard of 0.1 lb/10⁶ Btu for particulates.

For those pressurized, combined-cycle power generation systems wherein the hot gases from the combustor are to drive a gas turbine, Keairns et al.⁷ estimate that to avoid excessive erosion of the turbine blades, particulate loadings of the combustion gases may have to be reduced to levels well below those required just to satisfy the current EPA emission standards. To accomplish such reductions at the high temperature of the gas emerging from the combustor is expected to place very severe burdens upon the particulate removal equipment and may require modified or new approaches to the removal problem. On the brighter side, however, gas turbine requirements may well ensure that such a system will more than meet present environmental limitations on particulate emissions.

Finally, Dow Chemical Company, in a study of the observed effects of combustor size on pollutant emissions from fluidized-bed combustors, reports that gross particulate concentrations in the off gases apparently tend to increase as the size of the combustor is increased, and that this is true for both atmospheric-pressure and pressurized units.¹⁸

*By comparison, conventional pulverized-coal combustors produce solid particulates at a rate of 5-12 lb/10⁶ Btu.

6.4.3.2 *Characterization of Particulate Emissions*

Solid particulate emissions from fluidized-bed combustors may consist of fly ash, soot, unburned or partially-burned coal, and calcined or sulfated SO_2 sorbent.⁷ The relative amounts of each will depend not only upon the properties and preparation of the fuel and sorbent, but also upon the manner in which the combustor is operated.

The mean size and size distribution of the particulates (along with other physical properties of the emitted particles) are not well defined on the basis of available experimental data. Jonke et al.²⁶ state that particles of fly ash elutriated from a fluidized bed are typically larger than those from conventional combustors burning pulverized coal (100 vs. 20 μm average size). Sargent and Lundy¹³ reports that the literature indicates that the mean particle diameter emitted from a fluidized bed is "shifted to the larger size." Iammartino²⁰ writes that the fly ash "looks favorably coarse." For the purpose of design studies, Keairns et al.⁷ have made use of three different assumed size distributions for the emitted particulates, giving mass median particle sizes of $\sim 35 \mu\text{m}$ to $\sim 150 \mu\text{m}$. On the other hand, Fennelly et al.³¹ report that the mass median diameter of the flue-gas particles is only $\sim 7 \mu\text{m}$, which could mean that significant concentrations of hazardous submicron particles may be emitted. This matter warrants further investigation.

The ash formed in a fluidized-bed combustor has been alleged to be relatively soft and friable because it is formed well below the fusion temperature of coal ash, but these qualities have not been demonstrated experimentally.³² If true, this ash quality could be helpful in reducing the severe requirements for particulate removal in systems employing gas turbines. It is also reported that the highly effective removal of SO_2 from the off gases causes the particulates emitted from a fluidized-bed combustor to have unusually high electrical resistivity, a property that can adversely affect the operation of electrostatic precipitators.³

6.4.3.3 *Factors Affecting Particulate Emission*

Of various factors known to influence the level of particulate emissions from fluidized-bed combustors, three of the most important are:

(1) the properties and preparation of the sulfur sorbent, (2) the Ca/S mole ratio, and (3) the superficial velocity of the fluidizing air. The size distribution of sorbent particles in the feed is significant in that very small particles are likely to be entrained by the fluidizing air, elutriated from the bed, and carried out of the combustor along with the off gases. Hence, this factor suggests that the limestone or dolomite be crushed to a size no smaller than needed to achieve the required degree of sulfur retention and calcium utilization, and that the crushed stone be screened to eliminate any unnecessarily fine particles before the stone is fed into the bed. Once in the bed, sorbent particles undergo further size degradation resulting from thermal shock, abrasion, and internal stresses and pressures accompanying the chemical processes of calcination and sulfation. The resistance to this sort of attrition has been observed to vary considerably depending upon the source of the limestone or dolomite and even between different shipments of stone from a given source. Attempts are being made to develop simple laboratory tests to predict the attrition resistance of samples of stone intended, or being considered, for use in fluidized-bed combustors.³³

Vogel et al.⁹ found that particulate emissions increased both with increasing Ca/S mole ratio and with increasing superficial velocity of the fluidizing air. Using a 6-in. diameter fluidized-bed combustor operating at a pressure of 8 atm with dolomite as the SO₂ sorbent, it was observed that with a fluidizing-air velocity of 3.5 ft/sec the particulate emission level increased by ~80% as the Ca/S mole ratio was increased from 1 to 3. Also, with a Ca/S mole ratio of 2, the particulate emission level was found to increase by ~230% as the air velocity was increased from 2 to 5 ft/sec. While these results suggest the desirability of maintaining low Ca/S ratios to minimize particulate emission from the sorbent, it is probable that high Ca/S ratios can still be used at suitably selected air velocities and sorbent particle sizes.

6.4.3.4 Add-on Particulate Control Devices

Clearly, the reduction of solid particulate emissions from fluidized-bed coal combustors to acceptable levels will require the use of add-on control devices. Possible options include cyclones, electrostatic precipitators, wet scrubbers, and various types of filters.

In the case of atmospheric-pressure fluidized-bed combustors, where only the *environmental* emission standards for particulates need be met and where high-temperature particulate removal is not a necessity, it seems probable that adequate removal of particulates from the flue gases can be achieved by employing several stages of conventional particulate collection equipment, e.g. two cyclones in succession to collect the coarser particles followed by a low-pressure-drop baghouse to remove finer particles. Low-temperature electrostatic precipitators are not expected to be very effective, owing to the anticipated high electrical resistivity of the particulates. Hot precipitators may not do well either. The presence of alkali salts in the fly ash has been reported as a major reason for the good performance of hot precipitators used in conjunction with conventional combustors, but fluidized-bed combustors operate at such low temperatures that alkalis may remain unvaporized in the bed.⁵

The prospects are less clear in pressurized systems where (to prevent excessive erosion and loading of the gas turbine) the hot, pressurized gases leaving the combustor must be very effectively cleansed of particulate solids. According to Strom et al.³ the only *proven* hot particulate collector is some form of cyclone, but there is doubt that cyclones alone can fill the need. Thus Vogel et al.⁹ found that passage of the offgases from their 6-in. diameter, pressurized fluidized-bed combustor through two cyclones in series reduced the solids loading by only about 90%, which is not nearly enough. Also there are indications that particles in the size range of 2 to 10 μm may be of significance for gas-turbine blade erosion, and most cyclones do not collect such small particles very effectively.

Fortunately, improved types of high-temperature particulate removal devices, including high-efficiency cyclones, granular bed filters, and porous metal and ceramic filters, are under development and are showing promise.⁷ It could be, though, that the final solution will involve not only better high-temperature particulate removal equipment but also improvements in gas-turbine materials and designs to provide increased erosion resistance.

6.4.4. Trace Elements

Coal contains an abundance of trace elements, some of which might be harmful to man and to the environment. With the large amount of coal being utilized, appreciable amounts of some of these elements might escape to the environment.

In order to estimate the distribution of these trace elements, studies have been made of the disposition of some of these elements in the combustion of coal in conventional pulverized-coal power plants.^{34,35} In studying the distribution of these elements, it has been observed that the distribution conforms to Goldschmidt's geochemical classification.³⁴ The trace elements are separated into four classes: (1) lithophile, (2) chalcophile, (3) elements emitted in the vapor phase, and (4) unclassified elements exhibiting the properties of either Class 1 or 2. Those elements listed in Class 1 are associated with aluminosilicate minerals in coal and are apt to be high-boiling compounds that do not decompose during combustion. Class 2 elements are present as sulfides, and during combustion the metal-sulfur bond is broken and the elements form low-boiling species. These elements are enriched on small particulates. Class 3 elements boil below the furnace and flue-gas temperatures and can exit from the stack as vapors.

In one such study,³⁴ a group of elements (Nb, Sr, Al, Fe, Rb, Y, and Zr) was found not to be enriched in any outlet stream and the bulk of these elements are found in Class 1. Other elements (Pb, Mo, As, Zn, Sb, and Cu) were enriched in the finer fractions and are found to be included in Class 2, the chalcophiles. Less than 10% of the mass input of Al, Fe, Cu, Rb, Sr, Y, Zr, and Nb; 13% of the Zn; and 18% of the Mo were shown leaving as stack emissions. Thus the bulk of these elements were retained in the power plant. There were poor material balances for Hg and Se, suggesting that the major portion of these materials left in the flue gas.

In another study,³⁵ the same general behavior was noted for the elements studied. Hg, Cl, and Br were reported to remain essentially in the gas phase.

There have been several studies of the behavior of trace elements in fluidized-bed combustion. One study³⁶ was carried out on the ANL 6-in. pressurized fluidized-bed combustor (the bench-scale unit) and mass balances

were made for the following trace and minor elements: Hg, F, Be, Pb, As, Br, Co, Cr, Fe, K, La, Mn, Na, and Sc. Of these elements, Mn, Co, Fe, K, La, Na, and Sc had material balances of $100 \pm 10\%$, indicating that within analytical accuracies there were essentially no losses by volatilization. Comparison of some of the ANL material balance data with data obtained at Exxon gave good agreement, as indicated in Table 6.3.³⁷

The data on fluorine indicate that the retention of fluorine in the solid phases leaving the combustor was considerably enhanced when additive (limestone) was used in the experiment. The implication is that less fluorine will be released in the flue gas in the fluidized-bed combustor than for the conventional coal-fired boiler. The same general trend was observed for bromine.

The concentrations of several elements (Ba, Co, La, Sb, Sc, and Ta) showed a slight tendency to increase with decreasing particle size of the ash.

Comparison of the projected trace-element emissions from conventional and fluidized-bed combustion systems (Table 6.4) shows that the projected emissions from the fluidized-bed combustion of coal are consistently as low or lower than those measured on conventional pulverized-coal boilers, except possibly for chromium.³⁶ However a closer examination of the chromium data suggests that the chromium retention is higher than that reported.

The reduced emission of As in the fluidized bed may be due to the presence of the calcium sorbent. It has been reported that the volatility of As is dependent upon the calcium present. With high calcium content, it will be bound as the arsenate and not volatilized as As_2O_3 .^{14, 34}

At ANL a systematic study has been made of the trace elements in coal.^{38, 39} The starting material in these experiments was an ash prepared by ashing coal at 340°C for 48 hours in an air flow of 9 L/min. Samples of this ash were heated to various temperatures up to 1250°C in an air flow for approximately 20 hours. The following elements, Be, Fe, Al, Pb, Na, K, Mg, Ca, Ti, Zn, Mn, Ni, Co, Cu, Cr, Li, and V were studied and none of them showed any measurable volatilization up to 1250°C . Under the dry oxidizing conditions present in the treatment of the 340°C ash, most of the chlorine in the coal evolves at temperatures below 640°C , although trace amounts still remain in the high-temperature ashes.

Table 6.3 Mass Balance for Trace Elements in Fluidized Bed Combustion of Coal--Comparison of Exxon and ANL Results

Element	Percent Element Recovered (Mass Balance)	
	Exxon ^a	ANL ^b
As	86	84
Cr	207	100
Fe	80	93
Mn	96	110
K	75	76
Sc	85	85
Na	88	92

^aBatch combustor, run temperature 1730°F.

^bBench scale reactor, average of two runs at 1660 and 1550°F.

These results were modified from those in reference 36 to include only the data obtained in a dolomite bed.

Table 6.4 Projected Emissions of Trace Elements from Conventional and Fluidized-bed Combustors Expressed as a Percentage of the Element Entering the System³⁶

Element	Conventional Combustion ^a	Fluidized-bed Combustion
Hg	90-100	80
F	90-100 (estimated)	40
Br	90-100	65
As	0-60	15
Pb	10	0-20
Be	Not Available	20-40
Sc	10	0
Cr	0	0-25
Co	10-20	0-20
Na	0-10	5
K	0-10	10
Fe,La,Mn	0	0

^aProjected from data in the literature on trace-element emissions from conventional power plants.

These additional results support the conclusions stated just above. However, because of the toxicity of Be, As, and Hg, an awareness should be maintained as to the disposition of these elements from the fluidized-bed combustor.

6.4.5 *Hydrocarbon Emissions*

Of particular concern among hydrocarbon emissions are the so-called polynuclear aromatic hydrocarbons, inasmuch as some of these compounds, such as benz(a)pyrene, are known carcinogens. The relative rates of formation and decomposition of such compounds during the burning of coal are strongly dependent upon combustion conditions. Conditions leading to relatively low combustion temperatures, as in fluidized-bed combustors, are especially suspect, since it is believed that compounds such as benz(a)pyrene may form more rapidly than they decompose at combustion temperatures of 1500-1700°F. It is emphasized, however, that virtually no experimental information is available concerning the presence or concentration levels of such organic compounds in the emissions from fluidized-bed combustors.

6.4.6 *Other Forms and Sources of Pollutants*

Standard industrial practices, such as are now in use at conventional coal-fired utility plants, are believed to be capable of accomplishing effective control of pollutant emissions (and any other undesirable environmental impacts) resulting from the transportation, handling, storage, and preparation of coal and stone, from cooling operations and waste-heat disposal, and from water treatment and usage at power plants equipped with fluidized-bed coal combustors. The environmentally acceptable disposal of the spent stone is discussed in the following section of this report.

6.5 *MANAGEMENT OF FBC SOLID WASTES*

6.5.1 *Introduction*

As is characteristic of any coal-burning power plant, FBC boilers produce large quantities of ash.* In addition, as is true for any system using limestone as sorbent for SO₂, FBC boilers produce large quantities of

*Disposal of this solid waste is discussed in Section 4.4.2.

spent sorbent.* Two alternatives are generally available for disposition of these waste solids--disposal (dumping) and utilization.

Disposal of FBC spent sorbent may pose a minor aesthetic problem and a troublesome pollution problem, since calcium sulfate, the chief component of the spent sorbent, is somewhat soluble in water. Trace elements originally present in coal are detectable in the spent sorbent. Because leachates are often alkaline, leaching of the exposed sorbent must be controlled in order to prevent degradation of surface and groundwaters.

This section of the report compiles and evaluates information regarding technology available or being developed for disposition of this waste. It assesses methods for ponding and/or landfilling as a means of disposal, and the environmental impact of these methods. It also assesses the current status and potential for utilizing the spent sorbent in agriculture, paving, manufacture of cement and wallboard, production of sulfur and sulfuric acid, etc.

Information gaps and needed R&D programs are identified.

6.5.2 *Magnitude and Nature of the Problem*

6.5.2.1 *Quantities Expected*

The amount of spent sorbent generated by an FBC plant will depend among other factors on the amount of coal burned, sulfur content of the coal, the ratio of sorbent to sulfur (Ca/S mole ratio), pressure, choice of sorbent (limestone or dolomite), and SO₂ removal efficiency.

In regard to the quantity of waste solids, it is useful to compare FBC to FGD systems employing lime/limestone. Until recently, FBC units were expected to require a higher Ca/S mole ratio than FGD (e.g., 2.0 vs 1.2) in order to achieve the desired SO₂ removal efficiency (90%). The higher Ca/S ratio would result of course in a greater amount of spent sorbent for FBC operations. However, work has been reported by Westinghouse in which it was possible to reduce the Ca/S ratio to 1.2 when operating an FBC unit under pressure with dolomite. But for one factor, this would have equalized the dry weight of spent sorbent each produces. That factor is the composition

*On the order of 1000 tons per day from a 500-MWe plant.

of dolomite; its CaCO_3 content is only about 1/2 that of limestone (the rest is mainly magnesium carbonate). Thus, about 84% more stone (dolomite) is required by the FBC unit to provide the same Ca/S mole ratio.

This FGD weight advantage is almost completely offset, however, by the following:

1. The FGD material as produced contains 10% more fly ash.
2. The land-filled FGD solids contain about 20% occluded water, 10% lime and/or cement as chemical fixative, and 20% fly ash added to give it final stability.
3. The 10% loss in weight resulting from the calcination of the MgCO_3 content of the dolomite in the FBC material reduces the mass of FBC wastes.

Whatever the weight differences, it is certain in both instances that at a given plant site the problem of disposal will be a fairly massive one. But because of the anticipated slow rate of commercial development of FBC (see forecast in Section 6.6), the problem will not be a major national or regional concern until perhaps the last few years of this century.

6.5.2.2 Properties of the Spent Sorbent

Spent sorbent is discharged in a slipstream from the FBC unit as a dry particulate solid. Typically it has the composition shown in Table 6.5.

Table 6.5 Typical Spent FBC Sorbent Composition

Component	Tymochtee Dolomite ^a	Grove Limestone ^b
CaSO_4	57%	26%
CaCO_3	9	58
CaO	2	8
MgO	20	1
Other (including ash)	12	8

^aANL pressurized pilot plant.

^bExxon pressurized pilot plant.

FBC spent sorbent does not contain CaSO_3 , which, in the form of its hemihydrate, tends to occlude water and imparts thioxotropic properties to the slurry (sludge) discharged by the FGD systems. Thus, even if exposed to rainwater or runoff water, FBC spent sorbent is not expected to form a sludge. However, the greater solubility of CaSO_4 as compared to CaSO_3 (2000-3000 vs. 40 ppm) poses a somewhat greater threat of groundwater pollution by leaching.

6.5.3 Disposal Modes

Since the spent sorbent is discharged as a dry particulate solid, it should be easy to dispose of as landfill. Leaching tests were carried out by Westinghouse⁷ to assess the possibility that rain or runoff water would dissolve harmful amounts of salts and trace elements and eventually contaminate ground or surface waters. These bench-top tests on a limited number of small samples of spent dolomite sorbent indicated that the leach water contained insignificant amounts of heavy metal ions -- several orders of magnitude less than drinking water standards. The concentration of magnesium ions was also negligible. However, calcium and sulfate concentrations exceeded water quality criteria, and the pH of one sample was too high (10.6-12).*

On the basis of these admittedly meager data, it is possible that leaching of FBC spent sorbent will most likely not pose a major threat of groundwater pollution provided that landfill techniques such as lining the bottom and sides of the site with impervious clay or impermeable liners, controlling surface water drainage into the landfill, etc., are utilized. However, because of the limited amount of spent sorbent available, field tests to confirm this hypothesis could not be made. The difficulty will soon be resolved as the new 30-MWe FBC plant at Rivesville goes into operation. This plant is expected to produce about 60 tons/day of spent sorbent which should be sufficient for extensive ponding, leaching, and weathering tests.

6.5.4 Utilization Alternatives

Here again the differences between the composition and properties of FBC and FGD spent sorbent gives FBC spent sorbent an advantage in qualifying

*The pH of runoff leachates showed a gradual decrease with continued leaching.

and competing for a share of large-tonnage markets, such as agriculture, wallboard, cement, soil stabilization, highway foundation, treatment of mine or municipal acid wastes, etc.

For many of these end uses, it may be necessary to cleanse the spent sorbent of coal-ash particles. A simple air classifier is not satisfactory; a vibrating screen works better, and this technique is being applied at the Rivesville 30-MWe plant.⁴⁰

6.5.4.1 Agriculture

Soil Amendment to Control pH

T.D. Hinesly, Professor of Soil Ecology at the University of Illinois, Urbana, indicates that waste dolomitic and calcitic materials from FBC plants are sufficiently high in calcium carbonate equivalence to suggest that these materials may be useful in correcting soil acidity conditions to optimum pH levels (6.2 to 6.5) for growing crops.

Soil Amendment for Peanut Crops

Rather favorable results have been obtained with limestone spent sorbent as a nutrient for peanut growing. When applied to plots planted with peanuts, spent limestone sorbent from the Pope, Evans, and Robbins small (about 0.7-MWe) pilot plant improved yields by about 10% over those obtained with no fertilizer. These results were equal to, or slightly better than, the improvements afforded by land plaster (natural gypsum).⁴¹

Incidentally, dolomite spent sorbent would need to be tested to determine what effect, if any, its higher magnesia content would have on the peanut crop. This will no doubt be covered in the programs listed below.

Outlook for Utilization in Agriculture

The outlook for FBC waste utilization seems quite favorable, subject of course to new findings in the following programs.

1. Ralph Stone and Company is under contract with the EPA to assess, among other factors, possible uses for FBC spent sorbent.

2. TVA is under subcontract with Pope, Evans, and Robbins Co. (PERCO), an EPA contractor, to evaluate FBC spent sorbent as an agricultural nutrient.
3. The V.P.I. Tidewater Research Center (Suffolk, Va.) is conducting soil amendment tests for PERCO.
4. ERDA and the USDA are cooperating in a \$1.7-million, 5-yr study of the use of FBC solid wastes for fertilizers and soil treatment. The project will include analyses of the wastes followed by greenhouse and field studies.

6.5.4.2 *Structural Material*

Wallboard

One of the uses considered for spent sorbent is in the manufacturing of gypsum board (wallboard utilized for the linings of walls, partitions and ceilings -- sometimes called stucco or plasterboard). It is estimated that about 15 million tons of gypsum ($\text{CaSO}_4 \cdot 2\text{H}_2\text{O}$) in the form of stucco ($\text{CaSO}_4 \cdot 1/2\text{H}_2\text{O}$) is being consumed for this purpose each year.

TVA is conducting a study project for EPA to provide a detailed assessment of abatement gypsum in terms of its production and market potential, including its use for wallboard manufacture. Completion of the project is expected late in 1976. However, it does not seem likely that spent limestone sorbent, which usually contains only about 25-35% CaSO_4 , or dolomite spent sorbent, with its high content (20%) of magnesia, could meet the industry's chemical specifications⁴² or displace the much-favored natural gypsum.

Other Structural Uses

The Coal Research Bureau of West Virginia University has investigated the use of spent lime sorbent plus fly ash for the manufacture of cement or cinder block, facing-quality brick, mineral wool, cracking beds, ceramic castings, and glaze-coated materials.⁴³ Of these, mineral wool production seems to have some promise.

The spent sorbent characteristics (particle size and composition) may make the material useful for soil stabilization. However many tests would be

required to establish optimum recipes to enable one to choose specific soil-waste material mixtures (with or without cement) for uses such as load-bearing materials in highway foundations and embankment structures.⁷

6.5.4.3 *Sulfur and Sulfuric Acid*

It is technically but not economically feasible to produce these chemicals from spent sorbent unless regeneration becomes a reality. In that case there will be no alternative except to convert the SO_2 liberated in the regeneration step to sulfuric acid for sale or to sulfur for either sale or storage. As for the market potential, the maximum possible production of such sulfur (or equivalent sulfuric acid) that could be expected in the last part of the century is about 60% of the lowest expected growth in demand, or about 27% of the maximum expected growth in demand. In the near term there would probably be no danger of swamping or upsetting the supply/demand balance.^{44,45,46}

6.5.4.4 *Miscellaneous End Uses*

Treating of mine or municipal acid wastes appears to be a promising use for spent FBC sorbent, especially if the plant is located near these wastes.

6.5.5 *Regeneration*

Regeneration of spent sorbent is an attractive alternative to the once-through/discard system because:

1. Consumption of raw limestone or dolomite might be reduced by 50% to 90%, with 75% the most likely reduction.
2. Similar reductions might be effected in the bulk of spent sorbent requiring disposal by landfill, etc.
3. Conservation and beneficial utilization of the sulfur derived from the coal becomes possible.

Regeneration processes are under development and have been demonstrated on the bench-scale and small pilot-scale levels.^{47,48} Given the present state of the art, regeneration will probably not be practiced commercially before about 1985.

6.5.6 *Limestone and Dolomite: Availability and Secondary Pollution*

Limestone resources will not constrain FBC use, as U.S. deposits are enormous and widely distributed, and the maximum requirements envisioned for FBC installations would be but a minor fraction of current production of the stone. The situation is comparable for dolomite. As with limestone, there could be logistic problems at a given plant site, but none of national supply.

The environmental impact resulting from increased production of limestone or dolomite is mainly one of airborne dust. The industry has developed techniques for minimizing this nuisance and will continue to use them.

The other environmental impacts are those regarding land use and aesthetic problems associated with quarry operations; these become of course more severe when the quarry is located close to residential areas. The stone industry will no doubt be able to cope with such impediments to expansion, although it will not be as easy or as inexpensive as it once was.

6.6 *IMPLEMENTATION*

6.6.1 *Costs Compared to Regular Combustion with Flue-gas Desulfurization (FGD)*

In comparing the costs of regular combustion with FGD to those of fluidized-bed combustion, one must bear in mind that the cost of a pulverized-coal steam power plant is based on plants built, whereas the values for FBC are engineering estimates of what such a plant would cost. One such evaluation by Westinghouse⁷ produced the results indicated in Table 6.6.

A later evaluation made in 1976 by NASA⁴⁹ for ERDA gave the results shown in Table 6.7. The General Electric results show a small increase in power costs for the pressurized fluidized-bed combustor as compared with a conventional plant, whereas the calculations for the atmospheric fluidized-bed combustor show a slight decrease. The Westinghouse data show slight improvements in the cost of electricity for fluidized-bed combustors compared with the conventional plant. The big difference between the two relates to the capital cost comparisons: The GE estimates for balance-of-plant costs are approximately \$125/kWe higher than those for Westinghouse.

Table 6.6 Economic Comparison of 600-MWe Plants

System ^a	Plant Costs ^b (\$/kWe)	Energy Cost (mills/kWh)
Conventional Plant (\$50/kWe Scrubbing)	465	20.63
Conventional Plant (\$115/kWe Scrubbing)	530	22.41
PFBC (100% excess air, 3 stages particulate removal)	426	19.40
PFBC (17% excess air, 3 stages particulate removal)	394	18.40
Adiabatic PFBC	468	20.77

^a70% capacity factor, 3% sulfur coal, Ca/S=1.2, 90% sulfur removal and \$10/ton sorbent.

^bBased on Nov. 1974 start of project.

A more detailed examination of the balance-of plant estimates indicated that the GE estimates were higher in all cases, the bulk of the difference being found in the "other mechanical equipment" and "civil and structural work." Further resolution of these differences was not achieved in this study.

In an attempt to relate these estimates to actual results, NASA made an in-house adjustment (to conform to the estimation ground rules), on the "as-built" price of the TVA Bull Run conventional coal-fired plant. The Bull Run estimate with cooling towers, scrubber, and adjusted for escalation is \$520/kWe. These results indicate that for a conventional plant GE is approximately \$115/kWe too high and Westinghouse is \$52/kWe too low. These differences probably reflect the differences between the two contractors in the cost for the advanced furnace systems. Thus, comparison between different contractors is difficult, but the trends for the different systems for any one contractor should be realistic.

These data reveal the difficulties in making cost estimates. The data indicate that fluidized-bed combustion could be cost competitive with conventional coal-fired plants and may even turn out to be somewhat cheaper. However, the difficulty of making cost estimates as indicated by the differences in the Westinghouse and General Electric estimates (Table 6.7) suggests that these estimates be used with caution.

The costs of the pressurized fluidized-bed combustor are particularly insensitive to many of the process variables. The effect of a change in bed temperature, fluidizing velocity, heat transfer surface configuration, gas-side heat transfer coefficient, boiler tub materials, or bed depth limitations

Table 6.7 Comparison of Advanced Steam Plants Using
Different Furnace Types⁴⁹

	Based on General Electric data			Based on Westinghouse data		
	CF	AFB	PFB	CF	AFB	PFB
<u>(a) Performance comparison^a</u>						
Steam turbogenerator output, MWe	800	800	600	800	800	640
Gas turbogenerator output, MWe	---	---	<u>177</u>	---	---	<u>114</u>
Total gross output, MWe	800	800	777	800	800	754
Auxiliary losses, %	<u>5.0</u>	<u>6.5</u>	<u>3.3</u>	<u>7.8</u>	<u>7.3</u>	<u>3.2</u>
Total net output, MWe	760	748	751	738	742	730
Overall efficiency, %	37	37	38	36	36	38
<u>(b) Capital cost comparison^b</u>						
Furnace/steam boiler cost, \$/kWe	110	126	192	118	103	140
Stack-gas cleanup cost, \$/kWe	139	63	(c)	97	48	(c)
Steam turbogenerator cost, \$/kWe	66	66	62	61	61	52
Gas Turbogenerator cost, \$/kWe	---	---	58	---	---	36
Balance-of-plant costs, \$/kWe	<u>320</u>	<u>337</u>	<u>310</u>	<u>192</u>	<u>198</u>	<u>194</u>
Total	635	592	622	468	410	422
<u>(c) Cost of electricity</u>						
Capital component of COE, mills/kWh	20.1	18.7	19.7	14.8	13.0	13.3
Operation and maintenance component of COE, mills/kWh	2.2	2.5	3.4	1.0	1.7	1.7
Fuel component of COE, mills/kWh	7.9	7.9	7.6	8.1	8.1	7.6
Total	<u>30.2</u>	<u>29.1</u>	<u>30.7</u>	<u>23.9</u>	<u>22.8</u>	<u>22.6</u>

^aSteam conditions-3500 psi/1000°F/1000°F; condenser pressure-1.5 in. of Hg for each; results developed by NASA from General Electric and Westinghouse data.

^bCosts for each line item are all inclusive, including applicable contingency, interest, and escalation. Cost basis is enclosed-type construction with land cost excluded and without provision for on-site disposal of waste. Contingency applied to General Electric-based results is 15 percent. Interest and escalation are per NASA factor of 1.49 for 5-yr construction period.

^cCost of gas cleanup equipment is included in furnace cost.

will result in no significant change in plant operability or performance, <2% increase in plant cost, and <0.2 mills/kWh increase in energy cost. The effect of increasing the dust loading to three times the design value will increase the plant cost ~4% and the energy cost <0.3 mills/kWh.⁵⁰

6.6.2 Time Frame for Availability

In evaluating the availability of fluidized-bed combustors, it is assumed that the present boiler manufacturers will fabricate fluidized-bed combustors and that fluidized-bed combustors will be substituted for conventional pulverized-coal furnaces. In comparing various estimates of the time frame for availability, a problem appears in deciding on the size of a demonstration plant.

Carls⁵¹ has estimated that commercial atmospheric-pressure fluidized-bed combustors will be operating in utility networks by 1987, assuming successful operation of the 30-MWe Rivesville plant and a 200-MWe demonstration plant. For the pressurized fluidized-bed combustor, operation in utility networks is projected for 1995, again assuming successful operation of the 13-MWe pilot plant and 300-MWe demonstration plant. He estimates that by the next century the electrical capacity supplied by fluidized-bed combustors will be 40,000-50,000 MWe. This estimate agrees very well with a projection made by Westinghouse that FBC contributions to the energy system will be 40,000 MWe.⁷

Sargent and Lundy¹³ estimates that the PFBC will not be commercially developed until 1995. That estimate is derived by assuming an orderly progression in plant size to 100 MWe, 300 MWe, and 500 MWe from the 13-MWe PFBC plant being built by Curtiss-Wright and scheduled to be completed in 1980. The 500-MWe plant is arbitrarily chosen as the commercial size, probably because current information indicates that boilers ordered in 1975 averaged about 511 MWc.⁵² The estimate for the Curtiss-Wright plant is that it will have demonstrated the technology by 1980 and that five years will be necessary for the demonstration of each next successively larger size. This schedule provides for no overlap. The time to commercial operation can be shortened by overlapping projects or even eliminating one step completely. For example, 13 MWe, 100 MWe, and 500 MWe is another possible progression. Elimination of one phase or overlapping may increase the degree of risk to the utilities.

Of course, this degree of risk acceptance may be reduced by government subsidy. These projections are quite similar to those of Carls except that he projects one less step on the way to commercial development and allows 7-8 years for the completion of each phase.

It is pointed out that the atmospheric fluidized-bed combustor being built at Rivesville is almost ready for operation. This 30-MWe boiler will demonstrate the capability of FBC to deliver electricity to a utility network under standard operating conditions.

6.6.3 Areas of Applicability

The most obvious application for fluidized-bed combustors is for the generation of electricity, and most of the previous discussion has been directed primarily to that sector alone. There are several other areas of applicability, including:⁵³

1. Combustion of municipal solid waste.
2. Waste heat recovery from a ceramic kiln; approximately 400,000 Btu/hr were recovered from waste gas at 600° C.
3. Metallurgical furnaces, for hardening and tempering heat treatment.
4. Industrial boilers. These are especially cost competitive when they replace or are added to in-place boiler facilities so that additional coal handling facilities are not required.

ERDA⁵⁴ has advertised its intention to support proposals for the industrial application of fluidized-bed combustors directed to four categories:

- 1) Industrial steam generator, in the capacity range of 50,000-500,000 lb/hr.
- 2) Industrial boiler, producing 15,000-150,000 lb/hr of steam at less than 250 psi.
- 3) Indirect-fired heater, utilizing heat exchange devices from a minimum of 20 million Btu/hr up to a maximum of 500 million Btu/hr.
- 4) Direct-fired heater, to heat process materials by direct contact of the combustion gases, with a capacity of 10-500 million Btu/hr.

More recently ERDA has executed letter contracts with several groups to build smaller-type fluidized-bed boilers for industrial and commercial application.⁵⁵

6.6.4 Possibility of Retrofit

In this general context, the greatest use of fluidized-bed combustors would be in replacing steam boilers that have reached the end of their useful lifetimes in a plant where several boilers were supplying process steam from a central boiler house.

6.6.5 Barriers to Implementation

These may be broken down into two categories, technical and institutional; the technical is discussed first. The experimental evidence to this point has demonstrated that fluidized-bed combustors can remove sulfur to better than 90% during the combustion, that NO₂ emissions are reduced, and that the sorbent may be regenerated if need be. Studies have also indicated the effects of bed temperature, fluidizing velocity, and calcium to sulfur ratio. The types of information yet to be resolved are listed below.

1. Operability of the fluidized-bed combustor on a large scale must be demonstrated.
2. The ability of the fluidized-bed combustor to follow load demand on a utility network must be demonstrated.
3. For the pressurized fluidized-bed combustor, the effectiveness of particulate removal must be evaluated, especially as to how it affects gas-turbine operation and life.
4. The capability of gas turbines to operate continuously must be demonstrated. Also, studies must be made to determine and characterize the environment in which gas turbines can operate.
5. The immersion of boiler tubes in the fluidized-bed introduces another problem in that their suitability over long periods of time in the fluidized-bed combustor environment must be demonstrated.
6. Continuous and problem-free operation of the coal- and sorbent-feed systems must be demonstrated, especially for the pressure system.
7. Disposal of spent sorbent in an ecologically acceptable manner must be demonstrated.

These points lead to the next item; namely, institutional barriers to implementation. This item is, of course, dependent upon successful response to those listed above. As they are successfully demonstrated, and if the economics turn out to be as currently estimated or better, then the introduction of fluidized-bed combustors should occur. Utilities as a rule will

tend to stay with what they understand and have had success with. But there are always those willing to try new concepts that have been demonstrated and shown to be cost effective.

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APPENDICES

APPENDIX A. STATE AMBIENT AIR QUALITY STANDARDS

Table A.1 Applicable State Ambient Air Quality Standards^a

(All concentrations in $\mu\text{g}/\text{m}^3$)											
State	Total Suspended Particulates				Sulfur Dioxide					Nitrogen Dioxide	
	Primary		Secondary		Primary		Secondary			Primary	Secondary
	Annual ^c	24-Hour ^d	Annual ^b	24-Hour ^d	Annual ^c	24-Hour ^d	Annual ^c	24-Hour ^d	3-Hour ^d	Annual ^c	Annual ^c
REGION I											
Connecticut	75	260	60	150	80	365	60	260	1300	-	-
Maine	-	-	50	100	-	-	57	230 ^e	1150 ^e	100	100
Massachusetts	75	260	-	-	80	365	-	-	-	-	-
New Hampshire	-	-	60	150	-	-	60	260	1300	100	-
Rhode Island ^f	-	-	50	130	-	-	57	286	-	-	-
Vermont ^f	-	-	45	125	-	-	57	150	-	-	-
REGION II											
New Jersey	75	260	60	150	80	365	-	-	1300	100	100
New York ^{f,g}	70 ^h	250 ^e	40 ⁱ	-	80	365 ^j	-	-	-	100	-
	85 ^h	250 ^e	50 ⁱ	-	-	260 ^j	-	-	-	-	-
	100 ^h	250 ^e	60 ⁱ	-	-	-	-	-	-	-	-
	110 ^h	250 ^e	70 ⁱ	-	-	-	-	-	-	-	-
Puerto Rico	-	-	60	150	80	365	-	-	1300	100	-
Virgin Islands	-	-	60	150	80	365	-	-	1300	100	-
REGION III											
Delaware ^k	70	200	60	150	70 ^b	260 ^j	60	150	1300	-	-
	-	-	-	-	80	340	-	-	-	-	-
Dist. of Columbia ^f	75	160	60	140	75	285	57	225	-	-	-
Maryland ^f	75	160	60	140	79	262	39	131	-	-	-
Pennsylvania	75	260	60	150	80	365	-	-	1300	100	-
Virginia	75	260	60	150	80	365	80	365	1300	100	100
West Virginia	75	260	60	150	80	365	60	260	1300	-	-
REGION IV											
Alabama	75	260	60	150	80	365	-	-	1300	100	100
Florida	^l	-	60	150	-	-	60	260	1300	100	-
	^{f,l}	-	50	180 ^e	-	-	8.6	28.6 ^e	-	-	-
Georgia ^f	-	-	60	150	-	-	43	229 ^e	-	-	-
Kentucky	75	260	60	150	80	365	60	-	1300	100	-
Mississippi	-	-	60	150 ^e	-	-	60	260	1300	100	-
North Carolina ^m	-	-	60	150	-	-	60	260	1300	100	-

Table A.1 (Cont'd)

(All concentrations in $\mu\text{g}/\text{m}^3$)											
State	Total Suspended Particulates				Sulfur Dioxide					Nitrogen Dioxide	
	Primary		Secondary		Primary		Secondary			Primary	Secondary
	Annual ^b	24-Hour ^d	Annual ^b	24-Hour ^d	Annual ^c	24-Hour ^d	Annual ^c	24-Hour ^d	3-Hour ^d	Annual ^c	Annual ^c
<u>REGION IV (Contd.)</u>											
South Carolina	-	-	60	250 ^e	80	365	-	-	1300	100	-
Tennessee	75	260	60	150	80	365	60	364	1300	100	100
<u>REGION V</u>											
Illinois	-	-	-	-	-	-	-	-	-	-	-
Indiana ^f	75	260	60	150	80	365	60	260	-	100	100
Michigan	75	260	60	150	80	365	-	-	1300	100	100
Minnesota	75	260	60	150	60	260	60	260	655	100	100
Ohio	-	-	60	150	-	-	60	260 ^j	1300 ^e	100	-
Wisconsin	75	260	60	150	80	365	60	260	1300	100	100
<u>REGION VI</u>											
Arkansas	75	260	60	150	80	365	-	-	1300	100	100
Louisiana	75	260	60	150	80	365	60	260	1300	100	100
New Mexico	-	-	60	150 ^e	-	-	60	260	-	100	-
Oklahoma	75	260	60	150	80	365	-	-	1300 ^e	100	100
Texas	75	260	60	150	80	364	-	-	1300	100	100
<u>REGION VII</u>											
Iowa	75	260	60	150	80	365	-	-	1300	100	100
Kansas	75	260	60	150	80	365	-	-	1300	100	100
Missouri	¹ f,1	200 ⁿ	-	-	-	-	-	-	-	-	-
	f,1	-	60	150 ^e	-	-	40 ^b	200 ⁿ	-	-	-
		-	60	150 ^e	-	-	40	160 ⁿ	-	-	-
Nebraska	75	260	60	150	80	365	-	-	1300	100	100
<u>REGION VIII</u>											
Colorado ^f	¹ 1	-	70 ^c	200 ^e	-	-	60	300	-	-	-
		-	45 ^c	150 ^e	-	-	25	150	-	-	-
Montana ^f	75	200 ^o	-	-	-	-	60	260 ^o	-	-	-
North Dakota ^{f,m}	-	-	60	150	-	-	60	260	-	100	-
South Dakota ^m	-	-	60	150	-	-	60	260	-	100	-
Utah	90	200 ^o	-	-	80	365	-	-	1300	100	100
Wyoming	-	-	60	150	-	-	60	260	1300	100	-

Table A.1 (Cont'd)

(All concentrations in $\mu\text{g}/\text{m}^3$)											
State	Total Suspended Particulates				Sulfur Dioxide					Nitrogen Dioxide	
	Primary		Secondary		Primary		Secondary			Primary	Secondary
	Annual ^b	24-Hour ^d	Annual ^b	24-Hour ^d	Annual ^c	24-Hour ^d	Annual ^c	24-Hour ^d	3-Hour ^d	Annual ^c	Annual ^c
REGION IX											
American Samoa	-	-	60	150	-	-	-	-	1300	100	-
Arizona	-	-	60	150 ^e	-	-	50	260 ^e	1300 ^e	100	-
California	-	-	60	100	-	-	-	260 ^e	1300 ^e	-	-
Guam	-	-	60	150	-	-	60	260	1300	100	-
Hawaii	-	-	55	100 ^e	-	-	20	80 ^e	400 ^e	70	-
Nevada	-	-	60	150 ^e	-	-	60	260 ^e	1300 ^e	100	-
REGION X											
Alaska	-	-	60	150	-	-	60	260	1300	100	-
Idaho	75	260	60	150	80	365	-	-	1300	-	-
Oregon	-	-	60	150	-	-	60	260	1300	-	-
Washington ^f	-	-	60	150 ^p	-	-	55	266	-	100	100

^aFor states that did not adopt both primary and secondary standards, the entries are made in the 'Primary' column if state standards are less stringent than or equivalent to the corresponding primary NAAQS.

^bGeometric mean.

^cArithmetic mean.

^dNot to be exceeded more than once per year.

^eNot to be exceeded.

^fState also has SO₂ standards for other averaging times.

^gNew York's TSP standards are based on four land-use categories. SO₂ standards apply statewide.

^hNot to be exceeded by more than 16% of the 24-hour values in any 12 months.

ⁱNot to be exceeded by more than 50% of the 24-hour values in any 12 months.

^jNot to be exceeded more than 1% of the time.

^kState also has TSP standards for other averaging times.

^lApply in part of state only.

^mState also has NO₂ standards for other averaging times.

ⁿNot to be exceeded more than one day in any three-month period.

^oNot to be exceeded more than 1% of time between April 1 and October 31 or more than 5% of the time between November 1 and March 31.

^pEast of the Cascade Mountain Crest the standard can exceed 150 if the background TSP level exceeds 30.

Table A.2 Summary of State Implementation Plan Regulations

Region/State	Type of Regulation				
	Particulates		Sulfur Oxides		
	1b/10 ⁶ Btu	Other	1b/10 ⁶ Btu ^a	%S	Other
<u>New England</u>					
CT	X		X	X	
ME	X			X	
MA	X		X		
NH	X		X		
RI	X		X		
VT	X			X	
<u>Middle Atlantic</u>					
NJ	X		X	X	x ^b
NY	X		X	X	
PA	X	x ^b	X	X	
<u>South Atlantic</u>					
DE	X			X	
DC	X			X	
FL	X	x ^c	X		
GA	X	x ^d	X	X	
MD	X			X	
NC	X		X		
SC	X		X		
VA	X				x ^d
WV	X	x ^d			x ^d
<u>East North Central</u>					
IL	X		X		
IN	X	x ^e	X		
MI		x ^b		X	
OH	X		X		
WI	X		X		
<u>East South Central</u>					
AL	X		X		
KY	X		X		
MS	X		X		
TN	X		X		
<u>West North Central</u>					
IA	X		X		
KS	X		X		
MN	X			X	

Table A.2 (Cont'd)

Region/State	Type of Regulation				
	Particulates		Sulfur Oxides		
	lb/10 ⁶ Btu	Other	lb/10 ⁶ Btu ^a	%S	Other
<u>West North Central (Cont'd)</u>					
MO	X		X	X	x ^{d,e}
NB	X		X		
ND	X		X		
SD	X		X		
<u>West South Central</u>					
AK		x ^{d,e}			x ^e
LA	X				x ^b
OK	X		X		x ^e
TX	X	x ^{d,e}	X		x ^{b,e}
<u>Mountain</u>					
AZ	X		X		x ^d
CO	X				x ^b
ID	X	x ^b		X	
MT	X		X		
NV	X	x ^b	X	X	
NM	X		X		x ^d
UT	X	x ^f		X	
WY	X				x ^e
<u>Pacific</u>					
CA	X			X	x ^b
OR		x ^b	X	X	x ^b
WA		x ^{b,d}	X		x ^b

^aIncludes regulations in lb SO₂ and lb S per 10⁶ Btu.

^bExhaust gas concentration.

^cAvailable technology.

^dPounds per hour.

^eAir quality.

^fPercent control.

Table A.3 Particulate Emission Regulations
for Fuel Combustion Sources

Region/State	Allowable Emissions (lb PM/10 ⁶ Btu)				Note
	Heat Input (10 ⁶ Btu/hr)				
	10	100	250	1000	
<u>REGION I</u>					
Connecticut	0.20	0.20	0.20	0.20	Existing sources.
	0.10	0.10	0.10	0.10	New sources.
Maine	0.60	0.34	0.30	0.30 ^a	Sources <3 not regulated.
Massachusetts	0.15	0.15	0.15	0.15	Existing sources.
	0.12	0.12	0.12	0.12	Existing sources in critical areas of concern.
	0.10	0.10	0.10	0.05	New sources. Sources <3 not regulated.
New Hampshire	0.60	0.41	0.35	0.28	Existing sources.
	0.60	0.35	0.28	0.10	New sources.
Rhode Island	0.20	0.20	0.20	0.10	Sources <1 not regulated.
Vermont	0.50	0.27	0.11	0.10 ^b	New sources >1000 limited to 0.02.
<u>REGION II</u>					
New Jersey	0.60	0.15	0.10	0.10	
New York	0.10	0.10	0.10	0.10	Oil-fired sources and new coal-fired sources >250.
	0.60	0.60	0.60	-	Coal in existing spreader stokers <300.
	0.60	0.60	0.37	-	Coal in existing sources < 300 other than spreader stokers.
	0.60	0.37	0.30	0.22	Coal in new sources < 250 and existing sources > 300.
					Sources < 1 not regulated.

Table A.3 (Cont'd)
Particulates

Region/State	Allowable Emissions (lb PM/10 ⁶ Btu) Heat Input (10 ⁶ Btu/hr)				Note
	10	100	250	1000	
<u>REGION II (Cont'd)</u>					
Puerto Rico	0.30	0.30	0.30	0.30 ^a	Solid fuel. No coal presently burned.
Virgin Islands	0.60	0.35	0.28	0.21 ^b	No coal presently burned.
<u>REGION III</u>					
Delaware	0.30	0.30	0.30	0.30 ^a	Sources <1 not regulated.
Dist. of Columbia	0.10	0.06	0.05	0.03	
Maryland	-	-	-	-	Various loading standards from 0.01-0.03 gr/scf apply depending on location, date of construction, and size of source. The Shell Bacarach Smoke Spot test is also specified either in addition to or in lieu of the loading standard.
	0.60	0.33	0.27	0.19	Existing sources outside Metropolitan Baltimore (#115) and National Capital (#47) AQCRs.
Pennsylvania	0.40	0.27	0.16	0.10 ^b	Outside Allegheny County (AQCR #197). Sources <2.5 not regulated.
	0.40	0.27	0.16	0.08 ^b	In Allegheny County. Sources <0.2 not regulated.
	-	-	-	-	City of Philadelphia (AQCR #45) -- loading standards of 0.2 (0.1) lb/1000 lb stack gas (12% CO ₂) for existing (new) sources.

Table A.3 (Cont'd)
Particulates

Region/State	Allowable Emissions (lb PM/10 ⁶ Btu)				Note
	Heat Input (10 ⁶ Btu/hr)				
	10	100	250	1000	
<u>REGION III (Cont'd)</u>					
Virginia	0.40	0.29	0.23	0.17 ^b	Outside National Capital AQCR #47.
	0.30	0.29	0.23	0.17 ^b	In National Capital AQCR #47.
West Virginia	0.05	0.05	0.05	0.05	Electric power plants. Emissions not to exceed 1200 lb/hr.
	0.09	0.09	0.09	0.09	Industrial and cyclone furnaces, gas-fired and oil-fired units,--emissions not to exceed 900 lb/hr.
<u>REGION IV</u>					
Alabama	0.50	0.18	0.12	0.12 ^a	Existing sources in Class I counties and all new sources.
	0.80	0.21	0.12	0.12	Existing sources in Class II counties.
Florida	-	-	-	0.10	Latest reasonably available technology required for sources <u>≤</u> 250.
Georgia	0.70	0.44	0.37	0.28	Existing sources.
	0.50	0.16	0.10	0.10	New sources.
					Maximum lb/hr limits dependent on stack heights also apply to sources and sets of sources within one mile of a city with population <u>≥</u> 50,000.
Kentucky	0.80	0.48	0.40	0.29	Existing sources in Priority III AQCRs.

Table A.3 (Cont'd)
Particulates

Region/State	Allowable Emissions (lb PM/10 ⁶ Btu)				Notes
	Heat Input (10 ⁶ Btu/hr)				
	10	100	250	1000	
<u>REGION IV (Cont'd)</u>					
Kentucky (cont'd)	0.75	0.44	0.35	0.23	Existing sources in Priority II AQCRs.
	0.56	0.33	0.26	0.16	Existing sources in Priority I AQCRs.
	0.56	0.33	0.26	0.10	New sources state-wide.
Mississippi	0.60	0.41	0.33	0.27 ^a	
North Carolina	0.60	0.33	0.24	0.18 ^b	
South Carolina	0.60	0.60	0.60	0.25	New sources with 100-ft stack. Less stringent limits apply for existing sources <30 and for all sources >330 having stacks higher than 100 ft.
Tennessee	0.60	0.33	0.26	0.18	Existing sources.. Some sources <4000 may have different allowable emissions until July 1, 1975.
	0.60	0.17	0.10	0.10	New sources.
<u>REGION V</u>					
Illinois	0.10	0.10	0.10	0.10	New sources state-wide. Existing sources using liquid fuel state-wide and solid fuel in uncontrolled sources in Chicago Major Metropolitan Area.
	1.00	0.20	0.10	0.10	Uncontrolled, existing sources using solid fuel outside Chicago area.

Table A.3 (Cont'd)
Particulates

Region/State	Allowable Emissions (lb PM/10 ⁶ Btu)				Notes
	Heat Input (10 ⁶ Btu/hr)				
	10	100	250	1000	
REGION V (Cont'd)					
Illinois (cont'd)	0.20	0.20	0.20	0.20	Maximum limit for controlled sources using solid fuel. Statewide.
Indiana	0.80	0.80	0.80	0.80	Existing sources outside Chicago and Indianapolis AQCRs. Smaller rate applies if necessary to meet specified maximum ground-level concentration.
	0.60	0.60	0.60	0.10	New sources outside Chicago and Indianapolis AQCRs. Smaller rate applies if necessary to meet specified maximum ground-level concentration.
	0.60	0.42	0.36	0.29	Existing sources in Metropolitan Chicago (#67) and Metropolitan Indianapolis (#80) AQCRs.
	0.60	0.42	0.36	0.10	New sources in Metropolitan Chicago (#67) and Metropolitan Indianapolis (#80) AQCRs.
Michigan	-	-	-	- ^a	Various loading standards exist ranging between 0.65 and 0.15 lb/1000 lb exhaust gas. More stringent limits apply in Wayne County (AQCR #123). The commission assigns limits for large sources outside Wayne County.

Table A.3 (Cont'd)
Particulates

Region/State	Allowable Emissions (lb PM/10 ⁶ Btu)				Notes
	Heat Input (10 ⁶ Btu/hr)				
	10	100	250	1000	
REGION V (cont'd)					
Minnesota	0.60	0.60	0.60	0.60	Existing sources and all sources outside Minneapolis-St. Paul AQCR #131.
	0.40	0.40	0.40	0.40 ^a	New sources and all sources in AQCR #131. More stringent limits can apply to sources with short stacks.
Ohio	0.40	0.20	0.15	0.10	Priority I AQCRs.
	0.60	0.30	0.23	0.15 ^a	Priority II and III AQCRs.
Wisconsin	0.15	0.15	0.15	0.10	New or modified sources outside Southeast Wisconsin AQCR #239.
	0.10	0.10	0.10	0.10	New or modified sources in AQCR #239. No coal burning allowed.
	0.15	0.15	0.15	0.15	Existing sources in AQCR #239. No coal burning allowed in sources <250.
	0.30	0.30	0.30	0.30	Existing sources in Brown, Outagamie, and Winnebago Counties (AQCR #237). Maximum limit. More stringent limits can apply depending on stack height.
	0.60	0.60	0.60	0.60	Existing sources in remainder of state. Maximum limit. More stringent limits can apply depending on stack height.

Table A.3 (Cont'd)
Particulates

Region/State	Allowable Emissions (lb PM/10 ⁶ Btu)				Notes
	Heat Input (10 ⁶ Btu/hr)				
	10	100	250	1000	
<u>REGION VI</u>					
Arkansas	-	-	-	- ^a	Various ground-level concentration limits apply to existing sources. For new sources, a lb/hr limit that varies with potential (uncontrolled) emissions applies.
Louisiana	0.60	0.60	0.60	0.60 ^a	No coal presently burned.
New Mexico	0.05	0.05	0.05	0.05	Coal.
	0.02	0.02	0.02	0.02	Coal. Applies to fines <2 μm.
	-	-	0.005	0.005	Oil. Sources <114 not regulated.
Oklahoma	0.60	0.33	0.26	0.18 ^a	
Texas	0.30	0.30	0.30	0.30 ^a	Coal-fired steam generating sources.
	-	-	-	- ^a	Various lb/hr limits that vary with effluent flow rates for sources other than coal-fired steam generators. More stringent limits can apply for short effective stack heights.
	-	-	-	-	Various maximum ground-level concentration limits also apply to sources or groups of sources other than coal-fired steam generators.

Table A.3 (Cont'd)
Particulates

Region/State	Allowable Emissions (1b PM/10 ⁶ Btu)				Notes
	Heat Input (10 ⁶ Btu/hr)				
	10	100	250	1000	
<u>REGION VII</u>					
Iowa	0.80	0.80	0.80	0.80	Existing sources outside standard Metropolitan Statistical Areas.
	0.60	0.60	0.60	0.60 ^a	Existing sources in Standard Metropolitan Statistical Areas and all new sources.
Kansas	0.60	0.35	0.28	0.21 ^a	Coal and R-oil ≤ 350 , D-oil ≤ 1 , and gas ≤ 100 not regulated.
Missouri	0.60	0.35	0.28	0.21 ^a	Metropolitan Kansas City AQCR #94, Springfield, and Independence.
	0.60	0.40	0.34	0.27 ^a	Other areas of state.
Nebraska	0.60	0.35	0.28	0.20 ^a	Gas-fired ≤ 100 , oil-fired ≤ 7.5 , and coal-fired ≤ 0.6 not regulated.
<u>REGION VIII</u>					
Colorado	0.27	0.15	0.12	0.10 ^b	
Montana	0.60	0.40	0.34	0.28	Existing sources.
	0.60	0.35	0.26	0.20 ^a	New sources.
North Dakota	0.80	0.80	0.80	0.80	Existing sources.
	0.60	0.44	0.39	0.33 ^a	New Sources.
South Dakota	0.30	0.30	0.30	0.30 ^a	
Utah	0.60	0.42	0.36	0.29 ^a	In Wasatch Front Range AQCR #220.
	-	-	-	-	85% control of potential emissions required outside Wasatch Front Range AQCR #220.

Table A.3 (Cont'd)
Particulates

Region/State	<u>Allowable Emissions (lb PM/10⁶ Btu)</u> <u>Heat Input (10⁶ Btu/hr)</u>				Notes
	10	100	250	1000	
<u>REGION VIII (Cont'd)</u>					
Wyoming	0.60	0.40	0.36	0.29	Existing sources.
	0.10	0.10	0.10	0.10	New power plants and industrial sources.
<u>REGION IX</u>					
American Samoa	0.30	0.30	0.30	0.30 ^a	No coal presently burned.
Arizona	0.60	0.35	0.28	0.21 ^a	
California	-	-	-	-	No data available.
Guam	-	-	-	- ^a	No particulate emissions regulations. No coal presently burned.
Hawaii	-	-	-	- ^a	A limit of 0.4 lb/100 lb bagasse burned applies. No limit for fossil-fuel-fired units.
Nevada	0.60	0.36	0.28	0.21 ^a	Outside Washoe County (Northwest Nevada AQCR #148).
	-	-	-	- ^a	In Washoe County a limit of 0.15 gr/scf (12% CO ₂) applies.
<u>REGION X</u>					
Alaska	-	-	-	-	0.05 gr/scf for gas and oil in new sources. 0.10 gr/scf for gas and oil in existing sources and coal in all sources.
Idaho	0.60	0.33	0.26	0.20 ^a	

Table A.3 (Cont'd)
Particulates

Region/State	Allowable Emissions (lb PM/10 ⁶ Btu) Heat Input (10 ⁶ Btu/hr)				Notes
	10	100	250	1000	
<u>REGION X</u> (Cont'd)					
Oregon	-	-	-	- ^a	0.20-0.10 gr/scf for existing sources and 0.10-0.05 gr/scf for new sources in Clackamas, Columbia; Multnomah, and Washington Counties (Portland AQCR #193). 0.20 gr/scf for existing sources and 0.10 gr/scf for new sources in remainder of state.
Washington	-	-	-	- ^a	0.20-0.05 gr/scf depending on age of source and AQCR.
	-	-	-	- ^a	40-lb/hr limit also applies in Eastern Washington-Northern Idaho AQCR #62.

^aFederal New Source Performance Standards would apply to new sources >250 x 10⁶ Btu/hr.

^bFederal New Source Performance Standards would apply to some new sources >250 x 10⁶ Btu/hr.

Table A.4 SO₂ Emission Regulations for Fuel Combustion Sources

Region/State	Regulations Specifying Allowable Emissions (1b SO ₂ /10 ⁶ Btu) Heat Input (10 ⁶ Btu/hr)				Regulations Specifying %S (%S)				Notes
	10	100	250	1000	D-Oil	Blends	R-Oil	Coal	
REGION I									
Connecticut					0.5	0.5	0.5	0.5	
Maine					2.5 ^a	-	2.5 ^a	2.5 ^a	Outside Metropolitan Portland AQCR #110.
					1.5 ^a	-	1.5 ^a	1.5 ^a	In Metropolitan Portland AQCR.
Massachusetts	0.34	0.34	0.34	0.34					D-Oil.
	1.1	1.1	1.1	1.1 ^b					R-Oil and coal. Sources <3 cannot use R-oil.
	0.56	0.56	0.56	0.56					R-oil and coal in core cities of Metropolitan Boston AQCR #119. Sources <6 cannot use R-oil.
					-	-	2.2 ^a	2.2 ^a	In Berkshire AQCR #117.
New Hampshire	5.6	5.6	5.6	5.6					Coal in existing sources--maximum.
	4.0	4.0	4.0	4.0					Coal in existing sources--3-mo average.
	3.0	3.0	3.0	3.0 ^a					Coal in new sources--maximum.
	2.0	2.0	2.0	2.0 ^a					Coal in new sources--3-mo average.
					0.4	1.0 ^a	1.5 ^a	-	Outside Androscoggin Valley AQCR #107.

Table A.4 (Cont'd)
SO₂

Region/State	Regulations Specifying Allowable Emissions (lb SO ₂ /10 ⁶ Btu) Heat Input (10 ⁶ Btu/hr)				Regulations Specifying %S (%S)				Notes
	10	100	250	1000	D-Oil	Blends	R-Oil	Coal	
REGION I (Cont'd)									
New Hampshire (Cont'd)					-	-	2.2 ^a	-	In Androscoggin AQCR #107.
Rhode Island	1.1	1.1	1.1	1.1	1.0 ^a	1.0 ^a	1.0 ^a	-	Lb/10 ⁶ Btu for coal.
Vermont					1.0 ^a	1.0 ^a	1.0 ^a	1.0 ^a	Revision to allow 1.5%-S fuel (2.5%-S in certain cases) is pending.
REGION II									
New Jersey	-	-	0.30	0.30	0.2	-	0.3	0.2	New Jersey - New York - Connecticut (#43) and Metropolitan Philadelphia (#45) AQCRs. Lower limit applies.
	--	-	0.30	0.30	0.3	-	0.5	0.7	New Jersey (#150) and Northeast Pennsylvania-Upper Delaware Valley (#151) AQCRs. Lower limit applies. Also 310 ppm for noncommercial units.
New York	0.40	0.40	0.40	0.40	0.2	0.3	0.3	-	New York City (AQCR #43). Lb/10 ⁶ Btu for coal only.
	0.40	0.40	0.40	0.40	0.37	0.37	0.37	-	Nassau, Rockland, and Westchester Counties (AQCR #43). Lb/10 ⁶ Btu for coal only.

Table A.4 (Cont'd)
SO₂

Region/State	Regulations Specifying Allowable Emissions (lb SO ₂ /10 ⁶ Btu)				Regulations Specifying %S				Notes
	Heat Input (10 ⁶ Btu/hr)				(%S)				
	10	100	250	1000	D-Oil	Blends	R-Oil	Coal	
<u>REGION II (Cont'd)</u>									
New York (Cont'd)	1.2	1.2	1.2	1.2	1.0 ^a	1.0 ^a	1.0 ^a	-	Five specified towns in Suffolk County (AQCR #43). Lb/10 ⁶ Btu for coal only.
	3.4	3.4	3.4	3.4 ^a	2.2 ^a	2.2 ^a	2.2 ^a	-	Niagara Frontier AQCR #162. Lb/10 ⁶ Btu for coal only.
	3.8	3.8	3.8	3.8 ^a	2.0 ^a	2.0 ^a	2.0 ^a	-	Outside areas specified above. Lb/10 ⁶ Btu for coal only.
	-	-	-	1.2	0.75 ^b	0.75 ^b	0.75 ^b	-	Certain new sources >250 outside New York City, Nassau, Rockland, and Westchester Counties. Lb/10 ⁶ Btu for coal only.
Puerto Rico					1.0 ^a	1.0 ^a	1.0 ^a	1.0 ^a	Outside critical areas.
					0.5	0.5	0.5	0.5	In critical areas. No coal presently burned.
Virgin Islands					0.5	0.5	0.5	0.5	No coal presently burned.
<u>REGION III</u>									
Delaware					0.3	1.0 ^a	1.0 ^a	1.0 ^a	D-Oil statewide. Other fuels regulated in New Castle County only.

Table A.4 (Cont'd)
SO₂

Region/State	Regulations Specifying Allowable Emissions (lb SO ₂ /10 ⁶ Btu) Heat Input (10 ⁶ Btu/hr)				Regulations Specifying %S (%S)				Notes
	10	100	250	1000	D-Oil	Blends	R-Oil	Coal	
REGION III (Cont'd)									
District of Columbia					0.5	0.5	0.5	0.5	1.0% S prior to July 1, 1975. Desulfurization to equivalent SO ₂ emission is allowed for higher %S fuels.
Maryland					0.3	-	0.5	1.0 ^a	1%-S R-oil until July 1, 1975. No limit for coal in sources <100 outside Metropolitan Baltimore (#115) and National Capital (#47) AQCRs.
Pennsylvania	3.0	2.7	2.4	1.9 ^a					In air basins. Sources <2.5 not regulated.
	1.0	0.89	0.78	0.65					In specified air basins and Allegheny County (AQCR #197). Sources <2.5 (<0.2 in Allegheny County) not regulated.
	4.0	4.0	4.0	4.0 ^a					Outside air basins.
	0.30	0.30	0.30	0.30	0.2	0.3	0.3	-	Commercial oil in City of Philadelphia (AQCR #45). Percent S does not apply for R-oil and blends if lb/10 ⁶ Btu limit is met.
Virginia	2.64	2.64	2.64	2.64 ^a					Can be 1.58 or 1.06 if necessary to meet air quality standards.

Table A.4 (Cont'd)
SO₂

Region/State	Regulations Specifying Allowable Emissions (1b SO ₂ /10 ⁶ Btu) Heat Input (10 ⁶ Btu/hr)				Regulations Specifying %S (%S)				Notes
	10	100	250	1000	D-Oil	Blends	R-Oil	Coal	
<u>REGION III (Cont'd)</u>									
Virginia (Cont'd)	1.06	1.06	1.06	1.06 ^b					In National Capital AQCR #45. Can be 0.55 if necessary to meet air quality standards.
West Virginia	2.7	2.7	2.7	2.7 ^a					Electric power plants in Priority I and II AQCRs. Limit of 2.0 by mid-1978.
	3.1	3.1	3.1	3.1 ^a					Other sources in Priority I and II AQCRs. Limit of 2.3 by mid-1978.
	1.6	1.6	1.6	1.6 ^a					Kanawha Valley AQCR #234. Not to exceed 45,000 lb/hr for electric power plants or 5,500 lb/hr for other sources.
	3.2	3.2	3.2	3.2 ^a					Priority III AQCRs.
<u>REGION IV</u>									
Alabama	1.8	1.8	1.8	1.8 ^a					Priority I AQCRs and Jefferson County.
	4.0	4.0	4.0	4.0 ^a					Priority II and III AQCRs. Sources >1,500 must also demonstrate that air quality standards will be met and that air quality will not be degraded.

Table A.4 (Cont'd)
SO₂

Region/State	Regulations Specifying Allowable Emissions (1b SO ₂ /10 ⁶ Btu) Heat Input (10 ⁶ Btu/hr)				Regulations Specifying %S (%S)				Notes
	10	100	250	1000	D-Oil	Blends	R-Oil	Coal	
REGION IV (Cont'd)									
Florida	-	-	-	1.1					Oil in existing sources.
	-	-	-	1.5					Coal in existing sources.
	-	-	-	0.80					Oil in new sources.
	-	-	-	1.2					Coal in new sources.
Georgia									Latest reasonably available technology required for sources <250.
	-	-	-	-					Existing sources and new sources <250. Limits vary with source size, location, and stack height.
	-	-	-	0.80					Oil in new sources.
	-	-	-	1.2					Coal in new sources.
					2.5	2.5	2.5	2.5	Maximum limit for all sources <100.
					3.0	3.0	3.0	3.0	Maximum limit for all sources >100.
Kentucky	4.0	1.7	1.2	1.2					Coal. Existing sources in Priority I AQCRs and new sources statewide.

Table A.4 (Cont'd)
SO₂

Region/State	Regulations Specifying Allowable Emissions (1b SO ₂ /10 ⁶ Btu) Heat Input (10 ⁶ Btu/hr)				Regulations Specifying %S (%S)				Notes
	10	100	250	1000	D-Oil	Blends	R-Oil	Coal	
<u>REGION IV (Cont'd)</u>									
Kentucky (Cont'd)	4.0	2.7	2.3	2.0					Coal. Existing sources in Priority II AQCRs.
	4.0	3.8	3.7	3.5					Coal. Existing sources in Priority III AQCRs.
	2.5	1.1	0.80	0.80					Oil. Existing sources in Priority I AQCRs and new sources statewide.
	2.5	1.8	1.6	1.5					Oil. Existing sources in Priority II AQCRs.
	2.5	2.2	2.1	2.0					Oil. Existing sources in Priority III AQCRs.
Mississippi									A maximum emission limit of 500 tpd applies to new sources and an aggregate limit of 750 tpd applies to all sources >100 tpy within 10 miles of a new source.
	2.4	2.4	-	-					Modified sources <250.
	4.8	4.8	4.8	4.8 ^a					Unmodified sources <250 and all sources <u>></u> 250.
									A maximum emission limit equal to the emission of the same source during calendar 1970 also applies.

Table A.4 (Cont'd)
SO₂

Region/State	Regulations Specifying Allowable Emissions (lb SC ₂ /10 ⁶ Btu) Heat Input (10 ⁶ Btu/hr)				Regulations Specifying %S (%S)				Notes
	10	100	250	1000	D-Oil	Blends	R-Oil	Coal	
REGION IV (Cont'd)									
North Carolina	2.3	2.3	2.3	2.3					Existing sources.
	1.6	1.6	1.6	1.6 ^a					New sources.
South Carolina	3.5	2.3	2.3	2.3 ^a					Class I counties.
	3.5	3.5	3.5	2.3 ^a					Class II counties.
	3.5	3.5	3.5	3.5 ^a					Class III counties.
Tennessee									Residential units exempt. Variances can be granted.
	1.6	1.6	1.6	1.6					Existing sources and new sources <250 in Class I counties.
	3.0	3.0	3.0	3.0					Existing sources and new sources <250 in Class II counties.
	4.0	4.0	4.0	4.0					Existing sources and new sources <250 in Class III counties.
	-	-	-	0.80					Oil in new sources >250.
	-	-	-	1.2					Coal in new sources >250.
REGION V									
Illinois	1.8	1.8	1.8	1.8					Coal in existing sources in Chicago, St. Louis, and Peoria major metropolitan areas.

Table A.4 (Cont'd)
SO₂

Region/State	Regulations Specifying Allowable Emissions (1b SO ₂ /10 ⁶ Btu) Heat Input (10 ⁶ Btu/hr)				Regulations Specifying %S (%S)				Notes
	10	100	250	1000	D-Oil	Blends	R-Oil	Coal	
REGION V (Cont'd)									
Illinois (Cont'd)	6.0	6.0	6.0	6.0					Coal in existing sources outside these areas.
	1.0	1.0	1.0	1.0					R-oil in existing sources.
	1.0	1.0	1.0	0.80					R-oil in new sources.
	0.30	0.30	0.30	0.30					D-oil.
	1.8	1.8	1.8	1.2					Coal in new sources.
Indiana	6.0	3.6	2.6	1.7 ^a					Smaller limit applies if necessary to meet specified ground-level concentration.
Michigan					1.5 ^a	1.5 ^a	1.5 ^a	1.5 ^a	Sources <500 outside Wayne County (AQCR #123). Does not apply to residential units.
					1.0 ^a	1.0 ^a	1.0 ^a	1.0 ^a	Sources >500 outside Wayne County (AQCR #123). Under a delayed compliance provision, Michigan has permitted many sources to use fuels exceeding these limits until January 1, 1980 where no air standards are being violated.
					0.3	0.7	0.7	1.0 ^a	Electric power plants and steam generation in Wayne County. Pulverized coal.

Table A.4 (Cont'd)
SO₂

Region/State	Regulations Specifying Allowable Emissions (1b SO ₂ /10 ⁶ Btu) Heat Input (10 ⁶ Btu/hr)				Regulations Specifying %S (%S)				Notes
	10	100	250	1000	D-Oil	Blends	R-Oil	Coal	
REGION V (Cont'd)									
Michigan (Cont'd)					0.3	0.7	0.7	0.3	Residential/commercial space and water heating in Wayne County.
					0.3	0.7	0.7	0.5	Other uses and other than pulverized coal in electric power and steam generation plants in Wayne County.
Minnesota	1.75	1.75	1.75	1.75 ^a	2.0 ^a	2.0 ^a	2.0 ^a	2.0 ^a	Percent S applies if 1b/10 ⁶ Btu limit is not met. Sources <250 in Minneapolis-St. Paul AQCR #131 and >250 outside AQCR #131.
					1.5 ^a	1.5 ^a	1.5 ^a	1.5 ^a	Sources >250 in AQCR #131.
Ohio	1.0	1.0	1.0	1.0 ^b					All sources in specified counties.
	1.6	1.6	1.6	1.0					Existing sources in specified counties.
	3.2	3.2	3.2	1.0					Existing sources in specified counties.
	4.0	4.0	4.0	1.0					Existing sources in specified counties.

Table A.4 (Cont'd)
SO₂

Region/State	Regulations Specifying Allowable Emissions (1b SO ₂ /10 ⁶ Btu) Heat Input (10 ⁶ Btu/hr)				Regulations Specifying %S (%S)				Notes
	10	100	250	1000	D-Oil	Blends	R-Oil	Coal	
REGION V (Cont'd)									
Ohio (Cont'd)	4.8	4.8	4.8	1.0					Existing sources in specified counties. Existing sources >250 have limits of 3.2 and 1.6 until July 17, 1975 in specified AQCRs.
	1.6	1.0	1.0	1.0 ^b					New sources in specified counties.
	3.2	1.0	1.0	1.0 ^b					New sources in specified counties.
	4.0	1.0	1.0	1.0 ^b					New sources in specified counties.
	4.8	1.0	1.0	1.0 ^b					New sources in specified counties.
Wisconsin	-	-	-	-	0.7	-	1.0 ^a	1.5 ^a	Percent S for standby fuel. No limits for normal fuels if air standards are not violated.
REGION VI									
Arkansas	-	-	-	- ^a					A ground-level concentration limit of 0.20 ppm SO ₂ , 30-min average, applies.

Table A.4 (Cont'd)
SO₂

Region/State	Regulations Specifying Allowable Emissions (1b SO ₂ /10 ⁶ Btu) Heat Input (10 ⁶ Btu/hr)				Regulations Specifying %S (%S)				Notes
	10	100	250	1000	D-Oil	Blends	R-Oil	Coal	
REGION VI (Cont'd)									
Louisiana	5.2	5.2	5.2	- ^a					Coal, 2,000 ppm limit.
	3.1	3.1	3.1	- ^a					Oil, 2,000 ppm limit. Lower limit can apply if air standards are violated. No coal presently burned.
New Mexico	-	-	-	1.0					Coal in existing sources.
	0.34	0.34	0.34	0.34					Coal in new sources.
	-	-	1.0	1.0 ^a					Oil. Sources <114 not regulated.
Oklahoma	-	-	-	-					Existing sources. Various maximum ambient concentration limits.
	2.0	2.0	2.0	2.0 ^a					Coal in new sources.
	0.30	0.30	0.30	0.30					Oil in new sources (80 until July 1, 1975).
	0.20	0.20	0.20	0.20					Gas in new sources.
Texas	0.30	0.30	0.30	0.30 ^a					Coal-fired steam generators. These sources must also use new proven technology to remove SO ₂ .

Table A.4 (Cont'd)
SO₂

Region/State	Regulations Specifying Allowable Emissions (1b SO ₂ /10 ⁶ Btu) Heat Input (10 ⁶ Btu/hr)				Regulations Specifying %S (%S)				Notes
	10	100	250	1000	D-Oil	Blends	R-Oil	Coal	
<u>REGION VI (Cont'd)</u>									
Texas (Cont'd)	0.68	0.68	0.68	0.68					Oil-fired steam generators limited to 400 ppm SO ₂ . More stringent limits can apply for short effective stack heights.
	-	-	-	- ^a					Maximum ground-level concentration limits must be met by any source or group of sources. More stringent limits apply in Galveston, Harris, Jefferson, and Orange counties.
<u>REGION VII</u>									
Iowa	-	-	-	5.0 ^a					Coal. Sources <u><250</u> not regulated.
	-	-	-	1.5 ^a					Oil. Sources <u><250</u> not regulated.
Kansas	3.0	3.0	3.0	3.0 ^a					Coal and R-oil <u><350</u> , D-oil <u><1</u> , and gas <u><100</u> not regulated.
Missouri	2.3	2.3	2.3	2.3 ^a				2.0 ^a	Metropolitan St. Louis AQCR #70. Percent S coal for sources <u><2,000</u> .
	-	-	-	- ^a	-	-	-	-	Outside AQCR #70, maximum ambient concentration limits must be met.

Table A.4 (Cont'd)
SO₂

Region/State	Regulations Specifying Allowable Emissions (lb SO ₂ /10 ⁶ Btu) Heat Input (10 ⁶ Btu/hr)				Regulations Specifying %S (%S)				Notes
	10	100	250	1000	D-Oil	Blends	R-Oil	Coal	
<u>REGION VII (Cont'd)</u>									
Nebraska	2.5	2.5	2.5	2.5 ^a					Gas fired <100, oil-fired <7.5, and coal-fired <0.6 not regulated.
<u>REGION VIII</u>									
Colorado	-	-	-	-					Regulations for existing sources withdrawn pending revision. New sources emitting more than 5 tpd cannot exceed 150 ppm. New sources controlled to emit less than 5 tpd cannot emit more than 500 ppm.
Montana	2.0	2.0	2.0	2.0 ^a					
North Dakota	3.0	3.0	3.0	3.0 ^a					
South Dakota	3.0	3.0	3.0	3.0 ^a					
Utah					1.5	1.5	1.5	1.0	Existing sources.
	-	-	-	-	-	-	-	-	80% control required on new sources with potential SO ₂ emissions >500 tpy.
Wyoming	-	-	-	0.80					Oil in new power plants and industrial sources.

Table A.4 (Cont'd)
SO₂

Region/State	Regulations Specifying Allowable Emissions (lb SO ₂ /10 ⁶ Btu) Heat Input (10 ⁶ Btu/hr)				Regulations Specifying %S (%S)				Notes
	10	100	250	1000	D-Oil	Blends	R-Oil	Coal	
REGION VIII (Cont'd)									
Wyoming (Cont'd)	-	-	-	1.2					Coal in existing sources.
	-	-	-	0.20					Coal in new power plants and industrial sources. Sources <250 not regulated.
REGION IX									
American Samoa					3.5 ^a	3.5 ^a	3.5 ^a	- ^a	No coal presently burned.
Arizona	2.2	2.2	2.2	2.2					Existing sources allowed by permit to use high S (>0.9%) oil.
	1.0	1.0	1.0	1.0					Existing sources. Coal and low-S oil.
	0.80	0.80	0.80	0.80					New sources.
California	-	-	-	-	-	-	-	-	No data available.
Guam	0.80	0.80	0.80	0.80					No coal presently burned.
Hawaii					2.0	2.0	2.0	-	Fuel oil.
					0.5	0.5	0.5	-	Power and steam sources >250. No coal presently burned.
Nevada	0.70	0.70	0.70	0.40					Outside Clark and Washoe Counties.

Table A.4 (Cont'd)

SO₂

Region/State	Regulations Specifying Allowable Emissions (lb SO ₂ /10 ⁶ Btu) Heat Input (10 ⁶ Btu/yr)				Regulations Specifying %S (%S)				Notes
	10	100	250	1000	D-Oil	Blends	R-Oil	Coal	
REGION IX (Cont'd)									
Nevada (Cont'd)	0.15	0.15	0.15	0.15	1.0	1.0	1.0	-	In Clark County (Clark-Mohave-Yuma AQCR #13).
	-	-	0.105	0.105	1.0	1.0	1.0	1.0	In Washoe County (Northwest Nevada AQCR #148). Percent S for sources <250. A limit of 0.2% SO ₂ by volume also applies in Washoe County.
REGION X									
Alaska	-	-	-	-	-	-	-	-	Statewide 500-ppm SO ₂ limit.
Idaho					0.3	-	1.75	1.0	For #1 D-oil.
					0.5				For #2 D-oil.
Oregon					0.3	-	1.75	1.0	For #1 D-oil outside Portland AQCR #193.
					0.5				For #2 D-oil outside AQCR #193.
	2.6	2.5	2.6	2.6 ^a					Coal (1,000-ppm SO ₂ limit in AQCR #193).
	1.6	1.5	1.6	1.6 ^a					Oil (1,000-ppm SO ₂ limit in AQCR #193).
Washington	1.5	1.5	1.5	1.5 ^a					Northern Washington AQCR #227.
					0.3	-	-	-	For #1 oil in Puget Sound AQCR #229.

Table A.4 (Cont'd)
SO₂

Region/State	Regulations Specifying Allowable Emissions				Regulations Specifying %S				Notes
	(lb SO ₂ /10 ⁶ Btu)				(%S)				
	Heat Input	10 ⁶ Btu/hr							
	10	100	250	1000	D-Oil	Blends	R-Oil	Coal	
REGION X (Cont'd)									
Washington (Cont'd)					0.5	-	-	-	For #2 oil in AQCR #229.
	3.9	3.9	3.9	3.9 ^a					A 1,500-ppm limit. Coal in Portland AQCR #193 and Olympic-Northwest Washington AQCR #228.
	2.3	2.3	2.3	2.3 ^a					A 1,500-ppm limit. Oil in AQCR #193 and AQCR #228. Ground-level concentration limit also applies in AQCR #228.
	2.6	2.6	2.6	2.6 ^a					A 1,000-ppm limit. Coal except as noted above.
	1.6	1.6	1.6	1.6 ^a					A 1,000-ppm limit. Oil except as noted above.

^aFederal New Source Performance Standards would apply to new sources >250 x 10⁶ Btu/hr.

^bFederal New Source Performance Standards would apply to some new sources >250 x 10⁶ Btu/hr.

Table A.5 NO_x Emission Regulations for Coal-Fired
Fuel Combustion Sources

Region/State	Allowable Emissions (1b NO _x /10 ⁶ Btu)				Notes
	Existing Sources		New Sources		
	Heat Input (10 ⁶ Btu/hr)		Heat Input (10 ⁶ Btu/hr)		
	250	1000	250	1000	
<u>REGION I</u>					
Connecticut	0.90	0.90	0.70	0.70	Sources >250 x 10 ⁶ Btu. Sources 5-250 x 10 ⁶ Btu regulated unless excepted by Commissioner.
Maine	-	-	a	a	
Massachusetts	-	-	a	a	
New Hampshire	-	-	a	a	
Rhode Island	-	-	a	a	
Vermont	-	-	0.30	0.30	Sources >250 x 10 ⁶ Btu.
<u>REGION II</u>					
New Jersey	-	-	a	a	
New York	-	-	0.70	0.70	Sources >250 x 10 ⁶ Btu.
Puerto Rico	-	-	a	a	No coal presently burned.
Virgin Islands	-	-	a	a	No coal presently burned.
<u>REGION III</u>					
Delaware	-	-	a	a	State standard for New Castle County only.
Dist. of Columbia	-	0.70	a	0.70	Sources >1000 x 10 ⁶ Btu. Solid fossil fuel except lignite.
Maryland	-	-	a	a	

Table A.5 (Cont'd)
NO_x

Region/State	Allowable Emissions (lb NO _x /10 ⁶ Btu)				Notes
	Existing Sources		New Sources		
	Heat Input (10 ⁶ Btu/hr)		Heat Input (10 ⁶ Btu/hr)		
	250	1000	250	1000	
<u>REGION III (Cont'd)</u>					
Pennsylvania	-	-	a	a	
Virginia	-	-	0.70	0.70	Sources >250 x 10 ⁶ Btu.
West Virginia	-	-	a	a	
<u>REGION IV</u>					
Alabama	-	-	0.70	0.70	Sources <u>></u> 250 x 10 ⁶ Btu.
Florida	-	-	0.70	0.70	Sources >250 x 10 ⁶ Btu.
Georgia	-	-	0.70	0.70	
Kentucky	-	-	a	a	
Mississippi	-	-	a	a	
North Carolina	1.3	1.3	1.3	1.3	Sources <u>></u> 250 x 10 ⁶ Btu.
South Carolina	-	-	a	a	
Tennessee	-	-	0.70	0.70	Sources <u>></u> 250 x 10 ⁶ Btu.
<u>REGION V</u>					
Illinois	0.90	0.90	0.70	0.70	Sources <u>></u> 250 x 10 ⁶ Btu. Existing source standards are for sources in Chicago and St. Louis MMAs only.
Indiana	0.70	0.70	0.70	0.70	Sources <u>></u> 250 x 10 ⁶ Btu. Existing source standards are for sources in "Basin Priority A" only.

Table A.5 (Cont'd)
NO_x

Region/State	Allowable Emissions (lb NO _x /10 ⁶ Btu)				Notes
	Existing Sources		New Sources		
	Heat Input (10 ⁶ Btu/hr)		Heat Input (10 ⁶ Btu/hr)		
	250	1000	250	1000	
<u>REGION V (Cont'd)</u>					
Michigan	-	-	a	a	
Minnesota	-	-	a	a	
Ohio	0.90	0.90	0.90	0.90	Sources <u>></u> 250 x 10 ⁶ Btu. Existing source standards are for sources in Priority I regions only.
Wisconsin	-	-	0.70	0.70	Sources <u>></u> 250 x 10 ⁶ Btu.
<u>REGION VI</u>					
Arkansas	-	-	a	a	
Louisiana	-	-	a	a	No coal presently burned.
New Mexico	0.70	0.70	0.45	0.45	Sources <u>></u> 250 x 10 ⁶ Btu.
Oklahoma	-	-	0.70	0.70	Sources <u>></u> 50 x 10 ⁶ Btu.
Texas	-	-	a	a	
<u>REGION VII</u>					
Iowa	-	-	0.70	0.70	
Kansas	-	-	a	a	
Missouri	-	-	a	a	
Nebraska	-	-	0.70	0.70	

Table A.5 (Cont'd)
NO_x

Region/State	Allowable Emissions (lb NO _x /10 ⁶ Btu)				Notes
	Existing Sources		New Sources		
	Heat Input (10 ⁶ Btu/hr)	Heat Input (10 ⁶ Btu/hr)	Heat Input (10 ⁶ Btu/hr)	Heat Input (10 ⁶ Btu/hr)	
	250	1000	250	1000	
<u>REGION VIII</u>					
Colorado	-	-	0.70	0.70	All new sources. Solid fossil fuel except lignite.
Montana	-	-	0.70	0.70	
North Dakota	-	-	a	a	
South Dakota	-	-	a	a	
Utah	-	-	0.70	0.70	Solid fossil fuel except lignite.
Wyoming	0.75	0.75	0.70	0.70	All sources. Solid fossil fuel except lignite.
<u>REGION IX</u>					
American Samoa	-	-	a	a	No coal presently burned.
Arizona	-	-	0.70	0.70	All new sources.
California	-	-	a	a	
Guam	-	-	a	a	No coal presently burned.
Hawaii	-	-	a	a	
Nevada	-	-	a	a	
<u>REGION X</u>					
Alaska	-	-	a	a	

Table A.5 (Cont'd)

NO_x

Region/State	Allowable Emissions (lb NO _x /10 ³ Btu)				Notes
	Existing Sources		New Sources		
	Heat Input (10 ⁶ Btu/hr)		Heat Input (10 ⁶ Btu/hr)		
	250	1000	250	1000	
<u>REGION X (Cont'd)</u>					
Idaho	-	-	0.70	0.70	Sources ≥250 x 10 ⁶ Btu. Solid fossil fuel except lignite.
Oregon	-	-	0.70	0.70	
Washington	-	-	a	a	

^aState has no regulation. Where state has no regulation, federal New Source Performance Standards apply.

*APPENDIX B. COAL MARKET MODEL**B.1 CHOICE OF REGIONS*

Choosing the number of demand regions and their boundaries is an integral aspect of a market model. Since it is important to capture large-scale forces, the level of detail has to be just great enough to capture aggregate market forces. However, using the expansive and irregularly bounded Census Regions leads to highly distorted transportation costs between supply and demand points. Moreover, the demand for coal is not uniformly distributed over a given Census Region. For example, Ohio and Pennsylvania demand disproportionately more coal than other states in their respective Census Regions. Finally, sulfur emission standards differ within Census Regions and thus create non-uniform demands for low sulfur coal. For these reasons, the Census Regions were disaggregated into 24 sub-regions. Demand centroids were chosen for each of the 24 regions after consideration of geography, coal consumption, and proximity to transportation lines. Each centroid was near a large coal consumption point, close to the geographic center of its region, and on a major rail line. The centroid points and demand regions are shown in Fig. B.1.

On the supply side, the main reasons for disaggregation are again to make transportation charges more accurate and to differentiate among coals of different characteristics. The mining cost conditions which vary within a region are less important, since the market acts to elevate all minemouth values for similar quality coal to the cost of the marginal producer within the area. The supply centroids were chosen to be in the center of expected mining activity within each coal supply area. These points also lie on coal loading points for rail shipment. The supply regions and production centroids are shown in Fig B.2. The Interior, Gulf, and Fort Union regions, although they contain significant deposits, were not considered in this report since they possess a negligible amount of coal that can meet federal New Source Performance Standards without applying sulfur removal technologies.

Fig. B.1 Demand Regions and Centroids

Fig. B.2 Coal Producing Areas

B.2 REGIONAL DEMAND

The demand for steam coal can be divided into electric utility and industrial uses. Coal demand for electric utilities depends on three variables: 1) the demand for electricity, 2) the portion of coal used in the fuel mix, and 3) the thermal efficiency of electrical generation. Electricity demand in 1985 was calculated by using Argonne electricity forecasts done for 14 midwestern states and Federal Energy Administration projections elsewhere.* Estimates of the proportion of coal used in the 1985 electric utility fuel mix were multiplied by the electric demand figures to produce the kWh of electricity generated by coal. To obtain the coal fuel input necessary to generate the coal-derived share of electrical energy, an adjustment was made for the thermal efficiency of electrical generation (an average efficiency of 0.33 was used for 1975 with marginal improvements afterwards).

The utility demand for coals of various sulfur contents is a critical determinant of regional coal production. Low sulfur coal demand was assumed to be a function of the delivered cost of low sulfur coal relative to the costs of high sulfur coal and associated supplementary control technologies. Cost estimates for SO₂ control technologies were obtained from published data as well as ongoing research at Argonne. This information was considered along with transportation costs and differences in state sulfur emissions standards for stationary sources** in order to project the proportion of demand for low sulfur coal boiler feed. The relative costs of high sulfur coal were determined after comparisons of contract prices and the costs of control technologies. Control technology costs were used because it was believed that these costs governed the level of rents being earned by vendors of low sulfur coal.

*The FEA projected electricity demand at the Census Region level (nine regions). In this paper, 20 demand areas have been used. The figures for the disaggregated areas were checked to assure conformity with the FEA projections. See the Federal Energy Administration, *National Energy Outlook*, Washington, D.C., pp. 271, C-29. The Argonne state-level demand models are described in G.C. Krohm and W.T. Pelletier, *Regionally Sensitive Electricity Demand Forecasting* (forthcoming).

**States must impose standards as stringent as the federal new source regulations (1.2 lb of SO₂ per million Btu), but can impose stricter standards if desired.

Industry comprises the second major component of demand for steam coal.* Industrial demand for steam coal has been estimated with the FEA-PIES model. This total demand was divided into coal used with flue gas desulfurization technologies and coal of low enough sulfur content to meet New Source Performance Standards. Since most industrial boilers are too small to economically use sophisticated flue gas desulfurization technologies, the control options available to industrial users of steam coal are more limited than utility users. Therefore, the majority of industrial demand was assumed to be for low sulfur coal.

B.3 COAL SUPPLY FUNCTIONS

Step functions were used to characterize the relationship between the minemouth value of coal and the volume of production. These relationships should be thought of as short-run market supply functions. They are constructed after calculating the marginal price for a probable level of supply in each region for a given year. It has also been determined how high the price must rise in each year to induce an expansion of supply. This increase might be thought of as satisfying "surge demand" which manifests itself in the coal spot market. The short-run supply of coal in Appalachia is currently more responsive (elastic) to a given price rise than the supply in western mining areas. This difference has been incorporated into the supply functions.

Estimation of mine characteristics was the most complex and essential stage in characterizing the supply function. Since it is assumed that the market price of coal will be set by the marginal mine, determination of the market price requires identification of the costs of the marginal mine. Data from a study by ICF, Inc. and the *Keystone Coal Manual* were used to identify the marginal mine. ICF formulas were used to adjust average mine costs to a marginal deep mine (i.e., one having thinner seams, a smaller than optimal

*The category utilized here (coal for direct combustion) does not include metallurgical coal. Metallurgical coal is not readily substitutable for steam coal and commands a much higher price. Therefore, it has been excluded from this analysis.

output, and perhaps a deeper shaft than other deep mines in the same region). Similarly, the marginal strip mine was adjusted to have a higher overburden ratio* and a smaller volume than average mines in the area.**

It is well to note that although the marginal mine will have higher costs than other mines in the same region, it still must generate a minimally competitive rate of return on investment.† Furthermore, it should be noted that although our marginal mines have a reasonable cost structure, they are abstractions. They do not describe actual mines in existence or planned for the individual mining areas.

Marginal mines for each region were selected through a two-part procedure. A determination was first made as to whether the marginal mine in a given region would be a strip or a deep mine. This was done by examining present data on mine type from the 1975 *Keystone Coal Manual*. Where a significant percentage of present supply from a given coal province was provided by deep mines, the deep mine was taken to be the marginal mine. This first step produced deep mines for Northern Appalachia, Southern Appalachia, and the Uinta region. Strip mines were chosen as the marginal mines in the Hanna, Powder River, and San Juan areas.

The second step involved capturing the characteristics of the 1985 marginal mine for output, seam thickness, and depth. Information for 1974 was available for deep mines on the distribution of mines by output volume in each state. These numbers were adjusted to project the marginal mine

*Overburden ratio is cubic yards of overburden (sandstone, shale, etc. on top of the seam) per ton of coal.

**One source of difference is the Btu (heat) content of the coal. For a given cost per ton of extraction, an increase in Btu content of the coal will increase the profit received on each ton mined because the purchaser will pay a higher price per ton. Therefore, differences in Btu content are one source of economic rents.

†The choice of the marginal unit is complicated if there are a number of mines operating only to minimize losses. These would be older mines which can generate sufficient revenue to defray the variable costs of operation and pay a minimal portion of the high fixed costs of mining. These firms are not earning a competitive rate of return and are in the process of egress from the industry.

outputs for 1985 (see Table B.1).^{*} Estimates next had to be made for the key geological parameters of deep mines: seam thickness and depth. The Bureau of Mines estimates seam thickness of the reserve base, but no such calculations are even attempted for depth.^{**} The seam thickness of the marginal mine in each region emerged after comparisons between this data and future demands for coal (assuming the thicker seams would be exploited first).

Marginal strip mines are equally difficult to characterize. No projections are made, for example, of overburden ratios or mine outputs. Therefore, ICF projections were assumed to be generally correct and were modified by Keystone information to capture differences in the Hanna and Powder River areas. The estimates are contained in Table B.2.

Once the physical parameters of the marginal mines in each area had been estimated, the next procedure was to relate these geological data to production cost. After examining the literature, it was decided that the ICF study was best suited to this purpose. Engineering cost studies by the Bureau of Mines were examined, but they provided no mechanism for adjusting the "model" mine to the characteristics of the marginal mine in each region. In addition, no estimates of these variations were supplied. In other words, their efforts were to represent an average, not a marginal, mine. This feature is also reflected by the Battelle cost studies. Although the Battelle authors do construct regional mines, they are also for large reference mines. Zimmerman has estimated the costs of operating a marginal deep mine, but the marginal strip mine was neglected. The ICF study was unique in that it contained a number of cost adjustment factors for translating the average cost estimates into the costs for a mine operating at smaller volumes, with thinner seams, or at greater depths. These factors were used to modify costs to reflect the mine parameters discussed above.

^{*}The reader familiar with the coal industry will quickly realize that the marginal mine has been conceptualized as a 100,000 tons per year mine, whereas many mines presently produce 50,000 tons per year or less. However, these mines would be minimizing losses in the future as the rise in the cost of labor increases the already substantial staffing costs. They would, therefore, be in the process of exiting the industry.

^{**}The degree of precision in Bureau of Mines estimates varies greatly according to the state sampled so that estimates should be interpreted with caution. For example, in Colorado, 53% of the reserves are of unknown sulfur content. Therefore, these reserves are probably, but not certainly, low sulfur. See the Bureau of Mines, *Reserve Base of U.S. Coal by Sulfur Content, Part II--1975*, p.81.

Table B.1 Estimated Geological Characteristics
of Marginal Deep Mines in 1985

Region	Seam Thickness (in.)		Depth (ft)	Mine Output (tons/yr)
	1970 Average	1985 Marginal Seam		
N. Appalachia	64	46	700	100,000
S. Appalachia	56	48	700	100,000
Uinta	104	85	400	500,000

Table B.2 Estimated Geological Characteristics
of Marginal Strip Mines in 1985

Region	Overburden Ratio		Mine Output (tons/yr)
	1970 Average	1985 Marginal Mine	
Powder River ^a	1.0:1	3.0:1	2,000,000
Hanna	1.0:1	3.0:1	1,000,000
San Juan	4:1	15:1	2,000,000

^aPowder River and Hanna together form the Northern Great Plains Region.

An especially useful aspect of the ICF study was the evaluation of mine prices as the product of an investment decision. A mining company approaches a new mine opening as an investment decision in which future returns are compared with present and future costs. A central feature of this decision is the concept of present discounted value. This requires that for a dollar invested today, one would expect to receive more than a dollar in the future because of the opportunity cost of the money; i.e., it could be placed in a financial institution and earn interest over the period. The ICF analysis utilized this present discounted value framework to calculate a minimum acceptable selling price rather than attempting to merely set a mine price by projecting variable costs and some arbitrarily allocated fixed costs. This procedure was used to set the value of the marginal mines' outputs for coal of intermediate sulfur content.

The minimum acceptable selling price depended on three basic factors:

- (1) the expected yearly quantity to be sold (1,000,000 tons per year here),
- (2) the rate of return required by investors (which is the factor determining present discounted value), and (3) the expected costs.

Estimating the rate of return required by investors is a complex process. ICF's estimate of a real rate of 8% seems reasonable in view of past cost-of-capital studies.* Merton Miller and Franco Modigliani estimated that in 1957 the average cost of capital for the electric utility industry was 4.6% in nominal terms. With an inflation premium of about 2%, this would leave a real cost of capital of 2.6%. However, data in Robert Hamada's study indicate that the coal industry could be three times riskier than electric utilities so that investors would require a much higher rate of return than 2.6% to invest in this industry. The 8% rate is also sufficiently high to cover possible increases in the real cost of capital produced by future demand for capital.

The final factor influencing minimum acceptable selling price -- the expected costs of the investment -- had two main components, investment and operating expenditures. Investment expenditures presumably covered all equipment costs. Operating expenses were generally adopted from the Bureau of Mines methodology.

Calculations with these inputs yielded minimum acceptable prices of \$13.98 per ton for the model deep mine and \$7.6 per ton for the model strip mine. These mines, of course, were assumed to have "ideal" characteristics: for the deep mines, a depth of 700 feet, an output of 1 million tons per year, and a seam thickness of 72 inches; for strip mines, an output of 1 million tons per year with a 10:1 overburden ratio.

The model mine prices were adjusted to reflect the higher cost of the less efficient marginal mine -- a relatively easy task using the formulas provided in Table B.3. These estimates were not quite region-specific mine prices because no correction had been made for the sulfur content of the coal.

*This estimate is in 1975 dollars. Due to inflation, actual costs in 1985 will be somewhat higher.

Table B.3 Mining Cost Adjustment Factors for Key Variables

	Initial Capital	Deferred Capital	Output/Man-day ^a	Power Supplies
<u>Underground Mines^b</u>				
Seam Thickness	+6%/ft Decline in Thickness	+6%/ft Decline in Thickness	-1.0 TPMD/ft Decline in Thickness ^c	+\$0.15/ton/ft Decline in Thickness
Seam Depth	\$500,000/100 ft	--	--	--
Annual Output	30%/10 ⁶ TPY ^d	15%/10 ⁶ TPY	0.5 TPMD/0.1 x 10 ⁶ TPY	100%/10 ⁶ TPY
Drift Mine	-\$6,000,000	-\$3,000,000	+10%	--
Conventional Mining	e	e	--	--
<u>Surface Mines^f</u>				
Overburden Ratio	-\$1.20/ton/UOR ^g	\$0.25/ton/UOR	10%/5 UOR	\$30,000/UOR
Annual Output:				
Mines >1.0 x 10 ⁶ TPY ^h			3 TPMD/0.1 x 10 ⁶ TPY	100%/10 ⁶ TPY
Mines <1.0 x 10 ⁶ TPY	-5%/0.1 x 10 ⁶ TPY	-5%/0.1 x 10 ⁶ TPY	3 TPMD/0.1 x 10 ⁶ TPY	100%/10 ⁶ TPY

^aThe cost effects of changes in output per man-day are calculated by dividing the estimated tons per man-day figure for a given mine type into the mine's annual output level to get the total number of man-days per year, and then multiplying that figure by the average labor cost per man-day (\$53.98 for underground mines and \$77.12 for surface mines). Note that output per man-day is calculated based on the total number of man-days worked by all classes of mine employees in one year.

^bVariations for underground mines are calculated from a base-case operation which is defined as a 1 million ton per year slope mine working a 6-ft seam 700-ft deep, using continuous mining and having unit train loading facilities, no cleaning plant, and an average output per man-day of 17.3 tons.

^cTPMD = tons per man-day.

^dTPY = tons per year

^eInitial capital (less the cost of required shafts) and deferred capital investment costs for mines producing less than 1 million tons per year are assumed to remain constant on a dollars per ton of annual output basis with the capital costs after all other adjustments are made for a 1 million ton mine with the same characteristics. This assumes that the capital intensity of mines with annual output levels of less than 1 million tons decreases with size.

^fVariations in surface mine costs are calculated from a base case mine defined to produce one million tons per year from a 6-ft seam with a 10:1 overburden ratio using area mining techniques and having unit-train loading facilities but not a preparation plant.

^gUOR = units of overburden ratio.

^hThe capital costs for surface mines producing over one million tons per year are assumed to experience increasing economies of scale with respect to capital costs. To reflect this, the incremental capital required for each million ton increase in annual output is assumed to decline ten percent from the capital costs for a 1 million ton per year operation. Thus, capital costs for a 2 million ton per year mine would equal 1.9 times those for a 1 million ton mine, and capital for a 3 million ton per year operation would equal 2.7 times those for the 1 million ton mine.

The estimates in Section 5.2.2 are for production costs at the mine, but costs are also incurred in processing the coal and in moving it from the mine to the railhead. Before shipping the coal, the mining company must remove dirt, shale, and other matter that contains no heat content but considerable weight, and thus adds to the shipping costs. It has been determined that this cleaning process is more complicated and expensive in Appalachia than in the Northern Great Plains and the Rocky Mountains. Therefore, a cost of \$.05 per ton has been added to western coal for processing and \$1.23 per ton has been estimated for the Appalachian cost.*

Projecting the costs of transporting the coal from the mine to the railhead was a difficult undertaking because of the difficulty in assigning an average distance from minemouth to loading point. Conversations with coal company officials and examination of the Rand McNally *Railroad Atlas* produced an estimate of 3 miles in Appalachia and 5 miles in the Northern Great Plains and the Rocky Mountains. At \$.05 per ton mile, total transport cost was calculated to be \$.15 per ton for eastern coal, and \$.25 per ton for western coal.**

After examining present production and the reserve base of the region, potential increases in future production could be postulated. As a check, the total quantity in the first step of all regional supply functions was compared with the quantity demanded to insure approximate equivalence.

B.4 TRANSPORTATION COSTS

Two major studies of coal transportation done by the Bureau of Mines and Martin Zimmerman provided a point of departure for constructing a model of rail transport costs. The bureau of mines study employs two regression equations, one each for short and long hauls. These simple regressions of rates on distances have several shortcomings. The most fundamental problem is that other variables that may affect rates, such as annual volume, train-load tonnage, and car ownership, were omitted without statistical testing.

*These costs have been obtained through personal communications with officials at Peabody and Amax Coal Companies, and from Peter J. Phillips and Paul P. DeRienzo, *Steam Preparation Economics*, Gibbs and Hill, Inc.

**The transportation figures were provided by executives at Peabody and Amax Coal Companies.

This means that the estimated coefficients for distance will be biased if the omitted variables do indeed affect rates. Secondly, the study presents no criterion by which the short- and long-haul distinction was drawn, i.e., it gives no justification for that particular specification of the rate function. Alternative functional forms, such as a hyperbolic or semilog, might better fit the apparent nonlinearity of rail rates as a function of distance. Thirdly, it mixes unit-train data with trainload data. Finally, it does not model the bargaining process by which rates are established. Correcting for this last deficiency was perhaps the main contribution by Zimmerman.

Zimmerman included the price differential of alternative fuels to coal as an explanatory variable. This is based on the assumption that the railroad can extract larger profits from utilities that have poor alternatives to burning coal. However, he used natural gas as the alternative fuel, which was relevant in 1970 but is not currently. The technique of including the affects of competition can be extended to include alternative modes of transportation. Rail rates are generally thought to be sensitive to rates charged by barge transporters. Moreover, the coal slurry pipeline offers a potent source of price competition in the future.

Zimmerman derived an equation which included average volume and trainload tonnage. It was estimated with current data (for railroad-owned cars), excepting that the alternative price differential was omitted for the above reason. The equation was of the following form:

$$T = a_1/AV + a_2/TT + a_3M + e \quad (B.1)$$

where T is the tariff in cents per ton, AV is annual minimum volume in millions of tons, TT is minimum trainload tonnage (in thousands), M is distance in miles, and e is a random error term. Zimmerman fitted his model separately to midwestern and eastern rates, and then fitted a different equation to western data, involving only distance and a dummy variable for crossing the Mississippi River. The significance of the dummy was vaguely attributed to the geographic market structure.

These considerations led us to separate the current unit-train rates collected from 20 major railroads into the four geographic areas of western (not crossing the Mississippi), western crossing the Mississippi, midwestern,

and eastern. A constant was added to Zimmerman's equation and dummy variables assigned to three of the four subregions. Contrary to Zimmerman's result, the dummy variable for crossing the Mississippi was not significant. However, inspection of the residuals indicated significantly higher rates originating in the Hanna region of Wyoming. The Hanna region was, therefore, assigned a dummy value. Despite the fact that there is no explanation for this phenomenon, it raised the explanatory power of the equation considerably and so was tentatively included in the regression equation, as follows:

$$\begin{aligned} \text{RATE} = & -529.657 + 1.1997D + 1210.43/TT + 162.987 \text{ DH} + 386.576 \text{ DMW} + \\ & (-4.21240) (15.6766) \quad (2.9394) \quad (4.5971) \quad (4.8760) \\ & 613.369 \text{ DE} + E \quad (B.2) \\ & (9.0710) \end{aligned}$$

$$R^2 = 0.9148 \quad F(5.71) = 152.554 \quad (B.3)$$

where t-statistics are in parentheses, DH is a dummy for the Hanna region, DMW a dummy for the midwestern routes, and DE a dummy for eastern routes. The variable annual volume was suppressed since it was not significant. The negative intercept term is counter-intuitive and strongly suggests a deficiency in the model. However, a number of nonlinear transformations were tested and all proved to have much less explanatory power.

Since all the econometric models reviewed appeared to have serious shortcomings, none of the individual models were employed. Average costs per ton mile were estimated separately for the eastern, midwestern, and the far western areas, since both our work and Zimmerman's efforts had revealed definite regional differences.* These estimates were then multiplied by railroad tariffs. Finally, these calculated rates were compared with the actual rates where possible, and close similarities were observed. The 1975 rates utilized in this study are displayed in Table B.4.

* These regional differences reflect different minimum tonnage requirements per unit train and different degrees of intermodal competition, as well as different price differentials between low sulfur coal and the next best alternative fuel. The height of the eastern rates reflects the greater congestion and smaller trainload sizes, which outweigh the fact that barges are stronger competition for railroads in the East and far West.

Table B.4 Rates for Shipment of Coal by Unit Train^a

Destination	Point of Origin											
	Uniontown, Pa		Beckley, WV		Forsyth, MT		Hanna, WY		Price, UT		Gallup, NM	
	1975	1985	1975	1985	1975	1985	1975	1985	1975	1985	1975	1985
Boston, MA	814	944	952	1104	1842	2138	1711	1936	2138	2481	2139	2483
New York, NY	539	625	677	785	1748	2029	1618	1377	2044	2372	2020	2345
Harrisburg, PA	325	377	593	688	1375	1596	1452	1635	1879	2180	1855	2152
Grand Rapids, MI	614	713	733	851	1145	1329	1117	1296	1448	1681	1436	1666
Terre Haute, IN	600	696	580	673	1144	1328	1097	1169	1330	1544	1266	1469
Springfield, IL	751	872	718	833	1137	1242	966	1042	1216	1412	1152	1337
Columbus, OH	287	333	354	411	1269	1473	1241	1440	1571	1823	1515	1758
Marshfield, WI	966	1121	1039	1206	821	953	1201	1394	1533	1779	1521	1765
St. Paul, MN	1105	1283	1175	1363	652	757	842	977	1173	1361	1305	1514
Bismark, ND	1648	1912	1688	1959	283	328	849	985	1340	1554	1479	1716
Salina, KS	1349	1565	1315	1526	1000	1160	761	883	807	936	762	885
Jefferson City, MO	966	1121	932	1082	1114	1253	846	981	1096	1272	1031	1197
Des Moines, IA	1060	1230	1129	1310	883	1012	669	776	1000	1161	1085	1259
Richmond, VA	425	536	428	433	1721	1998	1564	1815	1978	2295	1836	2131
Macon, GA	896	1040	727	844	1687	1958	1375	1596	1792	2079	1500	1741
Nashville, TN	670	918	661	785	1368	1587	1058	1345	1472	1709	1348	1476
Birmingham, AL	886	1028	907	1053	1572	1789	1189	1380	1587	1842	1284	1490
Hopkinsville, KY	778	902	650	783	1302	1511	1165	1277	1400	1625	1342	1468
Fort Smith, AR	1385	1607	1254	1455	1238	1407	875	1015	1227	1373	842	978
Houston, TX	1711	1986	1638	1901	1558	1867	1024	1189	1354	1571	893	991
Billings, MT	2183	2533	2225	2582	87	101	468	543	677	786	1100	1276
Salt Lake City, UT	2465	2860	2438	2887	655	761	441	512	109	126	974	1130
The Dalles, OR	3187	3699	3217	3734	820	952	1005	1166	922	1070	1552	1521
San Francisco, CA	3364	3904	3336	3930	1292	1499	1078	1251	803	932	880	1021

^acents per ton.

B.5 FUTURE RAIL RATES

The 1980 and 1985 rates were forecast by a model which explicitly related past rate changes to movements in unit labor costs (defined as wage costs adjusted for labor productivity), volume of coal carried, fuel costs, and carrying capacity.* In order to make rate projections, these variables are projected to 1980 and 1985. Fuel costs are estimated to grow at 0.8% per year and coal volume at 6.75% per year in accordance with forecasts published in the FEA, *National Energy Outlook*. Unit labor costs are extrapolated from their past trend, and capacity is projected to grow at 0.9% per year from 1975 to 1980, and then to return to its historic rate of 0.7% per year from 1980 to 1985.

These projected values are then inserted into the model to obtain the forecasts of the railroad rate index for 1980 and 1985. Taking the actual 1975 index, average annual growth rates are computed between 1975 and 1980, and between 1980 and 1985. Forecast rates for each route are then directly obtained by increasing the 1975 rates in Table B.4 by the annual growth rate predicted by the model. A slight adjustment in the relative growth of eastern rates was made to account for the poor condition of many eastern railroads. The calculated rates for 1985 are also shown in Table B.4. It is estimated that rates between 1980 and 1985 will level off and remain fairly constant in real terms due to a decrease in the growth rates of unit labor costs and fuel costs.

B.6 RAIL-BARGE COSTS

This section focuses on the transportation of low sulfur coal via a combination of rail and barge modes. In 1975, over 18% of the coal consumed by electric utilities traveled on various rivers throughout the U.S. Most of

*Quarterly data on rates from 1969 to 1975 were obtained from the Bureau of Labor Statistic's freight rate index for coal; fuel and labor costs were obtained from the Association of American Railroad's *Indexes of Railroad Material Prices and Wage Rates*; and volume and capacity were taken from *Survey of Current Business*.

this coal originated in the Appalachian regions that contain several navigable rivers. However, five rivers, the Ohio, Monongahela, Green, Mississippi, and Kanawha,* carried over 75% of the coal. In addition, approximately 4% of the coal consumed by electric utilities traveled via the Great Lakes.

Three recent events have increased the prospect that large quantities of western coal will be transferred at intermediate points for final shipment by barge:

1. The building of a rail-barge system by American Electric Power (AEP) which will transfer coal on the Ohio River near Metropolis, Illinois, for plants on the Ohio River.
2. The proposed plan by Burlington Northern for a transloading facility near St. Louis to receive western coal by water.
3. The construction of a large transshipment facility at Duluth, Minnesota.

The estimation of barge rates is complicated by the fact that barge rates are not readily available. Unlike rail rates, the large majority of barge rates are not regulated and operators need not publish rates. Only limited information on rates could be obtained from barge companies and electric utilities.

As an alternative, a model developed by Zimmerman was utilized to estimate 1975 barge costs. Zimmerman concluded that upstream rates are somewhat higher than downstream rates, and that differences in regulated and unregulated rates are insignificant.** Therefore river tariffs depend, in his model, on distance and whether the coal is traveling up or downstream. Since Zimmerman's model appears to simulate present conditions quite well, it was chosen to forecast future rates.

The first consideration in the estimation procedure was to determine which demand centers can practically receive coal via river barges. Out of the 24 designated demand centers only four -- St. Paul, Nashville, Hopkins-

* The Ohio River by itself carried over 30% of the coal that traveled on rivers.

** Kearney's *Domestic Waterborne Shipping Market Analysis* estimated the difference between upstream and downstream rates to be considerably greater than that estimated by Zimmerman. Kearney estimated that, on the average, upstream rates are 80% higher than downstream rates.

ville, and Fort Smith -- can feasibly receive coal via river barge and none can receive it via the Great Lakes.* Additional shipment points were therefore added to compare rail and water shipment charges.

Additionally, we had to estimate unloading and loading costs. From discussion with utility representatives, these costs in 1975 were estimated to be \$0.50 per ton.

The last component of the rail-barge rates, barge costs, required the measurement of upstream and downstream river distances between specific points. Once derived, they were then fitted into the Zimmerman model which estimated barge costs for 1975. The rail-barge costs are assumed to be equal to the sum of the rail costs from the mine to the water terminal, transloading costs, and the barge costs from the transloading facility to the power plant. The total costs can be expressed more simply by the following relation:

$$C_{mp} = R_{mw} + F_t + B_t C_p, \quad (B.4)$$

where

C_{mp} = rail-barge transport costs from supply region m to demand region p,

R_{mw} = rail costs from supply region m to water terminal,

F_t = transloading costs at location t, and

$B_t C_p$ = barge costs from transloading facility to demand region p.

Estimates of total transport costs for 1985 are contained in Table B.5. They are derived by extrapolating historical barge costs at a growth rate of 1% per year. This rate of increase is somewhat slower than that for railroads, whose rates are predicted to rise by 1.5% per year between now and 1985.

For this study, the relevant comparison is between rail and rail-barge costs over the specific supply-demand routes. The most pronounced conclusion implied by the numbers is that coal originating in the Appalachian regions can be obtained at a considerable savings if the rail-barge mode is employed (see Table B.6).

*Even though other demand centers lie near rivers, these rivers are either not navigable or the round-about nature of the rail-barge route would economically preclude transport by river.

Table B.5 Transport Costs via Inland Waterways (1985)^a

Destination	Region of Origin						
	Northern Appalachia	Southern Appalachia	Interior	Northern Great Plains	Hanna	San Juan	Uinta
St. Paul	12.83	13.63	8.11	b	9.77	15.14	13.61
Nashville	7.77	7.67	3.19	15.87	12.28	15.65	17.08
Hopkinsville	9.02	7.55	2.34	15.11	13.51	15.58	16.25
Fort Smith	16.07	14.55	5.95	14.36	10.15	b	14.24

^a1975 dollars per ton.^bCoal is assumed to arrive at St. Paul and Fort Smith via unit trains from the Northern Great Plains and San Juan, respectively.Table B.6 Differences Between Rail and Rail-Barge Costs (1985)^{a, b}

Destination	Region of Origin						
	Northern Appalachia	Southern Appalachia	Interior	Northern Great Plains	Hanna	San Juan	Uinta
St. Paul	2.28	3.87	2.92	-	-3.52	-5.17	-7.33
Nashville	.20	.89	-1.09	1.21	-.11	-1.54	-2.19
Hopkinsville	2.98	2.26	-2.33	.36	.74	-2.56	-3.40
Fort Smith	5.58	4.85	-.34	-2.32	-4.24	-	-7.03

^aA positive number indicates that the advantage lies with the rail-barge model.^b1975 dollars per ton.

Savings for rail-barge transport of coal from other supply regions are not as dramatic. Rail costs, in fact, are found to be lower than rail-barge costs to many of the demand centers. However, rail-barge costs are lower than all-rail costs between the Northern Great Plains and Nashville. This is important because the Nashville area has been considered too far east and south for western coal to be competitive, assuming the all-rail mode were utilized. A comparison of the rail-Great Lake mode with all-rail transport revealed, as will be illustrated below, that a similar advantage lay with the barge means of transport in this case.

Calculation of the cost for the mixed mode of transport was rather straightforward. Rail mileage from Forsyth, Montana to Duluth, Minnesota was computed from the Rand McNally *Railroad Atlas*, multiplied by the ton-mile rate assumed in Table B.4, and this product was added to the loading cost of \$0.50 per ton utilized earlier. Barge miles over the Great Lake system were multiplied by an average ton-mile rate obtained from industry sources to produce the estimate for the water section of the route. Total rail and barge cost to Detroit, Cleveland, Buffalo are displayed in the second row of Table B.7.

Computation of the cost associated with the all-rail route was simply computed. Mileage obtained from the Rand McNally *Railroad Atlas* was merely multiplied by the average ton-mile rate employed above to produce an estimate of railroad tariffs. These projections are displayed in the first row of Table B.7.

The results of this analysis combined with the data reported earlier on river barges imply that western coal will penetrate further south and east than is generally expected. These findings are substantiated by the present practices of Detroit Edison and the plans AEP has for shipping coal from Metropolis to power plants on the Ohio River. However, it should be emphasized that this conclusion does not support any contention that western coal will be widely used in the North or Southeast. Navigable waterways serve only a relatively small number of demand centers.

Table B.7 Comparison in 1985 of All-Rail and Rail-Barge Costs to Great Lakes Demand Centers^a

Transportation Mode	Destination		
	Detroit	Cleveland	Buffalo
All-Rail	13.96	14.65	16.45
Rail-Barge	11.29	11.88	12.57
	2.67 ^b	2.77	3.88

^a1975 dollars per ton.

^bA positive number indicates the advantage lies with the rail-barge mode.

B.7 MODEL DESCRIPTION

The Coal Resource Model is currently defined in terms of a linear optimization problem.* Linear programming (LP) methods provide a solution which minimizes total delivered fuel costs based on supply and demand constraints. The model minimizes the costs for the entire market system and not necessarily the costs for each demand area. Additional constraints are specified to incorporate the effects of other coal energy system characteristics. Some of the essential features explicitly considered are:

1. Coal availability.
2. Coal quality (Btu and sulfur content).
3. Total coal demand.
4. Disaggregated demand and supply points (spatial detail).
5. State air quality standards.
6. Extraction costs.
7. Transportation costs.
8. Coal beneficiation costs.
9. Economic rents.

Coal extraction costs versus availabilities are first expressed as step functions for the nine coal resource areas. Economic, technological,

*Work at ANL is proceeding to convert the Coal Resource Model to a quadratic optimization problem which will explicitly incorporate the effect of economic rents on market clearing prices.

and environmental factors are responsible for escalating the prices of coal as production levels increase. Supply functions are adjusted to distinguish between coal supplies graded according to sulfur content.

Technology costs provide the mechanism for simulating sulfur removal. Two types of sulfur removal technologies are included. Washing costs vary between coal resource areas because of regional differences in quality. Scrubbers costs are assumed to be constant across coal resource areas. Furthermore, cost variations may occur between demand areas due to differences in sulfur regulations necessitating different degrees of sulfur removal.*

Transportation costs are obtained for each link between supply area and demand center. At present, only rail costs are included, but additional links can easily be added to account for other modes of transportation.

Representative heat content values for each resource area are used to convert all cost and availability functions to common units of Btu. Extraction, transportation, and cleaning costs are summed to provide the final cost coefficients used in the LP objective function.

Coal availability provides the criteria for one set of constraints (Eq. B.6) in the model. Allocations must be less than or equal to supply limits for a given region and for each type of coal within that region.

Total coal demands define the LP equality constraints (Eq. B.8). These demands are exogenously introduced in accord with a set of prescribed coal demand scenarios. Demand includes all utility demands plus industrial demand for steam coal.

Additional constraints (Eq. B.7) are included in the LP and represent the portion of energy demands to be met by high sulfur coal. If modeled endogenously, the high cost of scrubbers would normally force high sulfur coal out of allocations except in extreme cases where low and intermediate sulfur coal supplies are exhausted or where transportation distances are significantly shorter for high sulfur coal supply areas. Constraints provide a more realistic mix of coal types according to the expected levels of

*In the present version the model considers only the federal sulfur standard of 1.2 lb SO₂ per million Btu, but is being expanded to include sulfur regulations that vary by demand area.

high sulfur coal use; therefore, the use of high sulfur coal is included as an exogenous input to the model.

The following equations define the coal market model in terms of an optimization problem that is examined using linear programming techniques. Step functions are not shown explicitly in order to simplify the problem definition.

Minimize the objective function:

$$\sum_{i=1}^{NSA} \sum_{j=1}^{NDA} c(i,j) \cdot x(i,j) \quad (B.5)$$

where:

NSA = number of supply areas, and

NDA = number of demand areas;

subject to:

$$\sum_{j=1}^{NDA} x(i,j) \leq S(i) \quad i = 1, \dots, NSA \text{ (supply constraints)} \quad (B.6)$$

$$\sum_{i \in HSSA} x(i,j) \geq D_{HS}(j) \quad j = 1, \dots, NDA \text{ (high sulfur demand constraints where HSSA = high sulfur demand area)} \quad (B.7)$$

$$\sum_{i=1}^{NSA} x(i,j) = D_T(j) \quad j = 1, \dots, NDA \text{ (total demand constraints)} \quad (B.8)$$

$$x(i,j) \geq 0 \quad \begin{matrix} i = 1, \dots, NSA \\ j = 1, \dots, NDA \end{matrix} \quad (B.9)$$

In matrix notation, the problem becomes one of minimizing the product:

$$C \cdot X$$

subject to:

$$A \cdot X \begin{pmatrix} < \\ > \\ = \end{pmatrix} B$$

$$X \geq 0$$

where:

C = the vector of cost coefficients,

- B = a partitioned column vector containing the constraints $S(i)$, $D_{HS}(j)$, and $D_T(j)$,
- X = the independent variables representing level of coal flows between supply areas and demand regions,
- A = zero-one entries for the summations indicated in Eqs B.6, B.7 and B.8,
- D_{HS} = high sulfur coal constraints,
- D_T = the total demand constraints, and
- S = the supply availability levels.

APPENDIX C. MODEL PLANT UNDER CONSIDERATION FOR THE ASSESSMENT OF TECHNICAL PROBLEMS ASSOCIATED WITH THE BURNING OF LOW SULFUR WESTERN COAL

Gross generating capacity	500 MWe
Boiler type	Pulverized coal; wet or dry bottom
Normal coal burn rate	428,000 lb/hr
Type of coal presently used	Illinois No. 6
Heat content	10,500 Btu/lb
Sulfur	3.5 wt %
Ash	7.0 wt %
Moisture	7.0 wt %
Hardgrove Grindability Index	63.0
Type of low sulfur coal	Northern Great Plains
Heat content	8,500 Btu/lb
Sulfur	0.4 wt %
Ash	4.5 wt %
Moisture	28.0 wt %
Hardgrove Grindability Index	53.0
Coal receiving facilities	Barge or rail
Pollution control equipment	High efficiency ESP

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