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December 1979

EPA

Technology Assessment Report for Industrial Boiler Applications: Coal Cleaning and Low Sulfur Coal

Interagency Energy/Environment R&D Program Report

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This report has been assigned to the INTERAGENCY ENERGY-ENVIRONMENT RESEARCH AND DEVELOPMENT series. Reports in this series result from the effort funded under the 17-agency Federal Energy/Environment Research and Development Program. These studies relate to EPA's mission to protect the public health and welfare from adverse effects of pollutants associated with energy systems. The goal of the Program is to assure the rapid development of domestic energy supplies in an environmentally-compatible manner by providing the necessary environmental data and control technology. Investigations include analyses of the transport of energy-related pollutants and their health and ecological effects; assessments of, and development of, control technologies for energy systems; and integrated assessments of a wide range of energy-related environmental issues.

EPA REVIEW NOTICE

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
INDUSTRIAL ENVIRONMENTAL RESEARCH LABORATORY
RESEARCH TRIANGLE PARK
NORTH CAROLINA 27711

March 27, 1980

Dear Sir:

A report is attached entitled Technology Assessment Report for Industrial Boiler Applications: Coal Cleaning and Low Sulfur Coal (EPA-600/7-79-178c). This report is one of a series of nine technology assessment reports on industrial boilers prepared by EPA's Industrial Environmental Research Laboratory at Research Triangle Park, N.C. This report is the fifth report in the series to be published. The entire list of reports and their status is listed below.

Report Title	Report No.	Status
Population...of Industrial...Boilers...	EPA-600/7-79-178a	Published
Technology Assessment Report for Industrial Boiler Applications:		
Oil Cleaning	EPA-600/7-79-178b	In Press
Coal Cleaning & Low Sulfur Coal	EPA-600/7-79-178c	Attached
Synthetic Fuels	EPA-600/7-79-178d	Published
Fluidized Bed Combustion	EPA-600/7-79-178e	In Press
NO_x Combustion Modification	EPA-600/7-79-178f	In Press
NO_x Flue Gas Treatment	EPA-600/7-79-178g	In Press
Particulate Collection	EPA-600/7-79-178h	Published
Flue Gas Desulfurization	EPA-600/7-79-178i	Published

You should have previously received the other reports that have been published. The remaining reports in the series will be sent to you as they become available.

I hope you will find the reports to be beneficial and informative.

Sincerely,

Lynn K. Pendergraft for

J. David Mobley
Mail Drop 61
Utilities & Industrial Power Division

Attachment

EPA-600/7-79-178c

December 1979

Technology Assessment Report for Industrial Boiler Applications: Coal Cleaning and Low Sulfur Coal

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Prepared for

U.S. ENVIRONMENTAL PROTECTION AGENCY
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Washington, DC 20460

PREFACE

The 1977 Amendments to the Clean Air Act required that emission standards be developed for fossil-fuel-fired steam generators. Accordingly, the U.S. Environmental Protection Agency (EPA) recently promulgated revisions to the 1971 new source performance standard (NSPS) for electric utility steam generating units. Further, EPA has undertaken a study of industrial boilers with the intent of proposing a NSPS for this category of sources. The study is being directed by EPA's Office of Air Quality Planning and Standards, and technical support is being provided by EPA's Office of Research and Development. As part of this support, the Industrial Environmental Research Laboratory at Research Triangle Park, N.C., prepared a series of technology assessment reports to aid in determining the technological basis for the NSPS for industrial boilers. This report is part of that series. The complete report series is listed below:

Title	Report No.
The Population and Characteristics of Industrial/ Commercial Boilers	EPA-600/7-79-178a
Technology Assessment Report for Industrial Boiler Applications: Oil Cleaning	EPA-600/7-79-178b
Technology Assessment Report for Industrial Boiler Applications: Coal Cleaning and Low Sulfur Coal	EPA-600/7-79-178c
Technology Assessment Report for Industrial Boiler Applications: Synthetic Fuels	EPA-600/7-79-178d
Technology Assessment Report for Industrial Boiler Applications: Fluidized-Bed Combustion	EPA-600/7-79-178e
Technology Assessment Report for Industrial Boiler Applications: NO_x Combustion Modification	EPA-600/7-79-178f
Technology Assessment Report for Industrial Boiler Applications: NO_x Flue Gas Treatment	EPA-600/7-79-178g
Technology Assessment Report for Industrial Boiler Applications: Particulate Collection	EPA-600/7-79-178h

Technology Assessment Report for Industrial Boiler Applications: Flue Gas Desulfurization | EPA-600/7-79-178i

These reports will be integrated along with other information in the document, "Industrial Boilers - Background Information for Proposed Standards," which will be issued by the Office of Air Quality Planning and Standards.

ABSTRACT

This report assesses the applicability of using three pollution control technologies - low sulfur coals, physical coal cleaning (PCC) and chemical coal cleaning (CCC) - for compliance with SO_2 emission regulations. It is one of a series of reports to be used in determing the technological basis for a New Source Performance Standard (NSPS) for Industrial Boilers.

Candidate emission control systems were selected after initial consideration of six naturally occurring low sulfur coals, five levels of sulfur removal by PCC and chemical desulfurization by eleven CCC processes. The Best Systems of Emission Reduction (BSER) - defined as the technology which can comply with a given emission control level with the least economic, energy and environmental impact - were identified for four coals at each of five emission control levels. It was found that low sulfur western coal can meet all emission levels down to 516 ng SO_2/J (1.2 lb $SO_2/10^6$ BTU) without cleaning. The uncleaned low sulfur eastern coal can achieve emission levels above 860 ng SO_2/J (2.0 lb $SO_2/10^6$ BTU). When physically cleaned, the low sulfur eastern coal can be used to meet an emission level of 516 ng SO_2/J (1.2 lb $SO_2/10^6$ BTU). The medium sulfur eastern coal could be beneficiated to meet an emission standard of 860 ng SO_2/J (2.0 lb $SO_2/10^6$ BTU). The candidate high sulfur coal can be cleaned to meet emission levels of 645 ng SO_2/J (1.5 lb $SO_2/10^6$ BTU) and higher. In the case of the medium and high sulfur coals, chemical coal cleaning must be used to produce fuels capable of complying with an emission limit of 516 ng SO_2/J (1.2 lb $SO_2/10^6$ BTU).

It must be emphasized that the findings apply only to those coals evaluated. In general each coal has a distinctly different desulfurization potential and a rigorous analysis of coal cleaning as a pollution control technique must consider the coal which is to be used for each application.

To partially offset these facts the report also presents estimates of the amounts of U.S. coals which can be physically and chemically cleaned to various sulfur levels.

For regulatory purposes this assessment must be viewed as preliminary, pending the results of a more extensive examination of impacts called for under Section 111 of the Clean Air Act Amendments.

The period of performance for work on this report was from September 1978 through July 1979.

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ACKNOWLEDGMENTS

This report was prepared for the Energy Assessment and Control Division of the Industrial Environmental Research Laboratory of the U.S. Environmental Protection Agency. The EPA Project Officer was Mr. James D. Kilgroe. Versar appreciates the assistance and direction provided by Mr. Kilgroe and by other IERL personnel including Messrs. David Kirchgessner and J. David Mobley. Versar would also like to acknowledge the assistance provided by industry and EPA personnel who reviewed earlier drafts of this report and provided constructive suggestions for improvement.

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The Versar Project Director was Dr. Robert Shaver, the Project Manager was Mr. Lee McCandless, the Project Coordinator was Mr. Jerome Strauss and the principal authors were Ms. J. Buroff, Ms. B. Hylton and Messrs. S. Keith, J. Strauss and L. McCandless. Special thanks are expressed to other members of the Versar staff for their review comments and assistance and particularly to the secretarial staff, Ms. P. Waggy and others for their invaluable help and patience.

SECTION 1.0

EXECUTIVE SUMMARY

1.1 INTRODUCTION

1.1.1 Purpose of the Report

The purpose of this Individual Technology Assessment Report (ITAR) is to provide background information and performance capabilities of three control technologies for controlling sulfur dioxide (SO_2) emissions from coal fired industrial boilers. The three emission control technologies presented are:

- Use of naturally-occurring low sulfur western coal;
- Beneficiation of raw coal by physical coal cleaning processes to remove ash and pyritic sulfur minerals; and
- Beneficiation of raw coal by chemical coal cleaning processes to remove pyritic and/or organic sulfur plus ash minerals.

These control technologies are not mutually exclusive. For example, beneficiation of naturally-occurring low sulfur coal is quite possible, as are combinations of physical and chemical coal cleaning operations to produce various grades of coal products to meet SO_2 emission control levels. In general, combinations of these three control technologies are more expensive than the individual options, but the combinations will increase the amount of coal that will meet a given SO_2 emission control level.

The evaluation of the three control technologies is based upon the emissions from a set of five reference boilers, using three reference coals. (A fourth reference coal is studied in Appendix G.) The methodology used is to apply a candidate emission control technique to the reference coals to produce a set of resultant cleaned or naturally occurring coal products. The control techniques are evaluated by comparing the properties of the cleaned coal, such as SO_2 reduction, ash reduction, and heating value enhancement with the raw coal recovery, and weight recovery. The cleaned coals or the candidate naturally-occurring low-sulfur coals are then assumed to be combusted in the five reference boilers and the quantities of air pollutants emitted are calculated. These emissions from the combustion of cleaned coal and naturally-occurring low-sulfur coals are then compared to the emissions from the same boiler burning the four reference raw coals. These data provide a comparison of performance factors on a variety of boiler types and sizes. The number of boiler cases studied is limited by choosing a set of four proposed SO_2 emission control levels plus a SIP level, which can be achieved by the coal products resulting from the candidate control technologies. Thus, the number of boiler cases studied and included in this report is 100 [five boilers x four coals x five emission control levels]. A calculation of pollutants emitted, annualized cost, energy impact and environmental impact is then made for each case and compared to the same factors for the uncontrolled boiler and SIP controlled boiler.

1.1.2 Scope of the Study

1.1.2.1 Pollutants Considered--

The major pollutant considered for control in this report is sulfur dioxide produced by the combustion of coal. Particulates and other second order pollutants are considered and discussed in the sections on energy impacts and enviornmental impacts.

1.1.2.2 Types of Sources--

The reduction of pollutants resulting from the use of industrial boiler emission control systems can best be determined by comparing pollutants emissions from each control system with those from a new uncontrolled boiler. To permit such a comparison, several typical reference boilers were established to permit comparison of control system performance, cost, energy impacts, and environmental impacts.

Five different coal-fired boiler types were selected for use in preparing emission factors, costs and energy requirements for the candidate control systems. These boiler types are presented in Table 1-1.

TABLE 1-1. STANDARD BOILERS SELECTED FOR EVALUATION[1]

Boiler Type	Fuel	Thermal input, MW (10^6BTU/hr)
Package, watertube, underfeed	Coal	8.8 (30)
Field-erected, watertube, chain grate	Coal	22.0 (75)
Field-erected, watertube, spreader	Coal	44.0 (150)
Field-erected, watertube pulverized coal	Coal	58.6 (200)
Field-erected, watertube pulverized coal	Coal	118 (400)

1.1.2.3 Coal Types Considered--

To permit a comparison of various candidate control systems for the five coal-fired boilers, a set of reference coals was provided to each control technology assessment study for use in each ITAR. These reference coals are representative of three coal types-- a high sulfur Eastern coal, a low sulfur Eastern coal, and a low sulfur Western coal. Unfortunately the identity of the source of these coals-- i.e. region, county, bed, etc, was not provided. The lack of specific data on these reference coals presented a problem in the application of the coal cleaning control techniques.

Thus, a set of three alternative reference coals were chosen for this analysis. These coals had similar properties to the specified reference coals, but were also characterized by coal specific washability data. These data are absolutely necessary for the determination of the performance of a physical coal cleaning operation on a specific coal type. The specified reference coals and the alternative reference coals are compared in Table 1-2. The only major change in coal type from the specified reference coals is in the low sulfur Western coal. The analysis provided for the specified western reference coal indicates that it is a subbituminous coal from the

Table 1-2 Comparison Of Properties Of Specified Versus Alternative Reference Coals Used In This Assessment Report

Source			High Sulfur Eastern Coal		Low Sulfur Eastern Coal		Low Sulfur Western Coal	
			Specified† Raw Coal	Alternative σ Raw Coal	Specified† Raw Coal	Alternative σ Raw Coal	Specified† Raw Coal	Alternative σ Raw Coal
Proximate Analysis	As-Received	Moisture, %	8.79	5.0	2.87	2.0	20.80	2.5
		Ash, %	10.58	22.23	6.90	10.17	5.40	24.19
		Total S, %	3.54	3.28	0.90	1.16	0.60	0.58
		Pyritic S, %	N.A.	2.38	N.A.	0.59	N.A.	0.29
		HV,kJ/kg	27,447	25,433	32,100	31,052	22,330	25,614
		HV,BTU/lb	11,800	10,934	13,800	13,350	9,600	11,012
	Dry Basis	Ash, %	11.60	23.90	7.10	10.38	6.82	24.81
		Total S, %	3.68	3.45	0.93	1.18	0.76	0.59
		Pyritic S, %	N.A.	2.51	N.A.	0.60	N.A.	0.30
		HV, kJ/kg	30,092	26,772	33,034	31,685	28,194	26,268
		HV, BTU/lb	12,937	11,510	14,202	13,622	12,121	11,294
Ultimate Analysis	As-Received	C, %	64,85	62.30	78.75	74.58	57.60	61.51
		H, %	4.43	3.99	4.71	4.77	3.20	3.94
		S, %	3.54	3.23	0.90	1.16	0.60	0.58
		O, %	6.56	2.08	4.91	5.92	11.20	6.11
		N, %	1.30	1.17	1.50	1.40	1.20	1.17
		Ash, %	10.58	22.23	6.90	10.17	5.40	24.19
	Dry Basis	C, %	71.04	65.58	81.04	76.10	72.73	63.09
		H, %	4.86	4.20	4.85	4.87	4.04	4.04
		S, %	3.68	3.40	0.93	1.18	0.76	0.59
		O, %	7.19	2.19	5.05	6.04	14.14	6.27
		N, %	1.43	1.23	1.54	1.43	1.52	1.20
		Ash, %	11.68	23.40	7.10	10.38	6.82	24.81

† Memorandum from PEDCo Environmental, Inc., specifying analysis of coals for standard boilers (2)

σ Coals chosen by Versar, Inc., as reference coals for technology assessment

Gillette, Wyoming or Rosebud, Montana coal reserve areas. These types of coals have a high bed moisture content and low ash content, which means that they are difficult to upgrade by coal preparation techniques. In place of the subbituminous specified reference coal, a bituminous low sulfur Western coal has been substituted. This coal has less moisture, higher ash and heating value than the specified reference coal and can be cleaned by both physical and chemical coal preparation techniques. In summary, the three coals used as alternative reference coals in this report are:

Coal Type	High Sulfur Eastern	Low Sulfur Eastern	Low Sulfur Western
Seam	Upper Freeport ('E' coal)	Eagle	Primero
County, State	Butler, Pa.	Buchanan, Va.	Las Animas, Co.
Rank	Bituminous	Bituminous	Bituminous
Raw Coal Analysis			
Ash, %+	23.45	10.38	24.81
Total S, %+	3.45	1.18	0.59
Pyritic S, %+	2.51	0.60	0.30
Heating Value (BTU/lb)+	11,510	13,622	11,294
Heating Value (kJ/kg)	26,772	31,685	26,268
Moisture Content	5.0	2.0	2.5
Ash Fushion Temp., °C	1,104-1,649	—	1,221-1,599
Lbs $SO_2/10^6$BTU	5.99	1.73	1.04
ng SO_2/J	2,576	744	447

+Values are on a moisture free basis.

A medium sulfur eastern coal has also been chosen for this study and the analyses are contained in Appendix G.

The three alternative reference coals also have similar properties to estimated average coals from each respective coal region. Although both the high sulfur and low sulfur Eastern coals contain approximately 25% less total sulfur than the average coals from their respective regions, the ratio of pyritic sulfur to total sulfur for the reference coals are very close in value to the average coals. This is a very important consideration when discussing physical coal cleaning since pyritic sulfur, and not organic sulfur, is removed in the cleaning process.

As stated above, the alternative low sulfur western coal is a bituminous coal whereas the specified reference coal is a sub-bituminous coal. The selection of the alternative low sulfur bituminous coal was based on accessibility of coal washability data and also on the basis that bituminous coal would be a more widely acceptable feed coal for industrial boilers.

Although this technology assessment report uses somewhat different coals for analysis, the results should be quite comparable with other control technology assessments because the differences in important raw coal properties are in general less than 10%.

1.1.2.4 Other Considerations--

Although this report deals primarily with the application of coal cleaning technology to the reference coals and the resultant clean coal products, this analysis should be viewed in the larger context of the vast amount of coal reserves and coal types available which could be candidate compliance coals for various control options. Estimates of coal reserve quantities and energy content for six coal regions in the U.S. are presented in Section 2.2. The quantity of energy content of compliance coals versus coal sulfur emission levels for several different types of coal cleaning processes are presented. An example of this type of data is the graphical presentation shown in Figure 1-1. This figure shows that for an 860 ng SO_2/J (2.0 lb $SO_2/10^6$ BTU) control level, the percent energy available in the coal reserve base for the Northern Appalachian region can be increased from 10% for the raw coal with no beneficiation, to 40% using a rigorous physical coal cleaning process, and up to 55% using the best available chemical coal cleaning process.

Coal clea ing occupies a unique place in the spectrum of control options because ts performance and cost characteristics can make other options more economically attractive. More importantly, coal cleaning does not significantly affect the boiler operator's freedom to consider additional control options which may complement a clean coal fuel supply.

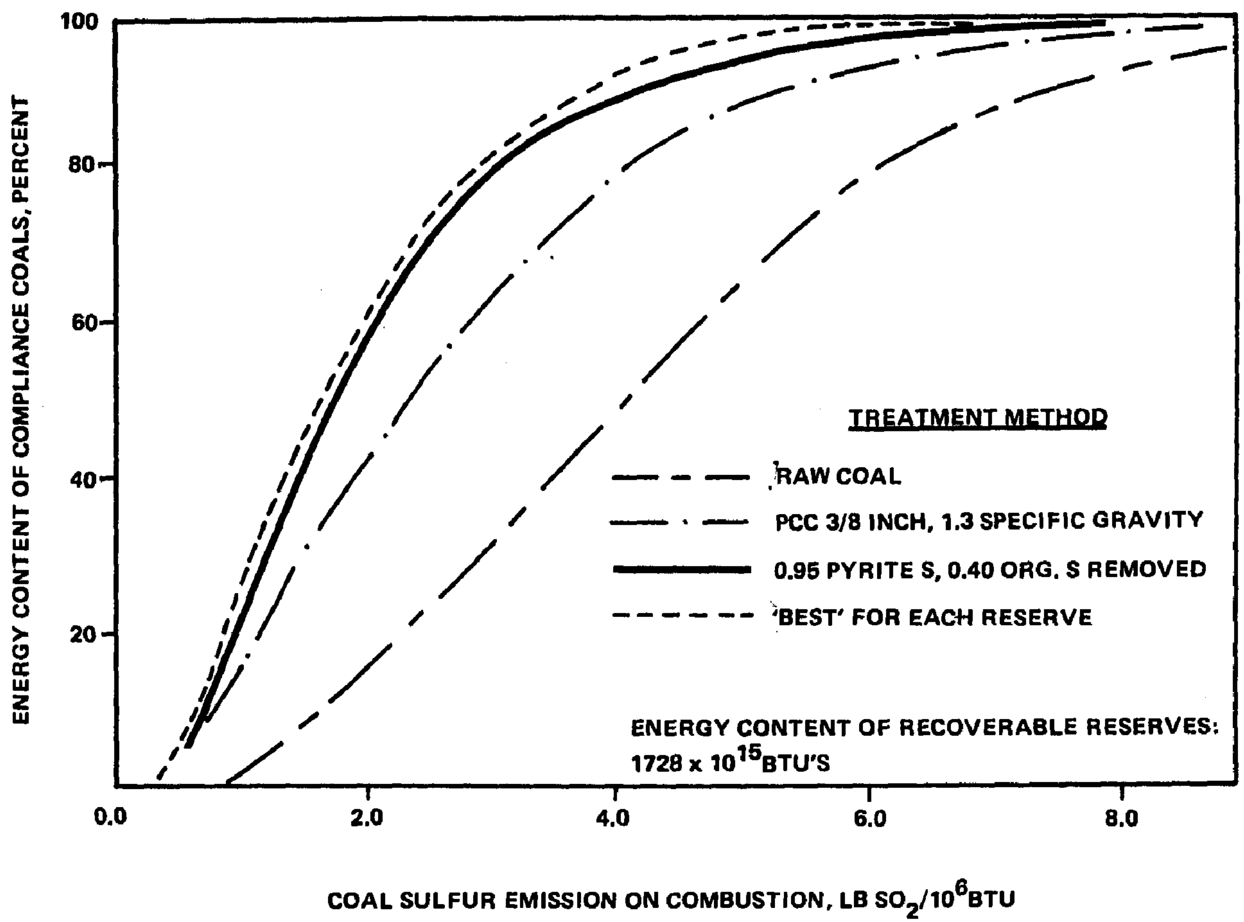

FIGURE 1-1 ESTIMATED CLEANING POTENTIAL OF NORTHERN APPALACHIAN COALS

Coal cleaning, accomplished by coal producers, does not compete for the boiler operator's capital budget, space availability, or manpower resources. Therefore, boiler-specific (combustion or post-combustion) control options can still receive full consideration, whether or not cleaned coal has been selected as a feed.

Compared to other SO_2 control technologies, physical coal cleaning may be viewed as a mature technology. Many coal cleaning plants have been in operation for fifteen or more years, and in fact, more than half of all the U.S. coal produced is prepared to some extent. However, the full technological potential of coal-cleaning has not been exploited commercially for two prime reasons. First, the historical incentive for cleaning coal has been the removal of ash - only recently has sulfur removal become important to coal producers. Second, the escalation of coal prices in the past few years has provided more economic margin and incentive to apply more sophisticated unit processes and plant designs. For these reasons, the sulfur-removal capabilities of coal cleaning extend beyond the demonstrated performance of older facilities.

Coal cleaning as a pre-combustion control technology results in the reduction of sulfur variability in the feed coal to the industrial boiler. As discussed in this report, coal cleaning effectively reduces the variability of coal sulfur as well as the mean sulfur content itself. Variations in SO_2 emissions from industrial boilers are thus reduced when using cleaned coal as opposed to raw coal. The result is that average coal sulfur content can be significantly closer to the mean sulfur content which complies with the SO_2 emission control level.

Since clean coal is a pre-combustion control technology for the industrial boiler feed, it is quite different from combustion or post-combustion options which are strongly integrated with each specific boiler facility. One important result is that the cost impact of coal cleaning upon boiler operation is much less than for boiler-specific control options. The lack of any additional equipment requirements at the boiler facility also obviates operational or maintenance concerns. One obvious facet of this is that coal cleaning is not a capital intensive control option to the boiler operator and represents less of a financial burden from a capital cost and annual cost standpoint.

The content of this ITAR is quite similar to technology assessment reports generated for other (competing) control technologies. However, the comparison and integration of the various control technologies must be accomplished with some care, for it is based upon several premises that may not be applicable to each control technology. The first premise is that each control technology may be evaluated independently by an industrial boiler operator, and the second premise is that each technology and its subsequent performance and costs is individual or uniquely definable.

However, coal cleaning as a control technology is only partially consistent with these premises. First, the operation of a coal cleaning facility is a commercial option which in most cases will be exercised by the coal producer and not by the industrial boiler consumer. The industrial boiler operator will thus have to compete in the market place for a coal product with specifications that meet both combustion requirements and air pollution emission control levels. The availability and price of the desired coal product will thus be a function of prevailing market conditions.

Second, coal cleaning is not one particular process but a number of different operations, which may be applied sequentially or alternatively in various combinations. In general, a coal cleaning plant design is based upon the properties of the feed raw coal and a set of market specifications for the clean coal product. Coal cleaning is the generic name for all processes which remove inorganic impurities from coal, without significantly altering the chemical nature of the coal itself. Coal cleaning therefore is a process objective, and several widely-varying technologies have been applied to achieve this process objective. Each coal cleaning plant is a uniquely-tailored combination of different unit operations which are determined by the specific coal characteristics and by the commercially dictated product specification. The plant designer has latitude among alternative unit operations and in selecting the sequence of unit operations. Basically, a coal cleaning plant is a continuum of technologies rather than one distinct technology.

1.2 SYSTEMS OF EMISSION REDUCTION FOR COAL-FIRED INDUSTRIAL BOILERS

The subsequent sections of this report include:

- a comprehensive summary of physical and chemical coal cleaning techniques plus a discussion and quantification of the availability of low sulfur coal reserves (Section 2.0);
- a selection of proposed SO_2 emission control levels, designated as moderate, intermediate, and stringent, which can be achieved by the control technologies plus a selection of several coal cleaning processes and low sulfur coals as candidate "Best Systems of Emission Reduction" (BSER), (Section 3.0);
- a cost analysis of the candidate control systems (Section 4.0);
- an energy impact analysis of the candidate control systems (Section 5.0);
- an environmental impact analysis of the candidate control systems (Section 6.0); and
- a summary of emission test data available on the control systems (Section 7.0).

1.2.1 Emission Control Techniques Considered

Table 1-3 summarizes all of the emission control techniques discussed in the report. These control techniques fall under three general headings: naturally-occurring low sulfur coal; physical coal cleaning processes; and chemical coal cleaning processes.

Each of the three control technologies are discussed from the standpoint of their effectiveness and applicability to reduce SO_2 emissions

TABLE 1-3 SUMMARY OF EMISSION CONTROL TECHNIQUES CONSIDERED FOR CONTROL OF SO_2 EMISSIONS FROM INDUSTRIAL BOILERS

NATURALLY OCCURRING LOW SULFUR COAL	PHYSICAL COAL CLEANING PROCESSES GENERAL LEVELS	CHEMICAL COAL CLEANING PROCESSES AND DEVELOPER
Various Candidate Low Sulfur Coals Types Including:	Level 1 - Crushing and Sizing	"Magnex",(SM) Hazen Research Inc., Golden Colorado
Buchanan, Va. (Bituminous);	Level 2 - Coarse Size Coal Beneficiation	"Syracuse" Syracuse Research Corp., Syracuse, N.Y.
Las Animas, Co. (Bituminous);	Level 3 - Coarse and Medium Size Coal Beneficiation	"Meyers", TRW, Inc. Redondo Beach, Cal.
Williston, N.D. (Lignite);	Level 4 - Coarse,Medium and Fine Size Coal Beneficiation	"Lol" Kennecott Copper Co. Ledgemont, Mass.
Gillette, Wy. (Subbituminous);	Level 5 - Multiple Product Plant Using "Deep Cleaning" Coal Beneficiation	"KVB" KVB, Inc. Tustin, Cal.
Rock Springs, Wy. (Bituminous); and		"Arco" Atlantic Richfield Company Harvey, Ill.
Gallup, N.M. (Subbituminous)		"ERDA" (PERC) Bruceton, Pa.
		"GE" General Electric Co., Valley Forge, Pa.
		"Battelle" Laboratories, Columbus, Ohio
		"JPL" Jet Propulsion Laboratory, Pasadena, Cal.
		"IGT" Institute of Gas Technology, Chicago, Ill.

based on specific fuel and process parameters, effects of boiler type and size, and status of development. To assess the uses of naturally-occurring low sulfur coal as an environmentally acceptable fuel to meet SO_2 emission control levels, the available coal reserves in each of six coal regions and the entire U.S., which meet various SO_2 emission control levels, have been estimated by a computer technique designated the Reserve Processing Assessment Methodology (RPAM).[3] The program was accomplished by a computer overlay of: Bureau of Mines-coal reserve base data; coal washability data; and coal sample analyses data.

To provide a systematic basis for a discussion and an evaluation of the capabilities of physical coal cleaning as an SO_2 emission control technology, coal preparation has been classified into five general levels as shown in Table 1-3. Coal preparation is a proven, existing technology for upgrading raw coal by removal of impurities. Depending upon the level of preparation and the nature of the raw coal, cleaning processes generally produce a uniformly sized product, remove excess moisture, reduce the sulfur and ash content and increase the heating value of coal. By removing potential pollutants and reducing product coal variability, coal cleaning can be an important control technique for complying with air quality control levels.

The third emission control technology to be evaluated is the beneficiation of raw coal by chemical coal cleaning processes. Chemical coal cleaning processes are capable of achieving lower sulfur dioxide emissions than those from the combustion of physically cleaned coals in industrial boilers. A variety of chemical coal cleaning processes are under process development which will remove a majority of pyritic sulfur from the coal with acceptable energy recovery. Some of these processes are also capable of removing organic sulfur from the coal, which is not possible with the physical coal cleaning processes. However, only one of these processes is developed to even the pilot scale stage, so the commercialization of these processes is 5 to 10 years away.

1.2.2 Candidates for "Best" Emission Control Systems

In the discussion of emission control technologies, candidate technologies were compared using three emission control levels labelled "moderate, intermediate, and stringent." These control levels were chosen only to encompass all candidate technologies and form bases for comparison of technologies for control of specific pollutants considering performance, costs, energy, and non-air environmental effects.

From these comparisons, candidate "best" technologies for control of individual pollutants are recommended for consideration in subsequent industrial boiler studies. These "best technology" recommendations do not consider combinations of technologies to remove more than one pollutant and have not undergone the detailed environmental, cost, and energy impact assessments necessary for regulatory action. Therefore, the levels of "moderate, intermediate, and stringent" and the recommendation of "best technology" for individual pollutants are not to be construed as indicative of the regulations that will be developed for industrial boilers. EPA will perform rigorous examination of several comprehensive regulatory options before any decisions are made regarding the standards for emissions from industrial boilers.

Emission Control Levels

The SO_2 emission control levels chosen to evaluate naturally occurring low sulfur coal and physical and chemical coal cleaning technologies are:

- stringent—516 ng SO_2/J (1.2 lbs $SO_2/10^6$ BTU)
- intermediate—645 ng SO_2/J (1.5 lbs $SO_2/10^6$ BTU)
- "optional" moderate—860 ng SO_2/J (2.0 lbs $SO_2/10^6$ BTU)
- moderate—1,290 ng SO_2/J (3.0 lbs $SO_2/10^6$ BTU)
- a SIP level of 1,075 ng SO_2/J (2.5 lbs $SO_2/10^6$ BTU)

Sulfur Content and Percentage SO_2 Removal in Relation to Emission Control Levels

The sulfur content of U.S. coals varies considerably. While 46 weight percent of the total reserve base can be identified as low sulfur coal (coal with less than 1 percent sulfur), 21 percent ranges between 1 and 3 percent sulfur and an additonal 21 percent contains more than 3 percent sulfur. The sulfur content of 12 percent of the coal reserve base is unknown, largely because many coal beds have not been adequately characterized.

Sulfur appears in coal in two principal forms: organic sulfur and mineral sulfur in the form of pyrite. Organic sulfur, which comprises from 30 to 70 percent of the total sulfur content of most U.S. coals, is an integral part of the coal matrix and can only be removed by chemical modification of the coal structure.

Pyritic sulfur occurs in coal as discrete particles, often of microscopic size. Pyrite is a heavy mineral which has a specific gravity of 5.0; coal has a maximum specific gravity of only 1.7. The pyrite content of most coals can be significantly reduced by crushing and specific gravity separation. However, gravimetric separation techniques which depend on the surface or electromagnetic properties of the particles must be used.

The specific gravity desulfurization potential of U.S. coals varies between coal regions and between coal beds within the same region. [4] Table 1-4 summarizes the average sulfur values in coals from six U.S. coal regions: Northern appalachian (NA), Southern Appalachian (SA), Alabama (A), Eastern Midwest (EMW), Western Midwest (WMW), and Western (W). Assuming that all of the pyritic sulfur could be removed by physical cleaning, average emissions from the organic sulfur would range from 0.73 to 2.86 lb $SO_2/10^6$ BTU. The percentage sulfur reduction (expressed in lb $SO_2/10^6$ BTU) achievable by removing all of the pyritic sulfur ranges from 34 to 68 percent.

The sulfur levels which could actually be achieved by crushing these coals by 3/8-inch top size and by gravimetrically separating them at 1.6 specific gravity are shown in Table 1-5. Total sulfur emissions would range from 0.9 to 5.5 lb $SO_2/10^6$ BTU. The percentage sulfur reduction at these cleaning conditions ranges from about 15 to 44 percent.

The above cleaning conditions are representative of the physical desulfurization which can be obtained by applying technology now used primarily to remove mineral matter from steam coals. By optimization of physical coal cleaning processes, it is probable that from 50 to 60 percent of the total sulfur can be removed from high sulfur coals. These data appear to be consistent with commercial coal cleaning plant operating data. Improvements in the cleaning conditions used for low sulfur coals could probably improve total sulfur removal capabilities to the range of 20 to 30 percent.

TABLE 1-4. AVERAGE SULFUR VALUES IN COALS FROM SIX U.S. COAL REGIONS [5]

($lb\ SO_2/10^6\ BTU$)

REGION	Total Sulfur (S_t)	Standard Deviation (*)	Pyritic Sulfur (S_p)	Organic Sulfur (S_o)	S_p/S_t
Northern Appalachian	4.8	2.7	3.20	1.60	0.667
Southern Appalachian	1.6	1.0	0.59	1.01	0.369
Alabama	2.0	1.5	1.04	0.96	0.520
Eastern Midwest	6.5	2.1	3.80	2.70	0.585
Western Midwest	9.0	4.5	6.14	2.86	0.682
Western	1.1	0.6	0.37	0.73	0.336

(*) Standard deviation of total sulfur values

TABLE 1-5. SUMMARY OF AVERAGE PHYSICAL DESULFURIZATION POTENTIAL OF COALS BY REGION [6]

(Cumulative analysis of float 1.60 product for 3/8-inch top size)

Coal Region	No. Samples	BTU Recovery, Percent	Ash Percent	Pyritic Sulfur, Percent	Total Sulfur, Percent	Emission on Combutions, lb $SO_2/10^6$ BTU	Calorific Content, BTU/lb
Northern Appalachian	227	92.5	8.0	0.85	1.86	2.7	13,766
Southern Appalachian	35	96.1	5.1	0.19	0.91	1.3	14,197
Alabama	10	96.4	5.8	0.49	1.16	1.7	14,264
Eastern Midwest	95	94.9	7.5	1.03	2.74	4.2	13,138
Western Midwest	44	91.7	8.3	1.80	3.59	5.5	13,209
Western	44	97.6	6.3	0.10	0.56	0.9	12,779
Total U.S.	455	93.8	7.5	0.85	2.00	3.0	13,530

In evaluating the data and other information on U.S. coals, the following general observations can be made:

- PCC can be used for moderate reductions in the sulfur contents of high sulfur Northern Appalachian and Midwestern coals. However, few of these coals can be cleaned to the 1.2 lb $SO_2/10^6$ BTU level specified by the current NSPS for coal-fired steam generators;
- Many Southern Appalachian, Alabama, or Western coals are capable of meeting the current NSPS coal fired steam generators, either as-mined or after cleaning;
- Emission regulations which specify emission limits below about 1.0 lb $SO_2/10^6$ BTU preclude the use of physically cleaned high sulfur coal for compliance with these regulations. This is a consequence of the high organic sulfur contents of these coals and the fine-sized pyrite which cannot be removed by PCC;
- Emission regulations which specify ng SO_2/J reduction requirements of 25 percent can usually be met by coal cleaning. A percentage reduction above 30 percent will preclude the burning of some low sulfur coals using coal cleaning as the sole control technology. The percentage of sulfur which can be removed from U.S. coals by PCC is directly proportional to the ratio of pyritic to total sulfur. Rarely can sufficient pyrite be removed from low sulfur coals to achieve a total sulfur reduction above 30 percent; and
- Emission regulations which specify any combination of emission limit below 500 ng SO_2/J and sulfur reduction above 30 percent will essentially eliminate PCC as a single control technology for compliance. For these types of regulations, PCC must be used in conjunction with some other control technology such as wet limestone scrubbing or dry scrubbing.

1.2.2.1 Low-Sulfur Coal Candidates--

A set of low-sulfur coals is presented as representative of candidate naturally-occurring coals. The candidates are: bituminous coal from Buchanan, Virginia; subbituminous coal from Gillette, Wyoming; bituminous coal from Las Animas, Colorado; lignite from Williston, North Dakota; bituminous coal from Rock Springs, Wyoming; and subbituminous coal from Gallup, New Mexico. The ultimate and proximate analyses of these coals are shown in Table 1-6.

The mineable U.S. coal reserves that are "low-sulfur"---not exceeding approximately one percent sulfur---are distributed among the major coal ranks as follows: 38 billion metric tons of bituminous coal, 26 percent of which is surface mineable; 146 billion metric tons of subbituminous, 38 percent of which is surface mineable; and 9 billion metric tons of lignite, all of which is surface mineable (see Tables 2-2 to 2-4). East of the Mississippi, 14 percent of the total mineable reserves of 176 billion metric tons is low-sulfur, 20 percent of which is surface mineable;[7] in the West, 71 percent of the total reserves of 234 billion metric tons is low-sulfur, 40 percent being surface mineable.[8] Anthracite coal has not been included . Mining losses are generally approximated as 50 percent for underground mining, and 20 percent for surface mining.

To evaluate low-sulfur reserves in terms of SO_2 standards, it is more meaningful to describe reserves in terms of ng SO_2/J than in terms of percent sulfur. According to these estimates--based upon an overlay of Bureau of Mines reserves and analytical data--about eight percent of the total U.S. reserves by weight can meet a control level of 215 ng SO_2/J, 48 percent can meet a standard of 650 ng/J, and 68 percent can meet the least stringent control level considered in this report--1,290 ng/J.

1.2.2.2 Physical Coal Cleaning Candidates--

The physical coal cleaning control technology is presented as five general process levels, with level five being the most sophisticated and level one the simplest. Coal preparation levels 1 and 2 can be used to accomplish ash reduction with corresponding high weight yields and energy

TABLE 1-6 CHARACTERISTICS OF CANDIDATE LOW-SULFUR COALS

	Low-Sulfur Coals					
	Buchanan, Va. (B)*	Los Animas, Colo. (SB)*	Williston, N. Dak. (L)	Rock Springs, Wyo. (SB)	Gillette, Wyo. (SB)	Gallup, N.M. (SB)
Heating Value						
10^3 KJ/Kg	31.7	26.3	16.3	26.7	19.8	23.3
(Btu/lb)	(13,620)	(11,290)	(7,000)	(11,500)	(8,500)	(10,000)
Sulfur Content						
% Total	1.18	0.59	0.80	0.80	0.70	0.80
Ash Content						
%	10.38	24.81	6.8	9.0	8.1	9.4
Moisture % as received	2.0	2.5	35	11	30	10
Volatile Matter %	13	12	12	15	29	19
Fixed Carbon %	75	62	46	65	33	62
Hydrogen %	4.8	3.9	6.2	5.0	4.5	5.0
Oxygen %	5.9	6.1	39	21.5	27.9	21.5
Nitrogen %	1.4	1.2	.70	.10	.75	1.0

Note: B = Bituminous; SB = Subbituminous; L = Lignite.
* These coals are analyzed as candidates for coal cleaning.

recovery but very little sulfur reduction. Levels 3, 4 and particularly 5 achieve large reductions in sulfur and SO_2 per unit heating value, but with decreased yields and energy recovery. This reflects the necessity for greater physical processing of the coal to achieve rejection of pyritic sulfur at the expense of rejecting larger amounts of coal. Thus, the design of physical coal cleaning processes for sulfur removal is a carefully balanced trade-off between sulfur reduction and energy recovery.

Table 1-7 presents a general performance summary of physical coal cleaning processes by the level of cleaning based upon a high sulfur Eastern coal. The performance characteristics shown in this table are averages developed from published values and do not reflect actual performance on a specific coal. The quantification of the performance of a physical coal cleaning process on a reference coal can only be achieved by the design of a detailed process flowsheet involving mass balance calculations of the various sizes of the coal. The mass balance calculations are based upon actual equipment performance factors for specific pieces of equipment designated by the process flowsheet. This type of performance data is obtained only after a series of engineering calculations are made and operating variable tradeoffs are considered for the process.

This report contains detailed physical coal cleaning flowsheets developed for each of the three representative coals. For example, the flowsheet designed for the high-sulfur Eastern coal uses a heavy media vessel to effectively separate the coarse-size coal into a product stream and a refuse stream. The intermediate-sized material is routed to a dual-stage heavy media cyclone circuit to produce a "deep cleaned" product from the first stage and a middling product from the second stage. The fine sized material is routed to a hydrocyclone circuit for cleaning and coal recovery. The clean coal product from this circuit is blended with other products to form the middling product. The mass balanced flowsheet for this two product level 5 plant is illustrated in Figure 1-2. Similar mass balanced flowsheets were developed for each of the reference coals. Table 1-8 is a summary of the performance of the selected physical coal

TABLE 1-7. SUMMARY OF PERFORMANCE OF PHYSICAL COAL CLEANING PROCESSES BY LEVEL OF CLEANING BASED UPON HIGH SULFUR EASTERN COAL (Upper Freeport Seam)

		LEVEL				5†	
Coal Parameter	Raw Coal	1	2	3	4	5a	5b
Weight % Ash in Product	23.90	22.5	20.0	11.5	7.6	5.80	11.31
Weight % Sulfur in Product	3.45	3.45	3.0	1.89	1.3	1.08	1.69
Heating Value kJ/kg (BTU/lb)	26,772 (11,510)	27,586 (11,860)	28,517 (12,260)	31,520 (13,551)	32,564 (14,000)	33,555 (14,426)	31,662 (13,612)
Net Coal Yield Metric ton/hr (tons/hr)	544 (600)	533 (588)	505 (557)	398 (439)	381 (420)	192 (212)	206 (228)
Yield - Weight %	100	98	93	73	70	35.3	38
Recovery - % Energy Value	100	97	94	85	82	43.4	44
ng/SO_2/J (lb SO_2/10^6 BTU)	2,576 (5.99)	2463 (5.73)	2102 (4.89)	1199 (2.79)	795 (1.85)	645 (1.5)	1075 (2.5)
Weight % Sulfur Reduction	-----	0	15	45	62	68	50
Weight % Ash Reduction	-----	6	16	52	68	75	52
% ng SO_2/J Reduction	-----	4	18	53	69	75	58

† 5a - Deep Cleaned Product 5b - Middlings Product

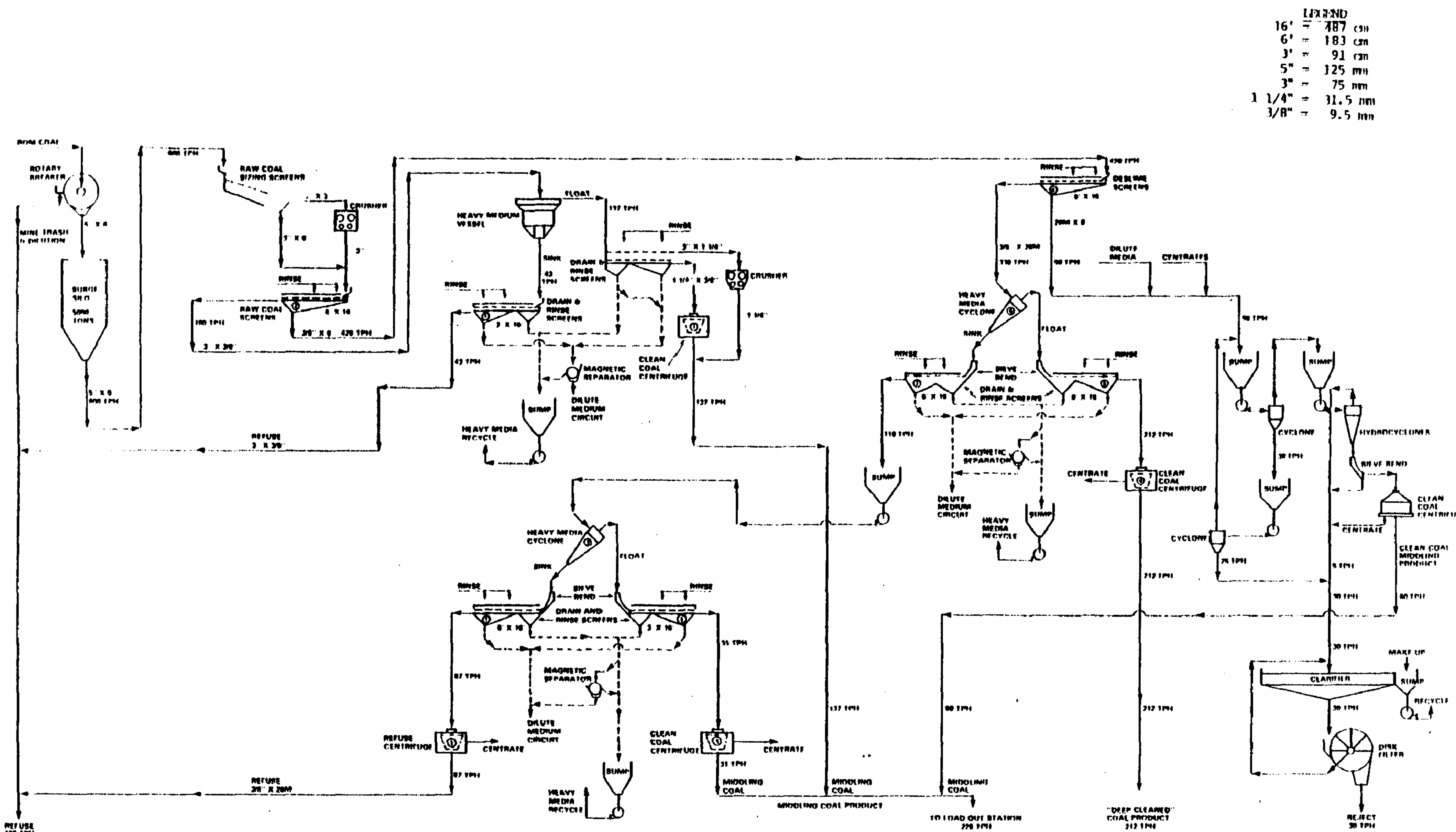

Figure 1-2. A LEVEL 5 COAL PREPARATION FLOWSHEET FOR BENEFICIATION OF A HIGH SULFUR EASTERN COAL (UPPER FREEPORT SEAM) FOR STEAM FUEL PURPOSES.

TABLE 1-8. PERFORMANCE SUMMARY OF CANDIDATE PHYSICAL COAL CLEANING BSERs FOR THE REFERENCE COALS

			High-Sulfur Eastern Coal			Low-Sulfur Eastern Coal		Low-Sulfur Western Coal	
			Raw Coal	Deep-Cleaned Pdt	Middling Pdt	Raw Coal	Product Coal	Raw Coal	Product Coal
Proximate Analysis	As-Received	Moisture, %	5.0	9.0	8.89	2.0	7.47	2.5	7.22
		Ash, %	22.23	5.28	10.30	10.17	3.82	24.19	15.31
		Total S, %	3.23	0.98	1.54	1.16	0.82	0.58	0.60
		Pyritic S, %	2.65	-	-	0.59	-	0.29	-
		HV,kJ/kg	25,940	30,533	28,847	31,052	31,352	25,614	27,093
		HV,BTU/lb	11,152	13,127	12,402	13,350	13,479	11,012	11,648
	Dry Basis	Ash, %	23.90	5.80	11.31	10.38	4.13	24.81	16.50
		Total S, %	3.45	1.08	1.69	1.18	0.89	0.59	0.65
		Pyritic S, %	2.51	-	-	0.60	-	0.30	-
		HV,kJ/kg	26,772	33,555	31,662	31,685	33,883	26,268	29,201
		HV,BTU/lb	11,510	14,426	13,612	13,622	14,567	11,294	12,554
Performance Characteristics		ng SO_2/J ($lbs\ SO_2/10^6$ BTU)	2,576 (5.99)	643 (1.50)	1,067 (2.48)	744 (1.73)	524 (1.22)	447 (1.04)	442 (1.03)
		Weight Recovery, %	-	35.3	38.0	-	84	-	82
		Energy Recovery, %	-	43.4	44.1	-	90	-	91.2
		Sulfur Reduction, %	-	68.2	50.3	-	25	-	(6.5)*
		Ash Reduction, %	-	75.2	51.7	-	60	-	33.5
		SO_2/Heating Value, Reduction, %	-	74.2	57.1	-	29	-	1.0

* Sulfur content increases in product coal

cleaning processes on the reference coals. The reduction in the quantity of SO_2 per unit heating value is a good measure of the performance of the control technology. As shown in Table 1-8, a maximum 74% reduction can be achieved by the level 5 preparation plant on this high-sulfur Eastern coal, a 29% reduction can be achieved by the level 4 preparation plant on this low-sulfur Eastern coal. Comparisons made of the performance of selected physical coal cleaning processes on the reference coals to the performance on estimated average coals from respective regions shows a decrease of 30% in SO_2 emissions for the high sulfur coal and a decrease of 10% in SO_2 emissions for the low sulfur Eastern coal. The matrix shown below indicates the ability of the raw and physically cleaned coals to comply with the emission control levels.

SO_2 Emission Control Levels
ng SO_2/J (lb $SO_2/10^6$ BTU)

Coal	1,290 (3.0)	860 (2.0)	645 (1.5)	516 (1.2)
High-S Eastern	PCC level 5 Middlings	PCC level 5 "Deep Cleaned"	PCC level 5 "Deep Cleaned"	None
Low-S Eastern	Raw Coal PCC level 4	Raw Coal PCC level 4	PCC level 4	PCC level 4
Low-S Western	Raw Coal PCC level 3	Raw Coal PCC level 3	Raw Coal PCC level 3	Raw Coal PCC level 3

1.2.2.3 Chemical Coal Cleaning Candidates--

Among all chemical coal cleaning processes the TRW (Meyers) process is the most advanced. It has been evaluated in an 8 metric ton per day Reaction Test Unit (RTU). The process removes 80-96 percent of the pyritic sulfur from nominally 14 mesh top size coal. Thirty-two different coals have been tested: twenty-three from the Appalachian; six from the Interior; one from Western Interior and two Western coals.

Another option for the Meyers processing plant, which is attractive, is a combination physical and chemical cleaning operation (the Gravichem process). In this process, the run-of-mine coarse coal would first be treated in a physical coal cleaning separation system. The heavy fraction from the gravity separation system, consisting of about 40 to 50 percent of the total coal and containing high ash and high concentration of pyritic sulfur is then fed to the Meyers process which will yield a low sulfur product. The Gravichem process can produce an overall weight yield of about 80 percent on the run-of-mine coal, will reduce the pyritic sulfur content by 80 to 90 percent and has a 91 percent energy recovery.

Among the processes capable of removing pyritic and organic sulfur the ERDA process has one of the highest probabilities of technical success. The ERDA process is currently active and most technologies employed in this system have been already tested in other systems such as Ledgemont and TRW. The process is attractive because it is claimed to remove more than 90 percent of pyritic sulfur and up to 40% of organic sulfur in minus 200 mesh coals. Coals tested on a laboratory scale include Appalachian, Eastern Interior and Western.

Unfortunately, none of these processes are beyond the pilot scale stage of development and are probably 5 to 10 years from commercial status.

Performance of Chemical Coal Cleaning Systems on the High-Sulfur Eastern Coal

The clean coal data presented in Table 1-9 reflects the best level of performance that each of the candidate chemical coal cleaning processes (Meyers, ERDA, Gravichem) can attain when applied to the reference high sulfur Eastern coal. This performance is based upon percent reduction of the amount of sulfur dioxide per unit heating value produced during coal combustion. The ERDA process most effectively accomplishes SO_2 reduction from this particular coal. The clean coal product from the other processes produces SO_2 reductions in the same range of emission control levels as ERDA.

TABLE 1-9. PROCESS PERFORMANCE OF CANDIDATE CHEMICAL COAL CLEANING SYSTEMS FOR A HIGH SULFUR EASTERN COAL

	Feed	Product Coal From MEYERS PROCESS	Product Coal From ERDA Process	Product Coal From GRAVICHEM Process
Net Coal Yield, Metric Tons Per Day (Tons/Day)	7,250 (8,000)	6,532 (7,200)	6,532 (7,200)	5,792 (6,384)
Percent Energy Recovery	-	94	94	91
Percent Weight Yield	-	90	90	79.8
Weight % Sulfur in Product	3.45	0.89	0.73	0.89
Heating Value kJ/kg (BTU/lb.)	26,772 (11,510)	28,507 (12,256)	28,507 (12,256)	31,126 (13,382)
Emission Rate, ng SO_2/J (lb. $SO_2/10^6$ BTU)	2,576 (5.99)	623.4 (1.45)	511.6 (1.19)	571.8 (1.33)

Performance of Chemical Coal Cleaning Systems on a Low-Sulfur Eastern Coal

The process performance information for the candidate chemical coal cleaning processes on the low-sulfur Eastern coal is summarized in Table 1-10. Of the three processes Meyers, ERDA, and Gravichem; the ERDA process extracts inorganic and organic sulfur, resulting in the lowest level of SO_2 emissions of the three processes, 300 ng SO_2/J (0.70 lbs $SO_2/10^6$ BTU). However, all of these processes produce a clean coal product having less than 387 ng SO_2/J (0.90 lbs $SO_2/10^6$ BTU). Since Gravichem is the least costly of the three processes, it was chosen as the candidate for the best system of emission reduction.

Performance of Chemical Coal Cleaning Systems on the Low-Sulfur Western Coal

The effects of chemical coal cleaning on the low-sulfur Western coal are shown in Table 1-11. The ERDA process results in the lowest level of SO_2 emissions of the three processes, 181 ng SO_2/J (0.42 lbs $SO_2/10^6$ BTU). However, the naturally occurring low sulfur Western coal will comply with all the evaluated SO_2 emission control levels without chemical coal cleaning. The matrix shown below indicates the ability of chemically cleaned coals to comply with the most stringent emissions standards.

SO_2 EMISSION CONTROL LEVELS
ng SO_2/J (lb $SO_2/10^6$ BTU)

COAL	645 (1.5)	516 (1.2)
High-S Eastern	ERDA	ERDA
Low-S Eastern	Gravichem	Gravichem
Low-S Western	Gravichem	Gravichem

1.2.3 Costs of the "Best" Emission Control Systems

Section 4.0 of this report presents the costs for industrial boiler operators to comply with emission standards using naturally-occurring or cleaned coal. The coal characteristics which most directly affect the

TABLE 1-10. PROCESS PERFORMANCE OF CANDIDATE CHEMICAL COAL CLEANING SYSTEMS FOR A LOW SULFUR EASTERN COAL

	Feed	Product Coal From MEYERS PROCESS	Product Coal From ERDA Process	Product Coal From GRAVICHEM Process
Net Coal Yield, Metric Tons Per Day (Tons/Day)	7,250 (8,000)	6,532 (7,200)	6,532 (7,200)	5,792 (6,384)
Percent Energy Recovery	-	94	94	91
Percent Weight Yield	-	90	90	79.8
Weight % Sulfur In The Product	1.18	.64	.5	.64
Heating Value kJ/kg (BTU/lb)	31,685 (13,622)	33,092 (14,227)	33,092 (14,227)	36,132 (15,534)
Emission Value ng SO_2/J (lb. $SO_2/10^6$ BTU)	744.0 (1.73)	387.0 (0.90)	301 (0.701)	352.6 (0.824)

TABLE 1-11. PROCESS PERFORMANCE OF CANDIDATE CHEMICAL COAL CLEANING SYSTEMS FOR A LOW SULFUR WESTERN COAL

	Feed	Product Coal From MEYERS Process	Product Coal From ERDA Process	Product Coal From GRAVICHEM Process
Net Coal Yield, Metric Tons Per Day (Tons/Day)	7,250 (8,000)	6,532 (7,200)	6,532 (7,200)	5,792 (6,384)
Percent Energy Recovery	-	94	94	91
Percent Weight Yield	-	90	90	79.8
Weight % Sulfur in the Product	0.59	0.32	0.25	0.32
Heating Value kJ/kg (BTU/lb.)	26,270 (11,294)	27,437 (11,796)	27,437 (11,796)	29,959 (12,880)
Emission Value ng SO_2/J (lb. $SO_2/10^6$ BTU)	447 (1.04)	232 (0.54)	180.6 (0.42)	210.7 (0.49)

industrial boiler operator costs are heating value and ash content. These characteristics impact the coal price to the preparation plant operator, heating value recovery and refuse disposal costs. As noted in Section 1.1, Versar chose coals that differed slightly from those specified by PEDCo Environmental, Inc. Table 1-2 shows the slight difference in heating value and larger differences in ash contents for the three coals.

A comparison of the annual operating costs to the preparation plant and industrial boiler operators for the specified (i.e. PEDCo) and chosen (i.e. Versar) coals was performed to determine if the difference in coal characteristics significantly affected operator costs. Coal cleaning costs for beneficiating the low sulfur Western coal were not developed because the raw coal could meet even the most stringent control level. For the Eastern coals, where heating value differences between the specified and chosen raw coals were less than five percent and ash contents differed by about 50 percent, it was determined that the impact on boiler operator costs is less than one percent. This is well within the uncertainty cost range specified by PEDCo for boiler costs. Therefore, the cost values in this ITAR can be used, as presented, for comparisons with other ITAR's without concerns of inconsistency.

The alternate Western, low-sulfur bituminous coal was used in determining raw coal costs at the boiler instead of the specified Wyoming subbituminous coal. The boiler operator costs for this alternate coal were 15-20 percent higher than for the specified subbituminous coal. The increase costs, however, were partially offset by lower boiler capital cost charges and decreased fuel requirements on a weight basis. Based upon the PEDCo cost uncertainty estimate of 30 percent, we again believe the coal differences do not significantly affect the comparability of this ITAR to other similar studies.

Transportation costs are treated separately in the cost analyses, although transportation has a major impact on which coal type is used. This separate treatment was necessary because reference boiler locations were not specified for ITAR analysis. Transportation costs can be of the same order-of-magnitude as the raw coal costs, when the coal has to be transported any long distances.

The cost to the consumer for beneficiated high sulfur eastern coal in terms of \$/metric ton were \$26.40 for the middlings product and \$36.38 for the deep cleaned product (as compared to a cost of \$18.74/metric ton for ROM coal). For beneficiated low sulfur eastern coal the cost was \$41.68/ metric ton versus an ROM coal cost of \$31.97/metric ton. These costs expressed in $\$/10^6$ KJ are \$0.83 and \$1.19 for the middlings and deep cleaned coal products, respectively, compared to a ROM coal cost of \$0.70; and \$1.24 for the cleaned low sulfur eastern coal product versus \$1.01 for the ROM coal.

Annualized costs for using naturally occurring low-sulfur coals in the reference boilers were also studied. These costs were based upon the annualized costs generated by PEDCo Environmental, Inc. with the fuel cost for using each coal providing the cost differentials. A summary of the costs is provided in Table 1-12. The costs to the industrial boiler operator for using a low-sulfur coal do not differ by more than 10 percent regardless of coal type used. For the 8.8 MW boiler the values ranged from \$18.90/MW to \$22.26/MW and for the 117.2 MW boiler the annualized costs were as low as \$11.36/MW to a high value of \$14.02/MW. These values do not reflect differences in coal handling, ash handling and/or transportation.

Annualized costs for using physically and chemically cleaned coals in the reference boilers were also calculated. These costs are summarized in Table 1-13. The cost increase to the consumer for using beneficiated coal rather than ROM coal with no controls in terms of \$/MW(t) were calculated to be about \$1.00-\$1.80 for the high-sulfur eastern (deep cleaned product), \$0.50-\$1.00 for medium sulfur coal, and \$0.60-\$0.90 for low sulfur eastern coal, respectively. These annualized cost increases reflect an increase in fuel costs and fly ash disposal requirements with some decrease in bottom ash disposal costs.

The increased costs for using chemically cleaned coal were calculated to be about \$5.00/MW for high sulfur eastern coal and about \$1.50 for low sulfur eastern coal, respectively.

The results of costing the BSER technologies revealed two major findings. First, for high-sulfur eastern coal, physical coal cleaning is an exceptionally

TABLE 1-12. SUMMARY OF ANNUALIZED COST OF OPERATING INDUSTRIAL BOILERS USING LOW SULFUR COAL.

Standard Boilers (MW(t))	Source and $/MWh for Low Sulfur Coal Types†					
	Buchanan, Va.	Williston, N.D.	Gillette, Wyo.	Rock Springs, Wyo.	Las Animas, Co.	Gallup, N.M.
8.8	$ 20.34	$ 21.39	$ 20.94	$ 18.90	$ 19.38	$ 22.26
22	16.00	16.41	15.95	14.57	15.05	17.27
44	13.40	13.77	13.31	11.97	12.45	14.63
58.6	13.86	14.46	14.01	12.41	12.90	15.33
117.2	12.81	13.15	12.70	11.36	11.85	14.02
Compliance Limits ng SO_2/J	744	987	798	507	449	689
($lb/10^6$ BTU)	(1.73)	(2.23)	(1.65)	(1.18)	(1.04)	(1.60)

† Above costs reflect changes in fuel cost and energy content of the fuel. No cost corrections have been made to the PEDCo Environmental[3] values for additional coal handling, ash handling or transportation to the boiler.

TABLE 1-13. SUMMARY OF ANNUALIZED COST OF OPERATING INDUSTRIAL BOILERS USING BSER.

[Costs are in \$/MWh (t)]

High Sulfur Eastern Coal

Boiler Size/ MW	Emission Control Level (ng SO_2/J) Uncontrolled	1290	1075	860	645	516
8.8	21.17	21.43	21.43	22.17	22.17	26.19
22	16.59	16.83	16.83	17.65	17.65	21.61
44	13.56	14.37	14.37	15.12	15.12	19.13
58.6	13.95	14.97	14.97	15.72	15.72	19.74
117.2	12.79	13.81	13.81	14.56	14.56	18.57

Medium Sulfur Eastern Coal

Boiler Size/ MW	Emission Control Level (ng SO_2/J) Uncontrolled	1290	1075	860
22	16.07	16.23	16.60	16.60
117.2	12.72	13.36	13.73	13.73

Low Sulfur Eastern Coal

Boiler Size/ MW	Emission Control Level (ng SO_2/J) Uncontrolled	1290	1075	860	645	516
8.8	20.48	20.48	20.48	20.48	21.11	21.11
22	16.17	16.17	16.17	16.17	16.81	16.81
44	13.50	13.50	13.50	13.50	14.34	14.34
58.6	13.91	13.91	13.91	13.91	14.83	14.83
117.2	12.86	12.86	12.86	12.86	13.78	13.78

Low Sulfur Western Coal

The costs for low sulfur western coal as a BSER are relevant for emission control levels greater than 450 ng SO_2/J:

Boiler Size	Uncontrolled	Controlled *
8.8	21.39	21.76
22	16.81	17.18
44	13.74	14.71
56.8	14.10	15.13
117.2	12.95	14.15

* Reflects costs for particulate control and ash disposal

low cost control technology. That is, to meet moderate or SIP control levels, a 60% reduction in sulfur dioxide emissions per unit heating value can be obtained from one coal with a 1-8 percent increase in annualized boiler operating costs. To comply with an optional moderate (860 ng SO_2/J) or intermediate control level (645 ng SO_2/J), a 75% reduction in sulfur dioxide emissions is required for the high sulfur eastern coal and can be obtained with only 4-14 percent increase in operating costs. The stringent emission control levels cannot be met with physical coal cleaning. The higher cost to meet this emission control level is reflected in the almost 30 percent increase in operating costs using chemically cleaned coal versus raw coal. The costs developed in this report are specifically applicable to the coals being analyzed. Costs and performance for other coals will be different but will be of the same order-of-magnitude. The range in increased annualized costs reflects the sensitivity of increasing boiler sizes to fuel costs.

The second major finding is that physically and chemically cleaned low-sulfur Eastern coal can meet a stringent control level of 516 ng SO_2/J (1.2 lbs $SO_2/10^6$ BTU) at relatively low increase in costs to the industrial boiler operator (see Table 1-13). This increase in annual cost is as low as 3 percent or as high as 7 percent, dependent upon control technology and size of the boiler. Because chemical coal cleaning is still in the development stage, the future cost to the boiler operator for chemically cleaned coal may be different than the values presented in this analysis.

The costs analyses were compared to actual 1977 coal cleaning plant capital and operating costs to check the validity of this study. Using an annual inflation rate of 8 percent, the cleaning costs were found to be in correct range and conservatively high.

1.2.4 Energy Impact of the "Best" Emission Control Systems (Summary of Section 5.0)

The energy impact of the chosen best systems of emission reduction, were determined by: 1) evaluation of energy usage in the fuel cleaning processes, 2) evaluation of energy usage at the boiler, 3) evaluation of potential for energy savings, and 4) evaluation of energy impacts of boiler modification and fuel switching.

Energy consumption common to all systems is transportation of the coal from the origin to the industrial site. Variables which affect this are mode of transportation, distance between origin and destination, optimally available routes and composition of the delivered coal. Transportation energy could not be quantified in this analysis because industrial boiler locations were not specified. The major energy consumption factor for cleaned coal is the quantity of energy rejected in the processing of the coals as refuse. Energy consumption for the physical or chemical coal cleaning processes also results from crushing, dewatering, pumping and thermal drying, plus elevated temperature and pressure conditions in the chemical processes.

The evaluation of energy usage at the boiler includes particulate control (electrostatic precipitator or fabric filter) and the effects of coal characteristics on the energy requirements of particulate control.

In presenting total energy usages for the five standard boilers (8.8 MW, 22 MW, 44 MW, 58.6 MW, and 118 MW), all energy factors except transportation are considered. Total values are given in Section 5.0 for each control level in kilowatts as well as kilojoules per kilogram. Table 1-14 shows the increased energy percentages over the uncontrolled boiler for the various control technologies.

1.2.5 Environmental Impacts of "Best" Emission Control Systems

The environmental effects of the BSERs have been evaluated from two standpoints. Air, water and solid waste pollutants have been identified and quantified to the extent possible for the cleaning processes used. These pollutants have then been quantified on a unit weight of product coal basis from the chemical and physical cleaning plants. Separately, the emissions from the five reference boilers have been quantified on the basis of combustion of the raw coal (uncontrolled emissions) and combustion of the cleaned coal. The multimedia emissions of pollutants from the cleaning processes are aggregated and combined with the boiler emissions to allow the comparison of the uncontrolled emissions from the boiler to the emissions resulting from the combustion of cleaned coal.

TABLE 1-14. SUMMARY OF ENERGY IMPACTS OF CONTROL TECHNOLOGIES.

Coal Type	Control Technology	Increase in Energy Requirements Over Uncontrolled Boiler, % (Range)
High Sulfur Eastern	PCC-Level 5 Middling	16.3-16.6
	PCC-Level 5 Deep Cleaned	15.4-15.8
	CCC-ERDA	8.0
Medium Sulfur	Raw Coal	(3.0)
	PCC-Level 3	0.1
	CCC-ERDA	3.3
Low Sulfur Eastern	Raw Coal	0.4-0.7
	PCC-Level 4	11.9-12.1
	CCC-Gravichem	10.7-10.8
Low Sulfur	Raw Coal	0.6-0.9

In terms of air pollution impacts, the emissions of SO_2, particulates, NO_x, CO and hydrocarbons all show a decrease for the clean coal products versus the uncontrolled boiler emissions resulting from the raw coal. For example, with the reference high sulfur eastern coal, SO_2 emissions are reduced from 57 to 78 percent over the uncontrolled case, and particulates are reduced from 58 to 80 percent over the uncontrolled case depending upon the cleaned coal process used. There are also small decreases in NO_x, CO and hydrocarbons as a result of burning any cleaned coal. For the reference medium sulfur coal, the SO_2 emissions are reduced by 37 percent using PCC and 56 percent using CCC. Ash removal (i.e., particulate reduction) by PCC is 35 percent and for CCC is 25 percent.

For the reference low sulfur eastern coal, SO_2 emissions are reduced by 30 percent from the uncontrolled boiler case and particulates are reduced by 63 percent. For the reference low sulfur western coal no reduction of SO_2 or particulates is accomplished over the uncontrolled boiler case because both are based on raw coal.

In the area of water pollution impacts, the only pollutants generated are from the coal cleaning processes. Wastewater pollutants from physical coal cleaning plants include: total suspended solids (TSS), chemical oxygen demand (COD), total organic carbon (TOC), acidity or alkalinity (pH), calcium, sodium magnesium, and trace elements such as iron, zinc, copper, and manganese. The emissions of these pollutants from the coal cleaning facilities are quantified in Section 6 and Appendix G for the four reference coals and aggregated to the five reference boilers.

Quantities of solid waste have been estimated for each of the physical and chemical cleaning processes then added to the quantities of bottom ash and fly ash from the combustion of cleaned coal in the reference boilers. This appears to be the greatest environmental impact area in that the BSER physical and chemical processes produce over twice as much solid waste as the raw coal.

At the preparation plant about 25% of the raw coal is rejected as refuse. These large quantities of refuse could have significant environmental impacts. However, at the boiler site the production of solid waste during combustion is less for cleaned coal than for raw coal. Cleaning results in the reduction of the amount of solid waste in the form of fly ash and bottom ash by more than 50%. Although the amount of solid waste produced at the boiler is decreased, the overall effect of the BSER is an increase in the amount of solid waste produced.

1.3 SUMMARY OF BEST SYSTEMS OF EMISSION REDUCTION

The "best systems of SO_2 emission reduction," (BSERs) which permit compliance with the five alternative SO_2 emission standards are chosen based upon performance, cost, energy, and environmental factors with respect to the four reference coals. The matrix shown in Table 1-15 indicates the choice of the best systems of emission reduction--chosen among raw coals, alternative levels of PCC, and alternative types of CCC.

TABLE 1-15. BEST SYSTEMS OF EMISSION REDUCTION FOR FOUR CANDIDATE COALS AND FIVE SO_2 EMISSION CONTROL LEVELS

SO_2 Emission Control Levels
ng SO_2/J (lb $SO_2/10^6$ BTU)

Coal	Moderate 1,290 (3.0)	SIP 1,075 (2.5)	Optional Moderate 860 (2.0)	Intermediate 645 (1.5)	Stringent 516 (1.2)
High-S Eastern	PCC level 5 Middlings	PCC level 5 Middlings	PCC level 5 "Deep Cleaned"	PCC level 5 "Deep Cleaned"	CCC-ERDA
Medium-S Eastern	Raw Coal	PCC level 3	PCC level 3	CCC-ERDA	CCC-ERDA
Low-S Eastern	Raw Coal	Raw Coal	Raw Coal	PCC level 4	PCC level 4
Low-S Western	Raw Coal	Raw Coal	Raw Coal	Raw Coal	Raw Coal

SECTION 1.0

REFERENCES

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2. PEDco Environmental, Inc., Memorandum, August 18, 1978, File No. 33105.

3. Battelle Columbus Laboratory, Reserve Processing Assessment Methodology (RPAM Computer Model) 1978.

4. Cavallaro, J.A., Johnston, M.T. and Deurbrock, A.W., "Sulfur Reduction Potential of the Coals of the United States," U.S. Bureau of Mines, RI 8118 (1976).

5. Ibid.

6. Ibid.

7. U.S. Department of the Interior, Bureau of Mines. Information Circular/ 1975. p.5 and 7.

8. U.S. Department of the Interior, Information Circular 8693, "The Reserve Base of U.S. Coals by Sulfur Content." p. 7.

SECTION 2

EMISSION CONTROL TECHNIQUES

This chapter of the Individual Technology Assessment Report describes various aspects of three emission control technologies for the reduction of sulfur dioxide (SO_2) emissions from coal-fired industrial boilers. The common element among these control technologies is that the resultant product is a coal which, upon combustion in various types of industrial boilers, will result in reduced emission of sulfur dioxide from the stack than would occur with combustion of the raw coal. The three emission control technologies to be presented are:

- Use of naturally occurring low sulfur coal as an environmentally acceptable fuel to meet SO_2 emission control levels;
- Beneficiation of raw coal by physical coal cleaning processes to remove ash and pyritic sulfur minerals to produce an environmentally acceptable fuel for SO_2 emission control levels; and
- Beneficiation of raw coal by chemical coal cleaning processes to remove pyritic and organic sulfur plus ash minerals to produce an environmentally acceptable fuel for SO_2 emission control levels.

These three control technologies are not mutually exclusive. For example, beneficiation of naturally occurring low sulfur coal is quite possible, as are combinations of physical and chemical coal cleaning operations to produce various grades of coal products to meet SO_2 emission control levels. In general, combinations of these three control technologies are more expensive than the individual options, but the combinations are capable of producing more usable coal to meet a given SO_2 emission level.

This chapter describes each of these control technologies from the standpoint of their effectiveness and applicability to reduce SO_2 emissions based upon key fuel and process parameters, effects on flue gas composition, boiler type and size, and status of development. The section is divided into two major subsections. Subsection 2.1 describes qualitatively each of the control technologies and the aspects of each that influence their effectiveness in reducing SO_2 emissions. Subsection 2.2 describes the performance of each control technology with emphasis on the emission control capability, applicability and availability of the technology.

2.1 PRINCIPLES OF CONTROL FOR COAL-FIRED INDUSTRIAL BOILERS

Three possible SO_2 emission control technologies are summarized in this subsection; the use of naturally occurring low sulfur coal, physical coal cleaning, and chemical coal cleaning.

2.1.1 Selection of Naturally Occurring Low Sulfur Coal as an SO_2 Control Technology

2.1.1.1 General Description of Availability, Location and Chemical Analysis-- (1)

The quantity of in-place coals calculated under specified depth and thickness criteria is termed the reserve base by the Bureau of Mines. Criteria applied for thickness are 71 centimeters or more for bituminous coal and anthracite, and 152 centimeters or more for subbituminous coal and lignite. The maximum depth of all ranks except lignite is 305 meters. Only the lignite beds that can be mined by surface methods are included - generally those beds that occur at depths no greater than 36 meters. Some coalbeds that do not meet the depth and thickness criteria are included because they are presently being mined or could be mined commercially at this time.

Essentially, the reserve base refers to in-place coal that is technically and economically minable at this time. It is not a fixed quantity but one that will increase with discovery and additional development, decrease with mining and change if the criteria for its calculation are modified.

The proportion of coal that can be recovered from the reserve base is termed the reserve. Recoverability varies in a range from 40 to 90 percent according to the characteristics of the coalbed, the mining method, legal restraints and the restrictions placed upon mining a deposit because of natural and man-made features. Mining experience in the United States has indicated that, on a national basis, at least one-half of the in-place coals can be recovered.

The demonstrated coal reserve base of the United States on January 1, 1974, was estimated to total 396 billion metric tons (437 billion tons). This quantity is widely distributed geographically, with 46 percent occurring in western states and Alaska.

The sulfur content of United States coals also varies. While 46 percent of the total reserve base can be identified as low sulfur coal, which is generally acceptable as coal with less than 1 percent sulfur, 21 percent ranges between 1 percent and 3 percent in sulfur, and an additional 21 percent contains more than 3 percent sulfur. The sulfur content of 12 percent of the coal reserve base is unknown, largely because many coalbeds have not yet been mined.

Variations in the sulfur content of the demonstrated low sulfur coal reserve base for coal-producing states are shown in Tables 2-1, 2-2, 2-3 and 2-4. These data show that 84 percent of the coal reserve base with less than 1 percent sulfur occurs in states west of the Mississippi River. The bulk of the western coals are of a lower rank than the eastern coals, however, and, on a calorific basis, it is estimated that at least one-fifth of the nation's reserve of low sulfur coal is in the East.

Approximately 40 percent of the nation's low sulfur coal is amenable to surface mining, and the bulk of the low sulfur surface minable coal is in the West. Nevertheless, more than one-half of the western low sulfur reserve consists of underground minable, while only 16 percent can be obtained by surface mining.

With respect to rank, 22 percent of the coal with less than 1 percent sulfur is of high rank (anthracite and bituminous) and 78 percent is sub-bituminous and lignite. Of the high rank low sulfur coals, 82 percent is amenable to underground mining, while only 58 percent of the low rank coals can be obtained by underground mining.

TABLE 2-1 DEMONSTRATED RESERVE BASE OF LOW SULFUR BITUMINOUS COAL IN THE UNITED STATES ON JANUARY 1, 1974, BY POTENTIAL METHOD OF MINING[1]

(Million short tons)

SULFUR RANGE, PERCENT

UNDERGROUND

STATE	≤0.4	0.5-0.6	0.7-0.8	0.9-1.0
Alabama	12.9	110.7	239.4	226.3
Arkansas	.0	0.6	14.6	20.0
Colorado	463.5	1,998.8	953.0	278.5
Georgia	.0	.0	.0	0.3
Illinois	.0	172.0	304.4	558.3
Indiana	77.1	67.4	118.9	180.1
Iowa	0.4	0.3	0.4	0.5
Kentucky, East	19.2	944.3	2,326.1	1,753.1
Kentucky, West	.0	.0	.0	.0
Maryland	.0	25.5	35.8	45.2
Michigan	.0	.0	.0	4.6
Missouri	.0	.0	.0	.0
Montana	0.3	2.0	55.4	100.1
New Mexico	.0	961.0	469.3	33.0
North Carolina	.0	.0	.0	.0
Ohio	.0	9.1	37.5	68.9
Oklahoma	6.5	12.4	82.3	53.3
Pennsylvania	21.2	103.5	326.5	530.0
Tennessee	1.8	19.5	60.1	58.0
Utah	87.2	726.2	638.1	464.7
Virginia	51.4	480.9	646.5	497.3
Washington	108.8	36.3	21.4	12.5
West Virginia	229.2	2,923.5	4,948.8	2,985.1
Wyoming	287.0	302.2	325.0	318.1
Total *	1,366.4	8,895.9	11,603.3	8,187.6

SURFACE

STATE	≤0.4	0.5-0.6	0.7-0.8	0.9-1.0
Alabama	1.1	6.5	14.6	13.2
Alaska	633.3	375.8	149.3	42.3
Arkansas	.0	8.9	18.7	10.3
Colorado	325.3	169.4	122.6	106.9
Illinois	.0	14.7	20.7	25.0
Indiana	16.4	18.6	29.3	41.0
Kansas	.0	.0	.0	.0
Kentucky, East	6.7	283.9	712.9	512.3
Kentucky, West	.0	.0	.0	0.2
Maryland	.0	6.1	11.7	10.8
Michigan	.0	.0	.0	.0
Missouri	.0	.0	.0	.0
New Mexico	40.8	75.5	74.0	38.8
North Carolina	.0	.0	.0	.0
Ohio	.0	3.0	5.3	10.6
Oklahoma	6.2	44.2	30.2	39.9
Oregon	.0	0.1	0.1	0.1
Pennsylvania	2.2	7.0	17.2	29.1
Tennessee	1.1	11.2	30.4	22.9
Utah	1.0	17.4	15.9	18.0
Virginia	9.2	100.4	162.6	139.4
West Virginia	44.1	799.3	1,363.4	798.6
Total *	1,087.3	1,941.9	2,778.5	1,859.5

* Data may not add to totals shown due to rounding.

TABLE 2-2. DEMONSTRATED RESERVE BASE OF ANTHRACITE IN THE UNITED STATES ON JANUARY 1, 1974, BY POTENTIAL METHOD OF MINING [2]

(Million short tons)

UNDERGROUND					SURFACE				
Sulfur Range, Percent									
STATE	≤0.4	0.5-0.6	0.7-0.8	0.9-1.0	STATE	≤0.4	0.5-0.6	0.7-0.8	0.9-1.0
Arkansas	.0	.0	1.0	7.2	Pennsylvania	2.1	17.2	39.0	24.8
Colorado	4.4	9.4	12.1	1.5	Total *	2.1	17.2	39.0	24.8
New Mexico	.0	.0	.0	1.4					
Pennsylvania	153.7	1,157.9	2,774.0	2,113.0					
Virginia	3.1	13.2	24.3	11.8					
Total *	161.2	1,180.5	2,811.5	2,134.8					

* Data may not add to totals shown due to rounding.

TABLE 2-3 DEMONSTRATED RESERVE BASE OF SUBBITUMINOUS COAL IN THE UNITED STATES ON JANUARY 1, 1974, BY POTENTIAL METHOD OF MINING.(3)

(Million short tons)

UNDERGROUND					SURFACE				
Sulfur Range, Percent									
STATE	≤0.4	0.5-0.6	0.7-0.8	0.9-1.0	STATE	≤0.4	0.5-0.6	0.7-0.8	0.9-1.0
Alaska	2,147.3	1,084.4	587.0	262.1	Alaska	3,231.5	1,798.5	684.7	187.4
Colorado	957.0	845.5	893.5	334.2	Arizona	27.7	39.9	50.7	54.9
Montana	27,190.8	19,748.3	12,304.7	4,062.8	Montana	20,960.7	7,167.9	4,654.8	1,603.8
New Mexico	18.5	106.5	158.3	146.4	New Mexico	.0	327.4	556.3	568.4
Oregon	0.7	0.3	.0	.0	Oregon	.0	.0	0.1	0.1
Washington	12.4	63.9	72.8	102.9	Washington	1.8	45.6	56.2	63.0
Wyoming	12,391.2	2,629.6	2,809.0	1,657.5	Wyoming	3,304.3	2,561.6	3,482.6	3,844.4
Total *	42,717.8	24,478.5	16,825.4	6,565.8	Total *	27,526.0	11,940.8	9,485.4	6,321.9

* Data may not add to totals shown due to rounding.

TABLE 2-4 DEMONSTRATED RESERVE BASE OF LIGNITE IN THE UNITED STATES ON JANUARY 1, 1974, BY POTENTIAL METHOD OF MINING[4]

(Million short tons)

State	Surface			
	Sulfur Range, Percent			
	≤ 0.4	0.5-0.6	0.7-0.8	0.9-1.0
Alabama	.0	.0	.0	.0
Alaska	92.6	83.8	65.4	33.2
Arkansas	.0	.0	.0	.0
Montana	1,678.9	763.0	808.9	544.4
North Dakota	500.9	1,112.3	1,816.9	1,958.9
South Dakota	.0	24.3	37.6	41.2
Texas	29.8	45.5	396.4	188.1
Washington	.0	.0	5.9	.0
Total *	2,302.2	2,028.8	3,131.1	2,765.8

* Data may not add to totals shown due to rounding.

States with the largest quantities of coal with less than 1 percent sulfur are Alaska, Montana, and West Virginia. Montana, with an estimated reserve base of 92.5 billion metric tons (102 billion tons) of coals of this sulfur content, has 51 percent of the total, followed by West Virginia with 7 percent and Alaska with 6 percent. However, virtually all of the Montana and Alaska coals are of low rank, whereas all West Virginia coals are high rank bituminous.

Twenty-nine percent of the coal reserve base consists of coals with less than 0.7 percent sulfur and 17 percent has less than 0.5 percent. The bulk of these coals occur in the western states, principally in Montana and Alaska. However, 7.3 billion metric tons (8 billion tons), 6 percent of the reserve base of coals with less than 0.7 percent sulfur, occurs in the East.

Table 2-5 presents a listing of 21 representative low sulfur coal seam analyses from 10 states. The average sulfur analyses range from 0.3 percent to 1.0 percent while the heating values range from 10,670 to 14,440 BTU/lb. The last column in the table shows the quantity of SO_2 associated with each coal type.

2.1.1.2 Factors Affecting Selection of Low Sulfur Coal as an SO_2 Control Technology—

Conceptually, the use of naturally occurring low sulfur coal is the simplest SO_2 control technology that could be implemented by an industrial plant operating a coal-fired boiler. However, its general use will be governed by a number of considerations.

- Availability of supply to the industrial user;
- Total cost of the coal fired at the industrial boiler;
- Effects of the physical properties of the low sulfur coal on boiler operations;
- Legal constraints on the importation of low sulfur coal supplies from coal producing areas outside the industrial user geographical areas;
- Environmental constraints from the standpoint of both the opening of new mining areas in the western states and the effects of the form of the new source SO_2 regulations on quality of low sulfur coal which can be burned; and

TABLE 2-5. REPRESENTATIVE ANALYSES FOR LOW SULFUR COAL SEAMS ACTIVELY BEING MINED.

STATE	SEAM	COUNTY	MOISTURE %	VOLATILE MATTER %†	FIXED CARBON %†	ASH %†	SULFUR %†	BTU *†	LBS $SO_2/10^6$ BTU **
Alabama	Montevallo	Shelby	2.4	38.2	54.9	6.8	.6	14,000	.857
Colorado	C Seam	Delta	8.8	41.8	53.8	4.2	.5	13,570	.736
Colorado	E Seam	Gunnison	5.5	40.9	54.2	4.7	.5	13,820	.723
Colorado	Cameo	Mesa	7.4	38.5	50.7	10.6	.6	12,710	.944
Kentucky	High Splint	Harlan	4.1	38.9	55.9	5.0	.6	14,090	.851
Kentucky	No. 1-1/2	McCreary	4.4	38.9	55.5	5.4	.5	14,090	.709
Kentucky	Leatherwood	Letcher	4.6	35.6	58.1	6.3	.6	13,920	.862
Kentucky	Hazard No.4	Letcher	3.5	38.3	56.4	5.2	.7	14,240	.983
Montana	Rosebud	Rosebud	21.8	38.0	51.5	10.4	1.0	11,760	1.70
New Mexico	No. 8	San Juan	10.4	37.9	40.2	21.8	.7	10,670	1.31
New Mexico	York	Colfax	3.3	37.0	53.9	9.1	.5	13,600	.735
Pennsylvania	Middle Kittanning	Jefferson	4.2	32.7	62.1	5.0	.6	14,420	.832
Utah	Blind Canyon	Emery	4.8	44.6	48.0	7.2	.4	13,590	.588
Utah	Castle Gate D	Carbon	3.1	43.0	49.4	7.4	.3	13,390	.448
Utah	Hiawatha	Carbon	6.4	43.9	48.1	7.8	.7	13,150	1.06
Virginia	Cedar Grove	Buchanan	3.1	34.6	60.6	4.7	.4	14,640	.546
Virginia	Jawbone	Russell	1.0	29.1	51.4	19.5	.5	12,110	.825
West Virginia	Pocahontas No. 4	McDowell	3.1	18.5	73.6	7.7	.6	14 440	.831
Wyoming	Hanna No. 2	Carbon	11.1	44.4	49.2	6.3	.3	12,580	.476
Wyoming	Mayfield	Hot Springs	12.3	35.6	44.7	7.4	.4	10,970	.729
Wyoming	Monarch	Sheridan	21.0	42.2	51.9	5.7	.6	12,300	.975

† Values are expressed on a moisture free basis.

Conversion Factors

* BTU to kilojoules, multiply by 1.055.

** LB $SO_2/10^6$ BTU to nanogram/Joule (ng/J), multiply by 430.

- Increased energy use due to longer transportation distances between the mine and the user which will consume greater quantities of petroleum or coal for fuel.

All of these factors need to be carefully considered in order to evaluate this control technology against other possible control technologies. Subsequent sections of this ITAR will attempt to quantify some of these factors on a basis that can be used for comparison with other control technology options.

2.1.2 Selection of Physical Coal Cleaning as a SO_2 Control Technology

2.1.2.1 Unique Characteristics of Physical Coal Cleaning as an SO_2 Control Technology--

The objective of this Individual Technology Assessment Report (ITAR) is to summarize the capabilities of an individual technology - coal cleaning - in controlling sulfur dioxide emissions from industrial boilers. The program plan is intended to produce an ITAR which is directly comparable to ITARs generated for other (competing) control technologies, and which can be integrated with these other ITARs to produce the required Comprehensive Technology Assessment Report (CTAR).

This program plan is based upon three hypotheses: that each technology may be evaluated by an industrial boiler operator as an option for complying with applicable emission control level; that each technology represents an independent option; and that each technology is "individual", i.e., uniquely definable. However, coal cleaning as a technology is only partially consistent with these three hypotheses. First, coal cleaning is a commercial option (for both technical and institutional reasons) to the coal producer and not to the industrial boiler consumer. Second, coal cleaning is a comparatively low-cost pretreatment technology which enhances rather than precludes the application of other boiler-specific control technologies. Third, coal cleaning is in itself not one particular process; it is instead several fundamentally different technologies which may be applied sequentially or alternatively in various permutations.

This ITAR has been structured to be responsive to the program objective. However, direct comparison and/or integration with other control technologies must be conducted with caution and with appreciation of the unique characteristics of coal cleaning. This section illuminates these unique characteristics and the impact of these characteristics upon the structure and use of this ITAR.

Viewpoint of Industrial Boiler Operators

Coal cleaning is not an SO_2 control option that operators of industrial boilers can use directly in their facilities. A fundamental problem is the discrepancy between requirements per operating an efficient and economical coal cleaning plant (500 to several thousand tons of coal per hour) and typical industrial boiler coal requirements (less than ten tons per hour). The major recourse for the industrial boiler user is to specify a compliance clean coal. In contrast, the physical coal cleaning plant operator can produce a clean compliance coal and maximize energy recovery by producing several products of varying grades. An industrial boiler operator could not exploit this degree of design freedom since his interests are in a single coal product to feed his boiler.

The one fundamental difference between coal cleaning and most alternative control options is that coal cleaning does not require on-site implementation by the industrial boiler operator. An industrial boiler is typically a service function within a manufacturing operation, so management will look to the coal supplier to provide an acceptable fuel. There is an obvious reluctance to divert personnel and financial resources from basic manufacturing operations. Although industrial boiler operators would have some of the same institutional impediments for other control options, coal cleaning is a practical option because it is not technically tied to the boiler's operation (as other options are).

A second fundamental difference from other options is that the industrial coal consumer competes in the overall market for low sulfur coal or for cleaned coal with metallurgical and utility consumers. A rigorous economic evaluation of the coal cleaning option for this ITAR will then necessitate a realistic supply/demand study for the entire coal market, as opposed to a battery-limit cost analysis for other, boiler-specific, control options.

Also to be considered in coal cleaning are the costs developed in the ITAR, i.e., incremental costs associated with sulfur removal, ash removal, and BTU enhancement operations. The situation is quite different for boiler-specific control technologies, where virtually all of the control costs are added costs, specific to one type of pollutant control.

Relationships to Other Control Technologies

Since clean coal is a control technology for the industrial boiler feed (i.e., a pre-combustion option) it is quite different from combustion or post-combustion options which are closely integrated with each specific boiler facility. One important result is that the impact of coal cleaning on boiler operation is much less than for boiler-specific control options. The lack of any additional equipment requirements at the boiler facility obviates operational or maintenance concerns, except for possible second-order effects (both positive and negative) upon existing equipment.

More importantly, coal cleaning does not significantly affect the boiler operator's freedom to consider additional control options which may complement a cleaned coal fuel supply. Coal cleaning, accomplished by coal producers, does not compete for the boiler operator's capital budget, space availability, or manpower resources. Therefore, boiler-specific (combustion or post-combustion) control options can still receive full consideration whether or not cleaned coal has been selected as a feed.

Coal cleaning occupies a unique place in the spectrum of control options because its performance and cost characteristics can make other options more economically attractive. As an SO_2 control technology, coal cleaning can readily and cheaply (compared to other technologies) remove 30-50 percent of the sulfur in many coals. Therefore, one must address the serial application of coal cleaning and boiler-specific control technologies to evaluate the potential of significant overall cost savings as well as coal cleaning as an individual control technology.

The characterization of coal cleaning as a pre-combustion control technology results in another unique factor— the reduction of sulfur variability in the feed to the industrial boiler. As discussed in this ITAR, coal cleaning does effectively reduce the variability of sulfur content as well as the sulfur content itself. Variations of SO_2 emissions from industrial boilers are reduced when using cleaned coal as opposed to raw coal. The result may be that proposed emission standards will not require as large a variable allowance, or alternatively, that average sulfur content can be significantly closer to that allowed by emission standards.

Coal Cleaning: A Process Objective Rather Than a Technology

Coal cleaning is the generic name for all processes which remove inorganic impurities from coal, without significantly altering the chemical nature of the coal itself. Coal cleaning therefore is a process objective, and several widely-varying technologies have been applied to achieve this process objective. Each coal cleaning plant is a uniquely-tailored combination of different technologies (different unit operations) which is determined by the specific coal characteristics and by the commercially dictated processing objectives. The plant designer has latitude among alternative unit operations and in selecting the sequence of unit operations. Basically, a coal cleaning plant is a continuum of technologies rather than one distinct technology.

Overall process design philosophy in coal cleaning plants employs step-wise separations and beneficiations, with a goal of eventually treating small, precise fractions of the feed with the more sophisticated and specific unit operations. In this way, the least costly technologies are applied to large throughputs and the more costly to much smaller throughputs. A characteristic of this design philosophy is that multiple product streams evolve, each with its own set of size and purity properties.

In conventional cleaning plants supplying one or several large utility boilers, the separate product streams are blended prior to shipment, with the composite coal meeting the consumer's specifications. Within the context of supplying industrial boilers with relatively small quantities of relatively low-sulfur product, every opportunity exists for premium products to be segregated from the final blending operation and targeted for specialty markets. A full assessment will be made of the special advantages multi-product coal cleaning plants possess in satisfying both major objectives - maximum sulfur reduction and maximum heating value recovery - which are naturally conflicting objectives in a single-product plant.

Compared to other SO_2 control technologies, coal cleaning may be viewed as a mature technology. Many coal cleaning plants have been in operation for many years, and in fact, more than half of all the coal produced is prepared to some extent. However, the full technological potential of coal-cleaning has not been exploited commercially for two prime reasons. First, the historical incentive for cleaning coal has been the removal of ash; only recently has sulfur removal become important to coal producers. Second, the escalation of coal prices in the past few years has provided more economic margin and incentive to apply more sophisticated unit processes and plant designs. For these reasons, the sulfur-removal capabilities of coal cleaning extend beyond the demonstrated performance of older facilities.

Aside from process selection and plant design factors, other degrees of operational freedom exist within coal cleaning technology. The historical emphasis placed upon plant productivity at some expense of product quality may be shifted (with tighter product specifications and with higher pri es for cleaner products) by adjusting operating variables such as the speci fic gravity of separation in existing or new plants, and by placing new importance upon process and quality control. These options emphasize the tangible differences between coal cleaning and emerging technologies. The latter are still in developmental and scale-up stages, and therefore there is minimal freedom in control opportunities.

2.1.2.2 General Description of Historical Approach to Coal Cleaning Processes--

Coal preparation is a proven technology for upgrading raw coal by removal of associated impurities. Coal cleaning has progressed from early hand-picking practices for the removal of coarse refuse material to present technology capable of mechanically processing very fine coal. Technological advances were introduced with mechanization of the mines and were stimulated by more demanding market quality requirements and increased coal production rates.

Coal preparation provides control of the heating value and physical characteristics of coal. Depending upon the degree of preparation and the nature of the raw coal, cleaning processes generally produce a uniformly-sized product, remove excess moisture, reduce the sulfur and ash content, and increase the heating value of the coal. By removing potential pollutants such as sulfur-bearing minerals prior to combustion, coal cleaning can be an important means of meeting air quality control levels.

Until recently, the degree of preparation required for a particular coal was determined by the market. The physical upgrading of metallurgical coal has long been a necessity because the steel industry has such stringent standards. On the other hand, utility (steam) coal has to date been subject to less extensive preparation, although utility coal does require a relatively uniform size. The economic benefits accrued from deep cleaning, however, were not sufficient to justify additional preparation costs. With the establishment of rigid sulfur dioxide emission control levels for power generating plants in certain areas, there will be a growing demand for more complete cleaning of utility coal.

Current commercial coal preparation is limited to physical processes. There are over 460 physical coal cleaning plants which can handle over 360 million metric tons (400 million tons) of raw coal per year. The principal coal cleaning processes used today are oriented toward product standardization and ash reduction, with increased attention being placed on sulfur reduction as the demand for cleaner utility coal continues to grow.

Sulfur reduction by physical cleaning varies depending upon the distribution of sulfur forms in the coal. There are three general forms of sulfur found in coal: organic, pyritic, and sulfate sulfur. Sulfate sulfur is present in the smallest amount (0.1 percent by weight or less). The sulfate sulfur is usually water soluble, originating from in-situ pyrite oxidation, and can be removed by washing the coal. Mineral sulfur occurs in either of the two dimorphous forms of ferrous disulfude (FeS_2) - pyrite or marcasite. The two minerals have the same chemical composition, but have different crystalline forms. Sulfide sulfur occurs as individual particles (0.1 micron to 25 cm. in diameter) distributed through the coal matrix. Pyrite is a dense mineral (4.5 gm/cc) compared with bituminous coal (1.30 gm/cc) and is quite water-insoluble thus the best physical means of removal is by specific gravity separation. The organic sulfur is chemically-bonded to the organic carbon of the coal and cannot be removed unless the chemical bonds are broken. The amount of organic sulfur present defines the lowest limit to which a coal can be cleaned with respect to sulfur removal by physical methods. Chemical coal cleaning processes, currently in the developmental stage, are designed to attack and remove up to 40% of the organic sulfur. Physical cleaning typically can remove about 50 percent of the pyritic sulfur, although the actual removal depends on the washability of the coal, the unit processes employed and the separating density.

2.1.2.3 Principles of Design--

Washability Data Generation

The potential for improving the quality of a coal through physical coal cleaning is determined by a series of washability tests. To determine the preparation method and the equipment to be used to clean the coal, the preparation engineer must conduct physical and chemical tests to obtain washability data. The coal is split into subsamples by size and specific gravity distribution. For size distribution, the coal is put through a series of screens with decreasing mesh size. To determine the specific gravity distribution, the coal is sent through a series of vessels containing liquids of carefully controlled specific gravity. This is commonly termed float sink analysis. The specific gravity fractions are then analyzed for moisture, ash, heating value, pyritic and total sulfur, and other characteristics. This provides the desired washability data as shown below. The test procedure may embrace all or only some of the above characteristics, depending on the information required. Washability studies are conducted primarily to determine the yield and quality of clean coal produced at a given specific gravity. These data are for a specific coal at a specific size and are often presented in the following tabular format.[6]

EXAMPLE OF WASHABILITY DATA

		Individual Fractions			Cumulative Float		
Specific Gravity		Wt %	Ash %	Ash Prod.	Wt %	Ash Prod.	Ash %
SINK	FLOAT						
	1.27	34.5	2.8	96.6	34.5	96.6	2.8
1.27 x	1.30	28.4	3.9	110.8	62.9	207.4	3.3
1.30 x	1.38	16.9	8.8	148.7	79.8	356.1	4.5
1.38 x	1.50	5.4	16.9	91.3	85.2	447.4	5.3
1.50 x	1.70	3.3	30.6	101.0	88.5	548.4	6.2
1.70 x	1.90	3.0	46.2	138.6	91.5	687.0	7.5
1.90		8.5	71.3	606.1	100.0	1,293.1	12.9

Washability Curves

The washability results can be plotted in a number of ways to produce a set of curves which are characteristics of the coal (Figure 2-1 is an example of washability curves).[7]

The specific gravity curve shows the theoretical yield of washed product from the raw coal for any specific gravity of separation.

The cumulative-float ash curve indicates the theoretical percent of ash of any given yield of washed product.

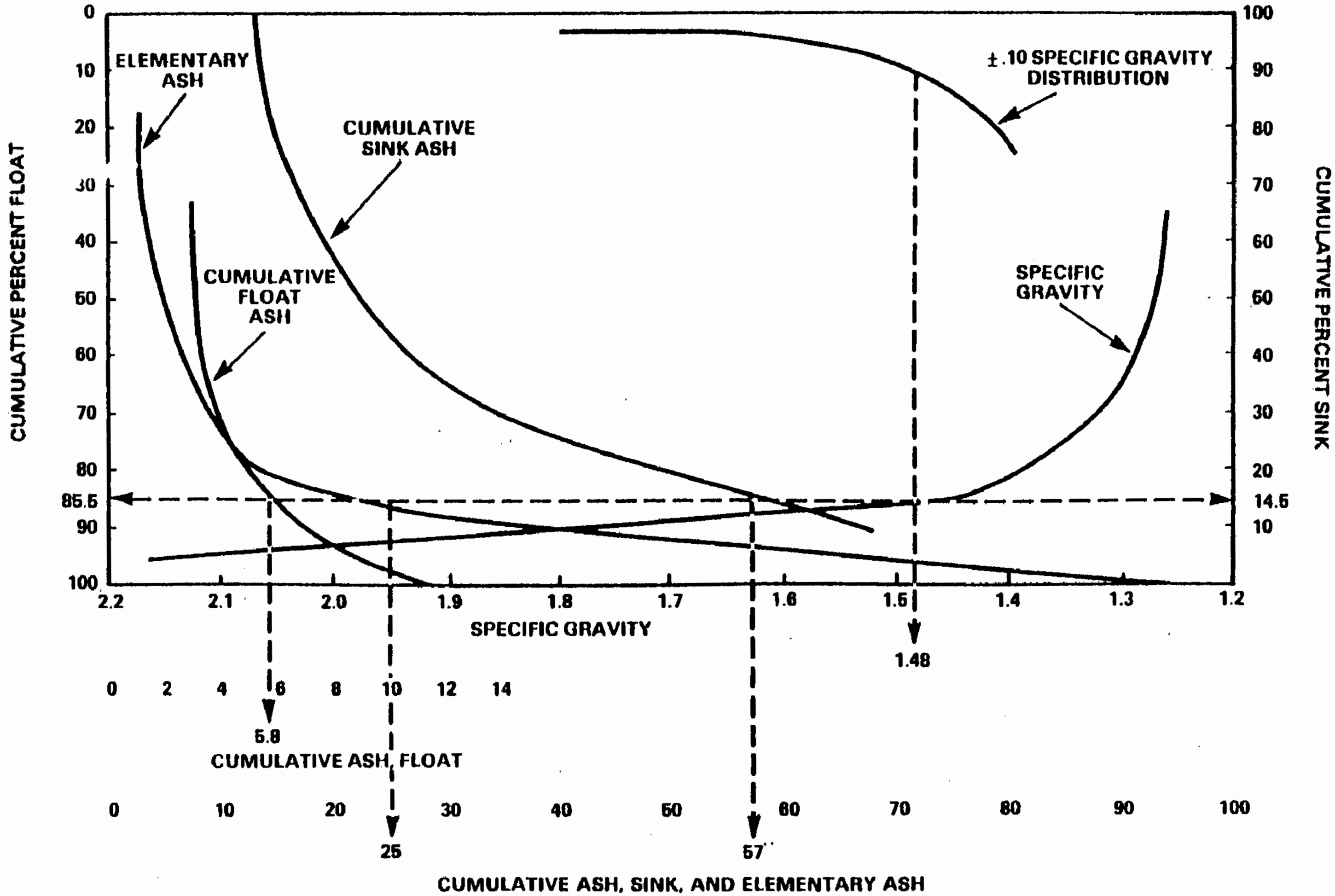


FIGURE 2-1 WASHABILITY CURVES

The cumulative-sink ash shows the theoretical ash content of the refuse at any yield of washed product.

The elementary-ash curve is a derivation of the cumulative percent ash in the float material and is intended to show the rate of change of the ash content at different specific gravities. The curve is designed to show the highest ash content of any individual particle that may be found in the float-coal product at any specific gravity.

The $\pm$ 0.10 specific-gravity distribution curve indicates the percentage (by weight) of the coal that lies within plus and minus 0.10 specific gravity units at any given specific gravity.

2.1.2.4 Recent Developments in Design for Pyritic Sulfur Removal Multi-Stream Coal Cleaning Strategy Approach--(8)

Intensive physical cleaning of amenable coals in a Multi-stream Coal Cleaning Strategy (MCCS) is a new technology to control the emissions of sulfur oxides from coal-fired boilers. The MCCS strategy is based on the separation of raw coal into three component streams. The first stream would consist of an intensively-cleaned, high BTU, low-ash and low-sulfur product. The second stream would be an intermediate sulfur and ash middling product suitable for use in existing units with moderate SIP control level which are permitted to burn intermediate sulfur coal. The third stream is a refuse stream.

A MCCS coal preparation facility is currently nearing completion on the Homer City Generating Station Power complex in Homer City, Pennsylvania. The coal preparation facility is partly owned by Pennsylvania Electric Company, a subsidiary of General Public Utilities Corporation, and New York State Electric and Gas Corporation. The coal preparation facility will process 4,720,000 metric tons (5,200,000 tons) of run-of-mine (ROM) coal per year, and has a design capability of processing 1,080 metric tons per hour (1,200 TPH). The facility will produce:

- A medium ash, medium sulfur coal for use in the two existing 600-MW units at the Homer City Power Plant which will meet existing federal and state emission regulations of 1,720 ng SO_2/J (4.0 lbs $SO_2/10^6$ BTU);
- A low ash, low sulfur coal to be utilized in the new 650-MW Unit #3 currently under construction which will comply with an emission control level of 516 ng SO_2/J (1.2 lbs $SO_2/10^6$ BTU) and;
- A high ash, high sulfur refuse product, which will be deposited in a refuse area approximately one mile north of the preparation plant.

2.1.2.5 Summary of Coal Cleaning Unit Operations--[9,10]

This section summarizes the major categories of unit operations used at most U.S. coal preparation plants. These operations include:

- Crushing and grinding;
- Screening;
- Coarse coal separation processes;
- Fine coal separation processes;
- Dewatering and drying;
- Refuse handling and disposal; and
- Storage and handling.

In a subsequent section, these unit operations will be arranged into coal preparation plant systems to demonstrate their performance in terms of sulfur reduction.

Crushing and Grinding

The initial operation performed on raw coal at most U.S. preparation plants is crushing. Crushing is a size reduction technique that is essential to an efficient, smooth-running cleaning process. The primary objectives of coal crushing are: (1) to reduce run-of-mine (ROM) coal to sizes which are acceptable by all cleaning and handling equipment and (2) to satisfy the demand for specific market sizes.

Crushing to a fine size range helps accomplish the task of releasing pyrite and other non-coal impurities, which can then be removed from the coal during cleaning. Coupled with these objectives is a desire to minimize the production of fine coal material during crushing. Modern crusher/grinder design has therefore been geared towards reducing the amount of this undersized material.

Crushing operations are broken down into two reduction levels, primary and secondary breakage. Primary breakage reduces raw coal to a top size of 10 to 20 cm. (4 to 8 in.). Incoming coal that is already smaller than the primary breaker product is usually screened out before entering the primary unit. This finer material can then either be sent on to further processing or simply routed around the breaker such that it joins up with the breaker product elsewhere. Product coal from primary breaking can be processed in one of two ways. Depending on product size, the coal will either be screened, and sent to further processing or it will be sent to secondary crushing units. Secondary crushing reduces raw coal to a top size of about 4.5 cm. (1 3/4 in.). Product material here is also sent to washing units and from there on to more intermediate cleaning processes.

Typical crushing equipment includes rotary breakers, single and double roll crushers, hammermills and ring crushers.

Screening

Raw coal screening is primarily a sizing operation. Two major reasons exist for the need of this sizing. They are: (1) to separate raw coal into different sizes for marketing purposes; (2) to furnish feed material to different types of washing units. Generally, screening allows raw coal to be sized so that it is able to be incorporated into the processing operations of other plant equipment.

The requirements for the type, number and style of screens that a plant will use is dependent upon the following:

- nature of the feed coal;
- type of mining employed;
- total coal tonnage;
- crushing demands;
- types of cleaning processes used;
- product specifications; and
- availability of water.

creen sizing operations also have the function of helping provide for the aximum recovery of coal in the preparation plant.

Coarse Coal Separation Processes

The basis for these processes is the difference in specific gravities xhibited by raw coal and its impurities. The term coarse here only refers o particle size [usually greater than 3.8 cm. (1 1/2 in.)]. These specific ravity differences allow the particles in the coal feed stream to stratify ut. One major piece of equipment used for this purpose is a jig. Jigs ccomplish stratification by a series of repeated expansions and contractions f a particle bed. Pulsating fluids, air,or water provide the means for the xpansion and contraction strokes of the stratification. Once stratification f coal and impurities is attained, another jig mechanism performs the task f separating the layers.

A second machine used to accomplish separation is a heavy media vessel. ere the coal and impurities are separated by immersion into a liquid with a ontrolled specific gravity. Such vessels are extremely useful due to their bility to make precise separations on coarse material despite often high perentages of near gravity material (± 0.10 specific gravity range). For the leaning of intermediate and coarse sized coal, these devices are very efficient.

Fine Coal Separation Processes

The gravity separation of fine sized coal is accomplished by one or more f the following four processes: (1) by the use of heavy media cyclones; (2) by e use of concentrating tables; (3) by the use of hydrocyclones; and (4) by e use of froth flotation. Heavy media cyclones differentiate between coal and refuse by effecting low gravity separations. Particles with higher specific gravities are forced out of the feed stream and go off as refuse, while low gravity fine coal is efficiently recovered.

Since the 1960's, the use of concentrating tables has increased rapidly. Concentrating tables operate by flowing a slurry of fine coal and water over an inclined riffled surface. The surface then effects particle separation, by size and specific gravity, by rapid shaking. Coarse, heavy particles travel to the bottom of the table, while fine, light particles ascend to the top. The stratification achieved here between different size fractions of coal resembles that produced by a jig.

Hydrocylones separate coal and its impurities by accelerating the slurry stream in a radial manner. The acceleration causes both a centrifugal and gravitational force to act upon the stream. These forces produce separations between light and heavy materials which result in a clean coal product and refuse. Presently, hydrocyclones are used to clean 0.42 mm (0.16 in.) size coal and smaller, but sizes as coarse as 6.4 mm (0.25 in.) can be used. Low capital investment on a cost-per-ton basis, small space requirements relative to capacity, negligible maintenance and high pyritic sulfur removal are all advantages of hydrocyclones.

The last process, froth flotation, is employed in the separation of suspended coal solids. This separation occurs due to the selective adhesion to air bubbles by some coal particles and the concurrent adhesion to water by other particles. Such a separation of the usable coal particles from the coal impurities is accomplished by injecting finely distributed air bubbles throughout the coal-water slurry. Fine coal material present in the slurry then adheres to the air bubbles and is transported to the free surface of the pulp mixture. These air bubbles and the attached coal, generally known as froth, are then removed. The remaining waste materials stay in suspension and are eventually passed out through the cells.

A primary means of modifying both the air bubble and water adhesions of the coal is the addition of certain chemical reagents. These reagents can act by either enhancing the floating characteristics of coals (making them more hydrophobic) or by enhancing the wetting characteristics of the waste materials (making them more hydrophilic). Froth stabilization is another use for reagents. Stabilization allows more time for a higher removal of floated coal. Of the factors affecting froth flotation, the following are of major importance:

- coal particle size;
- oxidation and rank of coal;
- density of the pulp mixture;
- chemical characteristics of plant water;
- flotation reagents used; and
- flotation equipment used.

Dewatering and drying

Water in a coal product is as much a contaminant as ash or sulfur. For this reason mechanical dewatering is a major unit operation. Water in coal (1) reduces its heating value, (2) increases its transportation cost, (3) causes handling problems during product transport, and (4) lowers the possible coke and input yields of metallurgical coal. In addition to product coal dewatering, coal feed to some cleaning units is also subject to dewatering. The manner and efficiency with which these intermediate dewatering steps are carried out influence the difficulties encountered during final product dewatering. The problems with coal dewatering increase with increases in the surface area of the particles to be dewatered. Consequently, the finer the coal particles, the more severe the dewatering difficulties.

The equipment used for mechanical dewatering can be divided into two principal categories:

- those which do not produce a final product - hydrocyclones some screens, spiral classifiers and static thickeners (primary dewatering devices); and
- those which produce a final product - screens, filters, and centrifuges.

In addition to dewatering, thermal drying is also performed on coal in order to rid it of surface moisture. Thermal drying can be described as high-speed evaporation of this moisture. Drying is performed in order that (1) freezing is avoided, thereby reducing difficulties in handling, storage and transport, (2) high crushing capacity at the user is maintained, (3) heat loss due to evaporation during burning is reduced, i.e.,heat efficiency is increased, and (4) transportation costs will be lowered.

Presently, driers are divided into two types:

- direct heat, those in which the coal comes into direct contact with the thermal transfer agent; and
- indirect heat, those in which the coal does not come into contact with the thermal transfer agent.

A number of individual drying systems exist for both direct and indirect technologies.

Refuse Handling

Physical coal cleaning generates waste refuse in such quantities that without proper handling and removal, problems can arise. In order to maintain high product quality, plant cleaning equipment generally removes some refuse during processing. The problem then becomes the safe and efficient disposal of all separate refuse.

Coarse refuse handling presents few problems because the material is generally composed of rock and shale and is generated in the early stages of the preparation process. This material is generally hauled to an on-site refuse pile.

Intermediate and fine size refuse handling however is another story, particularly when the refuse is generated from wet processes. Some of these refuse slurries are very dilute, and current practice is to send these to a settling pond for treatment. Their ultimate disposal is on the refuse pile after being scooped out of the pond. In many modern plants, centrifuges, thickeners and vacuum filters are used to dewater the refuse slurries to such a degree that they can be handled by conveyor.

Refuse may be removed from a plant in a number of ways. However, the following are the most preferred: (1) use of a conveyor to deliver material from the prep plant to the disposal area, (2) use of trucks to carry material from storage bins directly to disposal site, (3) use of conveyor to ship refuse to a holding area where it is loaded into trucks and then sent to final disposal and (4) use of slurry to transport the mixture to disposal site by pipe.

Storage and Handling

The storage of both raw and cleaned coal is practiced because of the needs of the production and utilization sectors of the coal cleaning industry. The satisfaction of these needs generally tends to increase cleaning plant efficiency, i.e., increase production rates and lower the final product cost. The following advantages of performing some type of storage and handling operation are illustrative of how these objectives can best be reached: (1) storage can help distribute plant feed during the whole operation period, thereby improving plant efficiency; (2) storage helps facilitate a production schedule whereby more days with smaller crews are employed, thereby reducing overall costs; (3) storage allows independent operation of mine and preparation plants, thereby reducing cleaning interruptions due to a lack of raw coal; (4) storage provides the ability to meet increasing fluxes in product demand; and (5) storage allows for increased coal blending thereby enhancing the composition of feed material such that higher efficiencies are achieved by the cleaning equipment.

Typical storage and handling equipment includes loaders, movers, silos, bins and conveyors. The added cost of such equipment might be a deterrent to using storage. Other disadvantages to coal storage include possible oxidation and spontaneous combustion and coal degradation due to increased rehandling.

Levels of Cleaning

There are five general levels of coal preparation which are used in upgrading of raw coal. Each level includes one or more of the major categories of unit operations. Although the levels may oversimplify a complex technology, they seem to illustrate and identify the basic coal preparation principles.

Level 1 - Breaker for top size control and for the removal of coarse refuse.

Level 2 - Coarse benefication - where larger fractions of coal (plus 3/8 inch) are treated. The separated and untreated minus 3/8 inch portion of the coal is combined with the cleaned coarse coal for shipment.

Level 3 - Fine and coarse size benefication - where all the feed is wetted. Plus 28M is beneficated; 28M x 0 material is dewatered and either shipped with clean coal or discarded as refuse.

Level 4 - Very fine benefication - where all the feed is wetted and washed. Thermal drying of 1/4" x 0 fraction generally is required to limit moisture content.

Level 5 - Full beneficiation which consists of rigorous cleaning. It requires crushing the raw coal to much finer sizes and results in multistage cleaning and multiproduct operation. A plant optimized to remove both pyritic sulfur and ash from amenable coals would most likely be of this type.

2.1.2.6 Factors Affecting Selection of Physical Coal Cleaning as an SO_2 Control Technology--

Introduction

The discussion in Section 2.1.2.1 explained that physical coal cleaning is a technology implemented by the coal producer, and is not a control mechanism which may be directly selected or implemented by the operator of an industrial boiler. Therefore, there are two sets of selection factors to be considered - those applicable to coal producers, and those applicable to industrial boiler operators.

Factors Affecting Coal Producers

The only choice available to coal producers is whether or not to provide deep-cleaning facilities suitable for removing a significant percentage of the pyritic sulfur in the coal. Two factors influence this choice. First is the potential for pyrite removal, in each specific coal seam, as determined from washability tests. Coal seams vary with respect to the ease of pyrite liberation from the coal. Some coals contain primarily macroscopic pyritic sulfur; upon moderate size reduction of the coal, most of the pyrite may exist as discrete pyrite particles amenable to sharp separation from pyrite-free coal by float-and-sink techniques. Conversely, other coals contain much microscopic pyrite, of dimensions in the order of 0.01 millimeters, widely disseminated in the coal and therefore not liberated from the coal by conventional crushing techniques. The coal producer will, of course, not select physical coal cleaning sulfur removal technology for those coal reserves with poor washabilities. For those coal reserves which do have the potential for pyrite removal, the washability data determines how much clean coal can be recovered at any given specific gravity of separation and at any given degree of crushing (size fractio as well as what the difficulty of separation is (how much material lies in a narrow specific gravity band about the specific gravity of separation). To a large extent, the washability of the coal guides the choice of physical coal cleaning unit operations and equipment and their arrangement in a cleaning plant design.

The second factor influencing the choice of coal cleaning for sulfur removal is the demand from coal consumers. If steam coal consumers, triggered by SO_2 emission control levels, specify a low-sulfur coal product, the coal producers will meet this demand by selecting deep-cleaning technology, provided the market will pay the premium for cleaned coal. One complication in the supply/demand picture is that the industrial boiler demand is only a minor fraction (about 20 percent) of the total U.S. coal consumed.

Factors Affecting Industrial Boiler Operators

There are three major factors which the boiler operator will consider in his selection of cleaned coal as a control option vs. the alternative selection of a boiler-specific (e.g., combustion or post-combustion technology) control option:

- annualized costs of control alternatives;
- capital investment, installation, and operating responsibilities; and
- degree of risk in continued compliance with applicable emission control levels.

For an industrial boiler operator, the annual costs for the cleaned-coal control option are basically the price differential (on an as-delivered basis) between coal cleaned to meet the applicable SO_2 emission control level and coal not specifically cleaned for sulfur removal. This price differential would include the processing charges, charges for heating value lost to refuse by the coal processor, charges for transporting any excess moisture (arising from fine coal washing), and any boiler costs arising from excess moisture in the coal. There are potential boiler credits to be applied, however, for cleaned coal, which include a higher heating value on a dry basis, and lower ash handling charges.

The boiler operator would compare these direct operating costs for the cleaned-coal control option with annualized costs for alternative options. Costs of other boiler-specific options would include capital amortization costs and operating and maintenance costs.

The second factor relevant to selection of physically-cleaned coal is the reluctance of the industrial boiler operator to commit capital funds and installation and operating responsibility for meeting SO_2 emission control levels on a boiler which itself is a service to a primary manufacturing operation. If cleaned coal is a viable alternative at competitive annualized costs, it would be regarded as a direct replacement for oil or natural gas as an environmentally acceptable fuel.

The third important factor to the industrial boiler operator is his assurance of continued operation. For other site-specific control options, the boiler operator has direct control, but he also must be concerned with the reliability of equipment and with the performance of such equipment in meeting emission standards. For the cleaned-coal option, the boiler operator must rely on a continued supply of environmentally-usable fuel: i.e., cleaned coal that not only has a low-enough average sulfur content, but that also has a low-enough variation in sulfur content to meet the emission control levels.

2.1.3 Selection of Chemical Coal Cleaning as an SO_2 Control Technology

Chemical coal cleaning is one method theoretically capable of achieving low sulfur dioxide emissions resulting from coal combustion in industrial boilers. The chemical cleaning processes now in the development stage remove as much as 95 percent of the mineral sulfur and up to about 40 percent of the organic sulfur.

Presently there are about twenty-nine bench and pilot scale processes which chemically clean coal. From these twenty-nine, Versar, Inc. identified the eleven most important U.S.-developed processes in a study for the Industrial Environmental Research Laboratory of EPA.[11] The following paragraphs present technical overviews of these processes and their current developmental status. Chemical coal cleaning processes are still 5-10 years from commercial development.

2.1.3.1 General Description of Chemical Coal Cleaning Processes and Status of Development--

Table 2-6 gives a listing of the eleven major processes studied. The first four processes listed (Magnex, Syracuse, TRW, and Ledgemont) will remove pyritic sulfur only and the remaining seven processes (ERDA, GE, Battelle, JPL, IGT, KVB, and ARCO) claim to remove most of the pyritic sulfur and varying amounts of organic sulfur. The first two processes listed are unique in that the coal is chemically pretreated, then sulfur separation is subsequently achieved by mechanical or magnetic means. In the remaining nine processes the sulfur compounds in the coal are chemically attacked and converted.

MAGNEX PROCESS [12]

Pulverized (minus 14 mesh) coal is pretreated with iron pentacarbonyl in this process to render the mineral components of the coal magnetic. Separation of coal from pyrite and other mineral elements is then accomplished magnetically. The process has been proved on a 90.7 kilogram (200 lb)/hour pilot plant scale using the carbonyl on a once-through basis. The use of the iron carbonyl does present some difficulties from a health and safety standpoint. Approximately 40 coals, mostly of Appalachian

TABLE 2-6. SUMMARY OF MAJOR CHEMICAL COAL CLEANING PROCESSES

PROCESS & SPONSOR	METHOD	TYPE SULFUR REMOVED	STAGE OF DEVELOPMENT	PROBLEMS
"MAGNEX"℠, HAZEN RESEARCH INC., GOLDEN COLORADO	DRY PULVERIZED COAL TREATED WITH $FE(CO)_5$ CAUSES PYRITE TO BECOME MAGNETIC. MAGNETIC MATERIALS REMOVED MAGNETICALLY	UP TO 90% PYRITIC	BENCH & 91 KG/HR (200 LB/HR) PILOT PLANT OPERATED	DISPOSAL OF S-CONTAINING SOLID RESIDUES. CONTINUOUS RECYCLE OF CO TO PRODUCE $FE(CO)_5$ REQUIRES DEMONSTRATION
"SYRACUSE" SYRACUSE RESEARCH CORP., SYRACUSE, N.Y.	COAL IS COMMINUTED BY EXPOSURE TO NH_3 VAPOR; CONVENTIONAL PHYSICAL CLEANING SEPARATES COAL/ASH	50-70% PYRITIC	BENCH SCALE	DISPOSAL OF SULFUR CONTAINING RESIDUES.
"MEYERS", TRW, INC. REDONDO BEACH, CAL.	OXIDATIVE LEACHING USING $FE_2(SO_4)_3$ + OXYGEN IN WATER	90-95% PYRITIC	8 METRIC TON/DAY PDU FOR REACTION SYSTEM. LAB OR BENCH SCALE FOR OTHER PROCESS STEPS.	DISPOSAL OF ACIDIC $FESO_4$ & $CASO_4$, SULFUR EXTRACTION STEP REQUIRES DEMONSTRATION
"LOL" KENNECOTT COPPER CO. LEDGEMONT, MASS.	OXIDATIVE LEACHING USING O_2 AND WATER @ MODERATE TEMP. AND PRESSURE	90-95% PYRITIC	BENCH SCALE	DISPOSAL OF GYPSUM SLUDGE, ACID CORROSION OF REACTORS

TABLE 2-6. SUMMARY OF MAJOR CHEMICAL COAL CLEANING PROCESSES (Continued)

PROCESS & SPONSOR	METHOD	TYPE SULFUR REMOVED	STAGE OF DEVELOPMENT	PROBLEMS
"ERDA" (PERC) BRUCETON, PA.	AIR OXIDATION & WATER LEACHING @ HIGH TEMPERATURE AND PRESSURE	~95% PYRITIC; UP TO 40% ORGANIC	BENCH SCALE 11 KG/DAY (25 LB/DAY) CONTINUOUS UNIT UNDER CONSTRUCTION	GYPSUM SLUDGE DISPOSAL. ACID CORRROSION AT HIGH TEMPERATURES
"GE" GENERAL ELECTRIC CO., VALLEY FORGE, PA.	MICROWAVE TREATMENT OF COAL PERMEATED WITH NAOH SOLUTION CONVERTS SULFUR FORMS TO SOLUBLE SULFIDES	~75% TOTAL S	BENCH SCALE	PROCESS CONDITIONS NOT ESTABLISHED CAUSTIC REGENERATION PROCESS NOT ESTABLISHED.
"BATTELLE" LABORATORIES COLUMBUS, OHIO	MIXED ALKALI LEACHING	~95% PYRITIC; ~25-50% ORGANIC	9 KG/HR (20 LB/HR) MINI PILOT PLANT AND BENCH SCALE	CLOSED LOOP REGENERATION PROCESS UNPROVEN. RESIDUAL SODIUM IN COAL
"JPL" JET PROPULSION LABORATORY PASADENA, CAL.	CHLORINOLYSIS IN ORGANIC SOLVENT	~90% PYRITIC; UP TO 70% ORGANIC	LAB SCALE BUT PROCEEDING TO BENCH AND MINI PILOT PLANT	ENVIRONMENTAL PROBLEMS, CONVERSION OF HCL TO CL_2 NOT ESTABLISHED
"IGT" INSTITUTE OF GAS TECHNOLOGY CHICAGO, ILL.	OXIDATIVE PRETREATMENT FOLLOWED BY HYDRODESULFURIZATION AT 800°C	~95% PYRITIC; UP TO 85% ORGANIC	LAB AND BENCH	LOW BTU YIELD (<55%). CHANGE OF COAL MATRIX

TABLE 2-6. SUMMARY OF MAJOR CHEMICAL COAL CLEANING PROCESSES (Continued)

PROCESS & SPONSOR	METHOD	TYPE SULFUR REMOVED	STAGE OF DEVELOPMENT	PROBLEMS
"KVB" KVB, INC. TUSTIN, CAL.	SULFUR IS OXIDIZED IN NO_2-CONTAINING ATMOSPHERE. SULFATES ARE WASHED OUT.	~95% PYRITIC; TO 40% ORGANIC	LABORATORY	WASTE & POSSIBLY HEAVY METALS DISPOSAL; POSSIBLE EXPLOSION HAZARD VIA DRY OXIDATION.
"ARCO" ATLANTIC RICHFIELD COMPANY HARVEY, ILL.	TWO STAGE CHEMICAL OXIDATION PROCEDURE	~95% PYRITIC; SOME ORGANIC	CONTINUOUS 0.45 KG/HR (1 LB/HR) BENCH SCALE UNIT	UNKNOWN

origin, have been evaluated on a laboratory scale. For the most part, the process will produce coals which meet State Implementation Plan regulations for sulfur dioxide emissions of 1,030 ng SO_2/J (2.4 lb $SO_2/10^6$ BTU).

SYRACUSE PROCESS [13]

Coal of about 3.8 cm (1½") top size is chemically comminuted by exposure to moist ammonia vapor at intermediate pressure. After removing the ammonia, conventional physical coal cleaning then effects a separation of coal from pyrite and ash. Generally, 50-70% of pyritic sulfur can be removed from Appalachian and Eastern interior coals, producing coals which meet state regulations for sulfur dioxide emission. Currently, the stage of development is only bench scale, however, construction of a 36 metric ton (40 tons per day) pilot plant is being contemplated. No major technical problems are foreseen for this process other than potential problems involving scale-up to pilot plant size.

MEYERS' PROCESS [14]

The Meyers' Process, developed at TRW, is a chemical leaching process using ferric sulfate and sulfuric acid solution to remove pyritic sulfur from crushed coal. The leaching takes place at temperatures ranging from 50° to 130°C (120°-270°F); pressures from 1 to 10 atmospheres (15-150 psia) with a residence time of 1 to 16 hours. The final separation stages use an organic solvent for removal of elemental sulfur from the filtered clean coal.

The TRW Process is the only chemical coal cleaning process developed to the 7.25 metric ton/day (8 ton/day) pilot scale level. The current mode of operation is a pilot scale Reactor Test Unit (RTU). Only one part of the overall system, namely the leaching-regeneration operation, has received intensive laboratory study, and this is also the only process component incorporated in the RTU.

Chemical reaction data for a few 24-hour runs using minus 14 mesh coal indicate faster pyrite removal than with the bench scale reactors. Approximately fifty different coals have been extensively tested on a bench scale. The Meyers' Process is best applied to coals rich in pyritic sulfur; thus it is estimated that about one-third of Appalachian coal could be treated to sulfur contents of 0.6 to 0.9 percent to meet the sulfur dioxide emission requirements of current EPA NSPS. Process by-products are elemental sulfur, gypsum from waste water treatment, and a mixture of ferric and ferrous sulfate, with the latter presenting a possible disposal problem.

LEDGEMONT PROCESS [15]

The Ledgemont oxygen leaching process is based on the aqueous oxidation of pyritic sulfur in coal at moderately high temperatures and pressures. The process has been shown to remove more than 90% of the pyritic sulfur in coals of widely differing ranks, including lignite, bituminous coals, and anthracite, in bench-scale tests. However, little, if any, organic sulfur is removed by the process. The process became inactive in 1975 during divestiture of Peabody Coal Company by Kennecott Copper Co. Although not as well developed as the Meyers' Process, the Ledgemont Process is judged to be comparable in sulfur removal effectiveness.

The principal engineering problem in this process is the presence of corrosive dilute sulfuric acid, which may pose difficulties in construction material selection and in choosing means for pressure letdown. The process also has a potential environmental problem associated with the disposal of lime-gypsum-ferric hydroxide sludge which may contain leachable heavy metals.

ERDA (PERC) PROCESS [16], [17]

The Energy Research and Development Administration (ERDA) chemical coal cleaning process is currently under study at DOE's Pittsburgh Energy Research Center (PERC). The ERDA air and steam leaching process is similar to the Ledgemont oxygen/water process except that the process employs higher temperature and pressure to effect the removal of organic sulfur and uses air instead of oxygen. This process can remove more than 90% of the pyritic sulfur and up to 40% of the organic sulfur. The process uses minus 200 mesh coal. Coals tested on a laboratory scale include Appalachian, Eastern Interior and Western. The developer's claim is that using this process, an estimated 45 percent of the mines in the Eastern United States could produce environmentally acceptable boiler fuel in accordance with current EPA new source standards. Effort to date is on a 11 kg/day (25 lb/day) bench scale, but a mini-pilot plant is expected to start up soon. The problems associated with this process are engineering in nature. The major one is associated with the selection of materials for the unit construction. Severe corrosion problems can be expected in this process as the process generates dilute sulfuric acid which is highly corrosive at the operating temperatures and pressures.

GE MICROWAVE PROCESS [18],[19]

Ground coal (40 to 100 mesh) is wetted with sodium hydroxide solution and subjected to brief (∿30 sec.) irradiation with microwave energy in an inert atmosphere. After two such treatments, as much as 75-90% of the total sulfur is converted to sodium sulfide or polysulfide, which can be removed by washing. No significant coal degradation occurs. That portion of the process which recovers the sulfur values and regenerates the NaOH is conceptual. Work to date is in 100 gram (0.2 lb) quantities, but scale-up to 1 kg (2.2 lb) quantities is presently in progress. The process attacks both pyritic and organic sulfur, possibly at about the same rate. Appalachian and Eastern Interior coals having wide ranges of organic and pyritic sulfur contents have been tested with about equivalent success.

BATTELLE PROCESS [20],[21]

In this process, 70 percent minus 200 mesh coal is treated with aqueous sodium and calcium hydroxides at elevated temperatures and pressures, which removes nearly all pyritic sulfur and 25-50% of the organic sulfur. Test work on a bench and pre-pilot scale on Appalachian and Eastern

Interior coals has resulted in products which meet current EPA NSPS for sulfur dioxide emissions. This mini-pilot plant will have a capacity of 9 kg/hr (21 lb/hr.). The conceptualized process, using lime-carbon dioxide regeneration of the spent leachant, removes sulfur as hydrogen sulfides which is converted to elemental sulfur using a Stretford process.

There are, however, two major technical problems:

- The feasibility of the closed-loop caustic regeneration feature in a continuous process is as yet undemonstrated; and
- The products may contain excessive sodium residues, causing low melting slags and making the coal unuseable in conventional dry-bottom furnaces.

JPL PROCESS [22]

This process uses chlorine gas as an oxidizing agent in a solution containing trichlorethane to convert both pyritic and organic forms of sulfur in coal to sulfuric acid. Since removal of sulfur can approach the 75% level, without significant loss of coal or energy content, products should generally meet current EPA NSPS for sulfur dioxide emissions. To date, the process has been tested on a laboratory scale only on several Eastern Interior coals. However, the effort will progress to bench-scale and pre-pilot plant scale in the near future. There are some potential environmental problems with the process. The trichloroethane solvent is listed by EPA as a priority pollutant in terms of environmental effects.

IGT PROCESS [23]

This process uses atmospheric pressure and high temperatures to accomplish desulfurization of coal. These high temperatures [about 400°C (750°F) for pretreatment and 815°C (1,500°F) for hydrodesulfurization] cause considerable coal loss due to oxidation, hydrocarbon volatilization and coal gasification with subsequent loss of heating value. Experimental results have indicated an average energy recovery potential of 60% for this process. The treated product is essentially a carbon char with 80-90% of the total sulfur removed. Most of the experimental work to date has been accomplished with four selected bituminous coals with a size of plus 40 mesh. Present effort is on a lab and bench-scale level. The net energy recovery potential of the system and the change in the coal matrix by the process have been identified as possible severe problems for the IGT Process. The process must be developed to a stage where the process off-gas can be satisfactorily utilized for its energy and hydrogen content. If this cannot be technically and economically accomplished, the process will prove to be inefficient and too costly for commercialization.

KVB PROCESS [24]

This process is based upon selective oxidation of the sulfur constituents of the coal. Dry, coarsely ground coal (plus 20 mesh) is heated in the presence of nitrogen oxide gases for the removal of a portion of the coal sulfur as gaseous sulfur dioxide. The remaining reacted, non-gaseous sulfur compounds in coal are removed by water or caustic washing. The process has progressed through laboratory scale but is currently inactive due to lack of support. Laboratory experiments with five different bituminous coals indicate that the process has desulfurization potential of up to 63 percent of sulfur with basic dry oxidation and water washing treatment and up to 89 percent with dry oxidation followed by caustic and water washing. The washing steps also reduce the ash content of the coal.

In cases where dry oxidation alone could remove sufficient sulfur to meet the sulfur dioxide emission control levels, this technology may provide a very simple and inexpensive system. Potential problem areas for this syst m are:

- Oxygen concentration requirements in the treated gas exceed the explosion limits for coal dust, and thus the operation of this process may be hazardous.

- Nitrogen uptake by the coal structure will increase NO_x emission from combustion of the clean coal product.

ARCO PROCESS [25]

Little information is available on this process. It is presently in the pre-pilot plant stage of development and is alleged to remove both pyritic and organic sulfur. Bench-scale units are also being operated continuously at rates of 0.45 kg/hr (1 lb/hr). The process was wholly funded internally until recently when EPRI financed a study on six coals in which there was a wide distribution of pyrite particle size. Energy yield for the process is alleged to be 90-95%, and ash content can be reduced by as much as 50%.

2.1.3.2 Factors Affecting Selection of Chemical Coal Cleaning as an SO_2 Control Mechanism—

Chemical coal cleaning like physical coal cleaning is a pretreatment fuel technology. The large cleaning facilities can only be operated by the coal producer and are not a control option which may be directly implemented by the operator of an industrial boiler. Thus the factors affecting this technology option are the traditional barriers within the coal industry toward the emergence of a new technology. The current engineering status of these processes is a major barrier to their implementation by the coal producer, since only one process is developed to the pilot plant stage. The lack of pilot plant engineering data creates cost uncertainties for commercial plant development and intensifies investor wariness toward commiting capital. Other factors which will affect the use of chemically cleaned coal include the following:

- cost to the industrial user
- supply reliability to the industrial user
- combustion characteristics of the cleaned coal

2.2 CONTROL TECHNIQUES FOR COAL-FIRED INDUSTRIAL BOILERS

This section describes the three control technologies - low sulfur coal, physical coal cleaning and chemical coal cleaning - and presents existing data on control capabilities relative to sulfur dioxide emissions. The intent is to provide a general overview of each control technology from which rational decisions can be made on the Best Systems of Emission Reduction and on the control option levels in Section 3.0. For each control technology the status of development, the coal supply/demand, the applicability to industrial boilers, and the factors affecting control performance are discussed. In addition, related topics briefly presented are the impact of each coal on industrial boiler performance and retrofitting or modifying existing boilers.

2.2.1 Use of Naturally Occurring Low Sulfur Coal

2.2.1.1 System Description--

For the purposes of the ITAR, low sulfur coal will be defined as run-of-mine coal which can comply with a given emission control level. For general discussion where no emission control level has been delineated, coals with a sulfur content of less than one percent by weight (i.e. $< 1\%$ S) will be considered low sulfur coals.

Reserves and Locations

For each state the total estimated reserves for low sulfur coal were provided previously in Tables 2-1 through 2-4. Although these reserve estimations are currently being questioned by the Department of Energy, they present a useful overall picture of how low sulfur coals are distributed among the states. The largest reserves of the lowest-sulfur class ($\leq$ 0.7%) are those subbituminous coals found in Montana, followed by New Mexico and Wyoming, each with roughly 40 percent the weight of the reserves in Montana. Next are the higher quality bituminous coals of Colorado, West Virginia, and Alaska. Nearly 85 percent of all U.S. coal with one percent sulfur content or less is found west of the Mississippi.

While information about percent sulfur (by weight) is adequate for standards that specify percentage removal of sulfur, additional information is required for emission control levels expressed in units of mass of SO_2 removed per unit of input energy. For such control levels it is necessary also to specify 1) the heating value of the coal for each range of sulfur content and 2) the percentage of sulfur emitted as SO_2 in the flue gas during combustion of the coal. About 54 percent of the total reserve base by weight is found west of the Mississippi, but because of their generally lower heating values, the western coals contain less than 50 percent of the total heat content of all U.S. coals.

The percentage of fuel sulfur emitted as SO_2 during combustion is higher for bituminous coal than for subbituminous coal and lignites, because of the higher concentration of alkaline materials—particularly NaO_2—in the ash of the lower-rank coals. The emission factors listed in EPA's "Compilation of Air Pollutant Factors" imply a 95 percent release value for bituminous coal[26], and a range of 50 to 90 percent for lignite[27].

Current Industrial Demand and Supply

At the present time it is estimated that eight to twelve percent of the total energy consumed in the U.S. is attributable to the fuel burned in industrial boilers[28]. About ten percent of this fuel—41 million metric tons in 1975—is coal[29].

Several sets of legislative measures being considered by Congress are intended to provide incentives for increasing the percentage of coal burned in industrial boilers[30]. Included in these measures are: 1) the imposition of taxes for the use of oil and natural gas and 2) financial incentives associated with the use of coal. Without governmental incentives, the economics may not be favorable for coal-burning boilers, because of high plant investment, pollution control needs, and land requirements.

Table 2-7 lists those states in which industries burned a significant quantity of coal in 1975 for heat and power. For each state that is listed, the quantity and cost of "all fuels," and the quantity and cost of delivered "coal" are presented for each major industry (2-digit SIC Code). Since the quantities of "all fuels" and "coal" are expressed in different physical units, and it might be of interest to compare the two sets of quantities, we observe: 1) the quantity of "all fuels" is presented in physical units of billions of kilowatt hours, 2) the quantity of coal is presented in thousands of tons. If we assume that the overall average heating value of coal is 2.42×10^7 J/kg (10,400 BTU/lb), the unit for coal (10^3 tons) is equivalent to 10,400 BTU/lb x 2 x 10^6 lb/10^3 ton x 1 kWh/3,412 BTU = 6.092 x 10^6 kWh. Multiplying the quantity of coal presented in Table 2-7 (in 10^3 tons) by the conversion factor 6.096 x 10^6 kWh/10^3 tons will, therefore, yield quantities of coal in kWh, the physical unit used for all fuels. For example, the table indicates that, nationwide, all industries purchased "all fuels" equal to 2,936 x 10^9 kWh, and coal equal to 44,623 x 10^3 tons. Using the above conversion factor, the total quantity of coal in kWh is 44,623 x 10^3 tons x 6.096 x 10^6 kWh/10^3 tons = 272 x 10^9 kWh of purchased coal (somewhat less than 10 percent of the 2,936 x 10^9 kWh of all purchased fuels).

The information upon which Table 2-7 is based[31] indicates that ten states accounted for 60 percent of the total purchased fuel and purchased electricity in 1975. These states, in descending order of purchased energy, are:

1 - Texas
2 - Pennsylvania
3 - Ohio
4 - Louisiana
5 - California
6 - Illinois
7 - Michigan
8 - Indiana
9 - New York
10 - Tennessee

Table 2-7

PURCHASED FUELS (ALL FUEL AND COAL)
FOR STATES BY INDUSTRY GROUP[+]
(1975)

State[σ]	Code[∞]	Purchased Fuels: All Fuels: Kilowatt-hour Equivalent (billions)	Purchased Fuels: All Fuels: Total Cost (million $)	Purchased Fuels: Bituminous Coal, Lignite, and Anthracite: Quantity (1,000 short tons)	Purchased Fuels: Bituminous Coal, Lignite, and Anthracite: Cost (million $)
ALL INDUSTRIES, TOTAL		2,936.3	12,904.5	44,623.3	1,310.3
New York	TOTAL	97.7	581.8	2,161.6	69.6
	26	11.3	69.3	150.3	5.7
	28	15.7	82.2	769.2	22.7
	32	10.9	56.1	393.9	12.8
	33	15.3	102.4	33.0	1.1
	35	4.9	29.6	28.0	.9
	36	5.0	30.7	5.0	.2
New Jersey	TOTAL	76.5	514.7	39.4	1.2
	33	5.5	39.6	1.4	.1
Pennsylvania	TOTAL	221.7	1,208.8	5,310.1	155.7
	20	9.5	63.8	40.0	1.7
	22	3.0	20.6	18.2	.5
	23	1.0	7.0	5.9	.3
	24	1.7	11.3	7.0	.2
	25	.6	3.8	13.9	.5
	26	13.4	65.6	686.0	16.1
	28	14.3	72.0	719.3	17.7

Table 2-7 (continued)

PURCHASED FUELS (ALL FUEL AND COAL)
FOR STATES BY INDUSTRY GROUP[†]
(1975)

State[σ]	Code[∞]	Purchased Fuels: All Fuels: Kilowatt-hour Equivalent (billions)	Purchased Fuels: All Fuels: Total Cost (million $)	Purchased Fuels: Bituminous Coal, Lignite, and Anthracite: Quantity (1,000 short tons)	Purchased Fuels: Bituminous Coal, Lignite, and Anthracite: Cost (million $)
Pennsylvania (con't.)	29	10.1	44.7	221.4	5.6
	31	.6	2.5	36.4	.6
	32	28.4	121.8	1,680.3	43.3
	33	112.7	635.4	1,592.0	61.7
	34	7.1	44.6	19.6	.8
	35	5.1	32.3	11.2	.4
	36	4.0	22.8	56.1	1.6
	37	3.8	18.4	185.6	3.8
Ohio	TOTAL	203.5	1,040.0	6,642.2	197.4
	20	9.0	46.8	268.5	9.0
	24	.6	3.3	6.5	.2
	25	.6	3.1	4.6	.2
	26	11.9	54.2	1,076.1	34.0
	28	25.4	106.6	1,761.5	45.3
	30	9.8	45.2	622.7	16.9
	32	27.1	120.3	984.6	28.3
	33	78.5	467.5	1,182.2	37.1
	34	10.5	49.7	168.9	5.3

Table 2-7 (continued)

PURCHASED FUELS (ALL FUEL AND COAL)
FOR STATES BY INDUSTRY GROUP†
(1975)

State^σ	Code^∞	Purchased Fuels: All Fuels: Kilowatt-hour Equivalent (billions)	Purchased Fuels: All Fuels: Total Cost (million $)	Purchased Fuels: Bituminous Coal, Lignite, and Anthracite: Quantity (1,000 short tons)	Purchased Fuels: Bituminous Coal, Lignite, and Anthracite: Cost (million $)
Ohio (con't.)	35	8.9	44.1	153.1	5.4
	36	4.2	20.0	61.8	2.1
	37	7.9	39.4	272.7	10.9
	39	.6	2.7	18.3	.5
Indiana	TOTAL	111.1	509.7	2,289.9	68.0
	20	7.2	31.6	210.5	7.0
	24	.7	4.0	5.7	.2
	25	.6	2.6	16.5	.4
	26	2.2	10.2	127.1	3.9
	28	6.9	27.9	102.7	2.3
	30	2.5	11.3	103.3	3.1
	32	13.2	49.1	623.8	14.6
	34	4.6	19.5	60.5	2.0
	35	3.1	14.0	64.4	1.8
	36	4.3	17.9	231.7	6.4
	37	5.8	27.1	132.4	4.1
Illinois	TOTAL	146.9	684.8	2,582.1	66.9
	20	22.6	103.1	500.2	14.8

Table 2-7 (continued)

PURCHASED FUELS (ALL FUEL AND COAL)
FOR STATES BY INDUSTRY GROUP†
(1975)

State$^{\sigma}$	Code$^{\infty}$	Purchased Fuels: All Fuels: Kilowatt-hour Equivalent (billions)	Purchased Fuels: All Fuels: Total Cost (million $)	Purchased Fuels: Bituminous Coal, Lignite, and Anthracite: Quantity (1,000 short tons)	Purchased Fuels: Bituminous Coal, Lignite, and Anthracite: Cost (million $)
Illinois (con't.)	23	.4	2.0	.5	---
	26	6.7	27.5	373.7	8.9
	28	22.1	81.7	891.6	19.0
	32	13.5	54.4	467.4	14.5
	33	41.8	228.4	5.5	.2
	35	9.6	41.4	243.3	5.7
	36	4.8	22.2	8.8	.2
Michigan	TOTAL	125.3	617.5	3,882.8	132.7
	20	5.8	30.3	79.3	3.1
	26	13.0	59.7	492.4	16.3
	28	19.3	90.2	829.6	22.6
	32	15.1	65.5	1,147.9	36.2
	33	25.0	129.4	244.9	9.5
	34	7.6	37.3	66.2	2.5
	37	24.7	134.3	940.2	38.5
Wisconsin	TOTAL	60.7	270.8	1,667.7	55.3
	20	11.0	50.6	45.8	1.5
	26	24.1	103.2	1,494.8	49.7

Table 2-7 (continued)

PURCHASED FUELS (ALL FUEL AND COAL)
FOR STATES BY INDUSTRY GROUP†
(1975)

State[σ]	Code[∞]	Purchased Fuels: All Fuels: Kilowatt-hour Equivalent (billions)	Purchased Fuels: All Fuels: Total Cost (million $)	Purchased Fuels: Bituminous Coal, Lignite, and Anthracite: Quantity (1,000 short tons)	Purchased Fuels: Bituminous Coal, Lignite, and Anthracite: Cost (million $)
Wisconsin (con't.)	34	5.2	19.8	.9	---
	35	4.7	19.4	29.9	.8
Minnesota	TOTAL	33.8	145.4	554.2	9.1
	20	9.9	34.0	378.1	2.8
	26	8.5	35.1	147.7	5.1
Iowa	TOTAL	43.1	155.9	1,201.7	31.6
	20	15.2	55.6	510.7	13.7
	35	4.5	18.6	122.8	2.8
Missouri	TOTAL	42.2	173.2	1,545.2	38.8
	23	.2	1.2	2.0	.1
	28	6.6	25.5	253.3	6.5
	31	.1	.5	1.0	---
	32	14.7	56.6	1,236.8	30.9
Maryland	TOTAL	29.9	169.1	515.2	12.9
	32	5.3	23.8	213.7	5.5
Virginia	TOTAL	49.7	278.8	1,989.3	68.5
	20	2.6	16.2	1.1	.1
	21	1.2	7.2	21.0	.3

Table 2-7 (continued)

PURCHASED FUELS (ALL FUEL AND COAL)
FOR STATES BY INDUSTRY GROUP[+]
(1975)

State[σ]	Code[∞]	Purchased Fuels			
		All Fuels		Bituminous Coal, Lignite, and Anthracite	
		Kilowatt-hour Equivalent (billions)	Total Cost (million $)	Quantity (1,000 short tons)	Cost (million $)
Virginia (con't.)	22	3.9	21.5	167.0	6.6
	25	.5	3.2	25.3	1.1
	26	11.1	59.0	579.6	21.1
	28	17.4	92.6	946.1	30.8
	32	4.4	22.4	245.5	7.8
West Virginia	TOTAL	51.5	224.5	3,049.9	95.6
	28	22.6	89.5	1,755.5	50.1
	33	17.4	87.9	1,126.6	40.2
North Carolina	TOTAL	60.8	356.6	1,440.6	51.8
	21	2.0	10.9	137.6	4.9
	22	15.7	94.1	326.1	12.8
	25	1.2	7.8	31.2	1.4
	26	13.4	76.1	660.4	23.7
	32	5.8	26.7	100.9	2.7
South Carolina	TOTAL	46.2	223.9	1,209.9	43.5
	22	11.4	57.2	233.3	9.0
	26	9.9	54.1	77.9	3.0

Table 2-7 (continued)

PURCHASED FUELS (ALL FUEL AND COAL)
FOR STATES BY INDUSTRY GROUP†
(1975)

		Purchased Fuels			
		All Fuels		Bituminous Coal, Lignite, and Anthracite	
State[σ]	Code[∞]	Kilowatt-hour Equivalent (billions)	Total Cost (million $)	Quantity (1,000 short tons)	Cost (million $)
Georgia	TOTAL	54.5	243.8	550.3	16.9
	22	8.8	37.8	115.5	4.1
Kentucky	TOTAL	40.2	195.4	1,092.2	32.6
	20	3.3	13.7	77.1	2.7
	21	.8	3.7	23.8	1.0
	24	.6	3.5	2.9	.1
	28	8.4	31.8	579.9	15.8
	35	1.8	9.2	70.4	2.2
Tennessee	TOTAL	64.2	248.6	3,156.0	85.5
	20	4.2	17.2	9.0	.3
	28	31.7	109.7	2,430.1	66.5
	32	7.9	30.0	436.2	12.3
Alabama	TOTAL	72.0	286.9	1,334.6	32.7
	22	2.8	9.8	40.0	1.4
	23	.3	1.4	1.1	---
	26	19.7	78.7	699.9	18.2
	32	7.9	30.2	157.8	4.3
	33	19.5	79.2	28.8	1.0

Notes to Table 2-7

† Reference [33]

σ The states listed above are those for which there are quantity and cost data relating to deliveries of bituminous coal, lignite, and anthracite.

∞ Based on 2-digit Standard Industrial Classification (SIC) codes:

20 - Food and kindred products
21 - Tobacco products
22 - Textile mill products
23 - Apparel, other textile products
24 - Lumber and wood products
25 - Furniture and fixtures
26 - Paper and allied products
28 - Chemicals, allied products
29 - Petroleum and coal products
30 - Rubber, miscellaneous plastic products
31 - Leather, leather products
32 - Stone, clay, glass products
33 - Primary metal industries
34 - Fabricated metal products
35 - Machinery, except electric
36 - Electric, electronic equipment
37 - Transportation equipment
39 - Miscellaneous manufacturing industries

In forecasting the use of low sulfur coal as a compliance strategy for meeting SO_2 NSPS,[32] the estimates of the utility industry for new coal fired units were analyzed. Between 1977 and 1981, 134 new electric utility coal units are projected to come on line of which 111 will comply with an emission control level of 516 ng SO_2/J (1.2 lbs $SO_2/10^6$ BTU). Of these 111 units, 67 units plan to comply using low-sulfur coal, one unit will use "deep" cleaned coal (Pennsylvania Electric in Homer City), and the remaining 43 units will operate flue gas desulfurization systems (FGD). All 21 units that must comply with emissions control levels lower than 516 ng/J plan to use FGD. (Note: two of the planned units specify neither emission control levels nor compliance strategies.)

Using steam-coal deliveries to electric utilities as a reference, Table 2-8 presents July, 1978 delivered prices at electric utilities for low-sulfur steam coal from given sources. These delivered prices are generally lower than those paid by industrial users since 1) unlike electric utilities, industrial users--barring exceptionally large users or cooperative arrangements such as those being discussed among some large Texas industries--are not in a position to invest in unit-train cars (for which freight rates may be half those of single cars) and 2) industries more frequently buy their coal on the more expensive spot market rather than by term contracts as do most utilities.

Table 2-9 presents the quantity of coal shipped by coal-producing districts in 1975 to electric utilities, and to industrial users (excluding coke and gas plants, but including non-boiler industrial users of coal) and retail dealers. The table also gives average sulfur content of the coal. According to this table 21,070 metric tons, or 39 percent, of the total weight of coal shipped to industrial users and retail dealers was low sulfur coal (less than or equal to one percent by weight of sulfur).

User Acceptance of Low-Sulfur Coal

In this section we discuss the acceptability of using low sulfur coal as an alternative energy source for firing industrial boilers. According to Table 2-7 above, nine to ten percent of the energy purchased

Table 2-8

STEAM COAL PRICES, JULY 1978, FOR DELIVERED COAL, SULFUR ≤ 1% (36)

Source State and Source	Destination Station	% Sulfur	Quantity (tons)	Price ($/$10^6$ BTU
Kentucky:				
Vols	Wansley/GA Power	1.0	26,600	1.32
Buckhorn	"	0.6	24,400	1.86
Blue Grass #4	"	0.8	46,500	1.59
Alla Coal	Power Plant 65/MI State U.	0.7	4,200	1.59
	"	0.7	8,900	1.53
	"	0.9	8,500	1.50
Oklahoma:				
Designer	Transfer Facility, LA/Tampa Electric	0.8	6,900	1.29
Utah:				
Wattis	Rush Island, MO/ Union Electric	0.8	19,000	1.79
Wattis	Labadie, MO/Union Electric	0.8	11,000	1.72
Wattis	"	0.8	9,000	1.71
Virginia:				
V.I.C.C.	Urquhart/SC Electric and Gas	0.8	4,700	1.43
Washington:				
Centralia Coal Field	Centralia, WA/PPL	0.8	400,000	0.78

Table 2-9

SHIPMENTS OF BITUMINOUS COAL AND LIGNITE BY CONSUMER USE AND AVERAGE SULFUR CONTENT, 1975 [37]

District	Quantity Shipped (thousand short tons)		Average Sulfur Content (percent)	
	Electric Utilities	Industrial Users and Retail Dealers[σ]	Utilities	Industrial Users and Retail Dealers[σ]
Eastern Pennsylvania	37,244	3,827	2.1	2.0
Western Pennsylvania	9,931	4,743	2.2	1.7
Northern West Virginia	24,012	2,559	2.6	2.2
Ohio	41,437	4,812	3.5	3.2
Panhandle	6,931	308	4.1	3.4
Southern Numbered 1	136	4,072	.7	.6
Southern Numbered 2	88,910	13,882	1.2	.9
West Kentucky	53,489	2,598	3.8	3.1
Illinois	47,415	8,729	3.3	2.7
Indiana	21,242	3,832	3.4	3.6
Iowa	618	1	3.9	3.0
Southeastern	13,175	1,781	1.4	1.9
Arkansas-Oklahoma	12	214	1.0	2.0
Southwestern	16,771	2,410	2.6	1.7
Northern Colorado	215	244	.4	.4
Southern Colorado	4,491	402	.6	.7
New Mexico	14,755	1	.7	.5
Wyoming	20,973	2,459	.6	.7
Utah	3,523	1,428	.5	.6
North Dakota	7,615	691	.7	.6
Montana	21,226	827	.7	1.2
Washington	4,451	51	.5	.3
TOTAL[∞]	438,571	59,871	2.3	1.8

[σ] Excluding coke and gas plants.

[∞] Data may not add to totals shown due to independent rounding.

by industries in 1975 for heat and power came from coal. Despite the Administration's emphasis on burning coal rather than oil or gas and despite industry's concern about having a reliable source of fuel should gas and oil become unavailable, only about six percent of new industrial boilers' energy requirements in 1981-1985 are expected to be met with coal[34].

The reluctance to burn coal in industrial boilers stems mainly from the higher capital cost of these boilers as compared to gas- and oil-burning boilers. A field-erected, coal-fired boiler can cost ten times more than a package oil/gas-fired boiler [35]. Although the differential in fuel cost between coal and oil implies that this additional investment can be recouped (in some parts of the country in as little as three years), industrial companies generally 1) have difficulty raising the additional capital and 2) choose other fuels because they are interested in a relatively high return on their investment, not in merely breaking even.

In addition to the higher investment costs, other deterrents are coal handling and ash-handling, disposal of ash and possibly FGD residuals, and uncertainty about air pollution control requirements.

The attractive feature of coal is that its future supply appears more assured than does the supply of oil and gas. A number of companies, therefore, want their new boilers to have the capability to burn a variety of fuels, including coal. As a result, a sizable fraction of new industrial boilers are expected to consist of oil/gas-fired boilers with the capability to burn coal but without the coal-burning equipment. These units are larger than units that can burn only gas or oil and will cost about 30 percent more. When necessary or practical, they can be converted to coal by adding handling and burning equipment. These units will also have the capability of burning lower-quality oil and coal-derived oil or gas.

While in the long run coal is considered a more dependable fuel than oil or gas, the four-month coal strike that started in December 1977, and was accompanied by frozen coal piles, has raised questions about that dependability. Methods for preventing coal-pile freezing are being developed. While we cannot forecast the degree of stability of the coal labor market, we observe that coal-burning industrial units capable of burning oil/gas and also accessing oil/gas during the emergencies need not interrupt their operations during a coal strike.

Some kinds of coal-burning boilers cannot operate effectively with some types of coals. For example, traveling-grate spreader stokers can handle a wide range of coals from eastern bituminous to lignite. Fixed-bed stokers, however, cannot handle caking coals, such as the western subbituminous coals. Spreader stokers cannot handle coals with ash-fushion temperatures below 1200°C (220°F), which are generally found in western low-sulfur coals (e.g., the Wyoming subbituminous and Utah bituminous and the lignites).

Pulverized-coal boilers can be designed for almost any type of coal. The initial choice of coal will, however, determine the type of pulverizer used, the tube spacing in the boiler and superheater (low-fusion temperature coals require greater spacing), and the type of materials used in the furnace walls. Furthermore, electrostatic precipitators (ESP) will be less effective with low-sulfur coals because of their higher resistivity, since electricity is conducted within the fly ash matrix through gases, e.g., H_2O and SO_3 (or H_2SO_4), absorbed on the surface of fly ash particles.

The above discussion focuses on new industrial boilers. The prospects for converting present oil/gas-fired boilers to coal appear dim. The costs and losses in efficiency (up to two-thirds) would be prohibitive. When compared with oil/gas boilers, coal-burning boilers differ primarily by requiring 1) lower heat-release rates, 2) lower flue-gas velocities, and 3) larger tube spacings in the boiler and superheater. Coal's lower heat-release rate implies a longer residence time and, therefore, a larger furnace. Tube spacing that is too tight can lead to plugging—a serious problem.

As will be described in Section 4.1.1, the delivered price of low-sulfur coal is strongly dependent upon the transportation costs, which, in some cases, can exceed the f.o.b. mine cost. For example, the cost of transporting coal from Northern Wyoming to Texas is currently about two times the cost of the coal as mined in Northern Wyoming.

2.2.1.2 System Performance--

The available low sulfur coal reserves in each of six coal regions and the entire U.S. that meet various SO_2 emission control levels have been estimated by a technique called the Reserve Processing Assessment Methodology (RPAM).[38] This program involved a computer overlay of Bureau of Mines-coal reserve base data, coal washability data and a third data tape containing approximately 50,000 records of coal sample analyses. This overlay may be manipulated to provide reasonable estimates of the quantity by energy or weight of the coal reserve base in a particular region meeting a given SO_2 emission level. These quantities are based upon average sulfur and BTU quantities and do not reflect coal sulfur variability.

The six coal regions used in the computer program are defined as follows:

1. Northern Appalachian Region includes Maryland, Pennsylvania (bituminous), and Ohio and the following 40 counties in central and northern West Virginia:

Barbour	Hampshire	Mineral	Ritchie
Berkeley	Hancock	Monongalia	Roane
Braxton	Hardy	Morgan	Taylor
Brooke	Harrison	Nicholas	Tucker
Calhoun	Jackson	Ohio	Tyler
Clay	Jefferson	Pendleton	Upshur
Doddridge	Lewis	Pleasants	Webster
Gilmer	Marion	Pocahontas	Wetzel
Grant	Marshall	Preston	Wirt
Greenbrier	Mason	Randolph	Wood

2. Southern Appalachian Region includes Tennessee, Virginia, Kentucky (east), and the southern West Virginia counties of Boone, Cabell, Fayette, Kanawha, Lincoln, Logan, McDowell, Mercer, Mingo, Monroe, Putnam, Raleigh, Summers, Wayne, and Wyoming.

3. Alabama Region includes only the State of Alabama.

4. Eastern Midwest Region includes Illinois, Indiana, and Kentucky (west).

5. Western Midwest Region includes Arkansas, Iowa, Kansas, Missouri, and Oklahoma.

6. Western Region includes Arizona, Colorado, Montana, New Mexico, North Dakota, Utah, and Wyoming.

States not assigned to a coal region in "Sulfur Reduction Potential of the Coals of the United States," U.S. Bureau of Mines, RI 8118 (1976), were assigned to specific regions. Georgia and North Carolina were assigned to the Southern Appalachian Region, Michigan to the Eastern Midwest Region, Texas to the Western Midwest Region and Idaho, Oregon, South Dakota and Washington were assigned to the Western Region.

Table 2-10 shows the available quantities of the reserve base in each of the six coal regions and the entire U.S. that will meet various emission control levels. Only the Western Region and S. Appalachian region have significant amounts of raw coal available to meet a stringent 215 ng SO_2/J (0.5 lbs $SO_2/10^6$ BTU). Each of these regions, however, has over 90% of their raw coal available at the SIP emission control level of 1,075 ng SO_2/J (2.5 lbs/10^6 BTU). In contrast, little or no coal in N. Appalachia, E. Midwest, and W. Midwest regions can comply with the 215 ng SO_2/J control level and less than 10% of the coal reserve base of those regions, except Alabama, can meet an intermediate control level of 650 ng SO_2/J (1.5 lbs $SO_2/10^6$ BTU). Figures 2-2 through 2-8 graphically illustrate these results.

The amount of complying low sulfur coal reserves can also be viewed from an energy availability standpoint. This is especially relevant for low sulfur coal since there are two distinct forms of low sulfur coal: the high rank, bituminous eastern coal and the lower rank, subbituminous western coal. Figures 2-9 through 2-15 present reserve base energy content of compliance coal versus emission level.

The energy content of the reserve base in Northern Appalachia available in the low sulfur spectrum <430 ng SO_2/J (1.0 lb $SO_2/10^6$ BTU),

TABLE 2-10. WEIGHT PERCENT OF REGIONAL LOW SULFUR COAL RESERVES THAT CAN MEET VARIOUS SO_2 EMISSION CONTROL LEVELS

Emission Control Level ng SO_2/J (lbs SO_2/10^6 BTU)	Northern Appalachian	Southern Appalachian	Alabama	Eastern Midwest	Western Midwest	Western	Entire U.S.
215 (0.5)	0	2	0	0	0	16	8
650 (1.5)	10	75	48	2	6	85	48
1,075 (2.5)	24	90	74	8	13	95	58
1,700 (4.0)	50	94	94	14	19	99	68

Values are in weight percent of regional reserves

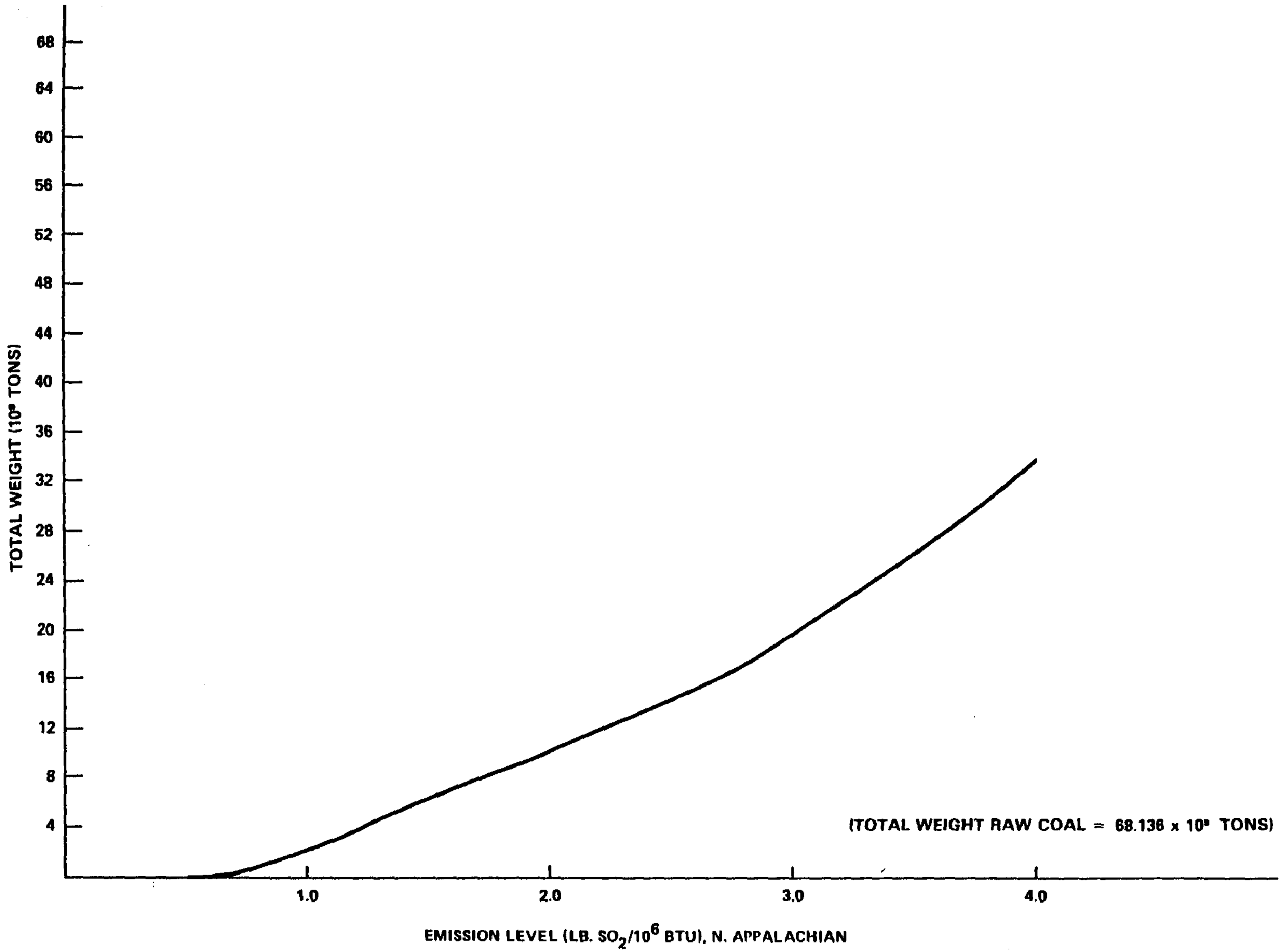


FIGURE 2-2 N. APPALACHIAN RESERVE BASE AVAILABLE AS A FUNCTION OF EMISSION CONTROL LEVELS

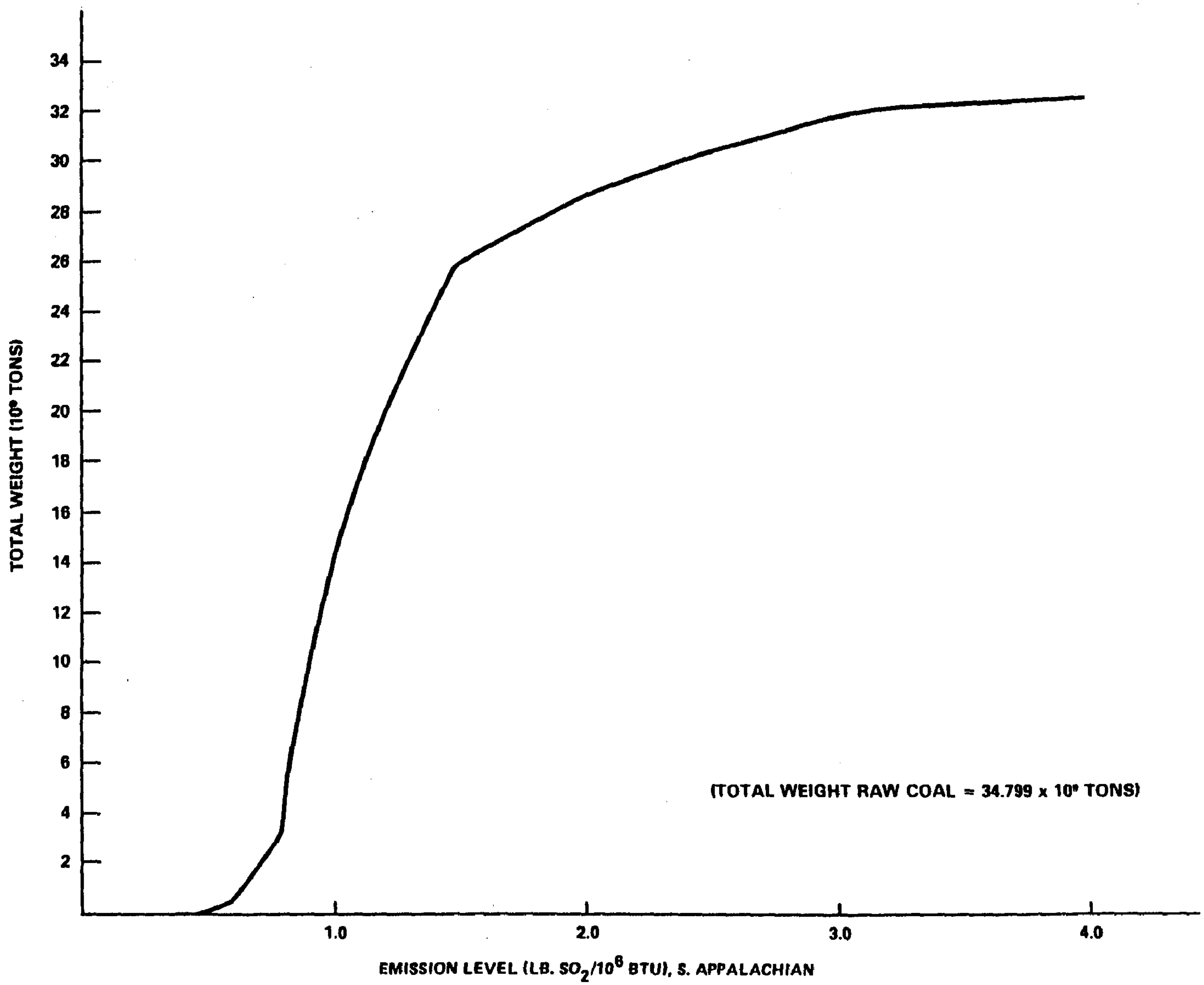


FIGURE 2-3 S. APPALACHIAN RESERVE BASE AVAILABLE AS A FUNCTION OF EMISSION CONTROL LEVELS

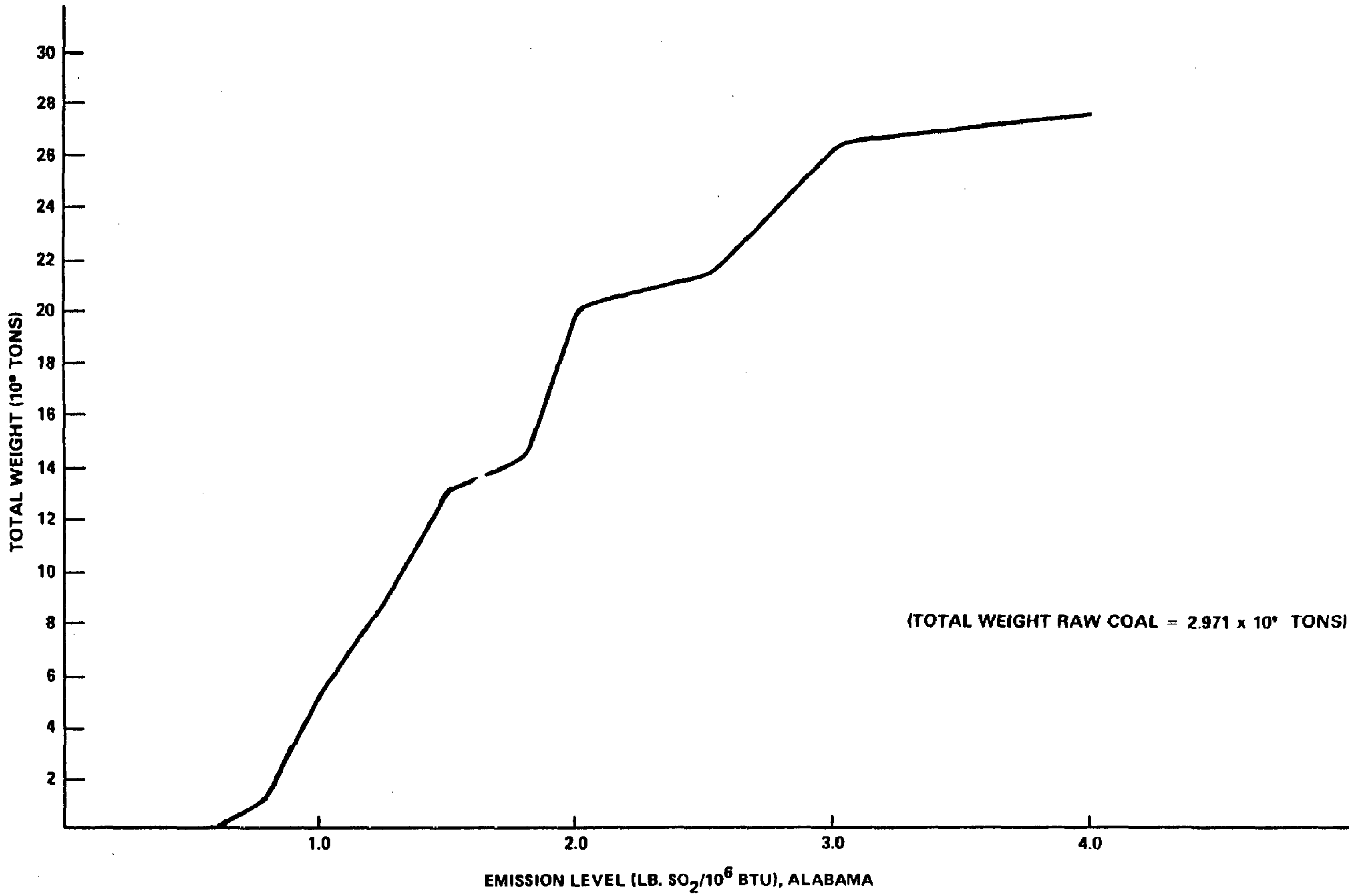


FIGURE 2-4 ALABAMA RESERVE BASE AVAILABLE AS A FUNCTION OF EMISSION CONTROL LEVELS

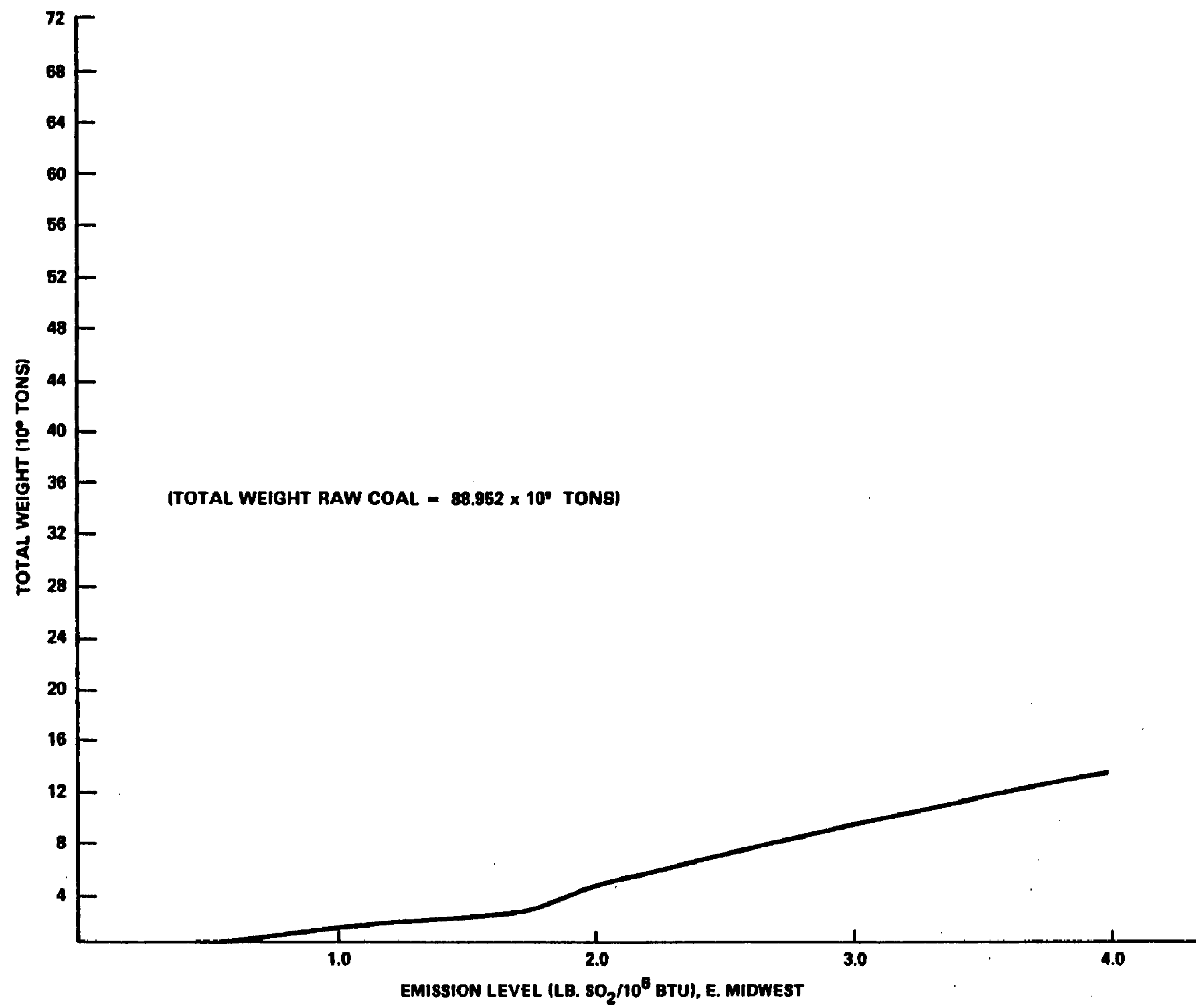


FIGURE 2-5 E. MIDWEST RESERVE BASE AVAILABLE AS A FUNCTION OF EMISSION CONTROL LEVELS

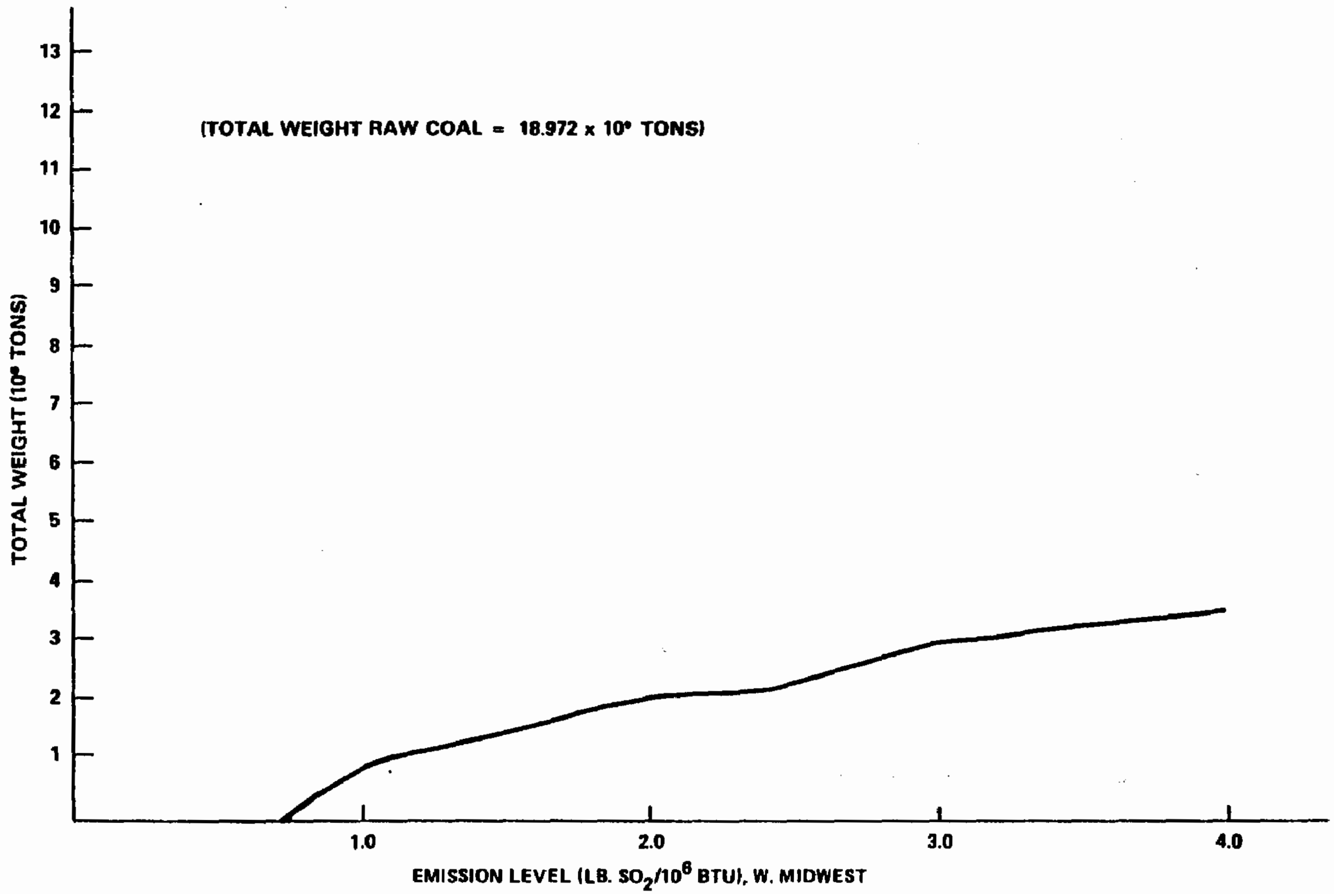


FIGURE 2-6 W. MIDWEST RESERVE BASE AVAILABLE AS A FUNCTION OF EMISSION CONTROL LEVELS

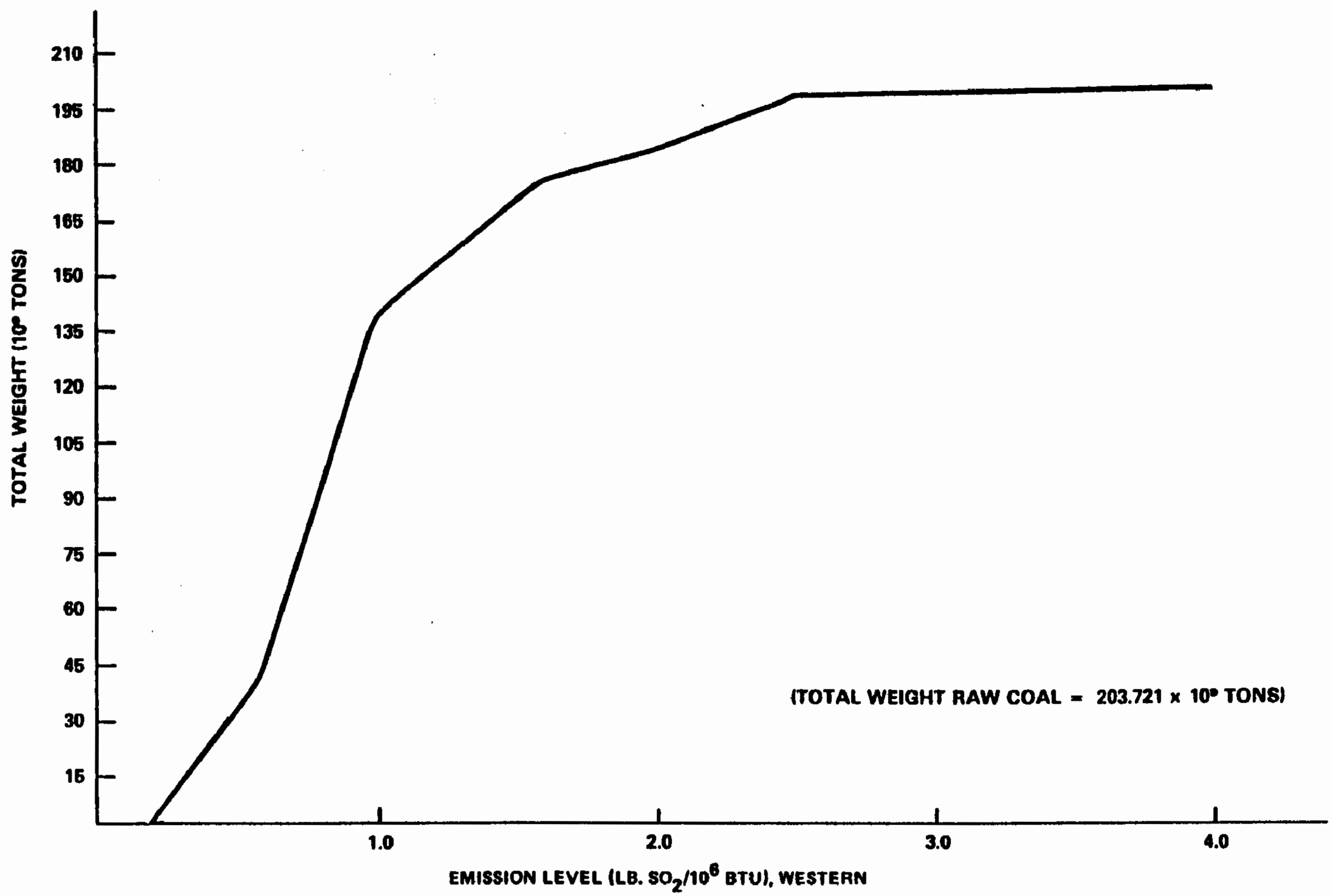


FIGURE 2-7 WESTERN RESERVE BASE AVAILABLE AS A FUNCTION OF EMISSION CONTROL LEVELS

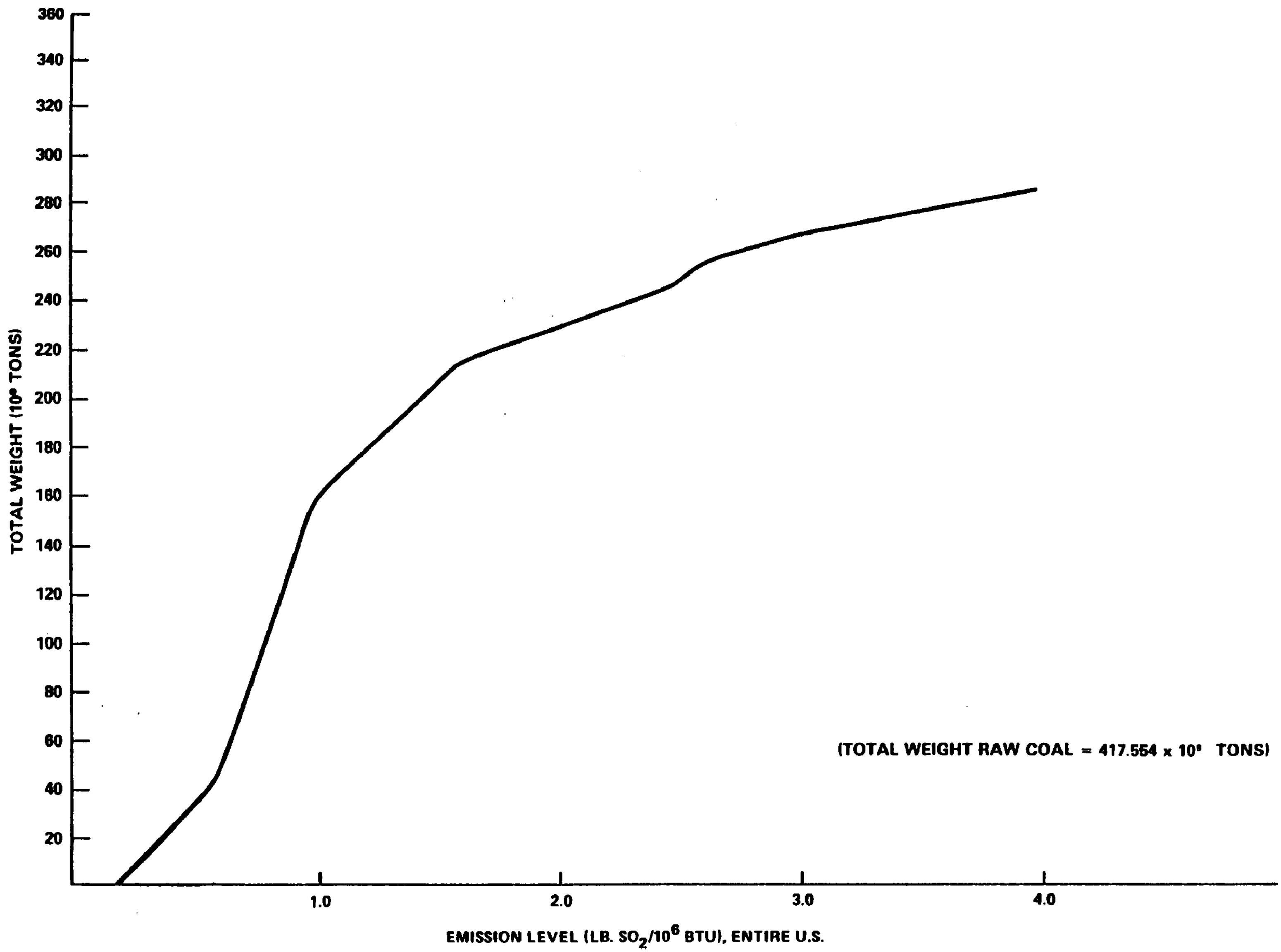


FIGURE 2-8 ENTIRE U.S. RESERVE BASE AVAILABLE AS A FUNCTION OF EMISSION CONTROL LEVELS

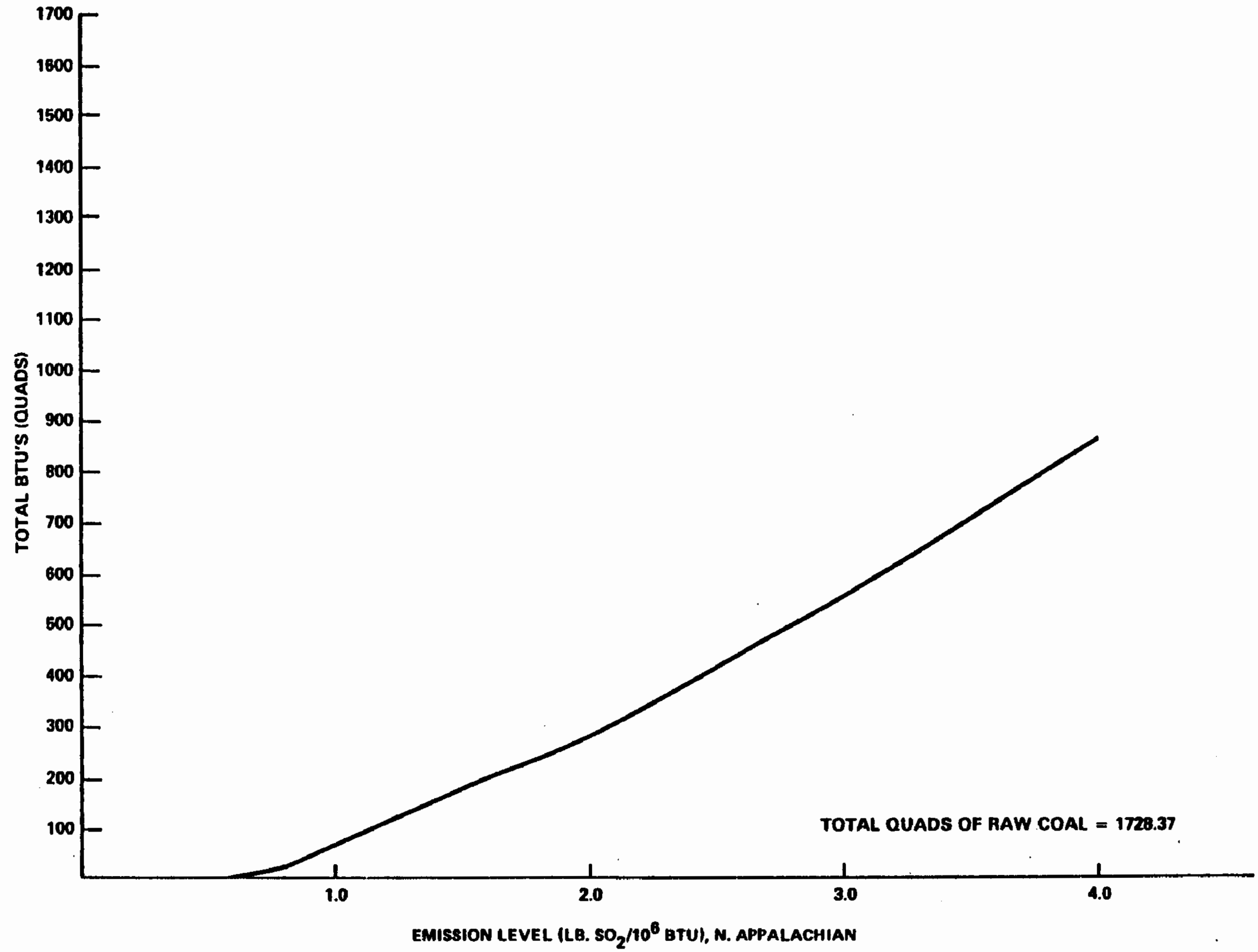


FIGURE 2-9 ENERGY AVAILABLE IN N. APPALACHIAN RESERVE BASE AS A FUNCTION OF EMISSION CONTROL LEVELS

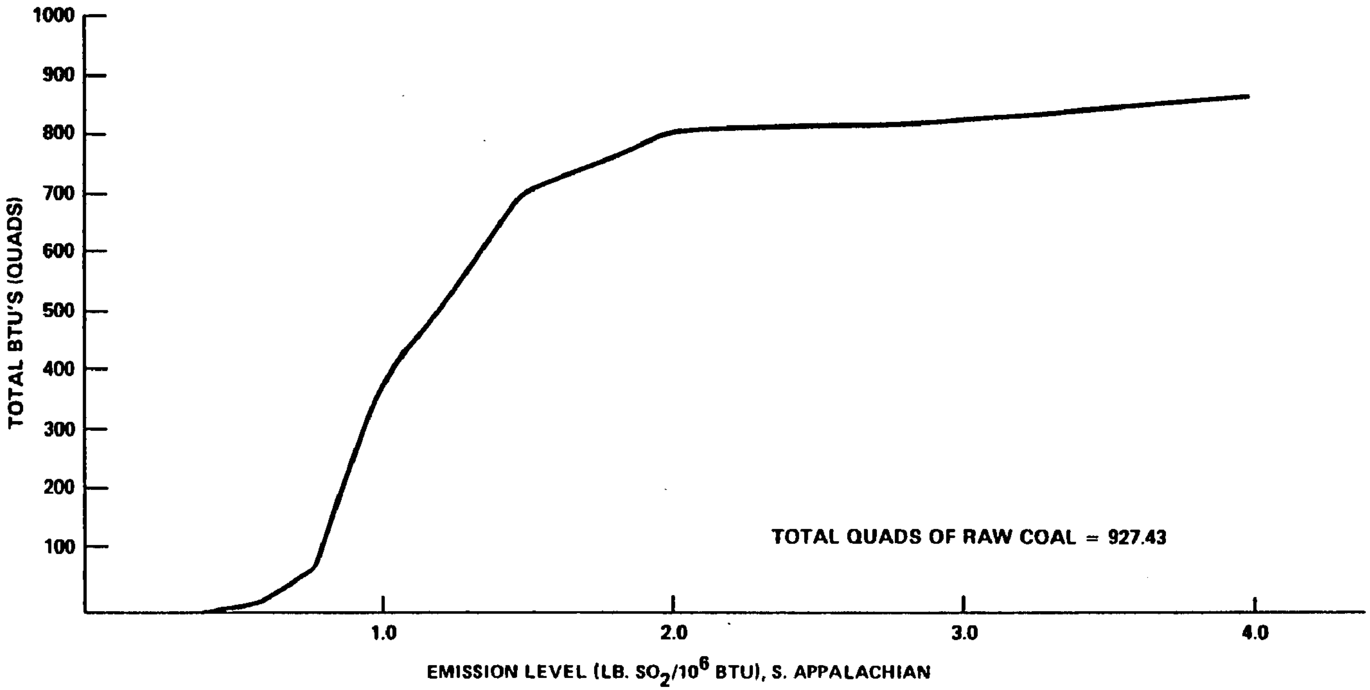


FIGURE 2-10 ENERGY AVAILABLE IN S. APPALACHIA RESERVE BASE AS A FUNCTION OF EMISSION CONTROL LEVELS

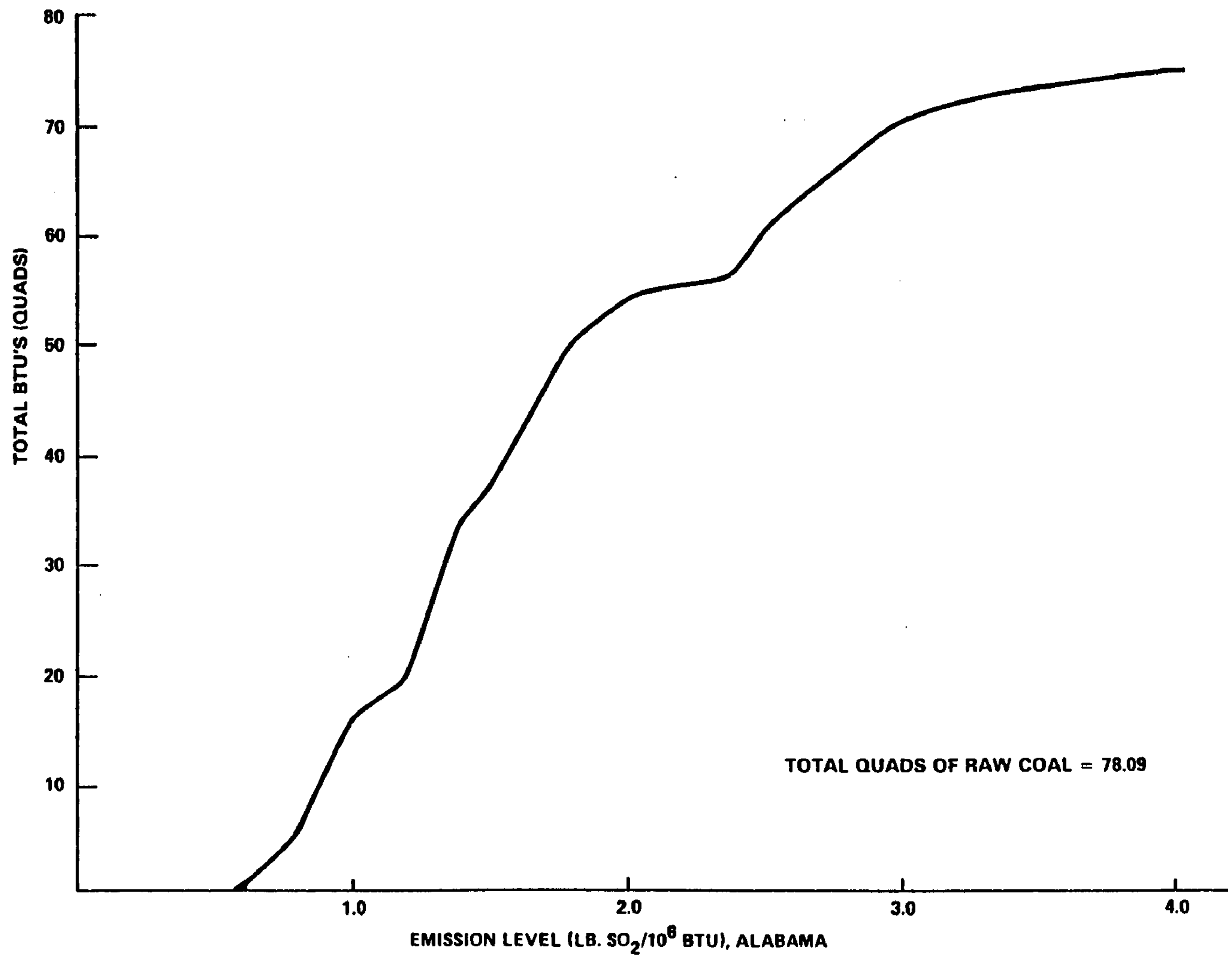


FIGURE 2-11 ENERGY AVAILABLE IN ALABAMA RESERVE BASE AS A FUNCTION OF EMISSION CONTROL LEVELS

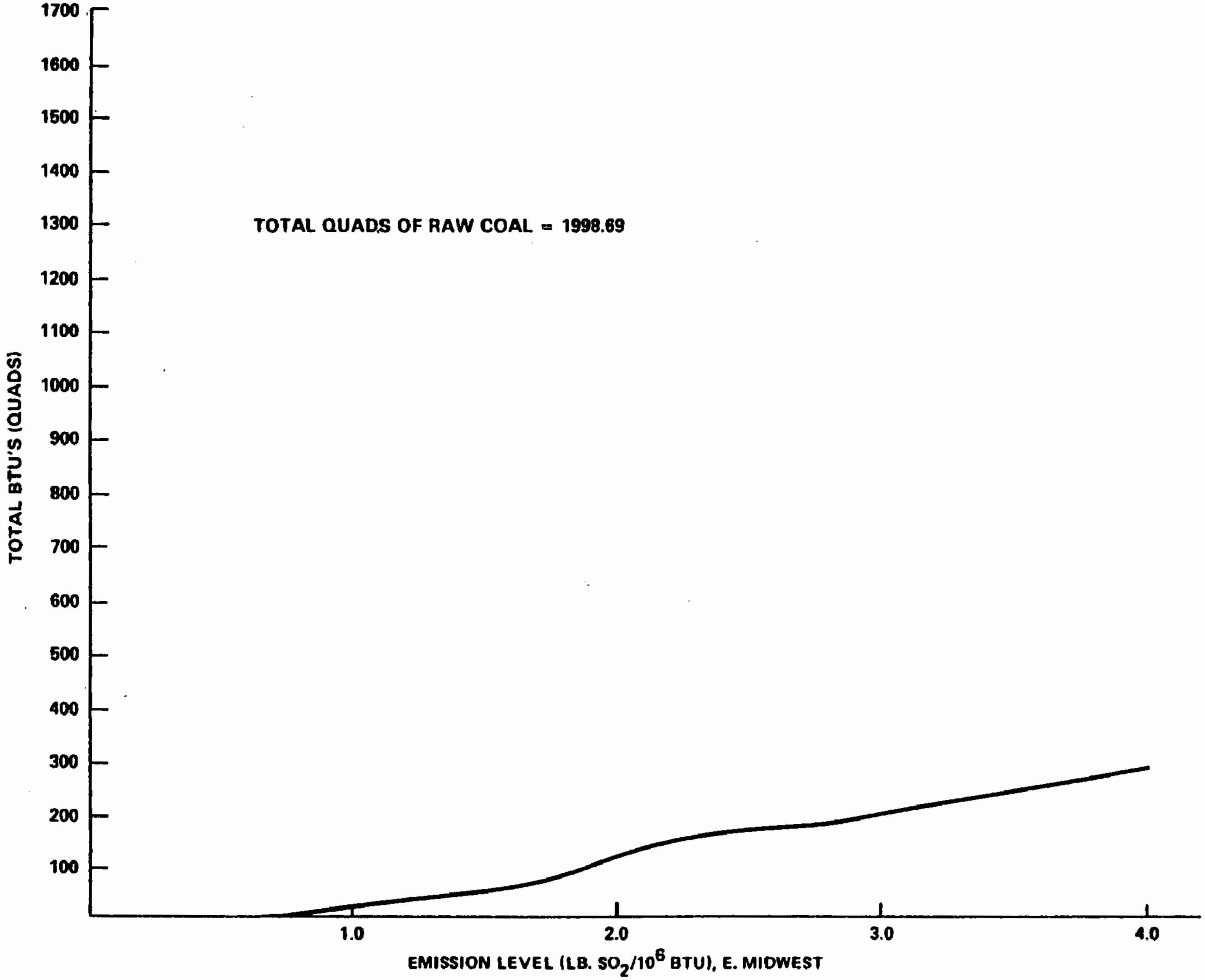


FIGURE 2-12 ENERGY AVAILABLE IN E. MIDWEST RESERVE BASE AS A FUNCTION OF EMISSION CONTROL LEVELS

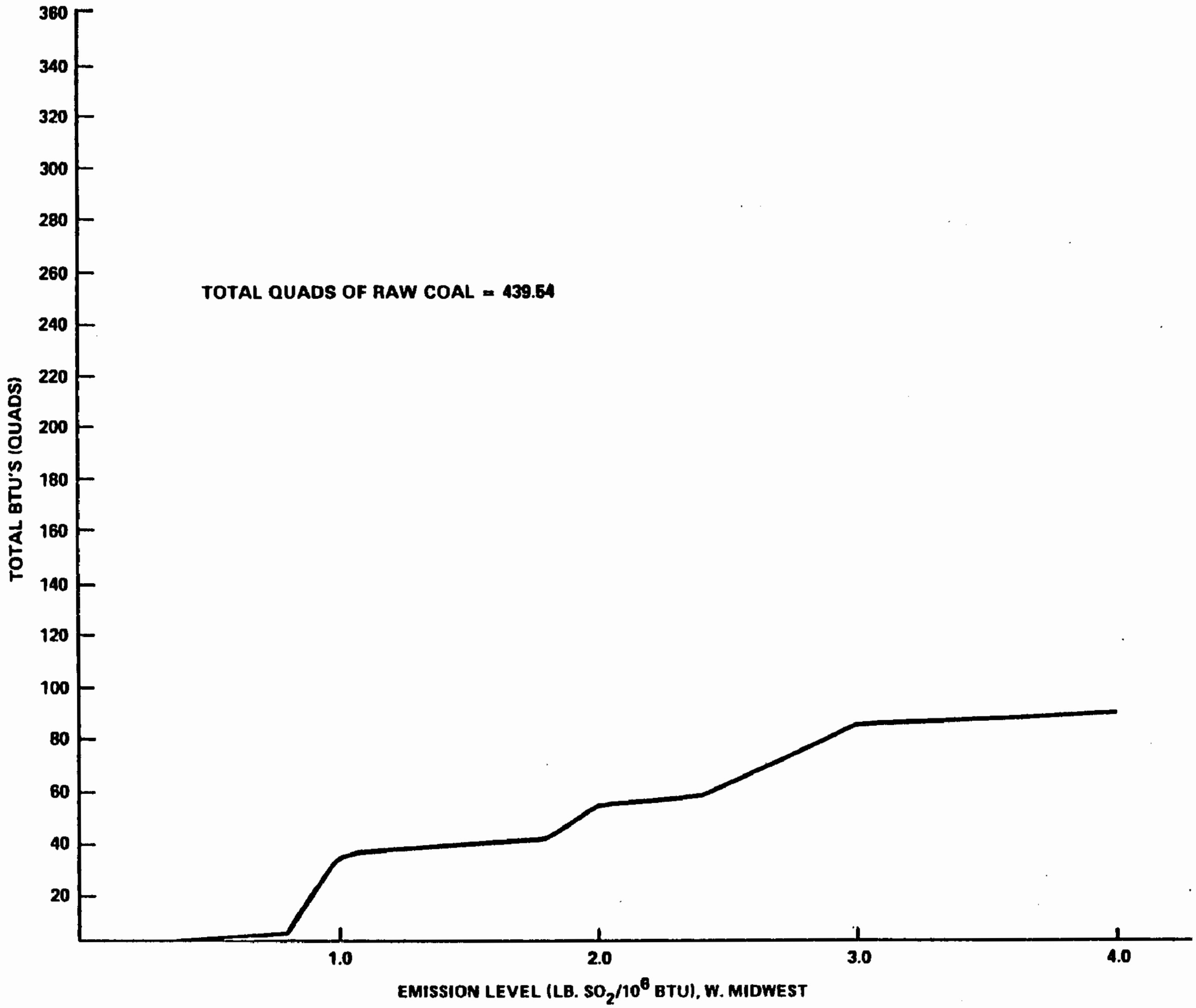


FIGURE 2-13 ENERGY AVAILABLE IN W. MIDWEST RESERVE BASE AS A FUNCTION OF EMISSION CONTROL LEVELS

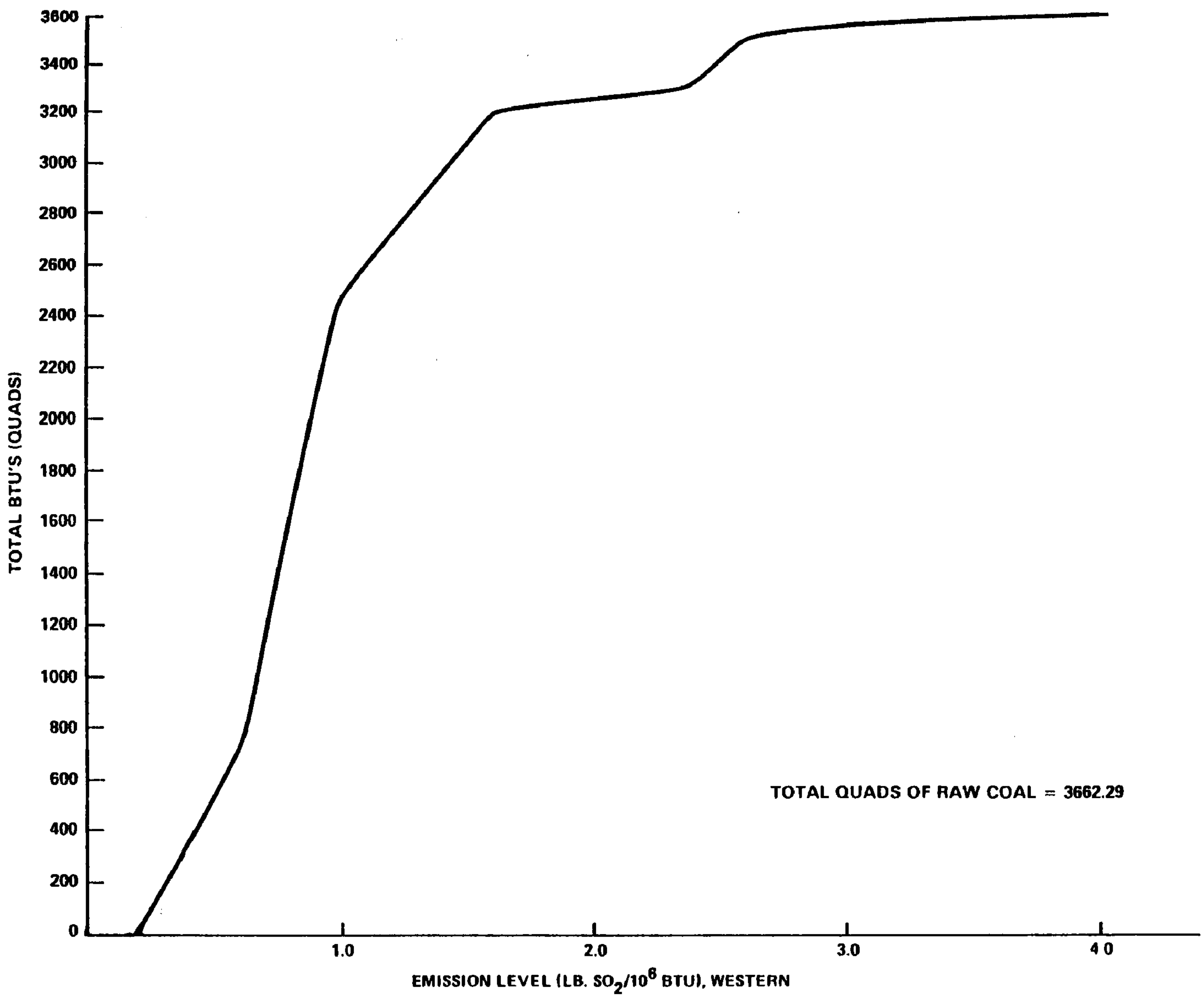


FIGURE 2-14 ENERGY AVAILABLE IN WESTERN RESERVE BASE AS A FUNCTION OF EMISSION CONTROL LEVELS

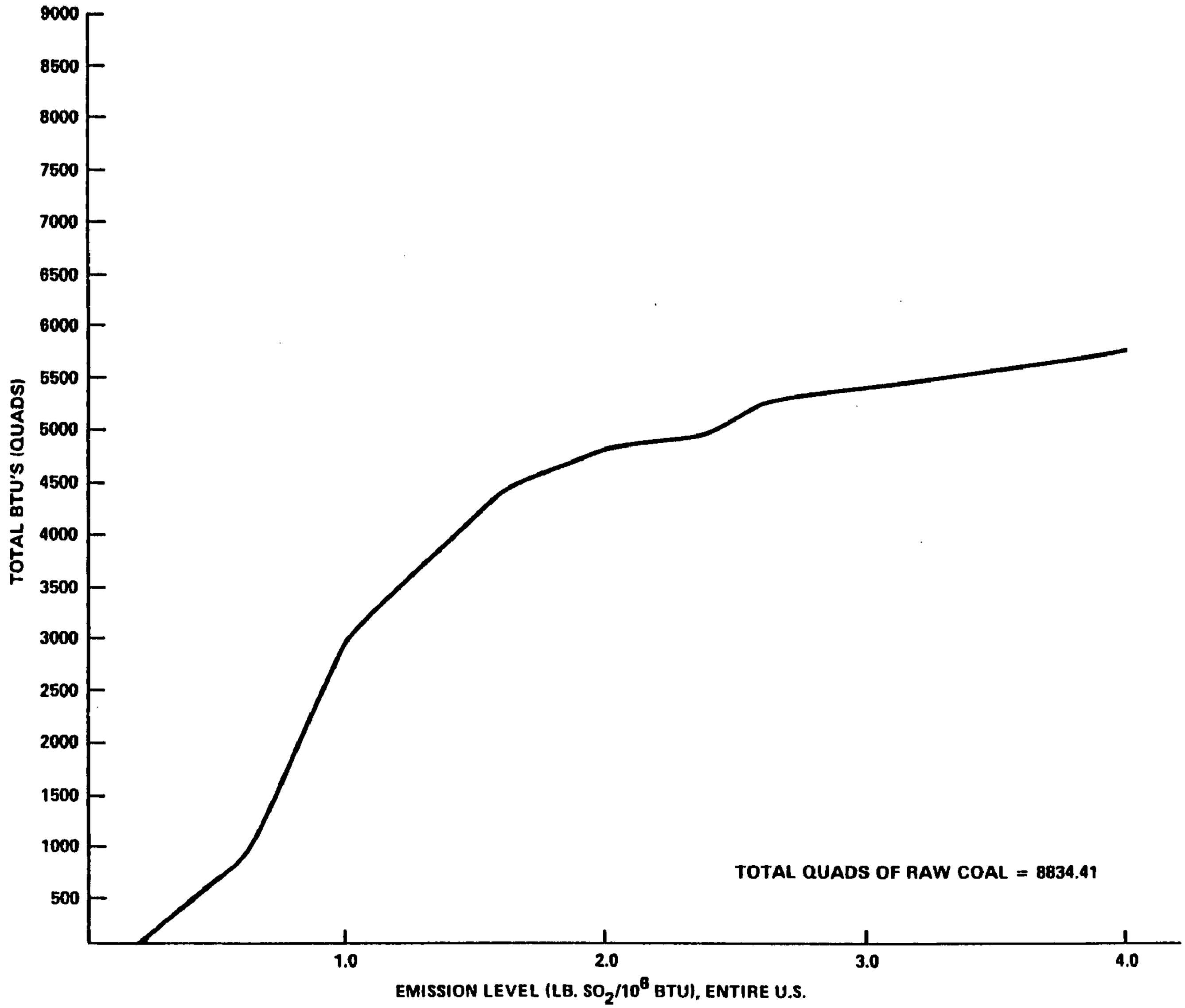


FIGURE 2-15 ENERGY AVAILABLE IN ENTIRE U.S. RESERVE BASE AS A FUNCTION OF EMISSION CONTROL LEVELS

is 74 x 10^9 GJ (70 quadrillion BTU). This small amount only represents 4 percent of the regional total and therefore the use of low sulfur coal as a control technology may not prove beneficial.

In the Southern Appalachian region the low sulfur reserve base energy content is about 370 x 10^9 GJ (350 quads). This is a sizable increase over the Northern Appalachian region, and therefore the use of low sulfur coal represents a possible control option.

The amount of reserve base which qualifies as being a low sulfur variety in Alabama equals 17 x 10^9 GJ (16 quads). Overall this value is small, but in this region where the total energy content is only about 85 x 10^9 GJ (80 quads), 15 x 10^9 GJ represents a sizable portion (20 percent). The use of these low sulfur reserves could therefore be available as a local control option.

The use of low sulfur coal in the Eastern Midwest region as a control option is limited. The energy reserve base available is 26 x 10^9 GJ (25 quads) compared to a total energy potential of about 2,300 x 10^9 GJ (2,100 quads).

For low sulfur raw coal in the West Midwest region, about 32 x 10^9 GJ (30 quads) can meet a 430 ng SO_2/J control level. This value is approximately 7 percent of the total available BTU reserve base of the region.

By far the highest available amount of low sulfur coal energy reserve base is in the western region. Approximately 2,610 x 10^9 GJ (2,480 quads) of coal can comply with a 430 ng SO_2/J control level which represents 68 percent of the total regional energy reserve base.

Nationwide the reserve base energy content of low sulfur coal is 3,000 x 10^9 GJ (2,850 quads). This computes to a total national coal reserve base energy content of 33 percent. Of this low sulfur coal energy reserve, 87 percent is located in the Western region. Since most coal-fired industrial boilers are located in the eastern half of the U.S., considerable transportation costs and energy will probably be associated with using low sulfur coal as a major SO_2 control technology.

Effects of Sulfur Variability on Quantity of Reserve Base Available to Meet SO_2 Emission Control Levels--

A basic factor affecting the use of low sulfur coal to meet SO_2 emission control levels is the variability of the properties of the coal as it comes from the mine. The composition and properties of coal can vary widely even within a given coal seam. This is an important consideration with respect to emission control.

Because the sulfur content varies, the average values for sulfur in coal can be used to determine compliance with a given control level only if long-term averaging of the resultant SO_2 emission is permitted. If, however, the emission control regulation includes a "never to be exceeded" statement, a coal with average sulfur and heat content equal to the stated emission control level will be out of compliance approximately half of the time. To increase the time within compliance, it is necessary to use a coal with a lower average sulfur content so that most upper deviations can be accommodated without resulting in noncompliance.

Table 2-11 and 2-12 show the percent weight and percent energy, respectively, of raw coal in each region that on combustion will meet emission control levels of 520 (1.2), 860 (2.0), 1,290 (3.0), and 1,720 (4.0) ng SO_2/J (lb $SO_2/10^6$ BTU). The regions used are as follows:

1. Northern Appalachia
2. Southern Appalachia
3. Alabama
4. Eastern Midwest
5. Western Midwest
6. Western
7. Entire U.S.A.

Omitted from these regions for lack of appropriate data are the Alaskan reserves.

The effect of taking sulfur variability into account is also shown on these tables for one boiler size over two different averaging time periods, which generally fix the lot sizes of coal being burned.

TABLE 2-11

PERCENT WEIGHT OF U.S. COALS BY REGION AVAILABLE TO MEET VARIOUS EMISSION CONTROL LEVELS

Region	Emission Control Levels: 520 (1.2)*	860(2.0)	1,290(3.0)	1,720(4.0)
	Variability Ignored			
1	6	16	32	49
2	53	83	92	94
3	27	68	90	94
4	1	6	10	14
5	6	11	16	19
6	71	89	97	99
7	41	55	63	69
	24-hr Average, 75 x 10^6 BTU/hr			
1	1	7	14	26
2	8	58	81	90
3	6	35	66	76
4	0	2	5	8
5	5	8	14	18
6	66	88	95	98
7	29	45	53	59
	30-day Average, 75 x 10^6 BTU/hr			
1	2	9	20	30
2	22	64	87	92
3	13	43	71	86
4	1	2	6	9
5	6	9	16	18
6	69	88	96	99
7	32	46	56	60

* Emission limits are given in ng SO_2/J ($SO_2/10^6$ BTU).(38)
Source: Reserve Processing Assessment Model (RPAM).

TABLE 2-12

PERCENT ENERGY OF U.S. COALS BY REGION AVAILABLE
TO MEET VARIOUS EMISSION CONTROL LEVELS

Region	Emission Control Levels			
	520 (1.2)*	860(2.0)	1,290(3.0)	1,720(4.0)
		Variability Ignored		
1	7	17	33	51
2	54	83	93	94
3	27	69	90	94
4	1	6	10	15
5	7	13	18	21
6	72	90	97	99
7	38	52	60	66
		24-hr Average, 75 x 10^6 BTU/hr		
1	1	8	15	27
2	8	59	82	91
3	6	36	67	76
4	0	2	5	9
5	6	9	16	19
6	67	89	96	98
7	29	46	54	59
		30-day Average, 75 x 10^6 BTU/hr		
1	2	9	20	31
2	23	65	87	92
3	13	44	72	86
4	1	2	7	9
5	7	11	17	20
6	70	89	96	99
7	32	47	56	61

* Emission limits are given in ng SO_2/J (lb $SO_2/10^6$ BTU).
Source: Reserve Processing Assessment Model (RPAM).[38]

The emission levels acceptable if sulfur variability is taken into account were computed on the basis of a 97.72 percent confidence level (two standard deviations from the mean based on a one-tailed test). The relative standard deviations (RSD) used are given below.

	Relative Standard Deviations			
	Eastern		Western	
	Raw	Washed	Raw	Washed
24 hour averaging, 75×10^6 BTU/hr	0.28	0.10	0.07	0.07
30 day averaging, 75×10^6 BTU/hr	0.19	0.07	0.04	0.06

These RSD's are postulated to approximate those for 24-hour and 30-day averages for the boiler size listed. At the confidence level used, the required emission limits will be exceeded only 2.28 percent of the time which is less than one day in thirty days and is approximately 30 minutes in twenty-four hours.

The effect of taking sulfur variability into account shows that for a 24-hour averaging period for a 79×10^6 kJ/hr (75×10^6 BTU/hr) boiler, the availability of low sulfur coal below 520 ng SO_2/J (1.2 lbs $SO_2/10^6$ BTU) is reduced nationwide from 41 percent to 29 percent by weight. Furthermore, on a regional basis only 3 percent of the coal reserve base in all regions other than Western has sufficiently low sulfur content to meet this standard with the 24-hour averaging, while 66 percent of the western reserve base meets the standard. A 30-day averaging period allows 32 percent of the entire U.S. reserve base to meet this control level and permits more substantial amounts of low sulfur coal from regions other than western to be used. For example, 22 percent of Southern Appalachian coal is now usable.

Impacts on Boiler—

Eastern Coal

Low-sulfur eastern coals are a highly desirable fuel for spreader stokers. Generally, these coals have relatively high ash fusion temperature, low ash content, and present few problems in handling. Generally, slagging is only a problem at excess air levels less than 50 percent (this is below the excess air level at which most stoker-fired boilers operate). Low-sulfur eastern bituminous coals can be fired in most spreader-stoker-fired boilers.

The eastern bituminous coals have relatively high free swelling indices and, thus, have a tendency to cake. This is not a problem in spreader stokers, but it may be a problem in underfeed and overfeed stokers. For example, an overfeed stoker designed to burn a noncaking Illinois coal may encounter operational problems if switched to a low-sulfur eastern coal.

Western Coal

Because of wide variability in the properties of western coals, it is difficult to make generalized statements. However, a recent report[39] assesses the operational aspect of coal switching to western fuels.

The testing of ten representative industrial coal-fired boilers in the upper-midwest resulted in an assessment of sulfur oxides, nitrogen oxides, carbon monoxide, unburned hydrocarbon and particulate emissions from these units as well as an assessment of the operational impact of coal switching.

This study has shown that western subbituminous coals can be substituted for eastern bituminous coals as an industrial boiler fuel. The western coals are compatible with industrial coal-fired units of current design. Two unit types of older design (underfeed and traveling grate stokers) were found to experience difficulty burning western coal. Some cases have been noted where the maximum load capacity of the boiler had to be reduced. This problem can be eliminated by pre-drying the coal or by increased superheat steam temperature capacity.

Western subbituminous coals were found to be superior to eastern coals in terms of SO_x, NO_x, particulate, and unburned hydrocarbon emissions. The western coals could be fired at lower excess air and exhibited substantially lower combustible losses than eastern coals.

The size of delivered western coal proved to be a problem in most of the stoker-fired units tested. The coal generally had too large a percentage of fine coal resulting from the poor weathering characteristics of western coals.

Boiler efficiencies on western coal were lower due to the high moisture content of the western coal. The reduced efficiency due to the moisture losses were somewhat offset by the lower combustible losses and lower excess oxygen (O_2) required for western coal combustion.

Additional Maintenance Requirements--

Firing of naturally-occurring low sulfur coal (eastern or western) in industrial stoker-fired boilers is not expected to have a significant effect on boiler maintenance costs. Firing of such coal in industrial pulverized-coal boilers may have some effect in reducing boiler maintenance costs.

Firing of low sulfur eastern coal in industrial boilers may reduce operating costs slightly due to the lower ash content typical of such coal. Firing of low sulfur western coal in industrial boilers may increase operating costs due to high ash and sodium content (i.e., increased slagging) typical of such coal.

Documentation--

Details of the data bases used in this study are given in section 2.2.2.2, the documentation of system performance for the physical cleaning process.

2.2.2 Physical Coal Cleaning

Coal preparation is a proven, existing technology for upgrading raw coal by removal of impurities. It provides control of the heating value and physical characteristics of coal. Depending upon the level of preparation and the nature of the raw coal, cleaning processes generally produce a uniformly sized product, remove excess moisture, reduce the sulfur and ash content, and increase the heating value of the coal. By removing potential pollutants and reducing product coal variability, coal cleaning can be an important control strategy for complying with air quality control levels.

2.2.2.1 System description--
Physical Coal Preparation Systems [40]

The physical coal cleaning processes used today are oriented toward product standardization and reduction of ash, with increasing attention being placed on sulfur reduction. Coal preparation in commercial practice is currently limited to physical processes. In a modern coal cleaning plant, the coal is typically subjected to (1) size reduction and screening, (2) gravity separation of coal from its impurities, and (3) dewatering and drying.

The commercial practice of coal cleaning is currently limited to separation of the impurities based on differences in the specific gravity of coal constituents, i.e., gravity separation process, and on the differences in surface properties of the coal and its mineral matter, i.e., froth flotation.

The types of processes and equipment used over the years in coal cleaning are summarized in Table 2-13. This summary table indicates that as of 1972, jig operations processed the largest portion of coal being beneficiated. However, dense-medium processes and concentrating tables show increasingly greater contributions and froth flotation use is growing.

To provide a systematic basis for discussion and evaluation, coal preparation has been classified into five general levels. A summary of these general levels is presented on the following page.

TABLE 2-13. PREPARATION OF COAL BY TYPE OF EQUIPMENT [41]

Percentage of Clean Coal Produced by Year

Washer Type	1942	1952	1962	1972
Jigs	47.0	42.8	50.2	43.6
Dense-medium processes	—	13.8	25.3	31.4
Concentrating tables	2.2	1.6	11.7	13.7
Flotation	—	—	1.6	4.4
Pneumatic	14.2	8.2	6.9	4.0
Classifiers	}29.6	8.5	2.1	1.0
Launders		5.2	2.2	1.9
Combination of methods	7.0	19.9	—	—

Level 1-crushing and sizing

This design uses rotary breakers, crushers and screens for top size control and for the removal of coarse refuse.

Level 2-coarse size coal beneficiation

Coal is crushed and sized, followed by dry screening at 9.5 mm (3/8 in.) and wet beneficiation of the plus 9.5 mm material with a jig or dense medium vessel. The minus 9.5 mm material is mixed with the coarse product without washing.

Level 3-coarse and medium size coal beneficiation

Coal is crushed and separated into three size fractions by wet screening. The plus 9.5 mm material is beneficiated in a coarse coal circuit. The 9.5 mm by 28 mesh material is beneficiated by hydrocyclones, concentrating tables or dense medium cyclones,and the 28 mesh by 0 material is dewatered and shipped with the clean coal or discarded as refuse.

Level 4-coarse, medium and fine size coal beneficiation

Coal is crushed and separated into three or more size fractions by wet screening. All size fractions are beneficiated in individual circuits. Thermal drying of the minus 6.4 mm fraction may be necessary to control the moisture content of the product.

Level 5-"deep cleaning" coal beneficiation

Level 5 is basically, a level 4 plant in which one size fraction is rigorously cleaned to meet a low sulfur-low ash product specification. Two or three coal products are produced to various market specifications. This level also utilizes a fine coal recovery circuit to increase total plant recovery.

The increasing complexity of the systems is followed by an increasing versatility for usage of coals with a wide range of washabilities. Thus, high level systems may be used for many different coal types. Lower levels on the other hand have a greater flexibility with regard to changes in raw coal size. Levels 1 to 3 are generally used in the preparation of steam coal. Level 4 is used for metallurgical grade coal and Level 5 has not yet been commercially demonstrated in this country.

A raw coal which is of marketable quality must be sized to be usable. Level 1 systems perform this sizing, while removing mine rock. Figure 2-16 illustrates a Level 1 plant. No washing is done and the entire process is dry. Since most removal of pyritic sulfur is accomplished by hydraulic separation, this level of cleaning is inefficient for reducing sulfur levels. In addition, only gross ash is removed. Because of these considerations, Level 1 systems are most effective for processing high quality coal with low sulfur content or when market specifications and raw coal characteristics are similar.

In a Level 1 system, raw coal is introduced to a receiving hopper equipped with grizzly bars to limit the size of the coal pieces and rocks entering the hopper. The oversize coal pieces are broken into smaller pieces which pass through the bars or are removed. From the receiving hopper, the coal is fed to various sizing and crushing equipment. Sizing units separate large pieces from the remainder of the coal. The large fractions then proceed to primary crushing while the smaller fractions bypass the crushing circuit or undergo secondary crushing. A magnetic separator is used to remove tramp iron. Unbroken material leaving the primary crusher is usually waste rock, which is collected in a refuse bin for disposal. This screening and crushing operation continues until the coal is of a commercially marketable size.

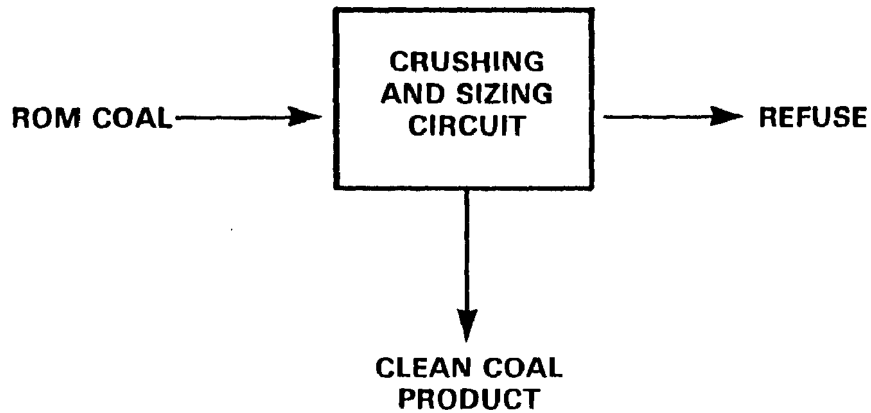


FIGURE 2-16 LEVEL 1 COAL PREPARATION PLANT FLOW DIAGRAM

Once sized, the coal may be diverted to a thermal drier if specifications require or taken directly to storage or transportation via belt conveyor. The processed coal is automatically weighed and sampled.

Level 2 cleaning plants, in addition to crushing and screening raw coal, also perform a minimum of cleaning. A general flow diagram for a Level 2 plant is illustrated in **Figure 2-17. A finer sizing of the coal is** accomplished for a Level 2 plant than in Level 1. This system provides removal of only coarse pyritic sulfur material and is therefore recommended for a moderate pyritic sulfur content coal.

Level 2 systems contain crushing and screening operations similar to Level 1. The final dry screening is usually limited to a minimum opening size of 6.4 mm. All finer coal goes directly to clean coal storage in a dry state. The larger fraction goes to a jig or some other coarse cleaning operation to be washed and separated into heavier and lighter fractions. Heavier refuse particles are rejected, dewatered and conveyed to the refuse bin. The clean coal is discharged with the process water over a dewatering screen. The large size material off the screens is sent to a crusher and then to clean coal storage. The underflow from the dewatering screens is conveyed to a thickening cyclone or centrifuge where most of the water is removed. This relatively dry product is then conveyed to clean coal storage with the effluent recycled.

Thermal drying of the clean coal is usually not required to meet moisture specifications in a Level 2 plant.

Level 3 cleaning is basically an extension of Level 2. **Figure 2-18** illustrates a flow diagram for a Level 3 type plant. Whereas Level 2 provides beneficiation by washing the coarse fraction obtained from screening, Level 3 involves a washing of both coarse and fine fractions. However, the level of beneficiation is not substantially greater than that of Level 2 with respect to sulfur removal and this system is recommended for use on low and medium sulfur coals which are relatively easy to wash. This process provides rejection of free pyritic and ash, as well as enhancement of energy content.

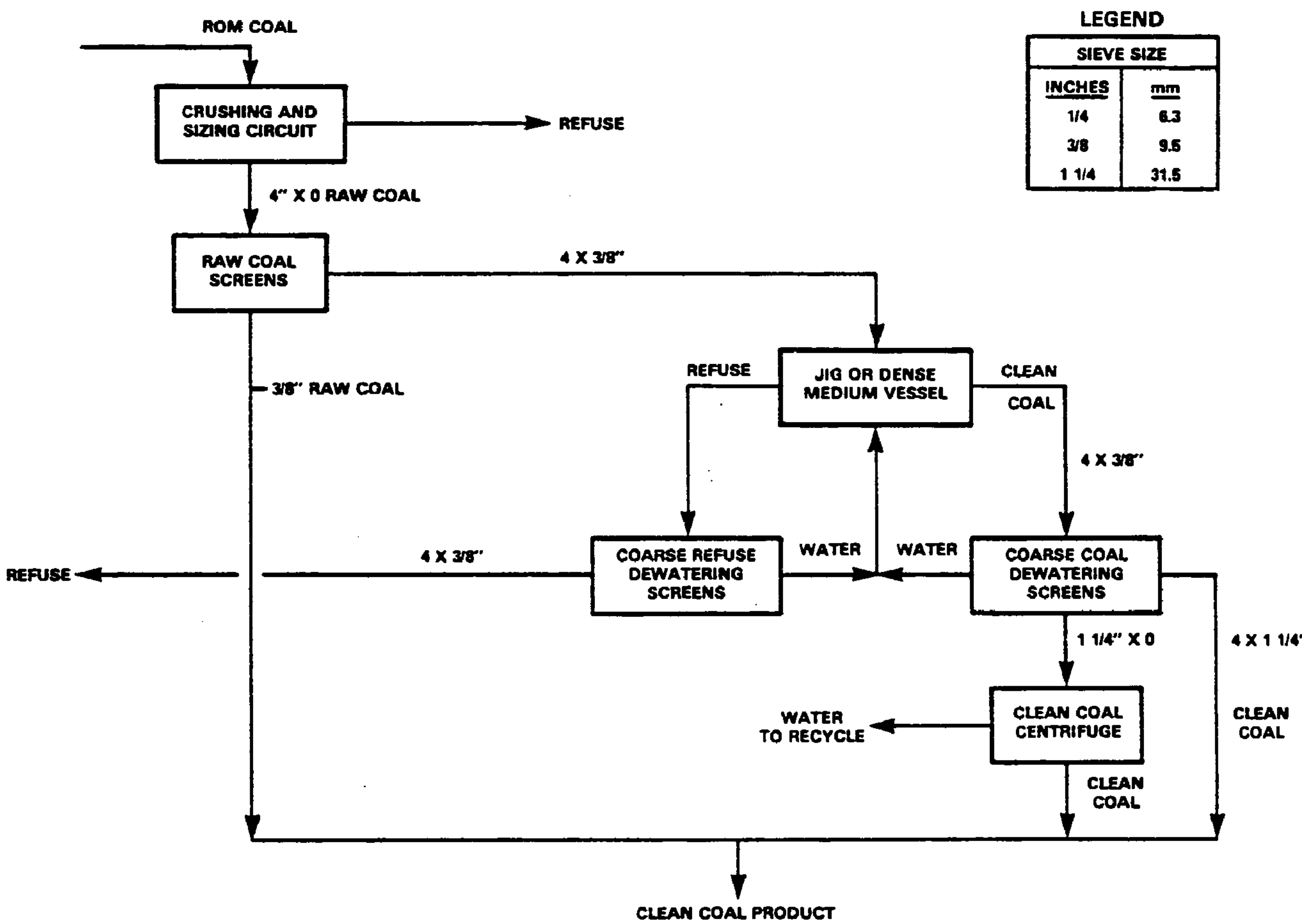
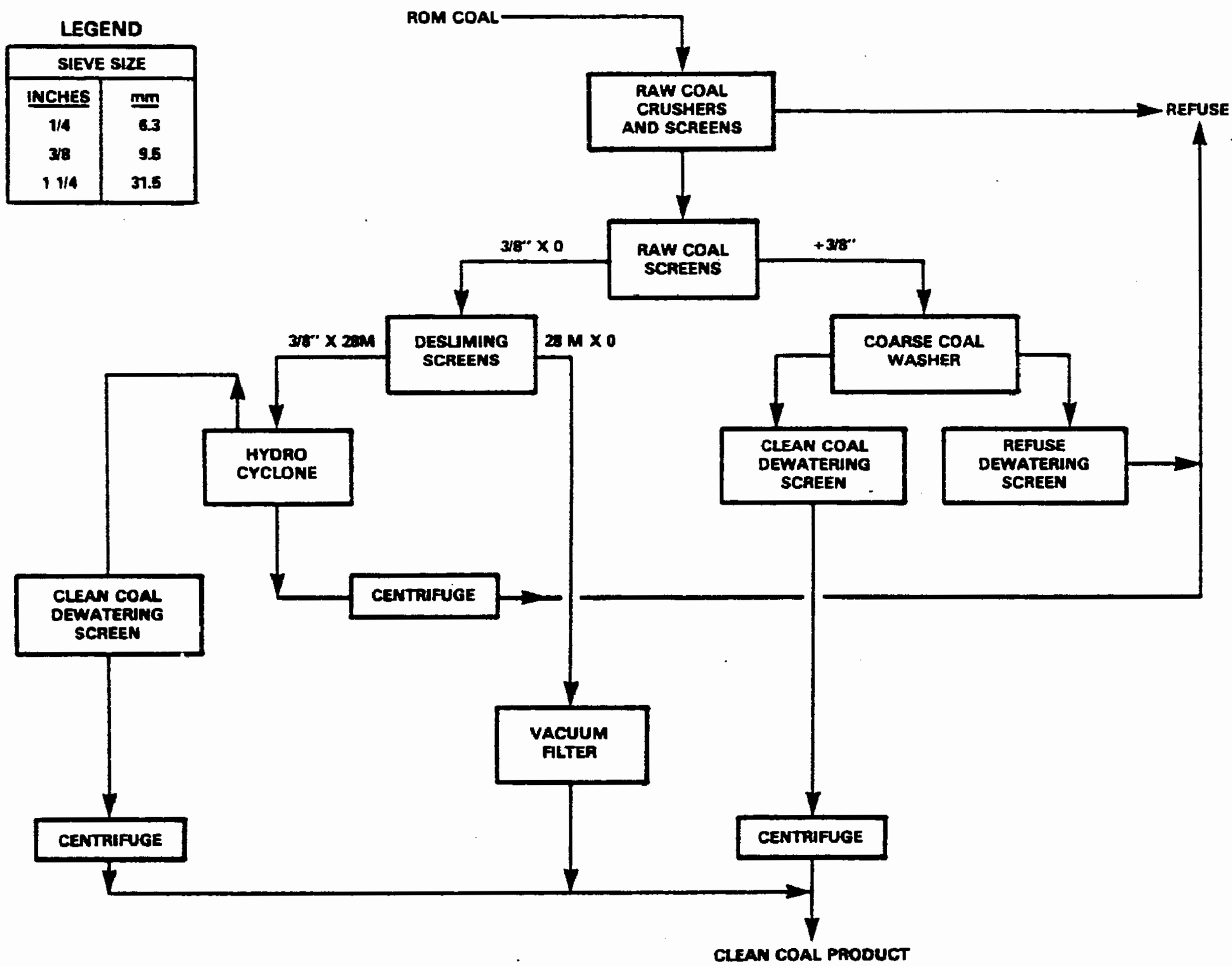


FIGURE 2-17 LEVEL 2 COARSE COAL PREPARATION FLOW DIAGRAM



LEGEND

SIEVE SIZE	
INCHES	mm
1/4	6.3
3/8	9.5
1 1/4	31.5

FIGURE 2-18 LEVEL 3 COAL PREPARATION FLOW DIAGRAM

Crushing and screening in Level 3 systems is performed in essentially the same manner as in Levels 1 and 2 except for the use of wet raw coal screens where coal particles are separated into plus 9.5 mm and 9.5 mm x 0 fractions. The plus 9.5 mm coal goes to a coarse coal washer such as a jig washer, where pulsating fluid flow separates particles according to density. Heavier ash material and pyrite concentrate in the bottom layers and are sent to refuse bins. Clean coal from the coarse coal washer is mechanically dewatered and sent to the clean coal storage.

Effluent from the dewatering processes containing fine coal may be combined with the raw 9.5 mm x 0 coal which is further classified into 9.5 mm x 28 mesh and 28 mesh by 0 fractions. The fine fraction, or underflow, from the desliming screens is dewatered and is sent to the clean coal product or is sent to refuse, depending upon product specifications. The 9.5 mm x 28 mesh coal is cleaned in a hydrocyclone circuit, or by concentrating tables, to achieve further ash and pyrite reduction. The clean coal is mechanically dewatered in a centrifuge and then sent to the clean coal storage. The fine coal is combined with the coarse coal and the composite product is sampled, weighed and transferred to clean coal storage.

Level 4 coal preparation systems provide high efficiency cleaning of coarse and fine coal fractions with lower efficiency cleaning of the ultrafines. This method accomplishes free pyrite rejection and improvement of BTU content. Since the cleaning at this level is so efficient, Level 4 has great versatility as to the coal it can process. A flow diagram for a Level 4 plant is shown on Figure 2-19.

The primary difference between Level 4 and the lower levels is the utilization of heavy media processes for cleaning specific size fractions above 28 mesh. For particles smaller than 28 mesh, cleaning by froth flotation processes or hydrocyclone processes is used.

Heavy media separation produces float and sink products according to specific gravity. The coal is lighter and floats, while the heavier mineral impurities sink. Magnetite suspensions are the usual dense media employed.

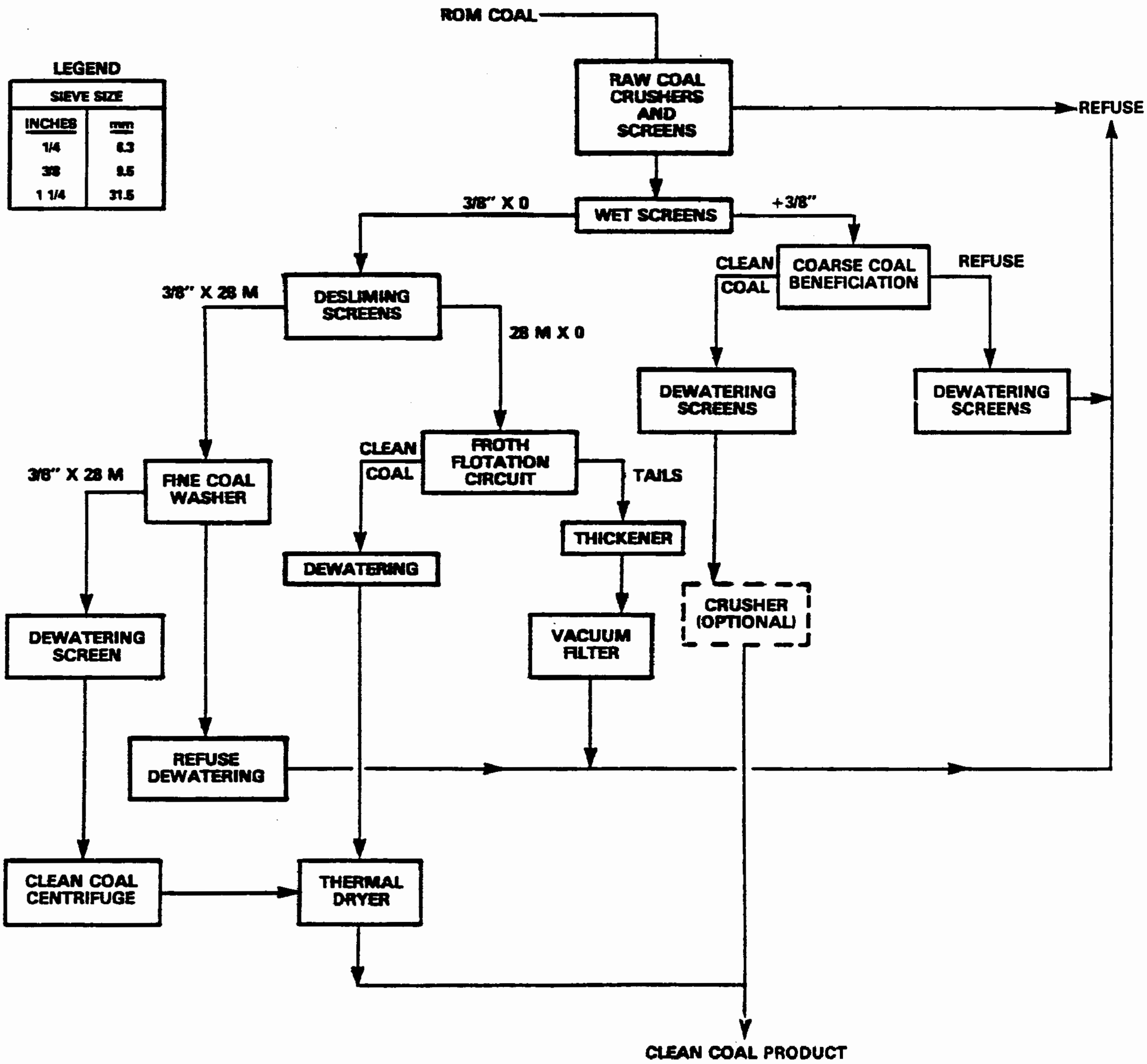


FIGURE 2-19 LEVEL 4 COAL PREPARATION PLANT FLOW DIAGRAM

Crushing and screening is performed as in the previously described systems. The coal is wet screened with the plus 9.5 mm material being subsequently fed to a heavy medium vessel or a heavy medium cyclone depending upon the top size of the coal used. For this separation, an intermediate specific gravity of 1.40 to 1.60 is used for the heavy medium depending upon the product weight yield. After separation, the product and refuse are screened and washed to remove the heavy medium which is subsequently recovered by magnetic separation and recycled to the circuit. Screening at this point also separates larger (10 x 3.8 cm) particles which can be crushed to within a 3.8 cm x 0 range. Products from the crushing are transported to clean coal storage, and refuse is transported to disposal bins.

The 9.5 mm x 0 coal from the raw coal screens is deslimed at 28 mesh. The 9.5 mm x 28 mesh fraction is fed, with heavy medium, into a heavy medium cyclone. After separation the product is rinsed, dewatered with a centrifuge and discharged to a clean coal conveyor which carries the coal to a thermal drier. After drying, the clean coal goes into storage.

The heavy medium, magnetite, is collected from the effluents and rinse waters by magnetic separators and recycled.

The slurry from the desliming screens containing the minus 28 mesh material is pumped to a froth flotation system or to a hydrocyclone circuit. In the froth flotation system, the clean coal is dewatered with a vacuum filter, while the tails are thickened in a static thickener and dewatered in a vacuum filtration operation. The clean minus 28 mesh coal is added to the 9.5 m. x 28 mesh clean coal and conveyed to the thermal drier.

To meet moisture specifications, the 9.5 mm x 0 fraction is usually thermally dried then combined with the coarse clean coal, weighed, sampled, and discharged into storage.

Level 5 coal preparation systems are distinctive in that there is production of two products, a high quality, low sulfur, low ash coal called "deep cleaned" coal and a middlings product with higher sulfur and ash content. Level 5 provides the most advanced state-of-the-art in physical coal cleaning with large reductions in pyrite and ash content and improvement of BTU content at high yields. In addition, this system is flexible relative to the types of coal it can process. Variations in raw coal and product specifications can be handled by varying the heavy medium densities and careful control of coal sizes treated in various circuits.

Level 5 coal cleaning plants use the techniques and principles utilized in the first four levels, but combine them in unique ways to maximize weight and energy recovery. Major operations involved are crushing, screening or sizing, heavy media separation, secondary separation, dewatering and removal of fines from process water. The especially high efficiency of Level 5 is due to the repeated use of these operations to produce the desired products.

In the Level 5 flow diagrams, shown in Figures 2-20 and 2-21, the raw coal screens classify the crushed and sized coal into two fractions, 3.2 cm x 6.4 mm and 6.4 mm x 0, each of which is further wet screened on desliming screens. Trash screens are used to remove the oversized and foreign material from the larger fraction. Then both fractions are further classified on desliming screens. In the coarse fraction (3.2 cm x 6.4 mm) some minus 6.4 mm fines will be washed through the desliming screens and channeled to the fine coal circuit. The remaining 3.2 cm x 6.4 mm fraction is conveyed to a high specific gravity heavy medium cyclone circuit which separates the coarse coal into an underflow refuse product and an overflow middling coal product. After separation in the heavy medium cyclone, the clean coal and refuse are rinsed of the heavy medium and dewatered. The middling coal is conveyed to thermal driers and then to storage, while the refuse fraction goes directly to disposal bins.

After the fine raw coal fraction is deslimed on screens, the smaller sized material (9 mesh x 0) is sent to the fine coal circuit. The larger sized material (6.4 mm x 9 mesh) is fed to a heavy medium cyclone circuit operating at a low specific gravity. The clean coal overflow is then rinsed, dewatered, thermally dried and conveyed to storage. Coal having reached this stage is termed "deep" cleaned coal and will meet stringent quality specifications for sulfur and ash.

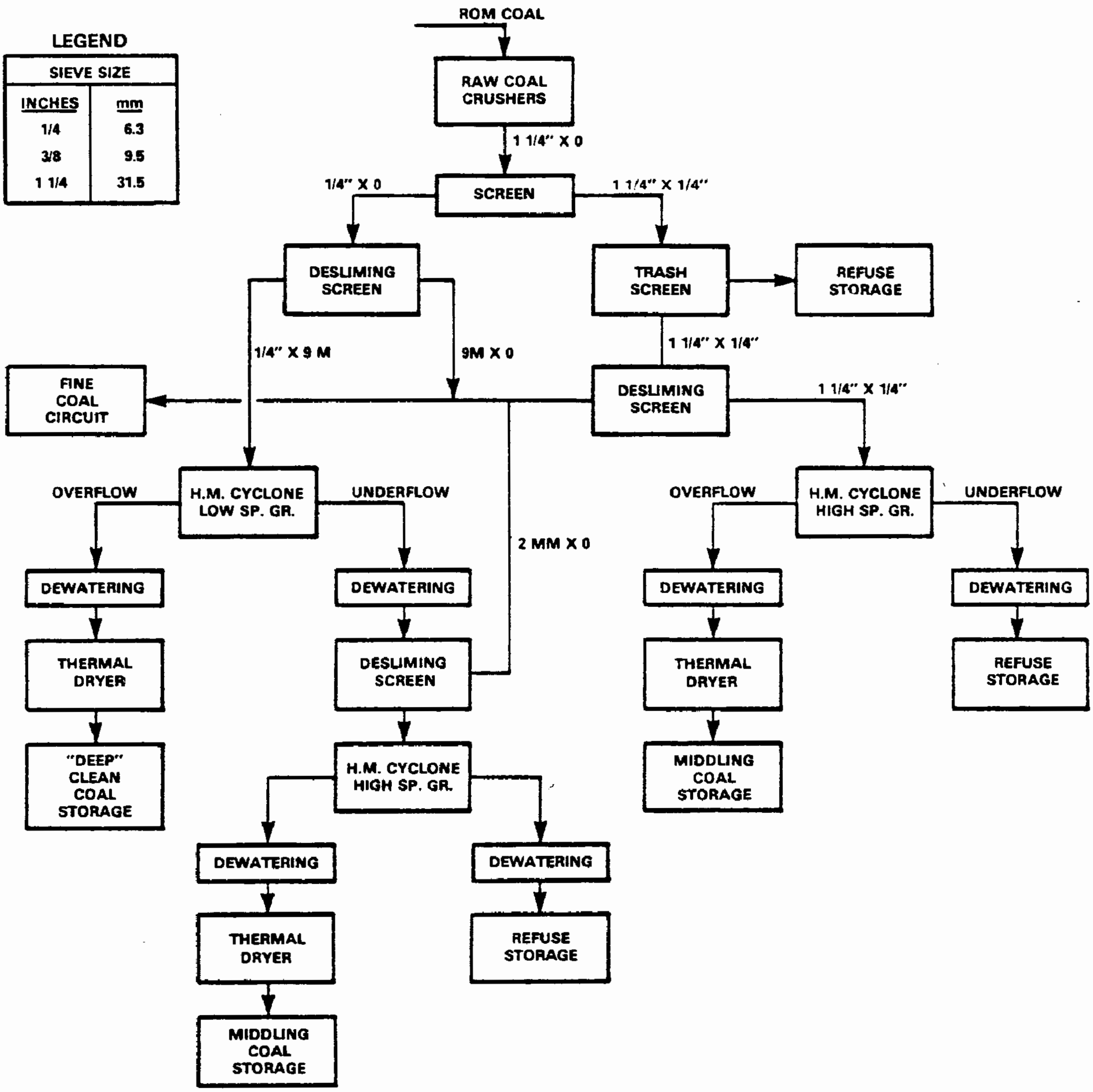


FIGURE 2-20 LEVEL 5a COAL PREPARATION FLOW DIAGRAM - COARSE COAL CIRCUIT (1 1/4" X 9 MESH) PRODUCING MIDDLING AND "DEEP CLEANED" PRODUCTS

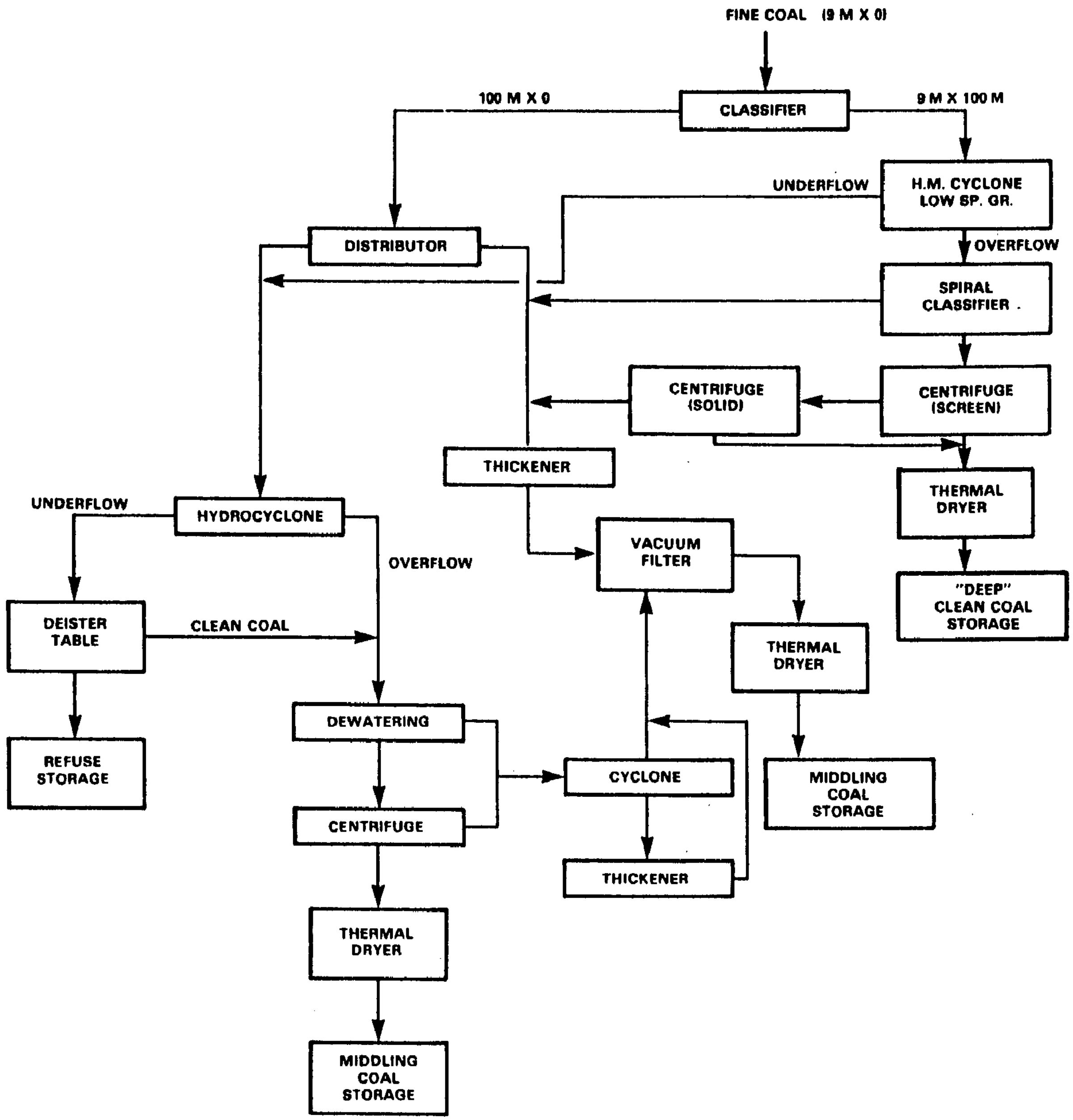


FIGURE 2.21 LEVEL 5b COAL PREPARATION FLOW DIAGRAM - FINE COAL CIRCUIT (9 MESH X 0)
PRODUCING MIDDLING AND "DEEP CLEANED" PRODUCT

The underflow from the low specific gravity heavy medium cyclone is rinsed and dewatered followed by classification on a desliming screen into a fine product, 2 mm x 0, and a larger product, 9 mesh x 2 mm. The fine product is transported to the fine coal circuit, and the larger product goes to a high specific gravity heavy medium cyclone for further cleaning. After rinsing and dewatering, the underflow is sent to refuse bins. The clean coal overflow or middling product is rinsed, dewatered, thermally dried and conveyed to middling coal storage.

Material flowing into the fine coal circuit is composed primarily of the size fraction, 9 mesh x 0. In the fine coal circuit these solids are further classified into a 9 mesh x 100 mesh fraction and a 100 mesh x 0 fraction. The larger size fraction, 9 mesh x 100 mesh, flows to a low specific gravity heavy medium cyclone, and the fines fraction is split into two streams for further treatment. One stream flows to a hydrocyclone circuit for further cleaning and one reports to a thickener. The underflow from the heavy medium cyclone also reports to the fines hydrocyclone, while the overflow flows to a spiral classifier. The spiral classifier yields a fines stream which goes to the fines thickener and another stream which flows to screen centrifuges. The underflow from the centrifuges is collected on conveyors and transported to thermal driers. This coal is then stored as "deep" clean coal. The overflow from the screen centrifuges goes to a solid bowl centrifuge which yields a "deep" clean coal product which is thermally dried and stored and a fines product which flows to the fines thickener.

The fines hydrocyclone produces an underflow product which goes to concentrating tables for refuse removal and a clean coal overflow product. The refuse from the Deister tables is conveyed to refuse bins for disposal while the middlings product from the tables is combined with the hydrocyclone overflow. This combined stream is dewatered and centrifuged to produce a middlings coal. Following thermal drying, the middlings product is conveyed to storage. The effluents from the dewatering operation and the centrifuge are sent to a cyclone for concentration of the solids. Ultrafines from the cyclone are further concentrated in a thickener. Dewatered solids from the cyclone and thickeners are further dewatered in a vacuum filter. The cake off the vacuum filter is conveyed to thermal driers and stored as a middling coal product.

Current Industrial Demand and Supply

There are currently over 460 physical coal cleaning plants in the U.S., which processed about 339.6 million tons of raw coal in 1975. Out of a total U.S. coal production of 588.6 million tons, this represents 58 percent.[42] The status of coal cleaning plants operated in 1975 is summarized in Table 2-14. Some plants use only one major cleaning process, while the majority use a series of cleaning processes. The capacity of individual plants varies widely from less than 200 metric tons per day to more than 25,000 metric tons per day.

During the past few years, the coal industry has undergone significant changes. First, steam coal prices tripled and metallurgical coal prices doubled from 1969 to 1974. This price structure created a new environment for coal preparation, and the increased value of coal justifies additional capital investment in cleaning facilities to optimize yield and quality of clean coal product. Also, environmental considerations have given impetus to the adaptation of existing coal cleaning technology and development of new or improved technology, particularly for the removal of sulfur from coal. Consequently, it is anticipated that the majority of new coal cleaning plants built will be in Levels 4 and 5 to obtain maximum ash and sulfur removal.

Research and Development on New Physical Coal Cleaning Processes

Only a portion of the pyritic sulfur content can be removed by currently practiced physical coal cleaning techniques. The percentage that is removed by any given technique depends on the size and distribution of pyrite grains within the coal. In some cases, where the pyrite exists in large, relatively discrete crystals, a high degree of separation is easily

TABLE 2-14. PHYSICAL COAL CLEANING PLANTS CATEGORIZED BY STATES FOR 1975 (42)

State	Estimated Total Coal Production, 1000 tons	Number of Coal-Cleaning Plants	Number of Plants for Which Capacity Data Reported	Total Daily Capacity of Reporting Plants, Tons	Estimated Annual Capacity of Reporting Plants,[a] 1000 tons	Number of Plants Using Various Cleaning Methods: Heavy Media	Jigs	Flotation Units	Air Tables	Washing Tables	Cyclones
Alabama	21,425	22	10	40,600	10,150	8	10	6	1	12	6
Arkansas	670	1	0	-	-	1	-	-	-	1	1
Colorado	8,168	2	0	-	-	2	-	1	-	-	-
Illinois	59,251	33	20	136,775	34,195	17	20	4	1	1	8
Indiana	24,922	7	6	42,000	10,500	2	5	1	-	1	3
Kansas	568	2	2	3,800	950	-	2	-	-	-	-
Kentucky	146,900	70	48	245,700	61,425	43	27	16	4	20	24
Maryland	2,792	1	0	-	-	-	-	-	-	-	1
Missouri	5,035	2	1	3,500	875	-	2	-	-	-	-
New Mexico	9,242	1	1	6,000	1,500	1	-	1	-	-	1
Ohio	44,582	18	13	102,750	25,690	6	11	-	1	2	5
Oklahoma	2,770	2	1	550	140	1	1	-	-	-	1
Pennsylvania (Anthracite)	5,090	24	14	13,000	3,250	21	4	4	-	3	2
Pennsylvania (Bituminous)	81,950	66	50	285,010	71,255	30	19	16	20	15	19
Tennessee	9,295	5	4	8,520	2,130	1	1	1	2	-	1
Utah	6,600	6	4	23,100	5,775	2	4	2	2	-	2
Virginia	36,500	42	29	143,550	35,890	26	15	9	8	15	11
Washington	3,700	2	1	20,000	5,000	1	1	-	-	-	-
West Virginia	110,000	152	113	577,375	144,345	104	55	59	12	55	59
Wyoming	23,595	1	1	600	150	-	-	-	1	-	-
Total	603,055	459	318	1,652,830	413,210	266	177	121	52	125	144

(a) The estimated annual-capacity values for the reporting plants were calculated from the daily-capacity values by assuming an average plant operation of 250 days per year (5 days per week for 50 weeks per year).

obtained. On the other hand, if the pyrite consists of small grains mixed intimately through the coal matrix, separation by physical means can be extremely difficult.

A number of new techniques for physical coal cleaning have been investigated to improve the pyritic sulfur removal. Among them are magnetic separation, two-stage froth flotation, oil agglomeration and heavy liquid separation. These processes are only in the experimental stage and need considerably more work to determine their full potential. A brief discussion of new processes is given below:

Two-Stage Froth Flotation--[43]

Single-stage froth flotation has long been used as a beneficiation method for fine coals usually denoted 28 mesh x 0. This process consists of agitating the finely divided coal and mineral suspension with small amounts of reagents in the presence of water and air. The reagents help to form small air bubbles which collect the hydrophobic coal particles and carry them to the surface, while the hydrophilic mineral matter is wetted by water and drawn off as tailings.

Recently, a novel two-stage froth flotation process was developed by the U.S. Bureau of Mines to remove pyrite from fine-size coals. In the first stage, coal was floated with a minimum amount of frother (methyl isobutyl carbinol) while coarse, free pyrite and other refuse were removed as tailings. In the second stage, coal was suppressed with a coal depressing agent (Aero Depressant 633), while fine-size pyrite was floated with a pyrite collector (potassium amyl xanthate).

The two-stage froth flotation process has been demonstrated in a half-ton-per-hour-capacity pilot plant. It is reported that negotiations are underway to install a full-scale prototype of 12 ton/hour capacity in an existing coal cleaning plant. The pilot plant data showed that up to 75 percent of pyritic sulfur could be removed from the Lower Freeport coal (minus 35 mesh) at about 60 percent of weight recovery.

Oil Agglomeration--

The use of a water-immiscible liquid, usually hydrocarbons, to separate coal from the impurities is an extension of the principles employed in froth flotation. The surface of coal is preferentially wetted by the hydrocarbons while the water-wetted minerals remain suspended in water. Hence, separation of two phases takes place and produces a clean coal containing some oil and an aqueous suspension of the refuse generally free from combustible material.

Recently, the National Research Council of Canada developed a spherical oil agglomeration process for cleaning coal fines in two steps: flocculation followed by a balling step. In the flocculation stage, a small amount of light oil (less than 5 percent) was added to a 20-30 percent coal slurry in a high-speed agitator to form micro-agglomerates. In the balling stage, a heavy, less expensive oil was added to a rotating pelletizer-disc to form strong spherical balls.

It is reported that the spherical oil agglomeration process has been incorporated into the coal fine recovery circuit of a western Canadian preparation plant. The results of laboratory-batch experiments showed that about 50 percent of the pyritic sulfur was removed from the Canadian coal ground to less than 50 microns at over 90 percent BTU recovery.

High Gradient Magnetic Separation--[44,45]

A high gradient magnetic separator utilizes electromagnets to generate a magnetic field and remove mineral components, especially pyrite, from either an aqueous suspension of finely ground coal or a dry powder. The separator consists of a column packed with Series 430 magnetic stainless steel wool or screens which are inserted in the base of a solenoid magnet.

General Electric Company, in conjunction with the Massachusetts Institute of Technology and Eastern Associated Coal, is attempting to establish the technical feasibility of removing inorganic sulfur from dry coal powders at commercially significant rates.

In addition, the Indiana University is currently investigating the use of a high-extraction magnetic filter for the beneficiation of a coal slurry containing fines below 200 mesh. A magnetic filter of 213 cm diameter can process up to 90 metric tons of raw coal per hour.

The utility of the process has not yet been established. Test data from the high gradient magnetic separation of dry coal powders showed that up to 57 percent of total sulfur could be removed from an eastern coal (48 mesh x 0) with the magnetic field intensity of 64 kilo oersteds at the flow velocity of 2.8 cm/sec. Laboratory tests of the Indiana University indicated that up to 93 percent of the inorganic sulfur could be removed from a coal slurry containing 90 percent of minus 325 mesh sizes with the magnetic field intensity of 20 kilo oersteds, using three passes at 30-seconds retention.

Heavy Liquid Separation--[46]

Heavy liquid separation is a practical extension of the laboratory float-sink test. The crushed raw coal is immersed in a static bath of a heavy liquid having a density intermediate between clean coal and reject. The float material is recovered as clean coal product and the sink material is rejected as refuse. The used heavy liquid is recovered completely by draining and evaporating it from the product coal and the reject material. The use of a heavy liquid for coal cleaning is not new. In 1936, a 45 kkg/hour pilot plant was built by the DuPont Company using chlorinated hydrocarbons. However, the high costs of these heavy liquids and the toxic effects of the vapors prohibited DuPont's commercialization of the process.

Recently, Otisca Industries reported the development of an anhydrous heavy liquid for gravity separation of coal. The chemical composition of their liquid is a chlorinated fluorocarbon, with a boiling point of 24°C, a heat of evaporation of 43.1 cal/g, and a specific gravity of 1.50 at 16°C. It is claimed that their process is capable of the near theoretical separation which can be obtained in the laboratory float-sink test. The data showed that about 44 percent of total sulfur was removed from 4 mm x 0 size coal at 74 percent weight recovery. The misplaced material fell in the range of 0.5 ± 0.25 percent under normal operating conditions.

Factors Affecting Physical Coal Cleaning Performance

Design factors

A physical coal cleaning plant is a combination of individual unit operations, each intended for a specific purpose, and chosen and integrated based upon four fundamental factors:

- the washability of the particular coal feed;
- the quality specifications of the product(s);
- the acceptable recovery of material and of heating value; and
- the acceptable costs of cleaning.

A plant's ultimate performance is limited by the coal washability characteristics, which measure the degree of liberation of the coal from its inorganic impurities at a given particle size distribution. The finer the coal is crushed, the more impurities including pyritic sulfur is liberated. However, microscopically-dispersed pyrite (which varies widely in relative quantity to macroscopic pyrite from coal to coal) cannot be liberated by conventional size reduction techniques.

Table 2-15 is the washability data for a typical high-sulfur (3.40 percent total S, 2.79 percent pyritic S) eastern coal. The limitations to pyritic sulfur removal, for different degrees of size reduction, are shown in Figure 2-16, which is the washability curve constructed from the data of Table 2-15. The "yield" curves show the percent of the feed that floats, i.e., the clean coal product recovery, in an ideal separation device, for any specific gravity of separation. Note that since the ash content of the raw coal is 23.4 percent, approximately 80 percent material yield (based upon ash rejection) is equivalent to virtually 100 percent recovery of heating value.

From Figure 2-22 a yield of 63 percent (coarse coal) or 65 percent (fine coal) occurs at an operating specific gravity of 1.40. The "cumulative float pyritic sulfur" curves show the corresponding concentration of pyritic sulfur at this clean coal yield - this is 0.85 percent pyrite (coarse coal) and 0.50 percent pyrite (fine coal). A pyritic sulfur reduction of 70 percent may therefore be achieved for the coarse (2" x 3/8")

Spec Gravity	Direct					Cumulative Float				
	Weight %	Ash %	Btu/ lb	Pyritic Sulfur,%	Total Sulfur	Weight %	Ash %	Btu/ lb	Pyritic Sulfur,%	Total Sulfur
Size Fraction: 2" x 3/8" (30.0%)										
Float 1.30	38.2	3.4	14589	0.44	0.85	38.2	3.4	14589	0.44	0.85
1.30 - 1.40	24.2	10.1	13613	1.51	2.27	62.4	6.0	14810	0.85	1.40
1.40 - 1.50	8.5	25.2	12011	2.28	2.70	70.9	8.3	13947	1.03	1.55
1.50 - 1.60	4.0	30.7	10566	2.95	3.70	74.9	9.5	13766	1.13	1.67
1.60 - 1.80	4.5	44.7	8837	5.35	5.70	79.4	11.5	13486	1.37	1.89
Sink 1.80	20.6	73.6	3949	8.74	9.03	100.0	24.3	11581	2.89	3.36
Size Fraction: 3/8" x 28 mesh (55.0%)										
Float 1.30	45.8	3.3	14604	0.43	0.85	45.8	3.3	14604	0.43	0.85
1.30 - 1.40	19.2	10.5	13767	0.96	1.50	64.0	5.4	14356	0.59	1.07
1.40 - 1.50	4.5	21.1	12050	1.84	2.20	70.5	6.3	14005	0.67	1.13
1.50 - 1.60	3.5	29.2	10752	2.30	2.80	74.0	7.4	13851	0.75	1.81
1.60 - 1.80	3.1	44.0	8852	3.63	3.90	77.1	8.9	13649	0.86	1.32
Sink 1.80	22.9	72.8	3887	8.71	10.35	100.0	23.5	11414	2.68	3.40
Size Fraction: 28 mesh x 0 (15.0%)										
Float 1.30	46.3	3.0	14649	0.32	0.74	46.3	3.0	14649	0.32	0.74
1.30 - 1.40	18.7	8.5	13822	0.96	1.50	65.0	4.6	14411	0.50	0.96
1.40 - 1.50	7.0	16.0	12080	1.57	2.22	72.0	5.7	14184	0.61	1.08
1.50 - 1.60	3.9	28.1	10840	3.10	3.65	75.9	6.5	14012	0.74	1.21
1.60 - 1.80	3.5	35.1	7977	3.76	4.10	79.4	7.8	13746	0.87	1.34
Sink 1.80	20.6	74.2	3781	1.12	11.9	100.0	21.4	11680	3.00	3.51

Table 2-15 Raw Coal Washability Data for the Upper Freeport Seam (47)

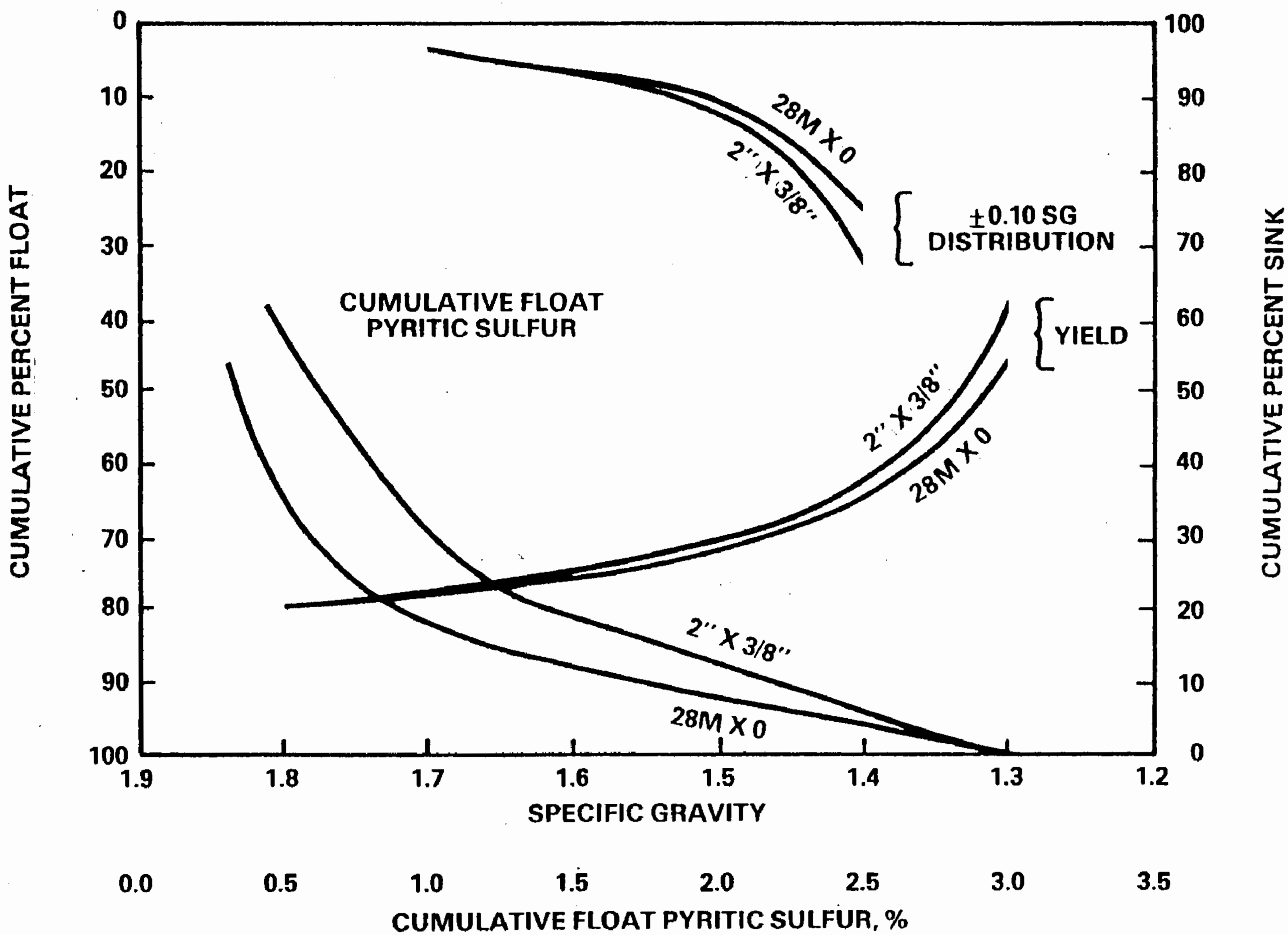


FIGURE 2-22 WASHABILITY CURVES, UPPER FREEPORT SEAM

coal fraction, and 82 percent reduction may be achieved for the fine (28 mesh x 0) fraction, reflecting greater pyrite liberation; all at a chosen specific gravity of separation of 1.40. This example illustrates one degree of design freedom - the extent of size reduction of the feed coal - which is used to achieve the required pyritic sulfur level in the product.

A second degree of design freedom is the specific gravity of separation. Again referring to Figure 2-22, the yields at a specific gravity of 1.55 are 73 percent (coarse coal) and 74 percent (fine coal). The corresponding concentration of pyritic sulfur in the product is 1.10 percent (a 61 percent reduction) for the coarse coal, and 0.68 percent (a 76 percent reduction) for the fine coal. Note that an increase in yield may be achieved at the expense of a decrease in product purity, utilizing the design parameter of specific gravity of separation.

This trade-off of yield vs. purity is basic for any one unit operation. One item of equipment cannot achieve both performance goals - either yield is maximized, or purity is maximized, or a compromise is made between yield and purity. This basic limitation to performance also exists for an entire plant which produces a single clean coal product.

However, the designer of a multi-product plant may in fact achieve <u>both</u> performance goals. One circuit may be selected for maximizing product purity although the quantity of this clean product is relatively small. For example, washing of 28 mesh x 0 coal (referring to Figure 2-22) at a specific gravity of 1.30 results in a product with a pyritic sulfur content of 0.31 percent, a reduction of 89 percent, but a yield of only 46 percent. If the rejected 54 percent were then washed again at a relatively high specific gravity in another (sequential) unit operation, a "middling" product with somewhat higher pyritic sulfur content may be recovered with an overall recovery (between the two products) of almost all the original heating value.

The inherent design advantages of a multi-product plant do have special significance for industrial boilers. Since the coal quantities used by industrial boilers are a small fraction of the total coal demand, it might be quite attractive for a coal cleaning plant to produce a very clean product for new industrial boilers (at a premium price) and a middling product suitable either for consumers with less stringent emission standards or for large consumers (utilities) with additional site-specific SO_2 controls.

Much of plant design practice is guided by equipment capabilities. There is a fundamental distinction between equipment suitable for coarse coal operations and that used for fine coal operations. Generally, 3/8-inch is regarded as the boundary between coarse and fine coal fractions. Moreover, a special class of equipment is suited for very-fine coal operations (-28 mesh). Classical design practice has been to perform one or more initial size classifications and then to separately clean each stream. For single-product plants, the designer plans to ultimately blend the clean products from each size-specific fraction. The designer meets his intended product quality by selecting individual unit operations in each size-specific circuit such that the composite goal is most economically achieved.

A design approach popular before sulfur removal became very important was to beneficiate only the coarse fraction; equipment for coarse-coal separation is relatively simple, efficient, inexpensive, and easy to operate and maintain, compared to fine-coal equipment. Moreover, fine coal after beneficiation is much more difficult to dewater and handle, and fine refuse handling and disposal is relatively expensive. Hence, the entire fine coal fraction in older plants was blended, without beneficiation, with a cleaned coarse coal product.

This practice represents another fundamental design trade-off: selective beneficiation of coarse coal for cost minimization conflicts with the performance goal of maximum liberation (and removal) of pyrite in fine coal circuits. Increasing demand for low-sulfur cleaned coal has shifted the design balance toward fine coal beneficiation (at higher processing costs).

Operating Factors

The washability characteristics of a specific coal represent the best performance attainable. In coal cleaning plants, each unit operation achieves somewhat lower than ideal separation efficiency. The term "misplaced material" is used to denote that material more dense than the specific gravity of separation which reports in the clean coal product, plus that material less dense which reports in the refuse.

For any given type of separation equipment, the quantity of misplaced material is a very strong function of the specific gravity difference (the driving force for separation). Thus, particles with specific gravities quite different from the specific gravity of separation would much more likely report in the proper place (float or sink) than particles in the "near-gravity" regime. The misplaced material quantity correlates well with specific gravity difference in a "distribution curve", which is a probabilistic plot of efficiency for each item of equipment operating upon a specific feed coal. The misplaced material may typically amount to 10 to 25 percent of the near-gravity material (that within $\pm$ 0.10 specific gravity units) but accounts for much less of the far-gravity material. The relative amount of near-gravity material (as determined in washability tests) in the feed coal therefore is an indicator of how inefficient a separation may be. Referring again to Figure 2-16, the "±0.10 SG distribution" curves show the percentage of near-gravity material in the coal as a function of specific gravity of separation. The designer or operator uses the washability curves (as in Figure 2-16) to choose a specific gravity of separation such that the quantity of near-gravity material does not exceed 10 percent of the feed. In this way, the quantity of misplaced material may be limited to a few percent of the feed.

The type of equipment is also very important in affecting the separation performance. Dense medium coarse coal vessels and dense medium cyclones, for example, are much more efficient (much lower misplaced material values) than jigs or concentrating tables. The size composition of the feed is also important - the coarser the coal, the less the misplaced material. For very fine coal, misplaced material values are high because surface effects become important.

Large variations in separation efficiency may occur because of purely operational (as opposed to design) factors. Throughput is most important;

the efficiency of most units is quite sensitive to overloading. Other factors are process control and stability of operation, the adjustment of equipment, and the mechanical condition of the equipment. These operational difficulties are quite controllable, and may be largely eliminated by applying good plant operating practices and skill. The coal cleaning industry generally operates on a 2-shift, 5-day basis, allowing sufficient time for plant maintenance. As more ambitious and sophisticated plants come on stream, responding to increasing demand for deeper-cleaned coal and to higher coal prices, the skill levels and resources committed to good operation, maintenance, and process control should also increase with a commensurate positive effect upon plant performance.

Maintenance problems in physical coal cleaning plants are typically related to handling the abrasive material, crushed coal. Since the equipment in a physical coal cleaning plant is not complex, maintenance is easier and cheaper than for most other control technologies. Corrosion in the plant is most often due to acid formation in process water through oxidation of the sulfur in the coal. This problem is mitigated through proper selection of construction materials and weekly or monthly maintenance scheduling.

2.2.2.2 System performance--

Versar has recently completed a survey and analysis of existing commercial physical coal cleaning plants.[48] The purpose of the study was to obtain sulfur and BTU content data from U.S. coal companies on feed and product coal. Versar requested from the coal companies small coal lot size information consistent with small utility boilers or large industrial boilers.

The coal companies were also asked to provide the cleaning level for each feed-product pair. Versar provided schematic process flowcharts representing four coal cleaning levels. The four cleaning levels (1-4) described in the survey correspond generally to levels 1-4 presented in Section 2.2.2.1 above. Level 5, a multi-product, deep cleaned coal beneficiation plant, was not encountered in the survey.

The coal companies basically responded with long-term, average data on about 50 plants. Short-term, small lot size feed and product data were not available because of the infrequent sampling of feed coal. Typically,one sample of the feed coal is taken on a daily or weekly basis, although the frequency is more dependent upon the occurrence of operating problems on a routine sampling schedule. As a result, the coal companies did not believe that one or two feed coal analyses would be representative of a lot shipment, so long-term averages were provided. One coal firm did provide extensive product coal information on small lot sizes.

The data received is summarized in Table 2-16.[49] The approach taken to investigate sulfur removal performance of coal cleaning plants was to initially analyze individual plants. For each plant with sufficient feed and product coal data,the mean (μ) standard deviation (σ) and relative standard deviation (RSD) were calculated to determine the variation in sulfur removal for the most constant situation (i.e.,only feed coal characteristics change). Data analyses for the nine individual plants are provided in Tables 2-17 through 2-25.[50]

The nine individual plants show that sulfur content per unit heat content (i.e. ng SO_2/J) is decreased by the coal preparation process. This occurs even though the plants were primarily designed to remove refuse and ash in their attempt to increase BTU content and are not designed specifically to remove sulfur. Sulfur removal percentages ranged from 18.3 to 48.3%. On absolute terms, a sulfur reduction equivalent of 150 ng SO_2/J was attained on the lowest sulfur coal (Plant I) and 1,400 ng SO_2/J was provided on one of the highest sulfur coals (Plant E).

Significantly in all nine plants the standard deviation (i.e.,sulfur variability) in ng SO_2/J was reduced, and in eight of the nine plants the RSD decreased.

TABLE 2-16. CHARACTERIZATION OF DATA RECEIVED FROM COAL COMPANIES AND TESTING

NO. OF DATA SETS = 129

REGIONAL DISTRIBUTION

N. Appalachia	=	39
S. Appalachia	=	40
E. Midwest	=	45
Alabama	=	5

CLEANING LEVEL

N. Appalachia	S. Appalachia	E. Midwest	Alabama
Level 1 = 2	Level 1 = 0	Level 1 = 4	Level 4 = 5
Level 2 = 7	Level 2 = 5	Level 2 = 22	
Level 3 = 22	Level 3 = 13	Level 3 = 18	
Level 4 = 8	Level 4 = 24	Level 4 = 1	

SULFUR CONTENT OF FEED COAL

>3%	=	61
1-3%	=	35
<1%	=	33

SULFUR CONTENT OF FEED COAL BY REGION

	>3%	1-3%	<1%
N. Appalachia	19	18	2
S. Appalachia	0	12	28
E. Midwest	42	2	1
Alabama		3	2

LOT QUANTITY (TONS) - DATA SETS IN EACH RANGE

≥500,000	=	5
100,000-499,999	=	49
10,000- 99,999	=	44
1,000- 9,999	=	18
<999	=	13

TABLE 2-17. MONTHLY AVERAGE SULFUR REDUCTION BY A LEVEL II CLEANING PLANT - ILLINOIS NO. 6 COAL

PLANT A

COAL USE	LOT QUANTITY* (metric tons)	FEED %S	FEED kJ/kg	FEED ng SO_2/J	PRODUCT %S	PRODUCT kJ/kg	PRODUCT ng SO_2/J
Steam	169,462	3.98	25,893	3,078.8	3.64	28,130	2,592.9
Steam	339,826	4.27	25,117	3,405.6	3.93	28,130	2,799.3
Steam	313,257	4.74	25,465	3,728.1	3.83	27,986	2,743.4
Steam	331,132	4.72	25,609	3,693.7	3.94	28,070	2,812.2
Steam	318,613	4.10	25,490	3,225.0	3.83	28,098	2,730.5
Steam	267,310	4.45	24,463	3,646.4	3.71	28,035	2,653.1
Steam	271,923	4.87	24,008	4,063.5	4.40	28,652	3,078.8
Steam	272,630	5.16	24,947	4,145.2	4.34	28,608	3,040.1
Steam	289,303	5.05	25,528	3,964.6	4.44	28,822	3,087.4
Steam	254,843	5.44	25,027	4,355.9	4.46	28,706	3,113.2
Steam	275,065	4.98	24,272	4,110.8	4.42	28,582	3,100.3
Steam	221,743	5.20	25,083	4,153.8	4.29	28,640	3,001.4

FEED (ng SO_2/J)

$\mu = 3,796.9$ $\sigma = 404.2$ RSD = 0.106

PRODUCT (ng SO_2/J)

$\mu = 2,898.2$ $\sigma = 193.5$ RSD = 0.067

SULFUR REMOVAL (%)

$\mu = 23.4$ $\sigma = 5.86$ RSD = .25

* Monthly Coal Throughput
Product sampled mechanically

TABLE 2-18. MONTHLY AVERAGE SULFUR REDUCTION BY A LEVEL II CLEANING PLANT - KENTUCKY #9 and #14

PLANT B

	Feed			Product		
Quantity* (metric tons)	%S	kJ/kg	ng SO_2/J	%S	kJ/kg	ng SO_2/J
184,913	4.17	25,712	3,250.8	3.21	30,411	2,115.6
162,692	4.64	27,557	3,375.5	3.23	30,437	2,124.2
189,817	4.08	27,981	2,919.7	3.24	30,360	2,137.1
183,209	3.96	24,533	3,233.6	3.14	32,450	1,939.3
266,168	3.98	27,054	2,949.8	3.13	30,236	2,072.6
180,382	4.13	25,430	3,255.1	3.18	30,187	2,111.3

Coal Use: Steam

Feed (ng SO_2/J)

μ = 3,164.8 σ = 191.78 RSD = 0.061

Product (ng SO_2/J)

μ = 2,085.5 σ = 43.43 RSD = 0.021

Sulfur Removal (%)

μ = 33.2 σ = 4.26 RSD = 0.128

* Monthly Coal Throughput
Product sampled mechanically

TABLE 2-19. MONTHLY AVERAGE SULFUR REDUCTION BY A LEVEL II CLEANING PLANT - KENTUCKY #9

PLANT C

Lot Quantity (metric tons)	FEED %S	FEED kJ/kg	FEED ng SO_2/J	PRODUCT %S	PRODUCT kJ/kg	PRODUCT ng SO_2/J
113,068	4.72	29,002	3,263.7	3.40	30,339	2,244.6
105,246	4.07	28,857	2,825.1	3.40	30,013	2,270.4
92,494	3.99	28,004	2,855.2	3.36	30,278	2,223.1
83,306	3.96	27,177	2,919.7	3.30	30,285	2,184.4
81,723	5.05	28,319	3,573.3	3.35	30,183	2,223.1
68,479	3.93	29,656	2,657.4	3.38	30,262	2,236.0

Coal Use: Steam

Feed (ng SO_2/J)

μ = 3,014.3 σ = 342.3 RSD = 0.114

Product (ng SO_2/J)

μ = 2,231.7 σ = 28.0 RSD = 0.012

Sulfur Removal (%)

μ = 25.2 σ = 7.96% RSD = 0.316

Product sampled manually

TABLE 2-20. MONTHLY AVERAGE SULFUR REDUCTION FOR A LEVEL 2 COAL CLEANING PLANT - KENTUCKY Nos. 11 and 12

PLANT D

LOT QUANTITY (metric tons)	FEED			PRODUCT		
	%S	kJ/kg	ng SO_2/J	%S	kJ/kg	ng SO_2/J
264,129	3.99	25,171	3,177.7	3.31	29,246	2,266.1
224,563	4.25	22,883	3,719.5	3.39	29,113	2,334.9
234,109	3.77	24,675	3,061.6	3.29	29,435	2,240.3
156,950	-	-	-	3.20	29,565	2,167.2
182,844	-	-	-	3.15	29,572	2,132.8
179,810	5.03	22,992	4,381.7	2.97	29,899	1,990.9

Coal Use: Steam

Feed (ng SO_2/J)

μ = 3,586.2 σ = 602.0 RSD = 0.168

Product (ng SO_2/J)

μ = 2,188.7 σ = 114.0 RSD = 0.052

Sulfur Removal (%)

μ = 36.83 σ = 12.89 RSD = 0.350

Product sampled manually

TABLE 2-21. MONTHLY AVERAGE SULFUR REDUCTION BY A LEVEL II CLEANING PLANT - MIDDLE KITTANING (Ohio No. 6)

PLANT E

COAL USE	LOT QUANTITY (metric tons)	FEED %S	FEED kJ/ng	FEED ng SO_2/J	PRODUCT %S	PRODUCT kJ/ng	PRODUCT ng SO_2/J
Steam	154,565	4.07	25,756	3,164.8	3.03	29,111	2,085.5
Steam	138,162	3.73	27,180	2,747.7	2.86	29,041	1,973.7
Steam	162,063	3.98	26,047	3,061.6	3.06	29,037	2,111.3
Steam	145,074	4.46	25,029	3,569.0	3.05	28,992	2,107.0
Steam	189,246	3.96	25,248	3,143.3	3.06	29,044	2,111.3
Steam	163,255	3.45	25,465	2,713.3	2.99	28,957	2,068.3

Feed (ng SO_2/J)

$\mu = 3,065.9$ $\sigma = 322.9$ RSD = 0.105

Product (ng SO_2/J)

$\mu = 2,076.9$ $\sigma = 37.4$ RSD = 0.018

Sulfur Removal (%)

$\mu = 32.0$ $\sigma = 5.91$ RSD = 0.185

Product sampled manually

TABLE 2-22. ANNUAL AVERAGE SULFUR REDUCTION BY A LEVEL III CLEANING PLANT - OHIO COAL

PLANT F

	FEED			PRODUCT		
SEAM	%S	kJ/kg	ng SO_2/J	%S	kJ/kg	ng SO_2/J
#8	3.28	22,524	2919.7	3.96	30,831	2575.7
LF	2.92	21,313	2743.4	2.94	32,203	1827.5
#8	2.05	21,750	1887.7	2.78	31,502	1767.3
LF	2.55	27,459	1861.9	2.34	32,571	1440.5
#8	5.09	28,622	3564.7	3.59	31,294	2300.5
#9	2.51	28,885	1741.5	2.15	30,024	1436.2
#9	3.02	29,130	2076.9	2.51	30,462	1651.2
#8	2.67	29,498	1814.6	2.33	32,282	1444.8

SEAM: Pittsburgh #8 and #9; Lower Freeport #6A ('D' Coal)

Coal Use: Steam

Feed

μ = 2326.3 ng SO_2/J σ = 670.8 ng SO_2/J RSD = 0.288

Product

μ = 1806.0 ng SO_2/J σ = 426.1 ng SO_2/J RSD = 0.236

Sulfur Removal

μ = 21.0% σ = 9.85% RSD = 0.469

Product sampled manually

TABLE 2-23. DAILY AVERAGE SULFUR REDUCTION BY A LEVEL III CLEANING PLANT - LOWER KITTANING - 5 DAY TESTS

	FEED			PRODUCT		
Day	%S	kJ/kg	ng SO_2/J	%S	kJ/kg	ng SO_2/J
1	2.80	31,420	1,784.5	1.11	34,069	653.6
2	2.24	30,008	1,496.4	1.20	33,200	722.4
3	1.84	28,198	1,307.2	1.22	32,960	739.6
4	1.46	29,491	993.3	0.82	33,533	490.2
5	1.38	31,756	872.9	0.99	33,634	589.1

Lot Size = 581 metric tons

Coal Use: Metallurgical

Feed (ng SO_2/J)

μ = 1,290 σ_x = 369.8 RSD = 0.29

Product (ng SO_2/J)

μ = 640.7 σ_x = 103.2 RSD = 0.16

Sulfur Removal (%)

μ = 48.3 σ = 11.4 RSD = 0.237

Seam Coal

Lower Freeport - Kittaning B,C,D,E

Grab sample taken every 15 minutes over four hour period per day

TABLE 2-24. DAILY AVERAGE SULFUR REDUCTION BY A LEVEL III PLANT - SOUTH WESTERN VIRGINIA SEAMS - 5 DAY TESTS

PLANT H

	FEED			PRODUCT		
Day	%S	kJ/kg	ng SO_2/J	%S	kJ/kg	ng SO_2/J
1	1.24	25,243	984.7	1.48	33,997	872.9
2	.92	24,178	761.1	1.31	33,666	778.3
3	.82	22,766	722.4	0.89	33,226	537.5
4	1.15	21,394	1,075.0	1.06	33,617	640.7
5	1.10	22,722	971.8	1.10	34,074	645.0

Lot Size = 2,395 - 2,503 metric tons per day

Coal Use: Steam

Feed (ng SO_2/J)

μ = 903.0 σ_x = 154.8 RSD = 0.17

Product (ng SO_2/J)

μ = 696.6 σ_x = 133.3 RSD = 0.19

Sulfur Removal (%)

μ = 21.7 σ = 17.2 RSD = .793

Seam Coal	% Feed
Elkhorn-Rider	12.5
Lyons	12.5
Dorchester	25
Norton	25
Clintwood	25

Grab sample taken every 15 minutes over four hour period per day

TABLE 2-25 DAILY AVERAGE SULFUR REDUCTION BY A LEVEL III CLEANING PLANT - REFUSE COAL - 5 DAY TESTS

PLANT I

	FEED			PRODUCT		
Day	%S	kJ/kg	ng SO_2/J	%S	kJ/kg	ng SO_2/J
1	.603	16,466	735.3	.948	31,555	602.0
2	.637	18,936	675.1	.835	30,854	541.8
3	1.099	21,166	1,040.6	1.009	30,083	670.8
4	.570	20,206	563.3	.830	31,066	533.2
5	.582	18,377	636.4	.850	30,716	554.7

Lot Size = 544 metric tons

Coal Use: Metallurgical

Feed (ng SO_2/J)

$\mu = 731.0$ $\sigma_x = 184.9$ ng SO_2/J RSD = 0.25

Product (ng SO_2/J)

$\mu = 580.5$ $\sigma_x = 55.9$ ng SO_2/J RSD = 0.099

Sulfur Removal (%)

$\mu = 18.3$ $\sigma = 11.1$ RSD = 0.605

GOB Coal (Refuse)

Grab sample taken every 15 minutes over four hour period per day

It is also noteworthy that the two preparation plants which did not provide at least 35% reduction of RSD were cleaning blends of coal or various coals during the time period studied (i.e., Plant F cleans three different seam coals and Plant H cleans a blend of five different coals).

To examine all the data received, avoiding complete aggregation, the information was analyzed on a seam and cleaning level basis. The results are provided in Tables 2-26 through 2-29.[51] These tables show that physical coal cleaning can be quite effective in reducing the ng SO_2/J emissions from a coal boiler by 20-40 percent. The tables also show that certain cleaning levels are more effective than others for a given seam or region. Southern Appalachian low sulfur coal is an excellent example, as one compares the effectiveness of cleaning level 4 to the ineffectiveness of levels 2 and 3. In contrast, there is little differentiation between the effectiveness of levels 2, 3 and 4 for coals in the Northern Appalachian and Midwest regions.

The major assumption inherent in the tables presented is that the infrequently sampled feed coal average values are representative of the actual feed coal quality. In contrast, the product coals were sampled on a regular basis, either mechanically or by ASTM methods on coal shipments, because of coal product specification requirements. Product coal quality is therefore considered quite representative of the actual coal quality.[52] Unless controlled tests are performed on commercial coal cleaning plants, this major assumption will not be tested.

A second major source of performance data is a 1972 EPA survey of air pollution potential from coal cleaning plants.[53] This survey included about 120 plants for which annual average feed and product coal quality was obtained. The results of that survey are provided in Table 2-30. The survey results generally support the conclusion that physical coal cleaning

TABLE 2-26. EASTERN MIDWEST COAL SULFUR REDUCTION BY SEAM AND CLEANING LEVEL

SEAM	1	Cleaning Level 2	3	4	Average Reduction Levels 2-4	Pts.
Illinois #6	5.6/3	36.3/2	26.7/16	34.9/1	28%	22
Illinois/Indiana #2 & #3		43.4/2			43%	2
Illinois #5			23.4/2		23%	2
Kentucky #9	0/1	29.2/12			29%	13
Kentucky #11 & #12		36.8/6			37%	6
Weighted Averages	4.2/4	33.2/22	26.3/18	34.9/1	30%	45

Values shown are percent reduction in ng SO_2/J/No. of data points.

TABLE 2-27. NORTHERN APPALACHIA COAL SULFUR REDUCTION BY SEAM AND CLEANING LEVEL

SEAM	1	Cleaning Level 2	3	4	Average Reduction Levels 2-4	Data Points
Pittsburgh, #8	(0/1)	21.5/1	30.6/13	29.8/3	30%	17
#9			19.0/2		19%	2
Middle Kittaning (#6)		32.0/6		49.2/2	36%	8
Lower Freeport (#6A)			23.0/2		23%	2
Lower Kittaning			48.4/5*	45.4/1	48%	6
Upper Freeport				35.1/2	35%	2
Weighted Averages	(0/1)	30.1/7	32.9/2	37.9/8	33%	37

Values shown are percent reduction in ng SO_2/J/No. of data points.

*Blend of B,C,D,E , 'B' predominates

TABLE 2-28. SOUTHERN APPALACHIA COAL SULFUR REDUCTION BY SEAM AND CLEANING LEVEL

SEAM	Cleaning Level 1	2	3	4	Average Reduction Levels 2-4	Data Points
Cedar Grove		11.3/3		-25.0/1	2%	4
Jewell				34.0/4	34%	4
Pocahontas 3 & 4				39.4/3	39%	3
Sewell			11.5/1	54.1/2	40%	3
Various Seams		0/2	14.3/12	29.3/14		
Weighted Averages		2.6/5	14.1/13	31.2/24	23%	42

Values shown are percent reduction in ng SO_2/J/No. of data points

TABLE 2-29. ALABAMA COAL SULFUR REDUCTION BY SEAM AND CLEANING LEVEL

SEAM	Cleaning Level 1	2	3	4	Average Reduction Levels 2-4	Data Points
Mary Lee				40.1/3	40%	3
Blue Creek				42.8/2	43%	2
Weighted Averages				41.1/5	41%	5

Values shown are percent reduction in ng SO_2/J/No. of data points

TABLE 2-30. SULFUR EMISSION REDUCTION DATA BASED ON THE 1972 EPA SURVEY

NON-METALLURGICAL COAL

Region	Cleaning Level 2	Cleaning Level 3	Cleaning Level 4	Mean Removal Levels 2-4	Total Data Points
N. Appalachia	17.2/10	25.5/2	35.5/8	26.1	20
S. Appalachian	20.7/8	7.4/10	16.2/14	14.8	32
E. Midwest	28.4/3	16.4/8	20.7/3	21.8	14
METALLURGICAL COAL					
N. Appalachian	37.8/3	40.9/2	46.7/5	41.8	10
S. Appalachian	34.5/2	16.5/8	28.6/27	26.5	37
E. Midwest	1.95/1	-1.73/1	16.6/3	5.61	5
Western	0	0	9/2	3.0	2
COMBINED					
N. Appalachian	22.0/13	33.2/4	39.8/13	31%	30
S. Appalachian	23.5/10	11.4/18	24.4/41	21%	69
E. Midwest	21.8/4	14.4/9	18.6/6	17%	19

(Percentage ng SO_2/J Reduction/No. of Points) can significantly reduce the ng SO_2/J emissions from industrial boilers, although the average reductions are smaller. Relative to cleaning levels, the reduction range is about the same as the Versar study, from 15 percent to 40 percent.

A third source of performance data is a study on the sulfur reduction potential of U.S. coals by physical and chemical coal cleaning techniques.[54] The report uses reserve base and washability data which are not based on actual results of commercial coal cleaning but are estimated from the data of float-sink analysis by the U.S. Bureau of Mines.[55] These data indicate hypothetical enhancement of coal quality which could be achieved by beneficiation. Actual values will vary with each installation, reflecting coal seam characteristics, mining procedures, and specific beneficiation processes selected. The report simulates physical coal cleaning at two different levels plus a hypothetical process:

- PCC 1-1/2 inch, 1.6 s.g. This process separates at 1.6 specific gravity after crushing to 1-1/2 inch top size. No energy penalties are imposed other than those inherent in the separation process.

- PCC 3/8 inch, 1.6 s.g. or 1.3 s.g. This process separates at 1.6 specific gravity after crushing to 3/8 inch top size if this produces a coal to meet the standard; otherwise 1.3 s.g. is used. An operating energy usage of 1 percent of the coal's energy content is assumed, in addition to the energy loss inherent in the separation process.

- Ninety percent pyritic sulfur removal. This process is assumed to remove 90 percent of the pyritic sulfur in the coal while losing 10 percent of the weight and 5 percent of the energy. An additional 2 percent energy loss is assumed as an operating penalty.

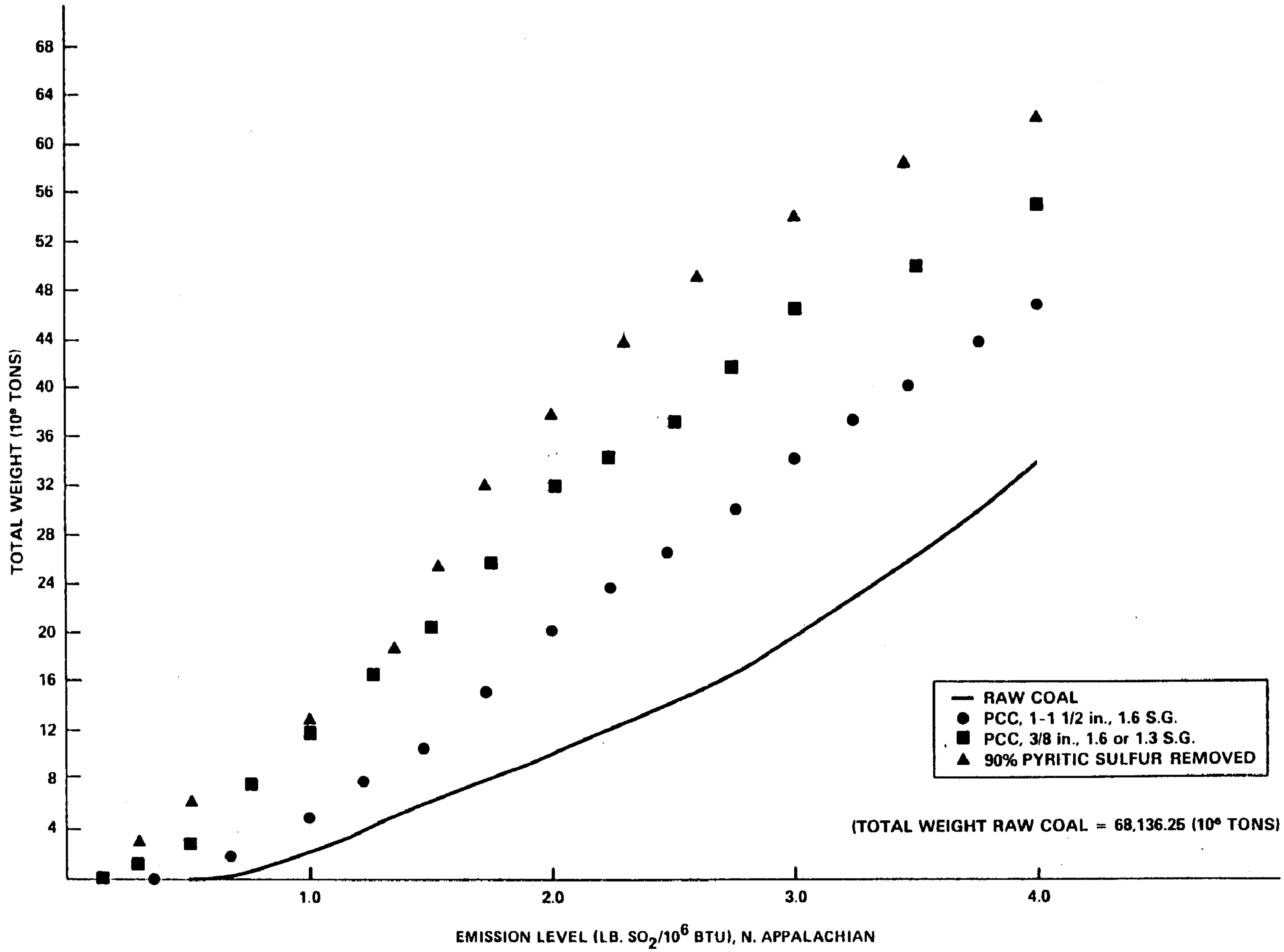


FIGURE 2-23 N. APPALACHIAN RESERVE BASE AVAILABLE AS A FUNCTION OF EMISSION CONTROL LEVELS FOF VARIOUS PHYSICAL COAL CLEANING LEVELS

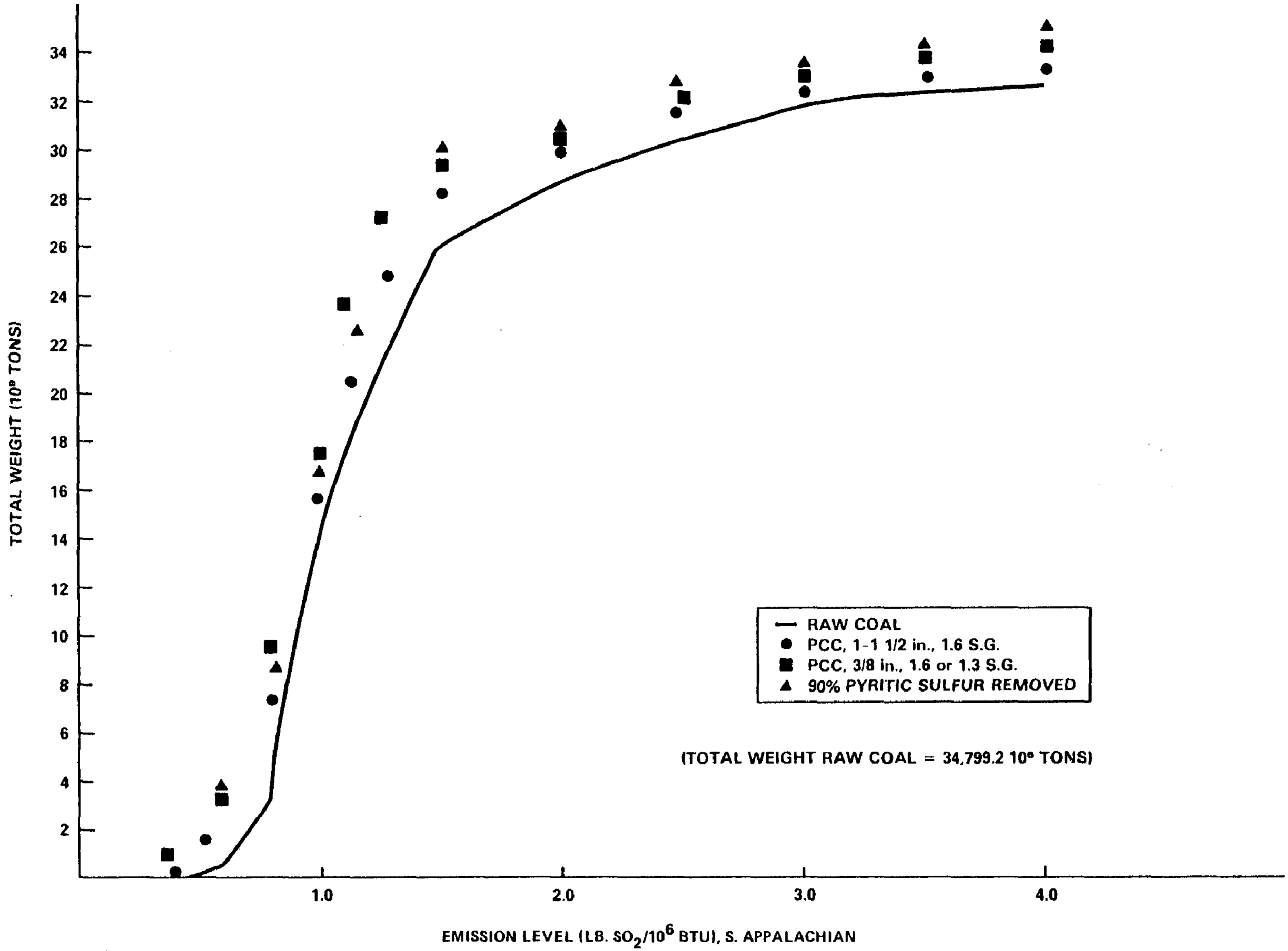


FIGURE 2-24 S. APPALACHIAN RESERVE BASE AVAILABLE AS A FUNCTION OF EMISSION CONTROL LEVELS FOR VARIOUS PHYSICAL COAL CLEANING LEVELS

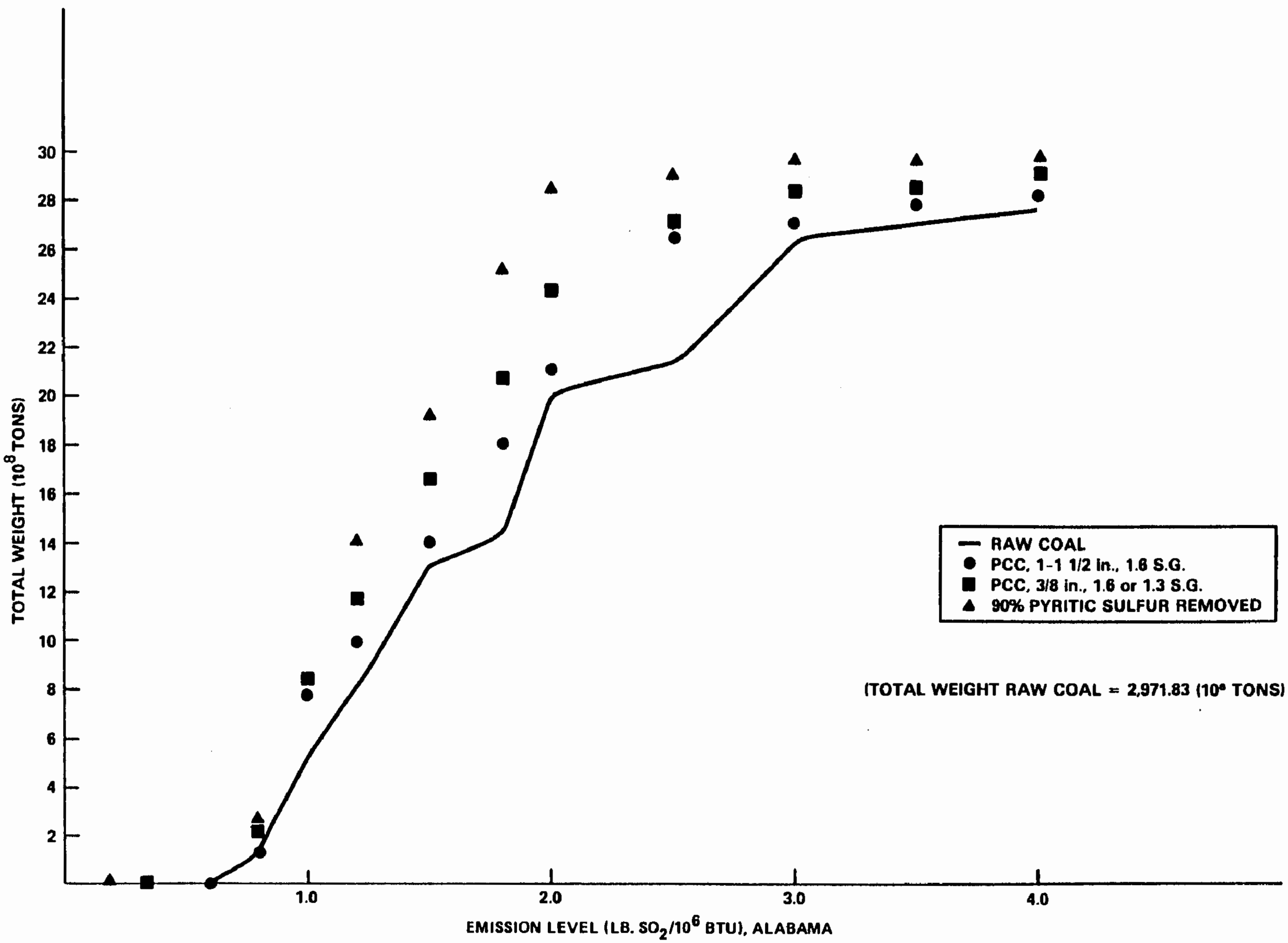


FIGURE 2-25 ALABAMA RESERVE BASE AVAILABLE AS A FUNCTION OF EMISSION CONTROL LEVELS FOR VARIOUS PHYSICAL COAL CLEANING LEVELS

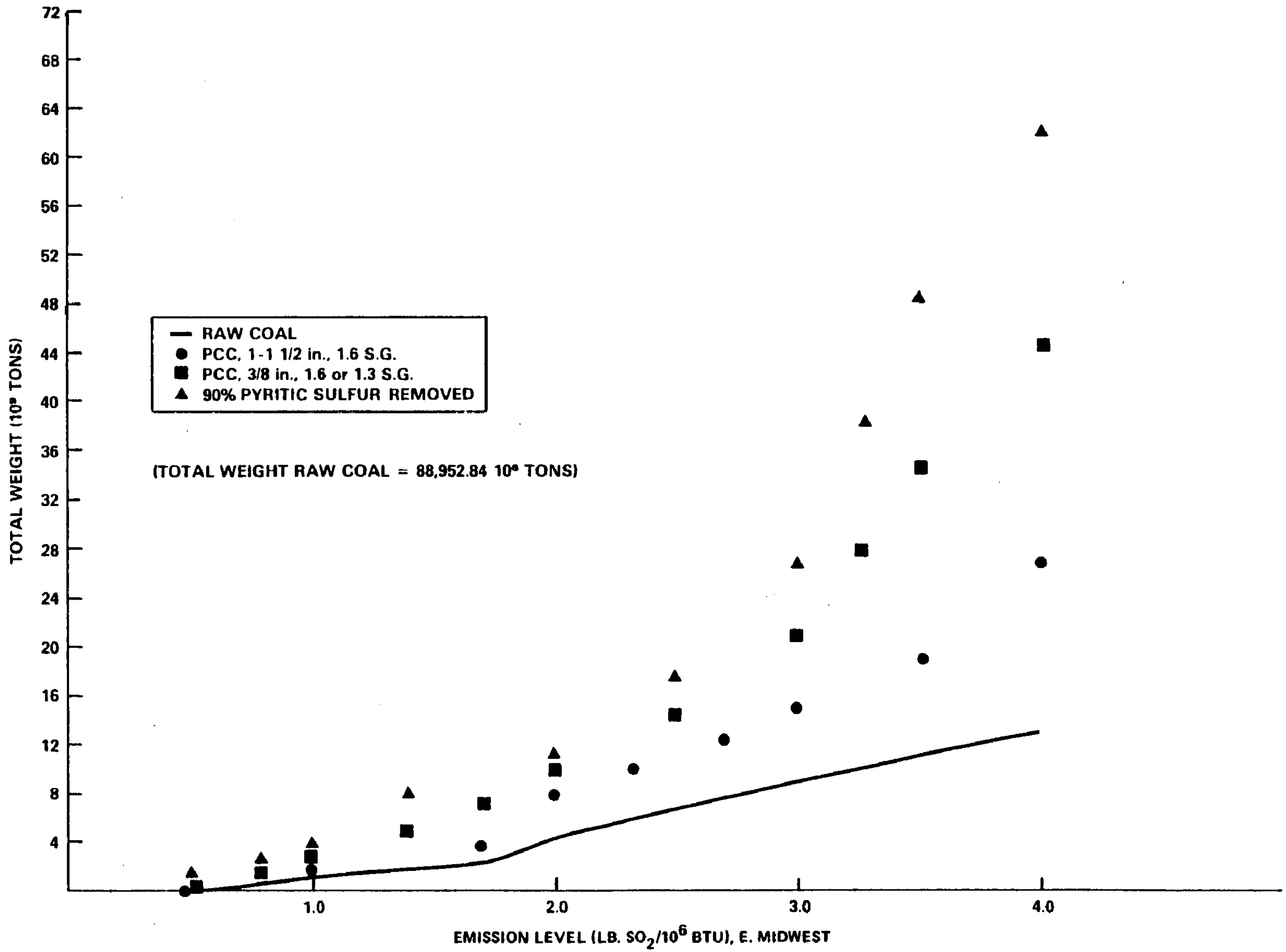


FIGURE 2-26 E. MIDWEST RESERVE BASE AVAILABLE AS A FUNCTION OF EMISSION CONTROL LEVELS FOR VARIOUS PHYSICAL COAL CLEANING LEVELS

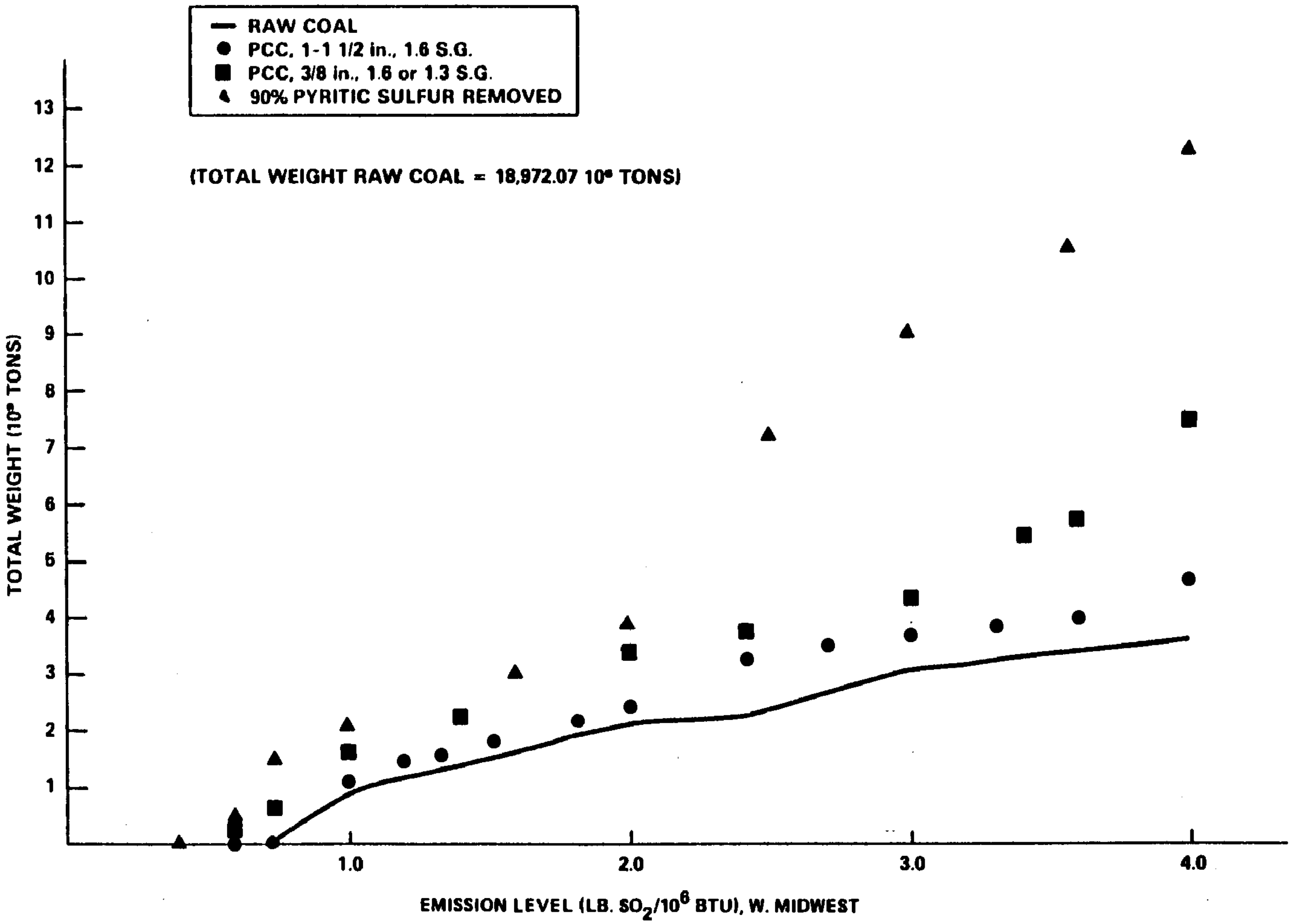


FIGURE 2-27 W. MIDWEST RESERVE BASE AVAILABLE AS A FUNCTION OF EMISSION CONTROL LEVEL FOR VARIOUS PHYSICAL COAL CLEANING LEVELS

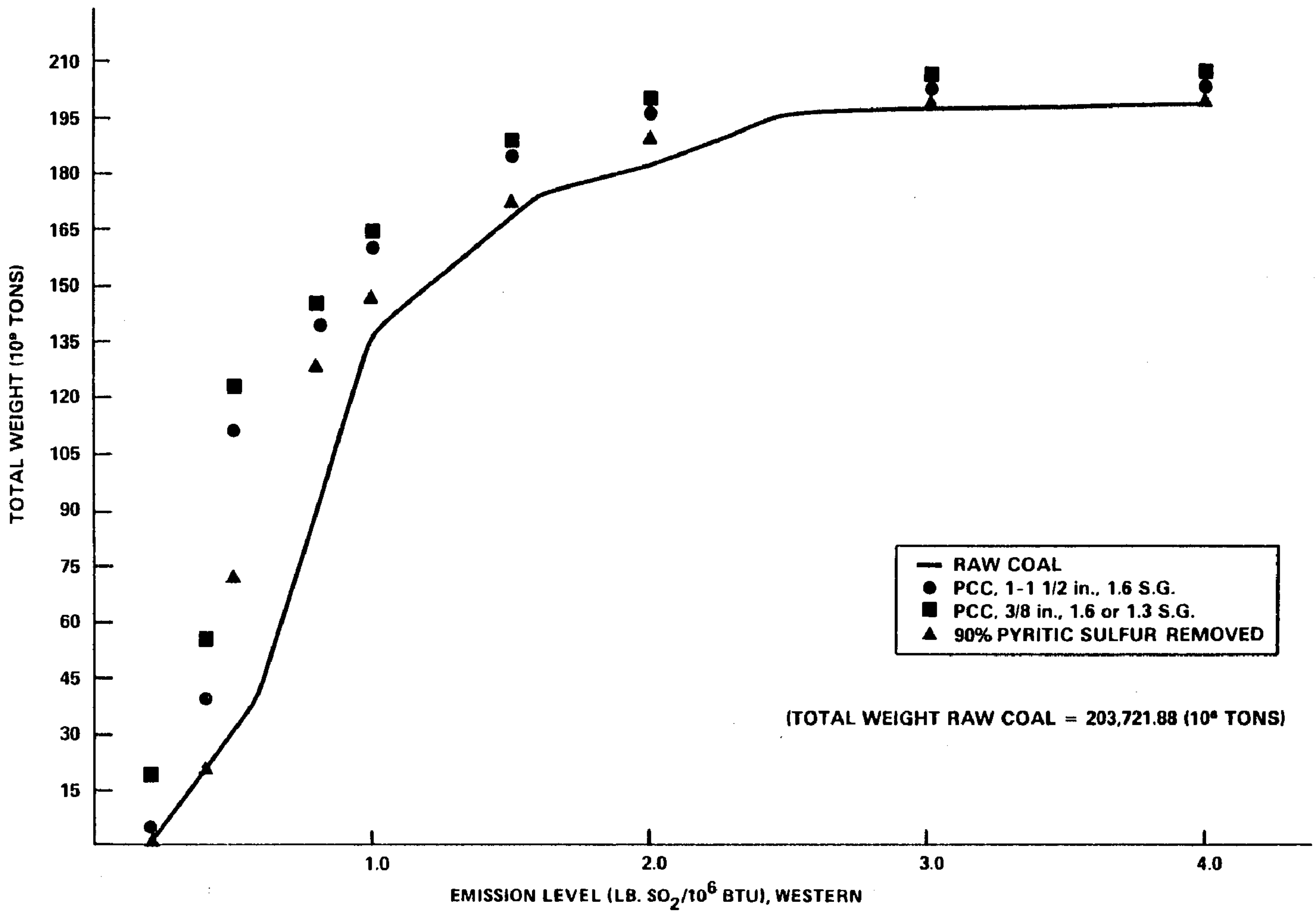


FIGURE 2-28 WESTERN RESERVE BASE AVAILABLE AS A FUNCTION OF EMISSION CONTROL LEVELS FOR VARIOUS PHYSICAL COAL CLEANING LEVELS

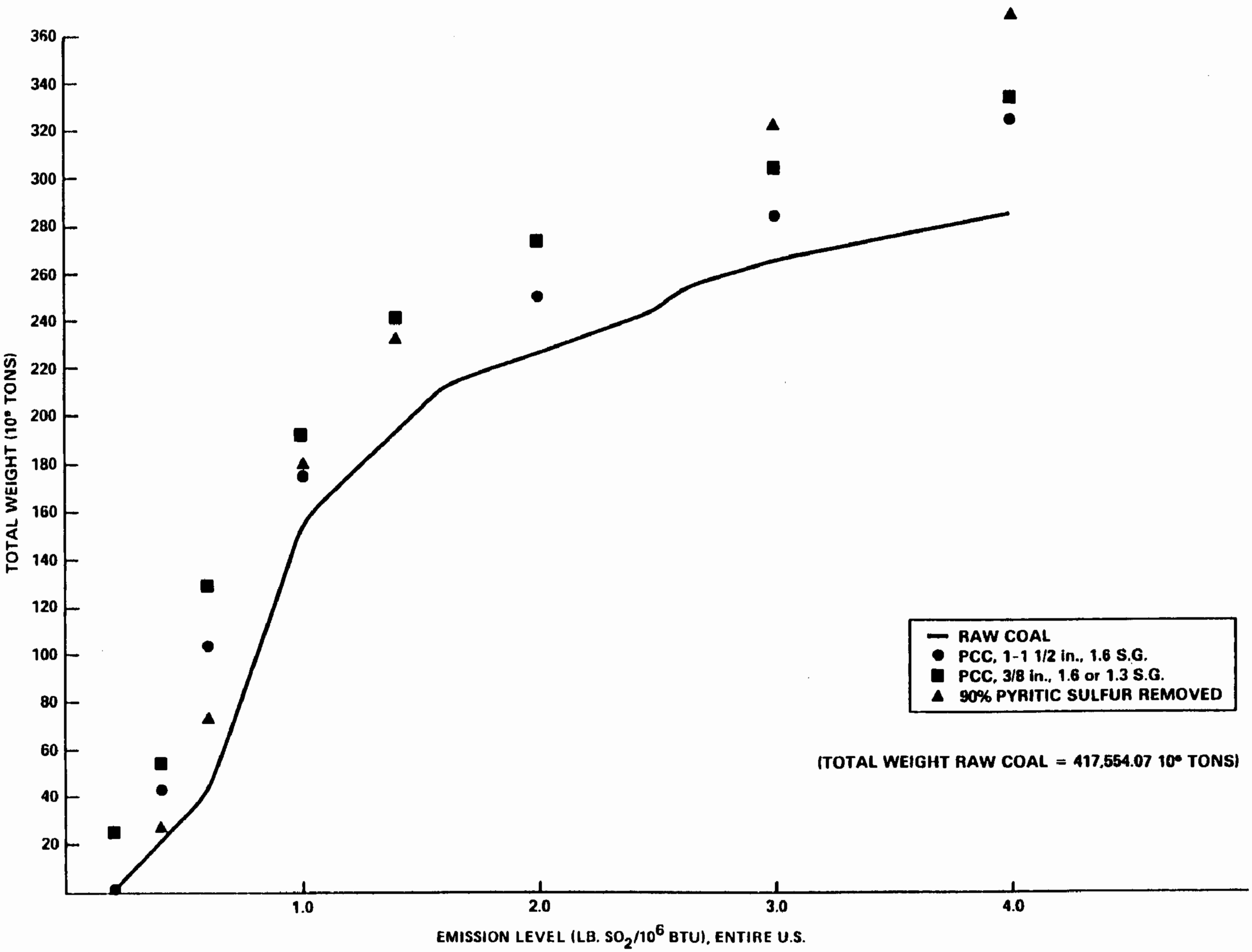


FIGURE 2-29 ENTIRE U.S. RESERVE BASE AVAILABLE AS A FUNCTION OF EMISSION CONTROL LEVELS FOR VARIOUS PHYSICAL COAL CLEANING LEVELS

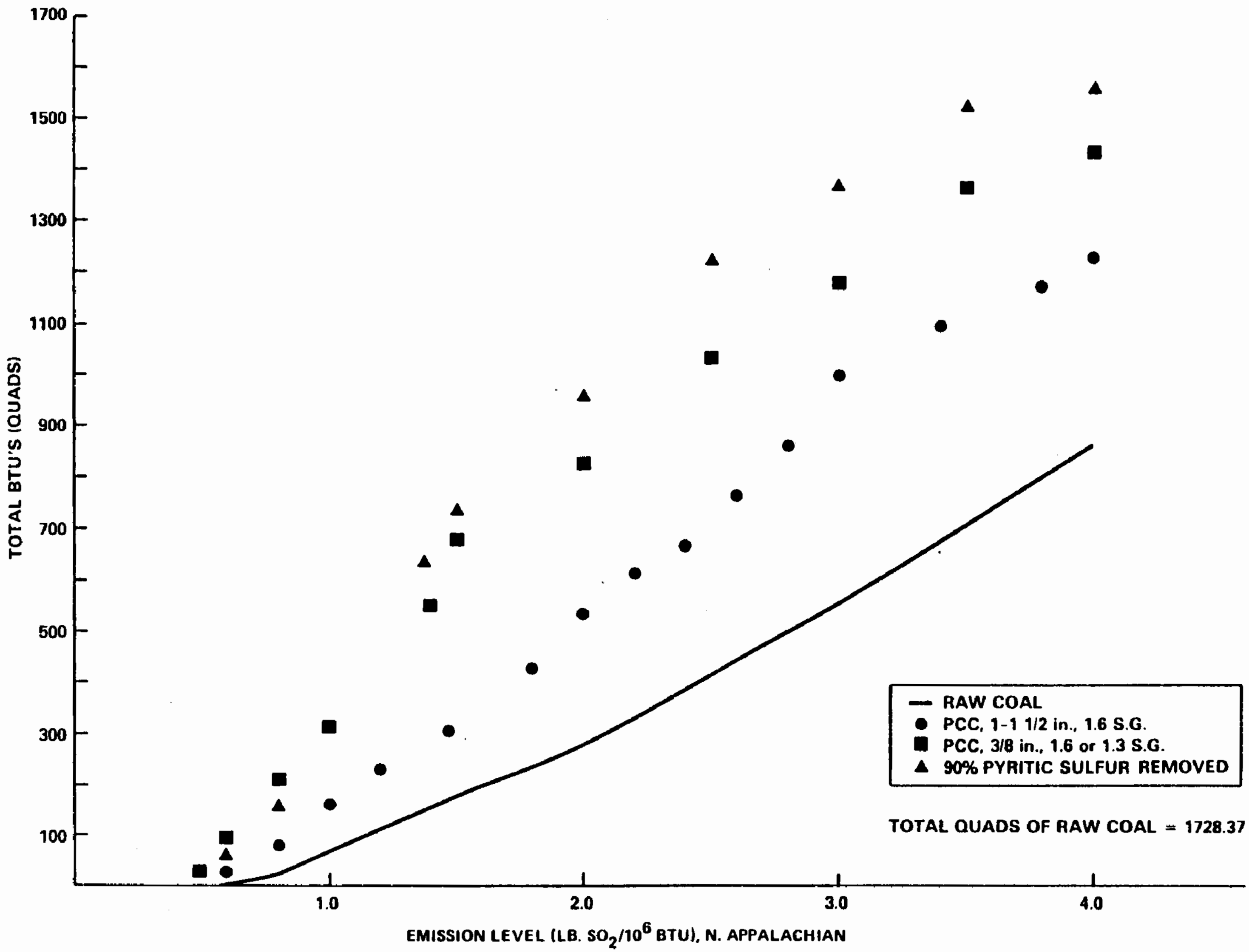


FIGURE 2-30 ENERGY AVAILABLE IN N. APPALACHIAN RESERVE BASE AS A FUNCTION OF EMISSION CONTROL LEVELS FOR VARIOUS PHYSICAL COAL CLEANING LEVELS

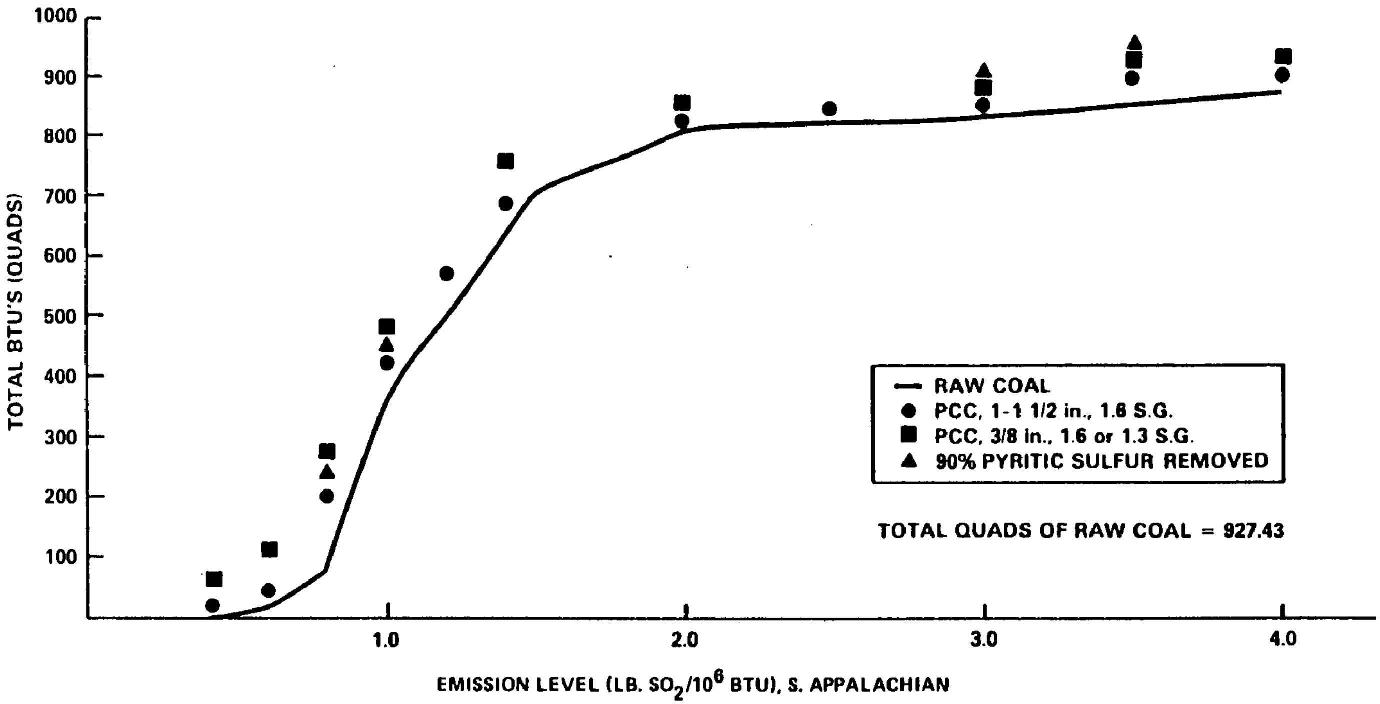


FIGURE 2-31 ENERGY AVAILABLE IN S. APPALACHIAN RESERVE AS A FUNCTION OF EMISSION EMISSION CONTROL LEVELS FOR VARIOUS PHYSICAL COAL CLEANING LEVELS

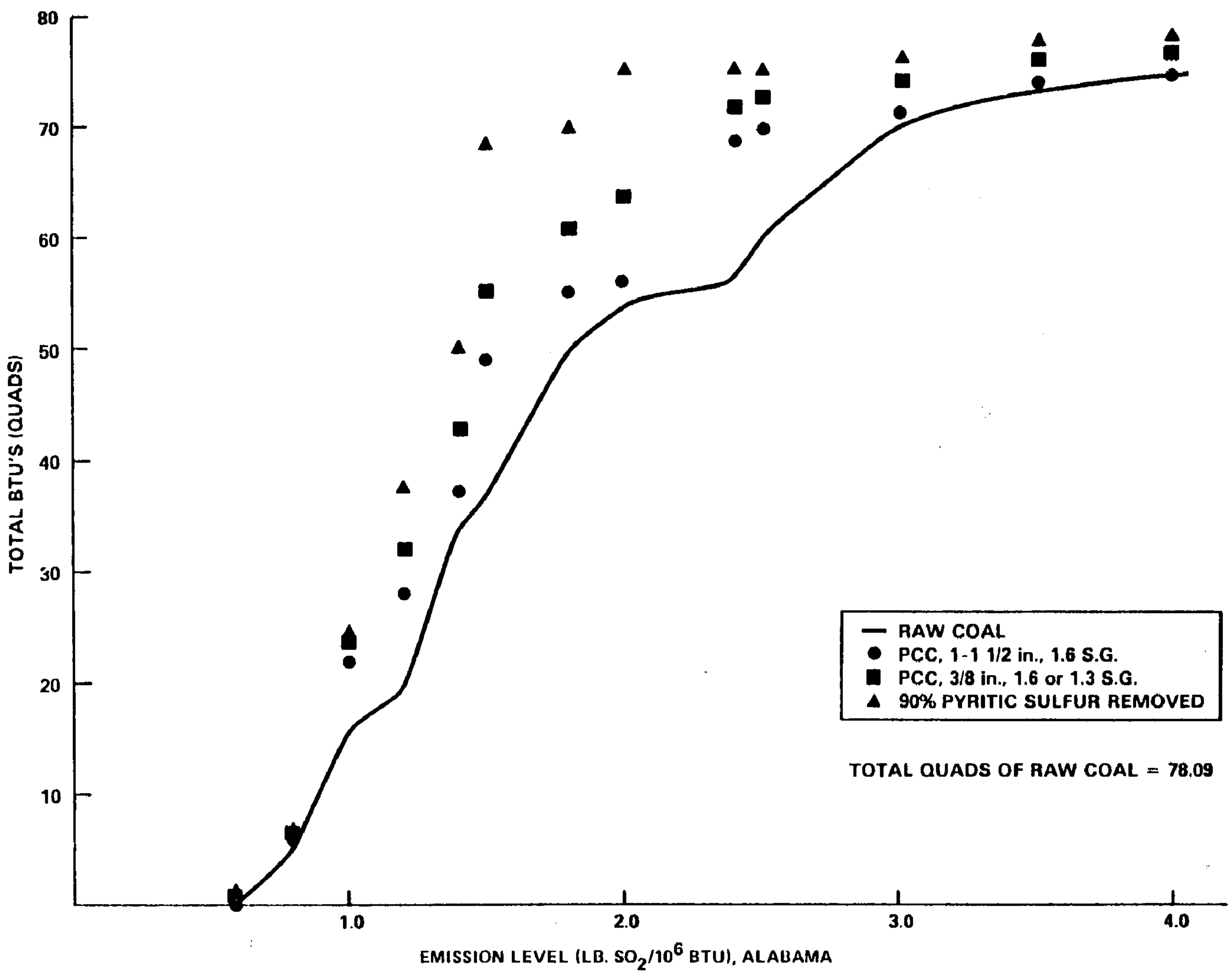


FIGURE 2-32 ENERGY AVAILABLE IN ALABAMA RESERVE BASE AS A FUNCTION OF EMISSION CONTROL LEVELS FOR VARIOUS PHYSICAL COAL CLEANING LEVELS

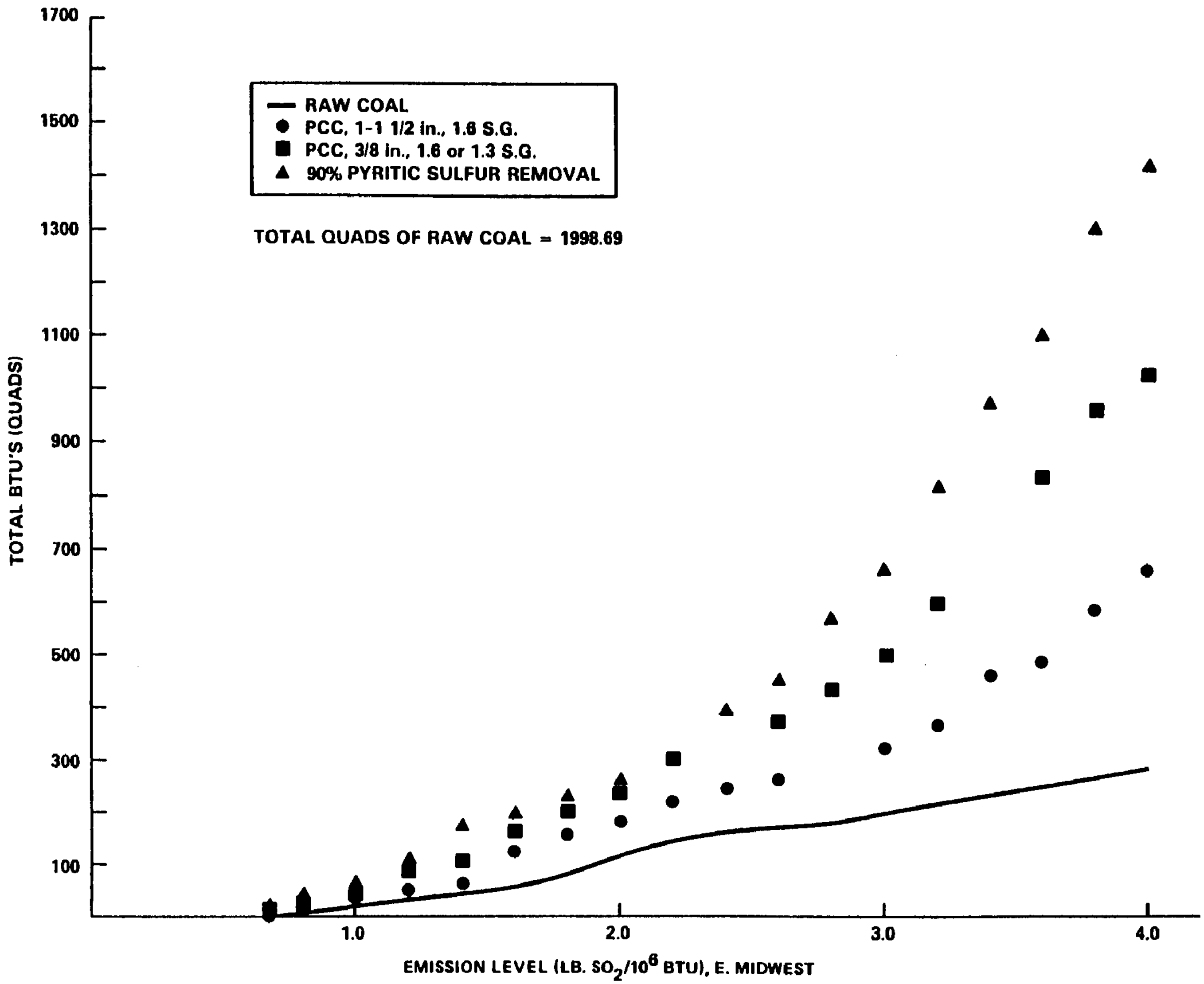


FIGURE 2-33 ENERGY AVAILABLE IN E. MIDWEST RESERVE BASE AS A FUNCTION OF EMISSION CONTROL LEVELS FOR VARIOUS PHYSICAL COAL CLEANING LEVELS

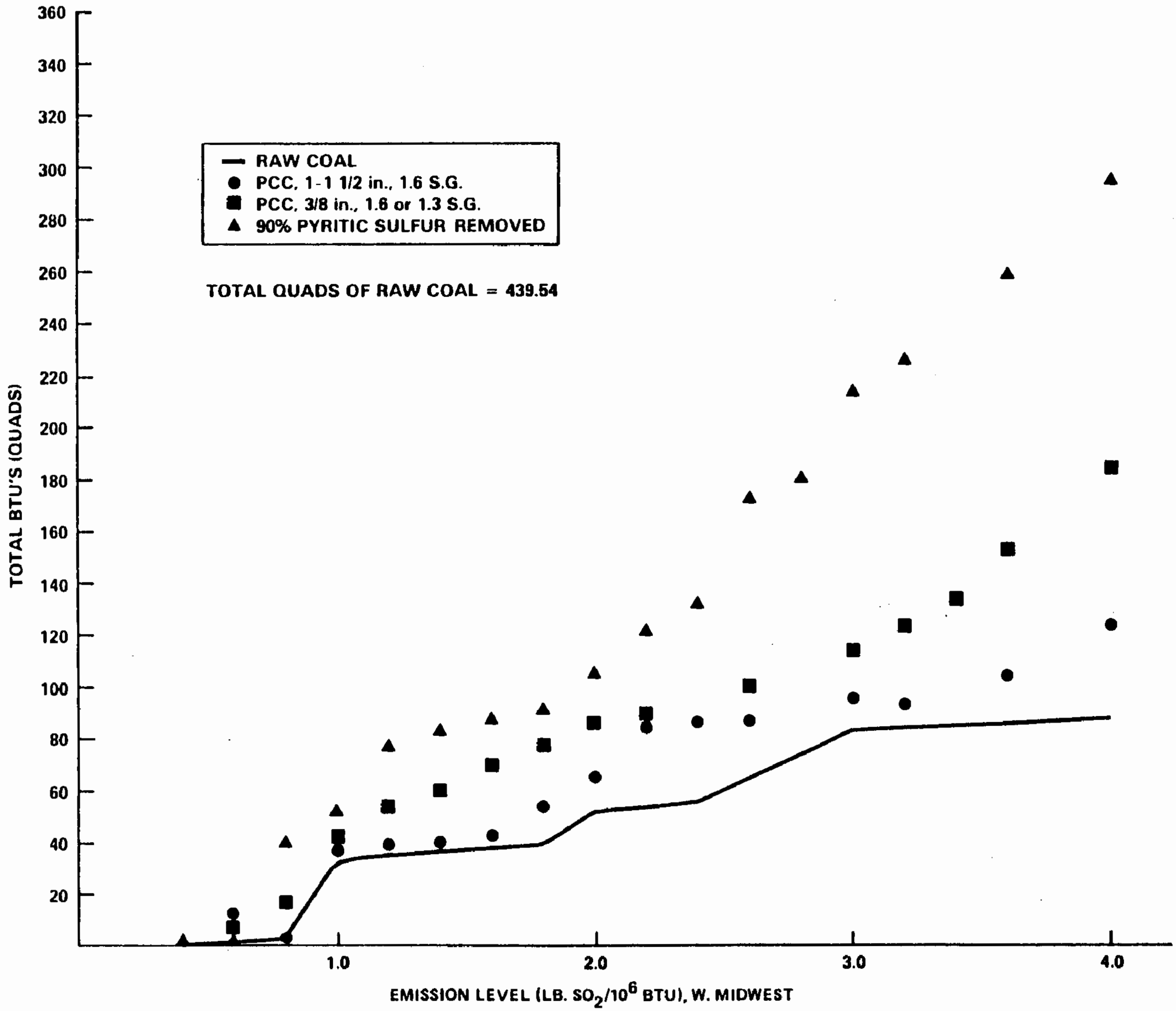


FIGURE 2-34 ENERGY AVAILABLE IN W. MIDWEST RESERVE BASE AS A FUNCTION OF EMISSION CONTROL LEVELS FOR VARIOUS PHYSICAL COAL CLEANING LEVELS

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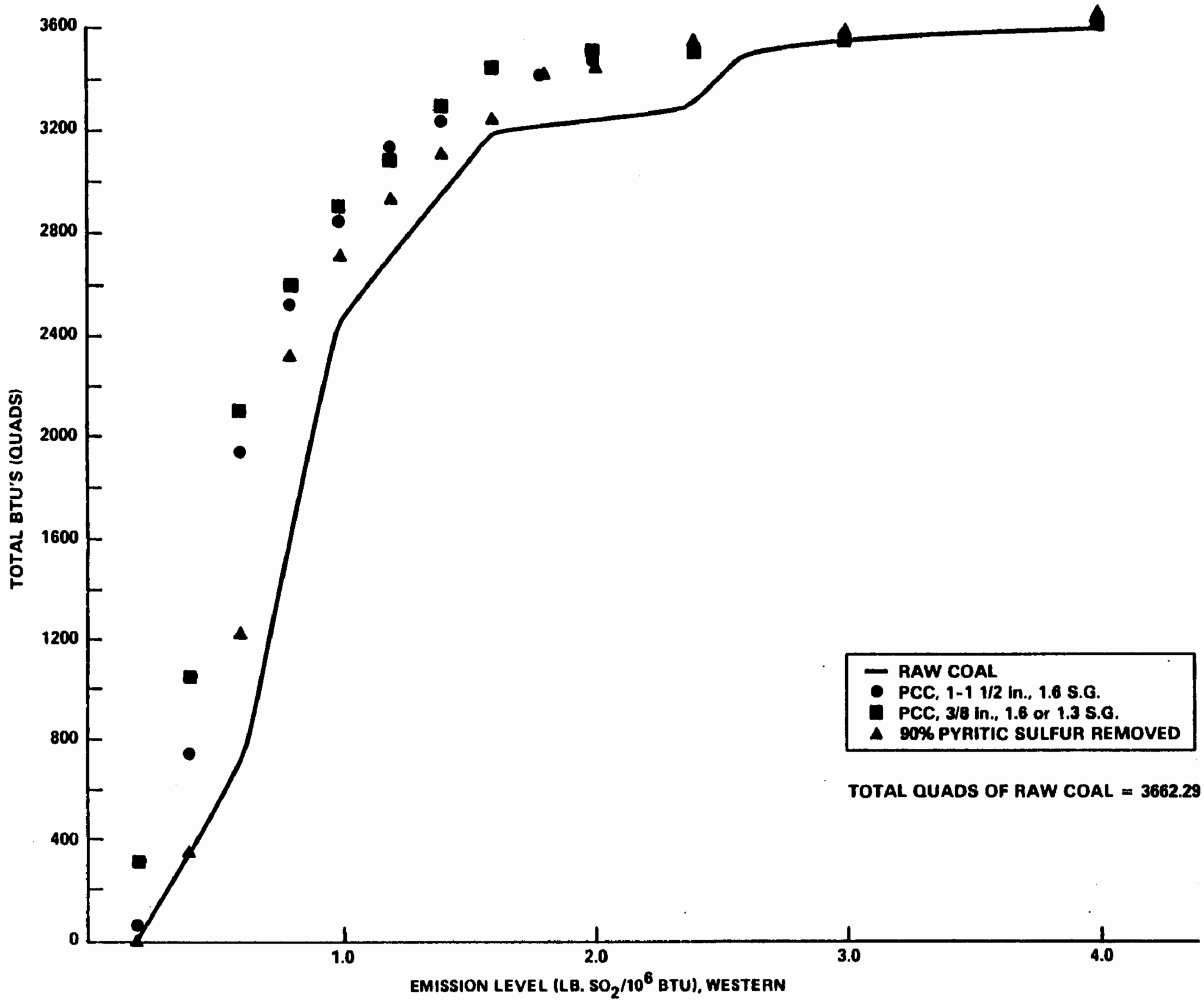


FIGURE 2-35 ENERGY AVAILABLE IN WESTERN RESERVE BASE AS A FUNCTION OF EMISSION CONTROL LEVELS FOR VARIOUS PHYSICAL COAL CLEANING LEVELS

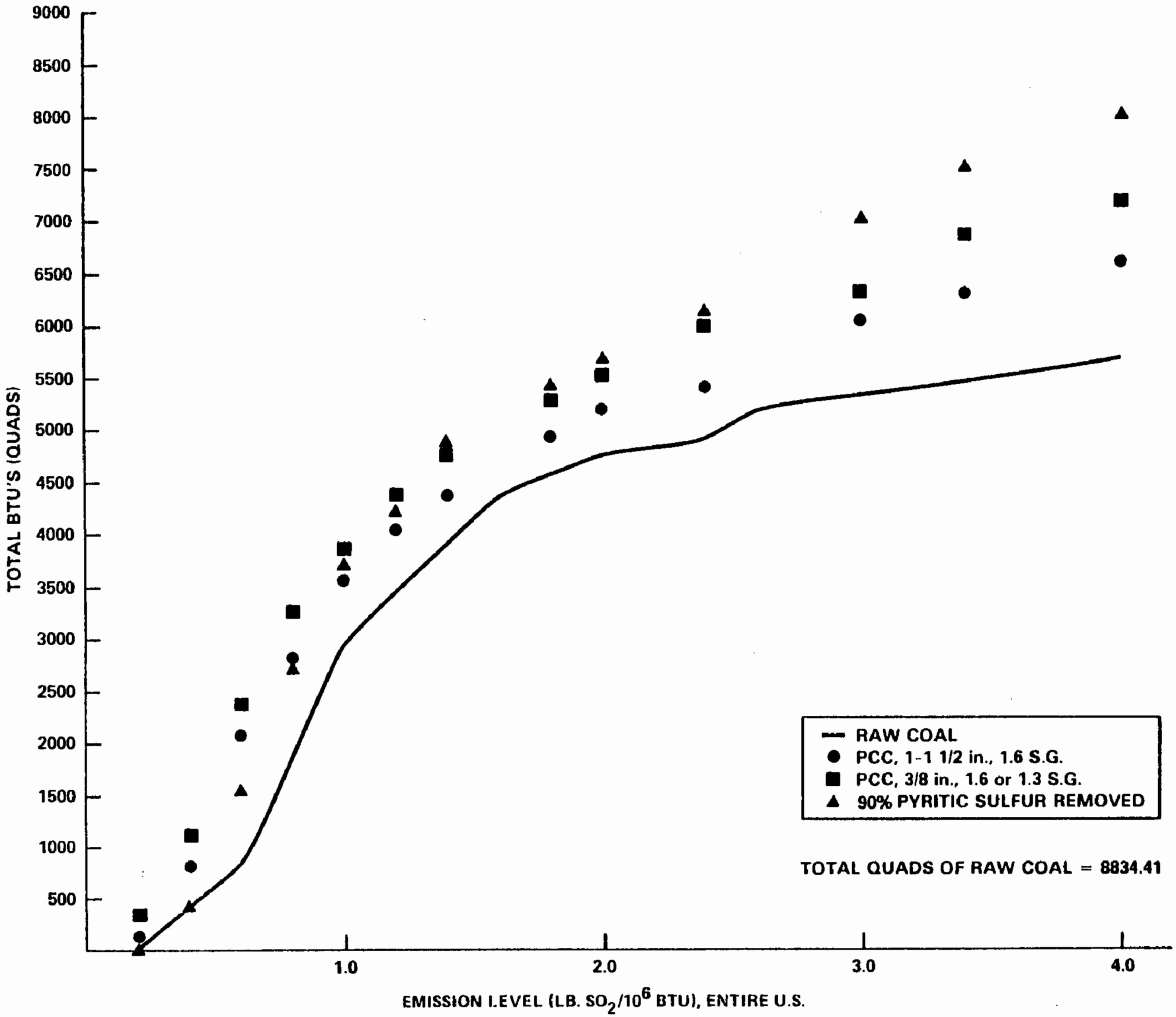


FIGURE 2-36 ENERGY AVAILABLE IN ENTIRE U.S. RESERVE BASE AS A FUNCTION OF EMISSION CONTROL LEVELS FOR VARIOUS PHYSICAL COAL CLEANING LEVELS

Consistent with the studies discussed above, the overlay curves (Figures 2-23 through 2-36) show the quantity of compliance coal that can be produced by coal cleaning at various emission standards. The curves show that coal cleaning is most effective in Northern Appalachia, where four times as much clean coal can comply with a 516 ng SO_2/J (1.2 lb $SO_2/10^6$ BTU) control level than raw coal. By contrast, physical coal cleaning can only achieve a 25 percent increase in compliance coal in Southern Appalachia, and a 15 percent increase in compliance Western coal reserve base. In the entire U.S., as shown in Figure 2-29, coal cleaning can produce an additional 36 billion metric tons of compliance coal, assuming a 516 ng SO_2/J emission control level.

Product Variability

Along with feed and product data, Versar studied product sulfur and BTU variability for different coal lots from the same cleaning plant or mine.[56] The feed coals were primarily from Eastern Midwest cleaning plants and Northern Appalachia, although Western Midwest and Western coals were also represented.

The data included 33 data sets for unwashed coals, consisting of a total of 4,209 data points (lots); and 25 data sets for washed coals, consisting of 692 data points. Included in the "unwashed" category were run-of-mine (ROM) coals and coals cleaned to Level I (sizing to remove large rock).

The "washed" category included Level II and higher coal preparation, where specific-gravity separation is conducted on one or more size fractions.

For each set of data points (lots), the mean ($\overline{Y}$), the standard deviation (Sy), and the relative standard deviation (RSD or Sy/$\overline{Y}$) were calculated for:

Y_1 = Total sulfur content, percent

Y_2 = Heating value, BTU/lb

Y_3 = Heat-specific SO_2 content, lbs SO_2/MM BTU

In each of the plants for which matched pairs of feed and product data were available, both the absolute standard deviation and the relative standard deviation for all three coal characteristics were reduced by the coal preparation process. The reductions in both percent sulfur variability and lbs SO_2/MM BTU variability were approximately 60 percent, while the heating value variability was reduced by approximately 80 percent.

Data from 20 sets of unwashed coal data and from 17 sets of washed coal data did not permit direct comparison of feed and product pairs. A second statistical analysis, conducted to exploit the entire available data base, compared the data sets of all unwashed coals to the data sets of all washed coals. This indirect approach is hampered because the two groups of data sets do not form logically-consistent or homogeneous populations sufficient for rigorous statistical analysis. Because of these inherent compatibility problems, the results of this second statistical analysis should not be regarded as definitive as those of the first analysis. Despite the limitations of the statistical treatment, the comparison of variabilities of the two groups of data sets surely suggest that the variability is reduced by the coal cleaning process. The reductions, from unwashed coals to washed coals, range from 25 to 64 percent depending upon how variability is measured. These results are consistent with the percent reductions in variability derived from the paired feed/product data sets.

Nine data sets (which accounted for 2,373 data points) were examined in three ways: without transformation, with a logarithmic transformation, and with a radical transformation. The distributions of the untransformed and transformed data were tested for normality. Six of the nine batches satisfied the chi-square test (for lbs SO_2/MM BTU) for normality, with either the untransformed data or the transformed data. The three batches failing the test failed regardless of whether the data were transformed or not. These results indicate the absence of sensible evidence for preferring any one distribution over the others.

Tests for autocorrelation of the data points within data sets gave positive results in 16 of 48 data sets (at the 95 percent confidence level). There is little doubt, therefore, that much of these coal data are serially correlated, verifying the expectations based upon geology and engineering rationale.

For each of 16 data sets which exhibited autocorrelation, the total variance (of lbs SO_2/MM BTU) was resolved into the long-term component, associated with the serial correlation according to geostatistical concepts, and the residual short-term (including sampling and analysis) component. An estimate of a generalized long-term component of relative standard deviation was 0.052, applicable to both unwashed coals and washed coals.

From previously-published data representing actual commercial practice, the component of relative standard deviation attributable to ASTM coal sampling, sample preparation, and laboratory analysis (in terms of lbs SO_2/MM BTU) was 0.045 for unwashed coals and 0.023 for washed coals. These values are smaller than the 0.07 to 0.08 maximum permitted by the ASTM protocols.

Estimates of the components of variability are:

	Uncleaned coals	Cleaned coals
RSD for long-term	0.052	0.052
RSD for short-term	0.096	0.053
RSD for S&A	0.045	0.023
(RSD) total for each source	0.118	0.078

It must be emphasized that these are generalized estimates, representing aggregated data sets. In no way may these values be utilized to characterize any one particular coal. Actual variabilities of individual data sets may be quite different from the generalized values shown above.

A prior study concluded that the relative standard deviation should be inversely related to lot size. By removing the long-term component of variability (which through autocorrelation interferes with the theoretical and empirical rationale of the prior study) from data in this study, an inverse relationship between the short-term component of RSD and lot size was demonstrated. A least-squares line had a correlation coefficient of 0.6, indicating a much clearer inverse relationship than was previously determined.

A simulation of product coal variability was performed in conjunction with the Reserve Processing Assessment Methodology.[58] The variability of the sulfur content of the coal was taken into account by assuming the maximum coal sulfur emission upon combustion to be

$$e = \mu_c \ (1 + a_c RSD_c)$$

where a_c, a coal variability coefficient, was taken to be 2.0 (97.7 percent confidence level, and μ_c is the mean coal sulfur value that must not be exceeded in order to achieve a maximum emission level e. The relative standard deviations (RSD) used are given in Table 2-31. These RSD values for Eastern coals are larger than the results of the Versar product variability study for large lot sizes. The RSD values for Western coals could not be verified because of a lack of independent data.

The geographical regions used are as follows:

(1) Northern Appalachia

(2) South Appalachia

(3) Alabama

(4) Eastern Midwest

TABLE 2-31

RELATIVE STANDARD DEVIATIONS POSTULATED FOR RAW AND WASHED COALS FOR INDUSTRIAL BOILERS

	Relative Standard Deviations			
	Eastern		Western	
	Raw	Washed	Raw	Washed
24 hour averaging, 75×10^6 BTU/hr	0.28	0.10	0.07	0.07
30 day averaging, 75×10^6 BTU/hr	0.19	0.07	0.04	0.04

(5) Western Midwest

(6) Western

(7) Entire U.S.A.

The physical cleaning processes used are as follows:

B1. 1-1/2 inch, 1.6 s.g. This process separates at 1.6 specific gravity after crushing to 1-1/2 inch size. No energy penalties are imposed other than those inherent in the separation process.

B2. 3/8 inch, 1.3 s.g. This process separates at 1.3 specific gravity after crushing to 3/8 inch mesh. An operating energy penalty of 1 percent is assumed, in addition to the energy loss inherent in the separation process.

B3. 1.6 separation on sink of 3/8 inch, 1.3 s.g. This process gives a middling product from the refuse of process B2. The sink from the 1.3 specific gravity separation at 3/8 inch mesh is further separated at 1.6 specific gravity. The operating energy penalty assumed is the 1 percent of process B2, in addition to that inherent in the separations.

B4. Ninety percent pyritic sulfur removal. This process is assumed to remove 90 percent of the pyritic sulfur in the coal while losing 10 percent of the weight and five percent of the energy. An additional 2 percent energy loss is assumed as an operating penalty.

The results of the simulation are presented in Tables 2-32 and 2-33.[59]

Table 2-32 shows the percent energy of the reserve base available, by region, to meet emission control levels of 516 (1.2), 860 (2.0), 1,290 (3.0) and 1,720 (4.0) ng SO_2/J (lb $SO_2/10^6$ BTU) if the coal is cleaned prior to combustion by these physical cleaning processes. A floor of 86 ng SO_2/J (0.2 lb $SO_2/10^6$ BTU) was used for all these emission control levels; if the raw coal emission level is below this floor, cleaning is assumed to be unnecessary. For comparison purposes, the percent energy of raw coal that meets the standards is also shown. Values are given both ignoring

TABLE 2-32 PERCENT ENERGY AVAILABLE FOR VARIOUS EMISSION LIMITS AND PHYSICAL COAL CLEANING PROCESSES

	516 (1.2)*					860 (2.0)					1290 (3.0)					1720 (4.0)				
REGION	B1	B2	B3	B4	RAW	B1	B2	B3	B4	RAW	B1	B2	B3	B4	RAW	B1	B2	B3	B4	RAW
Variability Ignored																				
1	12	23	9	26	7	32	42	22	54	17	52	64	40	77	33	71	79	57	91	51
2	65	67	57	75	54	89	89	84	90	83	94	96	93	98	93	98	98	95	99	94
3	37	42	29	57	27	73	82	71	97	69	93	95	91	99	90	95	98	94	99	94
4	3	3	2	7	1	9	11	6	16	6	18	23	11	32	10	34	47	17	68	15
5	8	12	8	18	7	14	17	13	23	13	22	24	19	47	18	27	41	22	68	21
6	86	82	79	84	72	97	95	92	96	90	99	98	98	98	97	100	100	99	100	99
7	46	47	41	51	38	59	61	54	65	52	67	71	63	77	60	75	80	68	89	66
24-hr Average, 75-mm Btu/hr																				
1	9	16	6	17	1	24	35	17	45	8	43	54	32	67	15	59	69	44	84	27
2	47	49	42	56	8	85	85	80	87	59	92	92	91	95	82	95	96	94	99	91
3	27	28	24	36	6	68	74	57	89	36	90	89	79	98	67	94	96	92	99	76
4	2	2	1	4	0	6	8	4	12	2	13	17	9	21	5	21	29	12	42	9
5	7	8	7	13	6	14	16	9	22	9	20	21	17	31	16	23	31	21	59	19
6	79	76	72	80	67	95	94	90	95	89	98	98	97	98	96	99	99	99	99	98
7	40	41	36	44	29	56	58	51	62	46	63	66	59	71	54	69	74	64	81	59
30-day Average, 75 mm Btu/hr																				
1	9	16	6	17	2	26	37	18	48	9	44	56	34	69	20	62	72	48	87	31
2	47	49	42	56	23	86	86	82	88	65	93	93	91	96	87	96	97	94	99	92
3	27	28	24	36	13	71	78	65	91	44	91	90	83	98	72	94	96	93	99	86
4	2	2	1	4	1	7	10	4	13	2	14	18	9	22	7	25	35	13	50	9
5	8	10	8	15	7	14	17	11	23	11	21	23	19	36	17	24	35	21	62	20
6	83	79	75	82	70	96	94	91	95	89	99	98	97	98	96	100	99	99	100	99
7	42	42	38	45	32	57	59	52	63	47	64	67	60	72	56	71	76	65	84	61

sulfur variability and averaging sulfur variability over 24 hours and 30 days for a 75 x 10^6 BTU/hr boiler. Cleaning the reserve base coals prior to combustion significantly increases the amount of coal that is available to meet the control levels, even for cleaning process B3, which gives only a middlings product.

Table 2-33 shows, for each region and in both ng SO_2/J and lbs $SO_2/10^6$ BTU, the emission control levels that can be set (both considering and ignoring sulfur variability) while obtaining 50 percent and 25 percent availability of the reserve base.

The results indicate that for a stringent control level of 516 ng SO_2/J (1.2 lbs $SO_2/10^6$ BTU) for industrial boilers nationwide the amount of coal energy available can be increased from 6-15 percent. Also, physical coal cleaning provides a greater increase of available reserves for the shorter averaging time (i.e., 24-hour average). Of more significance is that the increased available energy comes primarily from regions 1, 2, and 3 (i.e. N. Appalachia, S. Appalachia, and Alabama respectively). These regions are considerably closer to the areas of industrial coal demand than region 6 (Western).

The results are quite similar for an intermediate control level of 860 ng SO_2/J (2.0 lbs $SO_2/10^6$ BTU). However, as the control level becomes less restrictive the raw coal energy reserve base and physically-cleaned coal reserve base begin to converge. Note that for the moderate control levels, regions 1 and 4 (E. Midwest) provide the differential increase in energy reserves due to cleaning.

Under no circumstances does physical coal cleaning decrease the available energy reserve even though the coal refuse does contain some energy value. The primary reason is that the more uniform cleaned product (i.e.,lower RSD) permits higher average sulfur content coal to meet the control level.

Table 2-33 illustrates another important aspect of coal cleaning which is that for a desired percentage of compliance reserve base, a more stringent control level can be promulgated. Assuming that new industrial boilers require the best available physical coal cleaning product, the control levels can be reduced by 30-65 percent over the raw coal scenario. Given a) that no less than 25 percent of any regions reserve base can be excluded from the emission control level and

TABLE 2-33. PCC PROCESSES. EMISSION CONTROL LEVELS THAT CAN BE MET BY 50 PERCENT AND 25 PERCENT OF THE ENERGY AVAILABLE

($ng\ SO_2/J$)

	50 PERCENT					25 PERCENT				
REGION	B1	B2	B3	B4	RAW	B1	B2	B3	B4	RAW
				Variability Ignored						
1	1247	989	1547	816	1720	773	558	902	516	1075
2	473	430	473	430	516	344	344	396	300	386
3	645	601	688	516	638	430	430	430	366	516
4	1977	1805	2494	1547	2735	1547	1376	1977	1161	2192
5	2450	1892	3010	1332	3354	1633	1376	1935	902	2020
6	258	258	344	258	336	172	172	215	172	300
7	601	558	731	516	816	300	300	344	258	386
				24-hr Average, $75x10^6$Btu/hr						
1	1496	1186	1857	983	2683	929	670	1083	619	1676
2	567	515	567	515	804	412	412	464	361	603
3	773	722	825	619	1073	515	515	515	464	804
4	2373	2167	2992	1857	4360	1857	1651	2373	1393	3421
5	2794	2156	3431	1519	3823	1852	1568	2205	1029	2303
6	294	294	392	294	441	196	196	245	196	343
7	731	688	816	645	1075	344	344	386	300	516
				30-day Average, $75x10^6$Btu/hr						
1	1421	1127	1764	931	2373	892	637	1029	588	1483
2	539	490	539	490	712	392	392	441	343	534
3	735	686	784	588	949	490	490	490	441	712
4	2254	2058	2843	1764	3957	1764	1568	2254	1323	3026
5	2647	2043	3250	1433	3622	1764	1486	2089	975	2182
6	278	278	371	278	417	185	185	232	185	325
7	688	686	816	601	938	300	300	386	258	430
				($lb\ SO_2/10^6$ BTU) Variability Ignored						
1	2.9	2.3	3.6	1.9	4.0	1.8	1.3	2.1	1.2	2.5
2	1.1	1.0	1.1	1.0	1.2	.8	.6	.9	.7	.9
3	1.5	1.4	1.6	1.2	1.6	1.0	1.0	1.0	.9	1.2
4	4.6	4.2	5.8	3.6	6.5	3.6	3.2	4.6	2.7	5.1
5	5.7	4.4	7.0	3.1	7.6	3.8	3.2	4.5	2.1	4.7
6	.6	.6	.8	.6	.9	.4	.4	.5	.4	.7
7	1.4	1.3	1.7	1.2	1.9	.7	.7	.8	.6	.9
				24-hr Average, $75x10^6$ Btu/hr						
1	3.5	2.8	4.3	2.3	6.2	2.2	1.6	2.5	1.4	3.9
2	1.3	1.2	1.3	1.2	1.9	1.0	1.0	1.1	.8	1.4
3	1.8	1.7	1.9	1.4	2.5	1.2	1.2	1.2	1.1	1.9
4	5.5	5.0	7.0	4.3	10.1	4.3	3.8	5.5	3.2	8.0
5	6.5	5.0	8.0	3.5	8.9	4.3	3.6	5.1	2.4	5.4
6	.7	.7	.9	.7	1.0	.5	.5	.6	.5	.8
7	1.7	1.6	1.9	1.5	2.5	.8	.8	.9	.7	1.2
				30-day Average, $75x10^6$Btu/hr						
1	3.3	2.6	4.1	2.2	5.5	2.1	1.5	2.4	1.4	3.5
2	1.3	1.1	1.3	1.1	1.7	.9	.9	1.0	.8	1.2
3	1.7	1.6	1.8	1.4	2.2	1.1	1.1	1.1	1.0	1.7
4	5.2	4.8	6.6	4.1	9.0	4.1	3.6	5.2	3.1	7.0
5	6.2	4.8	7.6	3.3	8.4	4.1	3.5	4.9	2.3	5.1
6	.6	.6	.9	.6	1.0	.4	.4	.5	.4	.8
7	1.6	1.6	1.9	1.4	2.3	.7	.7	.9	.6	1.0

b) BACT for physical coal cleaning, then the most stringent control level is 1,393 ng SO_2/J (3.2 lbs $SO_2/10^6$ BTU). This compares to a most stringent value of 3,421 ng SO_2/J (8.0 lbs $SO_2/10^6$ BTU) for raw coal.

Impacts on Boilers

Physical cleaning of coal should improve the overall performance of a stoker-fired boiler provided the resultant coal size is acceptable for stoker firing (1-1/2 x 1/4 with minimal fines). Excess fines produced during cleaning must be sold for pulverized boiler operations or other uses, however, if the primary market is stoker-fired boilers. Physical cleaning partially removes pyrites, ash, and other impurities, thus reducing both SO_2 and particulate emissions. As compared to raw coal, physically cleaned coal is easier to feed, burns more uniformly with less chance for clinkering, and reduces ash disposal problems.

As an example, both a raw and the corresponding physically cleaned coal were fired in a steam plant spreader-stoker boiler.[42] When firing the raw coal, the boiler could operate only at about one half capacity. The high ash content of this coal resulted in non-uniform combustion caused by feeding problems, excessive ash buildup and clinker formation of the fuel bed. In contrast, the physically cleaned coal was fired at full capacity with no operational problems.

There are handling problems for the boiler operator associated with fine coal, including a tendancy to compact under pressure, absorb moisture, form dust, and create the possiblity of dust explosions.

Operating Factors

The use of physically cleaned coal (PCC), rather than raw coal will modify plant operations; in turn these modifications will influence the extent to which PCC will be used. Examples of how PCC will affect plant capacity and plant availability include the following.

- Stokers (used with many industrial boilers producing less than about 180,000 kg steam per hour) may have difficulty operating with the coal particle size distribution resulting from the comminution that precedes PCC.

- Where pulverized coal boilers are used, the smaller particle sizes are desirable ; less capacity and maintenance are required of the pulverizers when the incoming particle sizes are smaller.

- Removing incombustible matter in coal (up to 70-80 percent via PCC) decreases the need for (1) handling coal, (2) handling and disposing of ash, and (3) controlling fly ash emissions.
- Removing incombustible mineral matter may also reduce maintenance problems, thereby increasing plant availability. For example, less iron implies a higher fusion temperature and therefore less wall slagging; less sodium implies less fouling; less ash (the incombustible mineral material left behind when coal burns completely) can mean less plugging of the bottom-ash hopper.
- Where PCC reduces the percentage of ash in the boiler (to, say 2 to 3 percent) it may become economical to use anti-fouling and anti-slagging additives during combustion in order to increase plant availability.
- A negative effect of lowering the sulfur content is the lowering of the conductivity of the fly ash and a consequent derating of the fly ash removal capacity of an electrostatic precipitator for a given quantity of fly ash. However, since the quantity of fly ash is decreased by PCC, this derating may, in fact, be unimportant.

Overall, the factors mentioned above have a positive effect on both plant capacity and plant availability. To the extent that the effects of these factors can be quantified, they must be weighed against the marginal costs of PCC for specific coals and PCC processes, as well as the specific changes in the properties of the coal resulting from PCC.

Firing of physically cleaned coal in industrial stoker-fired boilers is not expected to have a significant effect on boiler maintenance costs. In industrial pulverized coal boilers, firing of physically cleaned coal may reduce boiler maintenance costs.

Impact of Coal Variability Upon Boiler Operation

The variability of coal has a large effect upon the ability and costs for boiler operators to comply with existing or proposed emission regulations. An emission control level, expressed as a maximum value for ng SO_2/J, to be exceeded only for a specified percentage of the time, has the effect of requiring a coal with a mean ng SO_2/J value lower than the emission control level.

General Relationship

The relationship between μc, the mean coal value for ng SO_2/J; and E, the emission control level value in ng SO_2/J, has been defined by EPA:[60]

$$\frac{\mu c}{E} = \frac{1}{\beta(1+t_{\alpha}\ RSD_{c})}, \tag{1}$$

where β = the fraction of sulfur in the coal which is emitted (less losses to bottom ash and fly ash). For the industrial boiler study, it is assumed to be 0.95.

t_{σ} = The one-tailed Students' "t" value assuring a percentage compliance time of σ.

RSD_{c} = The relative standard deviation for ng SO_2/J.

This relationship assumes a normal temporal distribution of ng SO_2/J values within a coal batch; it does not relate to the log-normal distribution of standard deviations among batches.

As presented earlier, RSD_{c} may be expressed as a function of the lot size T (tons):

(RSD_{c}) unwashed coals = $0.205-0.0216 \log_{10}T$

(RSD_{c}) washed coals = $0.159-0.0216 \log_{10}T$.

Substituting into Equation 1,

For unwashed coals:

$$\frac{\mu c}{E} = \frac{1}{\beta[1+t_{\sigma}(0.205-0.0216 \log_{10}T)]} \tag{2}$$

and washed coals:

$$\frac{\mu c}{E} = \frac{1}{\beta[1+t_\sigma(0.159-0.0216\ \log_{10}T)]} \tag{3}$$

These equations were applied to the reference boilers (i.e. 8.8, 22, 44, and 58.6 MW) and the reference coals to determine the maximum emission control levels that the boiler operator could meet. The results are presented in Table 2-34.

The overall conclusion reached from inspection of Table 2-34 is that wide ranges of the emission level (E), from 1.04 to 8.15 pounds SO_2 per million BTU, may be achieved under varying conditions of coal type, physical coal cleaning accomplished, boiler size, averaging time, and percentage compliance. The effect of physical coal cleaning is to reduce the achievable emission level by three complementary mechanisms: sulfur removal, heating value enhancement, and variability reduction. The data indicate that coal cleaning can comply with emission control levels as much as 76 percent below uncontrolled emissions and, more importantly, can provide a 35 percent reduction in complying emissions from low sulfur coal. It is noted that the effect on low sulfur western coal is minimal, producing less than a 5 percent reduction in complying emissions.

Environmental Considerations

A company that plans to install a coal-burning boiler will evaluate the use of PCC in terms of plant operations and applicable pollutant constraints. In this section we describe qualitatively how air pollution emission standards may affect the use of PCC and how PCC can affect boiler and other plant operations.

Although we are primarily concerned here with controlling the level of SO_2 emissions, we observe that PCC, by removing a large percentage of coal's incombustible material, results in less fly ash being formed during combustion. Therefore, there can be a lower design capacity for controlling emissions of particulates and for sluicing, storing, and disposing of ash and there will be a smaller quantity of trace elements and polycyclic particulate matter in the coal being burned.

TABLE 2-34

ACHIEVABLE VALUES OF E (ng SO_2/J Emission Level)

Boiler Feed Coal	Boiler	θ = 3 hours			θ = 24 hours			θ = 1 Week			θ = 1 month		
		σ=99	σ=95	σ=85	σ=99	σ=95	σ=85	σ=99	σ=95	σ=85	σ=99	σ=95	σ=85
F_1	B_1	8.15	7.32	6.62	7.94	7.17	6.54	7.68	7.00	6.43	7.50	6.88	6.35
High-Sulfur	B_2	8.02	7.23	6.57	7.82	7.09	6.49	7.57	6.92	6.38	7.38	6.79	6.30
Eastern,	B_3	7.93	7.17	6.53	7.73	7.04	6.45	7.48	6.85	6.34	7.29	6.73	6.27
Raw Coal	B_4	7.90	7.15	6.52	7.69	7.01	6.43	7.45	6.84	6.33	7.26	6.71	6.25
μc = 5.79	B_5	7.61	6.95	6.40	7.42	6.82	6.31	7.17	6.65	6.21	6.98	6.52	6.13
F_2	B_1	1.95	1.78	1.65	1.90	1.75	1.62	1.83	1.70	1.60	1.78	1.67	1.58
High-Sulfur	B_2	1.92	1.76	1.63	1.86	1.73	1.61	1.80	1.68	1.58	1.75	1.65	1.56
Eastern,	B_3	1.89	1.74	1.62	1.84	1.71	1.60	1.78	1.67	1.57	1.73	1.63	1.55
Cleaned Pdt 1	B_4	1.89	1.74	1.62	1.83	1.70	1.60	1.77	1.66	1.57	1.72	1.63	1.55
μc = 1.50	B_5	1.81	1.69	1.59	1.76	1.66	1.57	1.70	1.61	1.54	1.65	1.58	1.52
F_3	B_1	3.23	2.96	2.73	3.14	2.89	2.69	3.03	2.82	2.65	2.95	2.77	2.61
High-Sulfur	B_2	3.18	2.92	2.71	3.09	2.86	2.67	2.98	2.79	2.62	2.90	2.73	2.59
Eastern,	B_3	3.14	2.89	2.69	3.05	2.84	2.65	2.95	2.76	2.61	2.86	2.71	2.57
Cleaned Pdt 2	B_4	3.12	2.88	2.68	3.03	2.82	2.65	2.93	2.75	2.60	2.85	2.69	2.57
μc = 2.48	B_5	3.01	2.80	2.63	2.92	2.74	2.60	2.81	2.67	2.55	2.73	2.61	2.52
F_4	B_1	2.44	2.19	1.98	2.38	2.15	1.96	2.30	2.10	1.92	2.25	2.06	1.90
Low-Sulfur	B_2	2.40	2.16	1.97	2.34	2.12	1.94	2.26	2.07	1.91	2.21	2.03	1.89
Eastern,	B_3	2.38	2.15	1.96	2.31	2.10	1.93	2.24	2.05	1.90	2.18	2.01	1.87
Raw Coal	B_4	2.36	2.14	1.95	2.30	2.10	1.92	2.23	2.05	1.89	2.17	2.01	1.87
μc - 1.73	B_5	2.28	2.08	1.91	2.22	2.04	1.89	2.15	1.99	1.86	2.09	1.95	1.83
F_5	B_1	1.59	1.45	1.34	1.55	1.42	1.32	1.49	1.39	1.30	1.45	1.36	1.28
Low-Sulfur	B_2	1.56	1.44	1.33	1.52	1.41	1.31	1.47	1.37	1.29	1.43	1.34	1.27
Eastern,	B_3	1.54	1.42	1.32	1.50	1.39	1.31	1.45	1.36	1.28	1.41	1.33	1.27
Cleaned Pdt	B_4	1.54	1.42	1.32	1.49	1.39	1.30	1.44	1.35	1.28	1.40	1.33	1.26
μc = 1.22	B_5	1.48	1.38	1.30	1.44	1.35	1.28	1.38	1.31	1.26	1.34	1.29	1.24
F_6	B_1	1.40	1.26	1.14	1.37	1.24	1.13	1.33	1.21	1.11	1.29	1.19	1.10
Low-Sulfur	B_2	1.38	1.25	1.13	1.35	1.22	1.12	1.31	1.19	1.10	1.27	1.17	1.09
Western,	B_3	1.37	1.24	1.13	1.33	1.21	1.11	1.29	1.18	1.09	1.26	1.16	1.08
Raw Coal	B_4	1.36	1.23	1.12	1.33	1.21	1.11	1.28	1.18	1.09	1.25	1.16	1.08
μc = 1.04	B_5	1.31	1.20	1.10	1.28	1.18	1.09	1.24	1.15	1.07	1.20	1.12	1.06
F_7	B_1	1.34	1.22	1.13	1.30	1.20	1.12	1.26	1.17	1.10	1.22	1.15	1.08
Low Fulfur	B_2	1.32	1.21	1.12	1.28	1.19	1.11	1.23	1.15	1.09	1.20	1.13	1.07
Western,	B_3	1.30	1.20	1.02	1.26	1.17	1.10	1.22	1.14	1.08	1.18	1.12	1.07
Cleaned Pdt	B_4	1.29	1.19	1.11	1.26	1.17	1.10	1.21	1.14	1.08	1.18	1.12	1.06
μc = 1.03	B_5	1.24	1.16	1.09	1.21	1.14	1.08	1.16	1.11	1.06	1.13	1.08	1.04

The following table summarizes the results of an analysis of trace-element depletion caused by washing three major types of coal.[61] The table shows that, whereas only 9 to 18 percent of the coal was left behind in the dense-medium sink used in the studies (1.6 specific gravity), 26 to 54 percent of all the measured trace elements remained in the 1.6 sink fraction.

TABLE 2-35. AVERAGE % OF ALL TRACE ELEMENTS IN THE 1.60 SINK FRACTION[61]

	Average % of Trace Elements in Sink 1.60 Fraction	Average % of Coal in Sink 1.60 Fraction
Appalachian	54	18
Mid Western	37	10
Far Western	26	9
All Coals	38	13

Documentation

The desulfurization potential of the entire U.S. coal reserve was characterized by individually calculating, for each coal bed and county, the effectiveness of several coal cleaning processes in removing ash, pyritic sulfur, and organic sulfur, in recovering material and energy, and then by geographically aggregating the results to the state, regional, and national levels. The calculation required three types of data for the coal reserves in each bed/county unit:

1. The quantity of the reserve. These data were taken from the Bureau of Mines reserve data base, consisting of 3,167 records specifying the weight of each resource for both strip and underground coal, together with the maximum, minimum, and mean levels of the major constituents of the coal in that resource. These data are consistent with those summarized in Thomson and York[43] and Hamilton, White and Matson.[44]

2. The composition of the reserve. Approximately 50,000 detailed sample coal analyses were taken from the coal data base of the U.S. Bureau of Mines in Denver, Colorado. These data include

the composition of each sample in terms of its ash, sulfur, and heat content.

3. The washability of the reserve. The float-sink analyses were used for 587 coal samples, as reported by Cavallaro, Johnson, and Deurbrouck in RI 8118.[39]

Given these three sets of data as a starting point, the first step in the analysis was to overlay them into a single data base which contained the following information for each record:

- The location in terms of its region, state, county, and bed;
- The weight in tons of both strip and underground coal;
- The mean percent by weight of ash, organic sulfur, and pyritic sulfur;
- The mean heat content expressed in BTU/lb; and
- The float-sink distribution of the coal characteristics.

A fundamental problem in overlaying the three types of data was that an exact correspondence of reserve elements (coal bed and county) did not exist among the three data files. Furthermore, washability data were not available for many of the reserve elements, and multiple sets of composition data corresponded to individual reserve elements. These problems were overcome by rational matching, averaging, data rejection, and extrapolation techniques, so that a single internally-consistent (complete and single-value) file of approximately 36,000 records was obtained. Each record consists of the resource identification (by state, bed, and county), the weight of coal for both strip and underground recovery techniques, and the composition of the coal. Also each record is identified with a set of washability analysis data.

The resultant comprehensive coal reserves data file was then operated upon by physical and chemical coal cleaning processes. The results of each calculation were, for each bed/county reserve element, the weight and energy of cleaned coal recoverable by each process and the ash and pyritic and organic sulfur content of the processed coal. No allowance was made for process inefficiency (misplaced material) in this calculation. These bed/county processed coal quantities and characteristics were then aggregated into state and regional values. The results were displayed as the quantities (of coal material or of energy) in each region (when processed by one of several alternative coal cleaning techniques) which complied with predetermined levels either of sulfur content or of sulfur dioxide equivalent per unit of heating value.

2.2.3 Chemical Coal Cleaning

A variety of chemical coal cleaning processes are under development which will remove a majority of pyritic sulfur from the coal with acceptable heating value recovery, i.e., 95 percent BTU recovery. Some of these processes are also capable of removing organic sulfur from the coal, which is not possible with the physical coal cleaning processes. However, none of these chemical coal cleaning processes are expected to be commercially available before 1985.

This section presents available technical information of eleven major chemical coal cleaning processes. A detailed evaluation is included on each process in a format that identifies:

- Process details;
- Developmental status; and
- Technical evaluation.

The first three processes discussed are capable of reducing only the amount of pyritic sulfur in the feed coal; the next seven processes are capable of reducing both pyritic and organic sulfur.

2.2.3.1 System Description --

TRW MEYERS' CHEMICAL COAL CLEANING PROCESS

Process Description

The Meyers' process, developed at TRW, is a chemical leaching process using ferric sulfate and sulfuric acid solution to remove pyritic sulfur from coal. The leaching takes place at temperatures ranging from 50° to 130°C (120°-270°F) and pressures from 1 to 10 atmospheres (15-150 psia) with a residence time of 1 to 16 hours. Process development and optimization studies conducted to date have included a number of alternative processing methods.

Some of the variations which have been tested and considered are:

- Air vs. oxygen for regeneration;
- Coal top sizes from 0.64 cm (¼ inch) to 100 mesh;
- Leaching and regeneration in the same vessel and in separate vessels; and
- Removal of generated elemental sulfur by vaporization or solvent extraction.

Current development work is directed toward elemental sulfur recovery by acetone extraction. This system appears to be promising and may prove to be economical. However, since the technical and economic feasibility of this modification has not yet been proved, Versar, with TRW's concurrence, elected to assess their most promising process for fine coals (top size of 8 mesh or finer). This system includes the removal of elemental sulfur with superheated steam. The flow sheet for this preferred system is shown in Figure 2-37. The diagram includes the four distinct sections of the process which are described below.[63]

Reaction Circuit--

Crushed coal, with a nominal top size of 14 mesh, is mixed with hot recycled iron sulfate leachant. The mixing is performed in a continuous reactor with about 15 minutes residence time. The wetted coal, having undergone about 10 percent pyrite extraction in the mixer, is introduced into the reaction vessel at about 80 psig and about 102°C (215°F). In this step, about 83 percent of the pyrite reaction takes place under conditions of 5.4 atm. (80 psi) and 118°C (245°F), with varying residence time for different coals. Oxygen from an oxygen plant, which is an integral part of the coal cleaning plant, is simultaneously added to regenerate the leachate. The slurry then moves to a secondary reactor where the reaction continues to about 95% completion.

Wash Circuit--

The iron sulfate leachate is removed from the fine coal in a series of countercurrent washing and separation steps. The slurry from the secondary reactor is filtered and washed with water. Both the filtrate and the wash water are sent to the sulfate removal circuit. The filter cake is reslurried, filtered a second time, reslurried with recovered clear water, and finally dewatered in a centrifuge.

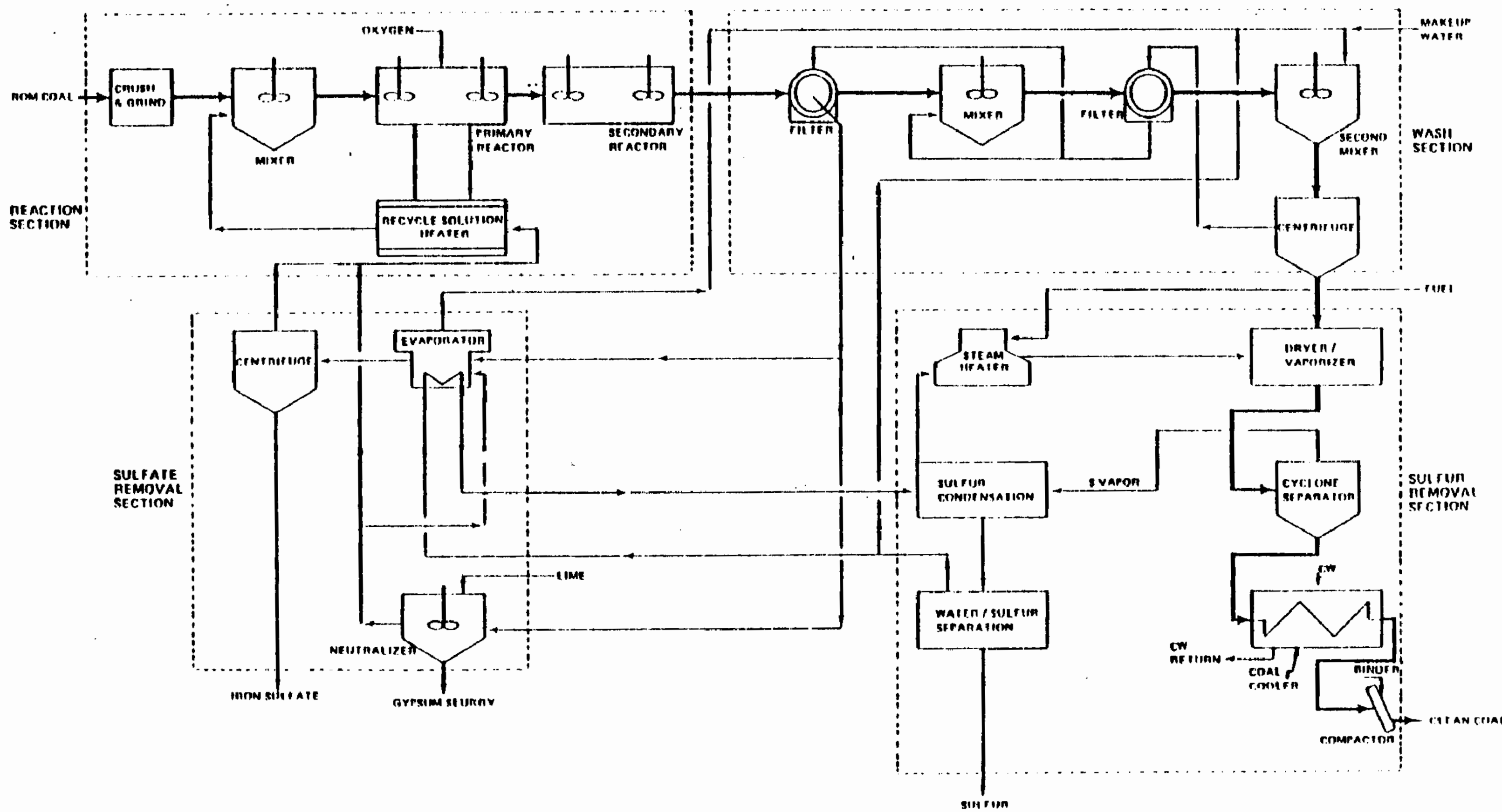


FIGURE 2-37 TRW (MEYER'S) PROCESS FLOW SHEET

Sulfate Removal Circuit--

The prime function of this circuit is to concentrate the leachate for recycle. The filtrate and the wash water from the first stage filter are fed to a triple effect evaporator which recovers most of the wash water. The byproduct iron sulfate crystals that are found in the third evaporation stage are removed from the concentrated leachate and stored or sent to disposal. The remaining wash water from the first filter is partially neutralized with lime to precipitate a gypsum byproduct. The partially neutralized wash water is combined with the dilute leachate from the centrifuge and recycled to the process as leach solution.

The fuel requirement of this circuit is equal to a few percent of the product coal. Makeup water is needed to replace water of crystallization and water vaporization losses due to vacuum filters and vacuum evaporator.

Sulfur Removal Circuit--

Wet coal from the centrifuge is flash-dried by high temperature steam which vaporizes both the water and the sulfur. The dry coal is separated from the hot vapors in a cyclone and cooled to give the clean product. The hot vapor from the cyclone is scrubbed with large quantities of recycled hot water from the evaporator. The gas and liquid phases from the gas cooler are separated in a cyclone. The liquid stream from the cyclone which contains water and sulfur is phase-separated in a vessel. The gas phase consisting of saturated steam is compressed, reheated and recycled to the drier.

It is recognized that the processing steps and equipment needed for recovering sulfur from fine or suspended coal sizes would be different from those required for coarser material. The process developer's claim is that coarse coal can be treated in non-pressurized reaction vessels and would use support equipment significantly lower in cost than that necessary for the fine coal system. However, since the coarse coal processing has not been studied enough to allow an assessment of its technical feasibility, Versar elected to limit this description to the Meyers' fine coal process.

Status of the Process

TRW has conducted extensive bench-scale testing of the major treatment units for the Meyers' process.[63] More than 45 different coals have been tested, and over 100 complete material balances on the process have been calculated and tabulated. The initial bench-scale program was directed toward generating critical process data for the chemical removal of pyritic sulfur. This program was aimed at optimizing the leaching and regeneration steps, evaluating analytical techniques, and studying other process improvements. From these data, the chemistry and rate expressions for the various processing steps have been determined. Additionally, the applicability of the Meyers' process to a variety of coals has been established during a survey program. In this latter study, the process was compared to physical cleaning for thirty-five different coals.[64,65] It is the developer's claim that in all but two cases the Meyers' process was superior.

Developmental efforts for this process began in 1969. The bench-scale testing effort generated the data necessary for the design of the eight metric ton/day Reactor Test Unit (RTU). The erection of this unit at the Capistrano Test site was completed in early 1977. With EPA's sponsorship, the RTU started up in June, 1977.

In 1978, TRW efforts were directed toward:

- Bench-scale investigations in support of the RTU program on improved techniques for sulfur byproduct recovery and on the identification and evaluation of process modifications with potential for reducing processing costs; and

- Testing the RTU. The unit has been run with coal slurry and plans were to introduce the leachate in the circuit in the near future.

The RTU is designed to handle coal less than 0.32 cm (1/8 inch) in size and variable test parameters of temperature, pressure, residence time and oxygen concentration. Limited ability to filter and wash the coal to remove the spent leachate is also included. This unit does not have the capability to remove the elemental sulfur produced by the leaching reaction or to handle coal particle sizes greater than 0.32 cm (1/8 inch).

The first ten months of operation of the RTU will be dedicated to treatment of two types of coal from the Martinka mine. It has been established that this coal will not meet the current NSPS SO_2 emission standards by physical coal cleaning techniques. The specific samples have been selected in cooperation with American Electric Power Service Corp. (AEP), which has elected to participate in this program for cleaning the Martinka mine coal to an acceptable fuel.

The selected coals will be treated in the RTU for the purposes of removing the pyritic sulfur. The treated coal will be washed and filtered to remove the iron salts leaving a wet filter cake (17 to 28 percent moisture by weight) containing some elemental sulfur. The product coal from this operation will be sent to various equipment suppliers to dry the coal and recover the elemental sulfur.

Extensive investigations are projected to optimize this process technically and economically. Some of the studies projected involve:

- Pelletizing the powdered product coal by compaction, without binder, to sizes greater than 0.95 cm (3/8 inch) to permit shipping in open hopper cars.
- Determining the effects of desulfurized coal on combustion and performance characteristics of utility boilers.
- Determining the effects of desulfurized coal on performance characteristics of electrostatic precipitators employed to remove particulates from the boiler flue gas.

Technical Evaluation of the Process

This process has been extensively studied and is currently on an eight metric ton/day pilot plant stage. Thus, an assessment of its industrial potential is possible at this time. Only pyritic sulfur is removed by this process. Therefore, the process is more applicable to coals rich in pyritic sulfur. These coals are found in the Appalachian region of the United States which now supplies about 60 percent of the current U.S. production. An estimated one third of Appalachian coal production can be treated to a level permitting the burning of product in conformance with current new source utility SO_2 emission standards. Some Interior Basin coal can also be treated by this process to meet the new SO_2 emission guidelines.

A Meyers' treatment plant can be located either at a centralized processing site or at a power plant site. If the treatment plant is located at a large power plant site, steam and power requirements may already be available on-site. This could result in some cost savings. Furthermore, the Meyers' processing plant can operate steadily with shutdowns only for required or scheduled normal maintenance. Thus, the plant would only have to be designed to furnish sufficient coal for the power plant's average load factor, which is, in general, 60 percent of the full name plate capacity. Additionally, capital and operating costs for such a plant would be even more favorable if the process were integrated with coal-fired power generating facilities which would already have included adequate raw coal handling, crushing, pulverizing and fine coal handling facilities. In some instances, when the treatment plant is added to a plant with a very large coal demand, the entire operating cost of the system can be obsorbed by the power plant because of improved product yield.

Another option for the Meyers' processing plant which is potentially attractive is a combination physical and chemical cleaning operation. In this case, the run-of-mine coarse coal containing high ash and high pyritic sulfur would be fed to a physical cleaning plant to reduce the ash content of the coal by about 75 percent. The ash discard consisting of about 15 percent of the ROM coal will contain primarily ash and 10 to 15 percent pyritic sulfur. The low ash coal can then be fed to a gravity separation system. The heavy fraction from the float/sink system, consisting of 40 to 50 percent of the total coal, will be used as feed to the Meyers' process. This latter fraction, containing high concentration of pyritic sulfur, will be reduced to 14 mesh top size and fed to a fine coal Meyers' circuit to yield a product with a very low sulfur content. The desulfurized sample may then be recombined with the float fraction giving an overall yield of about 80 percent on the run-of-mine coal feed. Thus, the combined treated product contains 10-20 percent of the total sulfur of the ROM coal while only processing a fraction of the total coal through the Meyers' process.

Potential for Sulfur Removal--

Only pyritic sulfur is removed by this process. A survey program (EPA Contract No. 68-02-0627) has established that this process is able to remove 80-99 percent of the pyritic sulfur (23 to 75 percent of the total sulfur) from 23 Appalachian Basin Coals and 91-99 percent of pyritic sulfur (43 to 55 percent of total sulfur) from the six Eastern Interior Basin Coals. Tests with western coals showed 92 percent removal of the pyritic sulfur (65 percent of total sulfur) from a single Western Interior Basin Coal, and 83-90 percent removal of the pyritic sulfur (25-30 percent of total sulfur) from the two western coals. Two other western coals (from Edna and Belle Ayr mines) were also investigated, however, since these coals contain very low pyritic sulfur (0.14 - 0.22 wt%), the results of these tests are inconclusive. Under the same program, tests conducted on float-sink have indicated that conventional coal cleaning at 1.9 specific gravity could reduce only two of the coals tested to a sulfur content as low as that obtained by the Meyers' process.

The results of these investigations are presented in Table 2-36.[64,65] Most coals, ground to 100 mesh x 0, were found to give the maximum pyrite removal (90-99 percent). However, several of the coals required 150 and some 200 mesh size reduction to achieve ultimate amounts of pyrite removal. The size reduction also resulted in an increase in the rate of pyrite removal so that, in most cases, the reaction time was reduced considerably.

TABLE 2-36. MEYERS' PROCESS - SUMMARY OF PYRITIC SULFUR REMOVAL RESULTS (100-200 MICRON TOP-SIZE COAL)

MINE	SEAM	STATE	% TOTAL SULFUR W/W IN COAL* INITIAL	% TOTAL SULFUR W/W IN COAL* AFTER MEYER'S PROCESS CURRENT RESULTS	MEYER'S PROCESS PYRITIC CONVERSION % W/W	MEYER'S PROCESS TOTAL SULFUR DECREASE % W/W	% SULFUR IN COAL ^ AFTER FLOAT-SINK
APPALACHIAN COALS							
KOPPERSTON NO. 2	CAMPBELL CREEK	W. VIRGINIA	0.9	0.6	92	33	0.8
HARRIS NOS. 1 & 2	EAGLE & NO. 2 GAS	W. VIRGINIA	1.0	0.8	94	23	0.9
WARWICK	SEWICKLEY	PENNSYLVANIA	1.4	0.6	92	54	1.0
MARION	UPPER FREEPORT	PENNSYLVANIA	1.4	0.7	96	50	1.2
MATHIES	PITTSBURGH	PENNSYLVANIA	1.5	0.9	95†	36	1.7
ISABELLA	PITTSBURGH	PENNSYLVANIA	1.6	0.7	96	54	1.5
LUCAS	MIDDLE KITTANNING	PENNSYLVANIA	1.8	0.6	90†	64	0.7
JANE	LOWER FREEPORT	PENNSYLVANIA	1.8	0.7	91	63	0.8
MARTINKA	LOWER KITTANNING	W. VIRGINIA	2.0	0.6	92	70	0.8
NORTH RIVER	CORONA	ALABAMA	2.1	0.9	91	55	2.2
HUMPHREY NO. 7	PITTSBURGH	W. VIRGINIA	2.6	1.5	91	42	1.9
NO. 1	MASON	E. KENTUCKY	3.1	1.6	90	48	2.3
BIRD NO. 3	LOWER KITTANNING	PENNSYLVANIA	3.1	0.8	96†	75	1.5
WILLIAMS	PITTSBURGH	W. VIRGINIA	3.5	1.4	96†	50	2.3
SHOEMAKER	PITTSBURGH	W. VIRGINIA	3.5	1.7	80	51	3.6
MEIGS	CLARION 4A	OHIO	3.7	1.9	93	48	2.8
FOX	LOWER KITTANNING	PENNSYLVANIA	3.8	1.6	89	57	2.0
DEAN	DEAN	TENNESSEE	4.1	2.1	90†	49	3.0
POWHATAN NO. 4	PITTSBURGH NO. 8	OHIO	4.1	1.9	85	53	3.3
ROBINSON RUN	PITTSBURGH	W. VIRGINIA	4.4	2.2	97†	50	3.0
BELMONT	UPPER FREEPORT	PENNSYLVANIA	4.9	0.8	96†	80	2.1
MUSKINGUM	MEIGS CREEK	OHIO	6.1	3.2	90†	47	4.4
EGYPT VALLEY #21	PITTSBURGH NO. 8	OHIO	6.6	2.7	89†	59	4.6
EASTERN INTERIOR COALS							
ORIENT NO. 6	HERRIN NO. 6	ILLINOIS	1.7	0.9	96†	44	1.4
EAGLE NO. 2	ILLINOIS NO. 5	ILLINOIS	4.3	2.0	91	54	2.9
STAR	NO. 9	W. KENTUCKY	4.3	2.5	91†	43	3.0
HOMESTEAD	NO. 11	W. KENTUCKY	4.5	1.7	93	47	3.2
CAMP NOS. 1&2	NO. 9 (W.KY.)	W. KENTUCKY	4.5	2.0	89	55	2.9
KEN	NO. 9	W. KENTUCKY	4.8	2.8	91	42	3.5
WESTERN COALS							
NAVAJO	NOS. 6,7,8	N. MEXICO	0.8	0.6	90	25	--
COLSTRIP	ROSEBUD	MONTANA	1.0	0.6	83	30	--
WESTERN INTERIOR COALS							
WELDON NO. 11	DES MOINES NO. 1	IOWA	6.4	2.2	92	65	3.9

* DRY, MOISTURE-FREE BASIS

^ 1.90 FLOAT MATERIAL, 14 MESH x 0, IS DEFINED HERE AS THE LIMIT OF CONVENTIONAL COAL CLEANING

† RUN AT 100 x 0

GRAVICHEM CHEMICAL COAL CLEANING PROCESS

Process Description

The Gravichem process is a variant of the TRW Meyers process. It utilizes a dense medium separation of ferric sulfate-sulfuric acid solution slurried with the coal for feed to the main reactor. It has been found that the float portion from a 1.3 specific gravity medium separation, as in physical coal cleaning, is clean enough to not benefit significantly by further chemical leaching. The float portion is washed, dewatered, and dried. The sink portion of the 1.3 specific gravity separation is then further cleaned through the Gravichem chemical coal cleaning process.

LEDGEMONT CHEMICAL COAL CLEANING PROCESS

Process Description

The Ledgemont oxygen leaching process is based upon the aqueous oxidation of pyritic sulfur in coal at elevated temperatures and pressures using a stream of oxygen as the oxidant. The process has been developed by the Ledgemont Laboratory of the Kennecott Copper Corporation. The process was patented in 1976.[66]

There has been no R&D effort by Ledgemont on the process since 1975. Based on a series of tests run prior to 1975, the Ledgemont process claims to remove 90% of the pyritic sulfur from a wide variety of bituminous coals with essentially zero organic sulfur removal. The product is suitable for combustion in standard utility boilers but will meet EPA NSPS for sulfur dioxide emissions only if the organic sulfur level in the coal is 0.7-0.8% or less.

The Ledgemont process as conceptualized, consists of five principal steps:

Coal Preparation--

The raw coal is crushed and ground to a suitable particle size for maximum leaching efficiency. The ground coal goes directly to a slurry tank for mixing with water. Alternatively, the ROM coal may be subjected to physical coal cleaning to remove pyrite and ash, before introduction into the process.

Oxidation Treatment--

The coal slurry is then fed to leaching reactors where essentially all of the pyritic sulfur is oxidized to soluble sulfates and insoluble iron oxide under suitable conditions of temperature, pressures, slurry density, oxygen dispersion, mixing and residence time.

When the process operates at the preferred temperature and pressure [between 50° and 150°C (120° and 300°F), 20 to 25 atm (300 to 350 psig) oxygen pressure], it is claimed that 75 percent of the iron sulfate formed in the reaction converts to iron ozide:

The Ledgemont laboratory has found that organic sulfur removed in the aqueous oxidation process is highly variable and, depending on the feed coal used, has ranged from 0-20% removal.

Fuel Separation--

The desulfurized coal slurry is partially dewatered and filtered. The filter cake is then water washed.

Drying and Agglomeration--

The washed coal is sent to a suitable drier where water is evaporated leaving a clean, dry solid fuel. This material is then compacted to a suitable pellet size for shipment to a power plant.

Table 2-37 presents Ledgemont's current best estimates of key parameters which would be involved in the process design of a continuous system.[67]

The process energy efficiency is estimated to be 83-85%. The bulk of the process energy use would be in treated coal drying and in oxygen plant operation. Oxidation of the coal results in conversion of carbon to carbon

TABLE 2- 37 Typical Values of Key Parameters in the Conceptual Ledgemont Oxygen Leaching Process for Bituminous Coal [68]

Operating Factor: 333 days per year

Overall Yield (avg. coal): 97-98%

Net yield after fuel uses: ≈90%

Net heating value yield (avg. coal): 93-95%

Pyritic sulfur removal: 90%

Organic Sulfur Removal: 0-20%

Chemical Process	Parameter	Typical Value
Coal preparation	Mesh size	80% -100 mesh
Coal desulfurization	Coal/water in feed	0.2/1
	Reaction time	2 hours
	Temperature	130° C (266° F)
	Oxygen pressure	20 atm. (300 psig)
	Oxygen consumption per metric ton coal feed	0.138 metric ton (0.125 ton)*
Treated coal/water separation system	Thickening:	
	Thickening area required	1 m^2/TPD (11 sq ft/TPD)
	Underflow solid concentration	43% solids
	Filtration:	
	Filtration rate	23 kg/hr/.09 m^2 (50 lb/hr/sq ft)
	Percent solids in fuel cake discharge	66%
	Wash water/dry solids	.46/1
Wastewater treatment	Lime addition rate	0.25 T/T coal feed φ

* The oxygen demand includes the following:

	metric ton O_2/metric ton coal
O_2 for pyrite reaction	0.035 †
O_2 for $Fe^{2+} \rightarrow Fe^{3+}$	0.0019
O_2 uptake by coal	0.054
O_2 to form CO_2	0.031
O_2 to form CO_2	0.0014
O_2 lost to flashing	0.0019
Total	0.1252

† Based on 2% pyritic sulfur in the coal. The amount of O_2 used in organic sulfur oxidation is unknown.

φ This is approximately 8 times the stoichiometric requirement for neutralization.

dioxide and carbon monoxide as well as trace amounts of higher hydrocarbons. Approximately 5-7% of the heating value of the coal is estimated to be lost at the process operating conditions.

Based on the published Ledgemont process information and recent contacts with the Ledgemont Laboratory, a schematic flow diagram for a 7,200 metric tons (8,000 tons) per day coal processing plant is shown in Figure 2-38. The process removes little or no organic sulfur and 90% of the pyritic sulfur (starting with 2% pyritic sulfur in the raw coal feed).

Status of the Process

The Ledgemont Laboratory of the Kennecott Copper Corporation began work on a process for coal desulfurization in 1970. The R&D effort was carried out in partnership with the Peabody Coal Company - then a wholly owned Kennecott subsidiary. The joint effort culminated in the Ledgemont flowsheet, the basic features of which have been demonstrated at the bench and semi-pilot scale levels. It is claimed that each step of the process has a complete experimental study to determine the operating range of process variables. Complete reports setting forth the experimental work, process specifications and process economics have been prepared. The entire developmental effort has been internally funded throughout - to the extent of approximately two million dollars.

In 1975, the FTC ordered the divestiture of Peabody Coal by Kennecott, and this resulted in halting further development work on the Ledgemont process. Plans for installing a ½ metric ton per day pilot scale desulfurization operation were scrapped and no further R&D work is planned. Kennecott is currently exploring the possibilities of licensing the Ledgemont process.

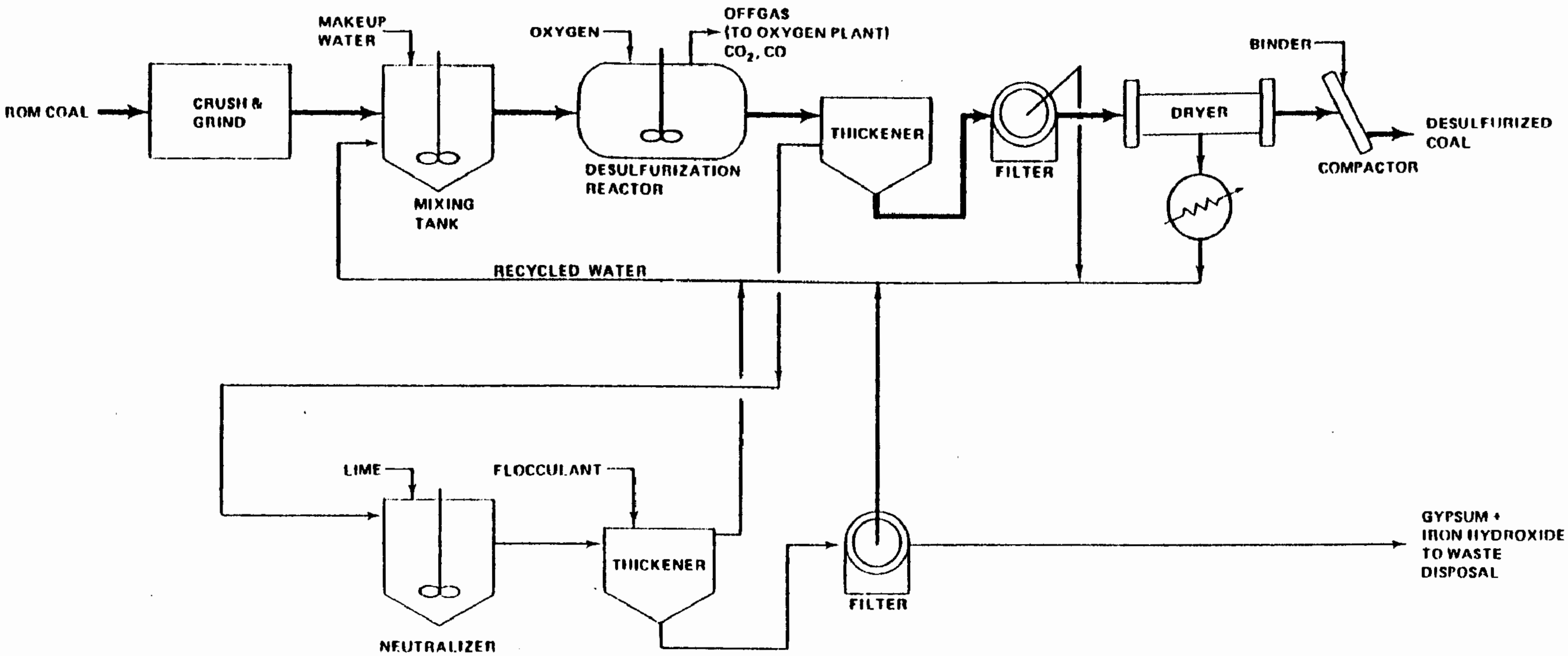


FIGURE 2-38 LEDGEMONT OXYGEN LEACHING PROCESS FLOW SHEET

Technical Evaluation of the Process

The Ledgemont Laboratory has made available an in-house report containing all of the information made public to date on the process. In addition, the Bechtel Corporation has made a technical and economic study of the Ledgemont process.[69] A study of this information plus direct contacts with Ledgemont personnel has permitted the following assessment of the process to be made.[68]

Potential for Sulfur Removal—

The Ledgemont process has been shown to remove more than 90% of the pyritic sulfur in coals of widely differing ranks including lignite, high volatile B bituminous, and semi-anthracite in bench-scale autoclave equipment. Reaction conditions have been standardized at 130° - 132°C (265°-270°F), 20 atm (300 psig) oxygen pressure and two hours residence time. Several bituminous coals including Illinois #6, Ohio #6, and Kentucky, have been treated in "semi-pilot scale" equipment with consistent removal of 90% of the pyritic sulfur. Little, if any, organic sulfur is removed by the process (from 0-20%, depending on coal treated), and there is no credit taken in the conceptual process for this type of sulfur removal.

MAGNEX(SM) CHEMICAL COAL CLEANING PROCESS

The Magnex(SM) process is a coal beneficiation process which utilizes vapors of iron pentacarbonyl [$Fe(CO)_5$] to render the mineral components of the coal magnetic. It has been experimentally demonstrated that free iron resulting from decomposition of the pentacarbonyl selectively deposits on or reacts with the surface of pyrite and other ash forming mineral elements to form magnetic materials. Microscopic observations and chemical analyses suggest that for pyrite the magnetic material is a coating of a pyrrhotite-like mineral, while for ash the magnetic material is metallic iron. It has also been demonstrated that the pentacarbonyl does not deposit iron on the surface of coal particles.

Process Description

The process involves four major steps:

- crushing and grinding;
- heating and pretreatment;
- carbonyl treatment, and cooling; and
- magnetic separation.

Figure 2-39 presents a flow diagram for the Magnex℠ process as described by the process developer, Hazen Research, Inc., of Golden, Colorado.

Run-of-mine (ROM) coal is crushed to minus 14 mesh and then fed to the thermal pretreating unit where it is heated to about 170°C (365°F) in the presence of steam. The steam and thermal treatment conditions the coal to improve the selectivity of the magnetic coating (increase yield and reduce sulfur content of the coal).

The heated coal is then gravity fed to the iron pentacarbonyl reaction vessel where it is subjected to the treatment vapors at atmospheric pressure for a residence time of thirty minutes to one hour. The reactor is insulated and maintains the sensible heat of the coal.

The carbonyl treated coal is conveyed to the magnetic separation section. The treated coal passes across three induced magnetic rolls in series. The first roll removes the strongly magnetic minerals,and the second and third rolls remove the weakly magnetic minerals. Several commercially available magnetic separators have been evaluated under funding by EPRI.

After passing through the magnetic separator, the clean coal is conveyed into a storage bin. Some clean coal from the storage may be returned to the CO burner for in-process use; the remaining will be conveyed to the compactor unit. The pelletized coal will be then conveyed to the product storage for subsequent shipment.

The process consumes 1 to 20 kilograms of iron pentacarbonyl per metric ton of coal (2-40 lb/ton), depending on the feed coal; and generates 0.6 to 13.0 kilograms (1.4 to 28.6 lb) of gaseous carbon monoxide (CO) for recycle.

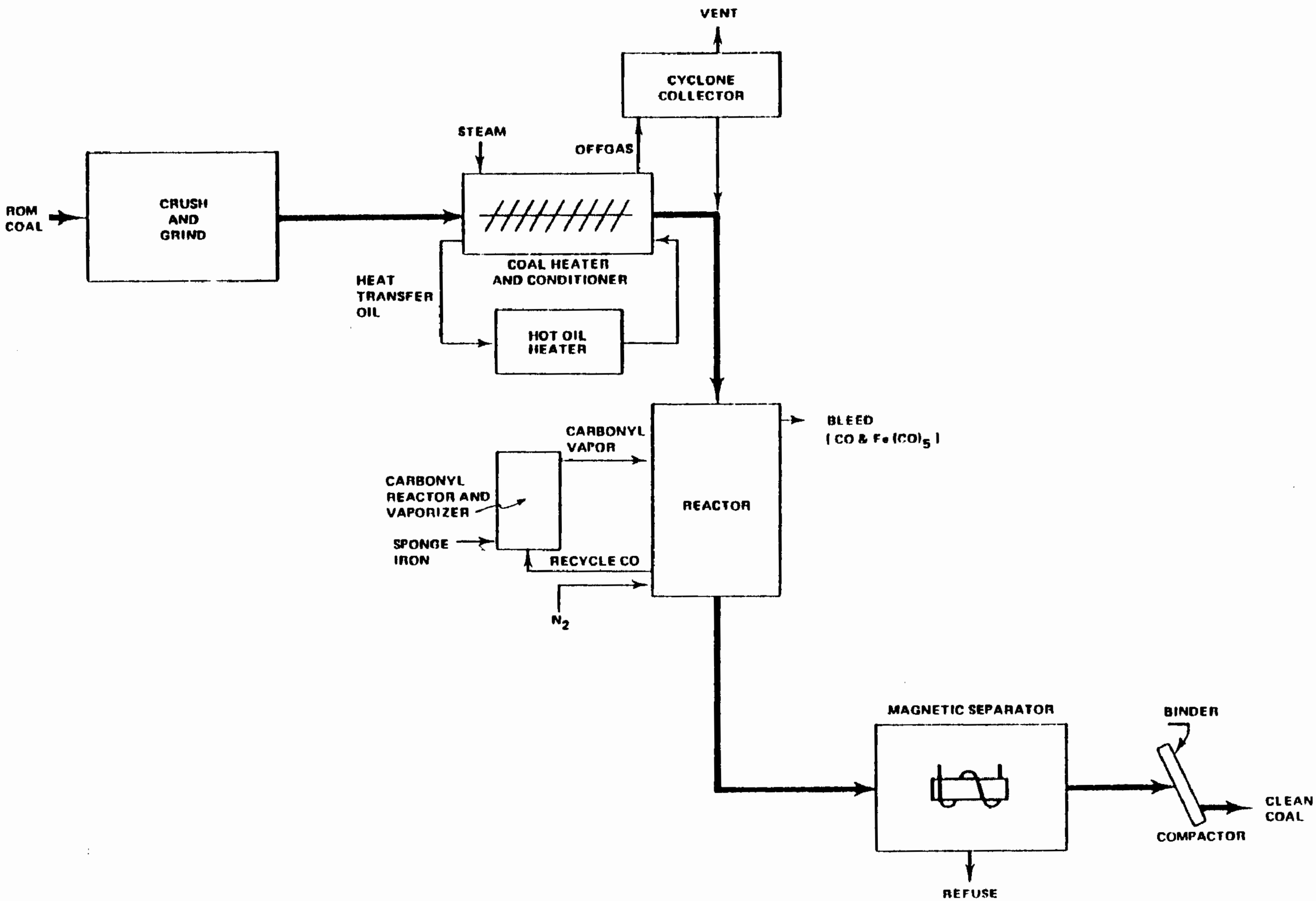


FIGURE 2-39 MAGNEX(SM) PROCESS FLOW SHEET

In the 1977 pilot plant, the CO-rich gas was not recycled to iron carbonyl generation. Rather, it was discharged through a hypochlorite scrubber to remove traces of iron carbonyl. Since the major operating cost for this process is associated with the consumption of the iron pentacarbonyl, it is planned to react the CO-rich gas with iron to produce iron carbonyl on-site. Even with a projected CO recirculation system, a bleed stream may be discharged from the reactor.

Status of the Process

The Magnex (SM) process has been under development for 30 months. For the first 18 months, the process has been investigated on a laboratory scale, using initially 75 gram samples and later one kilogram samples, on a batch scale basis. To date about 40 coals, mostly Appalachian in origin, have been tested.[70] The major emphasis of the laboratory work has been on the chemistry of the process. During this study efforts were directed to determine the effects of process variables such as reactor temperature, iron carbonyl requirements and reaction residence time.

On February 17, 1976, United States Patent #3,938,966 was issued to Hazen Research, Inc. The Magnex (SM) process is owned by the NEDLOG TECHNOLOGY GROUP. NEDLOG plans to continue process development and initiate design, construction and operation of a 54 metric tons (60 tons) per hour demonstration plant.

Start-up operation for the pilot plant was in November, 1976. The coal selected for the pilot plant evaluation was from the Allegheny group of Pennsylvania. This coal was run in the pilot plant during the first quarter of 1977 and was upgraded to meet the current new source sulfur dioxide emission standard of 520 ng SO_2/J (1.2 lb SO_2 per million BTU). Washability studies of this coal had indicated that conventional gravity cleaning would not significantly reduce the sulfur content of the feed coal.

At the present, various coal samples are being evaluated in the laboratory stage and research and developmental work is proceeding in the area of iron carbonyl generation.

Technical Evaluation of the Process

The Magnex (SM) process removes only pyritic sulfur and therefore, it is more applicable to coals rich in pyritic sulfur, which are found in the Appalachian region. The process also reduces the ash content of the coal.

It is claimed that fine coal crushing is not necessary to enable the Magnex (SM) process to find a wide application in pyrite-rich coal desulfurization. The Bureau of Mines prediction curves which correlate pyrite particle size with pyrite sulfur removal do not allow accurate prediction of sulfur reduction for a given coal by the Magnex (SM) process. These curves are only applicable to gravity coal cleaning techniques. It has been reported that in one test the average pyrite particle size of the minus 14 mesh coal sample was 15 micron. Removal of pyritic sulfur from this sample by the Magnex process was approximately 80 percent; while a 30 percent sulfur removal was predicted for this coal using the Bureau of Mines prediction curves.

Limited published information is available on Magnex (SM) process test results. A report covering the applicability of this process for desulfurization of coals surveyed may be issued in the future. However, available information is discussed below.

Potential for Sulfur Removal--

During the first quarter of 1977 a coal feed from the Allegheny Group of Pennsylvania was evaluated on the Magnex (SM) pilot plant. Table 2-38 presents the analysis of the feed coal. Two shipments of this coal were received from the same mine and seam. The ash content of the first shipment was considerably lower than the second (12.7 vs. 18.3 percent); however, the sulfur

TABLE 2-38 ANALYSIS OF MAGNEX(SM) PROCESS PILOT PLANT FEED COAL

Sample Number[Δ]	11089	10442
Ash, wt. %	18.29	12.7
Total sulfur, wt. %	1.27	1.27
Organic sulfur, wt. %	0.56	0.58
Inorganic sulfur,† wt. %	0.71	0.70
Calorific value, BTU/lb	11,980	12,903
Emission, lb $SO_2/10^6$ BTU	2.12	1.97

Δ Two shipments of coal were received. Although they were from the same mine and seam, the ash content was significantly higher in 11089.

† Inorganic sulfur = pyritic + sulfate.

TABLE 2-39 SUMMARY OF LABORATORY EVALUATION OF MAGNEX(SM) PROCESS PILOT PLANT FEED COAL*

	Units	Test Numbers A	B	C
Carbonyl treatment				
Temperature	°C	170	170	170
Dosage	lb/ton	2.5	10	40
Clean coal				
Yield	%	96.4	86.4	81.0
Ash	%	11.6	11.8	10.7
Total sulfur	%	1.08	0.89	0.66
Inorganic sulfur	%	0.34	0.24	0.09
Heating value	BTU/lb	12,992	12,964	13,160
Emission	lb $SO_2/10^6$ BTU	1.66	1.38	1.01

* Feed coal was 10442, minus 14-mesh, 1.27% total sulfur, 0.71% inorganic sulfur, 12.7% ash, 12,736 BTU/lb.

content of both shipments was the same (0.71 percent inorganic and 0.56 percent organic sulfur). Washability curves presenting specific gravity versus yield, cumulative percent ash float and ash sink, and plus or minus 0.10 specific gravity distribution curve of the ROM pilot feed are given in Figure 2-40. This plot indicates that at a specific gravity of 1.5 (where 10 percent of the raw coal feed lies within ±0.10 specific gravity curve) theoretical perfect sink/float cleaning would yield 87.7 percent clean coal containing 9.5 percent ash and 1.13 percent sulfur. While significant ash reduction can be achieved at that specific gravity by sink/float techniques, the resulting coal will not meet the current emission level of 520 ng SO_2/J (1.2 lb SO_2 per million BTU).

The results of the laboratory Magnex SM evaluation of the pilot plant feed are presented in Table 2-39 These data indicate that at 170°C (338°F) and 20 kg of iron carbonyl per metric ton (40 lb/ton) of coal, the clean coal yield was 81 percent with product sulfur content equivalent to 434 ng SO_2/J (1.01 lb SO_2 per million BTU).

Figure 2-41 is the graphical representation of the laboratory data with superimposed pilot plant test data shown by asterisk.[71] In two pilot plant runs, using 75 and 10 kg (15 and 20 lbs.) of iron carbonyl per ton of coal, the clean coal yields were significantly higher (7.9 and 3.6 percentage points, respectively) than the results obtained from the laboratory runs. The sulfur dioxide to BTU ratios for the pilot tests were close to that predicted by the laboratory runs. Pilot plant results indicated that for coal used in this evaluation 10 kg per metric ton (20 lb per ton) of iron carbonyl was adequate to yield a product to meet the current SO_2 level for utility boilers.

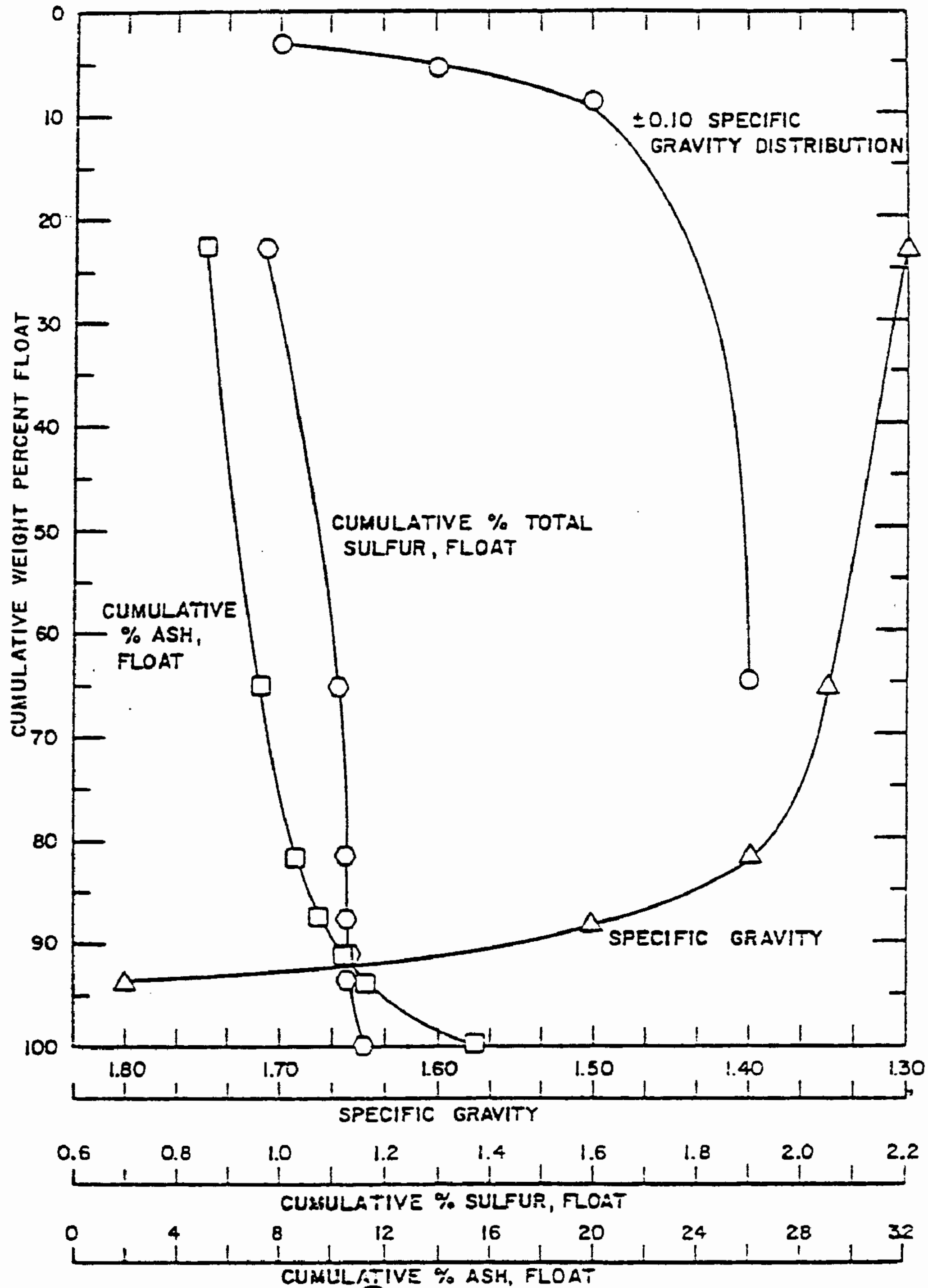


FIGURE 2-40 MAGNEX(SM) PROCESS WASHABILITY PLOT FOR A 6 INCH X 100 MESH COAL

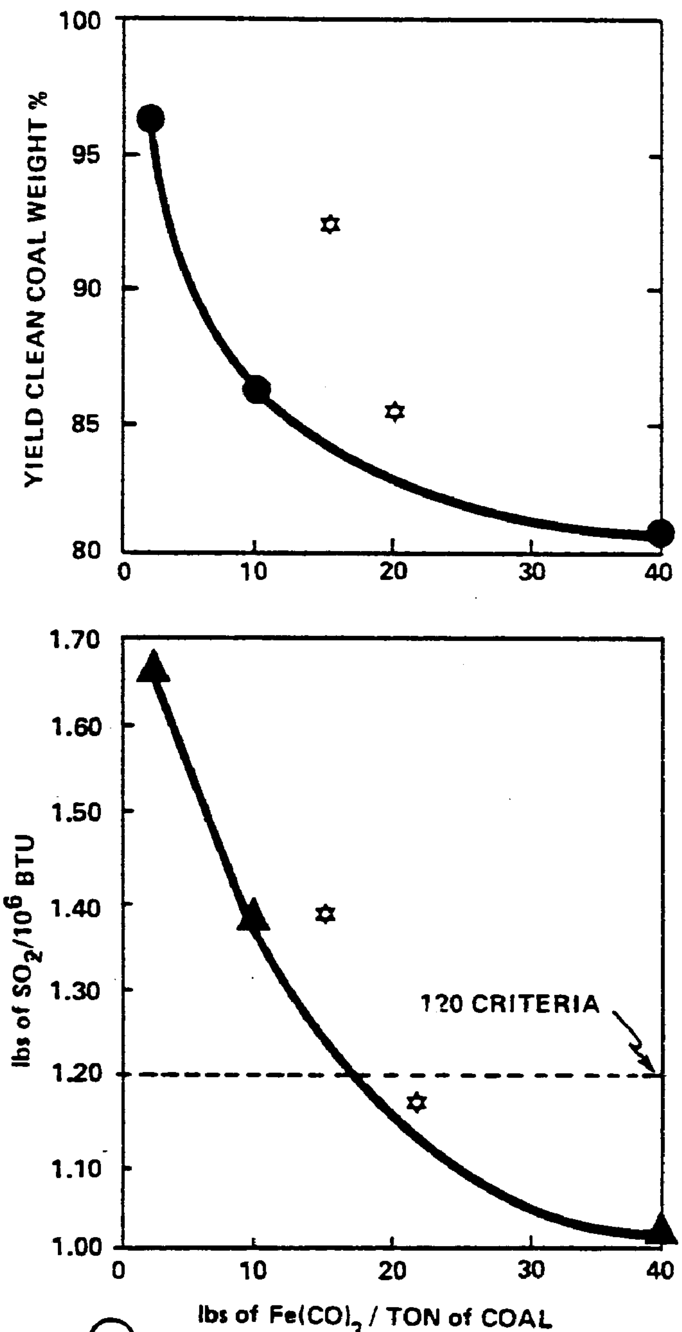


FIGURE 2-41 MAGNEX PROCESS EFFICIENCY COMPARISON OF LABORATORY AND PILOT PLANT DATA

SYRACUSE RESEARCH CHEMICAL COAL COMMINUTION PROCESS

The Syracuse Research Corporation has developed a process for the chemical fracturing or comminuting of coal, which is an alternative to mechanical crushing and fine grinding. The process is a precursor to the removal of pyritic sulfur and ash-forming components of coal by physical coal cleaning methods. Since the process is chemical in nature and it does remove pyritic sulfur when combined with a physical coal cleaning process, it has been included in this study of chemical coal cleaning processes.

Chemical comminution is a process that involves the exposure of the coal to certain low molecular weight chemicals that are relatively inexpensive and recoverable (usually ammonia gas or a concentrated aqueous ammonia solution). "The chemical disrupts the natural bonding forces acting across the internal boundaries of the coal structure where the ash and pyritic sulfur deposits are located. An apparent breakage of natural bonds occurs along these boundaries, thus exposing the ash and pyrite for follow-on separation. No significant dissolution of the coal occurs, nor is there any apparent reaction between the non-coal constituents and the comminuting chemical."(72)

"Since no mechanical breaking is involved in the chemical comminution approach, the size distribution of the comminuted (fractured) coal is governed by the internal fault system, the chemical employed, and the process operating parameters. The size distribution of the pyrite and other mineral constituents in the coal is solely dependent upon the characteristics and history of the coal being treated."(72)

Process Description

A conceptual flow sheet for the Syracuse process is presented in Figure 2-42. The starting material is raw coal which has been sized to 3.8 cm (1½ in) x 100 mesh. The minus 100 mesh coal is separated and shipped directly to the physical cleaning plant. The 3.8 x 100 mesh coal is weighed and charged to a batch reactor. In a typical cycle, the reactor is then closed and evacuated by a rotary seal pump for removal of air. The reactor is then

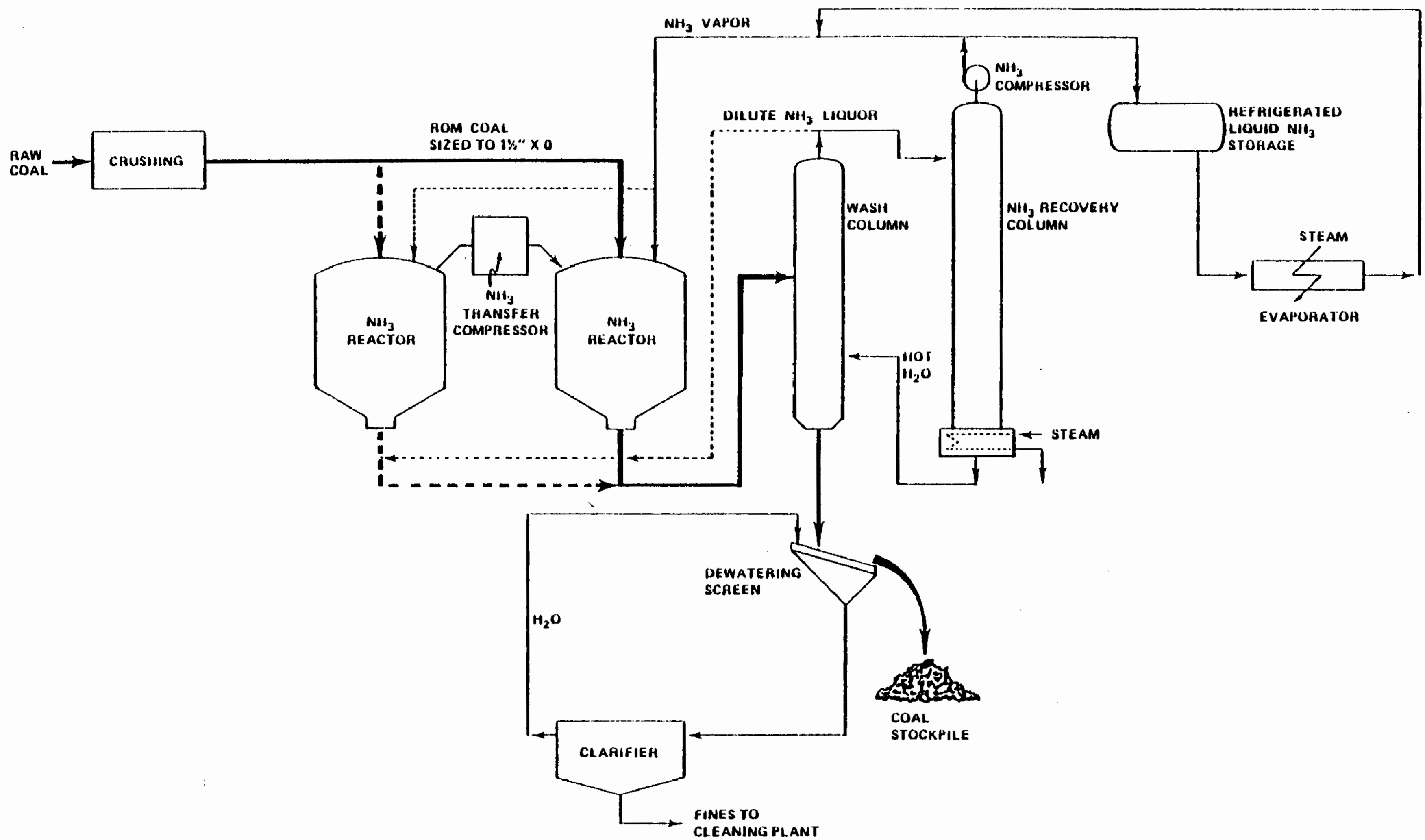


FIGURE 2-42 SYRACUSE COAL COMMINUTION PROCESS FLOW SHEET

pressurized with ammonia vapor to about 9 atm (120 psig). In a full scale operation this would be accomplished in two steps, first to 5 atm (60 psig) by equalizing ammonia pressure with another batch reactor (operated in parallel and just completing its reaction cycle), and then to 9 atm (120 psig), using ammonia from either the ammonia compressor or from an evaporator which draws from a liquified ammonia storage tank. The reactor is held at 9 atm (120 psig) pressure for 120 minutes. During the reaction period, the temperature in the reactor rises 50°C to 65°C above the ambient temperature due to heat of solution of ammonia absorbed by moisture in the coal. The coal is comminuted to about 1 cm (3/8") top size.

At the end of the reaction cycle, the reactor is depressurized to 0.14 atm (2 psia) by first equalizing with another reactor which is charged with fresh coal, and then exhausting with a transfer compressor. These steps minimize loss of ammonia in coal. By this time, the temperature of the coal has dropped to about 27°C (80°F). The vacuum is then released in the reactor, and the coal is conveyed directly to a slurry mix tank prior to washing. The cycle of a batch is suggested as follows:

Operation		Time (Min.)
Charging		30
Evacuation		30
Equalizing to 5 atm (60 psig)		30
Pressurizing and holding at 9 atm (120 psig)		120
Equalizing to 5 atm (60 psig)		30
Depressurizing to 1.1 atm (2 psig)		30
Release vacuum and discharge		30
Idle time		as required
	TOTAL	300 plus idle time

All vent gases are collected through a rotary seal pump and scrubbed. The scrubber effluent is added to coal slurry.

Comminuted coal is slurried with a recycle stream pumped from the ammonia wash column. This recycle stream contains minus 30 mesh coal of 15-20% solids, plus 5-10% dissolved ammonia. A 35% solids slurry is formed with the comminuted coal and is pumped to the midpoint of the wash column. As the coal sinks in this column it is washed free of ammonia with hot water. Coal containing about 20% moisture settles to the bottom of the column and is periodically discharged by a rotary valve to a dewatering screen.

The coal on the dewatering screen is washed to remove all minus 28 mesh fines and discharged to a stockpile, where it can then be sent to a cleaning plant. The minus 28 mesh fines from the dewatering screen leaves as a 20% slurry, and are sent to a clarifier. The fines are recovered as a 40% sludge, which is sent to the cleaning plant. The clarifier overflow water is recycled to product washing.

The ammonia recovery column is equipped with a feed preheater, a reflux condensor, and dome-cap trays. The column operates at one atmosphere pressure, nominally and the reboiler is heated by 2.7 atm (25 psig) steam. Ammonia is released from the incoming ammonia solution, and ammonia vapor containing about 2% moisture is cooled to 30°C (90°F) as it leaves the column. This vapor is compressed to 9.5 atm (125 psig) by the recycle compressor, and the vapor ammonia is either recycled immediately to a reactor, or is condensed and stored in a tank.

As has been stated above, all products from the chemical comminution step would be sent to a conventional coal cleaning or washing plant for separation of beneficiated coal from pyrite and ash-enriched refuse. A proposed operation of this type is illustrated in the flow sheet given in Figure 2-43. This flow sheet is proposed by the Syracuse Research Corp.[72]

Status of the Process

The 1971 Syracuse Research Corporation initiated development of a program aimed at the removal of pyritic sulfur and ash-forming substances from coal.

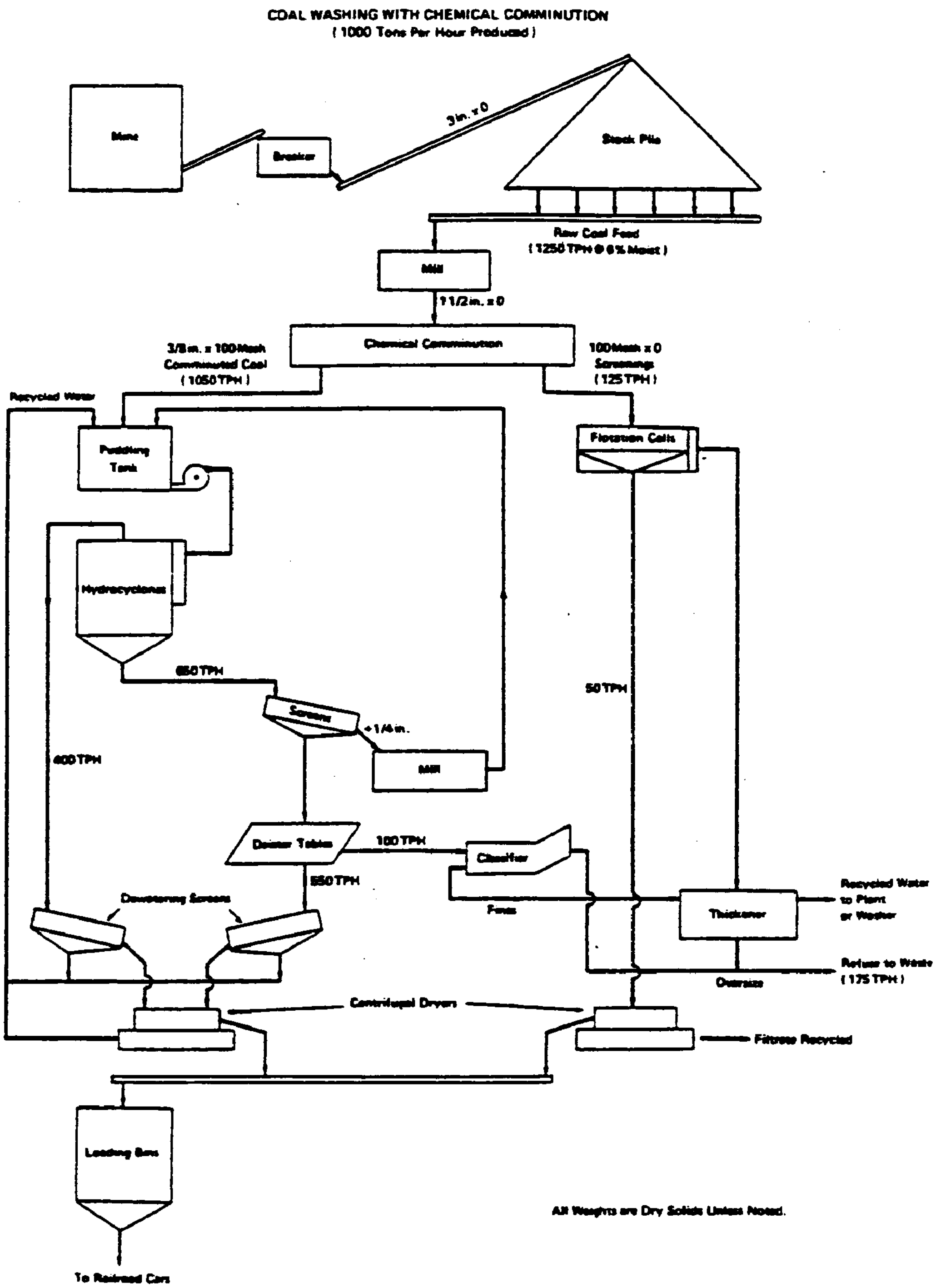


FIGURE 2-43 SYRACUSE PROCESS CHEMICAL COMMINUTION PLUS PHYSICAL COAL CLEANING

The results of this effort have been patented in the United States and in a number of foreign countries. During a portion of the project, effort was supported by the Energy Research and Development Administration, and a final report was published.[73]

All work to date has been performed on a laboratory or bench scale at the facilities of Syracuse Research. The largest tests have been with 23 kg (50 lb) batches of coal, which were run in large, specially constructed steel "bombs".

Proof of the "cleanability" of the chemically comminuted coal product has been limited to development of laboratory washability data, followed by complete sulfur and ash analyses of the various fractions, and development of cumulative percent sulfur and percent ash contents versus percent coal recovery curves. It appears that no chemically comminuted coal has yet been subjected to separation in a coal washing plant, or even on coal washing pilot plant equipment.

In 1977 marketing of the process was undertaken by Catalytic, Inc. of Philadelphia, Pennsylvania and a complete report of the process and process economics was prepared.[72]

Exploratory efforts by Catalytic, Inc. to build and operate a pilot plant at a suitable location include negotiations for a site at Homer City, Pennsylvania or at TVA.[74]

Catalytic performed a study, at EPRI's request, comparing chemical comminution with mechanical crushing, both followed by heavy medium separation facilities for the Homer City application.

Technical Evaluation of the Process

Potential for Sulfur Removal—

As stated previously, chemical comminution liberates pyritic sulfur more readily than mechanically fractured coal of the same size consist, the user can employ higher sulfur coals as feed stock to achieve a given sulfur level in the cleaned product. Conversely, for a given level of sulfur, chemical comminution will generally yield increased coal product.

In Figure 2-44, the washability data completed on Illinois No. 6 (Franklin County) coal is plotted to illustrate percent cumulative sulfur versus recovery. In this comparison, the chemically comminuted coal is clearly superior to the other three samples. For example, at a 90% recovery of plus 100 mesh coal, sulfur content would be 1.3%, for the Syracuse product, 1.48% for 1 cm (3/8 in) mechanically crushed coal, 1.44% for 14 mesh mechanically crushed coal and 1.51% for 3.8 cm (1½ in) ROM sample respectively. For a selected sulfur value of 1.40% weight yield recoveries would be 96%, for the Syracuse product, 78% for 14 mesh mechanically crushed coal, 70% for 1 cm (3/8 in) mechanical crushed coal, and 49% for 3.8 cm (1½ in) ROM sample.

As previously mentioned, the potential for removal of pyritic sulfur from ROM mechanically crushed coal, or chemically comminuted coal has been assessed to date only by laboratory washability data. This laboratory technique yields optimal results which are rarely duplicated in full-scale coal cleaning plants. Therefore, the washability comparisons made with respect to sulfur removal or product recovery, between chemically comminuted coal and mechanically crushed coals may be altered in plant operation.

Based on available data, it is anticipated that the Syracuse chemical comminution process followed by conventional physical coal cleaning, will remove 50 to 70 percent of pyritic sulfur in coals, with product recoveries of 90 to 60 weight percent. The coals used in laboratory studies contained high organic sulfur. Therefore, even removal of 100% of pyritic sulfur would not bring these coals into compliance with current EPA NSPS for SO_2 emissions. It is also concluded that the Syracuse chemical comminution process, followed by conventional physical coal cleaning, will bring some coals into compliance range if the organic sulfur level is sufficiently low.

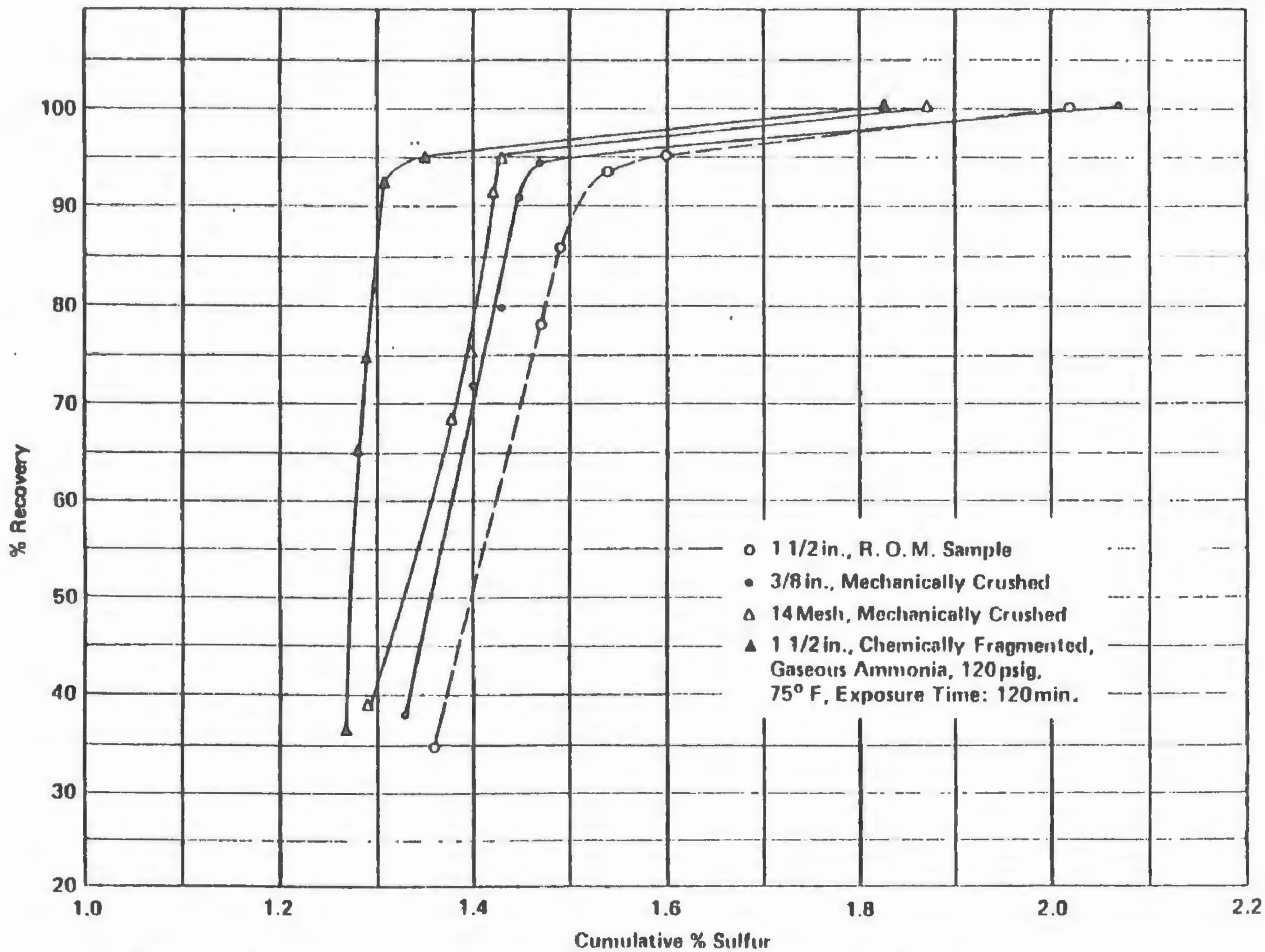


FIGURE 2-44 SYRACUSE PROCESS VS. MECHANICAL CRUSHING: PERCENT SULFUR VS. PERCENT RECOVERY OF ILLINOIS NO. 6 COAL

ERDA CHEMICAL COAL CLEANING PROCESS

The ERDA air/steam leaching process is similar to the Ledgemont oxygen/water process, except that the process employs higher temperature and pressure to affect organic sulfur removal and uses air instead of oxygen. A coal desulfurization process very similar to the ERDA process is also described in a U.S. patent 3,824,084 assigned to the Chemical Construction Corporation.

In the ERDA chemical coal cleaning process the pyritic sulfur is first oxidized to soluble sulfates. It is claimed that when the process operates at the preferred temperature and pressure of 150°C (302°F) and 34 atm (500 psia), essentially all the soluble sulfate is oxidized to insoluble iron oxide and sulfuric acid.

The organic sulfur leaching chemistry is not well known. It is the developers belief that the major portion (>50 percent) of the organic sulfur in coal is of the dibenzothiophene (DBT) type which is inert to air at relatively high pressure and temperature. However, the remaining fraction of organo-sulfurs are not DBT-like and can react with air and steam to produce sulfuric acid.[75]

Process Description

In the ERDA air/steam oxidative desulfurization process the coal slurry is heated in the presence of compressed air at temperatures of 150°C to 200°C (300°-400°F), pressures 34 to 102 atm (500 to 1,500 psia), and residence time of 1 hour or less. At these operating conditions, it is claimed that essentially all the mineral sulfur and approximately 40 percent of the organic sulfur is removed as sulfuric acid. The ERDA process has been conceptualized by Bechtel.[69]

A simplified flow diagram of the process as developed by Bechtel, is shown in Figure 2-45. Pulverized coal is mixed with water in the slurry mixing tank. The coal slurry is pumped to feed-effluent exchanges where the feed is heated with recovered heat from the reacted product. The feed is further heated in the flash gas quench tower by direct contact with desulfurization reaction off-gas, recycled from the product slurry flash tank. The feed slurry at operating temperature and pressure is passed

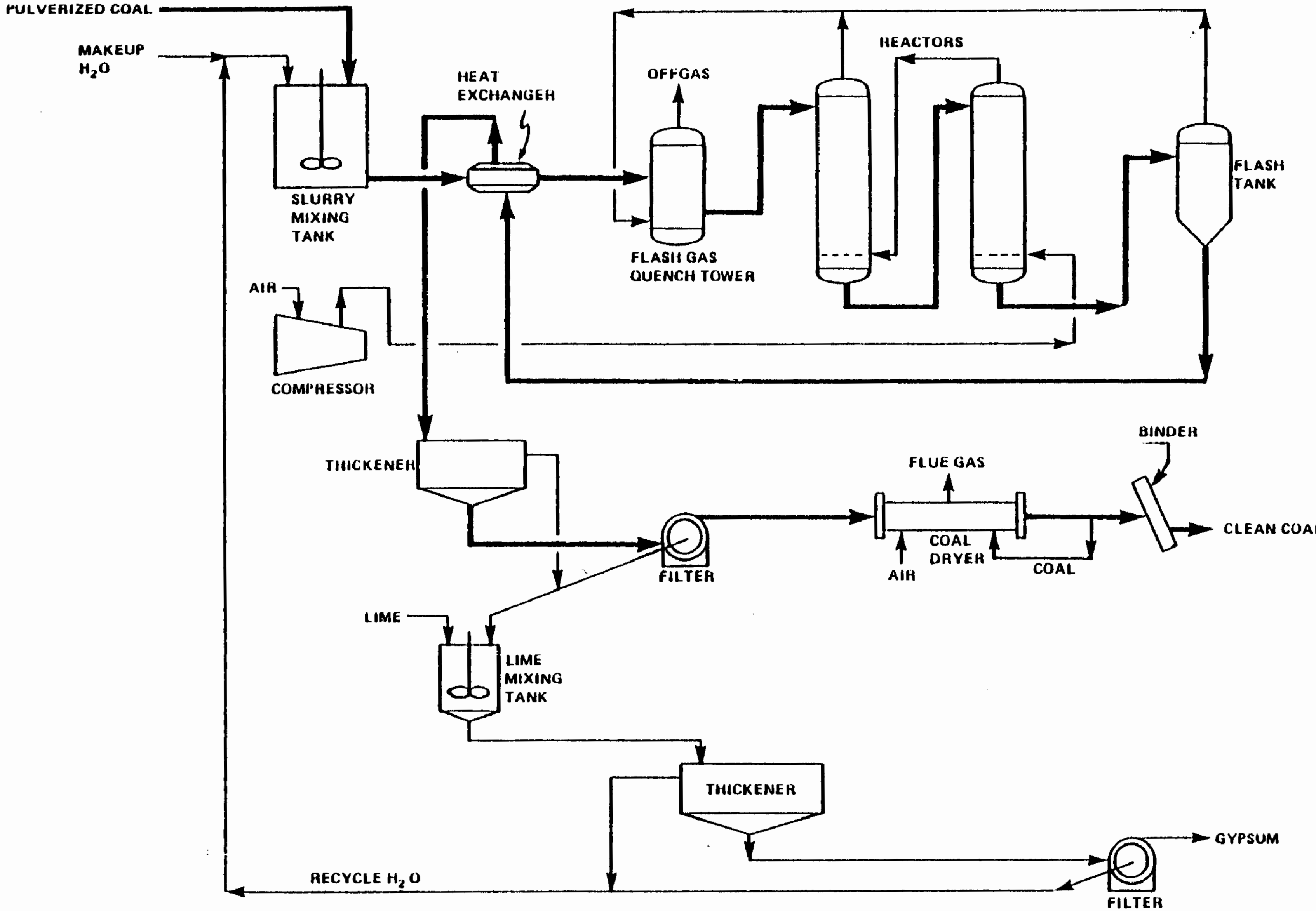


FIGURE 2-45 ERDA PROCESS FLOW SHEET

through a series of reaction vessels where the slurry in coal is oxidized in presence of compressed air. The product slurry is next flashed into product slurry tank and subsequently thickened, filtered and dried prior to compacting. A portion of the clean coal is burned to provide heat for drying.

The coal thickener overflow is combined with the filtrate from the coal filter and sent to lime treatment for neutralization of sulfuric acid and ferrous sulfate. The sulfuric acid in this stream is converted to gypsum and the ferrous sulfate to gypsum and ferrous hydroxide. These reaction products are sent to gypsum sludge thickener and subsequently filtered. The filter cake from this operation constitutes the solid waste from this process. The thickener overflow and the filtrate constitute the recycle water, which is sent to the slurry mixing tank.

Status of the Process

The ERDA chemical coal cleaning process was conceived approximately seven years ago by Dr. Friedman at the Bureau of Mines and the process is currently under study at DOE's Pittsburgh Energy Research Center (PERC). Initial experiments on the air/steam oxydesulfurization of coal were carried out using a batch, stirred autoclave system with 35 gram coal samples. This apparatus was modified to allow continuous air flow through the stirred reactor while the coal-water slurry remained as a batch reactant.

The current effort at PERC centers on the installing and operating of a 25 kg/day continuous reactor unit. The system consists of a slurry feeder, slurry pre-heater, air preheater, a single Monel pressure vessel capable of operating at up to 69 atm (1,000 psig), two parallel pressure let-down tanks and a product recovery tank.[76] This system is designed to obtain data on reaction rates and develop information on process engineering and economic evaluation. It is hoped that operating data will be available within nine months so that a decision can be made regarding the design, construction, and operation of a larger continuously operated process development unit (PDU). There is a possibility that a large, private engineering group may assume the PDU effort, with support from DOE.

Technical Evaluation of the Process

Technical evaluation presented here-in is based upon published information and discussion with ERDA researchers, as well as the Bechtel[9] conceptualization of this process and their prepared economic evaluation.

Potential for Sulfur Removal—

The developer's claim is that using this process, an estimated 45 percent of the mines in the eastern United States could produce environmentally acceptable boiler fuel in accordance with current EPA SO_2 standards for new utility boilers. [77] Available data from batch operations indicate that at mild temperatures of 150° to 160°C (300°-320°F) the ERDA air/steam oxydesulfurization process can remove more than 90 percent of the pyritic sulfur in coals. Table 2-40 [77] presents pyrite removal information from several representative coals. The process is also claimed to remove up to 40 percent of coal's organic sulfur if the reaction temperature is raised to 180-200°C (360-400°F), this information is shown in Table 2-41.[77] Table 2-42 [77] indicates that at low operating temperatures of 150 to 160°C (300-320°F) several high sulfur content coals, such as coals from Iowa and Indiana (Lovilia #4 and Minshall seams, respectively), can be significantly reduced in sulfur content by this process. Higher temperatures and pressures will be required to reduce the sulfur contents of these coals further.

The coal preparation requirements of this process are not known at this time. Minus 200 mesh ROM coal has been used in most runs, but a few runs using minus 14 mesh coal are claimed to produce comparable results. Due to physical sizing limitations in the mini-pilot plant minus 200 mesh coal will be processed.

GENERAL ELECTRIC CHEMICAL COAL CLEANING PROCESS

The General Electric microwave process for chemically cleaning coal consists of the following steps:

- Crushed and ground coal (40 to 100 mesh) is wetted with a sodium hydroxide solution, then subjected to a brief ($\leq$30 sec.) irradiation

TABLE 2-40 PYRITE REMOVAL FROM REPRESENTATIVE COALS USING THE ERDA PROCESS

Seam	State	Temp, °C	Pyritic sulfur, wt. % Untreated	Pyritic sulfur, wt. % Treated
Illinois No. 5	Illinois	150	0.9	0.1
Minshall	Indiana	150	4.2	0.2
Lovilia No. 4	Iowa	150	4.0	0.3
Pittsburgh	Ohio	160	2.8	0.2
Lower Freeport	Pennsylvania	160	2.4	0.1
Brookville	Pennsylvania	180	3.1	0.1

TABLE 2-41 ORGANIC SULFUR REMOVAL FROM REPRESENTATIVE COALS USING THE ERDA PROCESS

Seam	State	Temp, °C	Organic sulfur, wt. % Untreated	Organic sulfur, wt. % Treated
Bevier	Kansas	150	2.0	1.6
Mammoth*	Montana	150	0.5	0.4
Wyoming No. 9*	Wyoming	150	1.1	0.8
Pittsburgh	Ohio	180	1.5	0.8
Lower Freeport	Pennsylvania	180	1.0	0.8
Illinois No. 6	Illinois	200	2.3	1.3
Minshall	Indiana	200	1.5	1.2

* Subbituminous

TABLE 2-42 ERDA PROCESS OXYDESULFURIZATION OF REPRESENTATIVE COALS

Seam	State	Temp, °C	Total sulfur, wt. % Untreated	Total sulfur, wt. % Treated	Sulfur, lb/10^6 BTU Untreated	Sulfur, lb/10^6 BTU Treated
Minshall	Indiana	150	5.7	2.0	4.99	1.81
Illinois No. 5	Illinois	150	3.3	2.0	2.64	1.75
Lovilia No. 4	Iowa	150	5.9	1.4	5.38	1.42
Mammoth*	Montana	150	1.1	0.6	0.91	0.52
Pittsburgh	Pennsylvania	150	1.3	0.8	0.92	0.60
Wyoming No. 9*	Wyoming	150	1.8	0.9	1.41	0.78
Pittsburgh	Ohio	160	3.0	1.4	2.34	1.15
Upper Freeport	Pennsylvania	160	2.1	0.9	1.89	0.80

* Subbituminous

with microwave energy in an inert gas atmosphere. Both pyritic and organic forms of sulfur react with the sodium hydroxide to form soluble sodium sulfide (Na_2S) and polysulfides (Na_2S_x) during irradiation.

- The coal is washed to remove the partially spent caustic and the sodium sulfides, then it is again wetted with caustic solution, and subjected to microwave radiation for an equivalent period.
- The coal is again washed to remove the partially spent caustic and the soluble sulfides, it is then dried and compacted.

The uniqueness of microwave treatment lies in the fact that the sodium hydroxide and the sulfur species in the coal can be heated more rapidly and efficiently than coal itself. Thus the reaction between sodium hydroxide and sulfur occurs in such a short time and with such low bulk temperatures that an insignificant amount of coal degradation occurs. As a result, the heating value of the coal is either unchanged or is slightly enhanced.

A number of bituminous coals having total sulfur contents from 1 to 6%, and having either predominately pyritic sulfur or organic sulfur contents, have been tested with total sulfur removals of 70 to 99%. Thus, the process does address itself to both of the two major forms of sulfur in coal. For most coals, two microwave irradiation treatments with fresh caustic are necessary. However, for the few coals with relatively low total sulfur content, a single treatment may be adequate to reduce the sulfur to a sufficiently low level. Single treatments are generally 30-70% effective in total sulfur removal.

Process Description

In the absence of a flow sheet from G.E., a schematic flow sheet (Figure 2-46) of the desulfurization steps of the process has been proposed and discussed with G.E. project personnel. They agree with its principal features, which are as follows:

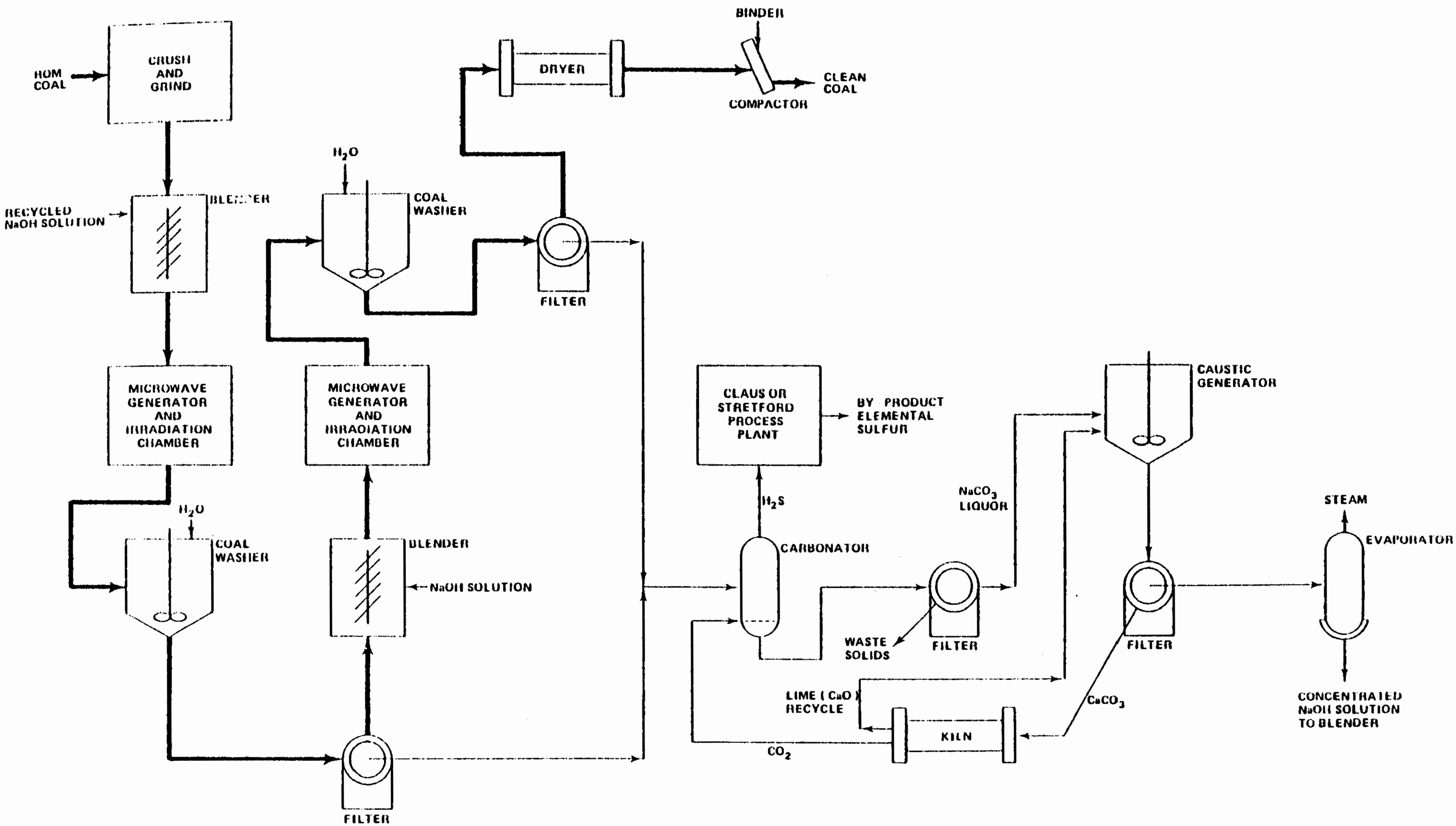


FIGURE 2–46 GENERAL ELECTRIC MICROWAVE PROCESS FLOW SHEET

- 40 mesh top-size coal is slurried with a 20% solution of sodium hydroxide so that the coal is thoroughly wetted by the caustic.
- The moist coal is then subjected to microwave radiation for seconds. During this brief time, 30-70% of the total sulfur in the coal is converted to sodium sulfide (Na_2S) or polysulfide (Na_2S_x) and some of the water is evaporated.
- The coal is then slurried in water to dissolve and remove the sodium sulfides, dewatered, and then resaturated with about the same concentration and amount of caustic as previously stated.
- After a second exposure to microwave energy, the desulfurized coal is again washed free of sulfides and excess caustic, and is dewatered and dried to the extent required for on-site use, or is dried and compacted prior to shipping. Depending on the coal itself, and certain operating factors, 70% of the total sulfur in the coal will have been removed.

A schematic flow sheet has been proposed for the sulfur recovery process steps, which is also shown in Figure 2-46. This is necessary for an adequate conceptualization of the entire G.E. process and for process cost estimation. It is G.E.'s present intent to process wash waters containing sulfur by carbonating these liquors to produce hydrogen sulfide gas (H_2S), and then recover elemental sulfur via the Claus Process. The sodium carbonate, which also results from the carbonation step, would be treated with lime to regenerate soluble sodium hydroxide and insoluble calcium carbonate. The latter is then kilned to produce the CO_2 and lime (CaO), which are both recycled and reused. This regeneration process is almost identical to the one being considered by the Battelle Institute as a part of their chemical coal cleaning process. The regeneration process at first glance appears simple and compact, however it may prove energy intensive due to:

- evaporative heat required to concentrate solids in the several filtate streams; and
- heat input to the kiln.

It will, therefore, be necessary to use minimum quantities of water and sodium hydroxide reactant in order to conserve heat energy in the subsequent sodium hydroxide regeneration steps.

Status of The Process

All work to date has been done on a laboratory scale with small (10-100g) quantities of coal subjected to microwave radiation from a 1 KW, 2.4 GHz or a 2.5 KW, 8.35 GHz generator. The coal is first impregnated with a 20% solution of sodium hydroxide (NaOH), and sufficient caustic solution is retained on the coal after dewatering so that about 16 parts of NaOH are present per 100 parts of coal at time of treatment. Batch tests have been made on a number of coals in which the coals were irradiated once or twice for varying periods of time. However, exposure periods exceeding 30 seconds rarely gained further benefits.

Total sulfur (combustible to SO_2) removals of 75% have been achieved for most bituminous coals provided that two sequential treatments are given. However, much remains to be done in terms of economic optimization of the process.

Technical Evaluation of the Process

Potential for Sulfur Removal--

A substantial removal of sulfur from bituminous coal appears technically feasible with this process, providing that microwave treatment of the coal is accomplished in two steps. Initially all analytical data indicated that 95-100% removal of sulfur could be achieved as a result of the two step treatment. Since that time, additional analytical techniques have been utilized and are yielding conflicting data. For example, on untreated coals the Leco and the Eschka methods show nearly identical sulfur analyses. On G.E. process treated coals, the Eschka (barium sulfate precipitation) method shows considerably more residual sulfur in the coal then does the Leco (combustion) method. Two conclusions are possible:

- The G.E. process does remove 75% or more of total S from coal, but not necessarily 95-100% in a 2-step process as was previously claimed.
- Since the sulfur which is not removed does not show up in a Leco combustion-type analysis, it may end up in the ash and thus may still not result in SO_2 emissions. Further effort to resolve this matter is in progress.

A one-step treatment is effective to the extent of 30-70% sulfur removal, depending on the coal itself and other processing factors. Sulfur removal in subbituminous coal, anthracite, or lignite has not yet been attempted.

BATTELLE CHEMICAL COAL CLEANING PROCESS

The Battelle hydrothermal coal process (BHCP) is based upon hydrothermal alkali leaching of mineral and organic sulfur compounds from coal. The process presently proposed by Battelle employs sodium and calcium hydroxides as a mixed leachant and operates under conditions of elevated temperatures and pressures. The desulfurized coal, after filtration and washing to separate the spent leachant, is dried and compacted for use in coal-fired utility boilers. At the present stage of development, the process must be considered as partially conceptual.

The BHCP desulfurization step has been tested on a series of raw bituminous coals and has been shown to extract essentially all of the pyritic sulfur and 25 to 50% of the organic sulfur starting with a range of total sulfur content of 2.4 to 4.6 percent. The product is a solid fuel which meets the current new source standard of a maximum of 520 ng SO_2/J (1.2 lbs SO_2/ 10^6 BTU) with certain coals.

Process Description

The proposed process consists of five principal steps:

Coal Preparation--

The raw coal is crushed and ground to suitable particle size, generally 70 percent minus 200 mesh. The coal then goes directly to a slurry tank for mixing with the leachant. Alternatively, the coal can be first physically beneficiated to remove some ash and pyritic sulfur before introduction into the slurry tank.

Hydrothermal Treatment--

The coal slurry is pumped into a reactor where it is heated to temperatures in the range of 200° to 340°C (400° to 650°F) and subjected to a pressure in the range of 18 to 170 atm (250 to 2,500 psig) to extract sulfur and dissolve a portion of the ash from the coal. Residence time is approximately 10 minutes. It is essential that this operation and the following one be carried out in an oxygen-free atmosphere to minimize the formation of oxysulfur compounds which prevent the quantitative recovery of sodium hydroxide from the spent leachant.

The recommended leachant for the process is a mixture of 8 to 10 percent sodium hydroxide (NaOH) solution in a 3 percent calcium hydroxide ($Ca(OH)_2$) slurry. Concentrations of these components of the leachant will vary depending on coal properties.

Fuel Separation--

The desulfurized coal is separated from the leachant by means of filtration and water washing. The leachant is then concentrated before regeneration.

Drying and Agglomeration--

Water is evaporated from the coal in a drier, leaving dry, clean, solid fuel. This material is then compacted to a suitable pellet size for shipment to the user.

Leachant Regeneration--

A chemical regeneration step uses carbon dioxide to remove sulfur from the leachate as hydrogen sulfide. This gas is then converted to elemental sulfur by either the Claus or Stretford process.

The schematic incorporates raw coal grinding, and treated coal drying and compaction steps, not included in the latest Battelle process flow sheet. Battelle proposes the production of treated coal as a wet material which is stored in silos prior to shipment to the utility. If located at a power plant site,the utility would be reponsible for grinding the raw coal and drying the treated coal. Battelle has included a charge to the BHCP for the cost of drying in their latest cost estimate. However, to make the cost estimate comparable to the other processes being considered in this study, i.e., for a plant not necessarily located adjacent to a power plant, the drying of the minus 200 mesh coal followed by a compaction (briquetting) step are included in the flow sheet and cost estimate.

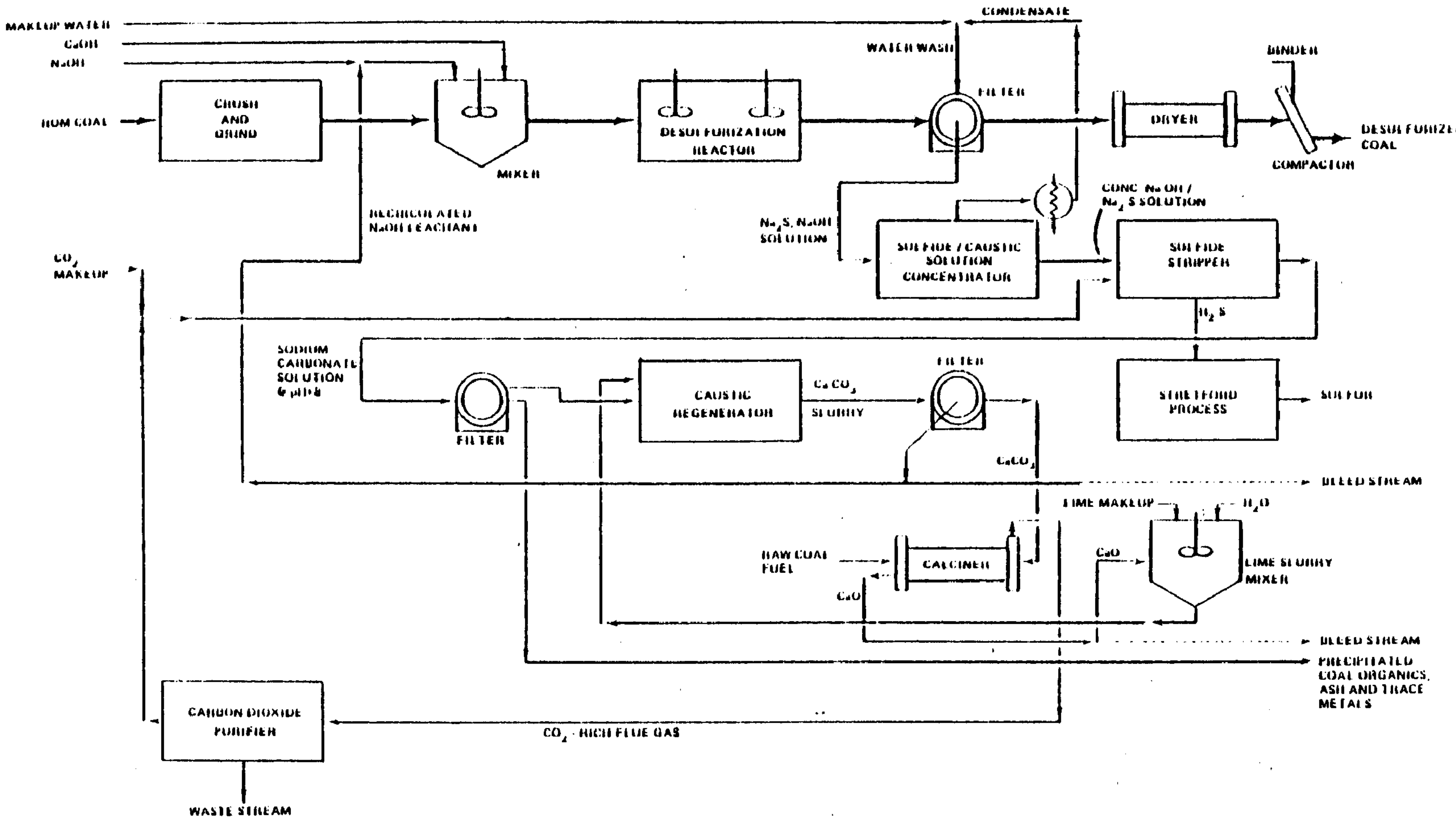


FIGURE 2-47. BATTELLE HYDROTHERMAL PROCESS FLOW SHEET

Status of the Process

The original Battelle hydrothermal coal process has been under development at the Columbus Laboratories since 1960 under Battelle sponsorship. The desulfurization step has been carried through pre-pilot level (continuous bench-scale) laboratory investigations. In this effort, sulfur extraction from approximately twenty different eastern and midwestern bituminous coals have been studied. Battelle has published pyritic sulfur extraction data on 6 coals, organic sulfur extraction data on 6 coals, and overall sulfur reduction data on 6 coals.(78) In all of these studies, the SO_2 emission on the BHCP treated coals was equal to or less than the current EPA-NSPS of 520 ng SO_2/J (1.2 lb/10^6 BTU) for coal-fired steam generators.

Liquid/solid separation and regeneration of spent leachant are being studied in bench-scale equipment in an attempt to:

- establish definitive information as to whether the process can operate in closed-loop fashion; and
- improve the economic viability of the process by reducing the cost of these two high cost segments.

The EPA has funded a third area of interest in the BHCP: a combustion study on BHCP treated coals (Contract No. 68-02-2119). This study was a laboratory scale evaluation of BHCP treated coal combustion characteristics. This work was completed and reported in "Study of the Battelle Hydrothermal Treatment of Coal Process", to IERL, RTP, in November of 1976.(79)

With respect to regeneration of spent leachant, experimental efforts have concentrated on screening the use of zinc and iron compounds as possible regenerants for spent leachant from the coal desulfurization step. Results so far have not indicated significant process viability for either of these two heavy metals as alkali regenerants. In the case of zinc, there are indications of residual zinc buildup in the coal as well as environmental problems expected when zinc sulfide is roasted to regenerate the zinc oxide. In the case of iron oxides or hydroxides as possible regenerants, there has been no notable success to date.

To date, no experimental work has been attempted on optimization of the solid, liquid separation treatment of the slurry from the desulfurization step. A computer model has been developed in order to optimize (on paper) the relationships between the parameters involved, including the method of separation (filtration, centrifugation or thickening), the number of separation/washing stages involved, the wash water/dry solids ratio, the percent of water in the underflow coal and the amount of entrained sodium in the coal. These parameters have all been related to the cost contribution per ton of coal product. This study has shown that nine countercurrent filtration/washing stages at an overall wash water/dry solids ratio of 1.5 with a final solids level of 45% in the underflow (filter cake) gave the lowest operating cost contribution per metric ton of product, i.e., \$10.50/metric ton (\$9.50/ton). At a cost contribution of \$10.50/metric ton (\$9.50/ton) with nine filtration/washing stages and 45% solids in the underflow, the lowest entrained sodium level was determined to be 0.0018 metric ton, i.e., about 1.8 kg entrained sodium per metric ton of dry solid (3.6 lbs/ton).

Using a value of 0.005 metric ton of bound sodium in the treated coal per metric ton of dry solid, the total sodium input to the process (as 73% NaOH) would be about 0.016 metric ton per metric ton of dry product coal, i.e., 16 kg/metric ton (32 lb/ton). With caustic at \$176/metric ton (\$160/ton), the sodium input represents about 27% of the total cost contribution of the solid/liquid separation portion of the process. This caustic input value is still subject to experimental verification.

In the preliminary combustion studies with two BHCP treated coals under Contract No. 68-02-2119, the combustion characteristics of these coals were determined in two test facilities at Battelle, a one-half kg/hr (one lb/hour) laboratory-scale furnace and a 10-40 kg (20-80 lb) per hour multi-fuel furnace facility. Tests in both units were conducted with dry, pulverized BHCP treated coal. The results of these tests indicated that the treated coals would meet the present U.S. EPA-NSPS for sulfur dioxide emissions and that combustion of these coals proceeded as well or better than the corresponding raw coals.[79]

Technical Evaluation of the Process

The BHCP is one of the few chemical coal cleaning processes that has made significant advances to a point permitting at least partial engineering evaluation. Based on the information available, a technical evaluation of the process follows.

Potential for Sulfur Removal--

The ability of the process to remove sulfur is shown in the table below.[78]

TABLE 2-43 PYRITIC SULFUR EXTRACTION BY THE BHCP

Source of Coal			Percent Pyritic Sulfur*		Extraction Efficiency, Percent
Mine	Seam	State	Raw Coal	BHCP Coal	
CN719	6	Ohio	4.0	0.1	99
Belmont	8	Ohio	1.6	0.1	92
NE41	9	Ohio	4.0	0.1	99
Ken	14	Ky.	2.1	0.2	92
Beach Bottom	8	Pa.	1.7	0.1	95
Eagle 1	5	Ill.	1.5	0.2	87

*Moisture and ash free basis. Coal samples were supplied from the various mines. Analyses were conducted by Battelle on raw and hydrothermally treated coals.

Ninety percent or greater pyritic sulfur removal has been demonstrated on a variety of bituminous coals from Ohio, Pennsylvania, Illinois and Kentucky. It is believed that pyritic sulfur can be almost completely removed (95%) from any bituminous coal using the BHCP.

It is believed that the BHCP is capable of removing 25-50% of organic sulfur from a wide variety of coals. The table[78] on the next page presents typical organic sulfur extraction data from the BHCP.

EXTRACTION OF ORGANIC SULFUR BY THE BHCP

			Percent Organic Sulfur*		
Mine	Seam	State	Raw Coal	BHCP Coal	Extraction Efficiency, Percent
Sunny Hill	6	Ohio	1.1	0.6	41
Martinka #1	Lower Kittaning	W. Va.	0.7	0.5	24
Westland	8	Pa.	0.8	0.5	38
Beach Bottom	8	W. Va.	1.0	0.7	30
Reign #1	4A	Ohio	2.3	1.1	52

*Moisture and ash free basis coal samples were supplied from the various mines. All analyses were conducted by Battelle on raw and hydrothermally treated coals.

Experiments have been conducted also on a semicontinuous bench-scale to confirm the results of laboratory batch experiments. The equipment has a capacity of about 9 kilograms (20 pounds) of coal per hour and can perform all of the basic steps of the desulfurization process. The operation, however, has not yet employed recycled, regenerated reactants, so that the influence on leaching due to buildup of contaminants in the system is unknown.

JPL CHEMICAL COAL CLEANING PROCESS

The Jet Propulsion Laboratory (JPL), California Institute of Technology at Pasadena, California, is developing a chemical coal cleaning process which attacks both pyritic and organic sulfur compounds in coal, and allegedly results in the removal of up to 75% of the total sulfur in coal.[80] Both types of sulfur are attacked during a low temperature coal chlorinolysis step; hydrolysis and dechlorination follow.

Process Description

A flow diagram based on the JPL process is shown in Figure 2-48.[81] Chlorine gas is sparged into a suspension of moist, pulverized coal (minus 100 to minus 200 mesh) in methyl chloroform (1,1,1-trichloroethane) at 74°C (165°F) and atmospheric pressure for 1 to 4 hours. The suspension consists of approximately 1 part coal to two parts solvent. Chlorine (Cl_2) usage is 3 to 3.5 moles of chlorine per mole sulfur, or about 250 kg Cl_2 per metric ton (500 lbs/ton) of coal. Moisture is added to the feed coal to the extent of 30-50% by weight.

After chlorination the coal slurry is distilled for solvent recovery, and the solvent is recycled for reuse in the chlorinolysis step. The chlorinated coal is hydrolyzed with water at 50-70°C (120-150°F) for 2 hours and then filtered and washed. The coal filter cake is simultaneously dried and dechlorinated by heating at 300-500°C (570-930°F) with superheated steam (or possibly a vacuum) for about 1 hour.

There are a number of byproduct streams which are as follows:

- Vented gas from the chlorinolysis reactors contains unreacted chlorine (Cl_2) and byproduct hydrogen chloride (HCl). The gas is cooled to condense Cl_2, which is recycled, and the relatively non-condensible HCl gas is piped to a Kel-Chlor process unit which converts the HCl to Cl_2.

- Vapors from the solvent evaporation step are cooled to permit condensation and recycling of the methyl chloroform. The HCl gas is piped to a Kel-Chlor unit for conversion.

- Filtrates and wash water from the filtration of hydrolyzed coal contain hydrochloric acid and sulfuric acid. The HCl is driven off in a stripper and recycled to a Kel-Chlor unit. The residual dilute sulfuric acid is concentrated to a saleable 91% sulfuric acid.

- Superheated steam exhausting from the dechlorination will also contain HCl gas which must be condensed as hydrochloric acid and recycled to a Kel-Chlor unit for chlorine recovery.

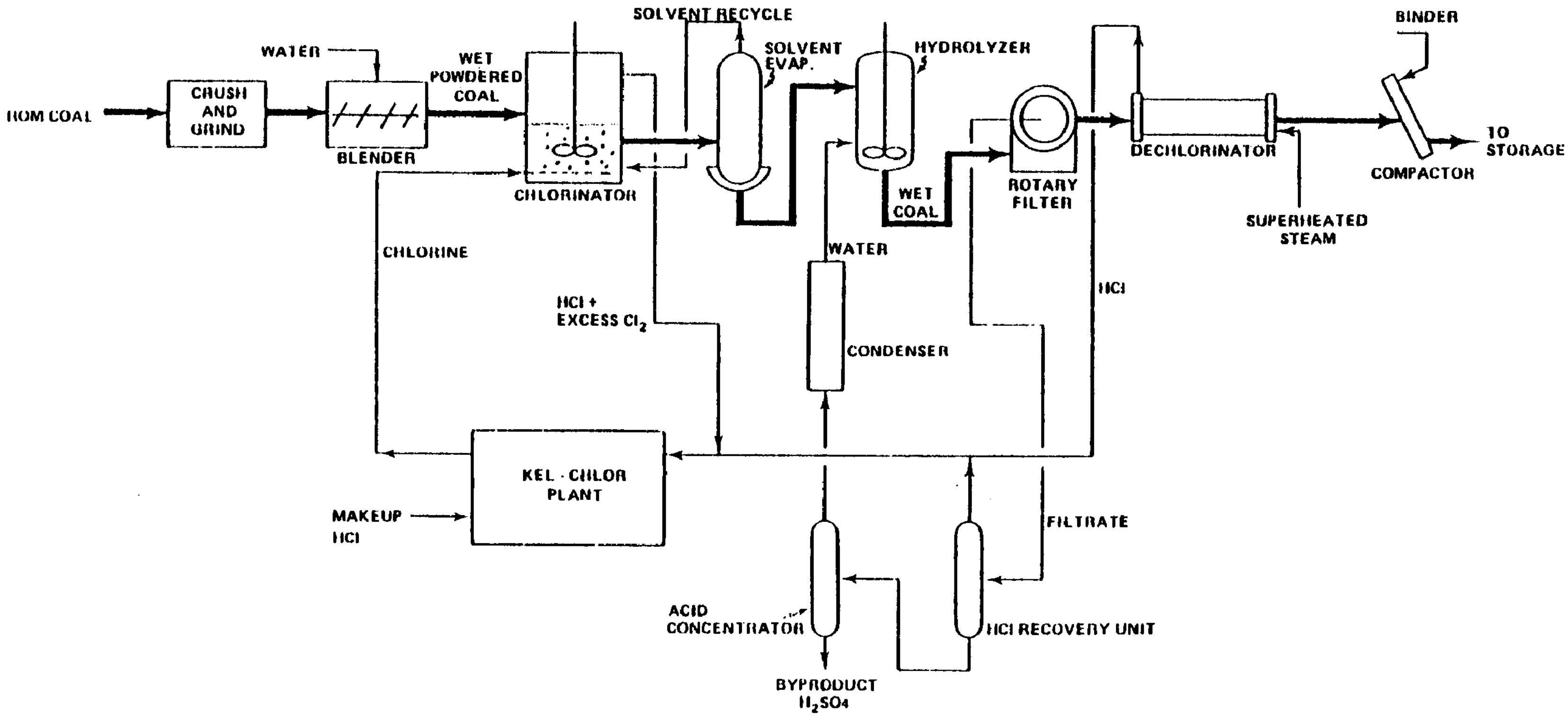


FIGURE 2-43. JPL PROCESS FLOW SHEET

Status of the Process

As of mid-July, 1977, effort on this process was on a laboratory scale batch operation using 100 g. coal samples. It was expected at that time that larger scale (1 kg) batch runs would be initiated in the near future, and at a still later date, a 1 kg/hour mini-pilot plant would be constructed and operated.

The early stages of the process research work were supported by the National Aeronautics and Space Administration (NASA) under Contract No. NAS 7-100. Recently the project obtained support from the Bureau of Mines for a period of approximately 16 months.

Technical Evaluation of Process

Potential for Sulfur Removal--

The process claims a 97-98% weight recovery of input coal, with about a 2% loss in heating value, and 70-75% removal of total sulfur. Two high sulfur coals have been examined carefully for sulfur removal. The Illinois No. 5 high volatile bituminous coal from Hillsboro mine had 4.77% total sulfur content. The other high volatile bituminous coal was a Kentucky No. 9 coal from Hamilton, Kentucky.

Experimental data obtained with Illinois No. 5 (Hillsboro) coal are given in Table 2-44.

The overall sulfur removal is 76% with a reduction from 4.77% to 1.50%. Results of experiments with this coal indicate that removals up to 70% organic sulfur, 90% pyritic sulfur and 76% total sulfur have been achieved.

The kinetic data for chlorination and desulfurization of minus 100 mesh, Illinois No. 5 coal are presented in Figure 2-49[83] The initial rate of chlorination is very fast. The chlorine content in coal is 23% a half-hour and then slowly increases to 26% within the next one and a half hours. Within the initial half-hour period most of the pyritic sulfur and a portion of organic sulfur are converted to sulfate sulfur. In the next one and a half hour period,pyritic and organic sulfurs are slowly converted to sulfate sulfur. Based on the sulfur balance, the gain in sulfate sulfur is equal to the combined reduction of pyritic and organic sulfurs. The above reactions extend to the hydrolysis period. The overall sulfate compounds produced either directly or indirectly through sulfonate are removed from coal in the hydrolysis step as indicated by the analysis of hydrolysis solution.

Experimental data obtained from a run on minus 200 mesh Kentucky No. 9 (Hamilton, Ky.) coal is given in Table 2-45.

The sulfur content of this coal is predominately organic (>90%). About 57% of the organic sulfur and 59% of the total sulfur are removed.

The data on the above two coals are the only detailed experimental results available at this time. Based on these results and discussions with JPL project personnel, it is concluded that the removal of pyritic sulfur by the JPL process is somewhat more complete than removal of organic sulfur. Consequently, if a high percentage of total sulfur removal is desired,this process should be used for coal rich in pyritic sulfur rather than in organic sulfur. Neither product from the two above experiments will meet EPA-NSPS SO_2/J (1.2 lb $SO_2/10^6$ BTU) when burned. A more extensive assessment of the sulfur removing potential of this process must await results from the 9 coals to be tested under the Bureau of Mines contract.

TABLE 2-44

JPL PROCESS: PRELIMINARY CHLORINOLYSIS DATA FOR ILLINOIS NO. 5 COAL DESULFURIZATION*

Sulfur Form	Raw Coal (% Sulfur)$^{\phi}$	Treated Coal (% Sulfur)$^{\phi}$	Sulfur Removal (%)
Pyritic	1.89	0.43	77†
Organic	2.38	0.72	70
Sulfate	0.50	0.35	100$^{\Delta}$
Total	4.77	1.50	76

* (Chlorination - stirred reactor, 74°C(165°F), 1 atm (14.8 psig), 1 hour, powdered coal 100-150 mesh with 50% water, methyl chloroform to coal 2/1; hydrolysis and water wash - stirred reactor, 60°C(140°F), 2 hours, excess water).

$^{\phi}$ Analyses by Galbraith Laboratories, Inc., Knoxville, Tennessee

$^{\Delta}$ Additional water washing should remove 100% of sulfate

† Up to 90% pyritic sulfur removal has been achieved in other conditions

TABLE 2-45

PRELIMINARY CHLORINOLYSIS DATA FOR THE JPL DESULFURIZATION PROCESS ON BITUMINOUS COAL (HAMILTON, KENTUCKY)*

Sulfur Form	Raw Coal (% Sulfur)$^{\Delta}$	Treated Coal (% Sulfur)$^{\Delta}$	Sulfur Removal (%)
Pyritic	0.08	0.03	62.5
Organic	2.67	1.16	56.5
Sulfate	0.15	0.29	100†
Total	2.90	1.48	59.0

* Chlorination - stirred reactor, 74°C(165°F), 1 atm (14.8 psig), up to 4 hours, minus 200 mesh coal with 30% water, methyl chloroform to coal 2/1; hydrolysis and water wash - stirred reactor, 60°C(140°F), 2 hours, excess water.

$^{\Delta}$ Analyses by Galbraith Laboratories, Knoxville, Tennessee

† 100% sulfate removal by added water wash

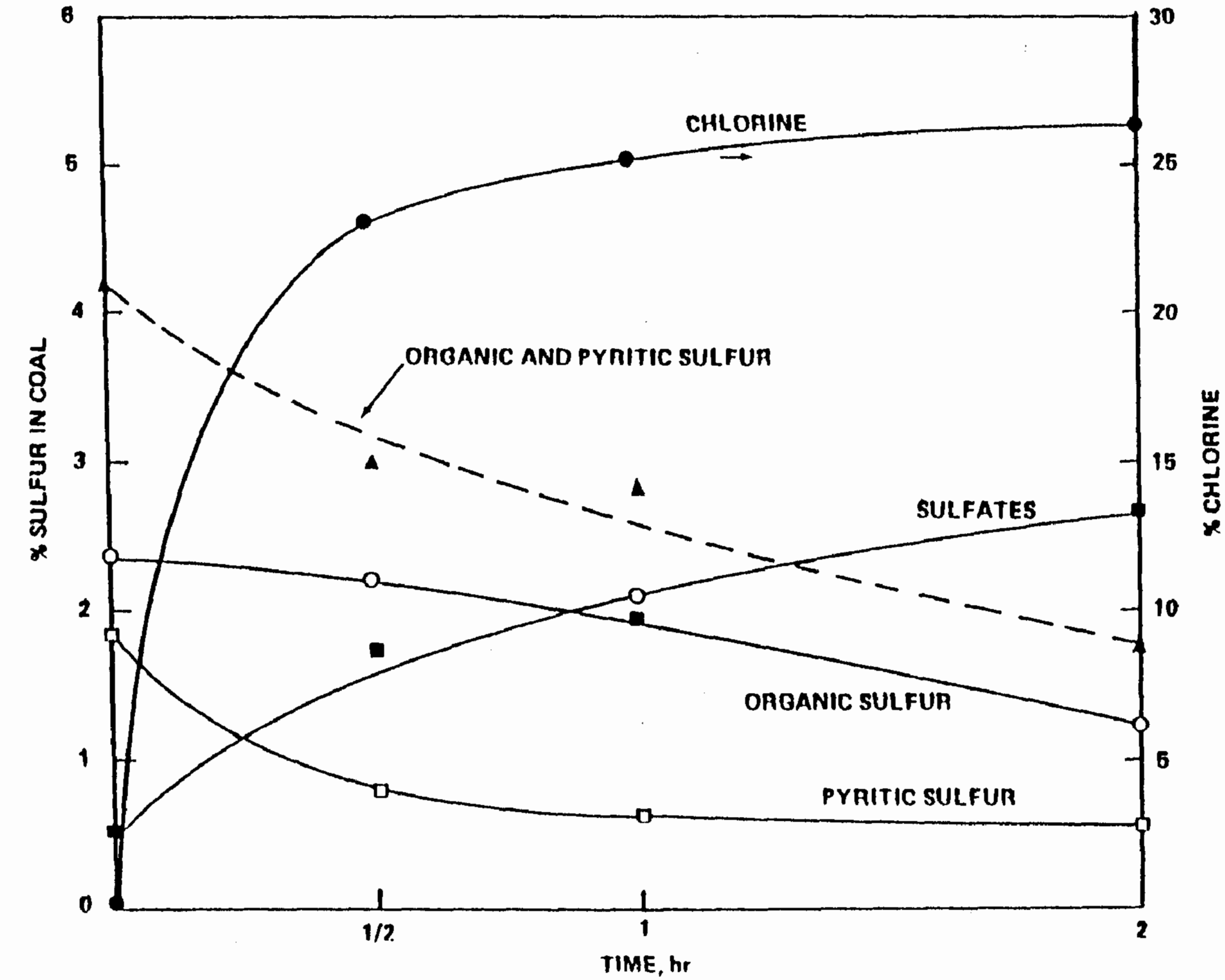


FIGURE 2-49. JPL PROCESS: PERCENT SULFUR AND CHLORINE IN COAL VS. TIME OF CHLORINATION

The IGT flash desulfurization process is based upon chemical and thermal treatment of coal. In this process, sulfur is removed from the coal by a hydrogen treatment under the proper conditions of temperature, heat-up rate, residence time, coal size, hydrogen partial pressure, and treatment gas composition.

An oxidative pretreatment is included in this system to prevent caking and also to increase the sulfur removal in the subsequent hydrotreating step. Both pyritic and organic sulfur are removed by the combination of these treatments. The treated product is a solid fuel (possibly char) which presumably may be burned without a need for flue gas scrubbing.

This report contains a conceptualized process design and process economics based upon IGT data. Subsequent to our cut-off date for data input, IGT has developed its own conceptualized process design that includes the effects of many factors derived from IGT's general background in coal conversion. The IGT-developed process efficiencies and costs are significantly better than those reported here, based upon the earlier IGT report specific to this program. The following discussion, therefore, does not include IGT's latest thinking on the process design; it should be regarded as preliminary and subject to significant process efficiency improvements and downward product cost modification.

Process Description

The process employs essentially atmospheric pressure and high temperatures [about 400°C (750°F) for pretreatment and 800°C (1,500°F) for hydrodesulfurization] to enhance the desulfurization of the coals. These high temperatures cause considerable coal loss due to oxidation, hydrocarbon volatilization, and coal gasification, with subsequent loss of heating value. Batch reactor tests have indicated an average product recovery potential of 60 weight percent based on the feed.

Experiments have been conducted with several coals in both laboratory and bench-scale batch hardware to test IGT concepts and to determine the pretreatment and hydrodesulfurization operating conditions. Adequate experimental data on heat and material balances are not yet available to conceptualize a process design. It is, however, anticipated that the process will employ the following equipment or processing steps:

- Fluidized bed reactors will be used for both pretreatment and hydrodesulfurization stages;
- Air will be used as the source of oxygen;
- Off-gases from the hydrodesulfurization, provided they contain hydrogen partial pressure, will be compressed and recycled to the hydrogeneration reactor to provide the necessary hydrogen for desulfurization of coal;
- Hydrogen make-up may be necessary to maintain hydrogen partial pressure;
- The exothermic pretreatment reaction will provide a portion of the heat necessary for the endothermic hydrodesulfurization reactions;
- The sulfide and sulfate sulfur will be removed from the hydrodesulfurized product by either chemical or mechanical means. This step will be necessary when the coal char product from the processing of certain coals contains residual sulfur levels exceeding the allowable limits;
- The hydrogen sulfide/carbon dioxide gases recovered from the hydrodesulfurizer off-gas will be treated in a Claus plant to produce elemental sulfur;
- Purification of the off-gas from the hydrodesulfurizer system will be necessary prior to recycle; and
- Off-gas cleanup from the pretreater will be necessary prior to venting the gases to the atmosphere.

Versar has provided a suggested process flow sheet which integrates the IGT concepts and is shown in Figure 2-50. This flow sheet has been provided to permit the development of process economics on a consistant basis with other processes.

Status of the Process

The IGT process is in an early stage of development. An extensive bench-scale and pilot level technical effort is needed before an integrated process design is conceptualized. The program, sponsored by EPA, is now directed toward testing in a 25 cm (10-inch) continuous fluidized-bed unit, which is sized for coal feeds of 10 to 45 kilograms (25 to 100 pounds) per hour.

Two pretreatment runs of about seven hours each have been made in this 25 cm (10-inch) unit. A beneficiated Illinois No. 6 coal, which was crushed to minus 14 mesh and contained 2.43 weight percent of total sulfur, was used as feed. The objectives of these runs were to test the operating conditions over a sustained period of time and to produce pretreated material for subsequent hydrodesulfurization evaluations. The pretreatment runs have been successful, and they have confirmed most of the results of corresponding batch tests. These runs indicated that a temperature of 400°C (750°F), a residence time of 30 minutes, an actual gas velocity of 0.3 meter (one foot) per second in the bed, and 0.616 cubic meter of oxygen per kilogram [one standard cubic foot (SCF) per pound] of coal are adequate to pretreat the coal when the unit is fed at a rate of about 23 kilograms (50 pounds) per hour. However, material and heat balance information generated on one of these runs contradicts conclusions derived from the batch runs.

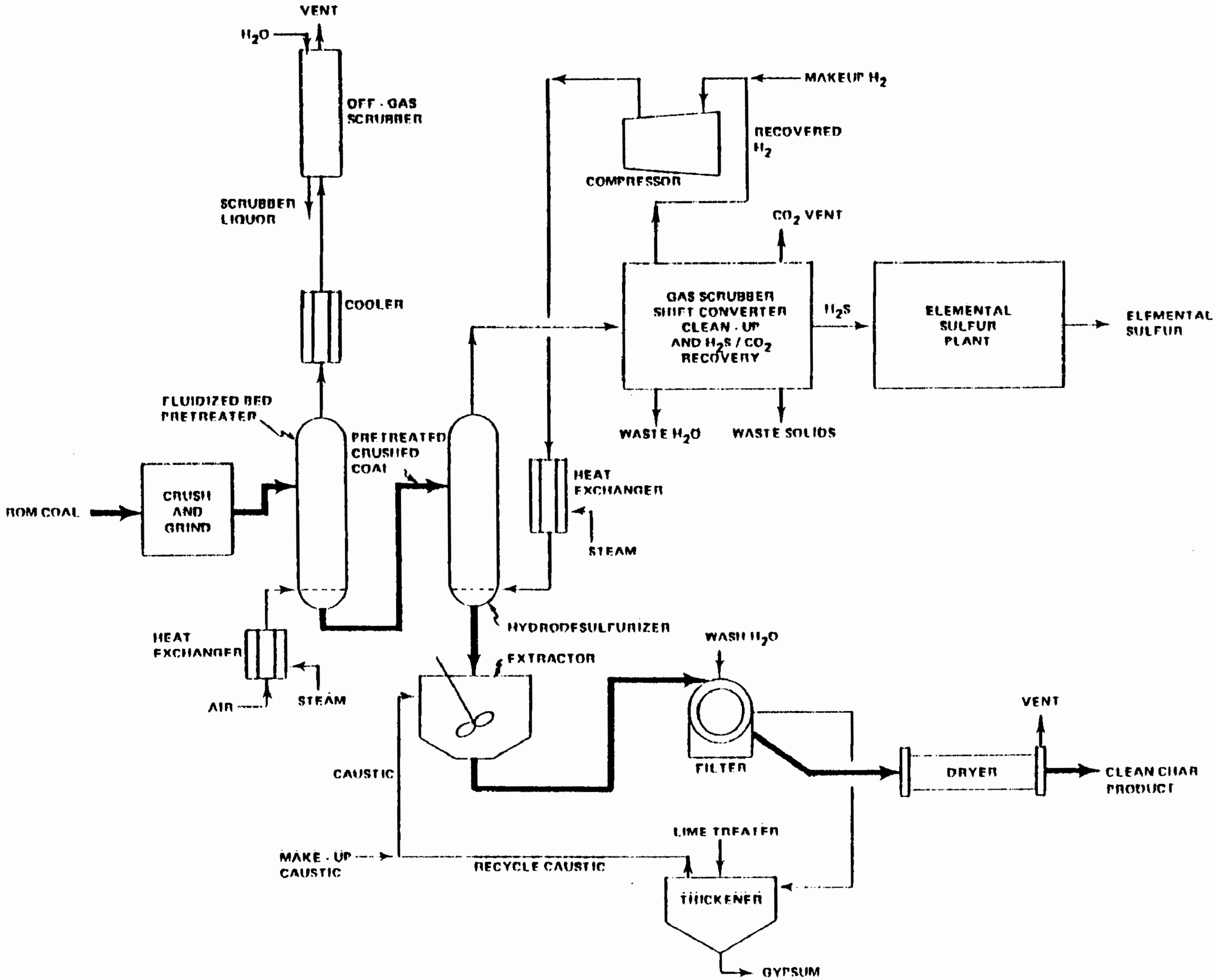


FIGURE 2-50. IGT PROCESS FLOW SHEET

The analyses of data indicated very low quantities of light hydrocarbon in the off-gases [.37 MJ/cu.m (10 BTU/SCF] and a very high solids recovery around the pretreatment unit (97.7 wt%). Thus only 2.3 wt % of the coal was consumed in off-gases and water as compared to the expected 8 to 12 percent. Information from a single run is not adequate to draw definitive conclusions; however, if these data are confirmed in the Pilot Demonstration Unit (PDU), then no excess heat would be available from the pretreatment stage for either steam generation or on-site consumption.

The data from the larger unit will be used to establish the necessary energy and material balance information for the design of an integrated system and for an accurate economic evaluation of the process.

Supportive runs are being continued in the batch reactor to determine the effects of nitrogen, carbon monoxide, water vapor and hydrogen sulfide concentrations in the treat gas on the hydrodesulfurization operation. Additionally, crushing tests on a run-of-mine, Illinois No. 6 coal are being conducted to determine the crusher conditions to minimize fines in coal preparation and to define the coal preparation requirements for the process.

IGT estimates that this process could be ready for commercialization in four or five years after the successful operation of a pilot demonstration unit.

Technical Evaluation of the Process

This process is currently at the bench-scale level, thus, a definitive assessment of its industrial potential is not possible at this time. However, available information is summarized in the following subsections.

Potential for Sufur Removal--

Laboratory and bench-scale experiments conducted thus far indicate that the IGT process can remove 83 to 89 percent of the total sulfur from four bituminous feed coals. The process removes both pyritic and organic sulfur. In most cases, enough sulfur is removed so that the treated product could be burned in conformance with current EPA new source performance standards for SO_2 emissions.

A preliminary evaluation of the desulfurization potential of four selected bituminous coals was conducted in a laboratory device (thermobalance) with 2 to 6 gram coal samples. Pyritic, organic, and total sulfur removal rates obtained from these investigations are reported in Table 2-46 [82]. Samples for the above thermobalance tests were +40 mesh pretreated coal. The feed was placed in the sample basket and then lowered into the treating zone. A heating rate of 2.8°C(5°F) per minute was used up to the terminal temperature of 815°C (1,500°F). Soaking time at the terminal temperature was 30 minutes for each test.

Table 2-46 indicates that for the Western Kentucky No. 9 coal, in addition to 98 percent pyritic sulfur removal, 88 percent of organic sulfur removal was also achieved. Sufficient total sulfur removal was realized in this test so that SO_2 emissions from combustion of the treated product would be 180 ng/J (0.42 lb/10^6 BTU).

The sulfur reduction obtained for the Pittsburgh seam coal from the West Virginia mine was 98 percent pyritic and 83 percent organic sulfur. The reduction in total sulfur content, accounting for sulfide/sulfate compounds, was 83 percent, with sufficient sulfur removed to comply with the current EPA new source performance standard of 516 ng/J (1.2 lb/10^6 BTU) of SO_2.

Results for the Pittsburgh seam coal from the Pennsylvania mine indicate that in addition to all of the pyritic sulfur, 77 percent of the organic sulfur was also removed. This coal having a lower initial total sulfur and relatively low initial organic sulfur content also yielded a product with acceptable SO_2 emission value.

The sulfur reduction obtained for a beneficiated Illinois No. 6 coal was 98 percent pyritic and 82 percent organic sulfur. This sulfur reduction was such that SO_2 emissions from combustion of the treated product would be below the current new source SO_2 standards.

TABLE 2-46. IGT PROCESS THERMOBALANCE SULFUR REMOVAL RESULTS

Source of Coal	Raw Coal Characteristics: Feed Type	Raw Coal Characteristics: Sulfur* Content wt.% of Feed (dry basis)	Sulfur Removal Efficiency, Weight Percent: Pyritic^Δ	Sulfur Removal Efficiency, Weight Percent: Organic^†	Sulfur Removal Efficiency, Weight Percent: Total
Western Ky #9	ROM	3.03	97.8	88.5	89.4
Pittsburgh Seam From W. Virginia	Highly Caking	2.41	98.4	83.1	83.0
Pittsburgh Seam From Pa. Mine	High Ash Content	1.01	100.0	77.1	78.1
Illinois #6	Beneficiated	2.28	98.0	82.0	87.7

NOTES:

Experimental Conditions Were: At 1500°F terminal temperature, 5°F heat-up rates and 30 mins. soaking time.

* Sulfur content of +40 mesh material.

Δ The pyritic sulfur removal during pretreatment ranges from 38% to 51%.

† The organic sulfur removal during pretreatment ranges from 0% to 10%

The KVB coal desulfurization process is based upon selective oxidation of the sulfur constituents of the coal. In this process, dry coarsely ground coal (+28 mesh) is heated in the presence of nitrogen oxide gases for the removal of a portion of the coal sulfur as gaseous sulfur dioxide (SO_2). The remaining reacted sulfur in the coal is claimed to be in the form of inorganic sulfates or sulfites or is included in an organic radical. These non-gaseous sulfur compounds are removed from the pretreated coal by subsequent washing with water or heated caustic solution followed by water wash.

The active oxidizing agent is believed to be NO_2. The process, however, uses a gas mixture containing oxygen (0.5 to 20 percent O_2 by volume), nitric oxide (0.25 to 10 percent NO by volume), nitrogen dioxide (0.25 to 10 percent NO_2 by volume) and nitrogen (N_2) the remainder.

The process can be operated either on a batch or continuous basis as desired. There are no data available, as yet, to indicate which system is more economical. For a continuous operation, the reaction may be carried out at 120°C (250°F) 2.4 atm (35 psia) for 1/2 to 1 hour period. The mechanism of oxidation is still unknown.

Process Description

Laboratory experiments have been conducted with several coals, on 50 gram samples, in a 2.54 centimeter (one-inch) diameter batch reactor to test the sulfur removal potential of the process. The process has been conceptualized both by KVB[83] and Bechtel.[69] The KVB design incorporates a somewhat more optimistic water and caustic extraction operation than the flow scheme suggested by Bechtel. In this section, the flow diagram developed by Bechtel will be used since it incorporates standard processing equipment in conceptualizing the process.

A simplified flow diagram of the process is shown in Figure 2-51 [69] Dry coal from the preparation section is pneumatically conveyed to a gas/solid cyclone where it is separated from its conveying gas (nitrogen). Then it is gravity fed into a fluidized bed reactor. The reactant gas is introduced through the bottom of the reactor through a distributor. The reaction gases leave the reactor, passing through a two-stage cyclone separator which removes the fine coal particles from the gas.

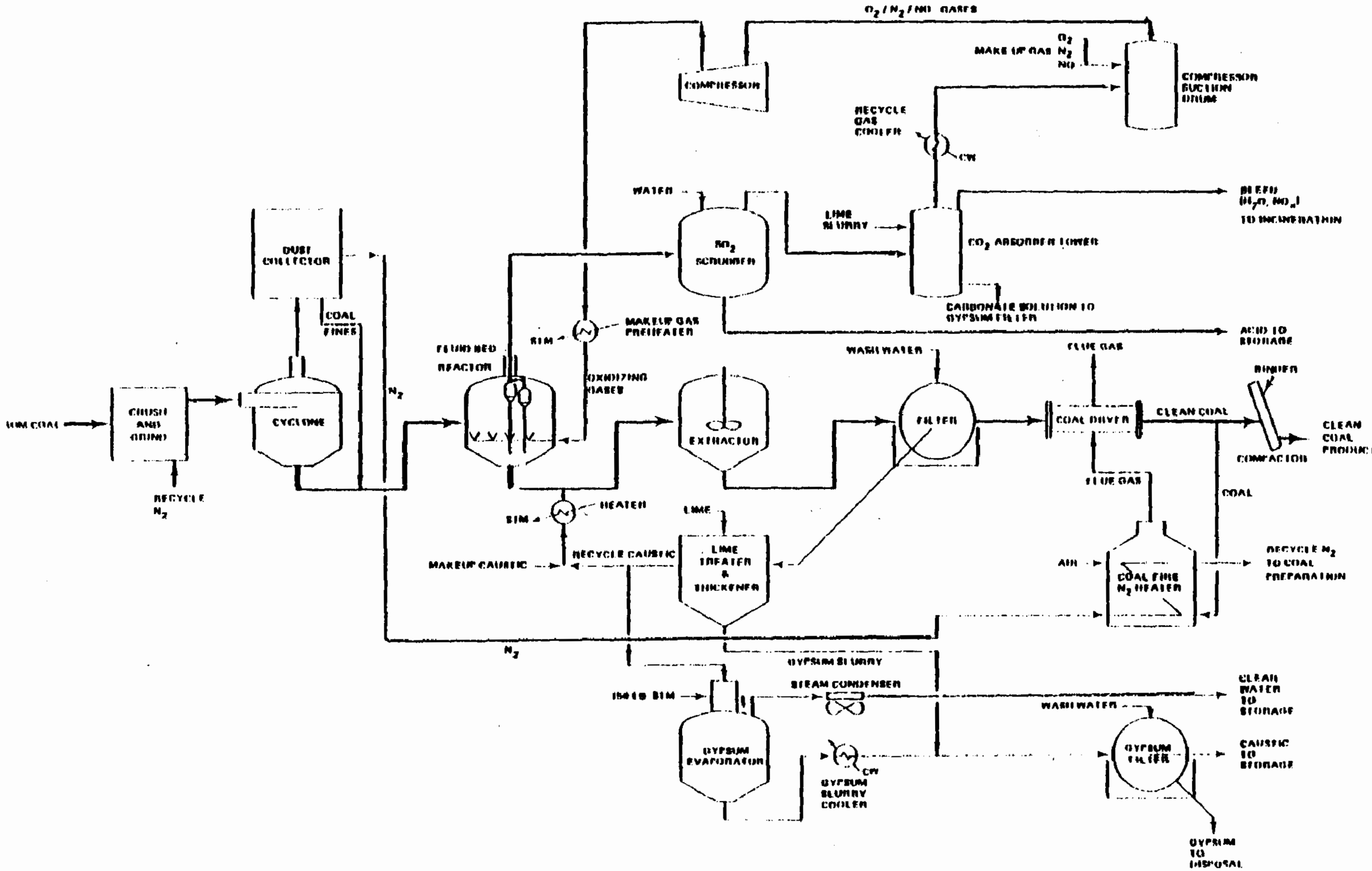


Figure 2-51. KVB Process Flow Diagram

The treated coal from the reactor is next reacted with caustic solution to remove additional sulfur (organic sulfur) and to convert the ferrous sulfate to ferrous hydroxide and soluble sodium sulfate. The coal slurry from the extractor is filtered and water washed on the filter. The product coal is then dried prior to compacting. The process also incorporates treatment of the various effluents from the system.

The KVB laboratory test work on their chemical coal cleaning process is presently inactive. Plans are to develop and commercially license the process to coal producers and users. Funding is being actively sought at this time to speed up the developmental schedule in view of the current energy shortage.

Technical Evaluation of the Process

This process is in its early stages of development, and thus it is difficult to make an accurate assessment of its industrial potential. However, depending on the amount of desulfurization required, the extraction and washing steps may or may not be required. It should be mentioned that in cases where dry oxidation only could remove sufficient sulfur to meet the sulfur dioxide emission standards, this technology could provide a very simple and inexpensive system. Thus, there may be a potential for this process for application to some coals, primarily metallurgical grade coals, where partial removal of sulfur could be very beneficial.

Potential for Sulfur Removal--

Laboratory experiments conducted on 50 gram samples in a batch reactor with five different coals indicate that the process has desulfurization potential of up to 63 percent of sulfur with basic dry oxidation plus water washing treatment and up to 89 percent with dry oxidation followed by caustic treatment and water washing. Table 2-47 presents the results of the laboratory studies.[63] The results indicate that higher desulfurization is achieved when the treat-gas contains 10 percent by volume of nitric oxide.

The washing step removes iron and loosely bound inorganic material which reduces the ash content of the coal. KVB claims a 95+ percent ash

TABLE 2-47. COAL DESULFURIZATION DATA USING THE KVB PROCESS

Coal Sample Identification	Size Mesh	Oxidation 200°F: Time Hrs.†	Oxidation 200°F: NO in Air % Vol.	Oxidation 200°F: Gas Flow l/min.	Feed Sulfur Level: Total	Feed Sulfur Level: Organic	Sulfur Level After Oxidation: Total S	Sulfur Level After Oxidation: % Sulfur Removed	Sulfur Level After Water Wash: Total S	Sulfur Level After Water Wash: % Sulfur Removed	Sulfur Level After 10% NaOH Wash & water wash: Total S	Sulfur Level After 10% NaOH Wash & water wash: % Sulfur Removed φ
Lower Kittanning	-14to+28	-	-	-	4.3	0.7	-	-	-	-	4.5*	0
	-14to+28	3	5	.42	4.3	0.7	3.3	23	2.4	43	2.1	51
	-14to+28	3	10	.44	4.3	0.7	-	-	1.6	63	0.5	89
	-14to+28	1.5	10	.44	4.3	0.7	-	-	-	-	1.4	67
	-80to+100	3	5	.42	4.3	0.7	-	-	-	-	2.9	32
Illinois #5	-14to+28	1.5	10	.42	3.0	1.9	-	-	-	-	2.5	17
	-14to+28	3	10	.44	3.0	1.9	-	-	2.0	33	1.0	67
	-14to+28	3	5	.42	3.0	1.0	-	-	1.9	37	1.2	59
K-16914Δ	-14to+28	3.5	10	.44	6.7	1.16	4.2	37	3.1	54	3.2	52
K-14702Δ	-14to+28	3.0	5	.42	5.3	1.3	4.3	19	3.0	43	3.1	41
	-14to+28	3.0	10	.44	5.3	1.3	2.7	49	2.5	53	-	-
K-16394Δ	-14to+28	3.0	5	.42	3.2	1.9	2.5	22	-	-	-	-
	-14to+28	3.0	10	.44	3.2	1.9	2.0	38	-	-	-	-

* No oxidation, wash only.
Δ U.S. Bureau of Mines Designation.
† It is claimed that recent tests achieved the same results in 10 minutes using a rotary reactor.
φ The samples were dried at 250°F before analysis.

removal with their system; however, there are no published experimental results to substantiate this claim.

Nitrogen (the transporting gas) from the cyclone is passed through a dust collector for the recovery of fine coal particles and is then discharged via a blower into a coal-fired heater prior to recycling this gas to the coal preparation and conveying section.

Off-gas from the reactor is scrubbed with water to remove sulfur oxides and nitrogen oxide gases. The acid product from the scrubber containing sulfurous, sulfuric and also nitric acid is cooled prior to storage. The treated gas from the water scrubber is subsequently reacted with calcium hydroxide to remove carbon dioxide as calcium carbonate sludge. The purified gas from the CO_2 remover is cooled to condense water vapor. A fraction of the gas leaving the purifier is vented to prevent a buildup of inert gas in the gas stream. By venting a portion of the gas and providing makeup gas, the required gas proportion can be maintained. The recycle gas is then combined with makeup NO_2 and O_2 to form the treat-gas. The treat-gas is compressed and recycled to the reactor.

The filtrate from the coal filter is treated with lime to regenerate caustic and form gypsum. The sludge from the lime treatment tank is concentrated in a thickener. The underflow of the thickener containing a large fraction of the gypsum is filtered to recover the caustic solution. The thickener overflow is divided into two streams. One portion is recycled to the extractor and the other is sent to an evaporator for further removal of gypsum in order to prevent gypsum buildup in the system. The steam generated in the evaporator is condensed and used as wash water for the filter cake. The gypsum slurry is cooled and set to the gypsum filter. Gypsum constitutes the solid waste from this process.

Status of the Process

The process has been tested batchwise in the laboratory, using 50 gram coal samples. KVB owns all rights to the process as of April 1977 and has funded all the work thus far. U.S. Patent No. 3,909,211 was issued on

September 30, 1975,[84] and the filing of foreign patents in major coal producing countries is in progress.

ATLANTIC RICHFIELD COMPANY CHEMICAL COAL CLEANING PROCESS [25]

Process Description

The Atlantic Richfield Company (ARCO) is developing a chemical coal cleaning process at Harvey, Illinois, which removes both pyritic and organic sulfur compounds and ash from coal. The process requires the use of either a recoverable or a non-recoverable reaction promoter.

Very little has been published about the process, no flow sheet is available, and ARCO has not permitted an on-site inspection.

Status of the Process

Process development work has largely proceeded on the basis of data generated from batch-scale experiments. However, a 0.45 kg (1-pound) per hour continuous reactor system was recently built and is currently being used to provide additional data.

Until recently ARCO has financed this experimental program without external assistance. The Electric Power Research Institute, Palo Alto, California (EPRI) has financed a study on the continuous reactor system on five coals in which there is a wide distribution of pyrite particle size. This study is now complete and a final report is expected to be issued in 1979. The EPRI contract has been extended to demonstrate in the continuous pilot plant low cost process options which ARCO has developed.

Technical Evaluation of the Process

Potential for Sulfur Removal--

The five coals selected by EPRI and tested in the ARCO process are:

- Lower Kittanning, Martinka #1
- Illinois #6, Burning Star #2
- Pittsburgh #8, Montour #4
- Western Kentucky #9/14, Colonial
- Sewickley, Green County, Pennsylvania (beneficiated)

The coals were selected to meet the following criteria:

- Mean pyrite crystallite chord size for the five coals should cover a wide range;
- Pyrite and organic sulfur content should cover a wide range;
- Reduction of sulfur content to the NSPS compliance level; i.e., 258 ng/J (0.6 lbs/10^6 BTU), should be attainable by removal of pyritic sulfur in the case of at least one coal; and
- The coals should be from producing mines on seams with substantial reserves.

Depending on the coal treated, overall reduction of sulfur was up to 98% for pyritic sulfur, up to 20% for organic sulfur, and 66-72% for total sulfur. Overall reduction of iron was up to 96% and of ash up to 78%. The BTU yield of the process is estimated at 90-98%. Ash content of the product is frequently reduced by 50%, compared to feed coal, and the process weight yield is about 95%, depending on ash removal.

2.2.3.2 System Performance

The performance of chemical coal cleaning systems was simulated using the Reserve Processing Assessment Model.[38] Performance was measured by the increase in the available reserve base, after applying chemical coal cleaning, which could meet a given emission control level. The three most efficient and best developed of the chemical coal cleaning process were included: 1) Meyers Process; 2) Gravichem Process; and 3) ERDA Process. Figures 2-52 through 2-58 present the model results. For discussion of these results, three emission control levels were selected: 1) the National SIP Average of 1,075 ng SO_2/J (2.5 lbs $SO_2/10^6$ BTU); 2) an intermediate goal or future guideline of 650 ng SO_2/J (1.5 lbs $SO_2/10^6$ BTU); and 3) a more stringent level of 260 ng SO_2/J (0.6 lbs $SO_2/10^6$ BTU). Product variability was not included in the analysis because of the lack of available information on chemically cleaned coal products and the current status of chemical coal cleaning processes.

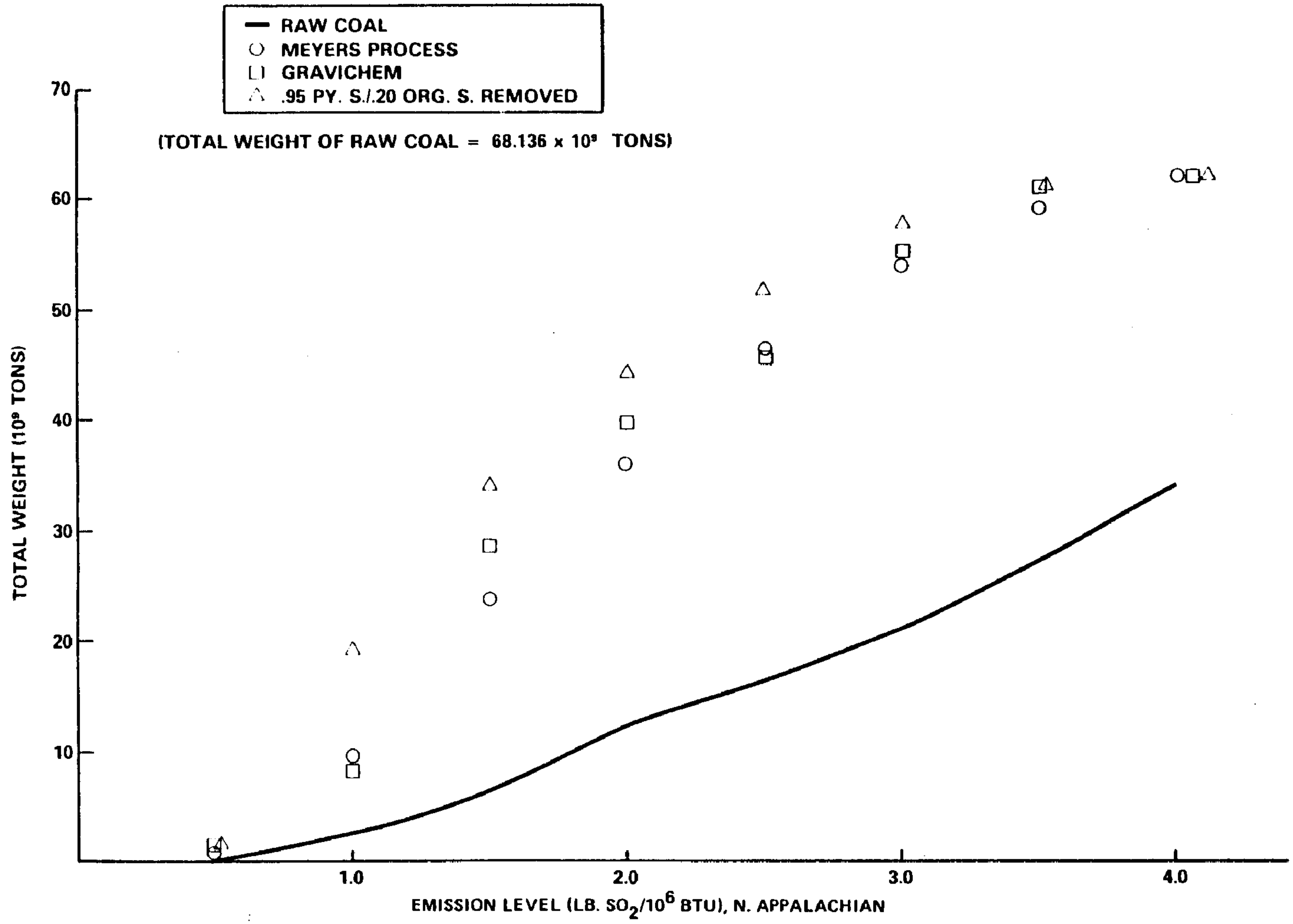


FIGURE 2-52 N. APPLACHIAN RESERVE BASE AVAILABLE AS A FUNCTION OF EMMISSION CONTROL LEVELS FOR VARIOUS CHEMICAL COAL CLEANING PROCESSES

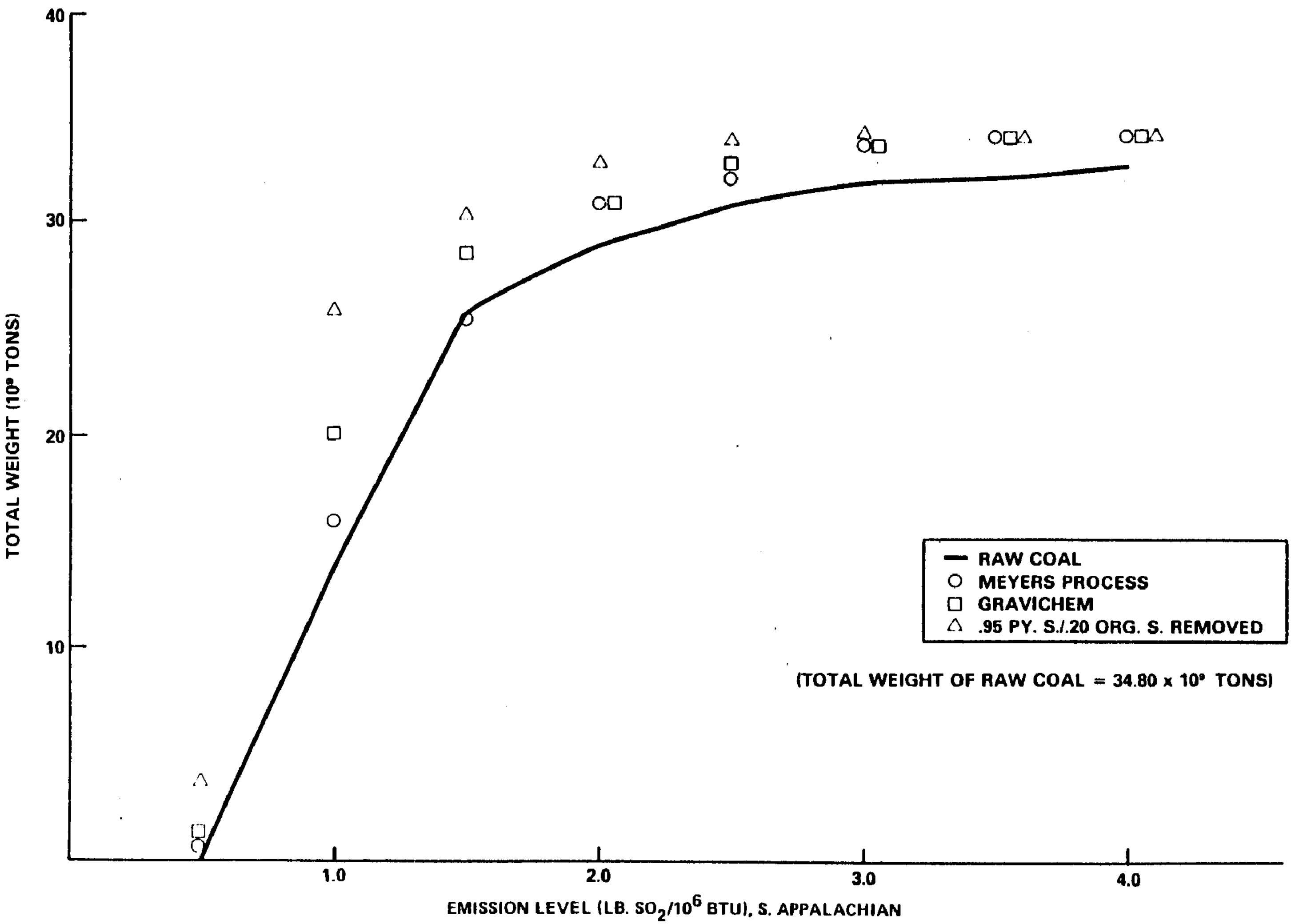


FIGURE 2-53 S. APPALACHIAN RESERVE BASE AVAILABLE AS A FUNCTION OF EMISSION CONTROL LEVELS FOR VARIOUS CHEMICAL COAL CLEANING PROCESSES

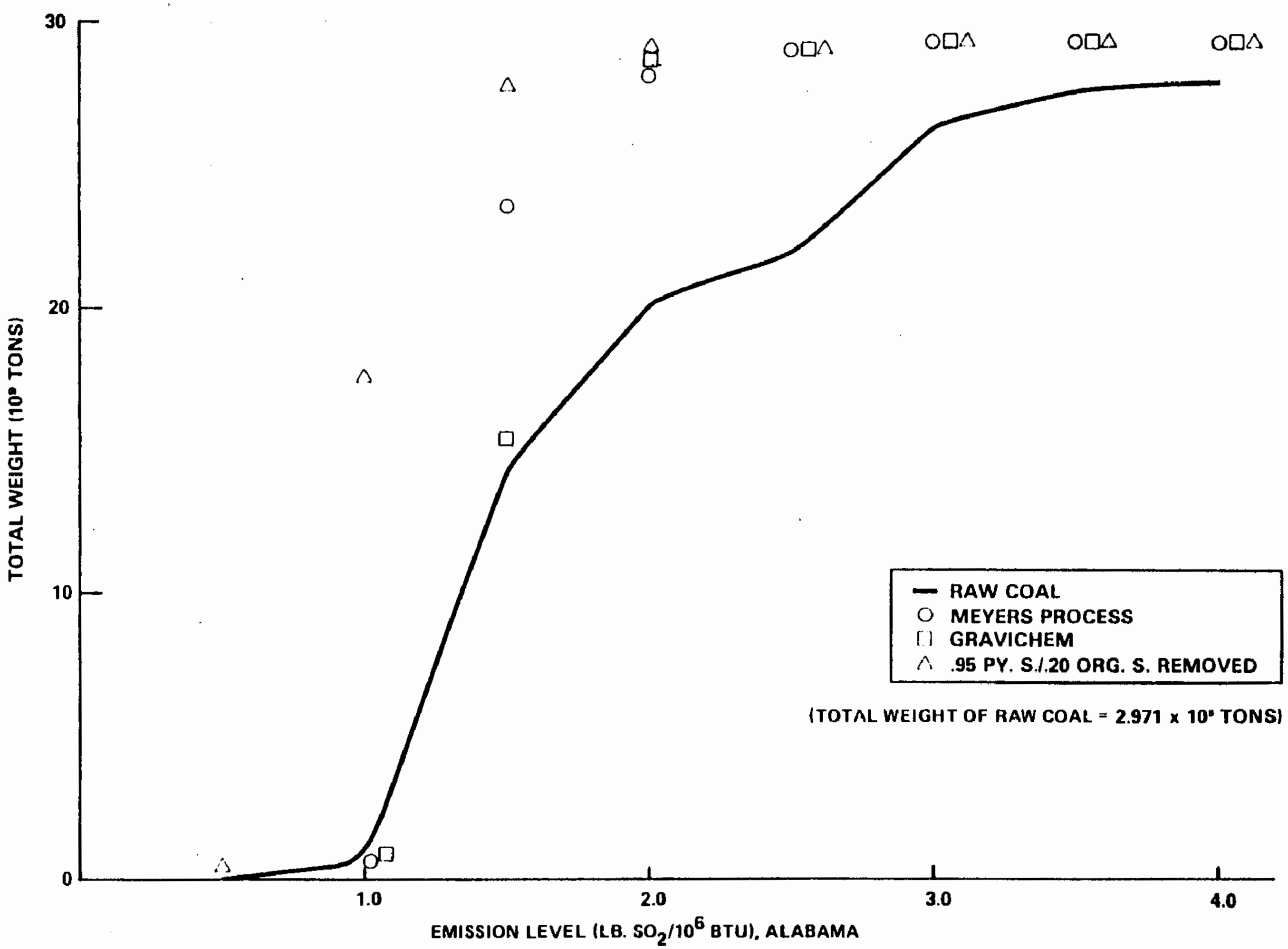


FIGURE 2-54 ALABAMA RESERVE BASE AVAILABLE AS A FUNCTION OF EMISSION CONTROL LEVELS FOR VARIOUS CHEMICAL COAL CLEANING PROCESSES

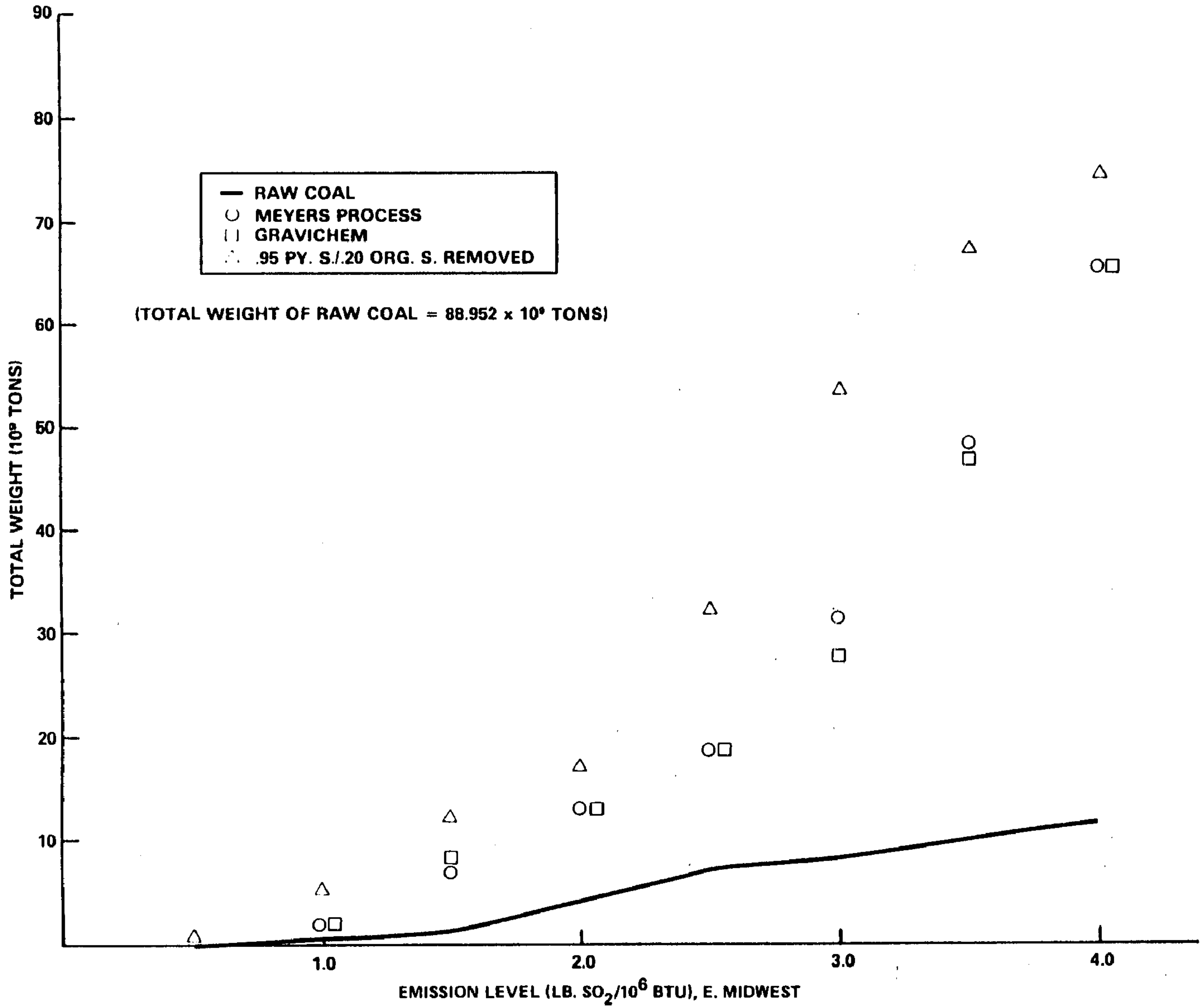


FIGURE 2-55 E. MIDWEST RESERVE BASE AVAILABLE AS A FUNCTION OF EMISSION CONTROL LEVELS FOR VARIOUS CHEMICAL COAL CLEANING PROCESSES

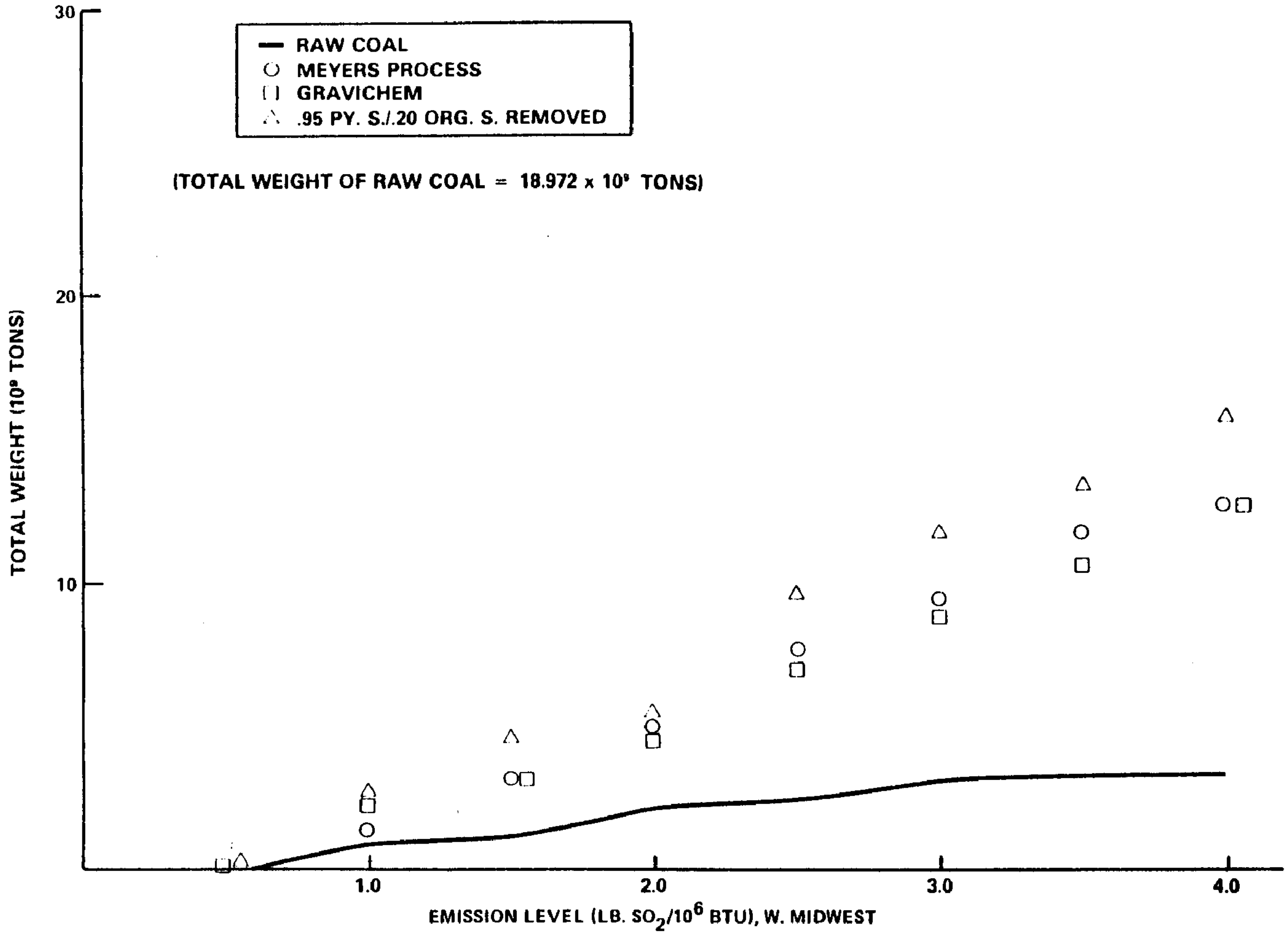


FIGURE 2–56 W. MIDWEST RESERVE BASE AVAILABLE AS A FUNCTION OF EMISSION CONTROL LEVELS FOR VARIOUS CHEMICAL COAL CLEANING PROCESSES

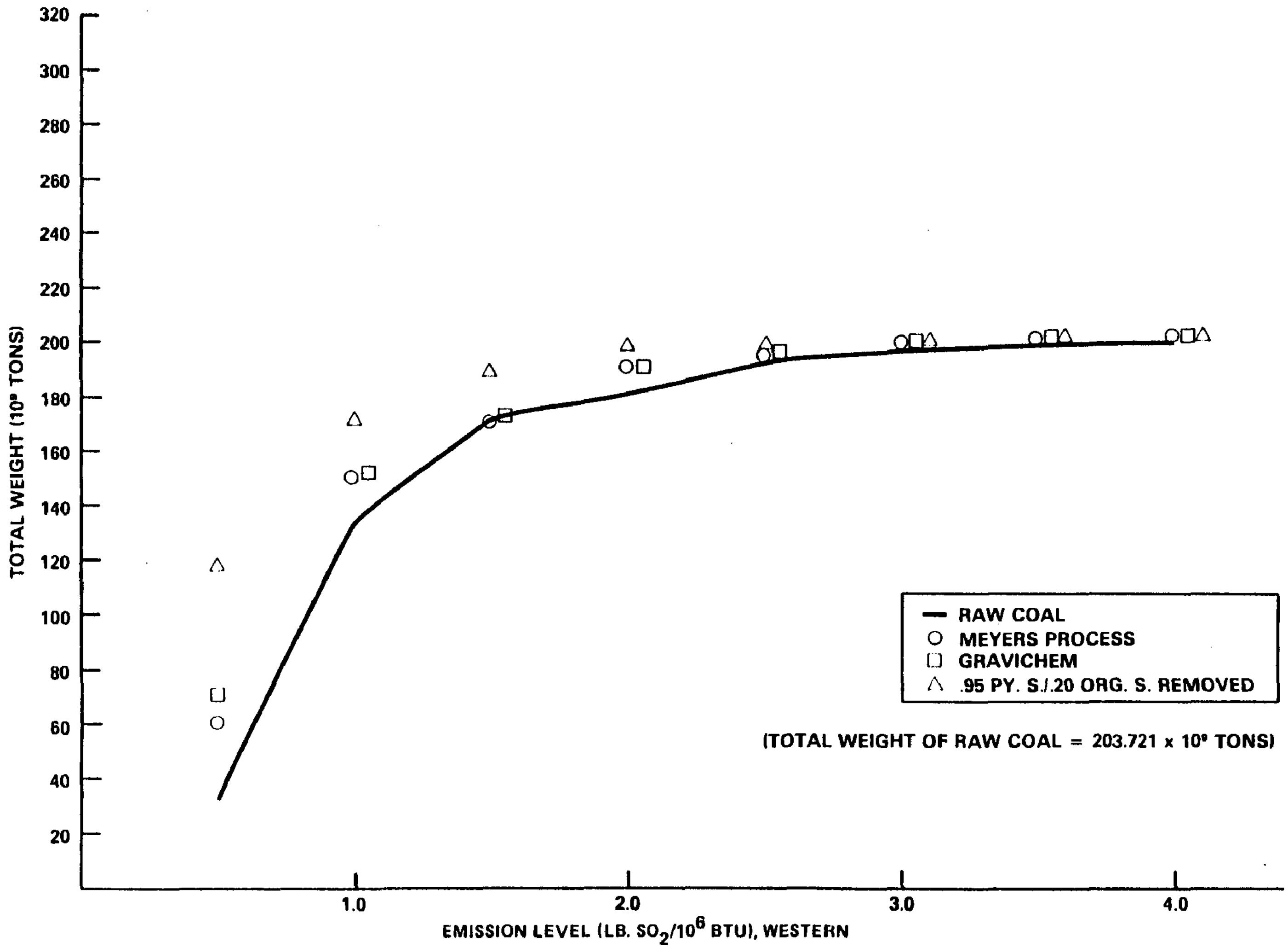


FIGURE 2-57 WESTERN RESERVE BASE AVAILABLE AS A FUNCTION OF EMISSION CONTROL LEVELS FOR VARIOUS CHEMICAL COAL CLEANING PROCESSES

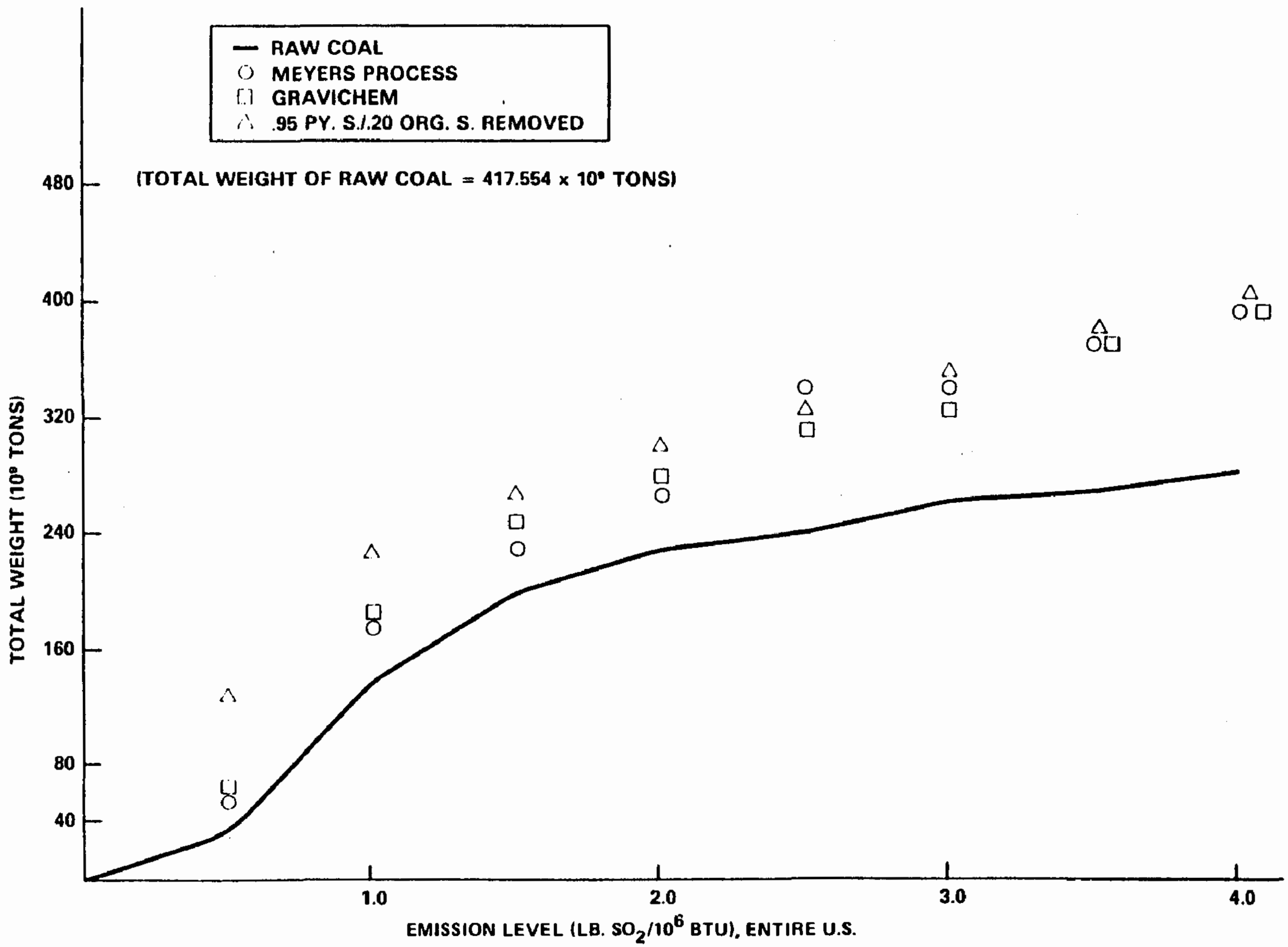


FIGURE 2-58 ENTIRE U.S. RESERVE BASE AVAILABLE AS A FUNCTION OF EMISSION CONTROL LEVELS FOR VARIOUS CHEMICAL COAL CLEANING PROCESSES

In the Northern Appalachian region, the increase in the available coal as a result of chemical coal cleaning at the 260 ng SO_2/J control level is negligible. However, at the 650 ng SO_2/J emission level, the amount of coal which becomes available due to chemical coal cleaning increases five fold, and at the 1,075 ng SO_2/J level, three times as much of the coal reserves are potentially available when chemical coal cleaning is applied. [Note: above the SIP control level of emission, the effect of coal diminishes].

In the S. Appalachia region, chemical cleaning increases the total amount of coal available up to 10%, with the greatest increase at the 400-700 ng SO_2/J range of emission levels. Since the coal in this area is low in pyritic sulfur content, the chemical cleaning processes do not have a significant impact on compliance coal supply.

In the Alabama region, no raw or chemically cleaned coal is available which would meet the 260 ng SO_2/J emission control level. At the 650 ng SO_2/J control level, chemical cleaning almost doubles the amount of coal potentially available and at the 1,075 ng SO_2/J control level, the effect of cleaning is to increase compliance coal by 50 percent. Interestingly, at the 650 ng SO_2/J level using chemical coal cleaning, 95% of the cleaned coal becomes available. In contrast, 95% of the raw coal reserve base is in compliance only if the emission level is greater than 1,700 ng SO_2/J.

The Eastern Midwest region has a very minimal raw or cleaned coal reserve base that can meet the most stringent emission level of 260 ng SO_2/J, because the coal in this region is typically high in sulfur content. Chemical coal cleaning in high sulfur coal regions proves beneficial for increasing coal availability. For example, at the emission control level of 1,075 ng SO_2/J, chemical coal cleaning processes will increase the amount of coal by three times the amount of available raw coal.

The same holds true in the Western Midwest. High sulfur coal is found in this region which also cannot meet a stringent emission level of 260 ng SO_2/J. Chemical coal cleaning will significantly increase the amount of coal available for meeting the more moderate emission control levels.

Chemical coal cleaning will increase the coal residue from 6% to 26% in meeting an emission control level of 516 ng SO_2/J and from 31% to 81% at a control level of 1,290 ng SO_2/J.

In contrast to other regions, over 15 percent of western coals can meet the 260 ng SO_2/J emission control level. When chemical cleaning is applied, upwards of 35% of western coal is made available. At levels above 260 ng SO_2/J, chemical cleaning does not greatly enlarge the amount of coal available. It is interesting to note that 95% of the raw coal in this area can satisfy the 1,075 ng SO_2/J emission control level.

In the entire U.S., approximately 8 percent of the raw coal can meet a stringent level of 260 ng SO_2/J. Chemical cleaning increases the total amount by 10 percent (equal to 42 billion tons of coal). By weight this means chemical coal cleaning can increase the amount of United States compliance reserves by 38 billion metric tons.

Another approach to determine complying coal reserves after chemical cleaning is to calculate the available energy (in KJ) that can meet a given emission control level. The results, again using the RPAM and ignoring product variability are provided in Figures 2-59 through 2-65. [38]

At the most stringent emission level, 260 ng SO_2/J, no coal in the Northern Appalachian region reserve base can comply with the control level. The chemical cleaning of the raw coal, however, will produce approximately 100-160 x 10^9 GJ at the 260 ng SO_2/J emission level. At the intermediate level 650 ng SO_2/J of (1.5 lbs SO /10^6 BTU), Northern Appalachian reserves, if chemically cleaned, can reach a total of about 700 x 10^9 GJ. In the raw coal, approximately 110 x 10^9 GJ are available at this same emission standard. At the national average SIP emission level of 1,075 ng SO_2/J (2.5 lbs SO /10^6 BTU), raw coal energy reserves are 475 x 10^9 GJ. If chemical cleaning is practices at the 1,075 ng SO_2/J level, 1,400 x 10^9 GJ become available. Chemical coal cleaning typically raises the amount of complying energy reserve base about three to four times.

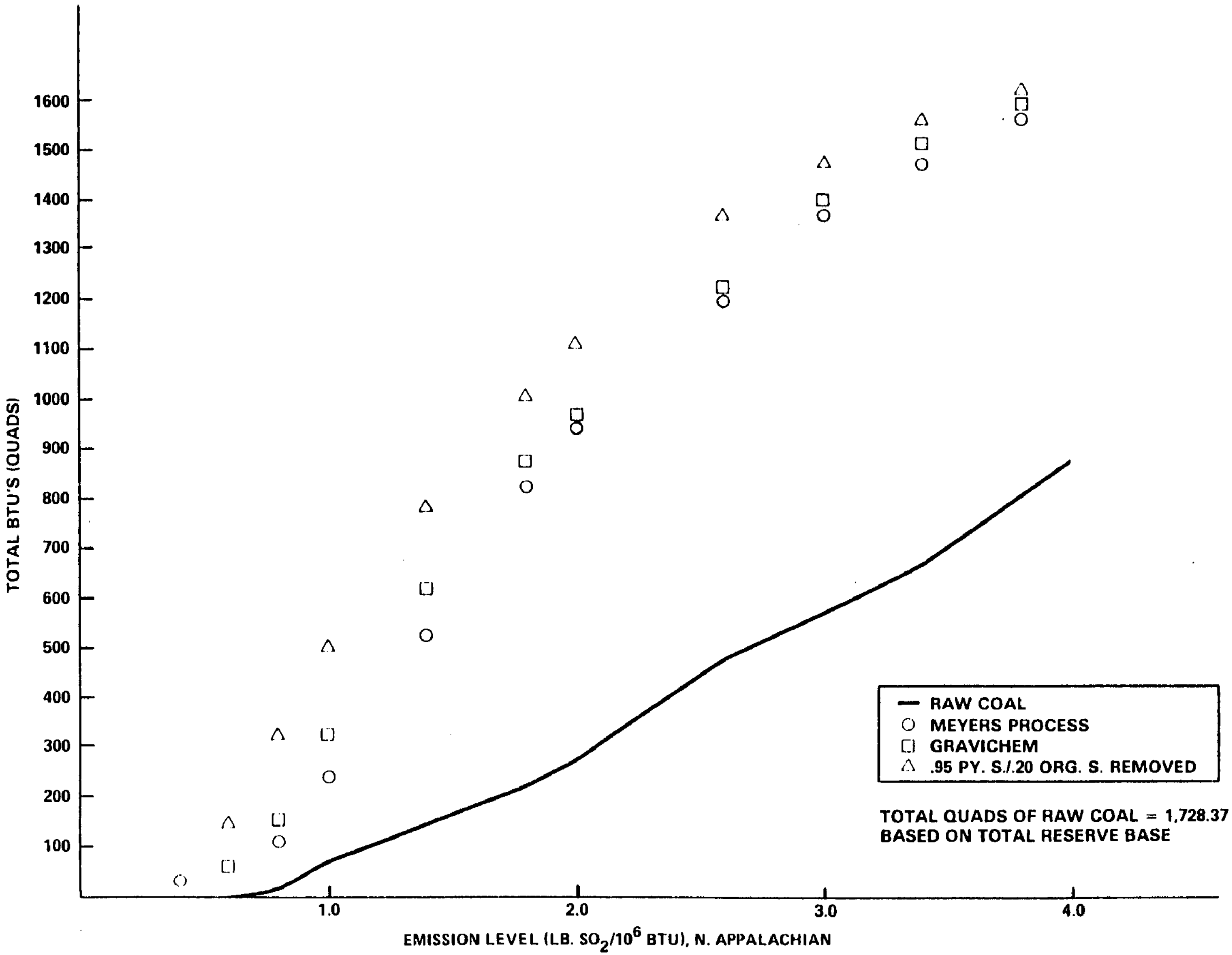


FIGURE 2-59 ENERGY AVAILABLE IN THE N. APPALACHIAN REGION AS A FUNCTION OF EMISSION CONTROL LEVEL FOR VARIOUS CHEMICAL COAL CLEANING PROCESSES

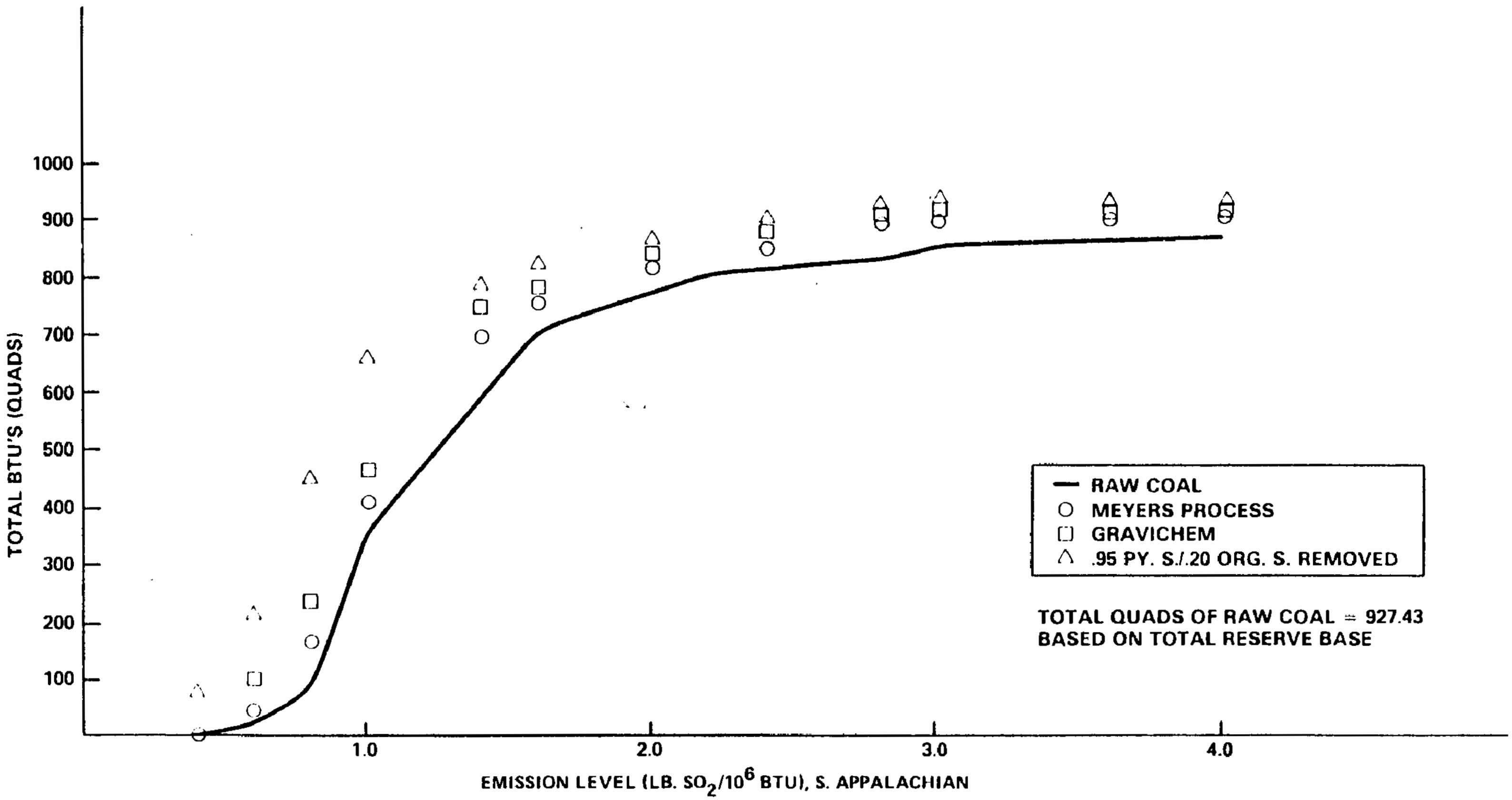


FIGURE 2-60 ENERGY AVAILABLE IN THE S. APPALACHIAN REGION AS A FUNCTION OF EMISSION CONTROL LEVEL FOR VARIOUS CHEMICAL COAL CLEANING PROCESSES

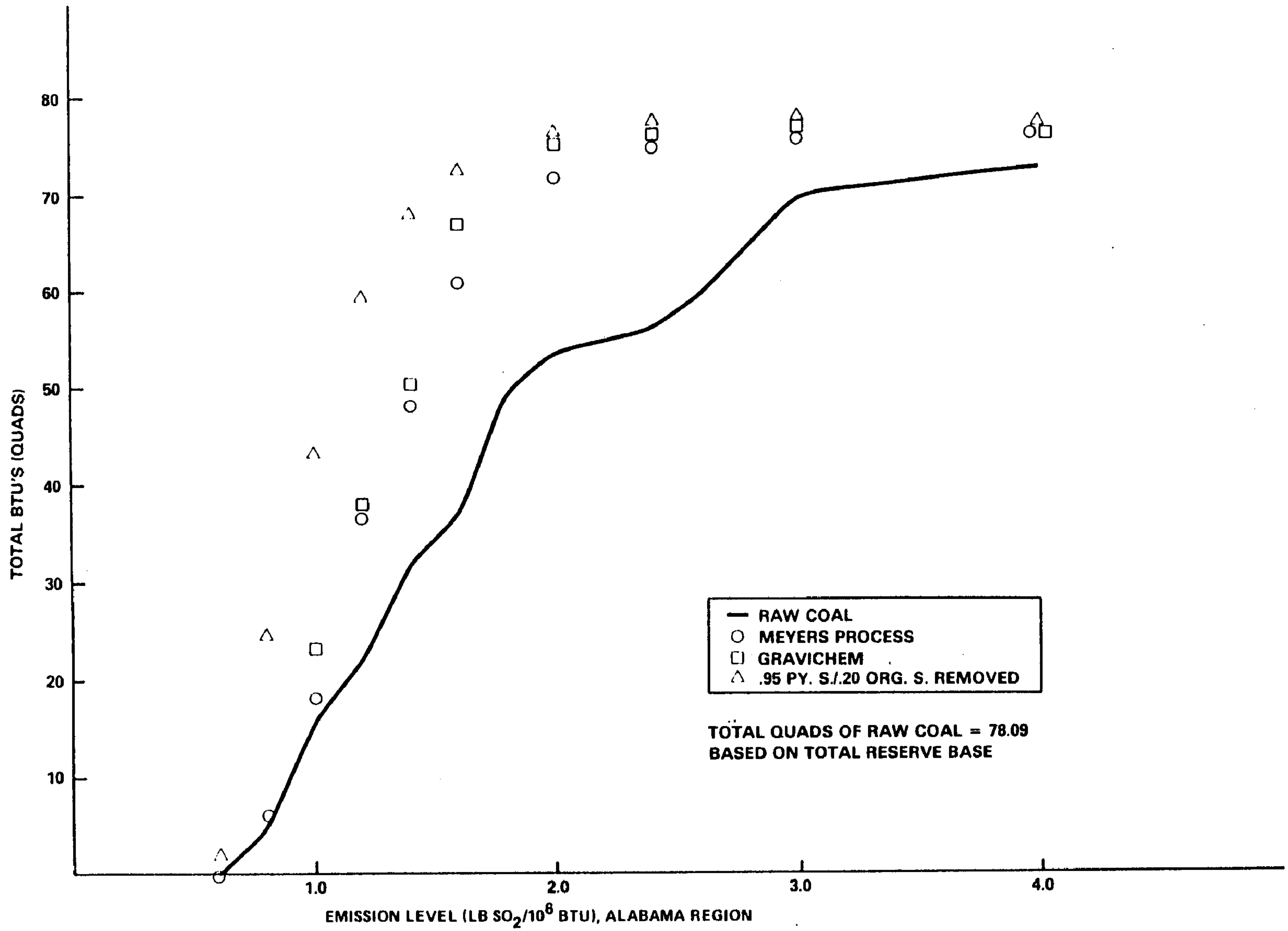


FIGURE 2-61 ENERGY AVAILABLE IN THE ALABAMA REGION AS A FUNCTION OF EMISSION CONTROL LEVEL FOR VARIOUS CHEMICAL COAL CLEANING PROCESSES

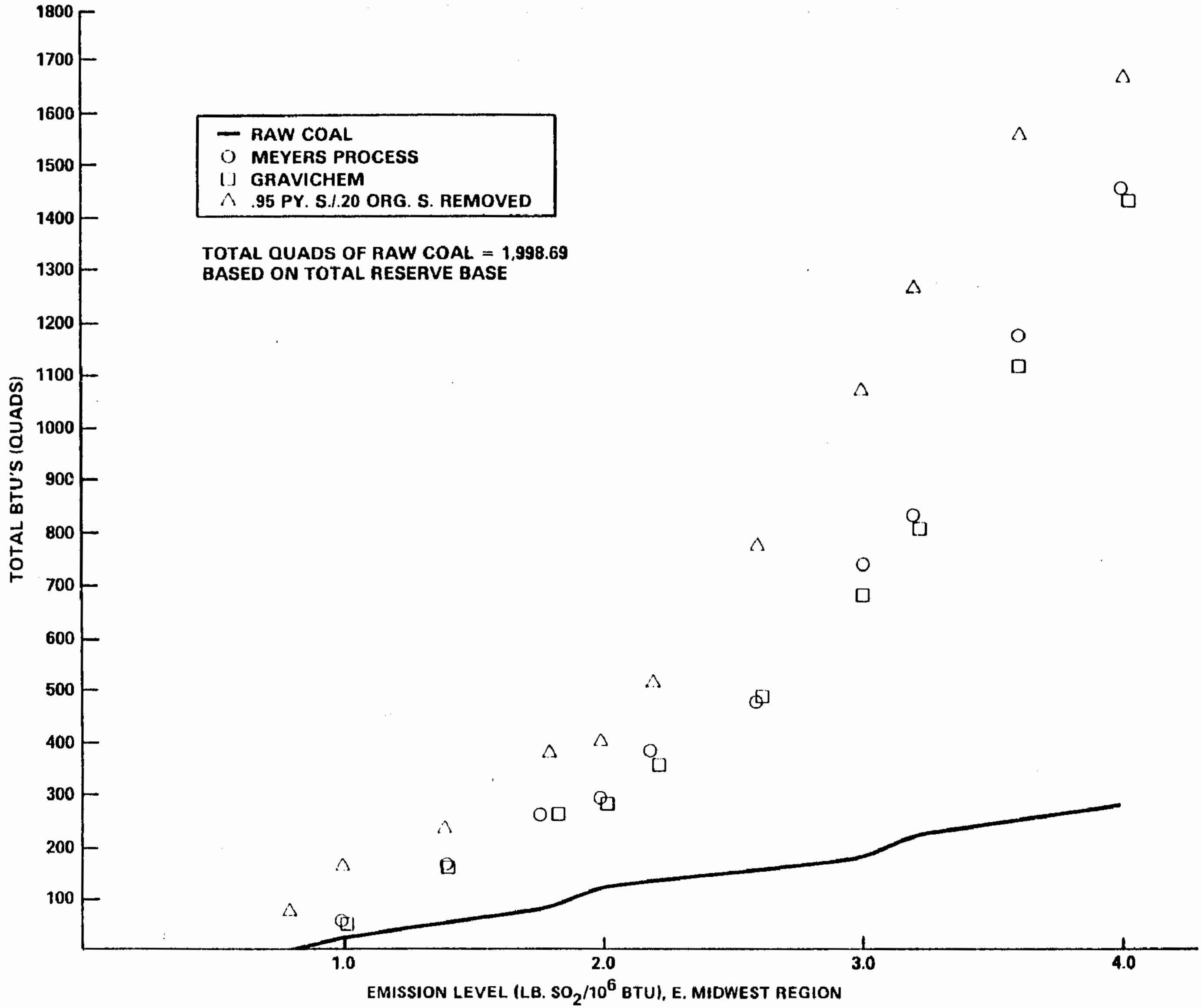


FIGURE 2-62 ENERGY AVAILABLE IN THE E. MIDWEST REGION AS A FUNCTION OF EMISSION CONTROL LEVEL FOR VARIOUS CHEMICAL COAL CLEANING PROCESSES

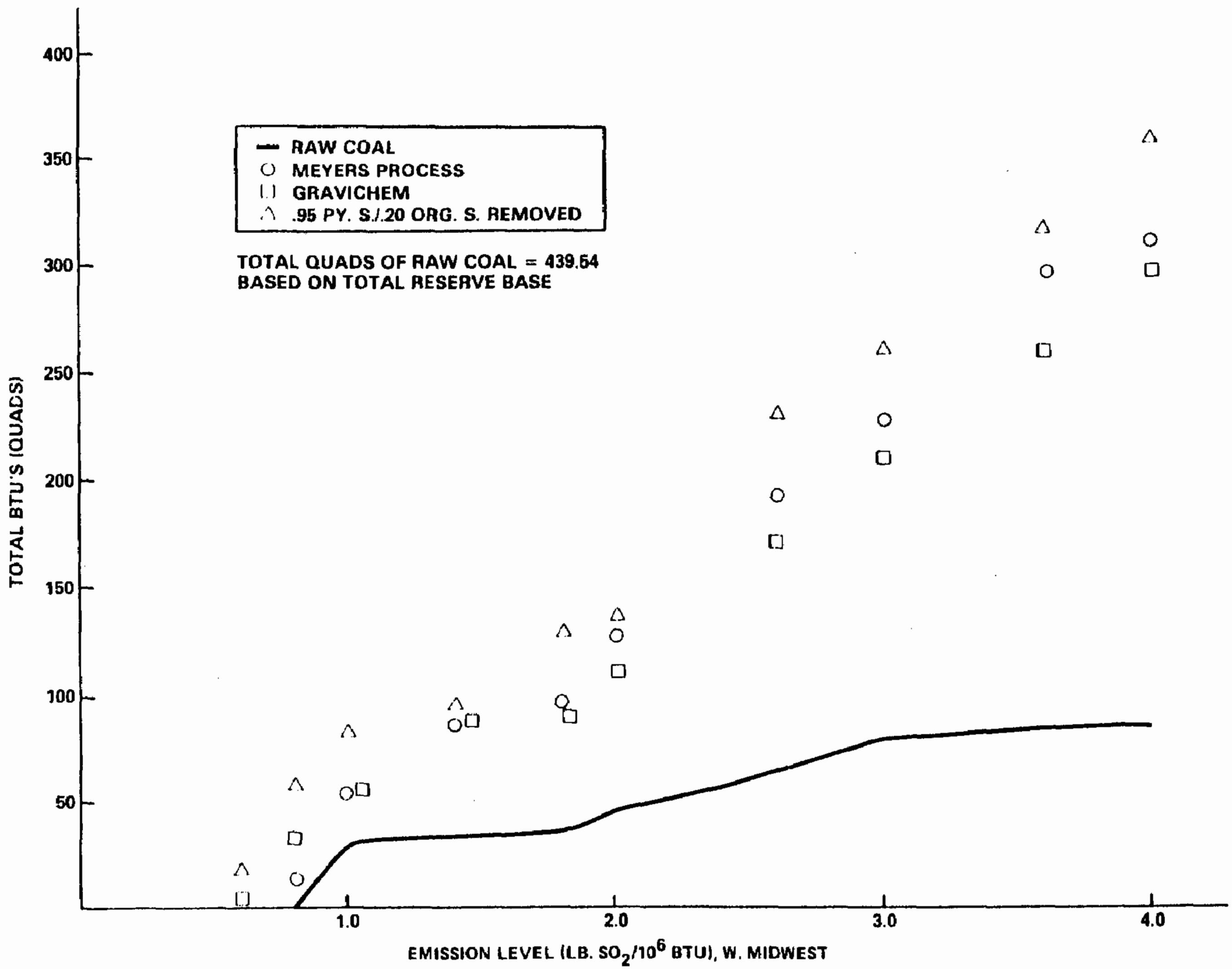


FIGURE 2-63 ENERGY AVAILABLE IN THE W. MIDWEST REGION AS A FUNCTION OF EMISSION CONTROL LEVEL FOR VARIOUS CHEMICAL COAL CLEANING PROCESSES

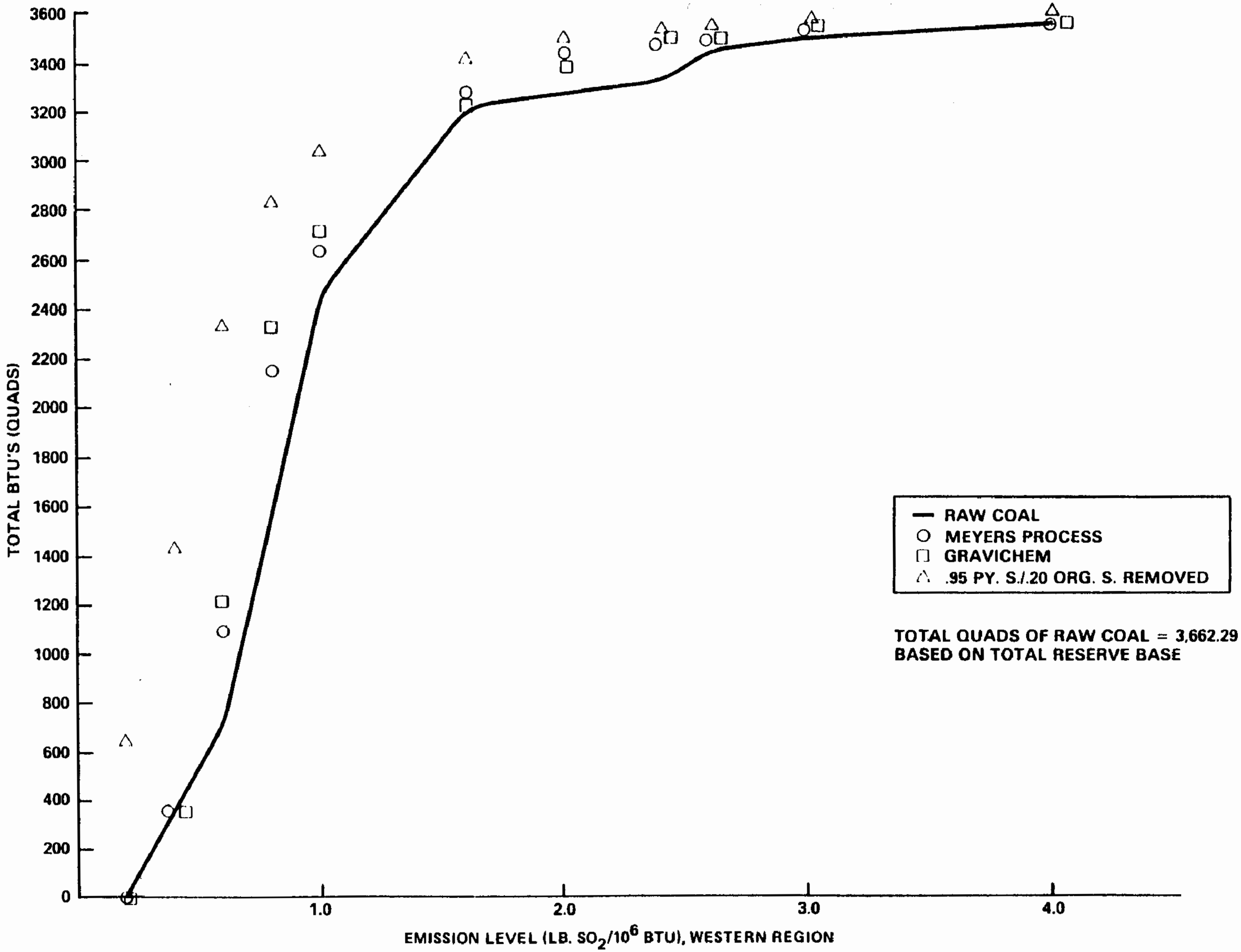


FIGURE 2-64 ENERGY AVAILABLE IN THE WESTERN REGION AS A FUNCTION OF EMISSION CONTROL LEVEL FOR VARIOUS CHEMICAL COAL CLEANING PROCESSES

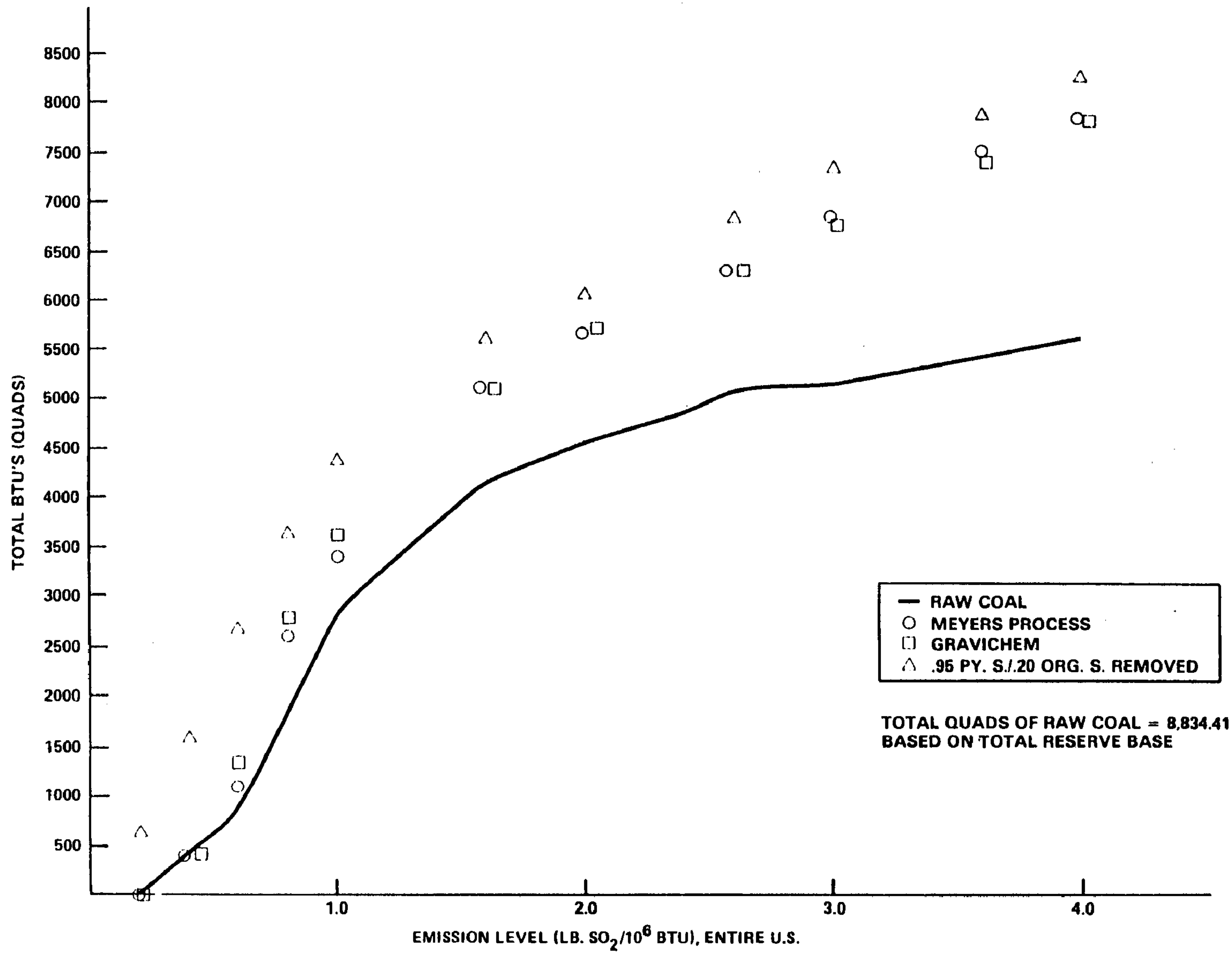


FIGURE 2–65 ENERGY AVAILABLE IN THE ENTIRE U.S. AS A FUNCTION OF EMISSION CONTROL LEVELS FOR VARIOUS CHEMICAL COAL CLEANING PROCESSES

At the most stringent control level of 260 ng SO_2/J, large differences exist in raw and cleaned coal reserves in the Southern Appalachian region. For raw coal, 20 x 10^9 GJ are present, while for a chemically cleaned produce 210 x 10^9 GJ are available. At the next two levels of 650 and 1,075 ng SO_2/J, the differences become less pronounced. At the 650 ng SO_2/J level, standard compliance raw coal has 500 x 10^9 GJ while complying chemically cleaned coal has almost 700 x 10^9 GJ. Smaller differences exist at the 1,075 ng SO_2/J level where raw coal has energy reserves of 860 x 10^9 GJ and chemically cleaned coal contains 950 x 10^9 GJ.

In the Alabama region essentially no raw coal exists which could meet the 260 ng SO_2/J emission control level. When chemically cleaned, approximately 2 x 10^9 GJ are available to meet the level. At the 650 ng SO_2/J control level, 23 x 10^9 GJ of the reserve base become available. Chemically cleaning the coal increases the energy available to approximately 40 x 10^9 GJ. For the SIP level of 1,075 ng SO_2/J, 60 x 10^9 GJ are available in the reserve base versus 90 x 10^9 GJ for chemically cleaned coal.

At the 260 ng SO_2/J level in the Eastern Midwest region there are no reserves either for raw coal or chemically cleaned coal. The 650 ng SO_2/J level also has small reserve values when compared to the total of the region. Raw coal contains 40 x 10^9 GJ, while chemically cleaned coal can supply 160 x 10^9 GJ. This fourfold increase from cleaning is potentially significant for new source SO_2 emitters. For the least stringent level of 1,075 ng SO_2/J, raw coal reserves contain 160 x 10^9 GJ; coal which has undergone chemical cleaning contains 600 x 10^9 GJ, again a fourfold increase. These differences again point out and reinforce the fact that four to five times more compliance fuels can be obtained from Eastern Midwest coal at intermediate or moderate emission levels if the coal undergoes chemical cleaning.

Virtually no energy reserves exist in the Western Midwest region for raw coal at the 260 ng SO_2/J emission control level. When chemical cleaning is instituted, 18 x 10^9 GJ of reserve become available. When the emission control level is raised to 650 ng SO_2/J, 33 x 10^9 GJ of raw coal can comply. The addition of chemical cleaning at this level raises the available energy reserves to approximately 80 x 10^9 GJ. By imposing a least stringent level of 1,075 ng SO_2/J, this region's raw coal has reserves of 65 x 10^9 GJ. By instituting chemical cleaning there would be a benefit of more than tripling the available energy to about 210 x 10^9 GJ. Definite gains in energy reserves are then possible in this region by implementing chemical coal cleaning. The advantages gained became more pronounced when the emission control level is 1,000 ng SO_2/J and above.

Most raw coal in the Western region is capable of meeting low sulfur emission control levels. At the 260 ng SO_2/J emission level 770 x 10^9 GJ are available in the raw coal. For chemically cleaned coal, up to 2,400 x 10^9 GJ can be utilized. At 650 ng SO_2/J the difference in the raw and clean coals is much less. Raw coal has a reserve energy content of 2,600 x 10^9 GJ, while the chemically cleaned reserve base is 3,100 x 10^9 GJ. As the emission control level rises even higher to 1,075 ng SO_2/J, the energy content differences between cleaned and uncleaned coals are even less. Raw coal has a value of 3,600 x 10^9 GJ, and chemically cleaned coal contains 3,700 x 10^9 GJ. Further increases in SO_2 emission levels reduce the differences to the point at which they become insignificant.

Nationwide, approximately 840 x 10^9 GJ are present in raw coal that can meet a 260 ng SO_2/J emission control level. Note that 92 percent of this energy comes from the Western reserve base. Implementing chemical coal cleaning on the U.S. reserve base provides about 2,600 x 10^9 GJ of energy at the stringent level. At the 650 ng SO_2/J emission level, raw coal contains 3,700 x 10^9 GJ, while chemically cleaning the coal raises this figure to as much as 4,800 x 10^9 GJ. The magnitude of the differences remain about the same for cleaned and raw coal as the emission level increases. At the 1,075 ng SO_2/J level, raw coal has available 5,300 x 10^9 GJ, while the chemically cleaned coal energy reserve base rises to 6,900 x 10^9 GJ.

Impact on Boilers

Chemically cleaned coal could improve the overall performance of stoker boilers, provided the end product is suitable to be fed and fired in a stoker. Many of the chemical treatments would require that the coal be pulverized to a 100-micron size or less. These coals would have to be pelletized for stoker firing.

Any size cleaning plant could provide a product for any size boiler. However, practically speaking, larger cleaning plants will provide cleaning at a lower unit cost. Thus, one cleaning plant might be used to provide coal for all of the industrial boilers in one area. The cleaning plant would probably be located near the mine with the product distributed to the users by truck, rail or barge.

Some of the chemical processes would increase surface reactivity of the coal which would improve combustion. Also, the free-swelling index may be reduced (provided the coal cleaning process involves an oxidation step); thus reducing the caking tendencies of coal. Environmentally, the coals become more attractive as more sulfur and ash are removed. Coals fired in stokers require at least 5 percent ash to protect the grates from overheating. Chemical cleaning of the coal should not drastically alter the volatile content of the coal. Reducing the volatile matter below 15 percent would cause problems in ignition and could preclude its use in spreader stokers.

Due to process development status (i.e., pilot plants), maintenance requirements are indeterminate, although problems with abrasion and acid-initiated corrosion would be expected.

It is assumed that the use of chemically cleaned coal would improve the operation of boilers designed to burn coal and that boiler modifications would not be necessary.

2.2.4 Performance of Physical and Chemical Coal Cleaning Techniques on U.S. Coal Reserve Base at Various SO_2 Emission Limits and Percent Reduction Requirements

Previous portions of this section of the report have addressed the weight and an energy percentage of U.S. coal that is capable of meeting various SO_2 emission control levels based upon SO_2 per unit heating value. This section addresses the impact SO_2 emission control levels might have on the availability of the U.S. coal reserve base.

Since it is quite conceivable that EPA may consider alternative regulatory options of the same format as the utility boiler proposed standard for the industrial boiler sector, it was decided that some estimates of coal availability under various possible emission scenarios should be made.

The Reserve Processing Assessment Model[92] has been used to estimate the weight and energy percentages of various regions of the U.S. coal reserve base, which would be available after processing by four coal cleaning technologies, to meet a series of proposed SO_2 emission control levels. The geographical regions used in this analyses included: 1) Northern Appalachia; 2) Eastern Midwest; 3) Western; and 4) Entire U.S. The cleaning processes simulated in the model are as follows:

A - PCC at 1 1/2 inch and 1.6 s.g. This process separates the coal and impurities at 1.6 specific gravity after crushing the raw coal to 1 1/2 inch top size. Weight and energy losses are calculated based upon those inherent in the separation process.

B - PCC at 3/8 inch and 1.3 s.g. This process separates the coal and impurities at a lower specific gravity of 1.3 after crushing the raw coal to a 3/8 inch top size to liberate ash and pyritic sulfur. This process simulates about the best that PCC can achieve with respect to sulfur rejection, but with a large penalty in weight and energy loss to the refuse.

C - Meyers process. A chemical coal cleaning process capable of removing 90-95% of the pyritic sulfur in the raw coal. It is assumed that the process reduces the pyritic sulfur of the coal to a level of 0.2 percent. A 10 percent weight loss and a five percent energy loss is assumed in the process as well as a 2 percent energy loss penalty.

D - Gravichem process. This is a combined physical and chemical cleaning process in which the coal is first crushed to 14 mesh and separated at 1.3 specific gravity. The sink material from this separation is then treated in the Meyers process and combined with the float. The energy penalties assumed in the process are those inherent in the separation plus the penalties attributed to the Meyers processing of the sink material.

Figures 2-66 to 2-89 show the availability in percent of the total reserve base, for the Northern Appalachian, Eastern Midwest, and Western regions plus the entire U.S. to meet percent SO_2 removal standards at various emission limits and floors, if the coal is cleaned prior to combustion. The curves plotted for each region and the entire U.S. show both percent energy and percent weight of the reserve base available. Three emission scenarios were chosen consisting of a cap and a floor to illustrate three levels of emission control. A moderate level was chosen at a cap of 1,290 ng SO_2/J (3.0 lb $SO_2/10^6$ BTU) and a floor of 520 ng SO_2/J (1.2 lb $SO_2/10^6$ BTU). An intermediate level was chosen at a cap of 860 ng SO_2/J (2.0 lb $SO_2/10^6$ BTU) with a floor of 344 ng SO_2/J (0.8 lb $SO_2/10^6$ BTU). A stringent level was chosen at a cap of 520 ng SO_2/J (1.2 lb $SO_2/10^6$ BTU) and a floor of 258 ng SO_2/J (0.6 lb $SO_2/10^6$ BTU). All of these cases neglect any consideration of sulfur variability. All of the cases assume that if the raw coal emission level is below the floor or the clean coal emission level reaches the floor, then further cleaning is not necessary. This is reflected in the graphs at the point where the curves level off.

In the Northern Appalachian region, at the moderate emission control level the available coal as a result of physical cleaning decreases from a range of 35 to 45 percent at 0 percent SO_2 reduction to a range 10 to 15%

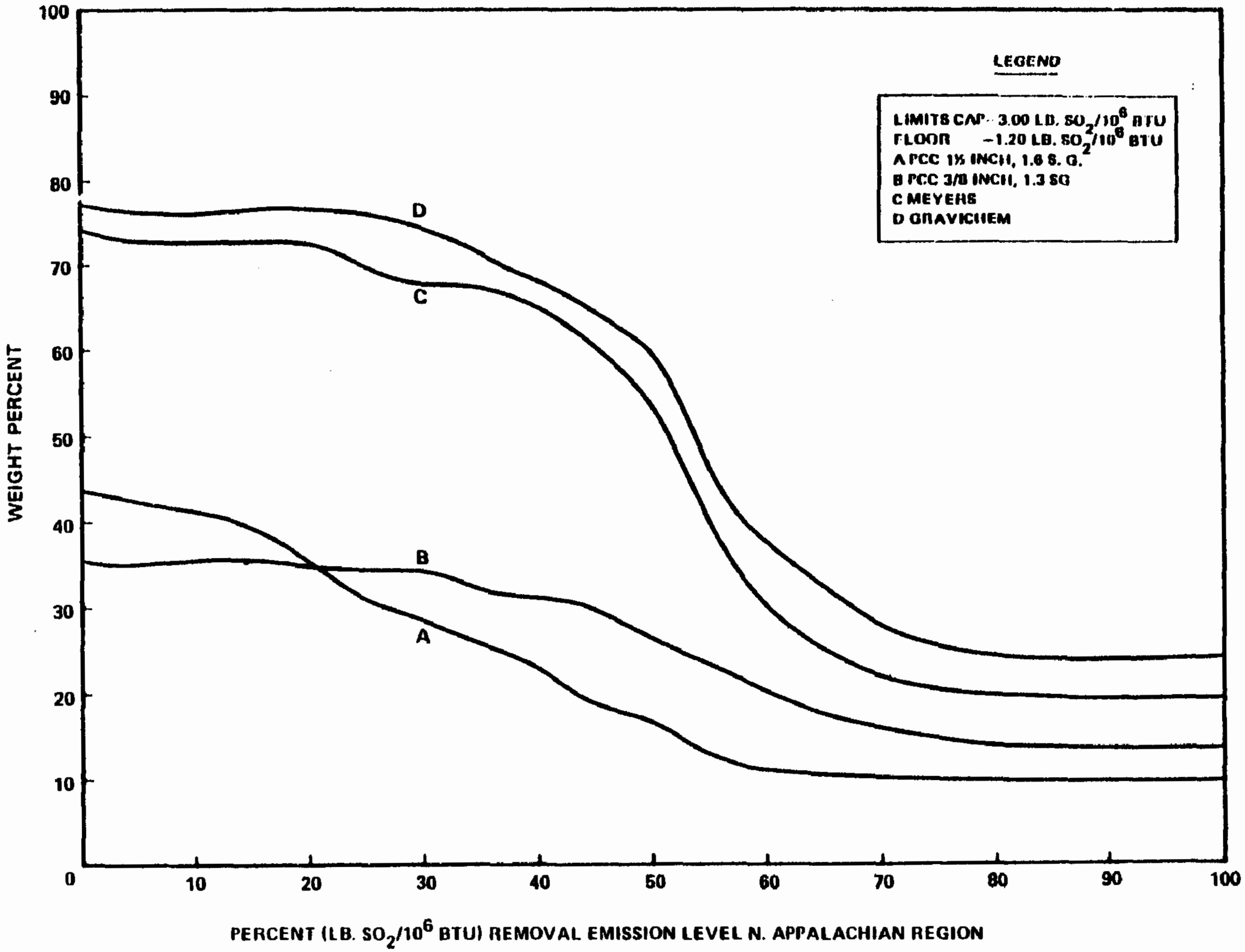


FIGURE 2-66 PERCENT WEIGHT AVAILABLE IN RESERVE BASE AFTER PROCESSING BY VARIOUS TECHNOLOGIES TO MEET A MODERATE PERCENT SO_2 REMOVAL CONTROL LEVEL

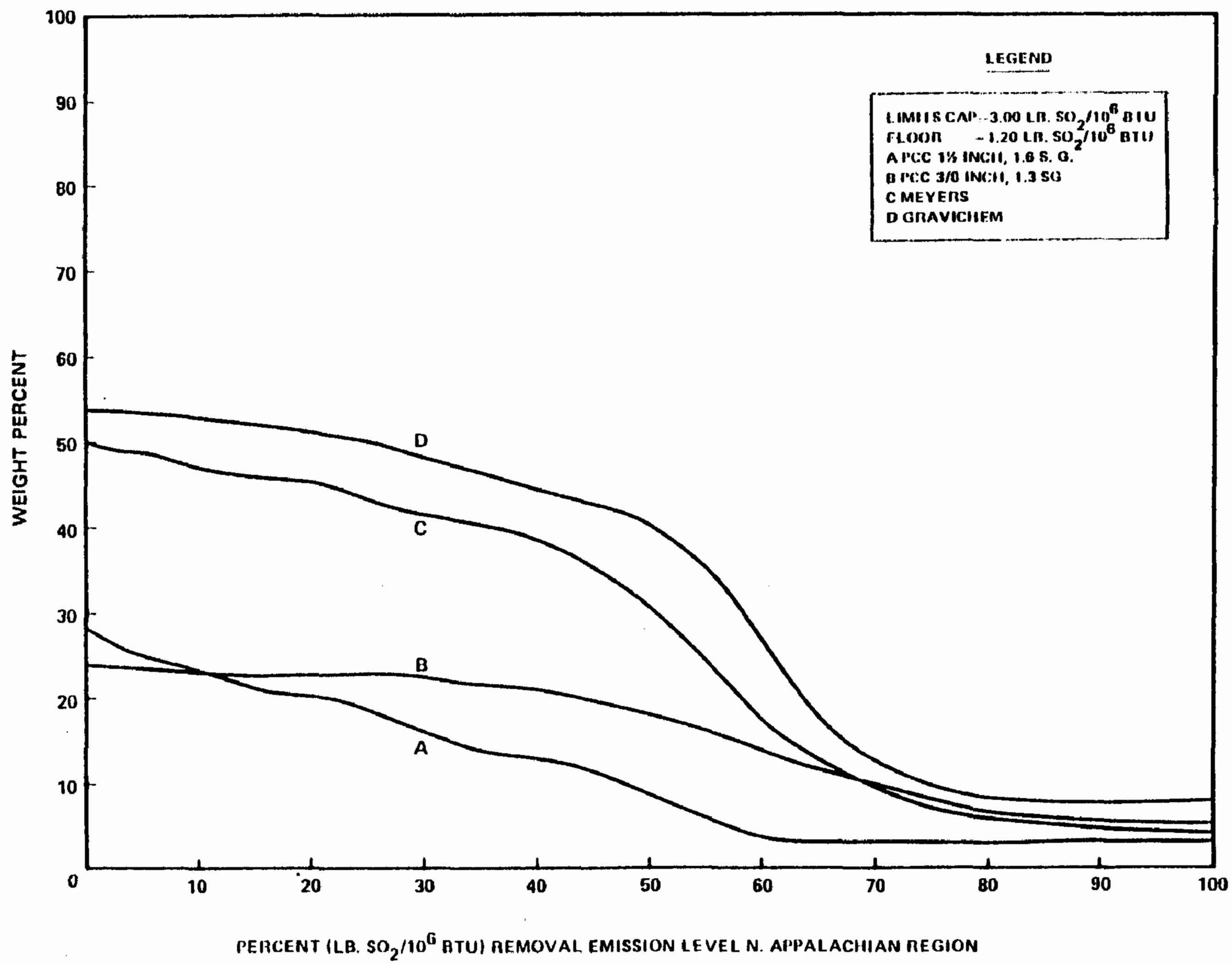


FIGURE 2-67 PERCENT WEIGHT AVAILABLE IN RESERVE BASE AFTER PROCESSING BY VARIOUS TECHNOLOGIES TO MEET AN INTERMEDIATE PERCENT SO_2 REMOVAL CONTROL LEVEL

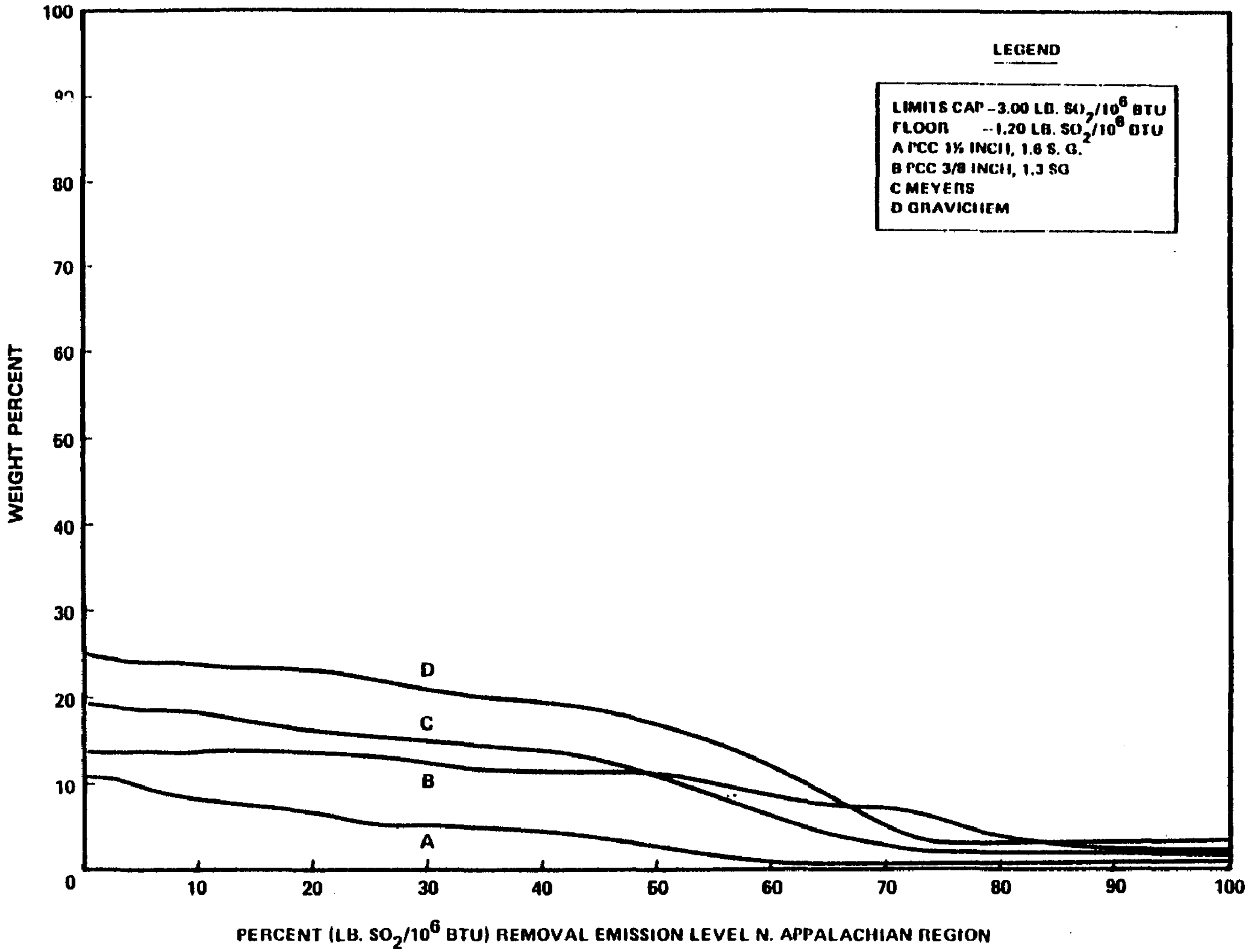


FIGURE 2-68 PERCENT WEIGHT AVAILABLE IN RESERVE BASE AFTER PROCESSING BY VARIOUS TECHNOLOGIES TO MEET A STRINGENT PERCENT SO_2 REMOVAL CONTROL LEVEL

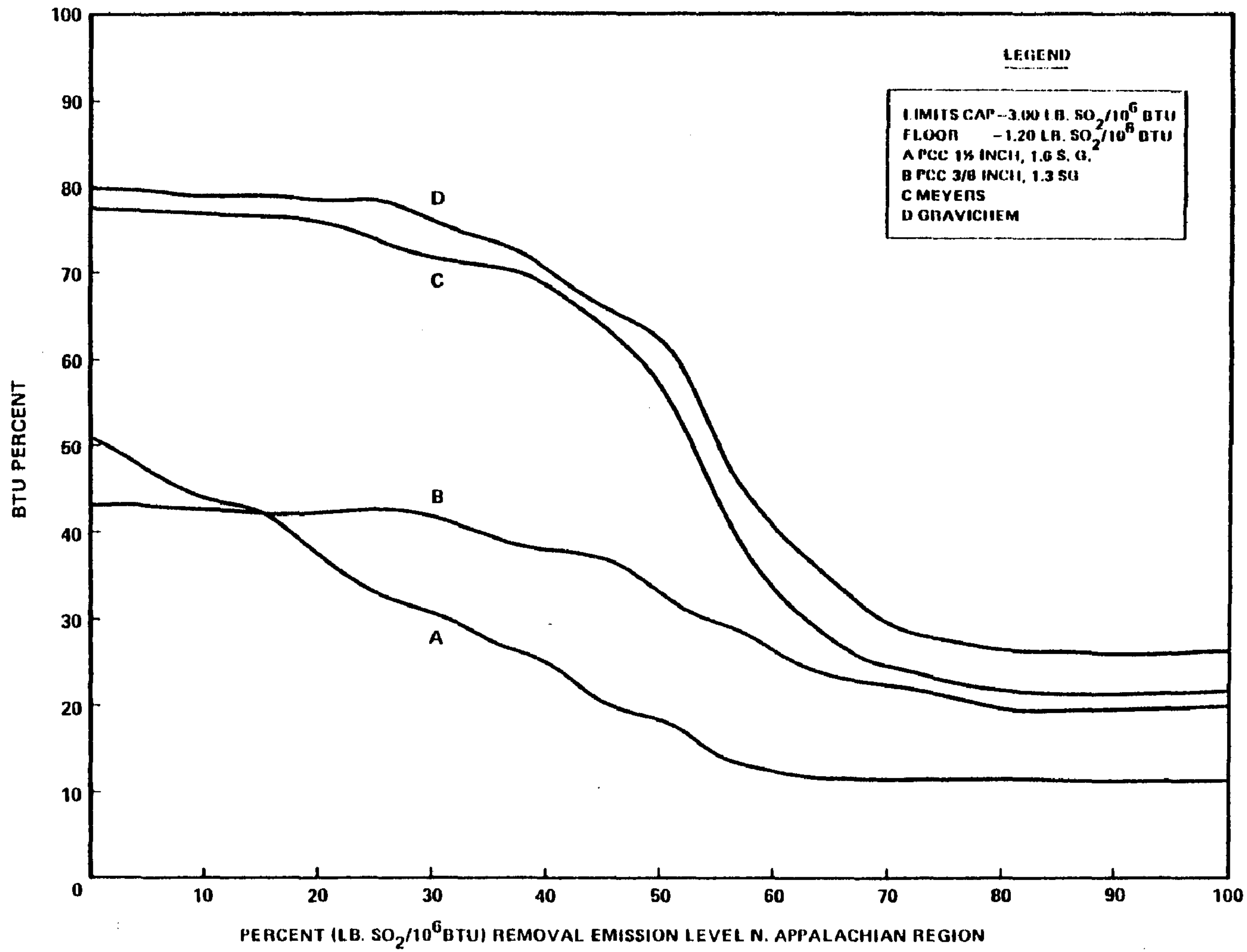


FIGURE 2–69 PERCENT ENERGY AVAILABLE IN RESERVE BASE AFTER PROCESSING BY VARIOUS TECHNOLOGIES TO MEET A MODERATE PERCENT SO_2 REMOVAL CONTROL LEVEL

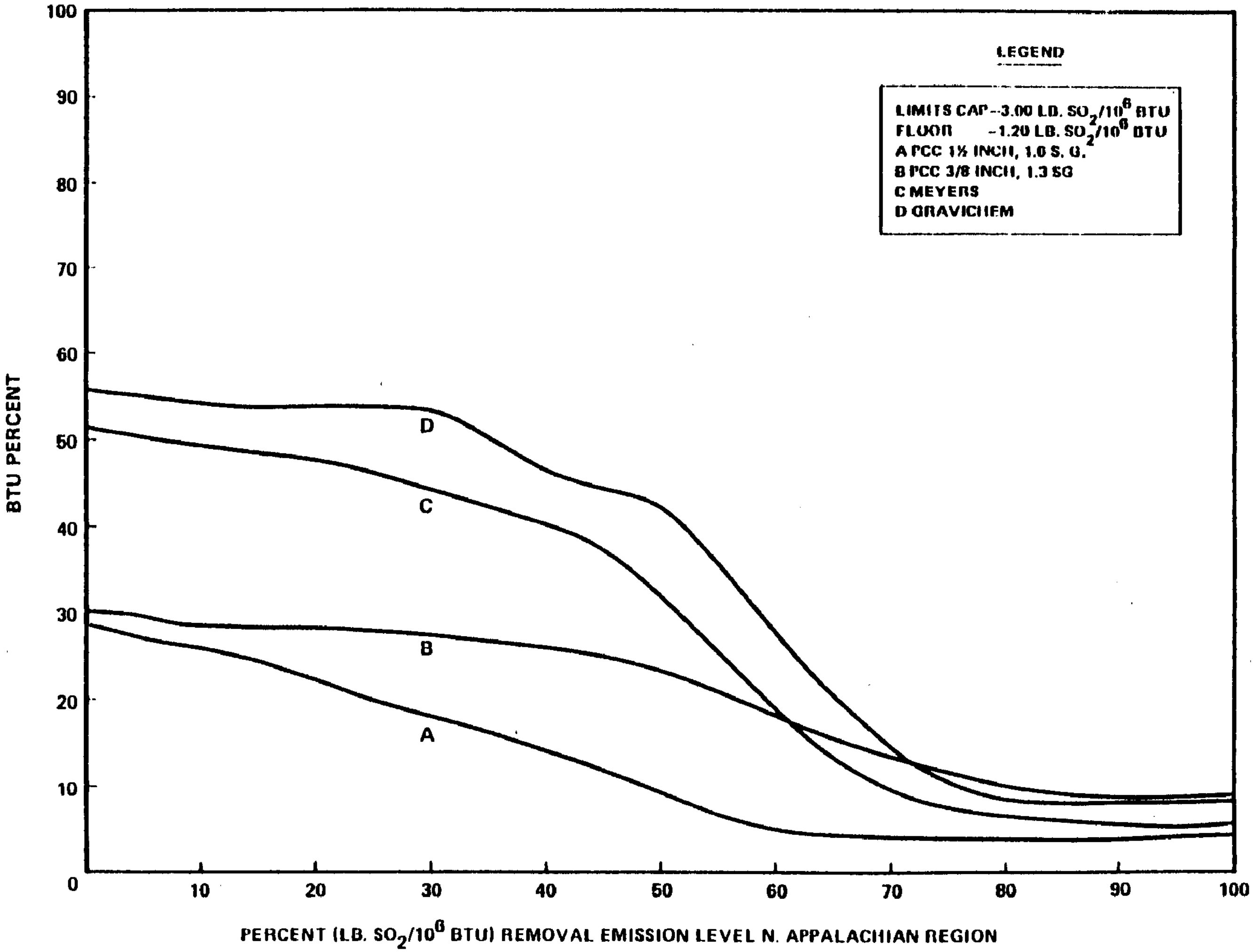
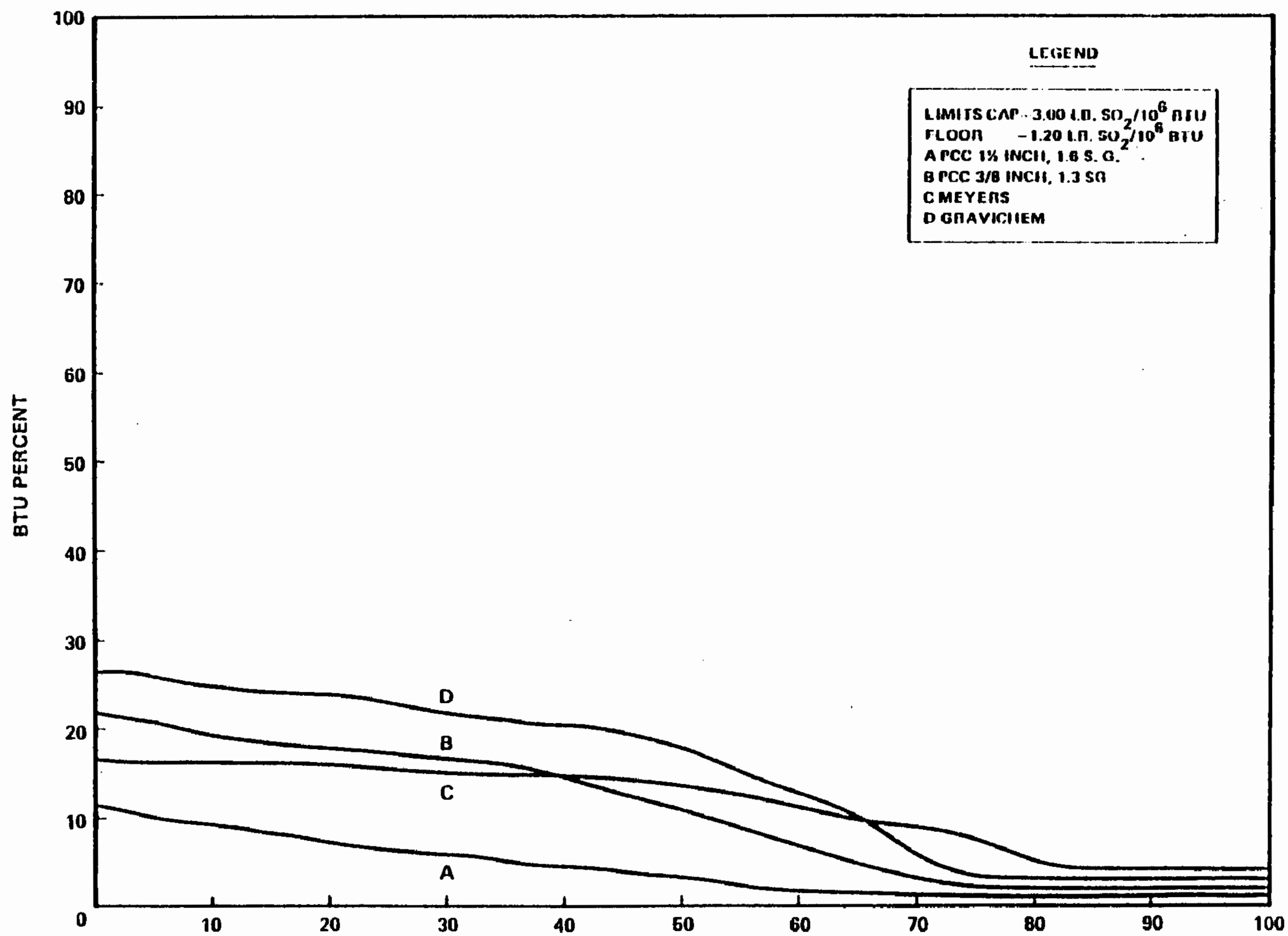


FIGURE 2-70 PERCENT ENERGY AVAILABLE IN RESERVE BASE AFTER PROCESSING BY VARIOUS TECHNOLOGIES TO MEET AN INTERMEDIATE PERCENT SO_2 REMOVAL CONTROL LEVEL



PERCENT (LB. $SO_2/10^6$ BTU) REMOVAL EMISSION LEVEL N. APPALACHIAN REGION

FIGURE 2-71 PERCENT ENERGY AVAILABLE IN RESERVE BASE AFTER PROCESSING BY VARIOUS TECHNOLOGIES TO MEET A STRINGENT PERCENT SO_2 REMOVAL CONTROL LEVEL

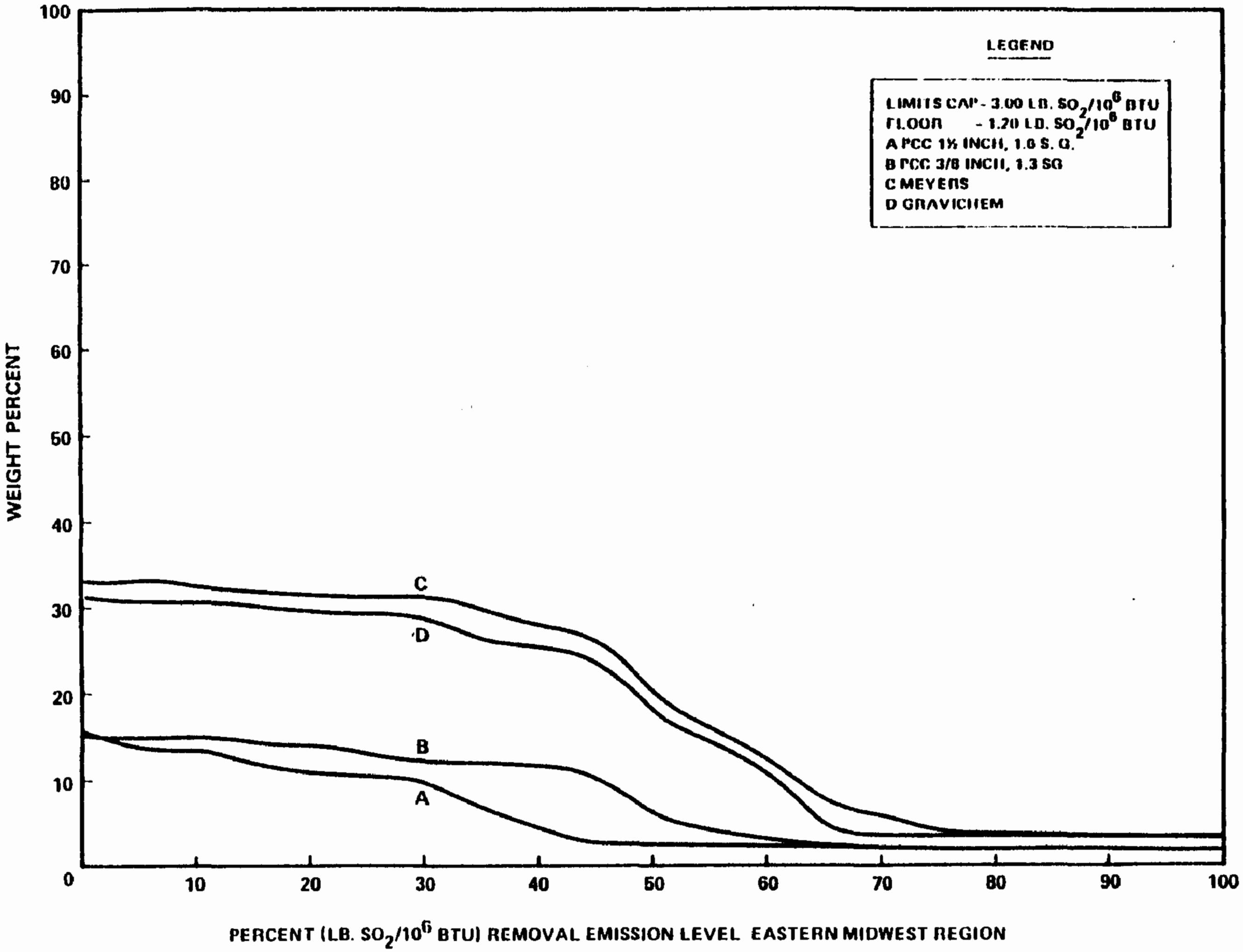


FIGURE 2-72 PERCENT WEIGHT AVAILABLE IN RESERVE BASE AFTER PROCESSING BY VARIOUS TECHNOLOGIES TO MEET A MODERATE PERCENT SO_2 REMOVAL CONTROL LEVEL

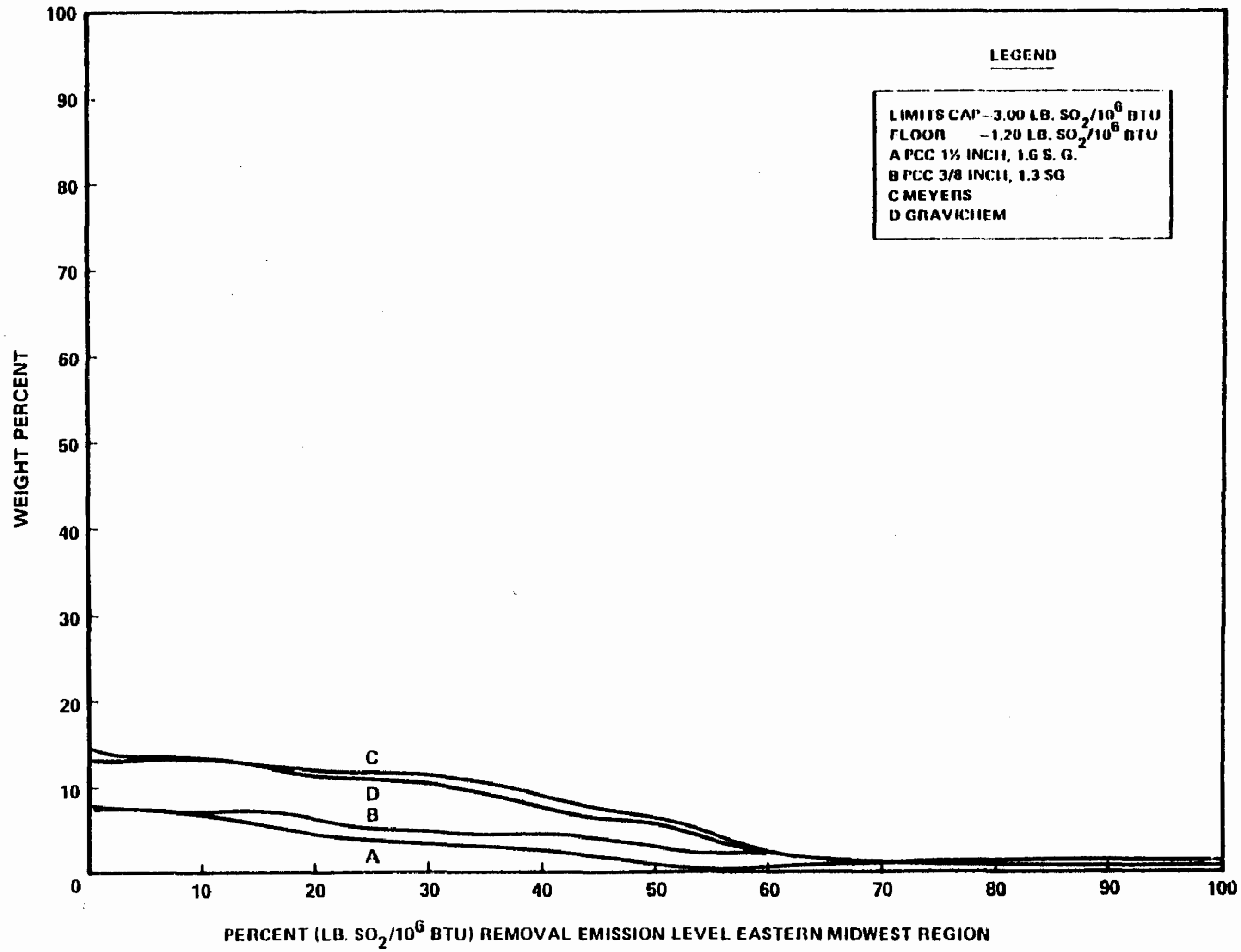


FIGURE 2-73 PERCENT WEIGHT AVAILABLE IN RESERVE BASE AFTER PROCESSING BY VARIOUS TECHNOLOGIES TO MEET AN INTERMEDIATE PERCENT SO_2 REMOVAL CONTROL LEVEL

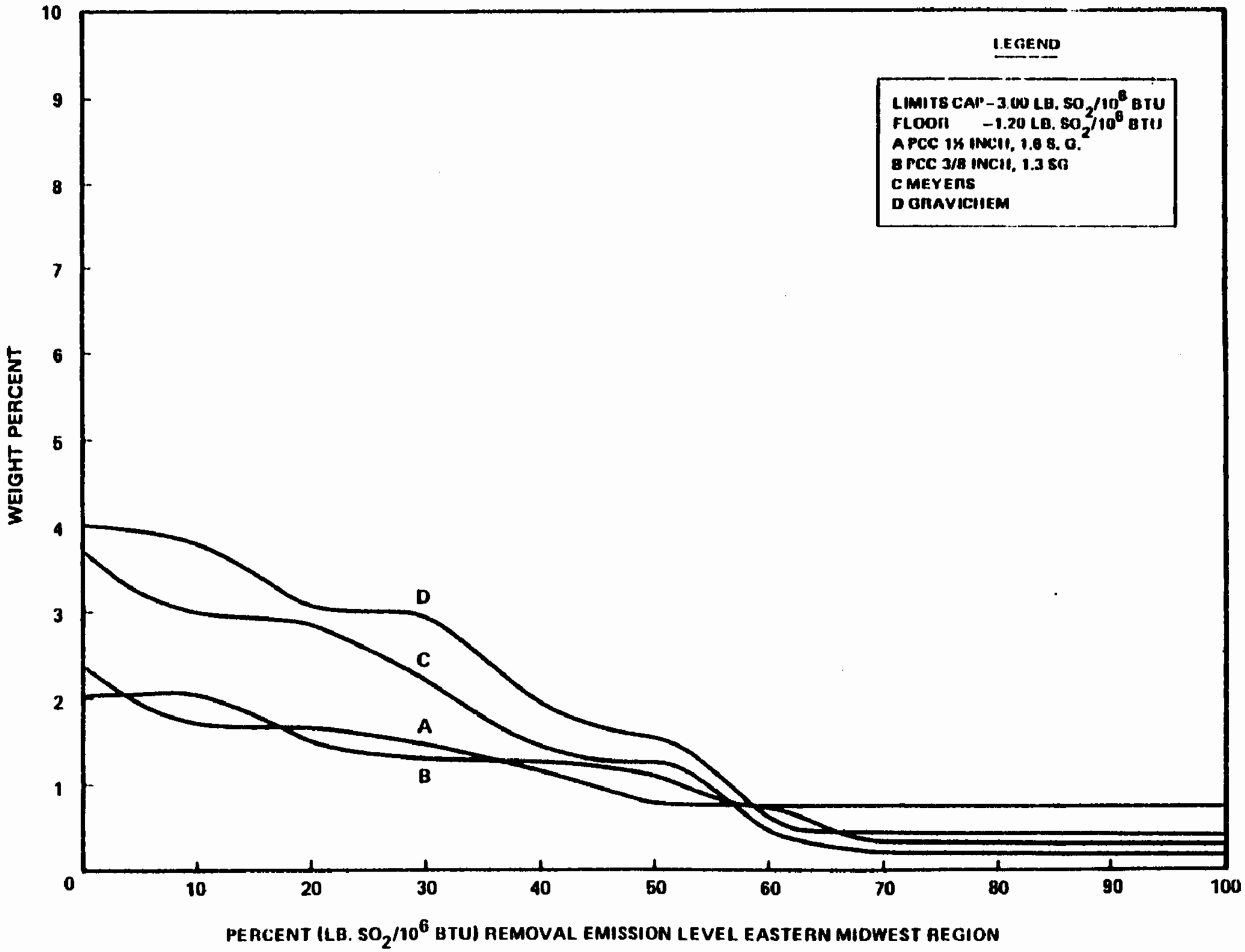


FIGURE 2-74 PERCENT WEIGHT AVAILABLE IN RESERVE BASE AFTER PROCESSING BY VARIOUS TECHNOLOGIES TO MEET A STRINGENT PERCENT SO_2 REMOVAL CONTROL LEVEL

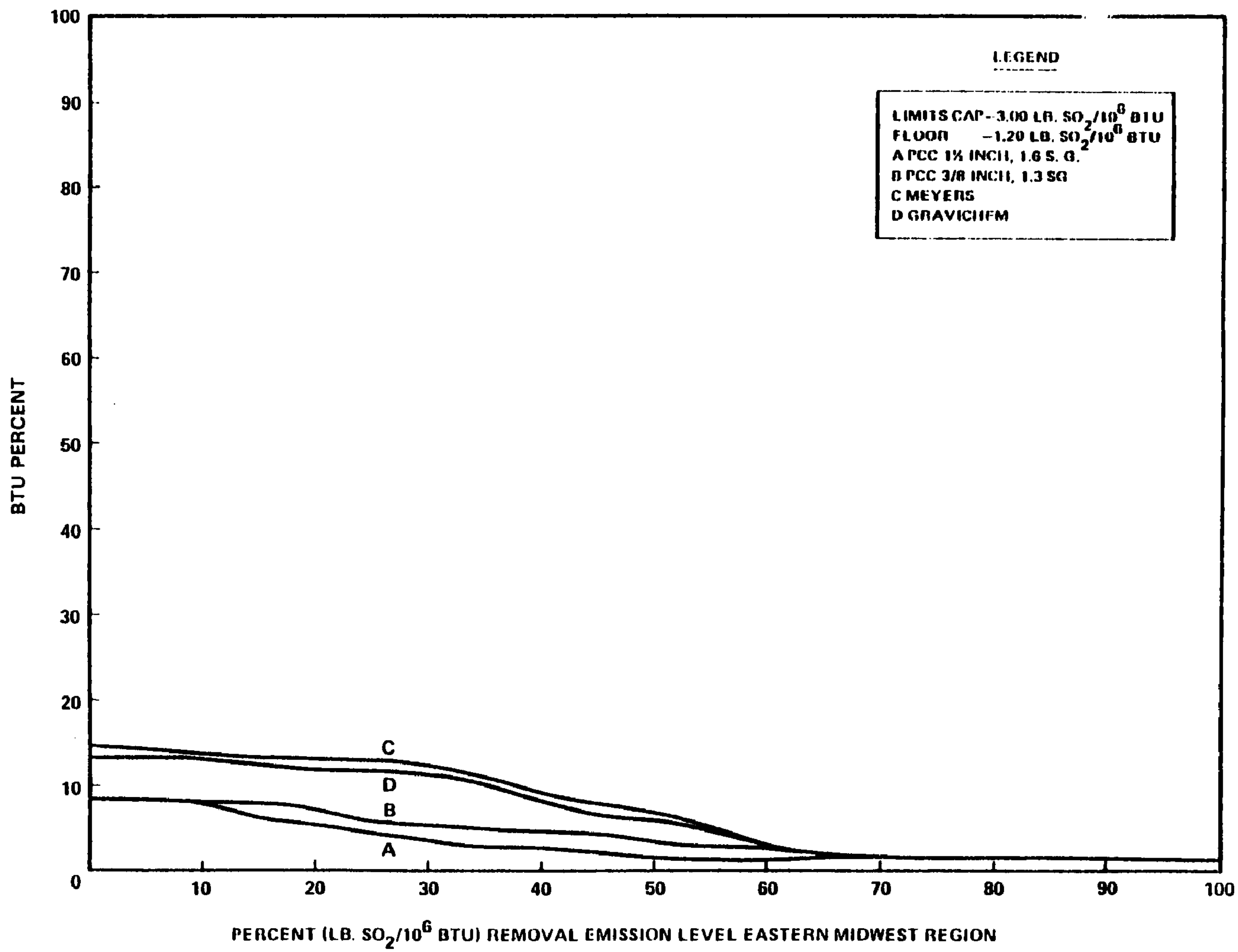


FIGURE 2-75 PERCENT ENERGY AVAILABLE IN RESERVE BASE AFTER PROCESSING BY VARIOUS TECHNOLOGIES TO MEET AN INTERMEDIATE PERCENT SO_2 REMOVAL CONTROL LEVEL

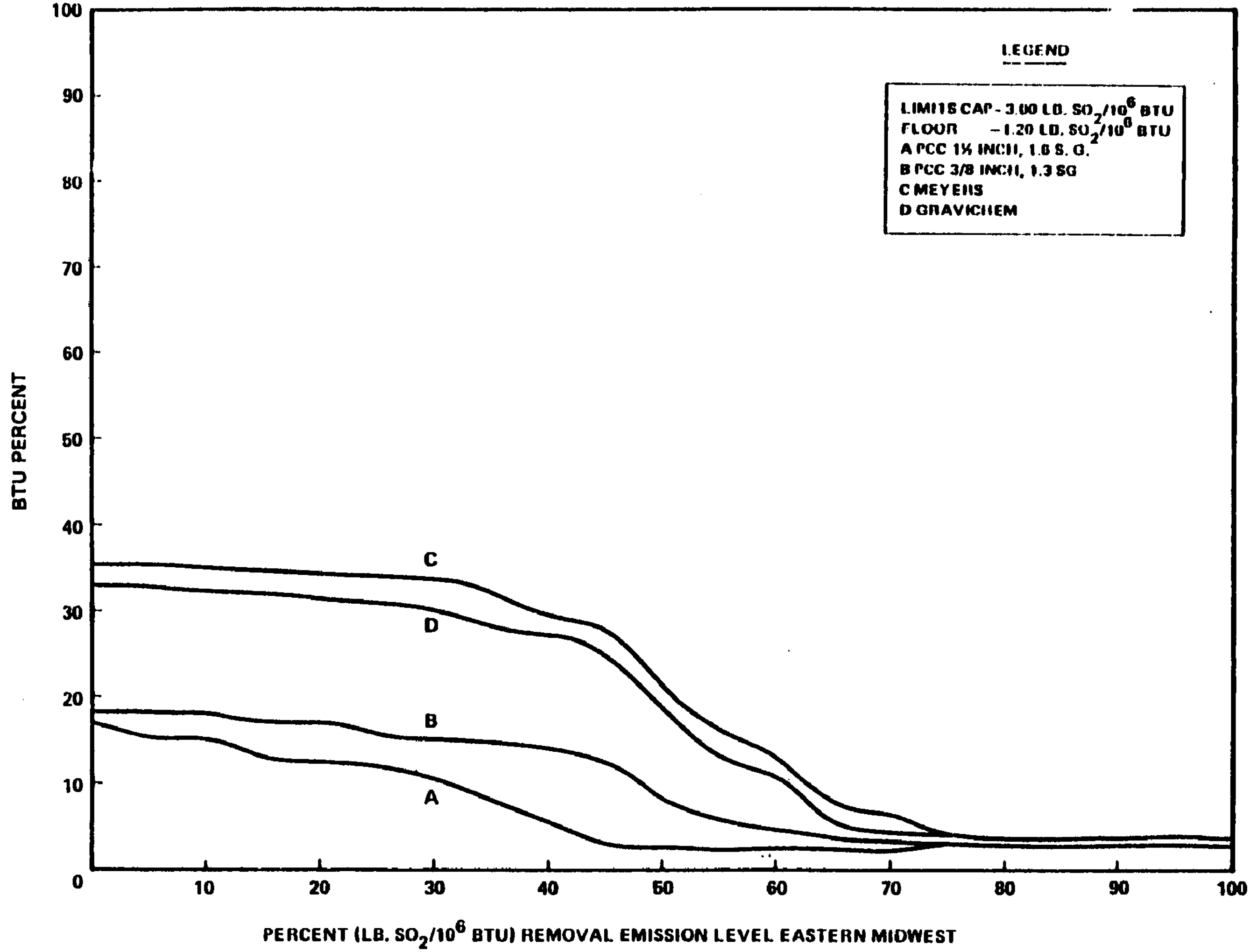


FIGURE 2-76 PERCENT ENERGY AVAILABLE IN RESERVE BASE AFTER PROCESSING BY VARIOUS TECHNOLOGIES TO MEET A MODERATE PERCENT SO_2 REMOVAL CONTROL LEVEL

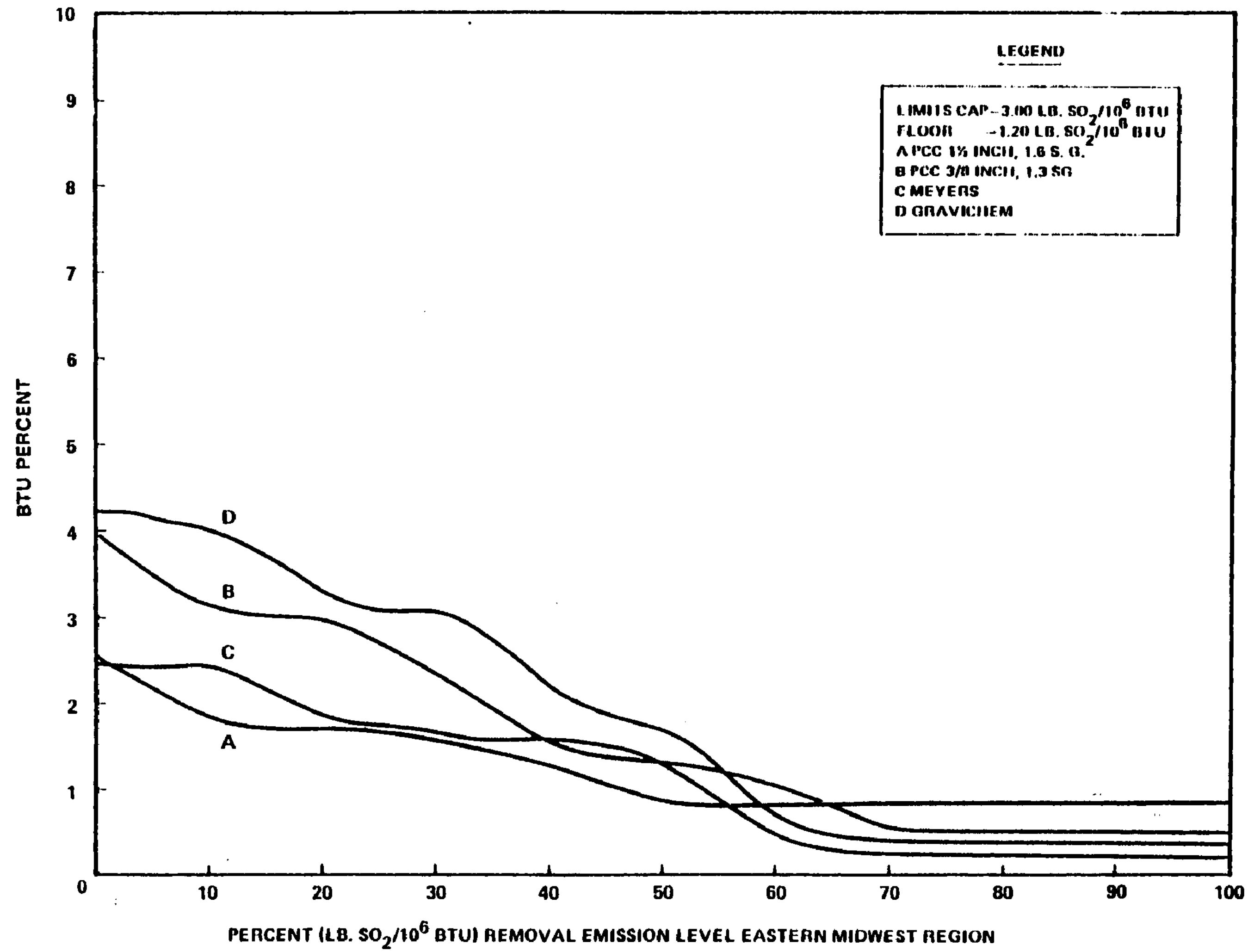


FIGURE 2-77 PERCENT ENERGY AVAILABLE IN RESERVE BASE AFTER PROCESSING BY VARIOUS TECHNOLOGIES TO MEET A STRINGENT PERCENT SO_2 REMOVAL CONTROL LEVEL

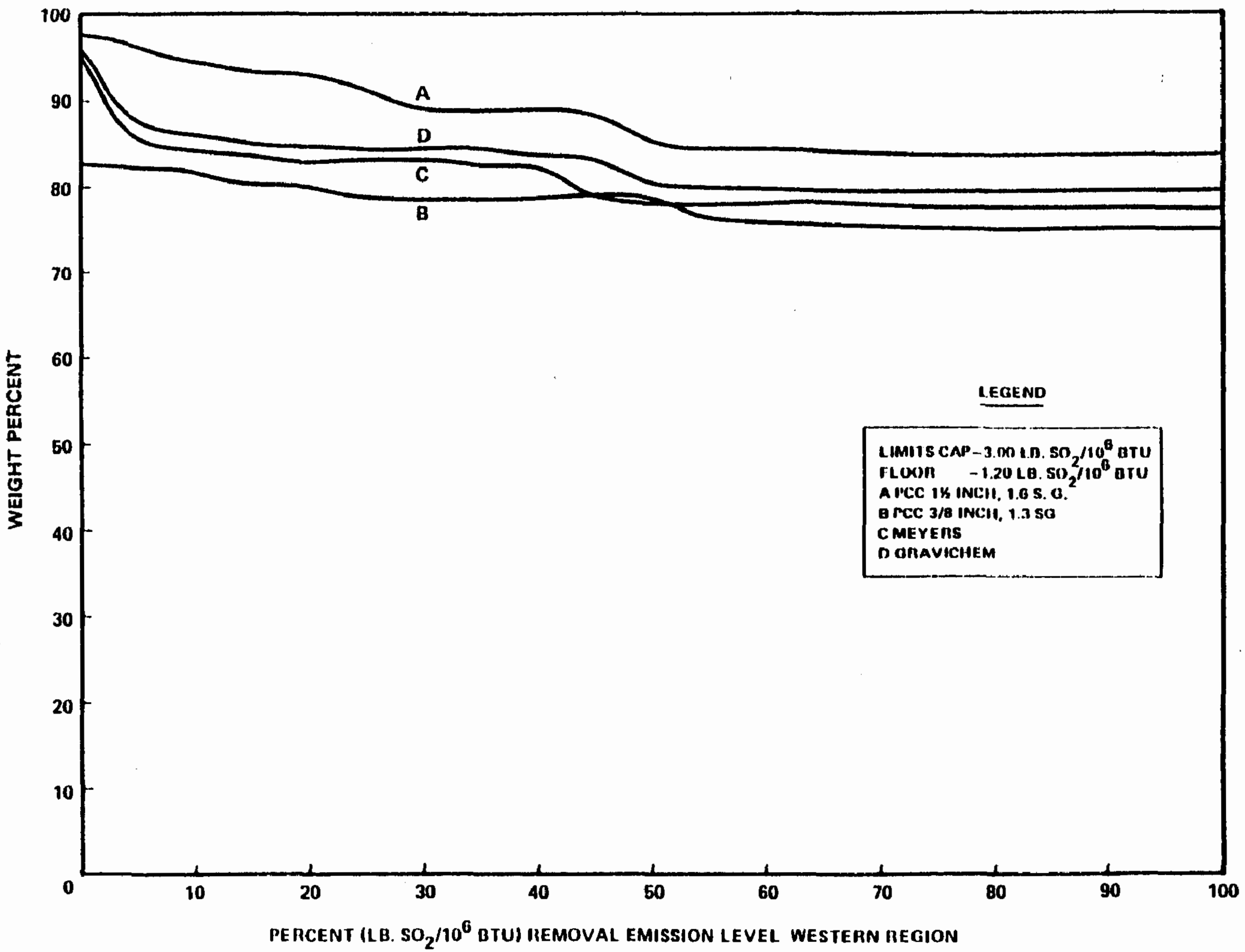


FIGURE 2-78 PERCENT WEIGHT AVAILABLE IN RESERVE BASE AFTER PROCESSING BY VARIOUS TECHNOLOGIES TO MEET A MODERATE PERCENT SO_2 REMOVAL CONTROL LEVEL

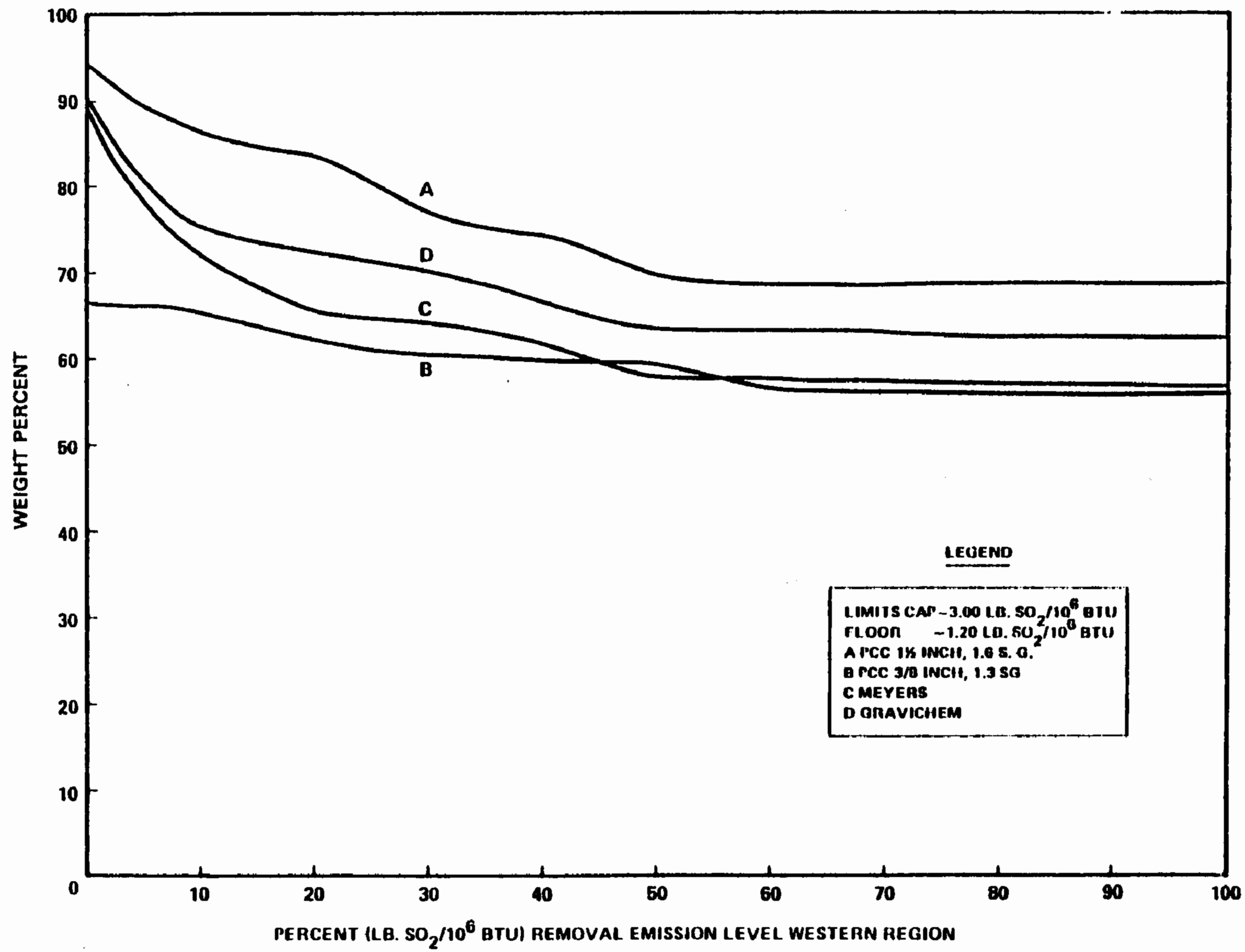


FIGURE 2-79 PERCENT WEIGHT AVAILABLE IN RESERVE BASE AFTER PROCESSING BY VARIOUS TECHNOLOGIES TO MEET AN INTERMEDIATE PERCENT SO_2 REMOVAL CONTROL LEVEL

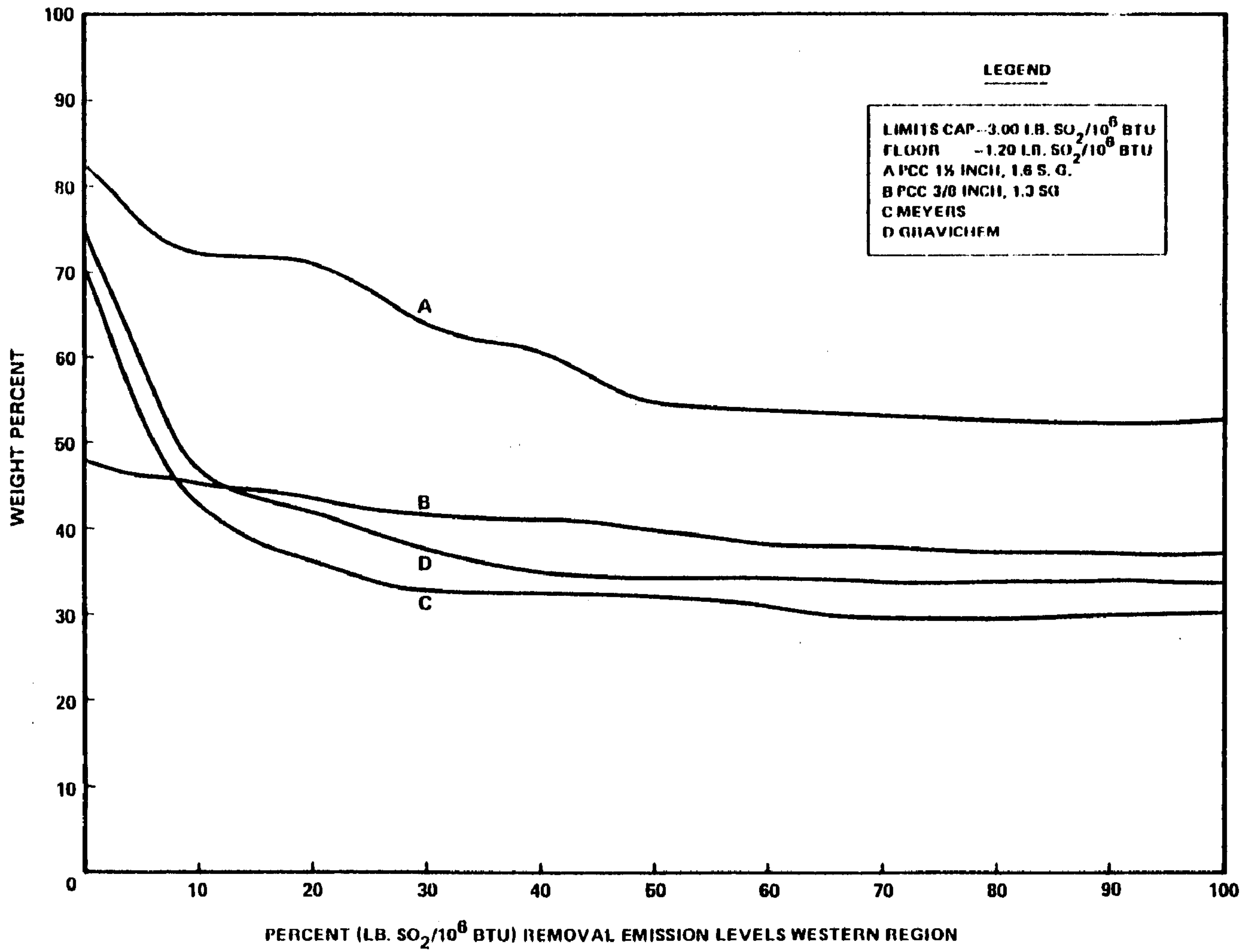


FIGURE 2–80 PERCENT WEIGHT AVAILABLE IN RESERVE BASE AFTER PROCESSING BY VARIOUS TECHNOLOGIES TO MEET A STRINGENT PERCENT SO_2 REMOVAL CONTROL LEVEL

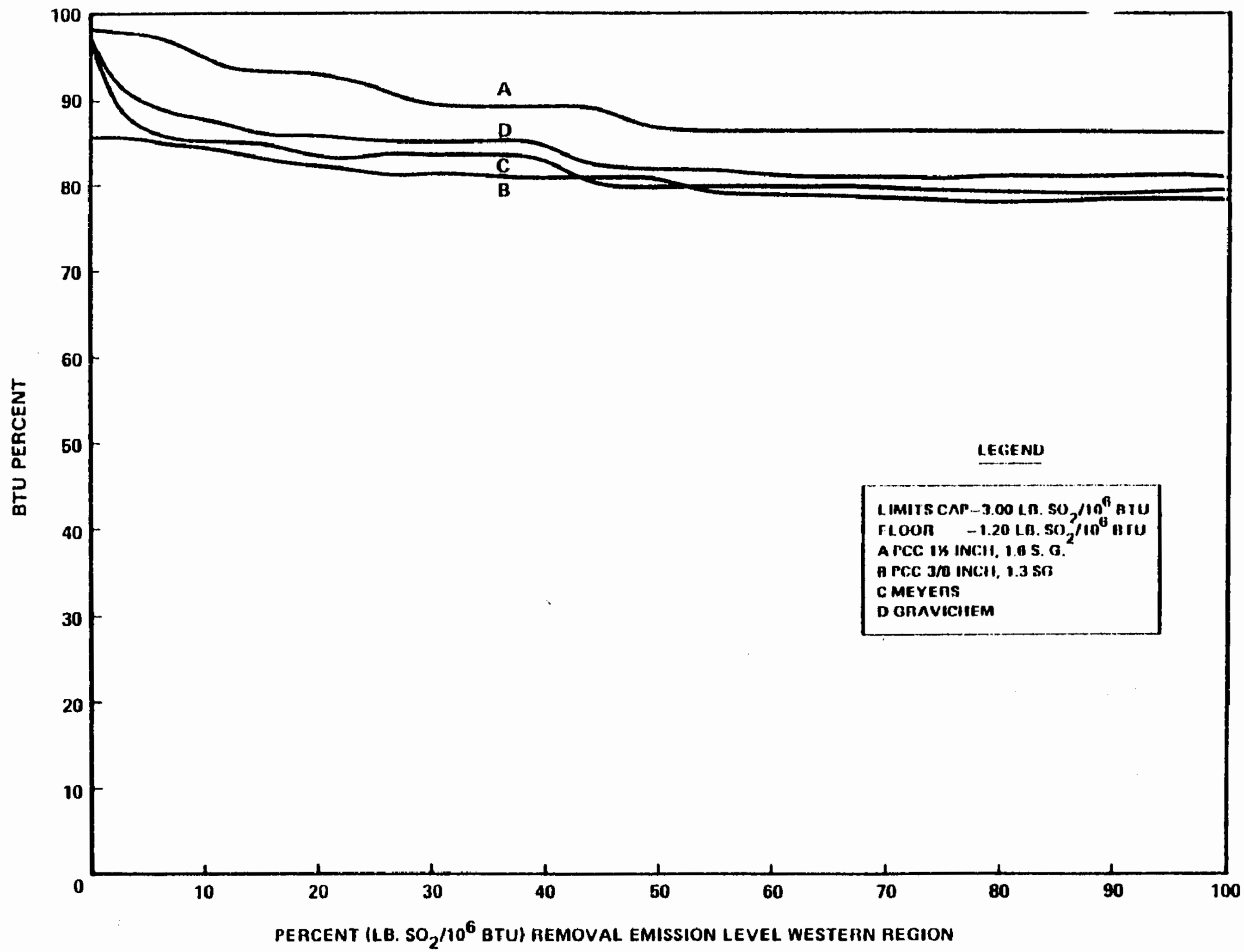


FIGURE 2-81. PERCENT ENERGY AVAILABLE IN RESERVE BASE AFTER PROCESSING BY VARIOUS TECHNOLOGIES TO MEET A MODERATE SO_2 REMOVAL CONTROL LEVEL

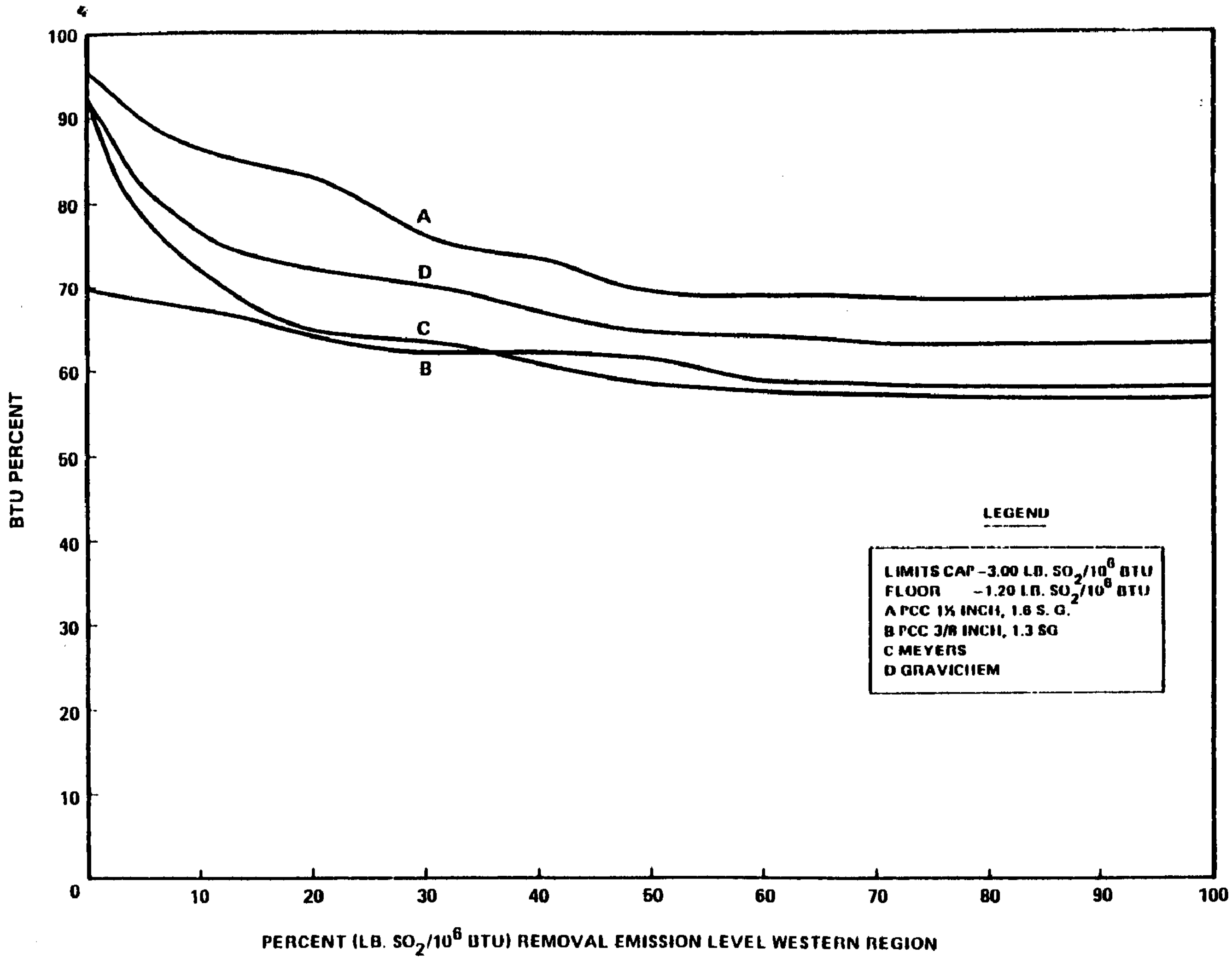


FIGURE 2-82 PERCENT ENERGY AVAILABLE IN RESERVE BASE AFTER PROCESSING BY VARIOUS TECHNOLOGIES TO MEET AN INTERMEDIATE PERCENT SO_2 REMOVAL CONTROL LEVEL

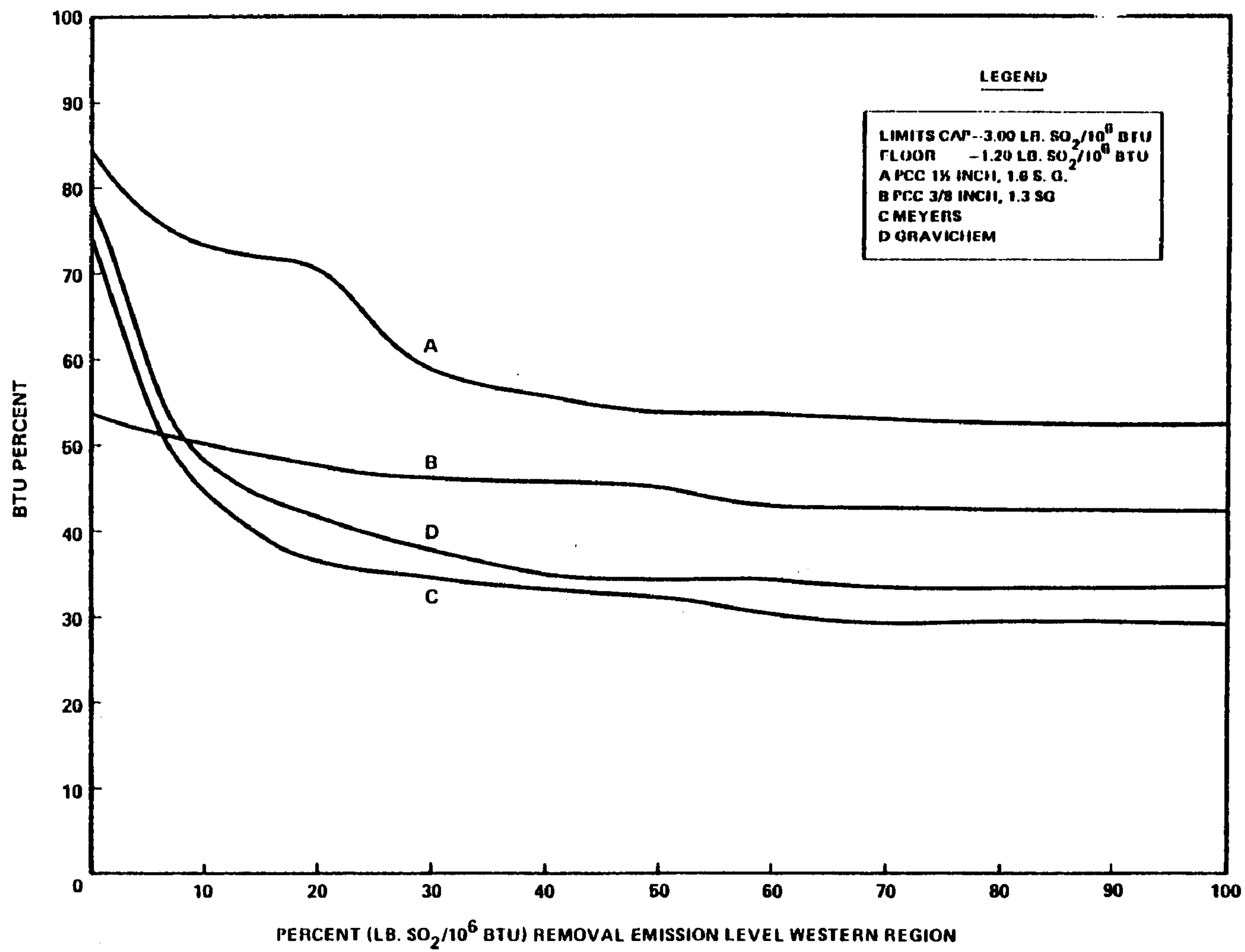


FIGURE 2-83 PERCENT ENERGY AVAILABLE IN RESERVE BASE AFTER PROCESSING BY VARIOUS TECHNOLOGIES TO MEET A STRINGENT PERCENT SO_2 REMOVAL CONTROL LEVEL

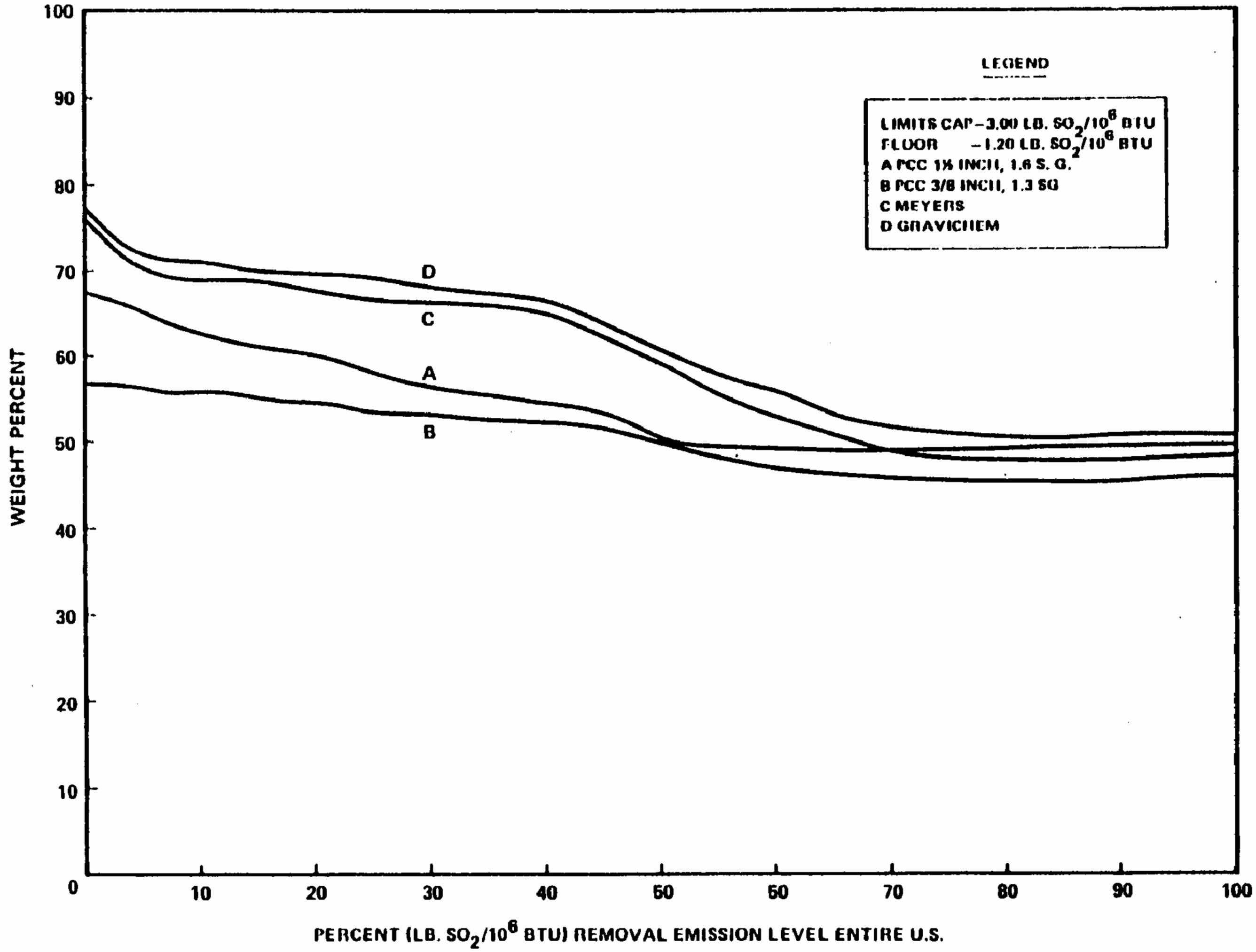


FIGURE 2-84 PERCENT WEIGHT AVAILABLE IN RESERVE BASE AFTER PROCESSING BY VARIOUS TECHNOLOGIES TO MEET A MODERATE PERCENT SO_2 REMOVAL CONTROL LEVEL

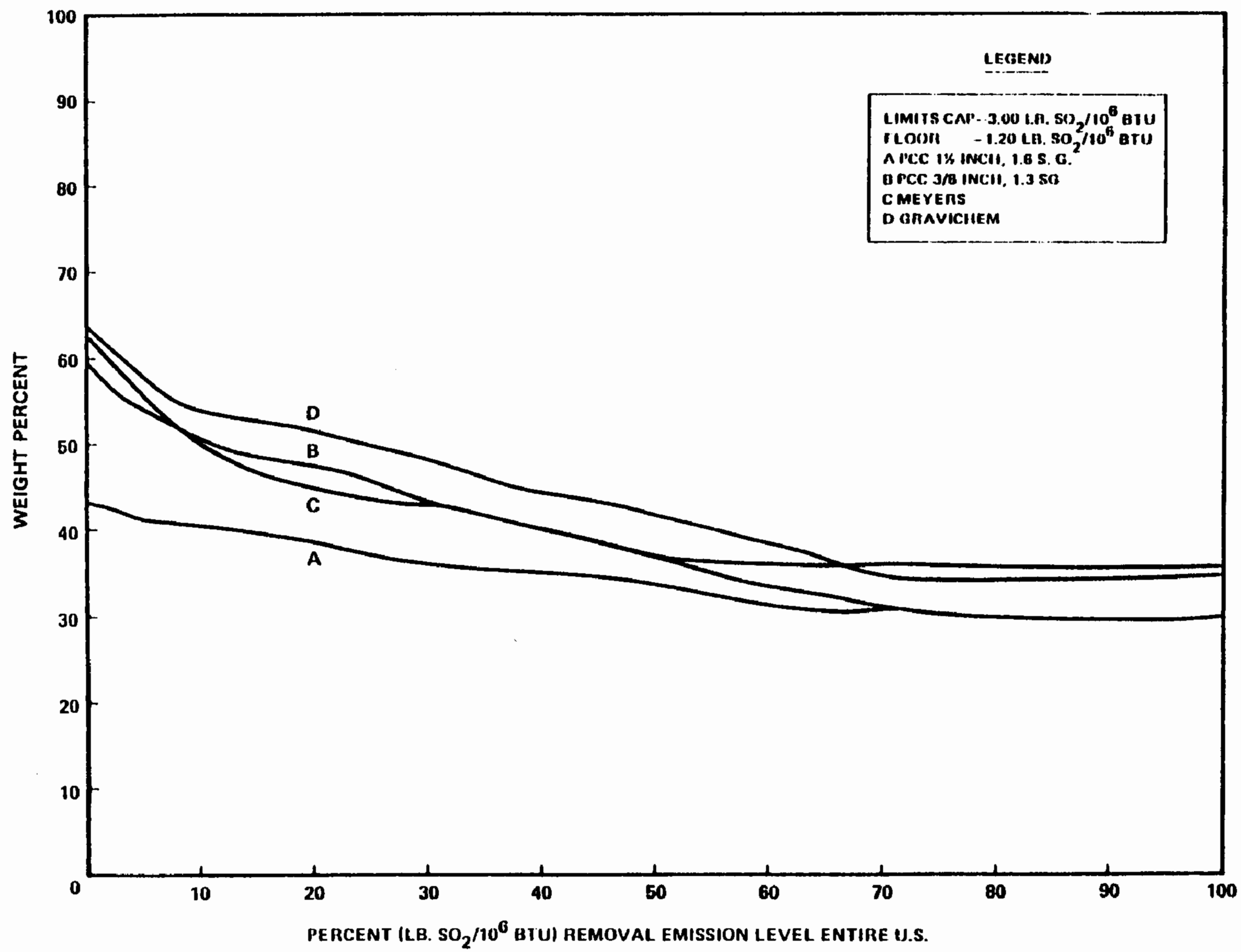


FIGURE 2-85 PERCENT WEIGHT AVAILABLE IN RESERVE BASE AFTER PROCESSING BY VARIOUS TECHNOLOGIES TO MEET AN INTERMEDIATE PERCENT SO_2 REMOVAL CONTROL LEVEL

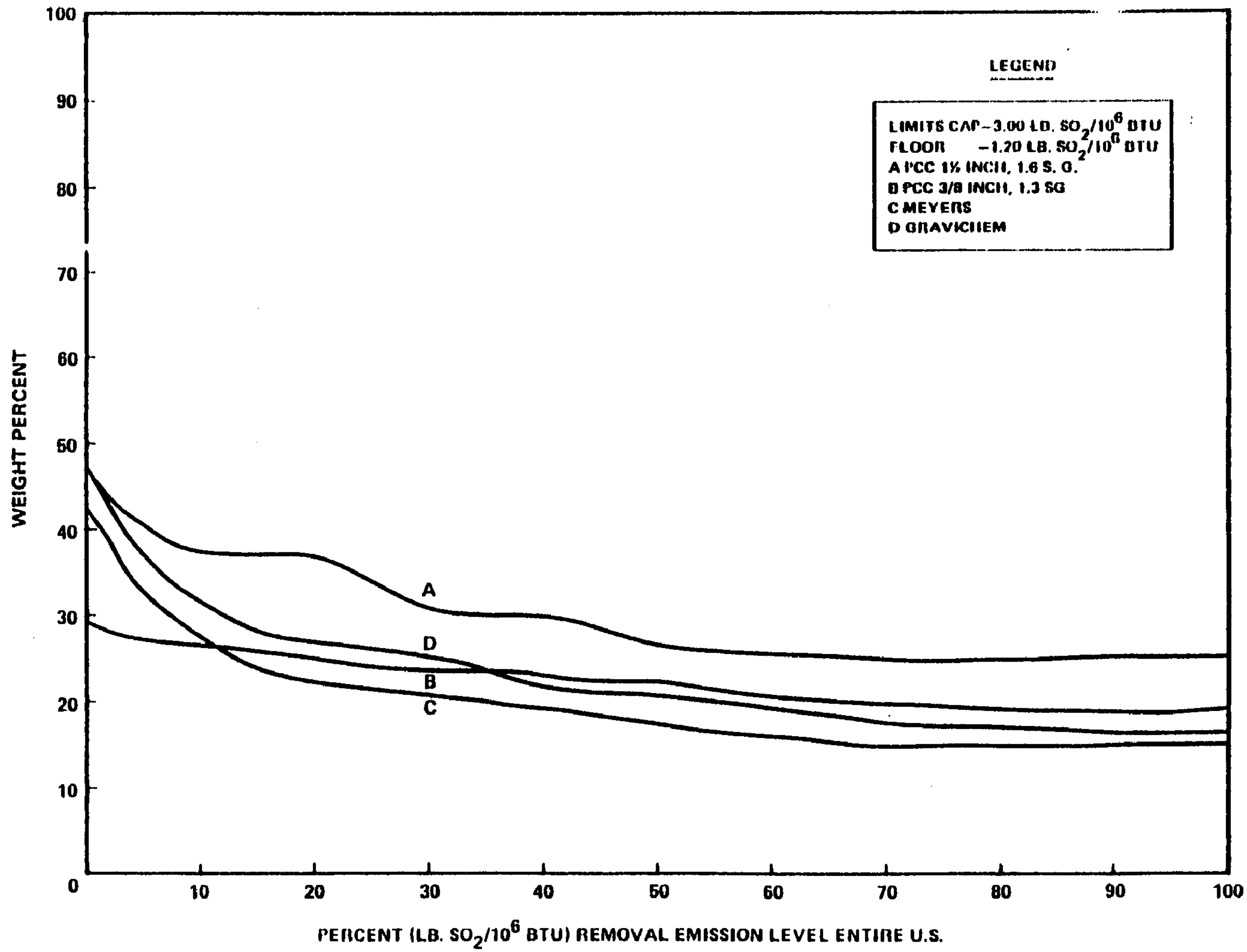


FIGURE 2-86 PERCENT WEIGHT AVAILABLE IN RESERVE BASE AFTER PROCESSING BY VARIOUS TECHNOLOGIES TO MEET A STRINGENT PERCENT SO_2 REMOVAL CONTROL LEVEL

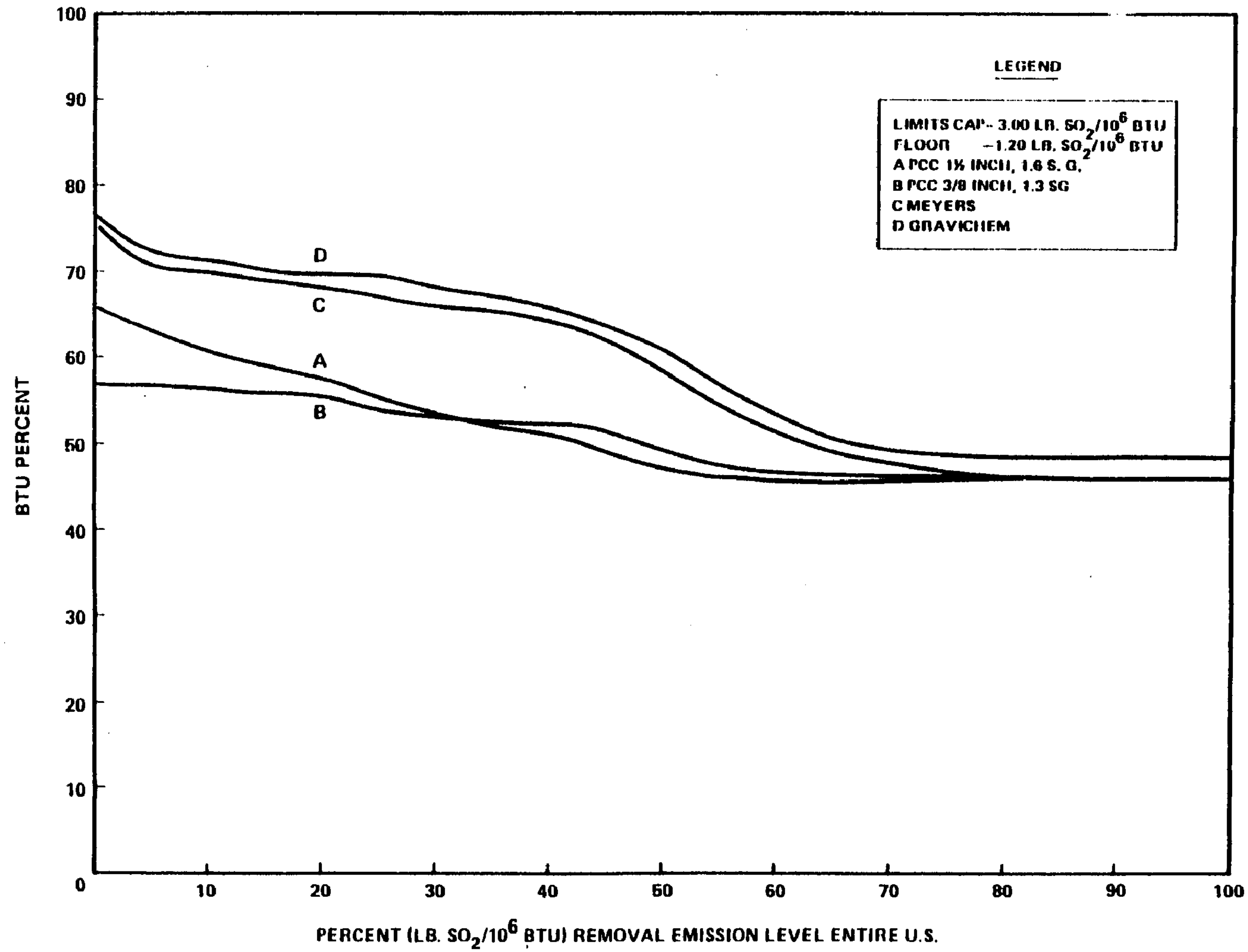


FIGURE 2-87 PERCENT ENERGY AVAILABLE IN RESERVE BASE AFTER PROCESSING BY VARIOUS TECHNOLOGIES TO MEET A MODERATE PERCENT SO_2 REMOVAL CONTROL LEVEL

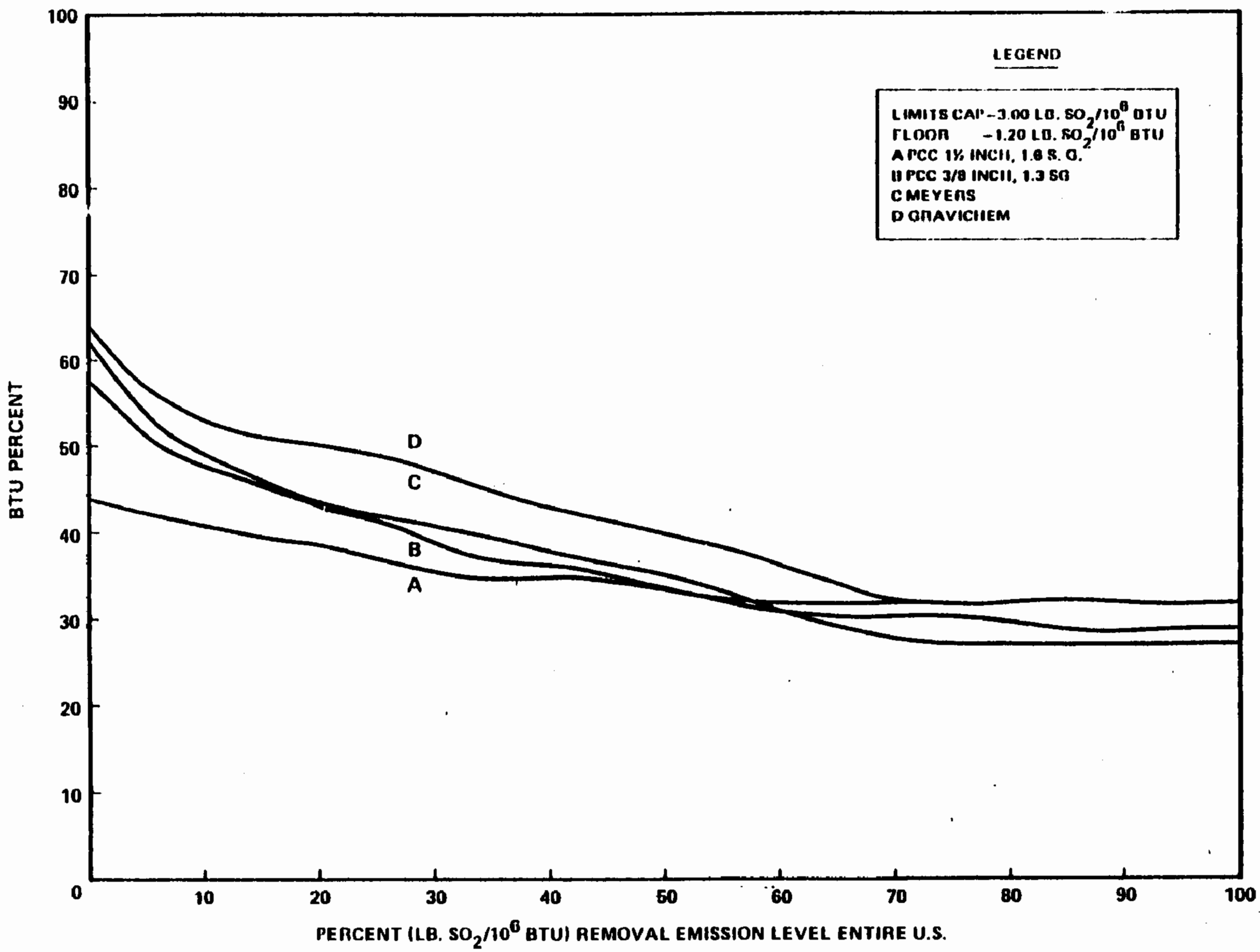


FIGURE 2-88 PERCENT ENERGY AVAILABLE IN RESERVE BASE AFTER PROCESSING BY VARIOUS TECHNOLOGIES TO MEET AN INTERMEDIATE PERCENT SO_2 REMOVAL CONTROL LEVELS

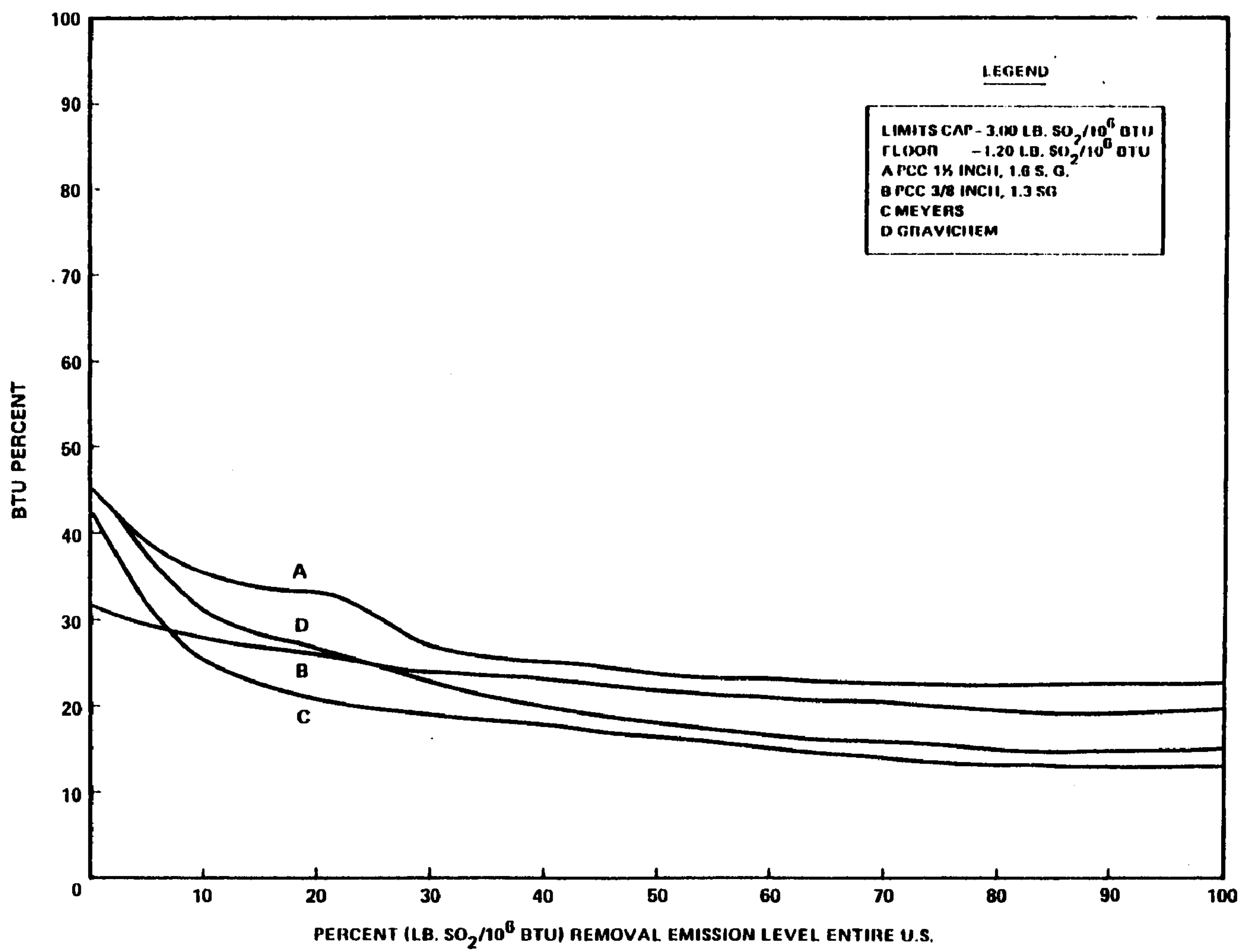


FIGURE 2-89 PERCENT ENERGY AVAILABLE IN RESERVE BASE AFTER PROCESSING BY VARIOUS TECHNOLOGIES TO MEET A STRINGENT PERCENT SO_2 REMOVAL CONTROL LEVEL

at the 90 percent SO_2 reduction level. At the intermediate emission level the available coal decreases from a range of 25-30 percent at 0 percent SO_2 reduction to less than 10 percent of 90 percent SO_2 reduction. At the stringent emission level, the available coal decreases from a level of only 10 to 15 percent at 0 percent SO_2 reduction to less than 3 percent at 90 percent SO_2 reduction. The trends of decreasing available coal are also directly applicable to the chemically cleaned coal in this region as shown on Figures 2-66 to 2-68. The available coal energy in the Northern Appalachian region as shown on Figures 2-69 to 2-71 follows the same general trends as the weight percent of coal.

The Eastern Midwest region has only a minimal reserve base of cleaned coal that can meet even the moderate emission level at 0 percent SO_2 removal. The reserve base estimates of cleaned coal are shown on Figures 2-72 through 2-77. The physically cleaned coal reserve decreases from 15 percent by weight at 0 percent SO_2 removal to less than 5 percent at 80 percent SO_2 removal. The chemically cleaned coal reserve decreases from a range of 30 to 35 percent by weight to less than 5 percent at 80 percent SO_2 removal. At the intermediate emission level the quantity of cleaned coal decreases from a range of 8 to 15 percent at 0 percent removal to less than 3 percent at 70 percent removal. At the stringent emission level the quantity and energy available of the cleaned coal starts out at less than 4 percent at 0 percent removal and decreases to less than 1 percent at 70 percent SO_2 removal.

The Western region has a much larger reserve base of cleaned coal which will meet the three emission control levels. The reason for this is that the Western region contains a large quantity of low sulfur coal which is already below the suggested floor emissions considered for this study. However, it is interesting to note that as shown on Figures 2-78 to 2-83 the quantity and energy of available cleaned coal decreases from the 80 to 90 percent level at the moderate level to less than 40 percent at the stringent level.

The effect of the three emission control levels on cleaned coal from the entire U.S. is shown on Figures 2-84 through 2-89. At the moderate emission limits, the availability of cleaned coal ranges from 55 to 78 percent of 0 percent reduction to 45 to 55 percent at the 80 percent reduction level. At the intermediate emission limits the availability of cleaned coal ranges from 43 to 65 percent at 0 percent reduction to 30 to 35 percent at the 80 percent reduction level. With the stringent level, quantity of cleaned coal decreases from a range of 30 to 48 percent at 0 percent reduction to 15 to 25 percent at 80 percent reduction.

The conclusion drawn from the above data is that alternative regulatory options will have a great effect on the availability of coal resources in this country for industrial boilers.

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SECTION 3.0

"BEST" SYSTEMS OF EMISSION REDUCTION

3.1 CRITERIA FOR SELECTION

In the ensuing discussion of emission control technologies, candidate technologies are compared using three emission control levels labelled "moderate, intermediate, and stringent." These control levels were chosen only to encompass all candidate technologies and form bases for comparison of technologies for control of specific pollutants considering performance, costs, energy, and non-air environmental effects.

From these comparisons, candidate "best" technologies for control of individual pollutants, i.e., Best Systems of Emission Reduction (BSER), are recommended by the contractor for consideration in subsequent industrial boiler studies. These "best technology" recommendations do not consider combinations of technologies to remove more than one pollutant and have not undergone the detailed environmental, cost, and energy impact assessments necessary for regulatory action. Therefore, the levels of "moderate, intermediate, and stringent" and the recommendation of "best technology" for individual pollutants are not to be construed as indicative of the regulations that will be developed for industrial boilers. EPA will perform rigorous examination of several comprehensive regulatory options before any decisions are made regarding the standards for emissions from industrial boilers. Within this ITAR, the BSER may be a naturally occurring compliance coal, a physical coal cleaning process, or a chemical coal cleaning process.

3.1.1 Operating Factors

Five criteria for selecting the BSER are applied: performance and applicability; preliminary cost; status of development; preliminary energy use; and preliminary environmental considerations. The descriptor "preliminary" signifies that the values are based on previous studies of a general nature and should be considered only as order-of-magnitude values. After selecting the BSER, more detailed analyses of cost (Section 4.0), energy use (Section 5.0), and environmental impact (Section 6.0) will be developed. For determination of the BSER, the first two criteria, performance and cost, will be weighted more than the other three, status, environmental impacts, and energy use.

3.1.1.1 Performance and Applicability--

Performance is given the most weight of the five operating factor elements in selecting a BSER. Performance relative to industrial boilers applies to control of particulates, sulfur dioxide, and nitrogen oxide emissions. Particulate emissions will require in-stack control devices because no naturally occurring or cleaned coal is ash-free. Physically cleaned coal does contain less ash, thereby reducing the particulate emission control requirements. However, this reduction will not be considered a major factor in determining the BSER performance.

The majority of nitrogen in the nitrogen oxide emissions from industrial boilers originates from the combustion air aupply. The control technologies studied in this ITAR have no effect on the amount of air delivered to the boiler. Physical coal cleaning does not reduce the inherent nitrogen content in the fuel itself; although chemical coal cleaning may reduce the inherent nitrogen content of the coal, the available results are inconclusive. Therefore, nitrogen oxide reduction capabilities will not be considered among the performance factors.

Physical and chemical coal cleaning can significantly increase the coal's energy content and reduce sulfur content in the ash and pyrite removal process. For certain coals this simultaneous BTU enhancement and sulfur removal capability can produce significant reductions in sulfur dioxide emissions. Combustion of a naturally-occurring low sulfur coal rather than high sulfur coal may also substantially reduce SO_2 emissions from existing industrial boilers.

In this report we generally refer to the emissions of sulfur in terms of the mass of SO_2 emitted per unit of combustion energy in the coal (ng SO_2/J or lb $SO_2/10^6$BTU), as is done in EPA's proposed New Source Performance Standards (NSPS) for utility boilers. This emission factor is used for both maximum allowable SO_2 emissions and the percentage of SO_2 removal. This basis reflects the wide range of heating values (kJ/kg or BTU/lb) among coals.

3.1.1.2 Preliminary Cost--

Cost is considered an important criterion for selecting a BSER for a particular coal and emission control level once performance is demonstrated.

Preliminary costs used here are historical costs, referring to a generic type of control system. For example, there are generic costs for Level 4 (process levels as defined in Section 2.0, pp. 120 through 134 physical coal cleaning plants. These costs, rather than the costs associated with a detailed analysis of a particular system configuration, will be used in judging a Level 4 cleaning plant as a candidate BSER.

Preliminary transportation costs are estimated by matching seven supply coals and six demand centroids. The seven supply coals include six low sulfur coals (see Section 3.2.1.1) and one high sulfur coal—a bituminous coal from Butler, Pennsylvania. The selected destinations are industrial cities within the six states that have the greatest industrial energy demand:

- Austin, Texas
- Harrisburg, Pennsylvania
- Columbus, Ohio
- Baton Rouge, Louisiana
- Sacramento, California
- Springfield, Illinois

Transportation of coal presently includes two modes, rail and barge; the use of slurry pipelines may begin sometime during the coming decade.

The main cost components for cleaned coals are the spot market F.O.B. mine price; the coal cleaning charge, which is a function of the type and level of cleaning; and transportation costs. The characteristics of the raw coal and the desired product must be investigated before designing a cleaning plant and estimating the costs. In general, the finer a coal is crushed, the more impurities are liberated. As the coal size is reduced, the coal plant for cleaning and dewatering the fines becomes more complex and, therefore, more costly. The transportation costs in dollars per unit of combustion energy are lower for cleaned coal (more so for physically cleaned than chemically-cleaned coal) because cleaning the coal reduces its weight per unit heat input.

3.1.1.3 Status of Development--

Status of development is defined as the commercial availability of the control technology. For naturally occurring coal, both the ability to profitably mine a given coal seam and the relation of supply and demand influence the status of the coal. For purposes of discussion and selection of BSER, it is assumed that the reference coals can be profitably mined and are available on the spot market.

A number of physical coal cleaning (PCC) processes are commercially available, as discussed in Section 2.0. A candidate PCC plant configuration will be considered available, even though no such plant exists. Less consideration is given to any plant configuration which uses present technology beyond its current application. There are some experimental PCC processes which are not commercially available (see Section 2.2.2.1); they are not considered in this section.

Chemical coal cleaning plants are presently in the research and development stage. Some pilot plant tests have been performed on several processes, and testing is continuing. Present estimates are that chemical coal cleaning plants are about 5-10 years from commercialization.[1] More weight will be given to those processes at the pilot plant stage which have plans for commercialization than to bench-scale processes.

3.1.1.4 Preliminary Energy Use--

Energy use is defined here as the energy required to implement a control technology. Only pre-combustion activities, excluding mining, are considered in selecting a BSER.

For naturally occurring low sulfur coals the primary energy use is in coal transportation. The breakdown by mode of transport for the total amount of coal produced in the U.S. in 1975 is given in Table 3-1.

As may be seen from the table, rail transport consumes petroleum-fuel energy at the rate of approximately 1.44×10^5 J per metric ton-km (200 BTU per ton mile), excluding the energy used for return rail hauls and for operations related to loading and unloading. Including the energy used in those activities raises the average energy consumption of delivered coal to

Table 3-1 TRANSPORTATION OF U.S. COAL PRODUCED IN 1975 [2]

Mode of Transport*	Mass of Coal Moved (10^3 kkg)
Rail	379.60
Barge	62.72
Truck	79.36
Other**	74.29
Total Production	588.70

* Leaving the mine. In some cases coal initially moved by rail is transshipped to a barge for final delivery to the consumer.

** Includes coal moved by conveyor belt to mine-mouth power plants, coal used at mine for power or heat and other miscellaneous uses, and coal shipped by slurry pipeline to the Black Mesa Mine in Arizona.

2.52×10^5 J per metric ton-km (366 BTU per ton-mile).[3] The most energy-efficient mode of transporting coal occurs on waterways: by barge on inland rivers and by ship on ocean or Great Lakes routes. Barges, on the average, consume approximately 2.12×10^5 J per metric ton-km (296 BTU per ton-mile) of delivered coal, with some variation depending on the angle between the velocity of the barge and the velocity of the water current.

For physically and chemically cleaned coal, the energy use is a combination of cleaning requirements and transportation. The energy used for cleaning is primarily the energy lost in the rejects. The operations that use significant amounts of energy are pulverizing, dewatering, and thermal drying.

3.1.1.5 Preliminary Environmental Considerations--

One of the main objectives of coal preparation is to reduce the quantity of pollutants in coal that is burned. Coal preparation involves, however, the transfer of potential pollutants from one segment of the environment to another: a fraction of the pollutants that would be emitted to air during the burning of raw coal become incorporated mainly into solid refuse, a state in which the pollutants may be easier to control.

The major potential sources of environmental contamination from coal preparation that will be assessed include: coal refuse disposal areas (solid waste), thermal dryers (air pollution), liquid effluent streams (water pollution), coal storage and handling (fugitive dust and runoff), and coal transportation (fugitive dust).

The disposal of coal cleaning plant waste is a potentially serious problem. Coal refuse consists of waste coal, slate, carbonaceous and pyritic shales, and clay associated with the coal seam. It varies considerably in physical and chemical characteristics depending on both its source and the nature of the preparation process.

The weathering and leaching of coal refuse dumps produces several types of water pollution. These include silt, acids, and other dissolved mineral matter. Refuse from chemical coal cleaning plants have additional chemical constituents due to the solvents used in removing sulfur during the cleaning processes.

Siltation from coal refuse dumps is caused by finely divided coal, minerals and discarded soil. Acid drainage is produced when iron sulfides are exposed to air and water. The sulfur is oxidized to sulfuric acid, and the iron is solubilized as iron sulfate. The acids formed run off into drainage ditches or percolate through the pile, where considerable mineral matter may be dissolved. The volume of wastewater from a refuse disposal area is highly dependent on precipitation and surface water flow patterns.

In contrast to the highly acidic nature of drainage from coal fields in eastern and interior regions, the runoff from western coal refuse disposal is usually alkaline. The dominant water contaminants are calcium, magnesium, and sodium salts. The low concentrations of iron and sulfates are direct results of the low concentrations of pyritic material in western coal. Furthermore, the annual precipitation in western coal fields is generally low, so that the chances of significant drainage of water through the waste materials are remote.

Potential air pollutants associated with physical coal cleaning are particulate emissions, and to a lesser extent SO_2, and fugitive coal dust. Chemical coal cleaning processes, however, produce additional air pollutants including NO_x and CO and fine particulates. The fine particulate and SO_2 emissions from both physical and chemical processes are largely caused by the thermal drying process.[4]

Coal cleaning operations produce two types of water pollutants: suspended materials and dissolved substances. The effluent streams from physical and chemical cleaning processes contain similar concentrations of suspended solids. However, dissolved substances from a chemical cleaning plant would contain small amounts of the solvents used. These solvents may also dissolve other mineral compounds and metal ions contained in the coal, thus changing the chemical characterization of the waste stream.

The principal air pollutant from storage, transportation and handling of naturally occurring and cleaned coal—especially thermally dried cleaned coal—is fugitive dust. The amount of dust generated varies widely depending on such factors as climate, topography, and characteristics of coal.

Another environmental consideration associated with coal storage is coal pile leachate contaminating ground water supplies. Outdoor coal storage piles have large surface areas and long residence times allowing rainwater to react and form acids or extract sulfur compounds and soluble metal ions. Coal pile leachate is generally similar to acid mine drainage. The quantity of coal pile leachate is highly variable depending upon the coal residence time, the topography and drainage area of the coal pile site, the configuration and volume of the stock pile, and the type and intensity of precipitation.

3.1.2 Selection of Regulatory Options

A set of SO_2 emission control levels is used to judge the performance of the candidate control options. Since the control technologies considered in this ITAR reduce neither nitrogen oxide nor particulate emissions from industrial boilers to a level comparable to current particulate control technology, emission levels are not considered for these pollutants.

The SO_2 emission levels chosen to evaluate naturally occurring low sulfur coal and physical and chemical coal cleaning control technologies are: 1) stringent--516 ng SO_2/J (1.2 lbs $SO_2/10^6$ BTU), 2) intermediate--645 ng SO_2/J (1.5 lbs $SO_2/10^6$ BTU), 3) optional moderate--860 ng SO_2/J (2.0 lbs $SO_2/10^6$ BTU), 4) moderate--1,290 ng SO_2/J (3.0 lbs $SO_2/10^6$ BTU), and 5) the State Implementation Plan (SIP)--1,075 ng SO_2/J (2.5 lbs $SO_2/10^6$ BTU).

The selected levels specified in this ITAR are based upon long term averages of SO_2 emitted per unit of combustion energy.

Stringent Level of Control--

The most stringent level of control chosen for evaluation of the three control technologies is 516 ng SO_2/J (1.2 lbs $SO_2/10^6$ BTU). It is selected for two reasons. The primary reason relates to the amount of potentially available coal in each region and the total U.S., based upon the reserve base assessments discussed in Section 2.0 and shown in summary Tables 3-2 and 3-3. These assessments show in a very forceful way that the available raw coal and physically and chemically cleaned coal below an emission level of 516 ng SO_2/J (1.2 lbs $SO_2/10^6$ BTU) decrease drastically. At this emission level, the amount of energy available for the entire U.S. was estimated to be only 38% for naturally occurring coal, 50% and below for physical coal cleaning processes, and 59% and below for chemical coal cleaning processes. The second reason for choosing this level is that it is currently the NSPS (New Source Performance Standard) emission limit for utility boilers greater than approximately 75 MWs. It therefore represents an existing achievable level for large scale boilers.

Intermediate Level of Control--

The intermediate level of control chosen for evaluation of the three control technologies is 645 ng SO_2/J (1.5 lbs $SO_2/10^6$ BTU). The rationale for the selection of this level is based upon the amount of potentially available coal estimated by the reserve base assessment and shown in summary Tables 3-2 and 3-3. This emission level illustrates a breakpoint in the reserve quantity curves for physically and chemically cleaned coal in the regions and throughout the U.S. For example, the Southern Appalachian and Alabama regions have much less energy available as either physically or chemically cleaned coal at the 645 ng SO_2/J (1.5 lbs $SO_2/10^6$ BTU) level.

"Optional" Moderate Level of Control--

The "optional" moderate level of control chosen, 860 ng SO_2/J (2.0 lbs $SO_2/10^6$ BTU), reflects a breakpoint in potentially available coal (and therefore the amount of energy available) for the Southern Appalachian and Western regions from raw coal, physically cleaned coal, or chemically cleaned coal. The Alabama region also shows a breakpoint in potentially available coal at the "optional" moderate level, but only for chemical coal cleaning.

Moderate Level of Control--

The moderate level of control chosen, based upon current practices of the industry, is 1,290 ng SO_2/J (3.0 lbs $SO_2/10^6$ BTU). The selection of this level is based upon the amount of potentially available coal from physical cleaning processes shown on Table 3-2.

TABLE 3-2.

WEIGHT PERCENT OF U.S. REGIONAL COAL RESERVE BASE AVAILABLE AT VARIOUS SO_2 EMISSION LIMITS FOR RAW AND PHYSICALLY CLEANED COAL (5)

	344 (0.8)*			516 (1.2)*			645 (1.5)*			860 (2.0)*			1,075 (2.5)*			1,290 (3.0)*		
	A	B	RAW	A	B	RAW	A	B	RAW	A	B	RAW	A	B	RAW	A	B	RAW
N. APPALACHIA	4	13	1	12	24	6	20	35	10	30	47	15	41	58	24	50	66	31
S. APPALACHIA	23	28	9	64	67	53	81	82	75	86	88	82	91	93	90	93	94	92
ALABAMA	7	7	6	36	41	29	55	66	48	72	82	68	90	94	74	93	96	90
E. MIDWEST	1	1	1	3	3	2	4	6	2	9	11	5	13	17	8	18	25	10
W. MIDWEST	4	5	0	5	11	6	6	13	6	13	18	11	17	20	13	20	23	16
WESTERN	70	71	45	85	85	70	92	92	85	97	96	90	97	97	95	98	98	96
ENTIRE U.S.	36	40	24	50	53	41	55	60	48	60	66	55	65	69	58	69	73	63

PERCENT ENERGY AVAILABLE OF U.S. REGIONAL COAL RESERVE BASE AT VARIOUS SO_2 EMISSION LIMITS FOR RAW AND PHYSICALLY CLEANED COAL

	344 (0.8)*			516 (1.2)*			645 (1.5)*			860 (2.0)*			1,075 (2.5)*			1,290 (3.0)*		
	A	B	RAW	A	B	RAW	A	B	RAW	A	B	RAW	A	B	RAW	A	B	RAW
N. APPALACHIA	5	13	1	12	28	8	20	35	10	31	48	15	42	60	26	52	70	32
S. APPALACHIA	24	29	9	66	69	54	80	85	72	90	93	84	94	94	90	94	95	90
ALABAMA	6	6	7	37	42	29	63	73	46	72	82	69	90	94	75	93	96	90
E. MIDWEST	2	2	0	3	3	1	5	7	3	9	12	6	12	19	8	18	26	10
W. MIDWEST	3	4	0	7	13	7	9	15	9	15	20	10	20	22	14	22	25	18
WESTERN	70	71	45	85	85	71	94	94	82	96	97	90	97	97	94	98	98	98
ENTIRE U.S.	32	36	20	47	50	38	54	59	45	59	62	52	64	68	56	68	75	60

A - PCC 1-1/2 inch, 1.6 S.G.
B - PCC 3/8 inch, 1.4 or 1.3 S.G.
* Emission limits are in ng SO_2/J (lbs $SO_2/10^6$ BTU)

TABLE 3-3.

WEIGHT PERCENT OF U.S. REGIONAL COAL RESERVE AVAILABLE AT VARIOUS SO_2 EMISSION LIMITS FOR RAW AND CHEMICALLY CLEANED COAL (5)

	344 (0.8)*				516 (1.2)*				645 (1.5)*				860 (2.0)*				1,075 (2.5)*				1,290 (3.0)*			
	C	D	E	RAW	C	D	E	RAW	C	D	E	RAW	C	D	E	RAW	C	D	E	RAW	C	D	E	RAW
N. APPALACHIA	5	9	17	1	21	26	36	6	35	42	50	10	53	58	65	15	67	68	76	24	79	81	85	31
S. APPALACHIA	19	25	46	9	59	67	80	53	74	83	88	75	90	90	94	82	93	95	98	90	98	98	99	92
ALABAMA	7	7	31	6	46	47	75	29	79	85	94	48	95	96	98	68	98	98	98	74	99	99	99	90
E. MIDWEST	2	2	4	1	4	4	9	2	8	9	14	2	15	15	20	5	22	22	37	8	36	32	61	10
W. MIDWEST	2	8	11	0	14	17	18	6	16	17	22	6	26	24	29	11	41	37	51	13	50	46	62	16
WESTERN	59	64	77	45	79	80	89	70	84	85	93	85	93	93	97	90	96	96	98	95	99	98	99	96
ENTIRE U.S.	31	35	45	24	49	51	59	41	55	60	65	48	64	67	72	55	71	74	77	58	78	80	85	63

PERCENT ENERGY AVAILABLE OF U.S. REGIONAL COAL RESERVE BASE AT VARIOUS SO_2 EMISSION LIMITS FOR RAW AND CHEMICALLY CLEANED COAL

	344 (0.8)*				516 (1.2)*				645 (1.5)*				860 (2.0)*				1,075 (2.5)*				1,290 (3.0)*			
	C	D	E	RAW	C	D	E	RAW	C	D	E	RAW	C	D	E	RAW	C	D	E	RAW	C	D	E	RAW
N. Appalachia	6	9	18	1	13	19	28	8	31	36	45	10	55	56	65	15	65	68	77	26	81	82	88	32
S. Appalachia	19	26	48	9	60	69	81	54	79	83	87	72	88	90	94	84	94	96	98	90	98	98	99	90
Alabama	8	8	32	7	48	49	76	29	70	78	90	46	92	97	99	69	98	98	98	75	99	99	99	90
E. Midwest	1	1	4	0	4	5	10	1	6	9	13	3	14	14	20	6	21	21	34	8	39	34	55	10
W. Midwest	3	9	14	0	15	18	19	7	19	20	22	9	30	25	32	10	41	35	49	14	52	49	61	18
Western	59	65	79	45	80	81	90	71	88	88	94	82	94	93	96	90	98	98	99	94	99	99	99	98
Entire U.S.	28	32	42	20	46	49	57	38	55	57	63	45	64	64	69	52	70	70	78	56	79	78	84	60

C - Meyer's Process
D - Gravichem
E - .95 Py.S./.20 Org. S. Removal
* Emission units are in ng SO_2/J (lbs $SO_2/10^6$ BTU)

This emission level would make available more than 90% of both raw coal and physically and chemically cleaned coal from the Southern Appalachian, Alabama, and Western regions. High emission levels are needed to allow appreciable amounts of eastern and midwestern raw coals to comply.

SIP Level of Control--

The SIP level of control was supplied in an August 29, 1978 memorandum from Acurex Corporation: 1,075 ng SO_2/J (2.5 lbs $SO_2/10^6$ BTU). At this emission level, the amounts of both raw coal and physically and chemically cleaned coal from the Southern Appalachian, Alabama, and Western Regions reach a peak and begin to level off with only small increases thereafter.

3.2 BEST SYSTEMS OF EMISSION REDUCTION (BSER)

3.2.1 Description of Candidate BSERs

This section provides the rationale for choosing the candidate BSERs and presents the selections. The methodology is to evaluate the major characteristics of the available control technologies relative to the five operating factors presented in Section 3.1.1 and the regulatory options chosen in Section 3.1.2.

The candidate BSERs will then be compared and a BSER chosen in Section 3.2.2 for each reference coal and regulatory option combination.

3.2.1.1 Candidate Naturally Occurring Coals--

In this section we introduce the set of reference high- and low sulfur coals which were chosen (based on engineering judgment) as representative of the myriad of coals available to the industrial boiler operator. A greater variety of low sulfur western coals were considered candidates because of their ability to meet lower sulfur dioxide emission levels and their lower costs. The candidates are:

- High .ulfur bituminous coal from Butler, Pennsylvania;
- Bituminous coal from Buchanan, Virginia;
- Subbituminous coal from Gillette, in northern Wyoming;
- Bituminous coal from Las Animas, Colorado;
- Lignite from Williston, North Dakota;
- Bituminous coal from Rock Springs, in southern Wyoming; and
- Subbituminous coal from Gallup, New Mexico

Of these seven coals, the first three are the reference coals chosen to represent the coals used by PEDCo in developing parameters for standard boilers.[6] The remaining candidates have been selected to represent typical low sulfur coals from various western locations. The major relevant characteristics of these coals are summarized in Table 3-4.

Performance

Many alternatives for the supply of naturally occurring coal are available to meet environmental constraints. The criteria for determining which (low sulfur) coals from which region will be able to comply with a given SO_2 emission control level include the coal's estimated sulfur content, ash content, and heating value. These characteristics influence a coal's combustion properties and the degree to which sulfur oxides and other pollutants are generated in the boiler. The level of these pollutants and the eventual concentration of emissions in the atmosphere may then be reduced by the use of other control technologies.

Each candidate low sulfur coal can comply with only certain environmental constraints. Table 3-5 compares, for each coal, the level of uncontrolled SO_2 emissions per unit energy of coal burned with three alternative SO_2 emission levels. In general, stringent control levels can be met only by select low sulfur coals of subbituminous or higher rank. Coal with a sulfur content of one percent must have an energy content exceeding about 31 x 10^6 J/kg (14,000 BTU/lb) to meet the stringent control level, assuming that the sulfur contained by the boiler (bottom ash) is approximately 15 percent of that originally in the coal. From both Tables 3-4 and 3-5 we see that the western coals from Las Animas, Colorado and Rock Springs, Wyoming are the only candidates that meet the stringent control levels.

Intermediate control levels may be met by low sulfur coals of subbituminous or higher rank. Coal with a sulfur content of one percent must have an energy content of more than about 26 x 10^6 J/kg (11,000 BTU/lb) to meet intermediate control levels, assuming that the sulfur retained by the bottom ash is approximately 15 percent of that originally in the coal.

TABLE 3-4. CHARACTERISTICS OF CANDIDATE LOW-SULFUR COALS

	Low-Sulfur Coals					
	Buchanan, Va. (B)*	Los Animas, Colo. (B)	Williston, N. Dak. (L)	Rock Springs, Wyo. (B)	Gillette, Wyo. (SB)	Gallup, N.M. (SB)
Heating Value						
10^6 J/Kg	31.7	26.3	16.3	26.7	19.8	23.3
(Btu/lb)	(13,620	(11,290)	(7,000)	(11,500)	(8,500)	(10,000)
Sulfur Content						
% Total	1.18	0.59	0.80	0.80	0.70	0.80
Ash Content						
%	10.38	24.81	6.8	9.0	8.1	9.4
Moisture % as received	2.0	2.5	35	11	30	10
Volatile Matter %	13	12	12	15	29	19
Fixed Carbon %	75	62	46	65	33	62
Hydrogen %	4.8	3.9	6.2	5.0	4.5	5.0
Oxygen %	5.9	6.1	39	21.5	27.9	21.5
Nitrogen %	1.4	1.2	0.70	0.10	0.75	1.0

Note: B = Bituminous; SB = Subbituminous; L = Lignite.
* These coals are analyzed as candidates for coal cleaning.

TABLE 3-5. COMPARISON OF UNCONTROLLED EMISSIONS FROM CANDIDATE LOW-SULFUR COALS WITH ALTERNATIVE ENVIRONMENTAL CONTROL LEVEL (ng/J)

	Environmental Control Level ∂			
Candidate Coals	Moderate (1,290 ng SO_2/J)	"Optional" Moderate (860 ng SO_2/J)	Intermediate (645 ng SO_2/J)	Stringent (516 ng SO_2/J)
Butler, Pa. (B) ∝	2,060ϕ			
Buchanan, Va. (B) ∝		707		
Las Animas, Colo. (B) ∝				381
Williston, N.Dak. (L)		835		
Rock Springs, Wyo. (B)				508
Gillette, Wyo. (SB)			602	
Gallup, N.M. (SB)			584	

Note: B = Bituminous; SB = Subbituminous; L = Lignite.

∂ Assumed fraction of sulfur in the bottom ash: 5 percent for bituminous coal, 15 percent for all other coals.

∝ These coals are analyzed as candidates for coal cleaning.

ϕ Does not comply with moderate control level

Table 3-5 shows that the low-ranking coal from Gillette, Wyoming (with 19.8×10^6 J/kg, 0.70 %S) and the subbituminous coal from Gallup, New Mexico (23.3×10^6 J/kg, 0.80 %S) both meet the intermediate control level.

"Optional" moderate and moderate control levels may be achieved by low sulfur coals of nearly any rank, including lignites. Coal with a sulfur content of one percent must have an energy content exceeding only about 13.1×10^6 J/kg (5,666 BTU/lb) to meet moderate control levels for the same boiler assumption given above. The bituminous coal from Buchanan, Virginia, and the lignites from Williston, North Dakota, meet the "optional" moderate control level, while the high sulfur eastern coal from Butler, Pennsylvania exceeds the moderate control level.

Cost

F.O.B. mine prices (both term and spot prices) are shown in Table 3-6 for the reference coals. Except where indicated otherwise, these are May, 1978 prices.(7) Shipping costs are estimated from indices provided by the Bureau of Labor Statistics for railroad coal transport from 1969 through 1978. Through the use of these indices, the shipping cost for a metric ton of coal was estimated at $6.87/metric ton ($6.23/ton) for a 245-mile transport by rail.

Status

It is assumed that the reference coals are available and can be profitably mined.

Energy Impacts

Coal is a fuel of relatively low energy density compared with oil or gas. Hence, the energy consumed per unit of combustion energy in transporting coal is relatively greater.

Table 3-7 illustrates the energy consumed in transportation on two bases: (1) as the energy consumed per unit of mass of coal, and (2) as a fraction of the potential energy obtained by combustion of the coal. The computations are made for two very different coals, a local bituminous coal and a western subbituminous coal, delivered to a plant in Illinois

Table 3-6. F.O.B. MINE PRICES OF SELECTED LOW SULFUR COALS

Supply Area	F.O.B. Bid Prices - $1978 [α] Term $/ton	Term $/GJ ($/10⁶ BTU)	Spot $/ton	Spot $/GJ ($/10⁶ BTU)
Central Appalachia (WV, KY, TN, VA) e.g., Buchanan, VA	22.00	0.99 (0.94)	29.00	1.11[ə] (1.05)
Northern Wyoming e.g., Gillette, WY	6.25	0.40 (0.38)	8.00	0.52 (0.49)
Southern Wyoming e.g., Rock Springs, WY	14.50	0.73 (0.69)	15.00	0.75 (0.71)
Northern Lignite e.g., Williston, ND	7.00[ϕ]	0.46 (0.44)		(0.44)
Central Western e.g., Las Animas, CO	17.00	0.82 (0.78)	16.00	0.77 (0.73)
Southwestern e.g., Gallup, NM	13.75	0.73 (0.69)	15.00	0.74 (0.70)

[α] Except where indicated otherwise, the prices are those cited in <u>Coal Week</u>, May 29, 1978.[7]

[ϕ] Estimated at $7.00/ton and 8,000 Btu/lb.

[ə] The value in dollars per ton is from Coal Outlook, July 17, 1978.[8] The value in dollars per energy unit is based upon 32.1 J/Kg (13,800 Btu/lb).

Table 3-7. AN ILLUSTRATIVE EXAMPLE OF ENERGY CONSUMED IN TRANSPORTING TWO DIFFERENT COALS TO A PLANT IN SPRINGFIELD, ILLINOIS

	Source of Coal	
	Gillette, Wyo.	Mattoon, Ill.
Assumed heating value		
10^6 J/kg	19.76	25.57
(BTU/lb)	(8,500)	(11,000)
Average sulfur content		
ng SO_2/J	705	2,812
(lb $SO_2/10^6$ BTU)	(1.64)	(6.54)
Transportation distance		
km		
(mi)		
By rail	2,124	160.9
	(1,320)	(100)
By barge	0	0
	(0)	(0)
Energy consumed in transport		
10^6 J/kkg	562.0	42.6
% of coal-combustion energy	2.80	0.17

The table shows that energy needed to deliver the western coal to Springfield exceeds the energy needed to deliver the local coal by a factor of 13.2 on a per-weight basis. When measured as a fraction of the energy potentially available when the coal is burned, the factor rises to 16.5, illustrating the importance of the heating value of coal in cost trade-offs among alternative sources.

Environmental Factors Associated With Low Sulfur Coal

The nature and quantity of pollutants resulting from handling and burning naturally occurring coals vary significantly depending upon the characteristics of the coal. Coals in the U.S. vary widely in their content of ash, sulfur, iron and other metals. The type of coal utilized determines the kinds and quantity of pollutants produced from storage and refuse areas.

There is a high positive correlation between pyritic sulfur concentrations and other coal contaminants that have a high pollution potential. Therefore, the pyritic content of the coal is particularly important in determining the amount of metal sulfates and sulfuric acid produced in storage and refuse areas. Consequently, leachates from storage piles of high sulfur eastern coal are highly acidic and contain higher concentrations of other pollutants than leachates from lower sulfur coals. This occurs because the acid dissolves many other complex sulfides and metal salts, thereby increasing the concentrations of other contaminants in the leachate. In contrast, western coal, because of its low pyritic sulfur content, produces a basic leachate from its storage and refuse areas. The dominant contaminants produced from western coal--calcium, magnesium and sodium--are typically less hazardous to the environment than are sulfuric acid and metal sulfates.

Through coal preparation, pollutants which might normally be emitted during the combustion of naturally occurring coal are converted into solid refuse or waste water, a chemical state in which the pollutants may be easier to control.

3.2.1.2 Candidate Physical Coal Cleaning Processes--

This section presents a summary and comparison of physical coal cleaning systems from the standpoint of performance, preliminary costs, preliminary energy use, status of development, and effect on the environment.

Performance Factors for Physical Coal Cleaning Systems

A comparison of system performance can best be accomplished by looking at each process level described in Section 2.0 on a common coal feed. This basis allows the comparison of the following parameters level by level:

- Weight yield of clean coal product based upon a feed coal rate of 544 metric tons (600 tons) per hour;
- Weight percent ash in the clean coal product based upon the ash washability and equipment efficiency of the processing level;
- Weight percent sulfur in the clean coal product based upon the sulfur washability and equipment efficiency of the processing level; and
- Heating value yield of the process based upon a feed coal value of 27,300 KJ/kg (11,740 BTU/lb).

The common coal feed selected is a bituminous coal from the Upper Freeport seam, which can readily be cleaned by conventional washing techniques. The percent removal of ash and sulfur assigned to each process level is based on actual equipment performance calculations using the washability data for this coal. The washability data was presented in Section 2.0 (Figure 2-22,). The performance comparison is shown in Table 3-8 for the five coal cleaning process levels.

The table indicates a range of SO_2 emission levels for the clean coal products from 645 to 2,463 ng SO_2/J (1.5 to 5.73 lbs $SO_2/10^6$ BTU). The percentage reduction of sulfur in the clean coal product ranges from zero for the level 1 process to 68.2% for the "deep cleaned" product from the level 5 plant. The level 5 plant produces two products, a "deep cleaned" product and a middling product which have different product specifications and potentially different markets. The percentage reduction

TABLE 3-8 SUMMARY OF PERFORMANCE OF PHYSICAL COAL CLEANING PROCESSES BY LEVEL OF CLEANING BASED UPON HIGH SULFUR EASTERN COAL (Upper Freeport Seam)

		LEVEL					5α
Coal Parameter	Raw Coal	1	2	3	4	5a	5b
Weight % Ash in Product	23.90	22.5	20.0	11.5	7.6	5.80	11.31
Weight % Sulfur in Product	3.45	3.40	3.0	1.89	1.3	1.08	1.69
Heating Value kJ/ky (BTU/lb)	26,772 (11,510)	27,586 (11,860)	28,517 (12,260)	31,520 (13,551)	32,564 (14,000)	33,555 (14,426)	31,662 (13,612)
Net Coal Yield Metric ton/hr (tons/hr)	544 (600)	533 (588)	505 (557)	398 (439)	381 (420)	192 (212)	206 (228)
Yield - Weight %	100	98	93	73	70	35.3	38
Recovery - % Heating Value	100	99	97	84	87.5	43.4	44
$ng/SO_2/J$ (lb $SO_2/10^6$ BTU)	2,576 (5.99)	2,463 (5.73)	2,102 (4.89)	1,199 (2.79)	795 (1.85)	645 (1.5)	1,075 (2.5)
Weight % Sulfur Reduction	-----	0	12	44	62	68.2	50
Weight % Ash Reduction	-----	4	15	51	68	75.2	52
% ng SO_2/J Reduction	-----	3	17	53	69	75	58

α 5a - Deep Cleaned Product (Steam Fuel #1); 5b - Middlings Product (Steam Fuel #2) of SO_2 per unit heating value for the clean coal product ranges from 3% for level 1 to 75% for the deep cleaned product from the level 5 plant. The percentage increase over the sulfur reduction percentage is caused by the increase in heating value of the clean coal product.

As shown in Table 3-8 , the weight yields of the process levels range from 98% for level 1 to 73.3% for the combined products of level 5, and only 70% for a level 4 process. In general, as more processing operations are used in the system, the weight yield of the final product decreases. The exception to this is the level 5 plant where two products are obtained to maximize weight recovery. The energy content recovery of the process levels ranges from 99% for level 1 to 87.5% for level 4. The energy content recovery for the combined products of the level 5 process is slightly greater than that for level 4 - 87.9%.

In summary, levels 1 and 2 can be used to accomplish ash reduction with corresponding high weight yields and energy content recovery but very little sulfur reduction. Levels 3, 4 and particularly 5 achieve large reductions in sulfur and SO_2 per unit heating value, but with decreased yields and energy content recovery. This reflects the necessity for greater physical processing of the coal to achieve rejection of pyritic sulfur at the expense of rejecting larger amounts of coal. Thus, the design of physical coal cleaning processes for sulfur removal is a carefully balanced trade-off between sulfur reduction and energy content recovery.

Despite the simplifying breakdown of coal preparation into five levels, there are no generally defined standards for the selection of coal preparation process, and there is no off-the-shelf solution to producing clean coal. Few coal preparation plants in the United States are identical. Block diagrams showing general unit operations for the various levels of physical cleaning may indeed be identical for different coals, but the equipment selected to perform these unit operations will vary depending on a variety of factors including coal characteristics, such as washability and site specifics (e.g., availability of water, geographic conditions, market criteria). Note that by substitution or addition of equipment, a coal preparation plant may be converted from one level to another.

Status of Development For Physical Coal Cleaning Systems

Levels 1 through 4 presented above are all practiced in commercial plants operating today. Also, there are examples of level 5 practices at metallurgical coal plants where both a metallurgical product and a middling steam coal product are produced. Furthermore, all the unit operations proposed for a level 5 plant are being used in commercially operating plants today.

Level 1 processes are generally used to size raw coal to user specifications, to remove overburden, and sometimes in the case of western coals to reduce moisture content to decrease shipping weight and enhance heating value. Level 2 and 3 plants are mainly used to remove sulfur-containing mine dilutions from coal whose in-place characteristics actually or nearly comply with NSPS. The purpose of level 4 and 5 plants is to liberate and remove free pyrite from hard-to-clean coals. Level 4 plants have predominantly been used to beneficiate metallurgical grade coal, but market conditions may demand their adoption for steam coal cleaning.

Preliminary Costs and Energy Requirements for Candidate Physical Coal Cleaning Systems

All cleaning plants are assumed located at the mine mouth. All product transport equipment is assumed to belong to the railroad. The estimates are based on June 30, 1978 price and wage levels.

Capital Costs

The capital cost of coal cleaning plants is composed of direct and indirect costs. Direct costs include the cost of equipment and auxiliaries, land, and the labor and material required to install the equipment. Although real estate costs vary, land is assumed to cost $2,400 per acre.

Indirect capital costs are costs that cannot be attributed to a specific piece of equipment, but are necessary for the entire system including:

Engineering -	10% of direct costs
Construction and field expenses -	10% of direct costs
Contractor fee -	10% of direct costs
Start-up -	2% of direct costs
Contingency -	20% of total direct and indirect costs
Working capital -	25% of operating and maintenance costs including costs of utilities, chemicals, operating labor, maintenance and repairs and disposal costs

Annual Operating Costs

The coal processing costs include variable operating, maintenance, and associated overhead costs for operating the coal preparation facilities. Fixed charges consist of capital amortization, taxes, insurance and interest on borrowed capital.

Operating personnel costs are estimated based on two shifts of operation totalling 13 hours per day and a third 8-hour shift for maintenance. The plants are assumed to operate 250 days per year. The annual salary costs are $23,700 per year for direct and maintenance labor and $30,600 per year for supervisory personnel.[10] Operating manpower varies by coal cleaning level as follows:

Physical Cleaning Level	Direct Labor Man/Day	Supervisory Labor Man/Day	Maintenance Man/Day
1	8	2	4
2	10	2	6
3	10	3	6
4	18	3	10
5	20	3	15

Other operating cost bases are presented below.

Operating Cost Bases

Maintenance, supplies, and replacement parts - 7% of total turnkey costs

Utilities and Chemicals

power @$.0072/MJ ($0.0258/kwh)

water @ $0.15/1,000 gal.

magnetite @ $71.70/metric ton ($65/ton)

flocculant @$4.40/kg ($2/lb)

The quantities for utility and chemical requirements are based on available published information.[4]

Refuse Disposal Costs

$1.10/metric ton ($1.00/ton)

Overhead Costs

payroll overhead = 30 percent of total labor cost

plant overhead = 26 percent of labor, maintenance and supplies, and chemical costs

Capital Charges

Capital related charges include annualized capital costs, taxes, insurance and general and administrative costs. Assuming equal payment loans, the fixed charges per period per dollar of loan as a function of the loan period and the interest rate are given by:

$$R = \frac{i\ (1 + i)^n}{(1 + i)^n - 1}$$

where:

R = capital recovery per period per dollar invested

i = interest rate per period expressed as a decimal

n = number of periods in the amortization schedule.

The factor R multiplied by the amortizable cost will yield the per-period fixed cost covering interest and principal.

For purposes of this exercise a life expectancy of 20 years for a coal cleaning plant and an interest rate of 10 percent were assumed.

Property taxes and insurance vary considerably in different parts of the country. For this study, taxes, insurance and general and administrative costs were taken as 4 percent of depreciable investment.

Cost Estimates

A variety of organizations have made cost evaluations of the various levels of physical coal cleaning based on different plant designs. (10) (11) (12) (13) The basic problems in determining preliminary costs are:

- projecting past data to reflect current and future economic conditions;
- correlating plant designs and plant costs with levels and degrees of cleaning;
- lack of available cost information to cover all costs; and
- inconsistency in plant capacity.

The available data were carefully examined as a basis for developing preliminary cleaning plant total direct capital costs (in June 1978 dollars). In most cases the costs for each level were developed based on treating a reference coal to upgrade the energy content and reduce the sulfur content to meet the current NSPS sulfur dioxide emissions control level of 516 $ng/10^6 J$ (1.2 $lbs/10^6$ BTU). In one case (The Electric Light and Power Study) (11) costs were based on one selected coal being beneficiated at five preparation levels. In another case (Hoffman-Munter Study) (12) costs were developed for existing plants.

The study of updated direct capital costs indicated that for each generic type or class of cleaning (regardless of equipment used in the circuits) the spread of direct capital costs was relatively small. The range and average of adjusted direct capital costs (adjusted for throughput and pricing basis) are listed below:

Level	Range of Total Direct Capital Costs, 1978 $	Average Total Direct Capital Costs, 1978 $
1	2.4×10^6 to 3.4×10^6	2.9×10^6
2	5.3×10^6 to 6.6×10^6	6.0×10^6
3	9.3×10^6 to 11.4×10^6	10.5×10^6
4	10.3×10^6 to 14.5×10^6	12.0×10^6
5	18.1×10^6 to 18.4×10^6	18.3×10^6

Preliminary total annual operating cost estimates have been prepared for plants representing the five levels of physical coal cleaning discussed in Section 2.0. These estimates, presented in Table 3-9 , are based on an assumed plant throughput capacity of 7,200 metric tons (8,000 tons) per day. The reference coal used as the basis for these estimates is a high sulfur eastern coal which contains 3.40% total sulfur (2.79 percent pyritic sulfur) and 26,716 kJ/kg (11,846 BTU/lb) of heat content.

Energy Use

The energy requirements for the five levels of cleaning range from 245 kw to 2,304 kw for the 7,260 metric ton/day plant as shown on Table 3-9.

3.2.1.3 Environmental Factors Associated with Physical Coal Cleaning--

Characteristics of the wastes from a physical coal preparation plant are highly dependent on the raw coal utilized and the final product.

The two major sources of contamination associated with the candidate BSER physical coal preparation plants are fugitive emissions from coal storage and refuse area leachate. Note that the candidate plants do not have thermal dryers, so flue gas emissions from drying will not occur. Fugitive emissions may occur from the handling of coal, however. These emissions are minimized by proper coal handling procedures and the use of

TABLE 3- 9 ANALYSIS OF ANNUAL PHYSICAL COAL CLEANING COSTS- 7,260 metric tons/day (8,000 tons/day plant)*

Levels of Cleaning	1	2	3	4	5
Yield: wt %	98	85	75	70	78
Recovery: % Energy	100	92	85	87.5	92
BTU content ROM coal, kJ/kg (BTU/lb)	26,772 (11,510)	26,772 (11,510)	26,772 (11,510)	26,772 (11,510)	26,772 (11,510)
BTU content clean coal, kJ/kg (BTU/lb)	27,850 (11,974)	29,490 (12,678)	30,854 (13,265)	34,132 (14,674)	32,220 (13,852)**
Hourly input, ROM coal, metric tons/hr (tons/hr)	558.3 (615.4)	558.3(615.4)	558.3(615.4)	558.3(615.4)	558.3(615.4)
Hourly output, clean coal, metric tons/hr (tons/hr)	547(603)	474.4(523.1)	418.6(461.6)	390.7(430.8)	435.4(480.0)
Total Turnkey costs, $	3,962,000	9,506,400	16,634,400	19,010,400	28,989,600
Land cost, $	120,000	180,000	264,000	720,000	480,000
Working capital, $	170,800	365,200	555,600	714,300	933,800
Grand total capital investment, $	4,252,800	10,051,600	17,454,000	20,444,700	30,403,400
Total annual operating costs (excluding coal cost), $	1,572,400	3,377,500	5,409,200	6,635,300	9,393,100
Total annual operating costs (including coal cost), $	35,572,400	37,377,500	39,409,200	40,635,300	43,393,100
Cost of preparation (excluding coal cost), $/metric ton ($/ton) of clean coal	0.88(0.80)	2.19(1.99)	3.97(3.60)	5.22(4.74)	6.64(6.02)
Cost of preparation (including coal cost), $/metric ton ($/ton) of clean coal	20.01(18.15)	24.24(21.99)	28.97(26.27)	31.99(29.02)	31.67(27.82)
Cost of preparation (excluding coal cost) $/$10^6$ kJ ($/$10^6$ BTU) of clean coal	0.032(0.034)	0.074 (0.078)	0.128 (0.135)	0.153 (0.161)	0.206 (0.217)
Cost of preparation (including coal cost) $/$10^6$ kJ ($/$10^6$ BTU) of clean coal	0.729 (0.770)	0.822 (0.867)	0.939 (0.990)	0.937 (0.989)	0.952 (1.00)
Average Energy Requirement, Kw (10^6 BTU/hr)	250 (0.8)	650 (2.2)	1,000 (3.4)	1,300 (4.5)	2,300 (7.9)

* Based on 13 hr/day, 250 days/year operation

** Heating value of the combined product. The plant will generate two product streams, a very high BTU stream and a middling stream bag houses on grinding and crushing equipment. Coal storage and refuse area leachate from physical coal preparation plants is similar to acid mine drainage for the cleaning plants processing **eastern coals.** For the candidate BSER cleaning plant processing Colorado bituminous coal, the drainage will be basic rather then acidic.

The amount of refuse may be calculated for each cleaning plant. Eastern high sulfur coal preparation will produce 5.5×10^5 metric tons of refuse per year and eastern low sulfur coal preparation will produce about 4.0×10^5 metric tons of refuse per year.

3.2.1.4 Chemical Coal Cleaning--

This section presents a comparison of technical results obtained from the assessment of major chemical coal cleaning processes as described and discussed in Section 2.2.3. The analysis and conclusions presented herein are based on process claims made by individual developers, research reports and published information.

Sulfur Removal and Energy Content Recovery Potential

A comparison of process performance can best be accomplished by looking at each process on a common coal feed. This was done in a previous report on Chemical Coal Cleaning Processes published by Versar in 1978[15] (Although this study used a coal that is dissimiliar to the three reference coals, the results are applicable). This basis allows the comparison of the following parameters process by process:

- Weight yield of clean coal product based upon a feed coal rate (moisture free basis) of 7,110 metric tons (7,840 tons) per day [7,200 metric tons (8,000 tons) per day of 2 percent moisture coal];
- Weight percent sulfur in the clean coal product based upon the sulfur removal efficiency of the process; and
- Heating value yield of the process based upon a feed coal value of 28,610 kJ/kg (12,300 BTU/lb) and net energy content yield in percent.

The common coal feed selected is a bituminous coal from the Pittsburgh seam, which cannot readily be cleaned by conventional washing techniques to meet a control level of 1.2 lb $SO_2/10^6$ BTU for large boilers. This coal does have an organic sulfur content low enough (0.7 weight percent) so that complete removal of pyritic sulfur would result in a product which will meet the control level. The percent removal of pyritic and organic sulfur assigned to each process is based on data supplied by individual developers. The performance comparison is shown on data supplied by individual developers. The performance comparison of the eleven chemical coal cleaning processes is shown in Table 3-10. The table indicates a range of SO_2 emission levels for the clean coal products of 344 to 903 ng/J (0.8 to 2.1 lb/10^6 BTU). The calculated sulfur dioxide emissions for processes which remove both organic and inorganic sulfur are lower than the 516 ng/J (1.2 lb/10^6 BTU). Of the four processes which remove pyritic sulfur, only two (TRW and Ledgemont) will produce a slightly higher sulfur level than that required to meet the current control option; however, within the levels of accuracies involved they also might be considered to be in compliance.

As shown in Table 3-10, the energy content yields estimated for these processes are generally greater than 90 percent with a range from a low 57 percent for the IGT process to a high of 96 percent for the GE process. All energy content yields listed in Table 3-10 reflect both the coal loss due to processing and the coal used to provide in-process heating needs. However, with the exception of the IGT process, the actual coal loss due to processing is claimed to be small. For most processes, the major energy content loss is due to the use of clean coal for in-process heating.

It is believed that the high yield estimated for the GE process may not adequately reflect the heat requirements that may be needed to regenerate the caustic reagent employed in the process. This process is in its early stage of development, and the energy requirements for the process cannot be properly assessed at this time. It is possible, that in the final analysis, the energy content recovery from this process will be more in line with other chemical coal cleaning processes.

TABLE 3-10 PROCESS PERFORMANCE AND COST COMPARISON FOR MAJOR CHEMICAL COAL CLEANING PROCESSES

	PROCESSES WHICH REMOVE PYRITIC SULFUR ONLY				
	FEED†	TRW	LOL	SM MAGNEX	SYRACUSE† PHYSICAL CLEANING
Net coal yield, metric tons per day (tons/day)*	7,110 (7,840)	6,400 (7,056)	6,400 (7,056)	5,645 (6,225)	5,645 (6,225)
Weight % sulfur in the product	1.93	0.83	0.83	0.97	1.50
Heating value, kJ/kg (BTU/lb)	28,610 (12,300)	29,854 (12,835)	29,854 (12,835)	28,842 (12,400)	33,960 (14,600)
ng/J (lb $SO_2/10^6$ BTU)	1,333 (3.1)	559 (1.3)	559 (1.3)	688 (1.6)	903 (2.1)
Percent net energy content yield	—	94	94	80	95

	PROCESSES WHICH REMOVE PYRITIC AND ORGANIC SULFUR						
	ERDA	GE	BATTELLE	JPL	IGT	KVB	ARCO
Net coal yield, metric tons per day (tons/day)*	6,400 (7,056)	6,826 (7,526)	6,755 (7,448)	6,470 (7,135)	4,270 (4,704)	6,070 (6,690)	6,400 (7,056)
Weight % sulfur in the product	0.65	0.50	0.65	0.6	0.55	0.61	0.69
Heating value, kJ/kg (BTU/lb)	29,854 (12,835)	28,610 (12,300)	26,400 (11,350)	28,610 (12,300)	27,180 (11,685)	30,517 (13,120)	28,842 (12,400)
ng/J (lb $SO_2/10^6$ BTU)	387 (0.9)	344 (0.8)	516 (1.2)	430 (1.0)	387 (0.9)	387 (0.9)	473 (1.1)
Percent net energy content yield	94	96	88	91	57	91	91

* All values reported are on a moisture free basis.

† The coal selected is a Pittsburgh seam coal from Pennsylvania which contains 1.22 weight percent pyritic, 0.01 percent sulfate and 0.70 percent organic sulfur. It is assumed that this coal has a heating value of 28,610 kJ/kg (12,300 BTU/lb).

Processes which remove pyritic sulfur alone are primarily applicable to coals rich in pyritic sulfur, so that efficient removal of pyritic sulfur could bring these coals into compliance. Processes which remove both types of sulfur are primarily applicable to coals which cannot be adequately treated by pyritic removal processes.

Among all chemical coal cleaning processes, the TRW (Meyers) process is the most advanced, with an 8 metric ton per day Reaction Test Unit (RTU) in operation. The process removes 80-96 percent of the pyritic sulfur from nominally 14 mesh top size coal. Thirty-two different coals have been tested: two western coals, twenty-three from the Appalachian Basin; six from the Interior Basin; and one from the Western Interior Basin.

Another option for the Meyers processing plant which is attractive is a combination physical and chemical cleaning operation--the Gravichem process. In this process, the run-of-mine coarse coal containing high ash and high pyritic sulfur would first be treated in a physical coal cleaning plant. The heavy fraction from the gravity separation system, consisting of about 40 to 50 percent of the total coal and containing low ash and high concentration of pyritic sulfur is then fed to the Meyers process which will yield a low sulfur product. The Gravichem process can produce an overall yield of about 80 percent on the run-of-mine coal and will reduce the pyritic sulfur content by 80 to 90 percent.

Among the processes capable of removing pyritic and organic sulfur, the ERDA process has one of the highest probabilities of technical success. The ERDA process is currently active, and most technologies employed in this system have been already tested in other systems such as Ledgemont and TRW. The process is attractive because it is claimed to remove more than 90 percent of pyritic sulfur and up to 40% of organic sulfur in coals starting with minus 200 mesh coal. Coals tested on a laboratory scale include Appalachian, Eastern Interior and Western.

Preliminary Costs

This section presents preliminary economic information on the three candidate chemical coal cleaning BSERs. The first two processes, the Meyers and the Gravichem (physical coal cleaning plus Meyers) are capable of reducing only a portion of the pyritic sulfur in the feed coal, while the third process, the ERDA process, is capable of reducing both pyritic and organic sulfur.

The process economics are based on preliminary conceptual processing schemes. The process operating conditions, the process chemistry, the levels of removal of pyritic and organic sulfurs, the energy content and yield recovery information are based on evaluation of the individual developer's claims. Where cost information was supplied by a developer, these costs were utilized, to the extent possible, as the basis of the cost information in this report. However, the costs were modified to allow the evaluation of the various processes on a common basis.

The economic estimates presented for the Meyers and the ERDA processes are based on a plant which processes 302 metric tons (33 tons) per hour of high sulfur eastern coal on a 24 hour per day and 330 days per year basis (8,000 tons/day, three train plant). The basis for the Gravichem process is a 96 metric ton (106 tons) per hour Meyers process unit (a single train plant) operating 24 hours a day and 330 days per year basis. The physical coal cleaning section of the plant processes 558 metric tons (615 tons) per hour of raw coal (8,000 tons/day) operating 13 hours per day and 250 days per year. The third shift is set aside for scheduled plant maintenance.

Total Direct Capital Costs

Total direct capital costs for the Meyers and ERDA processes were extracted from "Technical and Economic Evaluation of Chemical Coal Cleaning Processes for Reduction of Sulfur in Coal".[15] These costs were adjusted to June 30, 1978 bases by using appropriate plant cost indices.[16] The direct capital cost for the physical coal cleaning portion of the Gravichem plant was extracted from the "Meyer's Process Development for Chemical Desulfurization of Coal" report.[17] This cost was adjusted to reflect June 30, 1978 prices by using appropriate indices and was then adjusted to the desired plant capacity using a scale factor of 0.7.

The cost of the land used in these estimates is the same as that used for developing costs of the physical coal cleaning plants.

Indirect Capital Cost

Items included in indirect costs and their values are the same as those developed for the physical coal cleaning plants.

Annual Operating Costs—

Operating manpower, energy and utilities requirements for the chemical coal cleaning plants were extracted from the Versar chemical coal cleaning report.[15] The operating and maintenance personnel wages and cost basis for utilities and chemicals are the same as discussed in physical coal cleaning. The costs for steam and other chemicals used only in chemical coal cleaning process estimates are listed below:

600 psig steam @ $4.83/1,000 lb.
Lime @ $35/metric ton ($32/ton)
Lignin sulfonate binder @ $0.06/lb.

Maintenance supplies and material for all chemical coal cleaning cases were taken as 5 percent of the total turnkey costs.

The cost for the disposal of byproducts generated by the chemical coal cleaning plants was extracted from the chemical coal cleaning report.[15]

The cost basis for overhead, capital charges and raw coal costs are presented in the physical coal cleaning discussion.

Preliminary capital and annual operating costs for each process based on a high sulfur eastern coal are presented in Table 3-11. The results

TABLE 3-11. ANALYSIS OF ANNUAL CHEMICAL COAL CLEANING COSTS - 7,258 metric tons/day (8,000 tons/day plant)

Process	Meyer's	ERDA	Gravichem
Yield, wt %	90	90	79.8
Recovery: % kJ (% BTU)	99.2(94)	99.2(94)	96.0
BTU content ROM coal kJ/kg (BTU/lb)	26,772 (11,510)	26,772 (11,510)	26,772 (11,510)
BTU content clean coal kJ/kg (BTU/lb)	28,507 (12,256)	28,507 (12,256)	31,126 (13,382)
Hourly input, ROM coal, metric tons/hr (tons/hr)	302 (333)	302 (333)	558(615.9)* 96(106)**
Hourly output, clean coal, metric tons/hr (tons/hr)	271 (300)	271 (300)	469(517)* 86(95)**
Total Turnkey costs, $	157,500,000	216,580,000	62,324,000
Land cost, $	120,000	120,000	120,000
Working capital, $	5,973,000	7,931,500	2,429,600
Grand total capital investment, $	163,593,000	224,631,500	64,873,600
Total annual operating costs (excluding coal cost), $	53,291,000	70,832,000	21,597,300
Total annual operating costs (including coal cost), $	98,171,000	115,712,000	55,597,300
Cost of preparation (excluding coal cost), $/metric ton ($/ton) of clean coal	24.73(22.43)	32.87(29.81)	14.92(13.53)
Cost of preparation (including coal cost), $/metric ton ($/ton) of clean coal	45.55(41.32)	53.70(48.70)	38.41(34.84)
Cost of preparation (excluding coal cost), $/$10^6$ kJ ($/$10^6$ BTU) of clean coal	0.867 (0.915)	1.15 (1.22)	0.48 (0.51)
Cost of preparation (including coal cost), $/$10^6$ kJ ($/$10^6$ BTU) of clean coal	1.60 (1.69)	1.88 (1.99)	1.23 (1.30)
Energy Requirement			
Electric power, Kw (10^6 BTU/hr)	25,200 (86)	15,650 (53)	8,400$^{\Delta}$(29) 1,000$^{\gamma}$ (3.4)
Product coal for in process leaching, metric tons/hr (tons/hr)$^{\delta}$	11(12)	25.8(28.5)	3.6(4) --
600 psig steam, kg (lbs)	—	0.9×10^9 (2×10^9)	— --

NOTES:

* Entering and leaving physical coal cleaning plant operating @ 13 hr/day, 250 days/year basis

** Entering and leaving chemical coal cleaning plant operating @ 24 hr/day, 330 days/year basis

Δ Meyer's coal cleaning plant

γ Physical coal cleaning plant

δ The use of product coal as fuel has been reflected in the weight yields reported above indicate that the cost of coal cleaning is \$24.73, \$32.87 and \$14.92 per metric ton, excluding the raw coal cost for the Meyers, ERDA, and Gravichem (physical coal cleaning plus Meyers process), respectively.

Energy Impact

The energy requirements for these plants are given in Table 3-11. It has been assumed that the physical coal cleaning plant included in the Gravichem process will operate 13 hrs per day, 250 days per year. All chemical coal cleaning plants will operate on a 24 hour per day and 330 days per year basis.

Environmental Factors Associated with Chemical Coal Cleaning

Characteristics of the wastes from a chemical coal preparation plant are highly dependent on the processes utilized, which are in turn dictated by the raw coal and final product.

As chemical cleaning processes become increasingly more complex and finer size fractions of the coal are cleaned and collected, the pollution potential changes because: (1) complex chemical cleaning plants frequently use thermal driers which are a source of gaseous (NO_x, SO_2 and CO) and particulate air pollution; (2) there is a greater opportunity during processing for the soluble pollutants to be contacted by a leachant; (3) chemical additives are used in the static thickeners and froth flotation cells, thus increasing the number of potential pollutants in air emissions and refuse; and 4) most chemical coal cleaning plants burn cleaned coal for steam/heat production and therefore have much the same kinds and amounts of air pollutants as the industrial boilers themselves.

There is insufficient data and operating experience to quantify the amount of leachant lost in the clean coal or refuse, so environmental impacts cannot be quantified. The annual amount of refuse material is known, however, based on a 7216 metric ton/day (8000 ton per day) plant. The amount of refuse disposed of is as follows: Gravichem - 6.8×10^5 kkg per year (7.5×10^5 tons per year), Meyers - 2.0×10^5 kkg per year (2.3×10^5 tons per year), and ERDA 2.0×10^5 kkg per year (2.2×10^5 tons per year).

3.2.2 Comparison of Candidate Best Systems of Emission Reduction for SO_2 Control

This section presents the selection and characteristics of three typical coals, which will be used for comparison of the candidate Best Systems of Emission Reduction (BSER). The performance, cost and other relevant factors for each candidate BSER will be compared for each coal type at the five selected emission levels.

Selection of Representative Coals for Industrial Boilers—

Three representative coals have been selected as a basis for determining the performance and costs of each candidate control technology. The coals are representative of those originally chosen by PEDCo Environmental to be used in the development of each ITAR[18], but are not identical. Because the design of a physical coal cleaning system is dependent upon the washability characteristics of an individual coal and the coal types supplied by PEDCo were merely average coals, they could not be used for this analysis. Thus, three coals were chosen whose characteristics were close to those specified and which are representative of a high sulfur eastern coal, a low sulfur eastern coal and a low sulfur western coal. The characteristics of the coals selected are shown in Table 3-12. These coals were selected primarily on quality and washability characteristics. These characteristics are presented in more detail in the later sections.

3.2.2.1 Naturally Occurring Low Sulfur Coal as a BSER--

The uncontrolled SO_2 emissions from each of the representative coals range from 447 ng SO_2/J (1.04 lbs $SO_2/10^6$ BTU) for the low sulfur western to 2,490 ng SO_2/J (5.79 lbs $SO_2/10^6$ BTU) for the high sulfur eastern. The matrix shown below indicates the ability of the three reference raw coals to meet the selected SO_2 emission levels on a long term average basis.

Coal	SO_2 Emission Levels ng SO_2/J (lbs $SO_2/10^6$ BTU) 1,290 (3.0)	1,075 (2.5)	860 (2.0)	645 (1.5)	516 (1.2)
High-S Eastern	Doesn't Meet	Doesn't Meet	Doesn't Meet	Doesn't Meet	Doesn't Meet
Low-S Eastern	Meets	Meets	Meets	Doesn't Meet	Doesn't Meet
Low-S Western	Meets	Meets	Meets	Meets	Meets

TABLE 3-12. REPRESENTATIVE COALS FOR INDUSTRIAL BOILERS

PARAMETER			
Coal Type	High Sulfur Eastern	Low Sulfur Eastern	Low Sulfur Western
Seam	Upper Freeport ('E' coal) Seam	Eagle Seam	Primero Seam
County, State	Butler, Pa.	Buchanan, Va.	Las Animas, Co.
RAW COAL ANALYSIS			
Ash, % †	23.9	10.38	24.81
Total S, % †	3.45	1.18	0.59
Pyritic S, % †	2.51	0.60	0.30
Heating Value kJ/kg (BTU/lb)†	26,772 (11,510)	31,685 (13,622)	26,270 (11,294)
Moisture Content	5.0	2.0	2.5
Ash Fusion Temp., °F	2,020-3,000	-	2,230-2,910
SO_2 Emission Level, ng/SO_2/J (lbs $SO_2/10^6$ BTU)	2,576 (5.99)	744 (1.73)	447 (1.04)

† Analyses are on a Moisture Free Basis

This matrix indicates that the naturally occurring low sulfur coal from the western region is easily capable of meeting all five emission levels on a long term average basis. Coupled with an F.O.B. mine price of \$18.75/kkg (\$17.00/ton) or \$0.82/GJ (\$0.78/10^6 BTU) makes it a prime candidate for BSER for all three emission levels. Also as shown above, the low sulfur eastern coal is capable of meeting the moderate, the optional moderate, and the SIP emission levels as a naturally occurring coal. This fact plus its F.O.B. mine price of \$24.25/kkg (\$22.00/ton) or \$0.99/GJ (\$0.94/10^6 BTU) makes it a prime candidate for BSER at this emission level.

However, the above analyses of naturally occurring low sulfur coals as possible BSERs do not take into account transportation costs of these coals to the industrial boiler site. It is only after calculation of transportation costs and transportation energy use from the coal supply area to a series of industrial demand centroids that a true picture of performance and cost can be determined to judge the BSERs with respect to the naturally-occurring coals.

3.2.2.2 Physical Coal Cleaning Systems as a BSER--

A primary factor in the choice of the three representative coals for performance and cost analysis, was that some washability data for each coal was available at various size fractions. Based upon this washability data and a knowledge of equipment efficiency performance factors, a flow sheet or series of flow sheets can be developed to beneficiate each representative coal.

The major design criteria used for the preparation of the flow sheets for each coal are summarized as follows:

- Plant input in each case is 544 metric tons per hour (600 tons per hour);
- Annual capacity throughput is 1.8 million metric tons (2.0 million tons) based upon a 13 hour operating day and 250 operating days per year;

- In all cases, the plant is located at the mine mouth, and all resources such as coal, water, power, etc. are assumed readily available;
- All process equipment used is commercially available and proven;
- Actual equipment performance partition factors have been used to adjust raw coal washabilities characteristic to performance guaranteed specifications; and
- Design of emission control facilities is based upon federal new source performance regulations - EPA standards for air and water quality, MESA regulations for refuse disposal, and MESA/OSHA noise limitations. The BSER designs do not contain direct thermal dryers, because they are not necessary to meet customer specifications for clean coal.

Washability Characteristics of Coals Selected

Raw coal washability data for the three representative coals selected are presented in Tables 3-13, 3-14, and 3-15. Each of these tables shows specific gravity float-sink characteristics of the representative coals according to specific size fractions. In the absence of any additional data, the flowsheet design is based upon the size fractions specified.

Physical Coal Cleaning Flow Sheet Design

The major objective for each design was to obtain maximum sulfur rejection at an acceptable heating value recovery. In most cases, the clean coal product specifications were chosen to reflect the lowest possible SO_2 per heating value unit emission level for each representative coal.

Coal Preparation Flowsheet for the High Sulfur Eastern Coal

The first task to be performed in designing a coal preparation flowsheet for this coal was to calculate the range of possible clean coal properties for each size fraction given in the washability tables. This is accomplished by calculating clean coal properties in terms of ash,

TABLE 3-13. Raw Coal Washability Data for a High Sulfur Eastern Coal-Upper Freeport "E" Seam, Butler, Pennsylvania(19)

Spec Gravity	Characteristics for Each Size Fraction/Specific Gravity Element (Dry Basis)					Cumulative Recovery (Dry Basis)				
	Weight %	Ash %	Btu/ lb	Pyritic Sulfur,%	Total Sulfur,%	Weight %	Ash %	Btu/ lb	Pyritic Sulfur,%	Total Sulfur,%
Size Fraction: 2" x 3/8" (30.0%)										
Float 1.30	38.2	3.4	14,589	0.44	0.85	38.2	3.4	14,589	0.44	0.85
1.30 - 1.40	24.2	10.1	13,613	1.51	2.27	62.4	6.0	14,210	0.85	1.40
1.40 - 1.50	8.5	25.2	12,011	2.28	2.70	70.9	8.3	13,947	1.03	1.56
1.50 - 1.60	4.0	30.7	10,566	2.95	3.70	74.9	9.5	13,766	1.13	1.67
1.60 - 1.80	4.5	44.7	8,837	5.35	5.70	79.4	11.5	13,486	1.37	1.90
Sink 1.80	20.6	73.6	3,949	8.74	9.03	100.0	24.3	11,522	2.89	3.37
Size Fraction: 3/8" x 28 mesh (55.0%)										
Float 1.30	45.8	3.3	14,604	0.43	0.85	45.8	3.3	14,604	0.43	0.85
1.30 - 1.40	19.2	10.5	13,767	0.96	1.50	65.0	5.4	14,356	0.59	1.04
1.40 - 1.50	4.5	21.1	12,050	1.84	2.20	69.5	6.4	14,005	0.67	1.12
1.50 - 1.60	3.5	29.2	10,752	2.30	2.80	73.0	7.5	13,851	0.75	1.20
1.60 - 1.80	3.1	44.0	8,852	3.63	3.90	76.1	9.0	13,649	0.86	1.31
Sink 1.80	23.9	72.8	3,887	8.71	10.35	100.0	24.3	11,414	2.74	3.47
Size Fraction: 28 mesh x 0 (15.0%)										
Float 1.30	46.3	3.0	14,649	0.32	0.74	46.3	3.0	14,649	0.32	0.74
1.30 - 1.40	18.7	8.5	13,822	0.96	1.50	65.0	4.6	14,411	0.50	0.96
1.40 - 1.50	7.0	16.0	12,080	1.57	2.22	72.0	5.7	14,184	0.61	1.08
1.50 - 1.60	3.9	28.1	10,840	3.10	3.65	75.9	6.8	14,013	0.74	1.21
1.60 - 1.80	3.5	35.1	7,977	3.76	4.10	79.4	8.1	13,747	0.87	1.34
Sink 1.80	20.6	74.2	3,781	1.12	11.9	100.0	21.7	11,694	.92	3.52

* 2" = 50 mm.; 3/8" = 9.5 mm.

TABLE 3-14. Raw Coal Washability Data for Low Sulfur Eastern Coal - Eagle Seam, Buchanan, Virginia [20]

SPECIFIC GRAVITY		DRY BASIS			CUM. RECOVERY (Float)			CUM. REJECT (Sink)		
Sink	Float	% Wt.	% Ash	% Sul.	% Wt.	% Ash	% Sul.	% Wt.	% Ash	% Sul.
				COMPOSITE 5" Rd x 1/4" Rd = 50.5% of Raw ROM Crushed to 5"						
	1.30	66.8	2.05	0.69	66.8	2.05	0.69	100.0	10.53	1.06
1.30	1.35	8.7	4.75	0.99	75.5	2.36	0.72	33.2	27.58	1.79
1.35	1.40	8.8	6.65	0.84	84.3	2.81	0.74	24.5	35.69	2.07
1.40	1.45	3.7	12.74	1.10	88.0	3.23	0.75	15.7	51.97	2.77
1.45	1.50	1.3	17.08	1.33	89.3	3.43	0.76	12.0	64.06	3.28
1.50	1.60	1.0	23.27	2.45	90.3	3.65	0.78	10.7	69.77	3.52
1.60	1.70	0.5	33.94	3.57	90.8	3.81	0.79	9.7	74.56	3.63
1.70		9.2	76.77	3.63	100.0	10.53	1.06	9.2	76.77	3.63
				1/4" Rd x 28 Mesh = 34.7% of Raw ROM Crushed to 5"						
	1.30	70.1	1.96	0.88	70.1	1.96	0.88	100.0	9.20	1.20
1.30	1.35	8.5	5.36	1.39	78.6	2.33	0.94	29.9	26.16	1.96
1.35	1.40	5.1	7.63	1.29	83.7	2.65	0.96	21.4	34.43	2.18
1.40	1.45	3.8	10.67	1.17	87.5	3.00	0.97	16.3	42.81	2.46
1.45	1.50	2.2	14.80	1.45	89.7	3.28	0.98	12.5	52.59	2.85
1.50	1.60	2.1	21.41	1.77	91.8	3.70	1.00	10.3	60.66	3.19
1.60	1.70	1.7	47.56	3.09	93.5	4.50	1.03	8.2	70.71	3.50
1.70		6.5	76.76	3.61	100.0	9.20	1.20	6.5	76.76	3.61
				28 Mesh x 60 Mesh = 7.6% of Raw ROM Crushed to 5"						
	1.30	54.4	2.32	0.79	54.4	2.32	0.79	100.0	11.08	1.10
1.30	1.35	16.0	5.00	0.95	70.4	2.93	0.83	45.6	21.54	1.59
1.35	1.40	7.1	9.41	1.24	77.5	3.52	0.86	29.6	30.48	1.94
1.40	1.45	3.8	12.61	1.16	81.3	3.95	0.88	22.5	37.13	2.16
1.45	1.50	3.5	14.90	1.08	84.8	4.40	0.89	18.7	42.11	2.36
1.50	1.60	4.7	18.17	1.11	89.5	5.12	0.90	15.2	48.38	2.60
1.60	1.70	2.3	26.34	1.41	91.8	5.65	0.91	10.5	61.90	3.39
1.70		8.2	71.87	3.89	100.0	11.08	1.16	8.2	71.87	3.89

* 5"=125 mm; 1/4"=6.3 mm

TABLE 3-14. Raw Coal Washability Data for Low Sulfur Western Coal - Eagle Seam, Buchanan, Virginia [20] (Continued)

SPECIFIC GRAVITY		DRY BASIS			CUM. RECOVERY (Float)			CUM. REJECT (Sink)		
Sink	Float	% Wt.	% Ash	% Sul.	% Wt.	% Ash	% Sul.	% Wt.	% Ash	% Sul.
				60 Mesh x 100 Mesh = 2.9% of Raw ROM Crushed to 5 "						
	1.30	46.6	3.02	0.79	46.6	3.02	0.79	100.0	12.63	1.26
1.30	1.35	17.7	5.12	0.84	64.3	3.60	0.80	53.4	21.02	1.67
1.35	1.40	8.4	8.69	1.05	72.7	4.19	0.83	35.7	28.90	2.08
1.40	1.45	4.5	12.44	1.14	77.2	4.67	0.85	27.3	35.12	2.40
1.45	1.50	3.8	15.03	1.08	81.0	5.15	0.86	22.8	39.60	2.65
1.50	1.60	6.3	17.28	0.97	87.3	6.03	0.87	19.0	44.52	2.96
1.60	1.70	3.6	24.85	1.19	90.9	6.77	0.88	12.7	58.03	3.95
1.70		9.1	71.15	5.04	100.0	12.63	1.26	9.1	71.15	5.04
				100 Mesh x 0 = 4.3 % of Raw ROM Crushed to 5"						
	1.30	4.0	2.93	0.83	4.0	2.93	0.83	100.0	15.91	2.55
1.30	1.35	22.4	4.98	0.80	26.4	4.67	0.80	96.0	16.45	2.63
1.35	1.40	20.3	7.66	0.83	46.7	5.97	0.82	73.6	19.94	3.18
1.40	1.45	11.4	11.77	0.89	48.1	7.11	0.83	53.3	24.62	4.08
1.45	1.50	11.0	13.34	0.81	69.1	8.10	0.83	41.9	28.12	4.95
1.50	1.60	14.7	17.74	0.92	83.8	9.79	0.84	30.9	33.38	6.42
1.60	1.70	6.9	23.45	1.08	90.7	10.83	0.86	16.2	47.57	11.41
1.70		9.3	65.47	19.07	100.0	15.91	2.55	9.3	65.47	19.07

* 1 1/2" = 37.5 mm; 1/4" = 6.3 mm

TABLE 3-15. Raw Coal Washability Data for Low Sulfur Western Coal - Primero Seam, Las Animas, Colorado [20]

SPECIFIC GRAVITY		DRY BASIS			CUM. RECOVERY (Float)			CUM. REJECT (Sink)		
Sink	Float	% Wt.	% Ash	% Sul.	% Wt.	% Ash	% Sul.	% Wt.	% Ash	% Sul.
				1 1/2" x 1/4" = 85.91% of Raw Coal						
	1.30	27.81	6.11	0.66	27.81	1.70	.18	100.00	26.04	.64
1.30	1.35	16.75	12.19	0.62	44.56	3.74	.29	72.19	24.34	.45
1.35	1.40	10.99	16.55	0.63	55.55	5.56	.36	55.44	22.30	.35
1.40	1.45	6.76	21.41	0.66	62.31	7.10	.40	44.45	20.48	.28
1.45	1.50	5.54	26.37	0.62	67.85	8.47	.44	37.69	19.03	.24
1.50	1.60	7.69	33.40	0.70	75.54	11.04	.49	32.15	17.57	.20
1.60	1.70	4.58	41.74	0.58	80.12	12.95	.52	24.46	15.00	.15
1.70		19.88	65.85	0.61	100.00	26.04	.64	19.88	13.09	.12
					1/4" x 0 - 14.09% of Raw Coal					
	1.30	55.46	4.93	0.66	55.46	2.73	.37	100.00	17.31	.64
1.30	1.35	13.92	11.62	0.62	69.38	4.35	.45	44.54	14.58	.27
1.35	1.40	6.05	16.65	0.59	75.43	5.35	.49	30.62	12.96	.19
1.40	1.45	3.70	21.42	0.57	79.13	6.15	.51	24.57	11.95	.15
1.45	1.50	2.33	26.41	0.57	81.46	6.77	.52	20.87	11.16	.13
1.50	1.60	3.22	32.23	0.59	84.68	7.80	.54	18.54	10.54	.12
1.60	1.70	2.20	39.66	0.61	86.88	8.68	.55	15.32	9.51	.10
1.70		13.12	65.80	0.64	100.00	17.31	.64	13.12	8.63	.08

sulfur and BTU for each specific gravity of separation at each size fraction using actual equipment separation efficiency factors. These performance characteristics are then graphically displayed as Figures 3-1A through 3-2B. These graphs show the attainable levels of each size fraction coal product in terms of sulfur, ash and heating value content as well as % weight recovery, % energy content recovery and amount of sulfur per energy content unit at various specific gravities of separation. These performance characteristics are all based upon the use of heavy media processes.

Based upon the performance characteristics graphs described above, it was decided that a two product level 5 flowsheet should be used to beneficiate this coal to obtain an optimal tradeoff between SO_2 reduction and energy content recovery. Figure 3-3 shows a simplified block style flow diagram of this conceptual flowsheet.

The flowsheet conceptualized for this high sulfur eastern coal uses a heavy media vessel to effectively separate the coarse size coal into a middling product stream and a refuse stream. The intermediate sized material is routed to a dual stage heavy media cyclone circuit to produce a "deep cleaned" product from the first stage and a middling product from the second stage. The fine sized material is routed to a hydrocyclone circuit for cleaning and coal recovery. The clean coal product from this circuit is blended with other products to form the middling product. The characteristics of the raw coal and clean coal products from this plant are compared in Table 3-16 .

The "deep cleaned" coal product will meet an SO_2 emission control level of 645 ng SO_2/J (1.5 lbs $SO_2/10^6$ BTU) on a long term average basis. The equivalent SO_2 reduction was 74.2% based upon SO_2 emission per unit energy content. The total sulfur in the coal is reduced from 3.40% to 1.08% which is a 68.2% reduction. Also significant is the ash reduction which decreases from 23.4% in the raw coal to 5.8% in the product, a reduction of 75.2%.

The middling product will meet an SO_2 emission control level of 1,075 ng SO_2/J (2.5 lbs $SO_2/10^6$ BTU) on a long term average basis. The SO_2

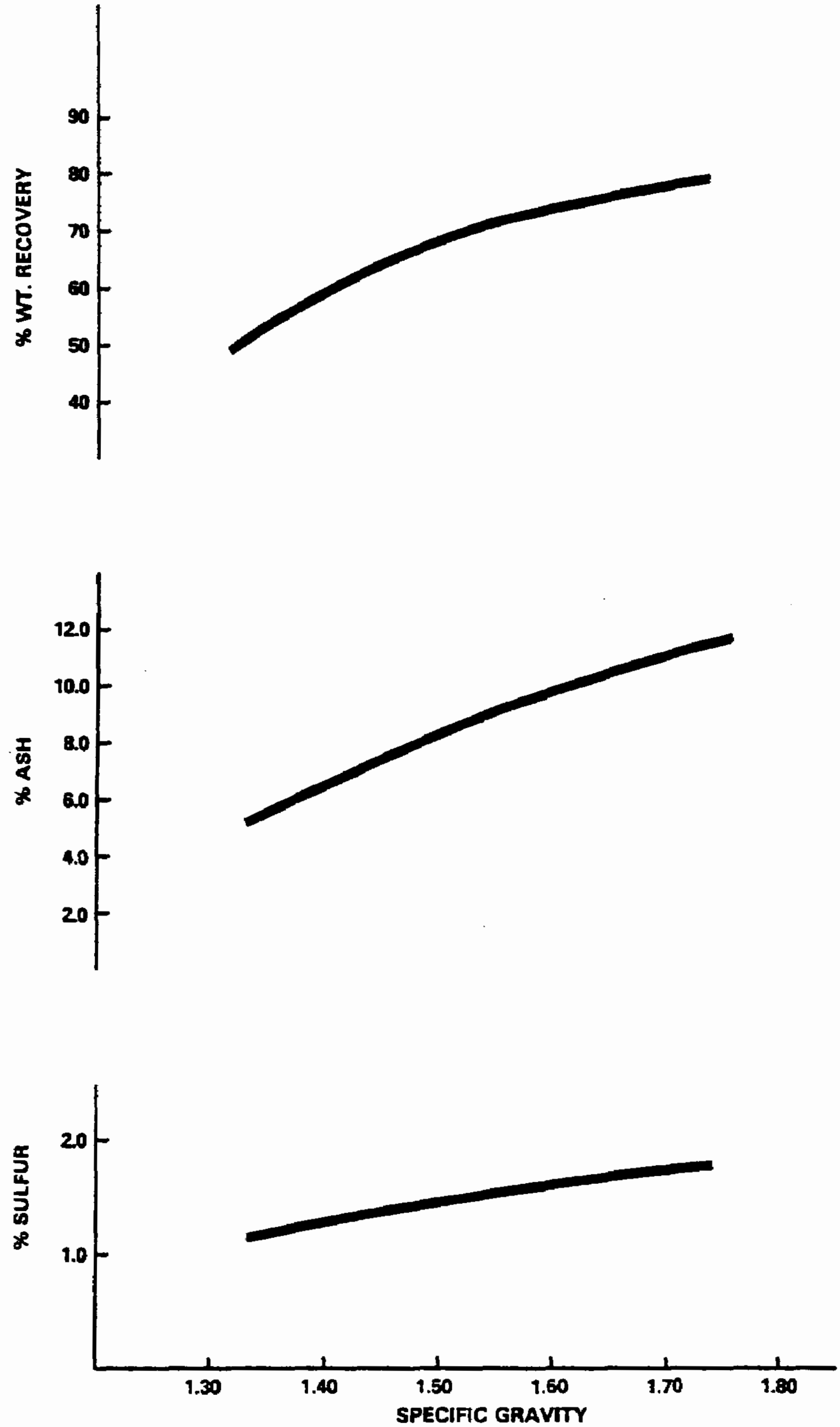

FIGURE 3-1a PERFORMANCE CHARACTERISTICS AT VARIOUS SPECIFIC GRAVITIES OF SEPARATION FOR A HIGH SULFUR EASTERN COAL (UPPER FREEPORT "E SEAM") AT A SIZE FRACTION OF 2" X 3/8" (50 mm x 9.5 mm) (DRY BASIS)

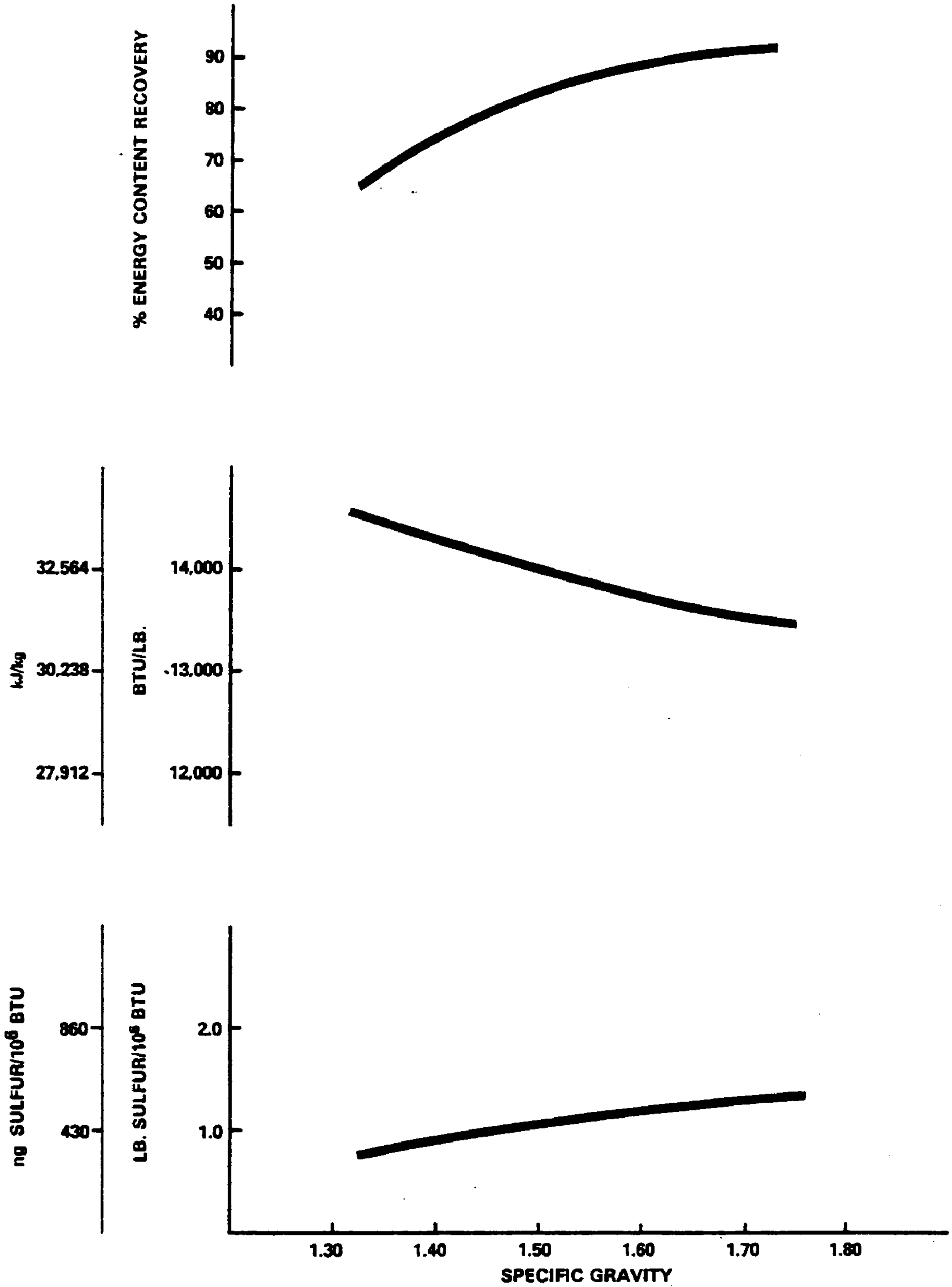

FIGURE 3-1b PERFORMANCE CHARACTERISTICS AT VARIOUS SPECIFIC GRAVITIES OF SEPARATION FOR A HIGH SULFUR EASTERN COAL (UPPER FREEPORT "E SEAM") AT A SIZE FRACTION OF 2" X 3/8" (50 mm x 9.5 mm) (DRY BASIS)

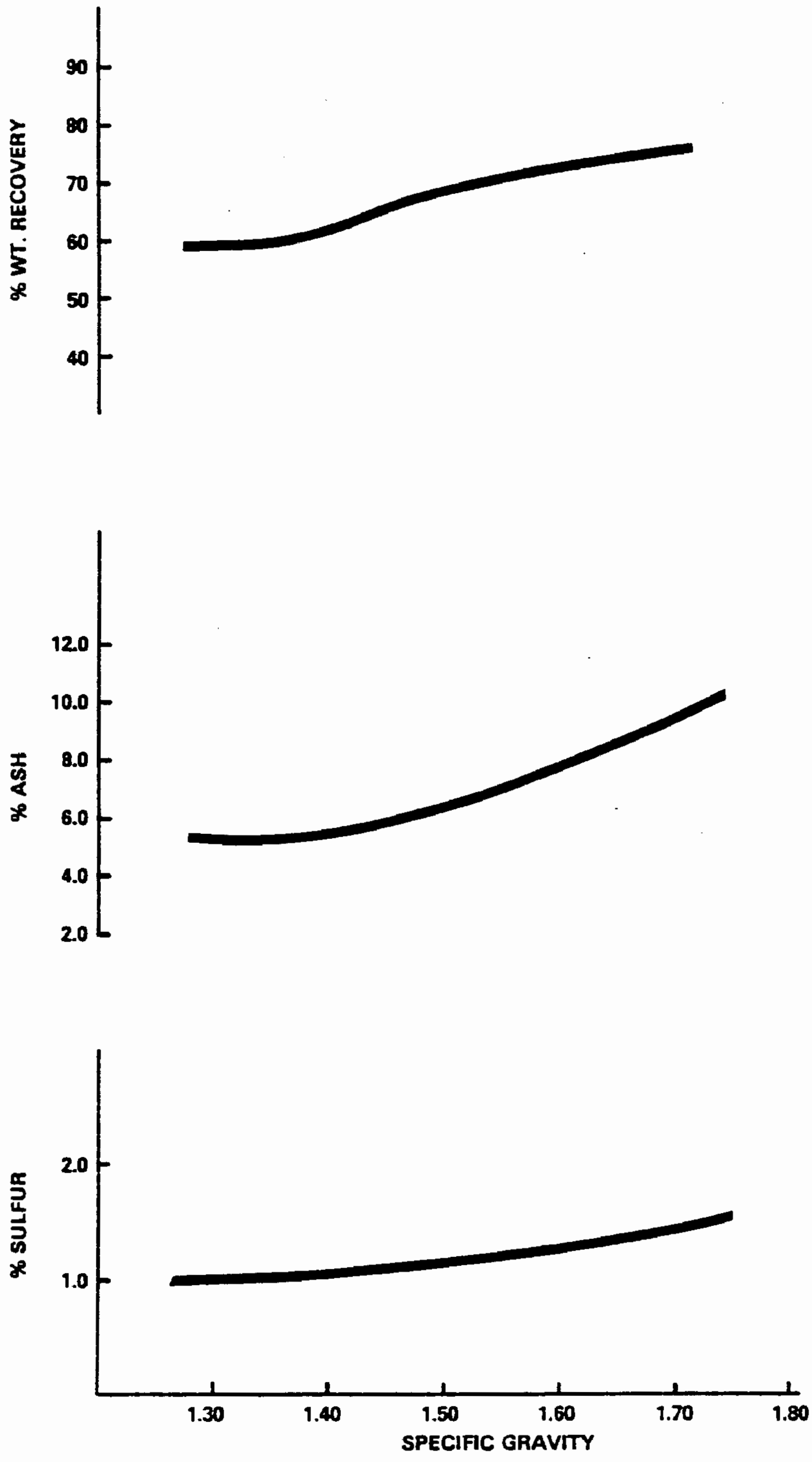

FIGURE 3-2a PERFORMANCE CHARACTERISTICS AT VARIOUS SPECIFIC GRAVITIES OF SEPARATION FOR A HIGH SULFUR EASTERN COAL (UPPER FREEPORT "E SEAM") AT A SIZE FRACTION OF 3/8" X 28M (9.5 mm x 28 M) (DRY BASIS)

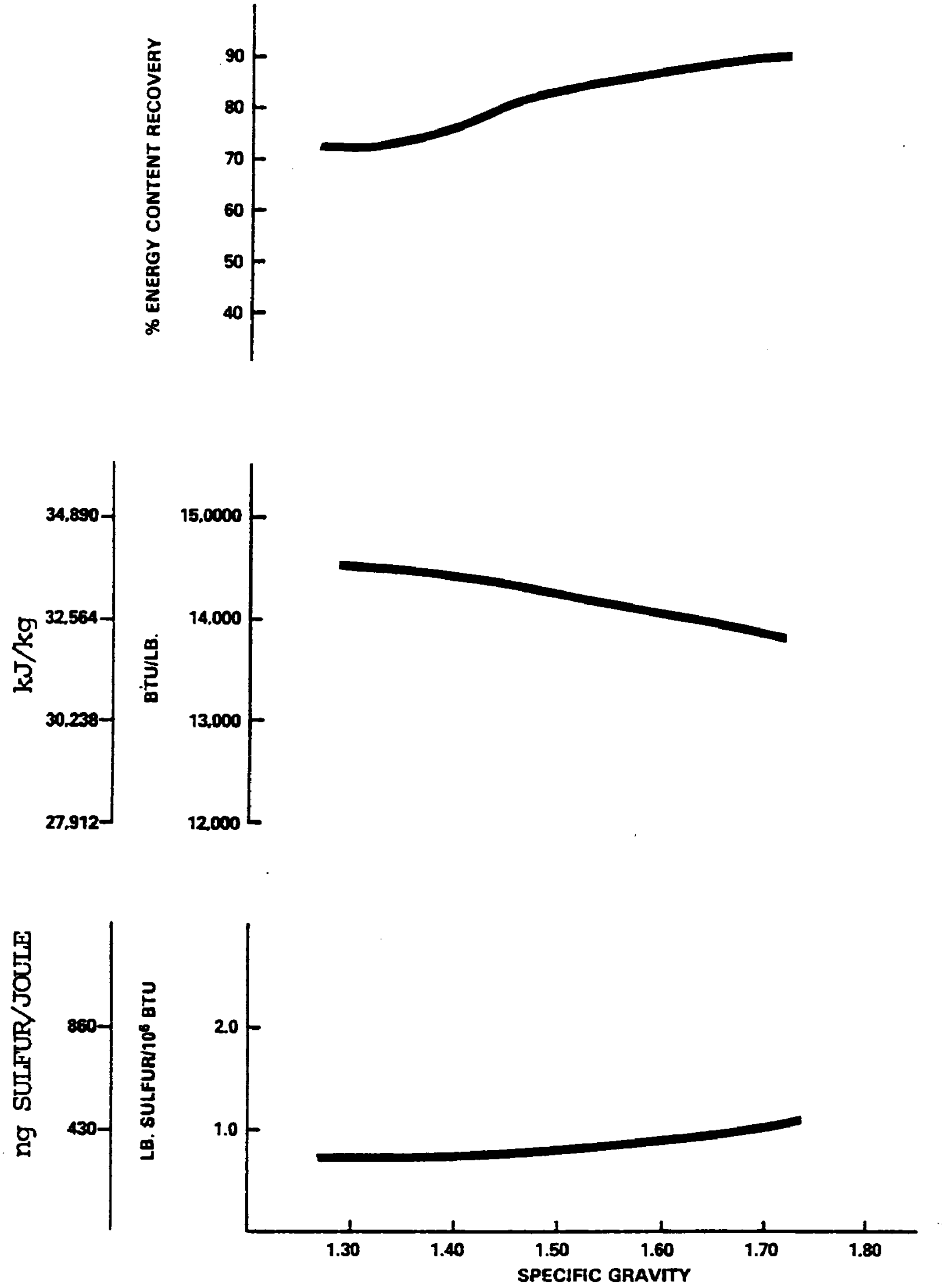

FIGURE 3-2b PERFORMANCE CHARACTERISTICS AT VARIOUS SPECIFIC GRAVITIES OF SEPARATION FOR A HIGH SULFUR EASTERN COAL (UPPER FREEPORT "E SEAM") AT A SIZE FRACTION OF 3/8" X 28 MESH (9.5 mm x 28 M) (DRY BASIS)

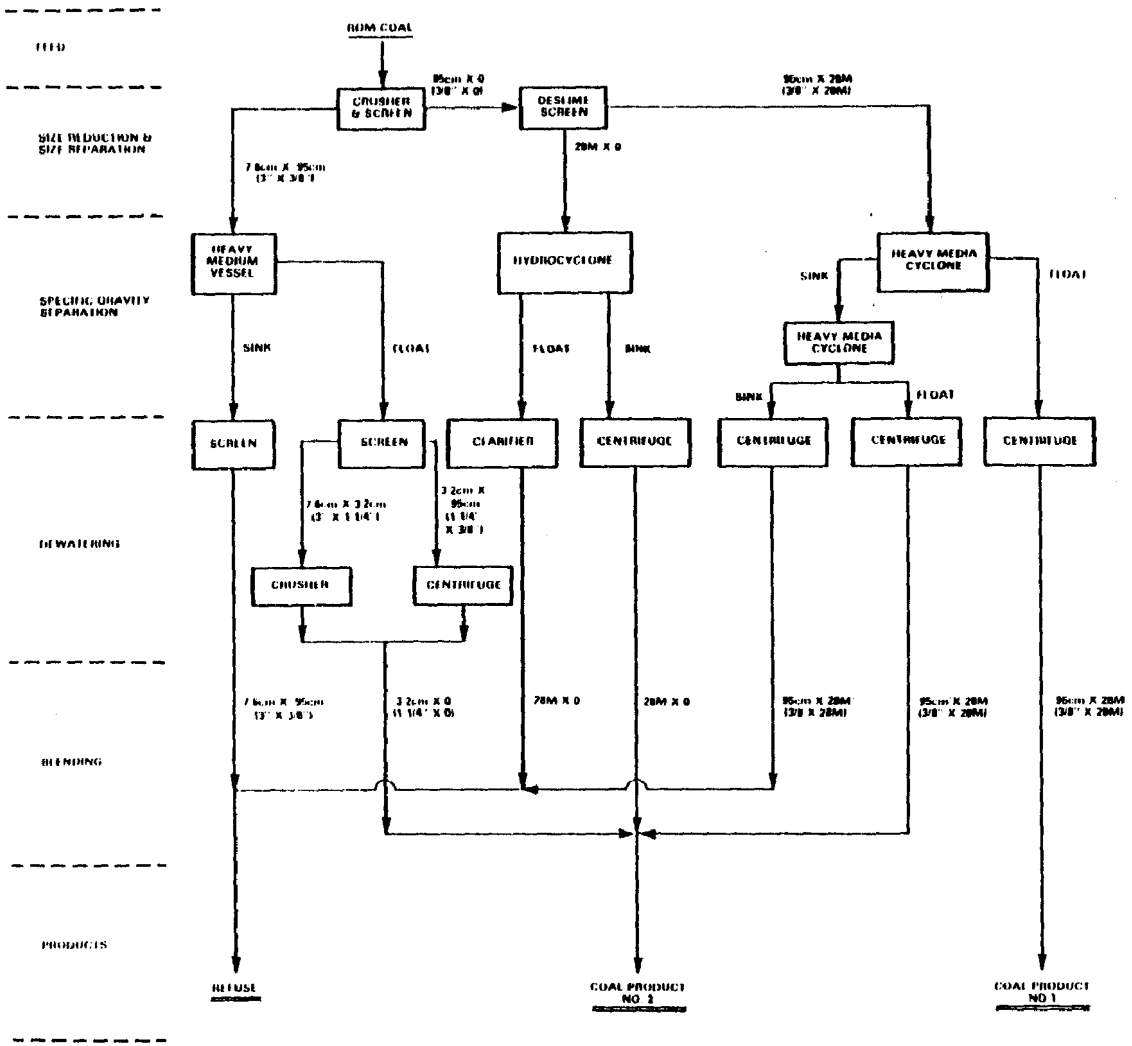

FIGURE 3-3 A LEVEL 5 COAL PREPARATION FLOWSHEET FOR BENEFICATION OF A HIGH SULFUR EASTERN COAL (UPPER FREEPORT SEAM) FOR STEAM FUEL PURPOSES

TABLE 3-16. PERFORMANCE SUMMARY OF LEVEL 5 COAL PREPARATION ON EASTERN HIGH SULFUR COAL FOR STEAM FUEL PURPOSES

RAW COAL

Heating Value +	26,772 kJ/kg (11,510 BTU/lb)
% Sulfur, Pyritic +	2.51
% Sulfur, Total +	3.45
Ash % +	23.90
Avg. Moisture %	5.0
ng $SO_2/10^6$ BTU	2,576 (5.99)

	Steam Fuel #1 (Deep Cleaned		Steam Fuel #2 (Middlings)	
Product Coal	Dry	As Rec'd	Dry	As Rec'd
Heating Value	33,555 kJ/kg (14,426 BTU/lb)	30,533 kJ/kg (13,127 BTU/lb.)	31,662 kJ/kg (13,612 BTU/lb.)	28,847 kJ/kg (12,402 BTU/lb.)
% Sulfur (Pyritic	-	-	-	-
Total	1.08	0.98	1.69	1.54
Ash %	5.80	5.28	11.31	10.30
Moisture %	-	-	-	-
ng $SO_2/10^6$.BTU (lb $SO_2/10^6$ BTU)	643 (1.50)	643 (1.50)	1,067 (2.48)	1,067 (2.48)

Performance

	Steam Fuel #1	Steam Fuel #2
% Wt. Recovery	35.33	38.00
% Energy Content Recovery	43.42	44.06
% Sulfur Reduction	68.24	50.30
% Ash Reduction	75.21	51.67
% SO_2/Energy Unit Content	74.15	57.12

Refuse

Ash % +	64.92
% Sulfur (Total) +	8.91
Heating Value +	12,563 kJ/kg (5,401 BTU/lb)

+ Values are on a dry basis

reduction from the raw coal is 57.1% based upon SO_2 emission per unit energy content. The sulfur reduction is 50.3%, while the ash reduction is 51.7%. This product would make an excellent fuel for a SIP-controlled industrial or utility boiler.

A mass balanced flowsheet for this two-product, level 5 plant is illustrated in Figure 3-4 . The input to the plant is 544 metric tons/hour (600 tons/hour) which is split into two streams at the raw coal screen. The coarser sized ma-terial is routed to the heavy media vessel at a rate of 163 metric tons/hour (180 tons/hour). This coarse sized coal is separated at a specific gravity 1.65 into a clean coal product of 124 metric tons/hour,(137 tons/hour) and a refuse stream of 39 metric tons/hour, (43 tons/hour). The clean coal from this coarse circuit is the major quantity of the middling product.

The fine coal stream from the raw coal screens is sized into two fractions at the deslime screens. The fine size fraction 28 mesh x 0 is cleaned in a hydrocyclone circuit with the clean coal reporting to the middling product and the refuse going to a clarifier and disk filter for dewatering. The intermediate-sized coal fraction 9.5 mm x 28 mesh (3/8" x 28 mesh) is fed to a heavy media cyclone circuit for separation at a low gravity, 1.43, to produce the "deep cleaned" coal product. The sink material from this circuit is recleaned in a heavy media cyclone circuit at 1.60 specific gravity to produce another portion of the middling product.

The conceptual flowsheet described above represents the BSER for physical coal cleaning on the high sulfur eastern coal. This control technology has been demonstrated to be capable of meeting a 645 ng SO_2/J (1.5 lbs $SO_2/10^6$ BTU) emission control level which is the intermediate emission limit. This 3SER physical coal cleaning control technology is also capable of meeting the moderate emissions control level of 1,290 ng SO_2/J (3.0 lbs $SO_2/10^6$ BTU) for this coal.

LEGEND

16'	= 487 cm
6'	= 183 cm
3'	= 91 cm
5"	= 125 mm
3"	= 75 mm
1 ¼"	= 31.5 mm
3/8"	= 9.5 mm
¼"	= 6.3 mm

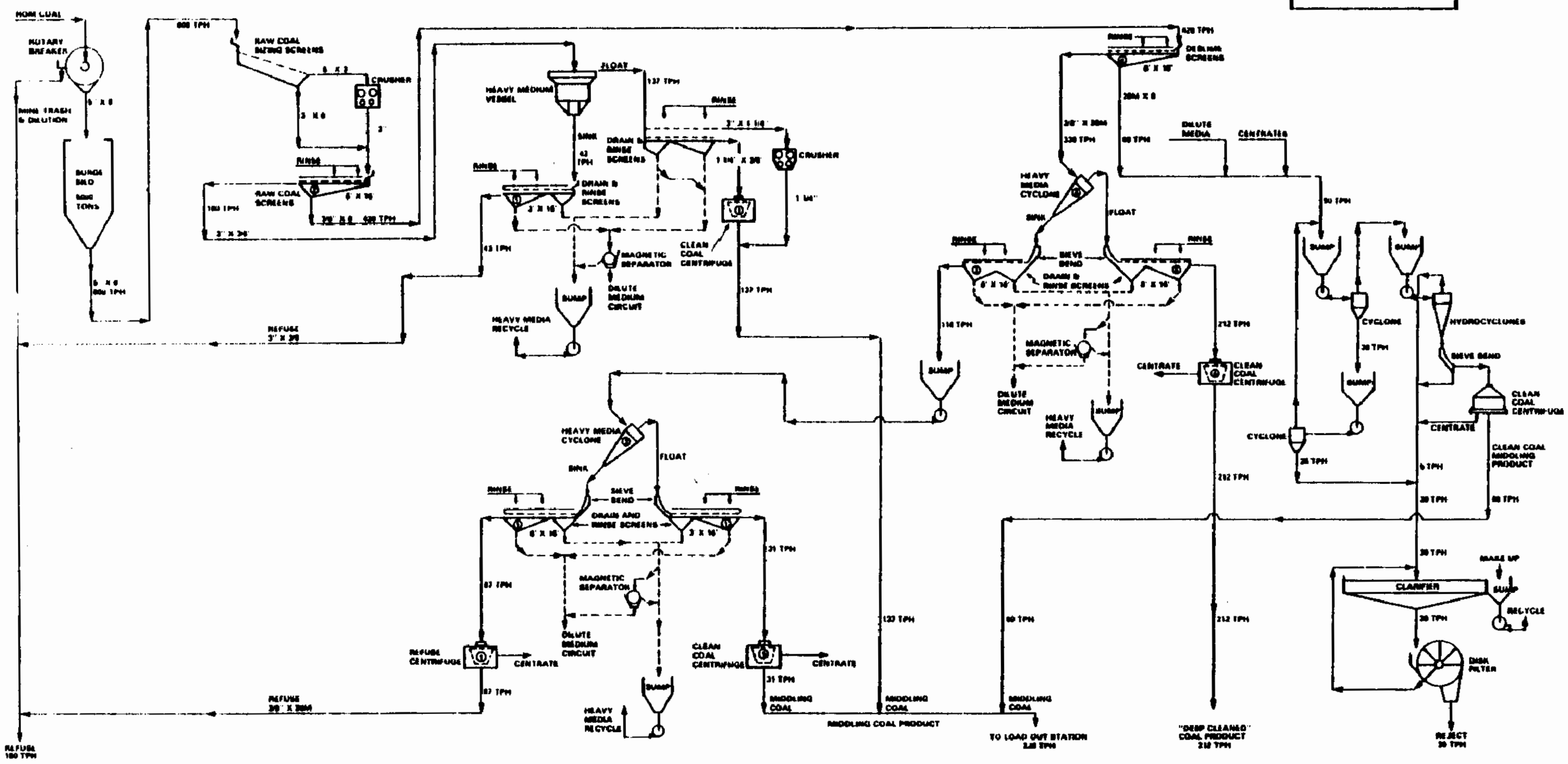

FIGURE 3-4 A LEVEL 5 COAL PREPARATION FLOWSHEET FOR BENEFICIATION OF A HIGH SULFUR EASTERN COAL (UPPER FREEPORT SEAM) FOR STEAM FUEL PURPOSES

Coal Preparation Flowsheet for the Low Sulfur Eastern Coal

A level 4 coal preparation flowsheet was designed to beneficiate the low sulfur eastern coal to produce a product coal which will achieve a 516 ng SO_2/J (1.2 lbs $SO_2/10^6$ BTU) emission control level on a long term average basis. The level 4 flowsheet was designed for this coal, based upon performance characteristic curves calculated for two size fractions from the washability data presented in Table 3-14 in a preceding section. The performance characteristics for two size fractions of the Eagle Seam low sulfur eastern coal at various specific gravities of separation are shown on Figures 3-5 and 3-6.

Based on the performance characteristics shown on these figures, it was decided that the flowsheet for this coal should include washing of three size fractions to obtain a clean coal product which achieves maximum SO_2 reduction at an acceptable energy recovery.

The coarse coal fraction is beneficiated in a heavy media vessel at 1.65 specific gravity to yield a coarse coal product with considerably less ash, some reduction in sulfur and enhanced energy content. The intermediate size coal fraction is beneficiated in a heavy media cyclone circuit at 1.5 specific gravity. This produces a product with slightly higher sulfur content than the coarse coal product, but a lower ash content and enhanced energy content. The fine size coal fraction is beneficiated in a hydrocyclone circuit to reduce ash and sulfur content, with an increase in product energy content. The clean coal products from each circuit are combined to produce a plant product which achieves maximum SO_2 reduction with an acceptable energy recovery.

A level 4 coal preparation flowsheet for the low sulfur eastern coal (Eagle Seam) is shown on Figure 3-7. Table 3-17 presents a performance summary of the clean coal product from this flowsheet. After crushing and removal of coarse refuse, the raw coal is screened, sized and further crushed to produce two size fractions, 5" x 1/4" (125 mm x 6.3 mm) and 1/4" x 0 (6.3 mm x 0).

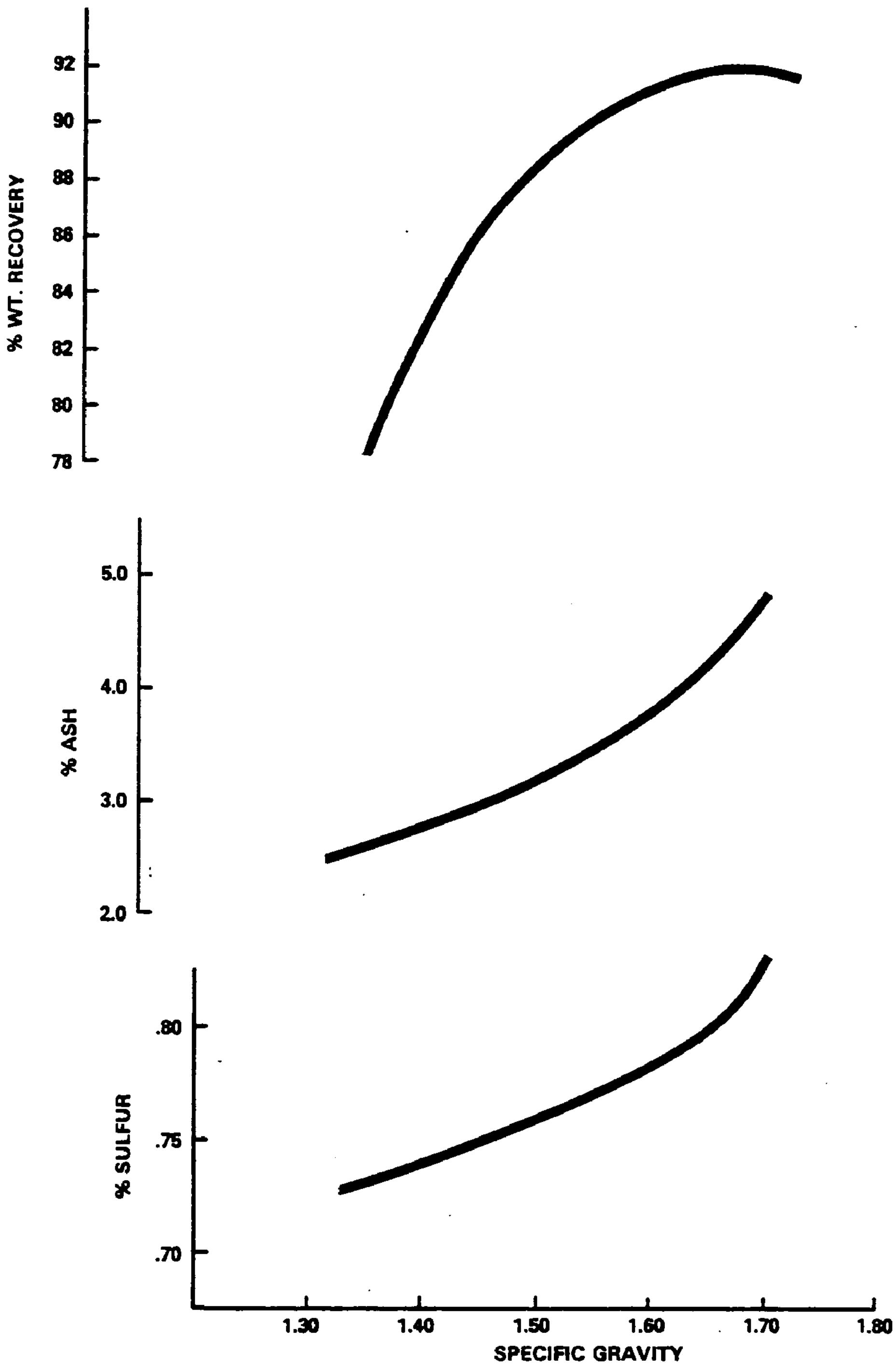

FIGURE 3-5a PERFORMANCE CHARACTERISTICS AT VARIOUS SPECIFIC GRAVITIES OF SEPARATION FOR A LOW SULFUR EASTERN COAL (EAGLE SEAM) AT A SIZE FRACTION OF 5" X 1/4" (125 mm x 6.3 mm) (DRY BASIS)

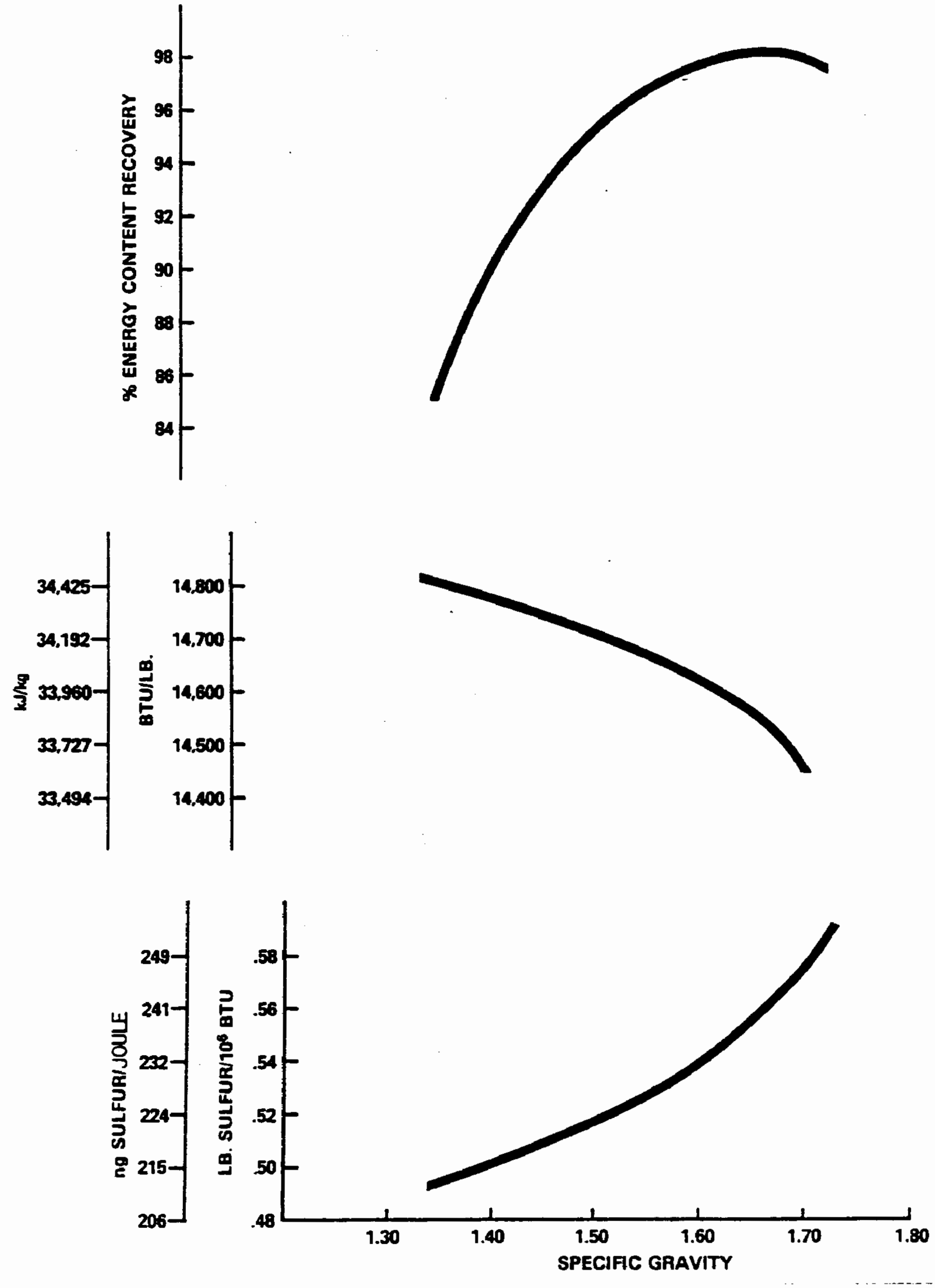

FIGURE 3-5b PERFORMANCE CHARACTERISTICS AT VARIOUS SPECIFIC GRAVITIES OF SEPARATION FOR A LOW SULFUR EASTERN COAL (EAGLE SEAM) AT A SIZE FRACTION OF 5" X 1/4" (125 mm x 6.3 mm) (DRY BASIS)

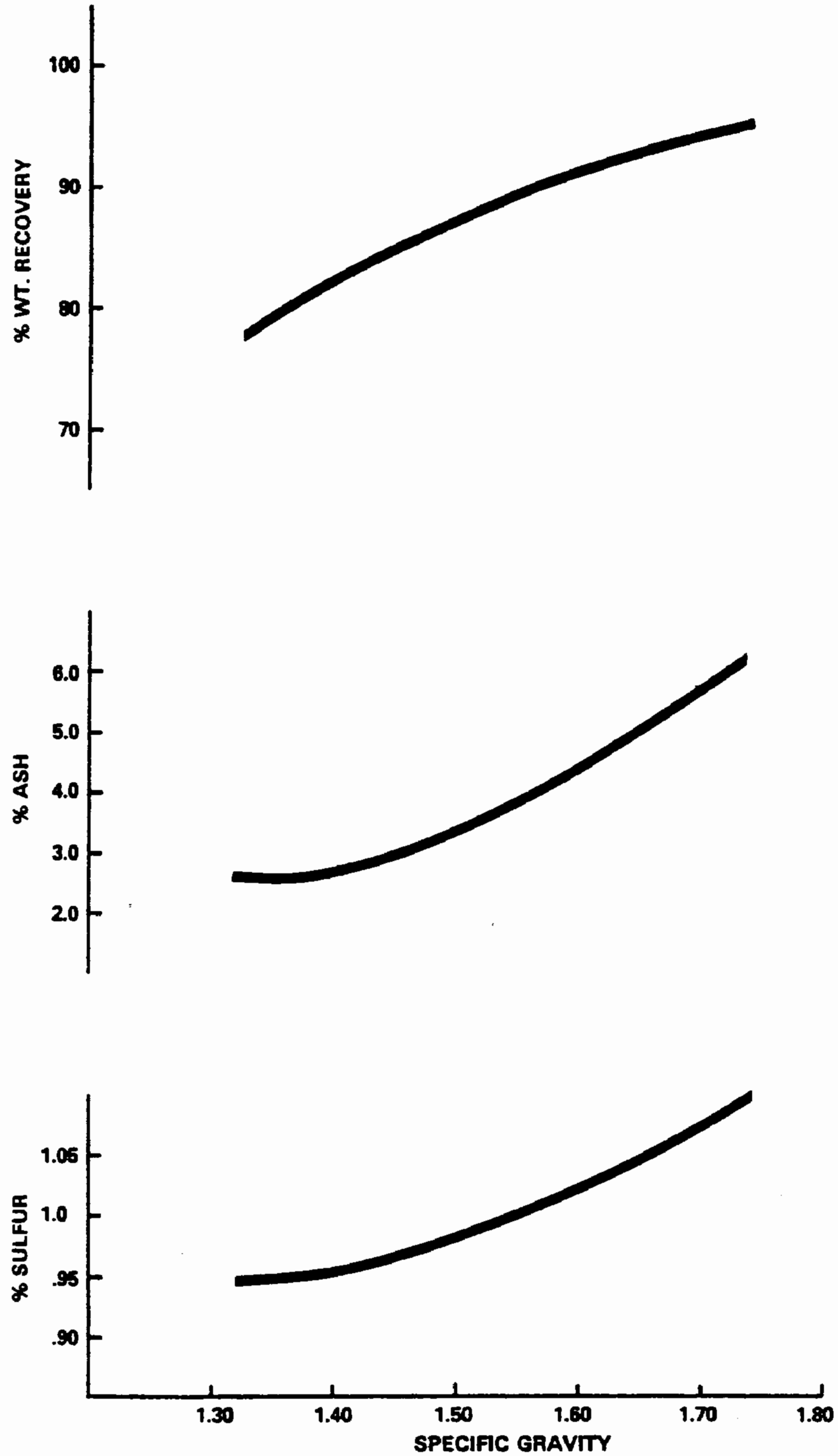

FIGURE 3–6a PERFORMANCE CHARACTERISTICS AT VARIOUS SPECIFIC GRAVITIES OF SEPARATION FOR A LOW SULFUR EASTERN COAL (EAGLE SEAM) AT A SIZE FRACTION OF 1/4" X 28 MESH (6.3 mm x 28 M) [DRY BASIS]

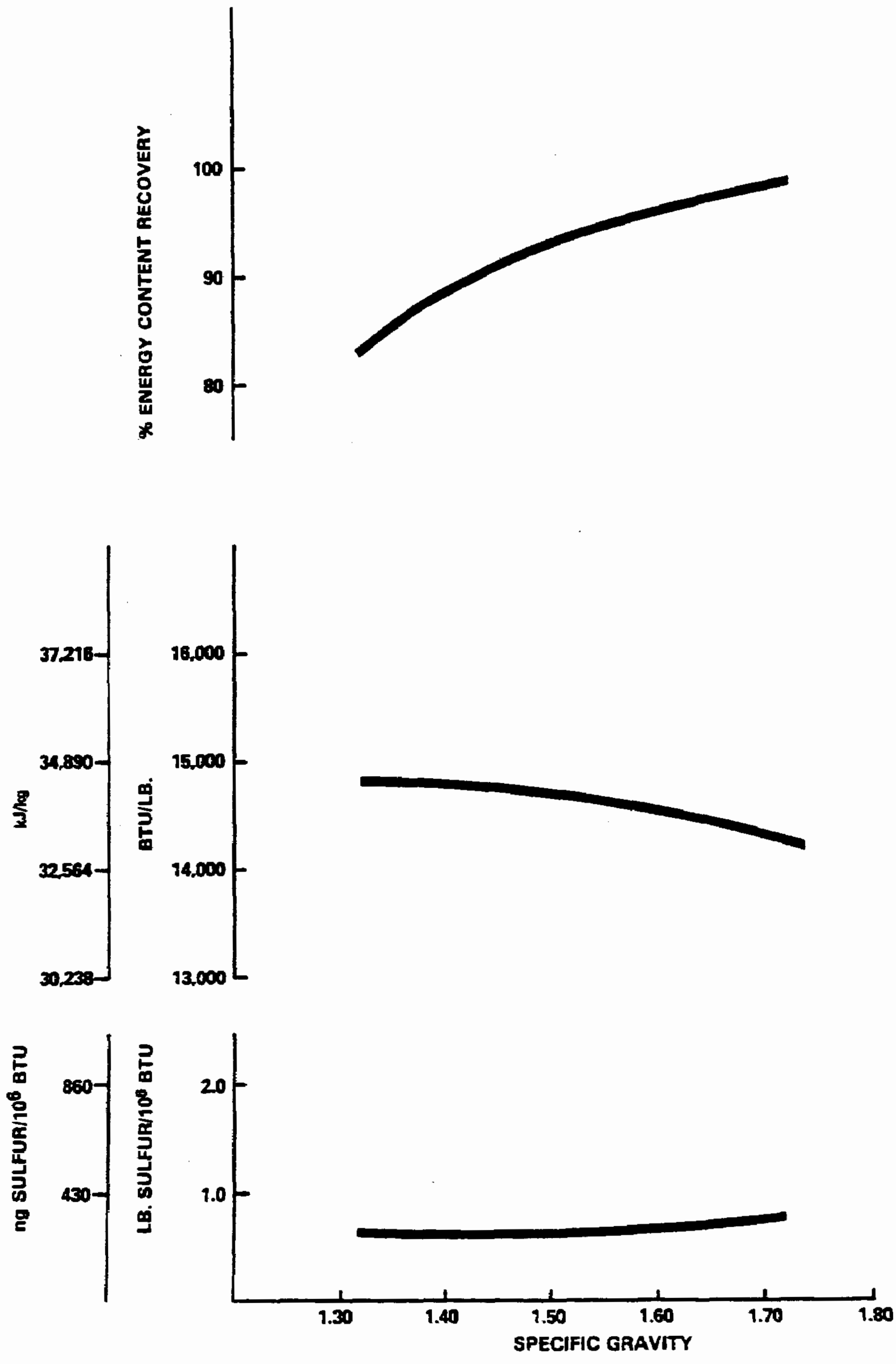

FIGURE 3–6b PERFORMANCE CHARACTERISTICS AT VARIOUS SPECIFIC GRAVITIES OF SEPARATION FOR A LOW SULFUR EASTERN COAL (EAGLE SEAM) AT A SIZE FRACTION OF 1/4" X 28 MESH (6.3 mm x 28 M) (DRY BASIS)

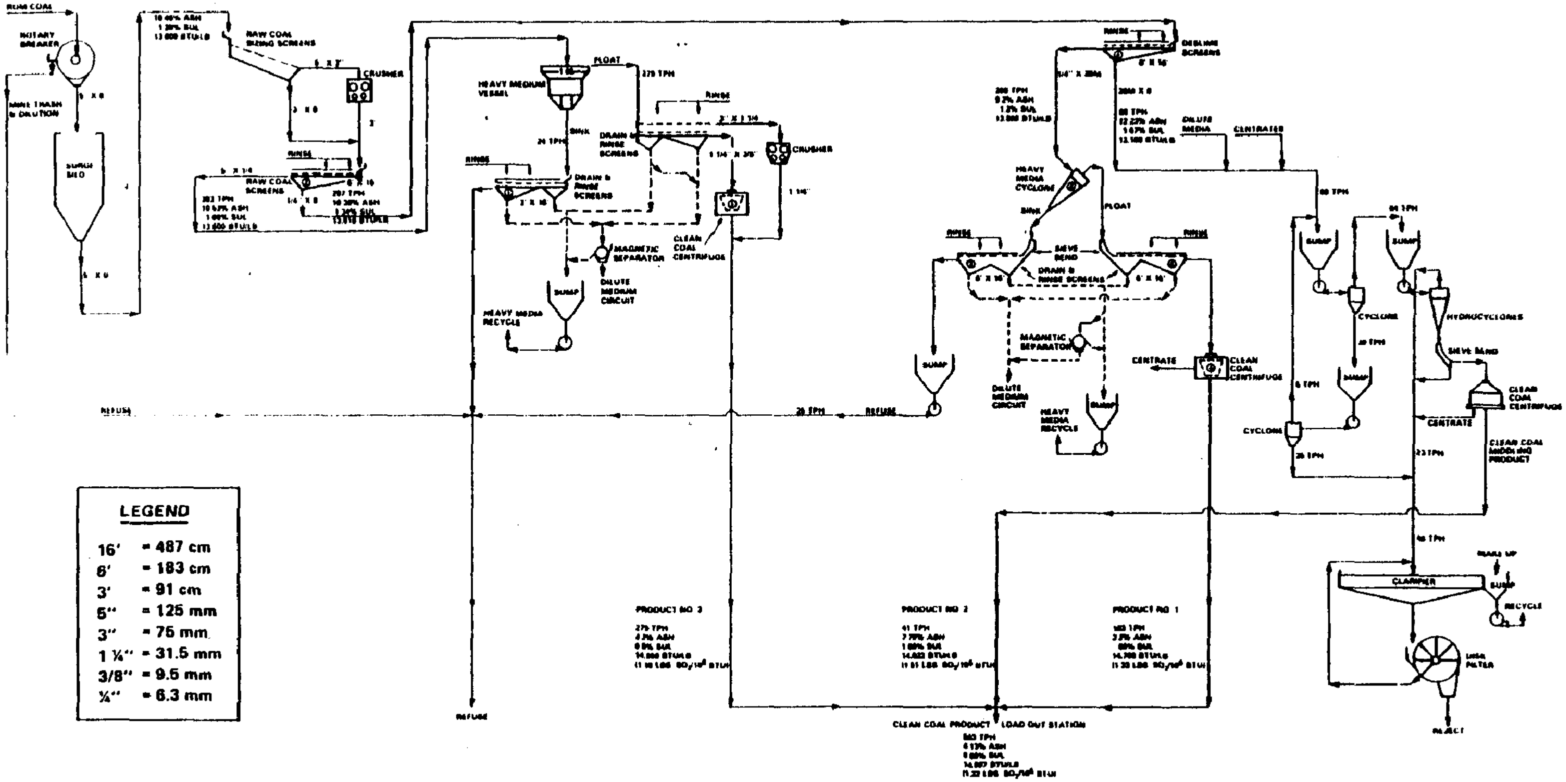

FIGURE 3-7 A LEVEL 4 COAL PREPARATION FLOWSHEET FOR BENEFICIATION OF A LOW SULFUR EASTERN COAL (EAGLE SEAM) FOR STEAM FUEL PURPOSES

TABLE 3-17. Performance Summary of Level 4 Coal Preparation on Reference Low Sulfur Eastern Coal For Steam Fuel Purposes

RAW COAL	
Heating Value,* kJ/kg (BTU/lb)	31,685 (13,622)
% Pyritic Sulfur*	0.60
% Total Sulfur*	1.18
% Ash*	10.38
% Moisture	2.0
ng SO_2/J (lb. $SO_2/10^6$ BTU)	744 (1.73)
PRODUCT COAL	
Heating Value,* kJ/kg (BTU/lb.)	33,883 (14,567)
% Total Sulfur*	0.89
% Ash*	4.13
ng SO_2/J (lb. $SO_2/10^6$ BTU)	524 (1.22)
PERFORMANCE	
% Wt. Recovery	84
% Energy Content Recovery	90
% Sulfur Reduction	25
% Ash Reduction	60
% ng SO_2/J (lb. $SO_2/10^6$ BTU) Reduction	12,468 (29)

* Moisture-Free

The coarse fraction is conveyed to a heavy media vessel of specific gravity 1.65. After removal of the heavy media in drain and rinse screens, the sink product of the heavy media vessel is disposed of and the float product is crushed to a minus 3.17 cm. (1 1/4") size, dewatered in a centrifuge and conveyed to clean coal storage. The fine raw coal fraction is further fractionated with the introduction of water on desliming screens into a 6.4 mm x 28 mesh (1/4" x 28 M) fraction and a 28 M x 0 fraction. The larger fraction is beneficiated in a heavy media cyclone, with the sink going to refuse storage and the float going to clean coal storage after dewatering in a centrifuge. As before, the heavy media is recovered from both sink and float products on drain and rinse screens immediately following separation in the cyclone.

The fine product off the desliming screens goes to a complex circuit of sumps and cyclones for further beneficiation and dewatering. A hydrocyclone is used to separate ultrafines from somewhat larger size particles. Ultrafines flow to a clarifier and then to a disk filter for thickening and dewatering. The filter cake is disposed of as refuse. The beneficiated fines are combined with previously cleaned coal products for blending and storage.

Coal Preparation Flowsheet for the Low Sulfur Western Coal

Graphs of attainable clean coal characteristics as a function of specific gravity of separation were produced for two coal size fractions from the washability data given in Table 3-15; for the low sulfur western coal (Primero Seam). These graphs are shown on Figures 3-8 and 3-9. Since the major weight fraction of the coal falls in the 3.8 cm x 0.63 cm (1 1/2 inch x 1/4 inch) size fraction, it was decided that a level 2 flowsheet should be designed for this coal type to maximize yield. In the level 2 flowsheet, the coarse coal fraction is washed, while the fine coal fraction is simply blended into the product coal. The combined clean coal product from this plant is considerably lower in ash than the raw coal, with a corresponding increase in heating value. However the percentage of total sulfur in the product is slightly greater than in the raw coal

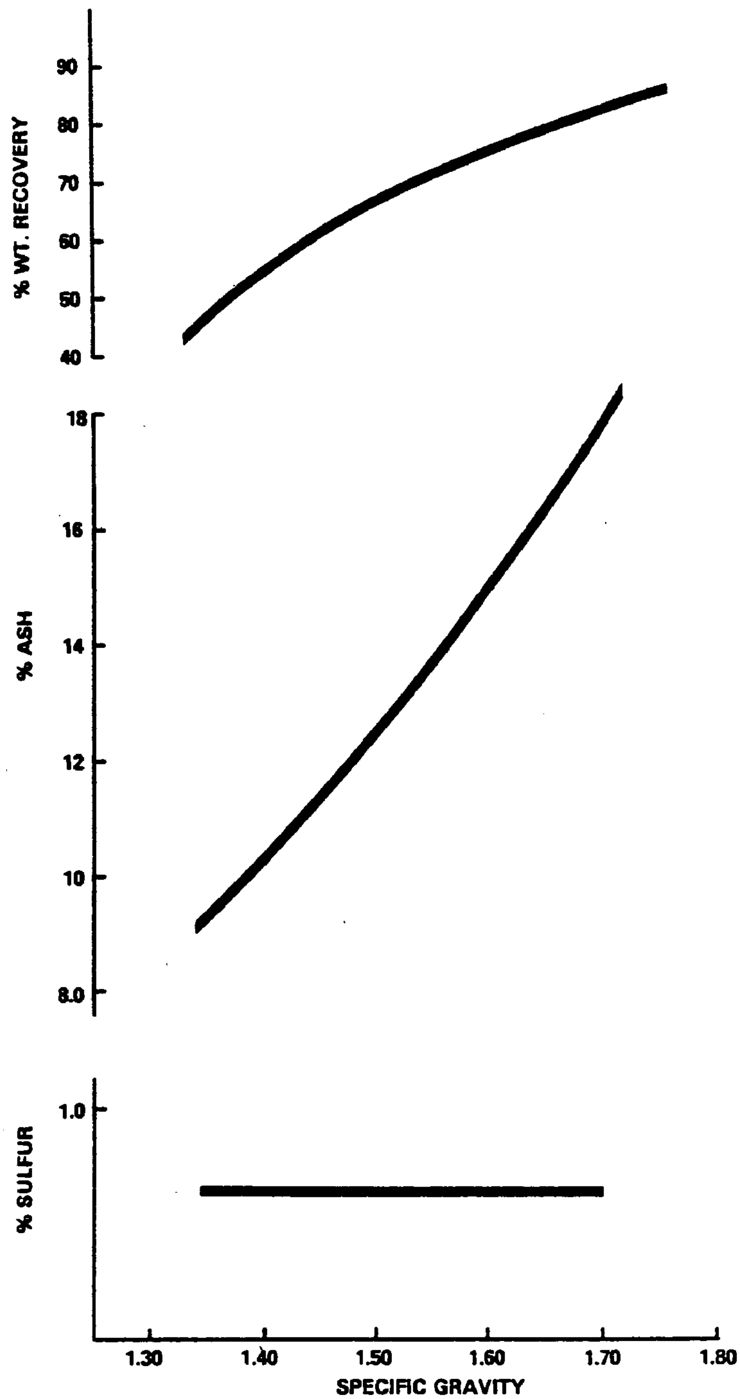

FIGURE 3–8a PERFORMANCE CHARACTERISTICS AT VARIOUS SPECIFIC GRAVITIES OF SEPARATION FOR A LOW SULFUR WESTERN COAL (PRIMERO SEAM) AT A SIZE FRACTION OF 1 1/2" X 1/4" (37.5 mm x 6.3 mm) [DRY BASIS]

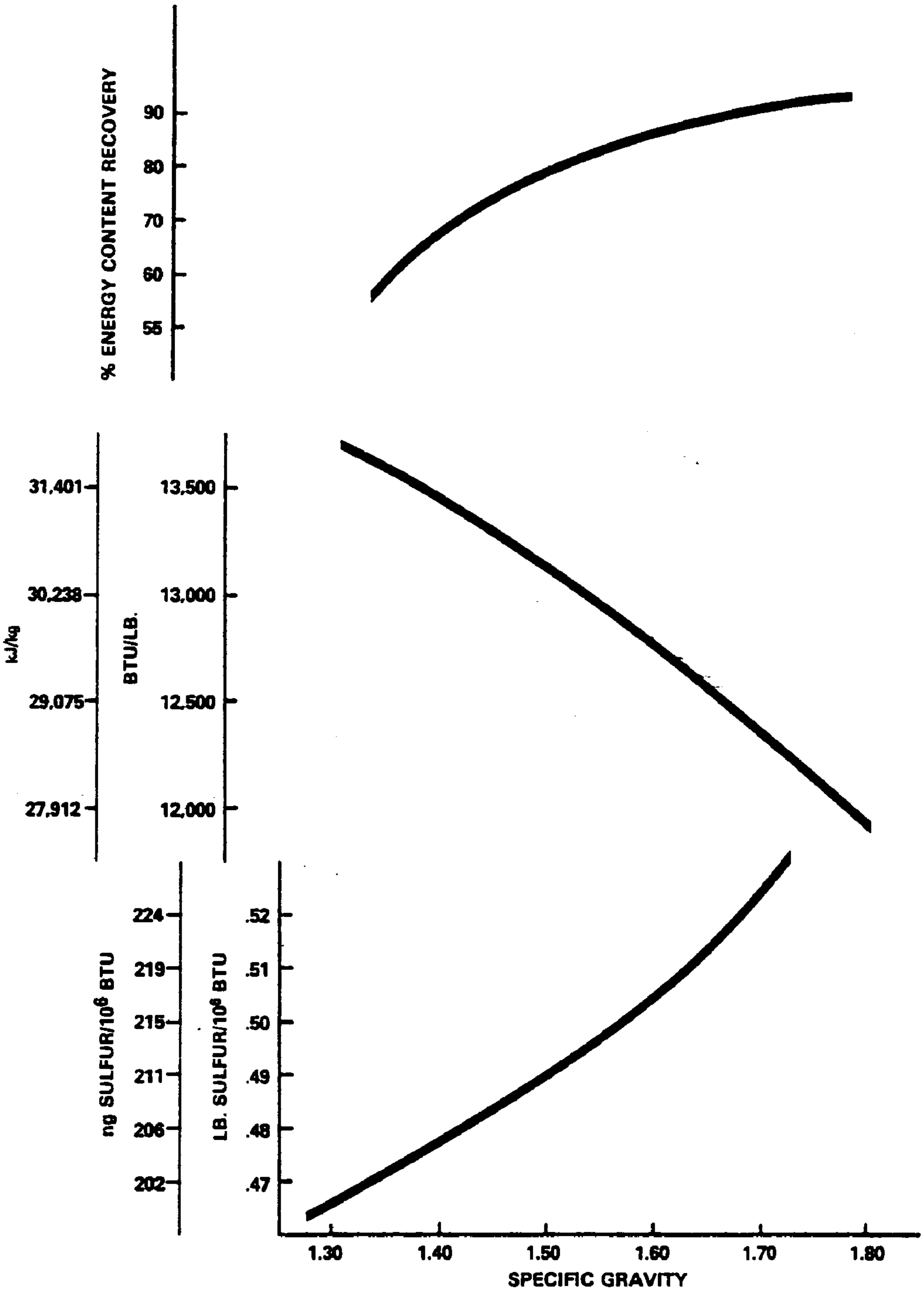

FIGURE 3-8b PERFORMANCE CHARACTERISTICS AT VARIOUS SPECIFIC GRAVITIES OF SEPARATION FOR A LOW SULFUR WESTERN COAL (PRIMERO SEAM) AT A SIZE FRACTION OF 1 1/2" X 1/4" (37.5 mm x 6.3 mm) [DRY BASIS]

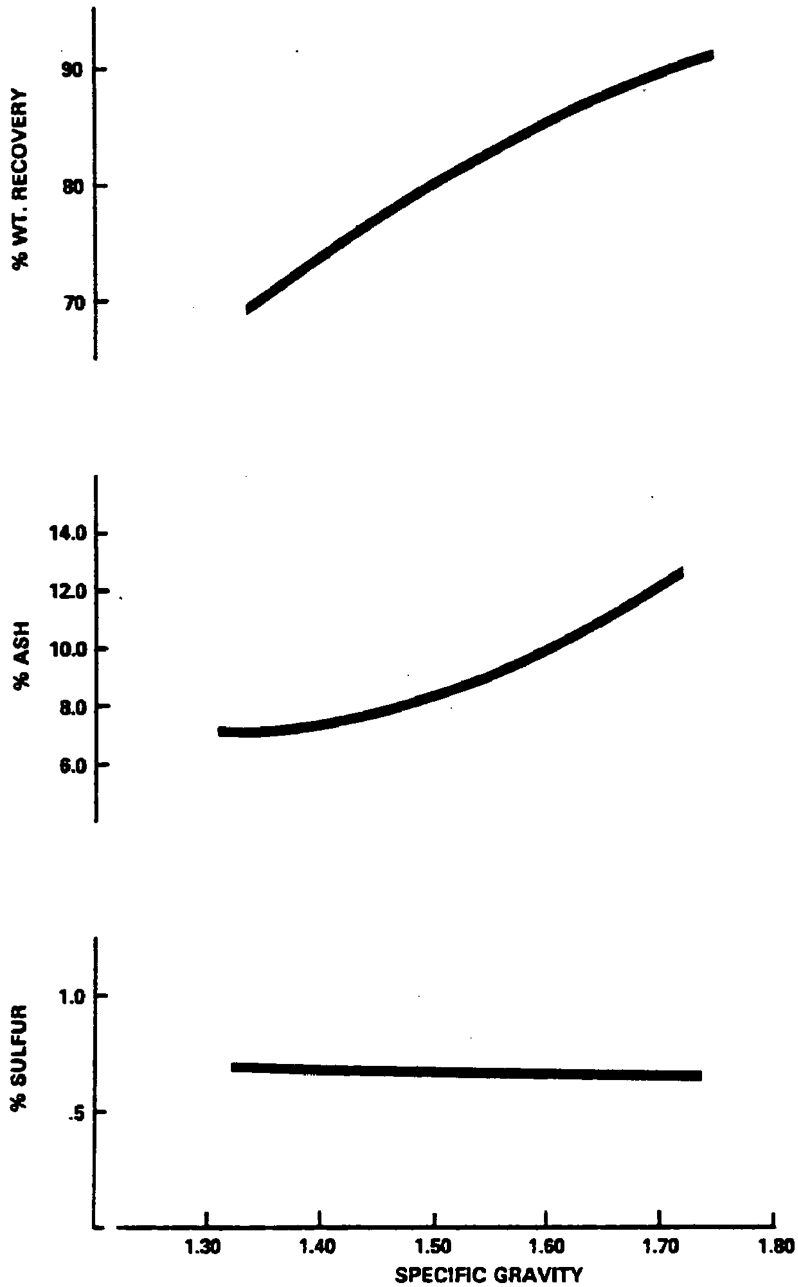

FIGURE 3-9a PERFORMANCE CHARACTERISTICS AT VARIOUS SPECIFIC GRAVITIES OF SEPARATION FOR A LOW SULFUR WESTERN COAL (PRIMERO SEAM) AT A SIZE FRACTION OF 1/4" X 28 MESH (6.3 mm x 28 M) (DRY BASIS)

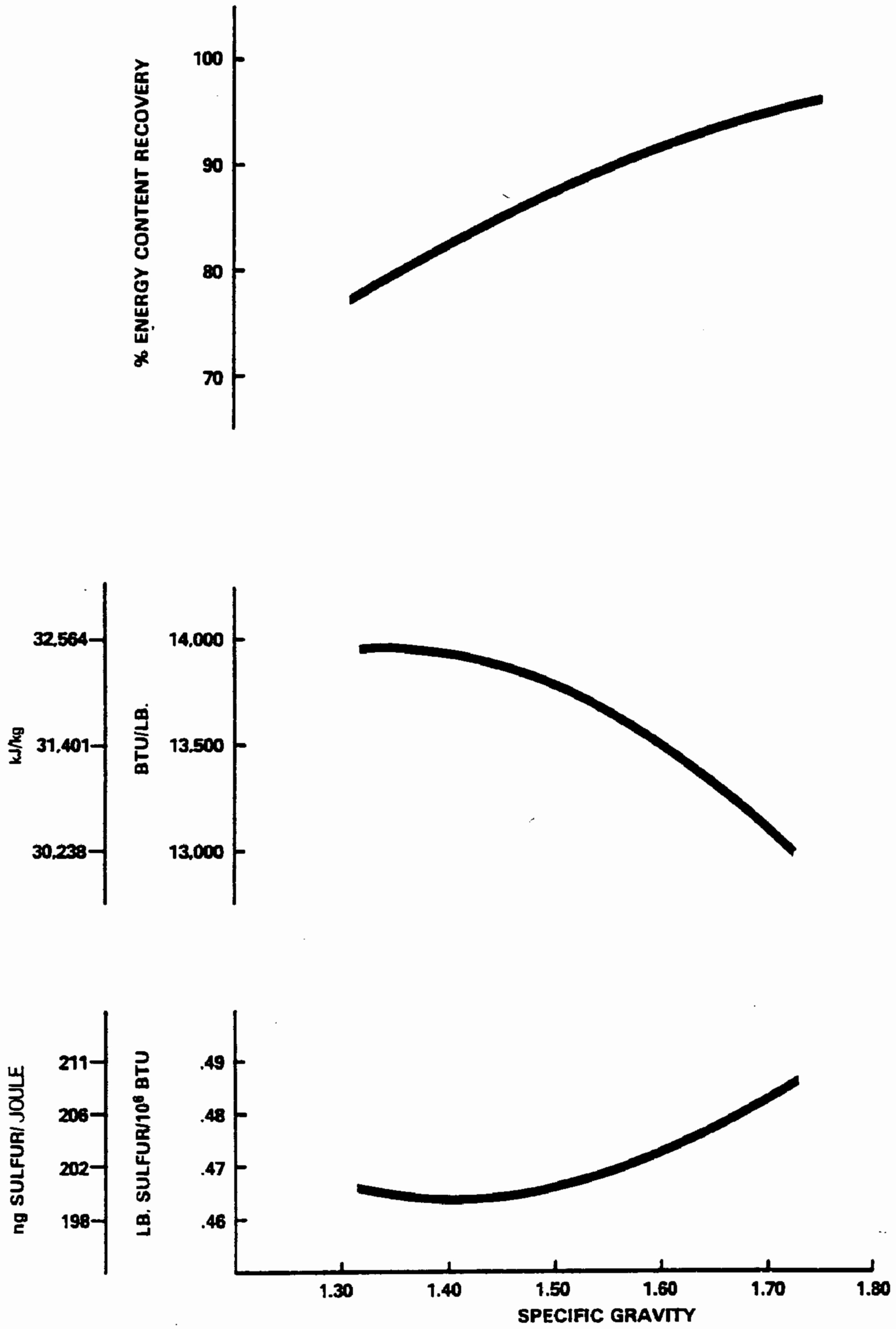

FIGURE 3-9b PERFORMANCE CHARACTERISTICS AT VARIOUS SPECIFIC GRAVITIES OF SEPARATION FOR A LOW SULFUR WESTERN COAL (PRIMERO SEAM) AT A SIZE FRACTION OF 1/4" X 28 MESH (6.3 mm x 28 M) (DRY BASIS)

reflecting a concentration of the organic sulfur in the product. The mass balanced flowsheet for this coal is shown on Figure 3-10 . Table 3-18 presents the performance characteristics of the clean coal product in comparison to the raw coal. As can be readily seen from the comparison shown in this table, the reduction in ash is appreciable, while the reduction in SO_2 emission per unit heating value is almost negligible, i.e., only 1%.

3.2.2.3 Chemical Coal Cleaning Systems as a BSER--

This section presents a comparison of technical results and preliminary costs obtained from conceptual application of three chemical coal cleaning systems on the three representative coals chosen for comparison in this ITAR. The analysis and conclusions presented herein are based on process claims made by the process developers, research reports and other published information. The results obtained are based upon best engineering judgment from conceptual systems.

Performance of Chemical Coal Cleaning Systems on the High Sulfur Eastern Coal

The data presented in Table 3-19 reflects the best level of performance that each of these candidate chemical coal cleaning processes (Meyers, ERDA, Gravichem) can attain when applied to a high sulfur eastern coal. The main objective in chemical coal cleaning is to reduce the emitted amount of sulfur dioxide produced during coal combustion. The ERDA process most effectively accomplishes this task of SO_2 reduction from this particular coal. Approximately 529 ng SO_2/J (1.23 lbs $SO_2/10^6$ BTU) are released after implementation of the ERDA technology. The Gravichem and Meyers processes perform in the same range of emission levels as ERDA [580.5 ng SO_2/J (1.35 lbs $SO_2/10^6$ BTU) and 636.4 ng SO_2/J (1.48 lbs $SO_2/10^6$ BTU), respectively], but not as effectively.

The second most important consideration in evaluating the performance of these chemical cleaning processes is the usable heating value of the product coal. Here the Gravichem process appears best, providing 30,466 kJ/kg (13,098 BTU/lb) of energy in the cleaned coal product. The ERDA and

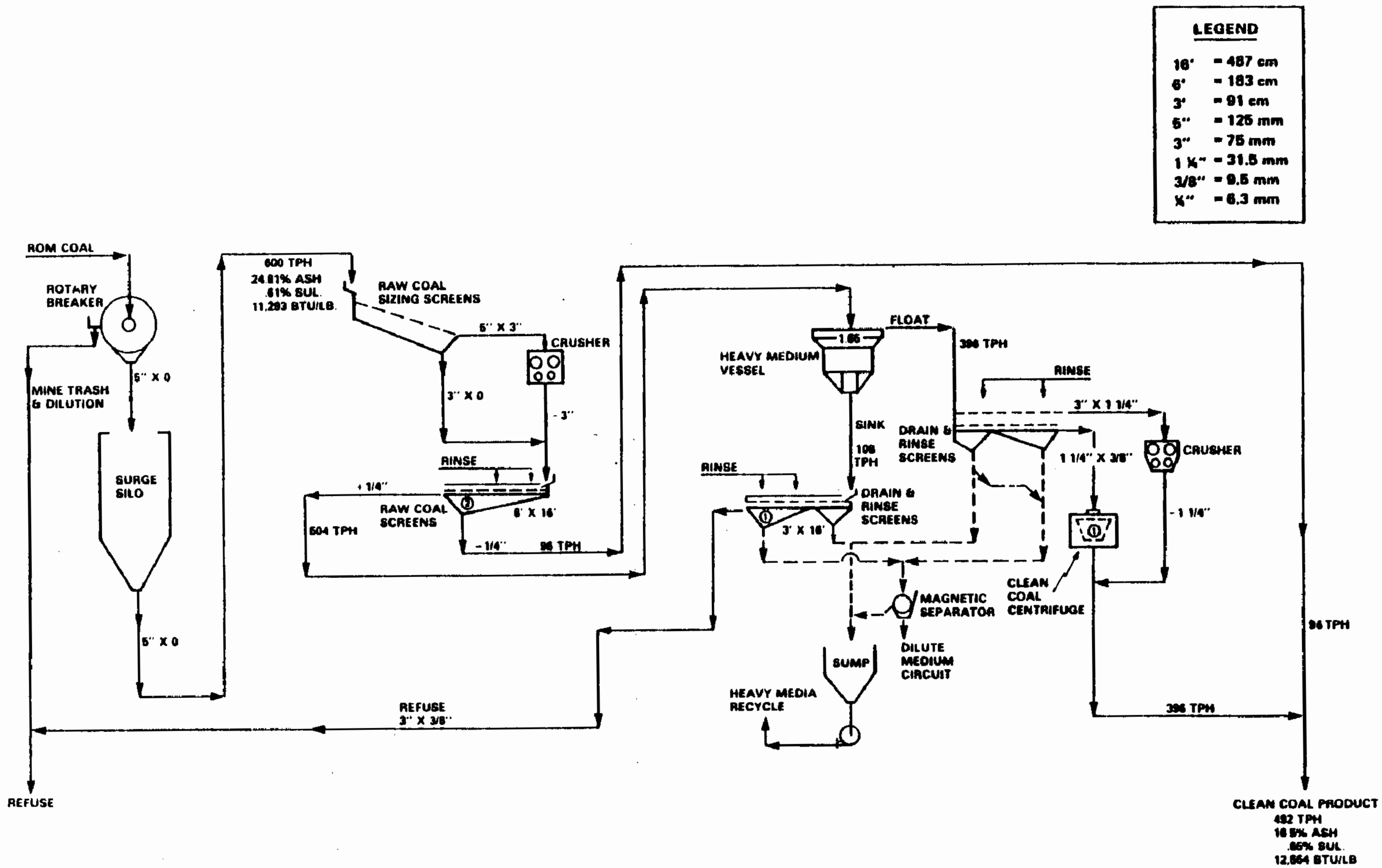

FIGURE 3-10 A LEVEL 2 FLOWSHEET FOR COAL PREPARATION OF A LOW SULFUR WESTERN COAL (PRIMERO SEAM) FOR STEAM FUEL PURPOSES

TABLE 3-18 Performance Summary of A Level 2 Flowsheet on the Western Low Sulfur Coal (Primero Seam)

RAW COAL	
Heating Value* kJ/kg (BTU/lb.)	26,268 (11,293)
% Pyritic Sulfur*	.30
Total Sulfur %*	.61
Ash %*	24.81
Moisture %	2.5
ng SO_2/J (lbs SO_2/10^6 BTU)	447.2 (1.04)
PRODUCT COAL	
Heating Value*, kJ/kg (BTU/lb.)	29,201 (12,554)
% Total Sulfur*	.65
Ash %*	16.5
ng SO_2/J (lbs SO_2/10^6 BTU)	442.9 (1.03)
PERFORMANCE	
% Wt. Recovery	82
% Energy Content Recovery	91.2
% Sulfur Reduction	6.5 (increase)
% Ash Reduction	33.5
ng SO_2/10^6 (% lb. SO_2/10^6 BTU) Reduction	430 (1.0)
REFUSE	
Energy Content kJ/kg (BTU/lb.)*	12,916 (5,553)
Ash %*	62.63
% Total Sulfur*	.46

* Moisture Free

TABLE 3-19 PROCESS AND COST PERFORMANCE OF CANDIDATE CHEMICAL COAL CLEANING SYSTEMS FOR A HIGH SULFUR EASTERN COAL

	Feed*	Product Coal From MEYERS PROCESS	Product Coal From ERDA Process	Product Coal From GRAVICHEM Process
Net Coal Yield, Metric Tons Per Day (Tons/Day)	7,250 (8,000)	6,532 (7,200)	6,532 (7,200)	5,792 (6,384)
Pyritic Sulfur Removal (%)	——	90	90	90
Organic Sulfur Removal (%)	——	——	25	——
Percent Net Energy Content	——	94	94	91
Percent Weight Yield	——	90	90	79.8
Weight % Sulfur in Product	3.45	0.89	0.73	0.89
Heating Value kJ/kg (BTU/lb.)	26,772 (11,510)	28,507 (12,256)	28,507 (12,256)	31,126 (13,382)
$\frac{NgSO_2}{J}$ (lb. $SO_2/10^6$ BTU)	2,576 (5.99)	623.4 (1.45)	511.6 (1.19)	571.8 (1.33)
Installed Capital Cost ($MM)	——	174.8	224.6	64.9
Annual Processing Excluding Coal Cost ($MM)	——	53.3	70.8	21.6
Annual Processing Including Coal Cost ($MM)	——	98.1	115.7	55.6
$/Annual Metric Ton ($ Annual Ton) of Clean Coal, Excluding Coal Cost	——	24.73 (22.43)	32.85 (29.80)	14.92 (13.53)
$/Annual Metric Ton ($/Annual Ton) of Clean Coal, Including Coal Cost +	——	45.55 (41.31)	53.69 (48.70)	38.40 (34.83)
$/Kilojoule ($/10^6BTU), Excluding Coal Cost	——	0.87 (0.92)	1.16 (1.22)	0.48 (0.51)
$/Kilojoule ($/10^6BTU), Including Coal Cost +	——	1.60 (1.69)	1.89 (1.99)	1.23 (1.30)

* The coal selected is an Upper Freeport ('E' Coal) from Butler County, Pennsylvania which contains 3.45 weight percent total sulfur, 2.51 weight percent pyritic and 0.94 weight percent organic sulfur on a dry basis. It is assumed that this coal has a heating value of 26,772 kJ/kg (11,510 BTU/lb).

+ Raw Coal Cost, $18.74/kkg ($17,00/ton).

Meyers processes each can provide 27,903 kJ/kg (11,996 BTU/lb) in the final product. One consideration which is closely tied to the obtainable energy content (in terms of evaluating the total product heating content) is the net coal yield attainable with each cleaning technology. Both the Meyers and ERDA processes have yields of 90 percent, while Gravichem will recover (by weight) 79.8 percent of the original raw feed.

The final major source of performance variability among the processes lies in the weight percent of sulfur in the product coal. The weight percentage of total sulfur in the product of coal cleaned by either the Meyers or Gravichem process equals 0.89%. Greater sulfur removal is accomplished by the ERDA process, producing a 0.73 total sulfur percentage. The reason ERDA has a lower percent figure is that it removes both pyritic and organic sulfur from the raw coal. Meyers and Gravichem processes only take out the pyritic sulfur. Comparison on a pyritic removal basis shows that all three processes remove 90 percent. In addition, ERDA removes 25 percent of the organic sulfur material from the coal.

The increased sulfur removal and cleaning efficiency of the ERDA process results in increased cleaning costs. For both the capital and processing cost segments of the total cost, the ERDA process has the highest of the three cleaning technologies. The total (pretransportation) cost to a user including the cost of the raw coal is \$1.82/kJ (\$2.03/10^6 BTU). The same cost figures for the Meyers and Gravichem processes are approximately 15 and 35 percent less, respectively, than ERDA.

To summarize, ERDA has the lowest SO_2 emission level, the highest per kilojoule (per BTU) cost and an intermediate energy content. The Meyers process gives the highest SO_2 emission level and an intermediate total cost and energy content. Gravichem cleaning results in the lowest total cost, the highest energy content and an intermediate SO_2 emission level.

Performance of Chemical Coal Cleaning Systems on a Low Sulfur Eastern Coal

The process performance and preliminary cost information for the candidate chemical coal cleaning processes on a low sulfur eastern coal are summarized in Table 3-20 . Of the three processes Meyers, ERDA, and Gravichem the ERDA process extracts sulfur in both its inorganic and organic forms, resulting in the lowest level of SO_2 emissions of the three processes, 300 ng SO_2/J (0.70 lbs $SO_2/10^6$ BTU). However, all of these processes produce a clean coal product having less than 387 ng SO_2/J (0.90 lbs $SO_2/10^6$ BTU).

Other important considerations of any coal cleaning processes are percent weight yield and the energy content of the resulting coal. Of the three processes, Gravichem attains the highest energy content; however, it ranks lowest in the weight percent yield. Each of the processes enhances the energy content of the raw coal.

The costs of installing and operating chemical coal cleaning processes are significant. They are an important factor in selection of which process is to be used. Preliminary cost figures for the three processes are also listed in Table 3-20.

The annual processing costs in Table 3-20 indicate the cost of processing the coal by the respective processes. The cost trend for the processing is highest for the ERDA process ($70.8 million) and lowest for Gravichem ($21.6 million). The processing and installation costs are reflected in the annual cost of clean coal per ton and also in the cost per million BTU. ERDA is the most expensive of the three processes while Gravichem is the least costly.

Performance of Chemical Coal Cleaning Systems on the Low Sulfur Western Coal

The effects of chemical coal cleaning on a low sulfur western coal are demonstrated in Table 3-21 . The three processes listed (Meyers, ERDA and Gravichem) are the most efficient and best developed of the chemical coal cleaning technologies. The values given for each are the best possible that system can achieve.

TABLE 3-20. PROCESS AND COST PERFORMANCE OF CANDIDATE CHEMICAL COAL CLEANING SYSTEMS FOR LOW SULFUR EASTERN COAL

	Feed*	Product Coal From MEYERS Process	Product Coal From ERDA Process	Product Coal From GRAVICHEM Process
Net Coal Yield, Metric Tons Per Day (Tons/Day)	7,250 (8,000)	6,532 (7,200)	6,532 (7,200)	5,792 (6,384)
Pyritic Sulfur Removal (%)	——	90	90	90
Organic Sulfur Removal (%)	——	——	25	——
Percent Net Energy Content	——	94	94	91
Percent Weight Yield	——	90	90	79.8
Weight % Sulfur In The Product	1.18	.64	.5	.64
Heating Value kJ/kg (BTU/lb)	31,685 (13,622)	33,092 (14,227)	33,092 (14,227)	36,132 (15,534)
$\frac{NgSO_2}{J}$ (lb. $SO_2/10^6$ BTU)	744.0 (1.73)	387.0 (0.90)	301 (0.701)	352.6 (0.824)
Installed Capital Cost ($MM)	——	174.8	224.6	64.9
Annual Processing Excluding Coal Cost ($MM)	——	53.3	70.8	21.6
Annual Processing Including Coal Cost ($MM)	——	129.8	147.4	79.6
$/Annual Metric Ton ($ Annual Ton) of Clean Coal, Excluding Coal Cost	——	24.73 (22.43)	32.85 (29.80)	14.92 (13.53)
$/Annual Metric Ton ($/Annual Ton) of Clean Coal, Including Coal Cost +	——	60.25 (54.65)	68.40 (62.04)	54.98 (49.87)
$/Kilojoule ($/10^6BTU), Excluding Coal Cost	——	.75 (.79)	1.00 (1.05)	.41 (.44)
$/Kilojoule ($/10^6BTU, Including Coal Cost +	——	1.82 (1.92)	2.07 (2.18)	1.52 (1.61)

* The coal selected is from the Eagle Seam in Buchanan County, Virginia, which contains 1.18 weight percent total sulfur, 0.60 weight percent pyritic sulfur and 0.58 weight percent organic sulfur on a dry basis. It is assumed this coal has a heating value of 31,685 kJ/kg (13,622 BTU/lb).

\+ Raw Coal Cost , $31.97/kkg ($29.00/ton).

TABLE 3-21 PROCESS AND COST PERFORMANCE OF CANDIDATE CHEMICAL COAL CLEANING SYSTEMS FOR A LOW SULFUR WESTERN COAL

	Feed*	Product Coal From MEYERS Process	Product Coal From ERDA Process	Product Coal From GRAVICHEM Process
Net Coal Yield, Metric Tons Per Day (Tons/Day)	7,250 (8,000)	6,532 (7,200)	6,532 (7,200)	5,792 (6,384)
Pyritic Sulfur Removal (%)	——	90	90	90
Organic Sulfur Removal (%)	——	——	25	——
Percent Net Energy Content	——	94	94	91
Percent Weight Yield	——	90	90	79.8
Weight % Sulfur in the Product	0.59	0.32	0.25	0.32
Heating Value kJ/kg (BTU/lb.)	26,270 (11,294)	27,437 (11,796)	27,437 (11,796)	29,959 (12,880)
ng SO_2/J (lb. $SO_2/10^6$ BTU)	447 (1.04)	232 (0.54)	180.6 (0.42)	210.7 (0.49)
Installed Capital Cost ($MM)	——	174.8	224.6	64.9
Annual Processing Cost Excluding Coal Cost ($MM)	——	53.3	70.8	21.6
Annual Processing Cost Including Coal Cost ($MM)	——	99.5	117.0	56.6
$/Annual Metric Ton ($ Annual Ton) of Clean Coal, Excluding Coal Cost	——	24.73 (22.43)	32.85 (29.80)	14.92 (13.53)
$/Annual Metric Ton ($/Annual Ton) of Clean Coal, Including Coal Cost +	——	46.15 (41.95)	54.27 (49.33)	39.03 (35.49)
$/Kilojoule ($/10^6 BTU), Excluding Coal Cost	——	.90 (.95)	1.19 (1.26)	.50 (.53)
$/Kilojoule ($/10^6 BTU), Including Coal Cost +	——	1.73 (1.82)	2.02 (2.13)	1.35 (1.42)

* The coal selected is from the Primers Seam in Las Animas County, Colorado which contains 0.59 weight percent total sulfur, 0.30 pyritic and 0.29 organic sulfur on a dry basis. It is assumed this coal has a heating value of 26,270 kJ/kg.

+ Raw Coal Cost, $18.74/kkg ($17.00/ton).

In terms of reducing the SO_2 emission level, the ERDA process is again the best, with an emission level of 180 ng SO_2/J (0.42 lbs $SO_2/10^6$ BTU). ERDA is followed in order by Gravichem at 210 ng SO_2/J (0.49 lbs $SO_2/10^6$ BTU) and Meyers at 232 ng SO_2/J (0.54 lbs $SO_2/10^6$ BTU). The SO_2 level of the ERDA product is low because of the small weight percentage (0.25) of sulfur in the clean coal. ERDA removes 90 percent of the pyritic contents and 25 percent of the organic material. Gravichem and Meyers also remove 90 percent of the pyrites.

The Gravichem operation produces a clean coal with the greatest energy content - 29,959 kJ/kg (12,880 BTU/lb). The lesser amount of 27,437 kJ/kg (11,796 BTU/lb) is present in the products from the Meyers and ERDA processes. Combining this information with the net coal yields (by weight percentage) from each process will give the total energy recovery of the processing. The highest coal yields of 90 percent result from using the Meyers and ERDA processes. Gravichem's net yield is 79.8 percent. The increase in its energy content is not enough to offset the low net yield; therefore, the Gravichem process does not yield the largest amount of total energy.

The greater cleaning potential of the ERDA process results in higher total costs in both the investment and operating sectors. The installed capital cost of $224.6 million and the annual cost of $119.6 million are the highest for the three processes. The Meyers process costs are $174.8 million for capital and $102.1 million for annual processing, while Gravichem has cost figures for the same respective areas at $64.9 million and $58.6 million. Translating these figures into dollars per unit energy numbers still indicates ERDA as the most expensive cleaning process. Including the price of raw coal, ERDA cost equals $2.02/kJ ($2.13/10^6 BTU). Meyers' and Gravichem's cost (including the cost of coal) equals $1.73/kJ of product ($1.82/10^6 BTU) and $1.35/kJ of product ($1.42/10^6BTU), respectively. These cost numbers reflect the magnitude of prices to the user before any transportation cost are added.

3.2.3 Summary of Best Systems of Emission Reduction

The "best systems of SO_2 emission reduction " (BSERs), which permit compliance with three alternative SO_2 emission control levels, are chosen based upon performance and cost with respect to the three reference coals. The matrix in Table 3-22 indicates the choice of the best systems of emission reduction--chosen among raw coals, alternative levels of PCC, and alternative types of CCC--for the three candidate coals and the five emission limitations.

TABLE 3-22 BEST SYSTEM OF EMISSION REDUCTION FOR THREE CANDIDATE COALS AND FIVE SO_2 EMISSION CONTROL LEVELS

	SO_2 Emission Levels ng SO_2/J (lb $SO_2/10^6$ BTU)				
Coal	1,290 (3.0)	1,075 (2.5)	860 (2.0)	645 (1.5)	516 (1.2)
High-S Eastern	PCC level 5 Middlings	PCC level 5 Middlings	PCC level 5 "Deep Cleaned"	PCC Level 5 "Deep Cleaned"	CCC ERDA
Low-S Eastern	Raw Coal	Raw Coal	Raw Coal	PCC level 4	PCC level 4 CCC Gravichem
Low-S Western	Raw Coal	Raw Coal	Raw Coal	Raw Coal	Raw Coal

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SECTION 4.0

COST IMPACT

4.1 BEST SYSTEM OF EMISSION REDUCTION - COST OVERVIEW

This section discusses the basic cost elements associated with the three control technologies considered in this ITAR: naturally-occurring, low sulfur coal, physical coal cleaning, and chemical coal cleaning. For each cost element the bases and references upon which the cost was determined are provided. From these cost elements, the BSER cost at shipping point is calculated for each reference coal (i.e., high sulfur eastern coal, low sulfur eastern coal and low sulfur western coal). These costs form the basis of the costs to the industrial boiler operator, presented in Section 4.2.

As discussed in Section 1.1, the reference coals used in this cost analysis differ from the reference coals provided to the ITAR contractors by PEDCo Environmental, Inc. The coal factors which produce cost differentials are primarily fuel price, ash content, and heating value. The high and low sulfur eastern coals are virtually the same, and from the standpoint of boiler operator costs the difference between the two sets of reference coals is insignificant. The fuel prices used for the eastern coals are the same as PEDCo suggested (i.e., $18.79/kkg for high sulfur eastern coal and $31.97/kkg for low sulfur eastern coal). Since the heating values of the eastern coals used in this ITAR are similar to those of the specified coals, the annual raw coal fuel costs paid by the boiler operator will be approximately the same for either set of reference eastern coals. The sulfur contents are also relatively close (see Table 1-2).

There is a more pronounced cost differential between the low sulfur western coals because this ITAR uses a western bituminous coal, while PEDCo presented a subbituminous coal. There are major cost differences associated with using a western bituminous coal mined in Colorado instead of a subbituminous coal from Wyoming. The fuel price of the Colorado coal is \$19.25/kkg versus \$7.15/kkg for the Wyoming coal. Also, the ash contents differ significantly with the Colorado coal containing 24.8 percent ash and the Wyoming coal containing 5.4 percent ash. The greater ash content will increase waste disposal costs by a factor of about 4. This value is smaller than the ratio of ash contents because the greater heating value of the Colorado coal reduces the fuel requirements.

The greater heating value of the bituminous western coal should reduce the capital coal and the capital charges to the boiler operator as compared to burning a subbituminous coal. Relative to the boiler costs presented by PEDCo, the bituminous coal should reduce capital charges by 10-12 percent, but will increase fuel costs by a factor of 1.85.

4.1.1 Cost Elements for Low Sulfur Coal Control System

In this section we present the costs associated with burning low sulfur, untreated coal. Three basic cost components are included: (1) fuel costs, (2) transportation costs, and (3) costs of burning the coal in specified boilers (with no post-combustion pollution controls).

The low sulfur supply coals are the six low sulfur coals described in Section 3 (Table 3-4).

4.1.1.1 Processing Costs at Mine Mouth--

A raw coal of marketable quality must conform to specific size characteristics and requirements. Thus, the raw low sulfur coal is normally crushed and screened prior to shipment to the user site. The method of screening and crushing depends on the hardness and moisture content of the run-of-mine coal. However, size reduction, screening and the rejection of rocks, where applicable, represent a minimal effort in coal preparation practice.

For this study, the spot market price for the low sulfur coal is defined as the breakeven cost plus profit for providing one ton of coal to the shipping point. This cost includes all appropriate expenses such as mine development costs, labor and equipment, appropriate insurance and taxes, royalties, profit, and a coal preparation cost equivalent to Level 1 cleaning cost.

Any processing costs are added directly to the raw coal price since this study treats the mine and the coal preparation plant as an integrated operation under a common ownership.

4.1.1.2 Compliance of Selected Low Sulfur Coals with Alternative SO_2 Emission Limitations--

This section examines the distribution of costs for burning low sulfur coal in compliance with specified SO_2 emission limitations. The SO_2 emissions associated with the six reference low sulfur coals are presented in Table 4-1. For Table 4-1, two bases are used: (1) a conservative basis in which no sulfur as SO_2 is retained by the bottom ash or slag in the boiler and (2) a more realistic basis in which some sulfur is retained in the bottom ash (five percent for bituminous coals and fifteen percent for subbituminous coals, in which alkaline components combine with some of the sulfur).

Table 4-2, based upon the values in Table 4-1, indicates which of the supply coals would be able to comply with a set of alternative emission limitations. This table shows that all of the selected low sulfur coals can meet the limitation of 1,075 ng SO_2/J (2.5 lb $SO_2/10^6$ BTU), which is assumed to be the average State Implementation Plan (SIP) requirement for existing boilers. Only one (the Las Animas, Colorado bituminous coal) can meet the most stringent control level of 516 ng SO_2/J (1.2 lb $SO_2/10^6$ BTU). All of the coals except the Williston, North Dakota lignite can meet the moderate control level of 860 ng SO_2/J (2.0 lb $SO_2/10^6$ BTU) if no sulfur retention in the boiler is assumed. The two western bituminous low sulfur coals meet the intermediate standard of 645 ng SO_2/J (1.5 lb $SO_2/10^6$ BTU) with no sulfur retention credit; in contrast, the two subbituminous coals can only meet this intermediate standard if credit for sulfur retention is taken.

4.1.1.3 Annualized vs. Levelized Costs--

The following sections present costs to the boiler operator for using low sulfur coals in the form of annualized costs (the method used by the EPA and its contractors). This section shows the method used to derive the annualized cost and provide the rationale for including a second type of cost - levelized cost. Appendix B describes the numerical

TABLE 4-1

SO_2 Emissions from Burning Candidate Low Sulfur Coals

Coal Source	Type	Heating Value kJ/kg BTU/lb	% Sulfur	Sulfur Emissions ng SO_2/J (lb SO_2/10^6 BTU) No Sulfur Retention*	Partial Sulfur Retention**
Buchanan, Va	B	31,700 (13,600)	1.18	744 (1.73)	705 (1.64)
Williston, ND	L	16,300 (7,000)	0.80	982 (2.23)	839 (1.95)
Gillette, Wy	SB	19,800 (8,500)	0.70	707 (1.65)	602 (1.40)
Rock Springs, Wy	B	26,700 (11,500)	0.80	599 (1.40)	569 (1.33)
Las Animas, Co	B	26,300 (11,200)	0.60	449 (1.05)	427 (1.00)
Gallup, NM	SB	23,300 (10,000)	0.80	689 (1.60)	585 (1.36)

Legend: B - bituminous; L - lignite; SB - subbituminous

*Assuming no retention of sulfur in the boiler
**Assuming some retention of sulfur emitted as SO_2: 5% for bituminous coals, 15% for subbituminous coals and lignites.

TABLE 4-2

Low Sulfur Coals in Compliance with Selected SO_2 Emission Limitations*

Coal Source	SO_2 Emission Control Levels ng SO_2/J (lb $SO_2/10^6$ BTU) 516 (1.2)	645 (1.5)	860 (2.0)	1075 (2.5)	1290 (3.0)
Buchanan, Va	-	-	A/B	A/B	A/B
Williston, ND	-	-	B	A/B	A/B
Gillette, Wy	-	B	A/B	A/B	A/B
Rock Springs, Wy	-	A/B	A/B	A/B	A/B
Las Animas, Co	A/B	A/B	A/B	A/B	A/B
Gallup, NM	-	B	A/B	A/B	A/B

*The symbol A indicates compliance when the value of SO_2 emissions does not account for retention of sulfur emitted as SO_2 during combustion; B indicates compliance with sulfur retention of 5% for bituminous coals and 15% for subbituminous coals (see Table 4-1).

bases, computational method, and resultant levelized costs. The values presented as annualized costs are the sum of (1) the levelized capital costs and (2) the first-year operation and maintenance (O&M) costs. The difference between the two is that the capital costs are levelized over the economic lifetime of the boiler, while the O&M costs are simply the operating charges incurred during the initial year of operation. Therefore the capital costs reflect inflation and interest burdens over an extended period of time, whereas O&M costs do not. This provides an inherent advantage to technologies that are operating cost intensive, since they are not penalized for inflated future costs. Levelizing both types of cost, as is done in Appendix B, eliminates this inconsistency.

The fixed charge rates and other cost factors for determining the annualized costs are listed in Table 4-3 for the four major types of industrial coal-burning boilers considered in this study.

4.1.1.4 Low Sulfur Coal Costs--

The fuel costs are one component of the operating costs of burning coal in an industrial boiler. The yearly fuel costs are based upon the spot market prices, F.O.B. mine, in 1978 dollars (listed in Table 4-4) and an assumed capacity factor of 60 percent. The 1978 annual fuel costs to the boiler operator are presented in Table 4-5.

4.1.1.5 Transportation Costs for Low Sulfur Coal Control Systems--

Transportation costs for shipping the representative coals (described in Section 3.1.1.3) can be an important element in the total cost of burning low sulfur coals. It is assumed that high sulfur coal transportation costs to the industrial boiler operator will result in primarily local demand. Presented in Tables 4-6 through 4-10 are the transportation costs of shipping the six representative low sulfur coals to industrial boilers located at six demand centers. The costs are presented as both $/kkg and $/year. The tables represent boilers with five input-fuel capacities — 8.8 MW, 22 MW, 44 MW, 58.6 MW, 117.2 MW — each operating at a capacity factor of 60 percent.

In most cases, these transportation costs reflect multiple-mode transport; e.g., rail and barge shipment of coal from Williston, North

TABLE 4-3

Assumptions Used in the Financial
Analysis of Low Sulfur Coal Combustion*

Assumption or Derived Factor/ Boiler Type	Packaged Watertube • Underfeed Stoker	Field Erected Watertube • Spreader Stoker • Chain-Grade Stoker • Pulverized Coal
Investment Life	30 years	45 years
Operating Cost Escalation Rate	7%	7%
Discount Rate	10%	10%
Other Fixed Charges*	4%	4%
Fixed Charge Rate	14.61%	14.14%

*Assumptions specified by PEDCo in a memorandum to Acurex/Aerotherm[15]

TABLE 4-4

F.O.B. Mine Prices of Selected Low-Sulfur Coals

	F.O.B. Bid Prices - $ 1978*			
	Term		Spot	
Supply Area	($/ton)	$/GJ ($/10^6 BTU)	($/ton)	$/GJ ($/10^6 BTU)
Low Sulfur Eastern e.g., Buchanan, Va	22.00	0.99 (0.94)	29.00**	1.12** (1.05)
Gillette, Wy	6.25	0.40 (0.38)	8.00	0.52 (0.49)
Rock Springs, Wy	14.50	0.73 (0.69)	15.00	0.75 (0.71)
Williston, ND†	7.00	0.46 (0.44)	7.00	0.46 (0.44)
Las Animas, Co	17.00	0.79 (0.75)	17.50	0.82 (0.78)
Gallup, NM	13.75	0.73 (0.69)	15.00	0.74 (0.70)

*Except where indicated otherwise, the prices are those cited in Coal Week, May 29, 1978.

**The value in dollars per ton is from Coal Outlook, July 19, 1978. The value in dollars per energy unit is based upon 32,100 kJ/kg (13,800 BTU/lb).

†Estimated.

TABLE 4-5 YEARLY FUEL COSTS (1978 \$) AND FUEL INPUTS BY BOILER-TYPE CAPACITY†

Boiler Capacity (Feed rate) / Coal Source	8.8 MW (30×10^6 BTU/hr)		22 MW (75×10^6 BTU/hr)		44 MW (150×10^6 BTU/hr)		58.6 MW (200×10^6 BTU/hr)		117.2 MW (400×10^6 BTU/hr)	
	\$/Year	kkg/Year	\$/Year	kkg/Year	\$/Year	kkg/Year	\$/Year	kkg/Year	\$/Year	kkg/Year
Buchanan, VA (Low-Sulfur Eastern)	165,600	5,250	414,000	13,150	828,000	26,300	1,109,000	35,200	2,218,000	70,400
Las Animas, CO	121,400	6,260	303,500	15,650	607,000	31,300	813,400	41,900	1,626,800	83,800
Williston, ND	78,740	10,200	196,850	25,500	393,700	51,000	527,600	68,300	1,055,200	136,600
Gillette, WY	57,800	8,410	144,500	21,000	289,000	42,000	387,300	56,100	774,600	112,200
Rock Springs, WY	99,100	6,210	247,750	15,500	495,500	31,000	664,000	41,600	1,328,000	83,200
Gallup, NM	118,800	6,350	297,000	15,900	594,000	31,800	796,000	42,500	1,592,000	85,000

† Costs are based upon (1) spot prices, F.O.B. mine, in \$/GJ (see Table 4-4) and (2) capacity factor equal to 0.6.

Table 4-6. TRANSPORTATION COSTS: 6 LOW SULFUR COALS TO 6 DESTINATIONS †
($/kkg and $/year, based upon demand by an 8.8 MW (30 x 10^6 BTU/hr)
Boiler operating at 60% capacity factor)

Coal Supply Center \ Demand Center	Austin, Tx.		Harrisburg, Pa.		Columbus, Oh.		Baton Rouge, La.		Sacramento, Ca.		Springfield, Il.	
	$/kkg	$/year	$/kkg	$/year	$/kkg	$/year	$/kkg	$/year	$/kkg	$/year	$/kkg	$/year
Buchanan, Va.	15.27	80,200	3.16	16,600	4.47	23,500	12.73	66,800	29.51	155,900	7.64	37,500
Las Animas, Co.	13.42	84,000	16.69	104,500	12.71	79,600	12.00	75,100	15.60	97,700	0.45	52,900
Williston, N.D.	17.78	181,400	15.49	150,000	12.82	130,800	15.11	154,000	17.78	181,400	11.18	114,000
Gillette, Wy.	16.47	138,500	19.25	161,900	16.53	139,000	18.33	154,000	17.24	145,000	14.40	121,100
Rock Springs, Wy.	15.27	94,900	23.13	143,600	19.09	118,600	10.87	117,200	9.60	59,600	15.05	93,500
Gallup, N.M.	12.05	76,500	23.73	150,700	19.64	124,700	14.84	94,200	10.96	69,600	15.60	99,100

† The values of $/kkg are based upon the following estimated rates.[1,2]

Railroad, Multiple Rates: 1.41¢/kkg-Km (2.5¢/ton-mile), <400 Km
0.68¢/kkg-Km (1.2¢/ton-mile), >400 Km

Water: 0.34¢/kkg-Km (0.6¢/ton-mile)

The cost in $/year is the product of $/kkg and the coal used in kkg/yr by an 8.8 MW boiler at 60 percent capacity factor (see Table 4-5).

Table 4-7. TRANSPORTATION COSTS: 6 LOW SULFUR COALS TO 6 DESTINATIONS †
($/kkg and $/year, based upon demand by an 22 MW (75 X 10^6 BTU/hr)
Boiler operating at 60% capacity factor)

Coal Supply Center \ Demand Center	Austin, Tx.		Harrisburg, Pa.		Columbus, Oh.		Baton Rouge, La.		Sacramento, Ca.		Springfield, Ill.	
	$/kkg	$/year	$/kkg	$/year	$/kkg	$/year	$/kkg	$/year	$/kkg	$/year	$/kkg	$/year
Buchanan, Va.	15.27	200,500	3.16	41,500	4.47	59,000	12.73	167,000	29.51	390,000	7.64	94,000
Las Animas, Co.	13.42	210,000	16.69	261,000	12.71	299,000	12.00	88,000	15.60	244,000	8.45	132,000
Williston, N.D.	17.78	403,500	15.49	395,000	12.82	327,000	15.11	385,000	17.78	453,500	11.18	285,000
Gillette, Wy.	16.47	346,000	19.25	405,000	16.53	347,500	18.33	385,000	17.24	362,500	14.40	303,000
Rock Springs, Wy.	15.27	237,000	23.13	359,000	19.09	296,500	18.87	293,000	9.60	149,000	15.05	234,000
Gallup, N.M.	12.05	191,000	23.73	376,500	19.64	312,000	14.84	235,500	10.96	174,000	15.60	298,000

† The values of $/kkg are based upon the following estimated rates.

Railroad, Multiple Rates: 1.41¢/kkg-km (2.5¢/ton-mile), <400 km
0.68¢/kkg-km (1.2¢/ton-mile), >400 km
Water: 0.34¢/kkg-km (0.6¢/ton-mile)

The cost in $/year is the product of $/kkg and the coal used in kkg/yr by an 44 MW boiler at 60 percent capacity factor (see Table 4-5).

Table 4-8. TRANSPORTATION COSTS: 6 LOW SULFUR COALS TO 6 DESTINATIONS †
($/kkg and $/year, based upon demand by an 44 MW(150 X 10^6 BTU/hr)
Boiler operating at 60% capacity factor)

Coal Supply Center \ Demand Center	Austin, Tx.		Harrisburg, Pa.		Columbus, Oh.		Baton Rouge, La.		Sacramento, Ca.		Springfield, Ill.	
	$/kkg	$/year	$/kkg	$/year	$/kkg	$/year	$/kkg	$/year	$/kkg	$/year	$/kkg	$/year
Buchanan, Va.	15.27	401,000	3.16	83,000	4.47	117,500	12.73	334,000	29.51	779,500	7.64	187,500
Las Animas, Co.	13.42	420,000	16.69	522,500	12.71	398,000	12.00	375,500	15.60	488,500	8.45	264,500
Williston, N.D.	17.78	907,000	15.49	790,000	12.82	654,000	15.11	770,000	17.78	907,000	11.18	570,000
Gillette, Wy.	16.47	692,500	19.25	809,500	16.53	695,000	18.33	770,000	17.24	725,000	14.40	605,500
Rock Springs, Wy.	15.27	474,500	23.13	718,000	19.09	593,000	18.87	586,000	9.60	298,000	15.05	467,500
Gallup, N.M.	12.05	382,500	23.73	753,500	19.64	623,500	14.84	471,000	10.96	348,000	15.60	495,500

† The values of $/kkg are based upon the following estimates rates.

Railroad, Multiple Rates: 1.41¢/kkg-km (2.5¢/ton-mile), <400 km
0.68¢/kkg-km (1.2¢/ton-mile), >400 km
Water: 0.34¢/kkg-km (0.6¢/ton-mile)

The cost in $/year is the product of $/kkg and the coal used in kkg/yr by an 44 MW boiler at 60 percent capacity factor (see Table 4-5).

Table 4-9. TRANSPORTATION COSTS: 6 LOW SULFUR COALS TO 6 DESTINATIONS†
($/kkg and $/year, based upon demand by an 58.6 MW (200 x 10^6 BTU/hr) Boiler operating at 60% factor)

Coal Supply Center \ Demand Center	Austin, Tx.		Harrisburg, Pa.		Columbus, Oh.		Baton Rouge, La.		Sacramento, Ca.		Springfield, Il.	
	$/kkg	$/year	$/kkg	$/year	$/kkg	$/year	$/kkg	$/year	$/kkg	$/year	$/kkg	$/year
Buchanan, Va.	15.27	537,300	3.16	111,200	4.47	157,500	12.73	447,600	29.51	1,044,500	7.64	251,300
Las Animas, Co.	13.42	562,800	16.69	700,200	12.71	533,300	12.00	503,200	15.60	654,600	8.45	354,400
Williston, N.D.	17.78	1,215,400	15.49	1,058,600	12.82	876,400	15.11	1,031,800	17.78	1,215,400	11.18	763,800
Gillette, Wy.	16.47	928,000	19.25	1,084,700	16.53	931,300	18.33	1,031,800	17.24	971,500	14.40	811,370
Rock Springs, Wy.	15.27	635,800	23.13	962,100	19.09	794,600	18.87	785,200	9.60	399,300	15.05	626,500
Gallup, N.M.	12.05	512,600	23.73	1,009,700	19.64	835,500	14.84	631,100	10.96	466,300	15.60	664,000

† The values of $/kkg are based upon the following estimated rates.

Railroad, Multiple Rates: 1.41¢/kkg-km (2.5¢/ton-mile), <400 km
0.68¢/kkg-km (1.2¢/ton-mile), >400 km

Water: 0.34¢/kkg-km (0.6¢/ton-mile)

The cost in $/year is the product of $/kkg and the coal used in kkg/yr by an 58.6 MN boiler at 60 percent capacity factor (see Table 4-5).

TABLE 4-10. TRANSPORTATION COSTS: 6 LOW SULFUR COALS TO 6 DESTINATIONS†
($/kkg and $/year, based upon demand by a 117.2 MW (400 x 10^6 BTU/hr)
Boiler operating at 60% factor)

Coal Supply Center \ Demand Center	Austin, Tx.		Harrisburg, Pa.		Columbus, Oh.		Baton Rouge, La.		Sacramento, Ca.		Springfield, Il.	
	$/kkg	$/year	$/kkg	$/year	$/kkg	$/year	$/kkg	$/year	$/kkg	$/year	$/kkg	$/year
Buchanan, Va.	15.27	1,074,600	3.16	222,400	4.47	315,000	12.73	895,200	29.51	2,089,000	7.64	502,600
Las Animas, Co.	13.42	1,125,600	16.69	1,400,400	12.71	1,066,600	12.00	1,006,400	15.60	1,309,200	8.45	708,800
Willision, N.D.	17.78	2,430,800	15.49	2,117,200	12.82	1,752,800	15.11	2,063,600	17.78	2,430,800	11.18	1,527,600
Gillette, Wy.	16.47	1,856,000	19.25	2,169,400	16.53	1,862,600	18.33	2,063,600	17.24	1,943,000	14.40	1,622,740
Rock Springs, Wy.	15.27	1,271,600	23.13	1,924,200	19.09	1,598,200	18.87	1,570,400	9.60	798,600	15.05	1,253,000
Gallup, N.M.	12.05	1,025,200	23,73	2,019,400	19.64	1,671,000	14,84	1,262,200	10.96	932,600	15.60	1,328,000

† The values of $/kkg are based upon the following estimated rates.

Railroad, Multiple Rates: 1.41¢/kkg-Km (2.5¢/ton-mile), <400 Km
0.68¢/kkg-Km (1.2¢/ton-mile), >400 Km

Water: 0.34¢/kkg-Km (0.6¢/ton-mile)

The cost in $/year is the product of $/kkg and the coal used in kkg/yr by an 117.2 MN boiler at 60 percent capacity factor (see Table 4-5).

Dakota, to Baton Rouge, Louisiana. Rail transport costs of bulk commodities like coal depend on a wide variety of factors. Such factors include origin service conditions (unloading method and trackage necessary to reach the mine); line haul service conditions (rating, annual weight, train schedule, interchange facilities); and destination service conditions (unloading method, trackage necessary to reach receiver). Given these factors, there are a multitude of rates that can apply to railroad shipment of coal.

The rates upon which the values in Tables 4-6 through 4-9 are based are: conventional railroad of 1.41¢/kkg-km (2.5¢/ton-mile) for rail distances less than 400 kilometers, and 0.68¢/kkg-km (1.2¢/ton-mile) for rail distances greater than 400 kilometers; water rates of 0.34¢/kkg-km (0.6¢/ton-mile).[1,2] These rates are based upon a composite of values, such as those represented in Figure 4-1. It should be emphasized that (1) large, industrial coal users probably could negotiate trainload or annual volume rates 20 to 30 percent lower than the rates used here and that (2) the transportation costs presented in Tables 4-6 through 4-9 are intended to illustrate only representative costs. Specific costs actually negotiated are situation dependent and could vary by ±25 percent.

4.1.1.6 The Costs of Burning Low Sulfur Coals in Representative Boilers--

Yearly costs are based on two types of coal being burned in the five representative boilers for which transportation costs were calculated. Based upon cost calculations by PEDCo[3], the yearly costs for burning coal in the representative boilers are presented in Table 4-11. Those costs are significantly higher for burning subbituminous coal than for burning the low sulfur eastern bituminous coal.

Tables 4-12 through 4-16 present the annualized costs for each low sulfur coal and reference boiler combination. Table 4-17 presents the normalized annualized costs for the low sulfur coal-boiler combustion. The costs to the industrial boiler operator for using a low sulfur coal do not differ by more than 16 percent regardless of coal type used. These costs are based upon the annualized costs generated by PEDCo Environmental, Inc., with the fuel cost for using each coal providing the cost differentials. The values in Table 4-12 do not reflect differences in coal handling, ash handling and/or transportation.

Figure 4-1. 1974 COAL TRANSPORTATION COSTS, $ 1974[1]

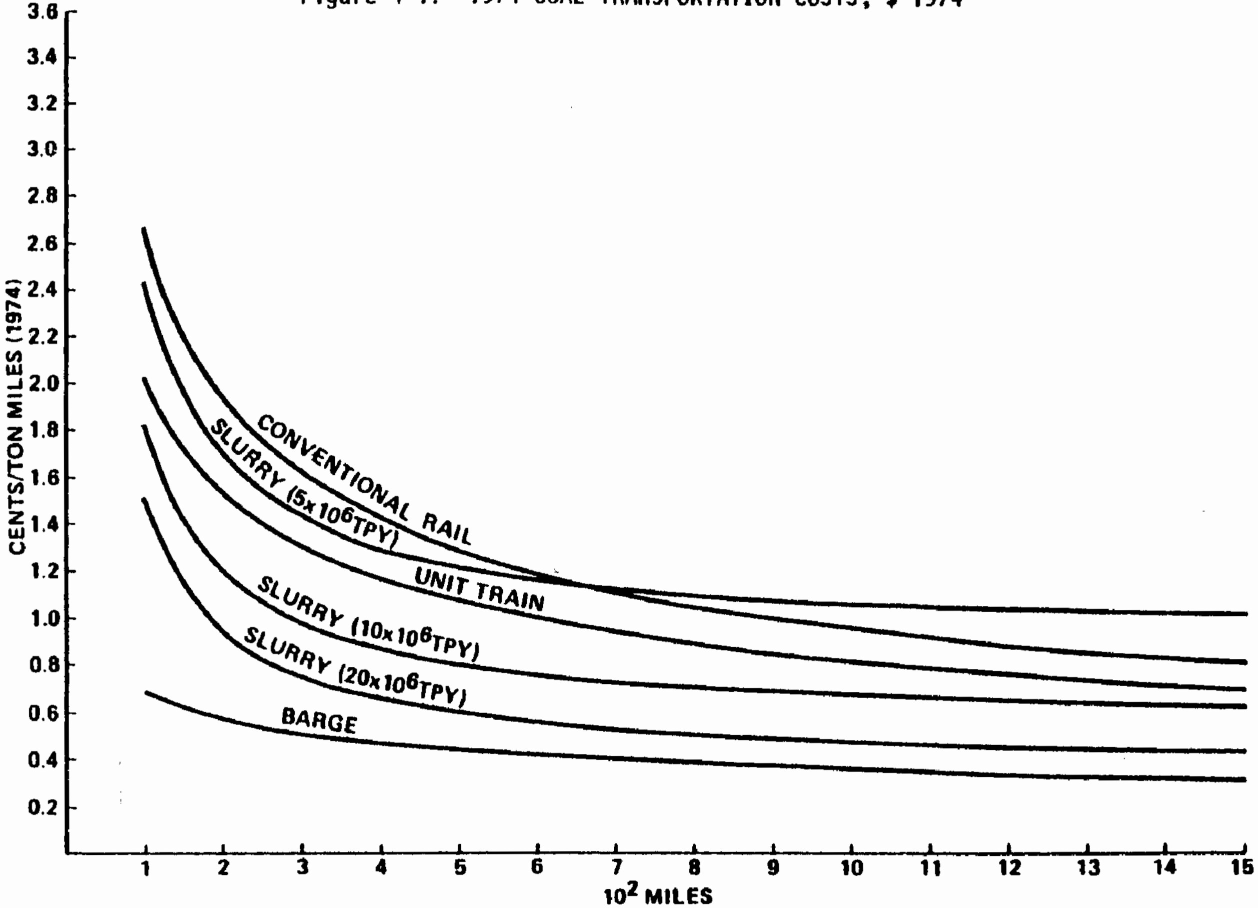

TABLE 4-11. ANNUALIZED COSTS FOR LOW SULFUR COALS IN THE STANDARD BOILERS (3) (1978 $)
(EXCLUDING COAL COSTS)

Boiler Type:	Package Watertube 8.8 MW		Field-Erected Watertube 22 MW		Field-Erected Watertube 44 MW		Field-Erected Watertube 58.6 MW		Field-Erected Watertube 117.2 MW	
Coal Type:	Eastern low sulfur	Subbit.	Eastern low sulfur	Subbit.	Eastern low sulfur	Subbit.	Eastern low sulfur	Subbit.	Eastern low sulfur	Subbit.
1 Direct Costs (less fuel)	400,200	441,700	660,300	730,200	889,400	1,013,600	1,269,700	1,486,400	2,221,100	2,591,600
2 Overhead	138,500	145,400	212,900	224,300	297,900	320,700	386,500	415,100	657,100	697,200
1+2 = 3 O&M Costs (excluding fuel)	538,700	587,100	873,200	954,500	1,187,300	1,334,300	1,656,200	1,901,800	2,878,200	3,288,800
4 Capital Charges (levelized)	236,300	323,600	563,400	745,700	1,084,500	1,455,700	1,504,400	2,025,600	2,792,500	3,758,200
5 Annualized Cost (excluding fuel)	775,000	910,700	1,436,600	1,700,200	2,271,800	2,790,000	3,160,600	3,927,400	5,670,700	7,047,000
6 Fuel Costs†	165,600	57,800	414,000	144,500	828,000	289,000	1,109,000	387,300	2,218,000	774,600
7 Annualized Cost (total)	940,600	968,500	1,850,600	1,844,700	3,099,800	3,079,000	4,269,600	4,314,700	7,888,700	7,821,600

†Gillette, W.Y., fuel cost figures used for subbituminous category.

TABLE 4-12. COSTS FOR OPERATING 8.8 MW (30 x 10^6 BTU/hr) COAL FIRED BOILERS USING LOW SULFUR COALS†

SYSTEM						IMPACT
STANDARD BOILERS		TYPE AND LEVEL OF CONTROL				
HEAT INPUT MW(10 BTU/hr)	TYPE	COAL SOURCE	COAL TYPE σ	LEVEL WITHIN WHICH UNCONTROLLED EMISSIONS FALL ng SO_2/J (lb $SO_2/10^6$ BTU) ∞	COSTS \$/MWh (\$/10^6 BTU) *	% INCREASE IN TOTAL ANNUALIZED COSTS OVER REFERENCE COALS **
8.8 (30)	Packaged Watertube Underfeed Boiler	Buchanan, Va.	Bituminous	860 (2.0)	\$20.34 (\$5.96)	(1.79)
		Las Animas, Co.	Bituminous	516 (1.2)	\$19.38 (\$5.68)	(5.88)
		Rock Springs, Wy.	Bituminous	645 (1.5)	\$18.90 (\$5.54)	(8.21)
		Williston, N.D.	Lignite	1,075 (2.5)	\$21.39 (\$6.27)	(1.28)
		Gillette, Wy.	Sub-bituminous	860 (2.0)	\$20.94 (\$6.14)	(0.85)
		Gallup, N.M.	Sub-bituminous	860 (2.0)	\$22.26 (\$6.52)	(5.40)

† The costs are found by adding the 1978 fuel costs in Table 4-5 to the yearly boiler costs excluding fuel costs in Table 4-11.

σ The western bituminous coals are assumed to be burned in boilers constructed to burn an average between eastern low-sulfur coal and western sub-bituminous coal; the sub-bituminous coal and lignite are assumed to be burned in boilers constructed to burn "sub-bituminous coal" (see Table 4-11).

∞ These are the most stringent of five SO_2 levels which the uncontrolled SO_2 emissions from each coal can meet. The levels are 516, 645, 860, 1,075 and 1,290 (ng SO_2/J). No retention of sulfur is assumed in the boiler.

* Costs reflect changes in fuel cost and energy content of the fuel. No cost corrections have been made to PEDCo Environmental [1] values for additional coal handling, ash handling or transportation to the boiler.

** Reference coals - Subbituminous coal and lignite are compared with subbituminous (PEDCo); Buchanan, Va. is compared with eastern high sulfur coal.

TABLE 4-13. COSTS FOR OPERATING 22 MW (75×10^6 BTU/hr) COAL FIRED BOILERS USING LOW SULFUR COALS†

SYSTEM						IMPACT
STANDARD BOILERS		TYPE AND LEVEL OF CONTROL				
HEAT INPUT MW(10 BTU/hr)	TYPE	COAL SOURCE	COAL TYPE$^{\sigma}$	LEVEL WITHIN WHICH UNCONTROLLED EMISSIONS FALL ng SO_2/J$^{\infty}$ (lb $SO_2/10^6$ BTU)$^{\infty}$	COSTS \$/MWh ($\$/10^6$ BTU)*	% INCREASE IN TOTAL ANNUALIZED COSTS OVER REFERENCE COALS **
22 (75)	Field Erected Watertube Boiler	Buchanan, Va.	Bituminous	860 (2.0)	\$16.00(\$4.69)	(2.32)
		Las Animas, Co.	Bituminous	516 (1.2)	\$15.05(\$4.41)	(6.00)
		Rock Springs, Wy.	Bituminous	1,075 (2.5)	\$14.57(\$4.27)	(8.99)
		Williston, N.D.	Lignite	860 (2.0)	\$16.41(\$4.81)	(1.67)
		Gillette, Wy.	Sub-bituminous	645 (1.5)	\$15.95(\$4.67)	(1.18)
		Gallup, N.M.	Sub-bituminous	860 (2.0)	\$17.27(\$5.06)	(7.00)

† The costs are found by adding the 1978 fuel costs in Table 4-5 to the yearly boiler costs excluding fuel costs in Table 4-11.

σ The western bituminous coals are assumed to be burned in boilers constructed to burn an average between eastern low-sulfur coal and western sub-bituminous coal; the sub-bituminous coal and lignite are assumed to be burned in boilers constructed to burn "sub-bituminous coal" (see Table 4-11).

∞ These are the most stringent of five SO_2 levels which the uncontrolled SO_2 emissions from each coal can meet. The levels are 516, 645, 860, 1,075 and 1,290 (ng SO_2/J). No retention of sulfur is assumed in the boiler.

* Costs reflect changes in fuel cost and energy content of the fuel. No cost corrections have been made to PEDCo Environmental[3] values for additional coal handling, ash handling or transportation to the boiler.

** Reference coals - Subbituminous and lignite are compared with subbituminous (See 8.8 MW sheet)

TABLE 4-14. COSTS FOR OPERATING 44 MW (150 x 10^6 BTU/hr) COAL FIRED BOILERS USING LOW SULFUR COALS†

SYSTEM						IMPACT
STANDARD BOILERS		TYPE AND LEVEL OF CONTROL				
HEAT INPUT MW(10 BTU/hr)	TYPE	COAL SOURCE	COAL TYPE°	LEVEL WITHIN WHICH UNCONTROLLED EMISSIONS FALL ng SO_2/J$^{\infty}$ (lb SO_2/10^6 BTU)$^{\infty}$	COSTS \$/MWh (\$/10^6 BTU)*	% INCREASE IN TOTAL ANNUALIZED COSTS OVER REFERENCE COALS**
44 (150)	Field Erected Watertube Boiler	Buchanan, Va.	Bituminous	860 (2.0)	\$13.40(\$3.93)	(2.76)
		Las Animas, Co.	Bituminous	516 (1.2)	\$12.45(\$3.65)	(6.39)
		Rock Springs, Wy.	Bituminous	1,075 (2.5)	\$11.97(\$3.51)	(10.0)
		Williston, N.D.	Lignite	860 (2.0)	\$13.77(\$4.03)	(2.0)
		Gillette, Wy.	Sub-bituminous	645 (1.5)	\$13.31(\$3.90)	(1.41)
		Gallup, N.M.	Sub-bituminous	860 (2.0)	\$14.63(\$4.29)	(8.37)

† The costs are found by adding the 1978 fuel costs in Table 4-5 to the yearly boiler costs excluding fuel costs in Table 4-11.

° The western bituminous coals are assumed to be burned in boilers constructed to burn an average between eastern low-sulfur coal and western sub-bituminous coal; the sub-bituminous coal and lignite are assumed to be burned in boilers constructed to burn "sub-bituminous coal" (see Table 4-11).

∞ These are the most stringent of five SO_2 levels which the uncontrolled SO_2 emissions from each coal can meet. The levels are 516, 645, 860, 1,075 and 1,290 (ng SO_2/J). No retention of sulfur is assumed in the boiler.

* Costs reflect changes in fuel cost and energy content of the fuel. No cost corrections have been made to PEDCo Environmental[3] values for additional coal handling, ash handling or transportation to the boiler.

** Reference coals - Subbituminous and lignite are compared with subbituminous (See 8.8 MW sheet).

TABLE 4-15. COSTS FOR OPERATING 58.6 MW (200 x 10^6 BTU/hr) COAL FIRED BOILERS USING LOW SULFUR COALS†

SYSTEM						IMPACT
STANDARD BOILERS		TYPE AND LEVEL OF CONTROL				
HEAT INPUT MW(10 BTU/hr)	TYPE	COAL SOURCE	COAL TYPE σ	LEVEL WITHIN WHICH UNCONTROLLED EMISSIONS FALL ng SO_2/J ∞ (lb $SO_2/10^6$ BTU) ∞	COSTS \$/MWh (\$/10^6 BTU) *	% INCREASE IN TOTAL ANNUALIZED COSTS OVER REFERENCE COALS **
58.6 (200)	Field Erected Water Tube Boiler	Buchanan, Va.	Bituminous	860 (2.0)	\$13.86 (\$4.06)	(2.53)
		Las Animas, Co.	Bituminous	516 (1.2)	\$12.90 (\$3.78)	(6.52)
		Rock Springs, Wy.	Bituminous	645 (1.5)	\$12.41 (\$3.64	(10.07)
		Williston, N.D.	Lignite	1,075 (2.5)	\$14.46 (\$4.24)	(1.97)
		Gillette, Wy.	Sub-bituminous	860 (2.0)	\$14.01 (\$4.10)	(1.20)
		Gallup, N.M.	Sub-bituminous	860 (2.0)	\$15.33 (\$4.49)	(8.11)

† The costs are found by adding the 1978 fuel costs in Table 4-5 to the yearly boiler costs excluding fuel costs in Table 4-11.

σ The western bituminous coals are assumed to be burned in boilers constructed to burn an average between eastern low-sulfur coal and western sub-bituminous coal; the sub-bituminous coal and lignite are assumed to be burned in boilers constructed to burn "sub-bituminous coal" (see Table 4-11).

∞ These are the most stringent of five SO_2 levels which the uncontrolled SO_2 emissions from each coal can meet. The levels are 516, 645, 860, 1,075 and 1,290 (ng SO_2/J). No retention of sulfur is assumed in the boiler.

* Costs reflect changes in fuel cost and energy content of the fuel. No cost corrections have been made to PEDCo Environmental[3] values for additional coal handling, ash handling or transportation to the boiler.

** Reference coals - Subbituminous and lignite are compared with subbituminous (See 8.8 MW sheet).

TABLE 4-16. COSTS FOR OPERATING 117.2 MW(400 x 10^6 BTU/hr) COAL FIRED BOILERS USING LOW SULFUR COALS†

SYSTEM						IMPACT
STANDARD BOILERS		TYPE AND LEVEL OF CONTROL				
HEAT INPUT MW(10 BTU/hr)	TYPE	COAL SOURCE	COAL TYPE$^\sigma$	LEVEL WITHIN WHICH UNCONTROLLED EMISSIONS FALL ng SO_2/J$^\infty$(lb SO_2/10^6BTU)$^\infty$	COSTS \$/MWh (\$/10^6BTU)*	% INCREASE IN TOTAL ANNUALIZED COSTS OVER REFERENCE COALS**
58.6 (200)	Field Erected Water Tube Boiler	Buchanan, Va.	Bituminous	860 (2.0)	\$12.81(\$3.75)	(2.66)
		Las Animas, Co.	Bituminous	516 (1.2)	\$11.85(\$3.47)	(6.25)
		Rock Springs, Wy.	Bituminous	645 (1.5)	\$11.36(\$3.33)	(10.12)
		Williston, N.D.	Lignite	1,075 (2.5) SIP	\$13.15(\$3.85)	(2.18)
		Gillette, Wy.	Sub-bituminous	860 (2.0)	\$12.70(\$3.72)	(1.32)
		Gallup, N.M.	Sub-bituminous	860 (2.0)	\$14.02(\$4.11)	(8.94)

† The costs are found by adding the 1978 fuel costs in Table 4-5 to the yearly boiler costs excluding fuel costs in Table 4-11.

σ The western bituminous coals are assumed to be burned in boilers constructed to burn an average between eastern low-sulfur coal and western sub-bituminous coal; the sub-bituminous coal and lignite are assumed to be burned in boilers constructed to burn "sub-bituminous coal" (see Table 4-11).

∞ These are the most stringent of five SO_2 levels which the uncontrolled SO_2 emissions from each coal can meet. The levels are 516, 645, 860, 1,075 and 1,290 (ng SO_2/J). No retention of sulfur is assumed in the boiler.

* Costs reflect changes in fuel cost and energy content of the fuel. No cost corrections have been made to PEDCo Environmental[3] values for additional coal handling, ash handling or transportation to the boiler.

** Reference coals - Subbituminous coal and lignite are compared with subbituminous (PEDCo); Buchanan, Va. is compared with eastern low sulfur coal; Las Animas, Co. and Rock Springs, Wyo. are compared with eastern high sulfur coal.

TABLE 4-17. NORMALIZED COST ($/MWh) FOR LOW SULFUR COALS

Standard Boilers (MW[t])	Source and $/MWh for Low Sulfur Coal Types† Buchanan, Va.	Williston, N.D.	Gillette, Wyo.	Rock Springs, Wyo.	Las Animas, Co.	Gallup, N.M.
8.8	$ 20.34	$ 21.39	$ 20.94	$ 18.90	$ 19.38	$ 22.26
22	16.00	16.41	15.95	14.57	15.05	17.27
44	13.40	13.77	13.31	11.97	12.45	14.63
58.6	13.86	14.46	14.01	12.41	12.90	15.33
117.2	12.81	13.15	12.70	11.36	11.85	14.02
Compliance Limits ng SO_2/J	744	987	798	507	449	689
(lb/10^6 BTU)	(1.73)	(2.23)	(1.65)	(1.18)	(1.04)	(1.60)

† Above costs reflect changes in fuel cost and energy content of the fuel. No cost corrections have been made to the PEDCo Environmental(3) values for additional coal handling, ash handling or transportation to the boiler.

4.1.2 Costs for BSER Coal Cleaning Facilities

Cost estimates have been prepared for the best phsycial coal cleaning systems to beneficiate the two representative eastern coals selected as the basis for this study. The reference low sulfur western coal does not require cleaning to meet SO_2 emission control levels studied in this ITAR so no cleaning plant cost estimates are presented. The characteristics of the two eastern coals are presented in Table 4-18.

A summary of "Best" Systems of Emission Reduction Costs for each coal is presented in Tables 4-19 and 4-20. These BSERs are level 5 (process levels as defined in Section 2.0) for high sulfur eastern coal and level 4 for low sulfur eastern coal. An example of the detailed installed capital costs is given in Section 4.2. Appendix E presents the detailed capital and operating costs for each BSER. These costs used are based on material balances and heating value yields developed from available washability data and partition curves on the reference coals. The plants are assumed to operate 3,333 hours per year.[4]

4.1.2.1 Capital Costs--

The capital cost of coal cleaning plants is composed of direct and indirect costs. Direct costs include the cost of equipment and auxiliaries and the labor and material required to install the equipment. Installation costs include: piping, ducting, electrical, erection, building structures, instrumentation, insulation, painting, site development, construction of access roads and railroad facilities for incoming and outgoing cars, and loading and unloading facilities for raw materials and by-product wastes. Costs for control rooms, administration building, maintenance shops and stockrooms are also a part of the direct costs. Indirect costs are costs that cannot be attributed to a specific piece of equipment, but are necessary for the entire system.

Cost estimates are based on conceptual flow sheets presented in Section 3.2.2. Both plants nominally process 1.8×10^6 metric tons (2.0×10^6 tons) of coal annually. They are located at the mine mouth, and the product coal is loaded into railroad cars for shipment to the consumer. Product transport equipment is not included in the cost estimates.

TABLE 4-18. CHARACTERISTICS OF THE REFERENCE HIGH SULFUR EASTERN COAL AND LOW SULFUR EASTERN COAL

Coal Type:	High Sulfur Eastern	Low Sulfur Eastern
Seam:	Upper Freeport ('E' coal) *	Eagle *
County, State:	Butler, Pa.	Buchanan, Va.
RAW COAL ANALYSIS		
Ash, % †	23.90	10.38
Total S, %†	3.45	1.18
Pyritic S, %†	2.51	0.60
Heating Value kJ/kg (BTU/lb) †	26,772 (11,510)	31,685 (13,622)
Moisture Content	5.0	2.0
ng SO_2/J	2,576	744
(lb $SO_2/10^6$ BTU)	(5.99)	(1.73)

* Versar reference coals

† Dry Basis

TABLE 4-19. SUMMARY OF CLEANING COSTS FOR HIGH SULFUR COAL (BSER--Level 5)

Basis: 1.87×10^6 metric tons (2.0×10^6 tons) per year of 26,772 kJ/kg (11,510 BTU/lb) coal feed

3,333 hours per year operation

Capital amortized over 20 years @ 10% interest

Grass roots plant installation

73.3% weight yield, 87.5% heating value recovery

Installed Capital Cost: $18,123,000

Annual Operating Costs on Clean Coal Basis: $6,350,200 processing cost excluding coal cost

$40,350,200 including coal cost

$4.78/metric ton ($4.33/ton), excluding coal cost †

$30.27 /metric ton ($27.52/ton), including coal cost †

$0.149/10^6 kJ ($0.158/10^6 BTU), excluding coal cost †

$0.934/10^6 kJ ($0.988/10^6 BTU), including coal cost †

† Values are an average for the two product streams

TABLE 4-20. SUMMARY OF CLEANING COSTS FOR LOW SULFUR EASTERN COAL (BSER—Level 4)

Basis: 1.87×10^6 metric tons (2.0×10^6 tons) per year of 31,685 kJ/kg (13,622 BTU/lb) coal feed

3,333 hours per year operation

Capital amortized over 20 years @ 10% interest

Grass roots plant installation

83.8% weight yield, 89.6% heating value recovery

Installed Capital Cost: $15,975,000

Annual Operating Costs on Clean Coal Basis: $5,258,900 processing cost excluding coal cost

$63,258,900 including coal cost

$3.46/metric ton ($3.14/ton), excluding coal cost

$41.60/metric ton ($37.75/ton), including coal cost

$0.102/10^6 kJ ($0.108/10^6 BTU), excluding coal cost

$1.23/10^6 kJ ($1.30/10^6 BTU), including coal cost

The cost estimates are based on information obtained from vendors as well as extrapolation from Versar in-house information. (5,6,7,8,9,10) Based on available data, installed capital costs for the preparation plants were estimated at 2.35 times the preparation plant equipment cost. This estimate assumes the following capital cost distributions for the preparation plant. (11)

	Percent
Plant Equipment	42.5
Building Structures	25.2
Piping	5.1
Electrical	11.6
Erection	15.5
	100%

Indirect Capital Costs

Indirect costs are those not attributed to specific pieces of equipment. Items included and their values are as follows:

Indirect Costs	Values (12)
Engineering	10% of direct costs
Construction and Field expenses	10% of direct costs
Contractor fee	10% of direct costs
Start-up	2% of direct costs
Contingency	20% of total direct and indirect costs
Working capital	25% of operating and maintenance costs including costs of utilities, chemicals, operating labor, maintenance and repairs and disposal costs

Land Cost

The cost of the land required for equipment is also a direct cost. Land costs vary considerably from location to location. For these estimates land is assumed to be $2,400 per acre. (13)

Pricing Levels

Estimates are based on June 30, 1978 price and wage levels. No allowance has been made for future escalation.

4.1.2.2 Annual Operating Costs—

The coal processing costs include all variable operating, maintenance, and associated overhead costs for operating the coal preparation facilities. In addition to these costs, fixed charges consisting of capital amortization, taxes, insurances and interest on borrowed capital are also included.

Operating and Maintenance Labor and Supervision

Operating personnel costs are estimated based on two shifts per day of operation totalling 3,333 hours per year and a third shift per day for maintenance.[14]

The cost of direct labor and maintenance labor is taken as $23,700. per year. Operating wage for supervisory personnel is assumed at $30,600 per year. These wages reflect mid-1978 wage levels.[15] Direct operating, supervisory and maintenance crew size for each level of coal beneficiation is based on available published information and actual data gathered from visits to coal cleaning plants. Operating manpower is specified as follows:[16]

Coal	Direct Labor Man/Day	Supervisory Labor Man/Day	Maintenance Man/Day
Cleaning Level IV	18	3	10
Cleaning Level III	10	3	6

The increased complexity and amount of equipment in the level 5 plant over a level 4 plant causes the increase in direct labor and maintenance requirements.

Maintenance, Supplies and Replacement Material

The equipment in a coal preparation plant is replaced on a frequent basis because it is subject to considerable wear. For these estimates the cost of replacement equipment, including maintenance supplies, is taken as 7 percent of the total turnkey costs of each plant.[17]

Utilities and Chemicals

The annual costs for utilities and chemicals are based on:

power @ \$.0072 mJ (\$0.0258/kwh)[18]
water @ \$0.04/1,000 l (\$0.15/1,000 gal)[19]
magnetite @ \$71.7/metric ton (\$65/ton)[20]
flocculant @ \$4.40/kg (\$2/lb)[21]

Consumption of magnetite is based on a rate of 0.376 kg/kkg (0.75 lb/ton) of course coal feed and 0.752 kg/kkg (1.5 lb/ton) of fine coal feed.[22] Flocculant consumption is based on 2 mg/liter of liquid in the flocculated stream.

Refuse Disposal Cost

The cost for refuse disposal was assumed to be \$1.1 per metric ton (\$1.0/ton).[23]

Overhead Costs

Overhead costs are business expenses not directly chargeable to a particular process unit but allocated to it. Overhead costs are usually presented as payroll overhead and plant overhead. Payroll overhead includes employee benefits, recreation and public relations. The plant overhead includes administrative, all local staff support, and plant management functions such as purchasing, scheduling, accounting of finance, safety and medical services. Values used in this analysis are:[24]

payroll overhead = 30 percent of total labor cost
plant overhead = 26 percent of labor, maintenance and supplies, and chemical costs

Cleaning Plant Capital Charges

Capital related charges include annualized capital costs, taxes, insurance and general and administrative costs.

Cleaning Plant Capital Equipment Amortization

It is assumed that regardless of tax and depreciation considerations, a plant operator would probably finance and amortize a coal preparation plant by means of an equal-payment, self-liquidating loan. If the loan is payable with equal installments, the amount due per period per dollar of loan as a function of the loan period and the interest rate is given by

$$R = \frac{i\ (1 + i)^n}{(1 + i)^n - 1}$$

where:

R = capital recovery per period per dollar invested

i = interest rate per period expressed as a decimal

n = number of periods in the amortization schedule.

The factor R multiplied by the amortizable cost will yield the per-period fixed cost covering interest and principal.

For purposes of this exercise a life expectancy of 20 years for coal cleaning plants and an interest rate of 10 percent were assumed.

Cleaning Plant Taxes, Insurance and General and Administrative Costs

Property taxes and insurance vary considerably in different parts of the country. For this study, taxes, insurance and general and administrative costs were taken as 4 percent of depreciable investment.[25]

4.1.2.3 Comparative Coal Costs to User Utilizing Cleaned and Run-of-Mine Coal from the Same Mine--

Table 4-21 presents a summary of costs for the Run-of-Mine coal and the same coal beneficiated at the BSER level. Included in this comparison is the effect of coal quality, preparation yield, pulverization, and ash disposal at the user plant.

TABLE 4-21. COMPARATIVE COAL COST TO USER UTILIZING RUN-OF-MINE COAL AND COAL BENEFICIATED AT BSER LEVEL.

Costs	High Sulfur Eastern* ROM Coal	High Sulfur Eastern* BSER Level	Low Sulfur Eastern ROM Coal	Low Sulfur Eastern BSER Level
Value at shipping				
\$/metric ton (\$/ton)	18.74(17.00)	36.38(33.00)	31.97(29.00)	41.68(37.89)
\$/10^6 kJ (\$/10^6BTU)	0.70(0.74)	1.19(1.26)	1.01(1.06)	1.23(1.30)
Value as fired (including grinding costs)				
\$/metric ton (\$/ton)	18.95(17.20)	36.49(33.10)	32.19(29.20)	41.90(38.09)
\$/10^6 kJ (\$/10^6 BTU)	0.72(0.75)	1.19(1.26)	1.02(1.07)	1.24(1.31)
Total fuel cost at user plant (including ash disposal at \$40/ton)				
\$/metric ton (\$/ton)	29.44(26.70)	42.63(38.66)	36.65(33.24)	43.76(39.78)
\$/10^6 kJ (\$/10^6 BTU)	1.10(1.16)	1.27(1.34)	1.16(1.22)	1.30(1.37)

Coal Data	ROM Coal	Deep Cleaned Product	Mid-dlings	ROM Coal	Cleaned Product
Yield, wt %	100	35.3	38.0	100	83.8
kJ/kg (BTU/lb) (Dry Basis)	26,772 (11,510)	33,555 (14,426)	31,662 (13,612)	31,684 (13,622)	33,882 (14,567)
Ash content, %	23.90	5.28	10.30	10.38	4.13
Sulfur content, %	3.45	0.98	1.54	1.18	0.89
ng of SO_2/J (lb of $SO_2/10^6$ BTU)	2,576 (5.99)	645 (1.5)	1,075 (2.5)	744 (1.73)	525 (1.22)

* Cost for Deep Cleaned Coal Product only

(Refer to table 4-39 for cost development)

Cost of Raw Coal Required per Ton of Clean Coal

For the purpose of this study the spot market price to the beneficiation plant of the three raw coals under study are taken as:[26]

High sulfur eastern	\$18.79/metric ton (\$17/ton)
Low sulfur eastern	\$31.97/metric ton (\$29/ton)
Low sulfur western	\$19.34/metric ton (\$17.50/ton)

Since the clean coal yield is less than 100 percent of the raw coal feed, it takes more than 1 ton of raw coal to provide for 1 ton of clean coal.

Grinding Costs

The grinding of coal for 70% minus 200 mesh pulverized firing requires energy. Hardness is expressed as Hargrove Grindability Index (HGI). A 55 HGI coal uses 31 mJ/metric ton (7.9 kwh/ton), a 100 HGI uses 18 mJ/metric ton (4.4 kwh/ton), a 110 HGI uses 16 mJ/metric ton (4 kwh/ton).[27] For these estimates power was charged at 7.17 mills per mJ (25.8 mills/kwh).[28] Estimated HGI before and after beneficiation and the power consumption values for each coal are given below.

	ROM Coal		Beneficiated Coal	
Coal Type	HGI	MJ/metric ton (kwh/ton)	HGI	MJ/metric ton (kwh/ton)
High Sulfur Eastern	55	31 (7.9)	110	16 (4)
Low Sulfur Eastern	60	30 (7.6)	60	30 (7.6)

Ash Disposal at the User Site

The value of ash disposal at the user site was taken as \$44.10/metric ton (\$40/ton).[29]

Analysis of Coal Cost to User

In Table 4-21 the cost differential to the user between the beneficiated and the raw coal in terms of \$/metric ton are \$13.19 and \$7.36 for the high sulfur eastern (deep cleaned product) and the low sulfur eastern coal, respectively. These costs expressed in terms of $\$/10^6$ kJ are 0.17 and 0.14 , respectively.

Additionally, Table 4-21 indicates high SO_2 emission levels for the run-of-mine coals as compared to the clean coal. The best physical coal cleaning system for the high sulfur eastern coal produces two product streams, a deep cleaned product which could be in compliance with a control level of 645 ng SO_2/J (1.5 lbs $SO_2/10^6$ BTU) and a middling stream which would be in compliance with a control level of 1,075 ng SO_2/J (2.5 lbs $SO_2/10^6$ BTU). Beneficiation of the low sulfur eastern coal at the BSER level produces a single stream with slightly higher sulfur level than that required to meet a control level of 516 ng SO_2/J (1.2 lbs $SO_2/10^6$ BTU), assuming no sulfur retention.

4.1.3 Cost of Chemical Coal Cleaning Processes

This section presents cost information on the three candidate chemical coal cleaning BSERs presented in Section 3.3. The first two processes, the Meyers and the Gravichem (physical coal cleaning plus Meyers) are capable of reducing only a portion of the pyritic sulfur in the feed coal, while the third process, the ERDA process, is capable of reducing both pyritic and organic sulfur. As stated in Section 3.3, chemical coal cleaning processes are still in the development stage and will not be available commercially for 10 years.

The process costs are based on preliminary conceptual processing schemes. The process operating conditions, the process chemistry, the levels of removal of pyritic and organic sulfurs, the heating value, and the yield recovery information are based on evaluation of the individual developer's claims. Where cost information was supplied by a developer, these costs were utilized, to the extent possible, as the basis of the cost information in this report. However, the costs were modified to allow the evaluation of the various processes on a common basis.

The cost estimates presented for the Meyers and the ERDA processes are based on a plant which processes 270 metric tons (300 tons) per day high sulfur eastern coal on a 24-hour per day and 330 days per year basis (8,000 tons/day, three train plant). The basis for the Gravichem process is a 96 metric ton (106 tons) per hour Meyers process unit (a single train plant) operating on a 24-hour a day and 330 days per year basis. The physical coal cleaning section of the plant processes 558 metric tons (615.4 tons) per hour of raw coal (8,000 tons/day) operating 13 hours per day and 250 days per year. The third shift is set aside for scheduled plant maintenance.

Total Direct Capital Costs

Total direct capital costs for the Meyers and ERDA processes were extracted from "Technical and Economic Evaluation of Chemical Coal Cleaning Processes for Reduction of Sulfur in Coal" issued in January 1978.[30] These costs were adjusted to June 30, 1978 bases by using appropriate plant cost indices. The direct capital cost for the physical coal cleaning portion of the Gravichem plant was extracted from the "Meyers Process Development for Chemical Desulfurization of Coal" report.[31] This cost was adjusted to reflect June 30, 1978 prices by using appropriate indices and was then adjusted to the desired plant capacity using a scale factor of 0.7.[32]

The cost of the land used in these estimates is the same as that used for developing costs of the physical coal cleaning plants.

Indirect Capital Cost

Items included in indirect costs and their values are the same as those developed for the physical coal cleaning plants.

Annual Operating Costs—

Operating manpower, energy and utilities requirements for the chemical coal cleaning plants were extracted from the Versar chemical coal cleaning report.[33] The operating and maintenance personnel wages and the cost bases for utilities and chemicals are the same as discussed in physical coal cleaning. The costs for steam and other chemicals used only in chemical coal cleaning process estimates are listed below:

600 psig steam @ $4.83/1,000 lb.[34]
Lime @ $35/metric ton ($32/ton) [35]
Lignin sulfonate binder @ $0.06/lb.[36]

Maintenance supplies and material for all chemical coal cleaning cases were taken as 5 percent of the total turnkey costs based on a lower expected maintenance requirement than physical coal cleaning plants.[37] The cost for the disposal of by-products generated by the chemical coal cleaning plants was extracted from the Versar chemical coal cleaning report.[38]

The cost bases for overhead, capital charges and raw coal costs are presented in the physical coal cleaning discussion.

Chemical Coal Cleaning Costs

Capital and annual operating costs for each chemical coal cleaning process based on the three reference coals are presented in Tables 4-22 through 4-24. The results indicate that the cost of cleaning high sulfur coal and low is $24.73, $32.85 and $14.92 per metric ton (excluding the raw coal cost) for the Meyers, ERDA, and Gravichem (physical coal cleaning plus Meyers process), processes, respectively. Note that the cleaning costs are independent of the sulfur content of the coal.

4.2 CONTROL COSTS TO USER

Control costs are the incremental costs that the boiler operator would pay in order to meet the emission limits. These costs include the increased cost of the cleaned coal, but lower costs associated with particulate collection and ash disposal.

Control costs here will exclude the cost of fuel transportation to the user, although in reality, the least cost BSER for a given standard would be chosen by the boiler operator with transportation costs included. For example, to meet the moderate control level of 860 ng SO_2/J (2.0 lb $SO_2/10^6$ BTU), the industrial boiler operator has the choice (within the control technologies described in this ITAR) of using a physically cleaned high sulfur eastern coal, a low sulfur eastern coal, or a low sulfur western coal. Dependent upon the location of the industrial boiler, the least cost BSER could be any of the three choices. Since location is unspecified, the control costs for the BSER will include a presentation of each BSER exclusive of transportation costs.

TABLE 4-22. CLEANING COSTS FOR CANDIDATE CHEMICAL COAL CLEANING SYSTEMS ON HIGH SULFUR EASTERN COAL.

	Feed*	Product Coal From MEYERS PROCESS	Product Coal From ERDA Process	Product Coal From GRAVICHEM Process
Net Coal Yield, Metric Tons Per Day (Tons/Day)	7,250 (8,000)	6,532 (7,200)	6,532 (7,200)	5,792 (6,384)
Percent Net Energy Content	—	94	94	91
Percent Weight Yield	—	90	90	79.8
Weight % Sulfur in Product	3.40	0.89	0.73	0.89
Heating Value kJ/kg (BTU/lb.)	26,772 (11,510)	28,507 (12,256)	28,507 (12,256)	31,126 (13,382)
$\frac{ng\ SO_2}{J}$ (lb $SO_2/10^6$ BTU)	2,576 (5.99)	623.4 (1.45)	511.6 (1.19)	571.8 (1.33)
Installed Capital Cost ($MM)	—	163.6	224.6	64.9
Annual Processing Excluding Coal Cost ($MM)	—	53.3	70.8	21.6
Annual Processing Including Coal Cost ($MM)	—	98.1	115.7	55.6
$/Annual Metric Ton ($ Annual Ton) of Clean Coal, Excluding Coal Cost	—	24.73 (22.43)	32.85 (29.80)	14.92 (13.53)
$/Annual Metric Ton ($/Annual Ton) of Clean Coal, Including Coal Cost +	—	45.55 (41.31)	53.69 (48.70)	38.40 (34.83)
$/Kilojoule ($/10^6BTU), Excluding Coal Cost	—	0.87 (0.92)	1.16 (1.22)	0.48 (0.51)
$/Kilojoule ($/10^6BTU), Including Coal Cost +	—	1.60 (1.69)	1.89 (1.99)	1.23 (1.30)

* The coal selected is an Upper Freeport ('E' Coal) from Butler County, Pennsylvania which contains 3.45 weight percent total sulfur, 2.51 weight percent pyritic and 0.94 weight percent organic sulfur on a dry basis. It is assumed that this coal has a heating value of 26,772 kJ/kg (11,510 BTU/lb).

\+ Raw Coal Cost $18.74/kkg ($17.00/ton).

TABLE 4-23. CLEANING COSTS FOR CANDIDATE CHEMICAL COAL CLEANING SYSTEM ON LOW SULFUR EASTERN COAL.

	Feed*	Product Coal From MEYERS Process	Product Coal From ERDA Process	Product Coal From GRAVICHEM Process
Net Coal Yield, Metric Tons Per Day (Tons/Day)	7,250 (8,000)	6,532 (7,200)	6,532 (7,200)	5,792 (6,384)
Percent Net Energy Content	——	94	94	91
Percent Weight Yield	——	90	90	79.8
Weight % Sulfur In The Product	1.18	.64	.5	.64
Heating Value kJ/kg (BTU/lb)	31,685 (13,622)	33,092 (14,227)	33,092 (14,227)	36,132 (15,534)
$\frac{ng\ SO_2}{J}$ (lb $SO_2/10^6$ BTU)	744.0 (1.73)	387.0 (0.90)	301 (0.701)	352.6 (0.824)
Installed Capital Cost ($MM)	——	163.6	224.6	64.9
Annual Processing Excluding Coal Cost ($MM)	——	53.3	70.8	21.6
Annual Processing Including Coal Cost ($MM)	——	129.8	147.4	79.6
$/Annual Metric Ton ($ Annual Ton) of Clean Coal, Excluding Coal Cost	——	24.73 (22.43)	32.85 (29.80)	14.92 (13.53)
$/Annual Metric Ton ($/Annual Ton) of Clean Coal, Including Coal Cost +	——	60.25 (54.65)	68.40 (62.04)	54.98 (49.87)
$/Kilojoule ($/10^6BTU), Excluding Coal Cost	——	.75 (.79)	1.00 (1.05)	.41 (.44)
$/Kilojoule ($/10^6BTU), Including Coal Cost +	——	1.82 (1.92)	2.07 (2.18)	1.52 (1.61)

* The coal selected is from the Eagle Seam in Buchanan County, Virginia, which contains 1.18 weight percent total sulfur, 0.60 weight percent pyritic sulfur and 0.58 weight percent organic sulfur on a dry basis. It is assumed this coal has a heating value of $31,685 kJ/kg.

\+ Raw Coal Cost $31.97/kkg ($29.00/ton).

TABLE 4-24. CLEANING COST OF CANDIDATE CHEMICAL COAL CLEANING SYSTEMS ON A LOW SULFUR WESTERN COAL.

	Feed*	Product Coal From MEYERS Process	Product Coal From ERDA Process	Product Coal From GRAVICHEM Process
Net Coal Yield, Metric Tons Per Day (Tons/Day)	7,250 (8,000)	6,532 (7,200)	6,532 (7,200)	5,792 (6,384)
Percent Net Energy Content	——	94	94	91
Percent Weight Yield	——	90	90	79.8
Weight % Sulfur in the Product	0.59	0.32	0.25	0.32
Heating Value kJ/kg (BTU/lb.)	26,270 (11,294)	27,437 (11,796)	27,437 (11,796)	29,959 (12,880)
$\frac{ng\ SO_2}{J}$ (lb $SO_2/10^6$ BTU)	447 (1.04)	232 (0.54)	180.6 (0.42)	210.7 (0.49)
Installed Capital Cost ($MM)	——	163.6	224.6	64.9
Annual Processing Cost Excluding Coal Cost ($MM)	——	53.3	70.8	21.6
Annual Processing Cost Including Coal Cost ($MM)	——	99.5	117.0	56.6
$/Annual Metric Ton ($ Annual Ton) of Clean Coal, Excluding Coal Cost	——	24.73 (22.43)	32.85 (29.80)	14.92 (13.53)
$/Annual Metric Ton ($/Annual Ton) of Clean Coal, Including Coal Cost +	——	46.15 (41.95)	54.27 (49.33)	39.03 (35.49)
$/Kilojoule ($/10^6BTU), Excluding Coal Cost	——	.90 (.95)	1.19 (1.26)	.50 (.53)
$/Kilojoule ($/10^6BTU), Including Coal Cost +	——	1.73 (1.82)	2.02 (2.13)	1.35 (1.42)

* The coal selected is from the Primers Seam in Las Animas County, Colorado which contains 0.59 weight percent total sulfur, 0.30 pyritic and 0.29 organic sulfur on a dry basis. It is assumed this coal has a heating value of 26,270 kJ/kg.

+ Raw Coal Cost $18.74/kkg ($17.50/ton).

4.2.1 Cost Breakdown

4.2.1.1 Capital Costs to the User--

Capital costs are assumed equal to the estimated capital costs of standard boilers provided by PEDCo Environmental, Inc.[39] Note, however, that cleaned coal has a higher energy content and lower ash content than the reference coals used in the cost estimates. Threfore, specific pieces of equipment including the boiler, the coal handling system, and the ash handling system, could be reduced in size to handle clean coal. The reduction in costs cannot be quantified, because the cost bases for the equipment are not sufficiently detailed to determine a cost reduction factor. An engineering judgment would suggest that the capital cost benefits accrued by using cleaned coal are probably not more than a few percent of the total installed capital costs.

4.2.1.2 Operation and Maintenance Costs--

The annual operating and maintenance costs (O&M) for the BSER are described in Sections 4.1.1, 4.1.2 and 4.1.3 for naturally occurring coal, physically cleaned coal, and chemically cleaned coal, respectively. The boiler annual operating costs are equal to those provided by PEDCo environmental with two modifications, which are (1) a reduction in waste disposal costs and (2) an adjustment in fuel cost to include the cleaning charge and increased fuel energy content per unit weight.

Waste disposal costs are primarily the cost for collecting and handling of both bottom ash and fly ash. The amount of ash is a function of the coal's ash content and energy content. It is assumed that ash disposal costs are proportional to the pounds of ash per energy content for each BSER.

The fuel cost to the industrial boiler operator for cleaned coal is the combined cost of the fuel, the cleaning charge, a five percent profit on the cleaning charge, and grinding costs (pulverized coal only). The fuel price is provided in Table 4-4. The cleaning charge is calculated as described in Section 4.1.2, with an assumed five percent profit (before taxes) added to the breakeven charge. The level 5 physical coal cleaning products present an exceptional pricing case because two coal products are generated, a deep cleaned low sulfur, low ash coal and a middling coal. Prices for this cleaning level were set by using the naturally occurring coal equivalent (in quality) price for the middling product and assigning a higher price to the top quality coal that provides a five percent (before taxes) profit to the cleaning plant operator. This pricing scheme is presented in the calculation example.

4.2.2 BSER Costs

The BSER 1978 annual costs are presented in Tables 4-25 through 4-36. These tables indicate that the cost per MWh gradually increases as emission control levels become more stringent. These control costs also decrease as boiler size increases, reflecting the economy of scale effect. Note that fuel costs become more significant (i.e., greater percentage of annualized costs) with increasing boiler capacity.

Figures 4-2 through 4-4 illustrate the magnitude of the increased annualized operator costs associated with increasingly stringent emission control levels. These figures indicate that the costs per MWh gradually increase as emission control levels become more stringent. These control costs also decrease as boiler size increases, reflecting the economy of scale effect. Note that fuel costs become more significant (i.e., greater percentage of annualized costs) with increasing boiler capacity.

Figure 4-5 shows more dramatically the increase in costs required to remove greater quantities of sulfur from the coal. Raw coal costs are not shown since they do not reflect any SO_2 removal. The most cost-effective technology would appear to be the middling product from a physical coal cleaning plant. This technology costs only \$.04 per kg of SO_2 removed. The middling product, however, is only effective for SO_2 compliance up to about 1,100 ng SO_2/J using this particular high sulfur coal. A more acceptable pre-treated fuel is the deep cleaned product, which costs only \$0.15 per kg of SO_2 removed and can comply with control levels as low as 525 ng SO_2/J. Large increases in cost are observed when chemical coal cleaning is employed.

TABLE 4-25. COSTS OF "BEST" SO_2 CONTROL TECHNIQUES FOR 8.8 MW COAL-FIRED BOILERS USING HIGH SULFUR EASTERN COAL

SYSTEM HIGH SULFUR EASTERN COAL				ANNUALIZED COSTS $/MW(t) ($/MBTU/hr)	IMPACTS *	
STANDARD BOILERS: Heat Input MW (MBTU/hr) **	STANDARD BOILERS: Type	TYPE AND LEVEL OF CONTROL	CONTROL EFFICIENCY+ (%)		% INCREASE IN COSTS OVER UNCONTROLLED BOILER	% INCREASE IN COSTS OVER SIP-CONTROLLED BOILER
8.8 (30) 26,772 kJ/kg 3.45% S	Underfeed Stoker	Raw Coal Uncontrolled	0	21.17 (6.20)	N.A.	N.A.
28,847 kJ/kg 1.54% S		SIP 1,075 $ngSO_2J$ Middling Prod. Level 5 pcc	58%	21.43 (6.28)	1.2	N.A.
"		Moderate 1,290 $ngSO_2/J$ Middling Prod. Level 5 pcc	58%	21.43 (6.28)	1.2	0
30,533 kJ/kg 0.98% S		Optional Mod. 860 $ngSO_2/J$ Deep cleaned Prod. Level 5 PCC	75%	22.17 (6.50)	4.7	3.4%
30,533 kJ/kg 0.98% S		Intermediate 645 $ngSO_2/J$ Deep Cleaned Prod.	75%	22.17 (6.50)	4.7	3.4%
27,903 kJ/kg 0.73%		Stringent 516 $ngSO_2/J$ Chemical CC ERDA	80%	26.19 (7.67)	23.7	18%

* BASED ONLY ON ANNUALIZED COSTS

** Raw Coal Analysis: 3.45% S; 26,772 kJ/kg; 23.90% ash (2,576 ng SO_2/J)

\+ Percent Reduction in $ngSO_2/J$

TABLE 4-26. COSTS OF "BEST" SO_2 CONTROL TECHNIQUES FOR 22 MW COAL-FIRED BOILERS USING HIGH SULFUR EASTERN COAL

SYSTEM HIGH SULFUR EASTERN COAL				ANNUALIZED COSTS	IMPACTS *	
STANDARD BOILERS: Heat Input MW (MBTU/hr) **	STANDARD BOILERS: Type	TYPE AND LEVEL OF CONTROL	CONTROL EFFICIENCY+ (%)	\$/MW(t) (\$/MBTU/hr)	% INCREASE IN COSTS OVER UNCONTROLLED BOILER	% INCREASE IN COSTS OVER SIP-CONTROLLED BOILER
22 (75) 26,772 kJ/kg 3.45% S	Watertube Grate-Stoker	Raw Coal Uncontrolled	0	16.59 (4.86)	N.A.	N.A.
28,847 kJ/kg 1.54%		SIP-1,075 $ngSO_2/J$ Middling Prod. Level 5 pcc	58%	16.83 (4.93)	1.0	N.A.
"		Moderate 1,290 $ngSO_2/J$ Middling Level 5 pcc	58%	16.83 (4.93)	1.0	0
30,533 kJ/kg 0.98% S		Optional Mod 860 $ngSO_2/J$ Deep Cleaned Prod. Level 5 PCC	75%	17.65 (5.17)	6.0	4.8
30,533 kJ/kg 0.98% S		Intermediate 645 $ngSO_2/J$ Deep Cleaned Prod. Level 5 PCC	75%	17.65 (5.17)	6.0	4.8
27,903 kJ/kg 0.73%		Stringent 516 $ngSO_2/J$ ERDA Chem CC	80%	21.61 (6.33)	30.3	28.4

* BASED ONLY ON ANNUALIZED COSTS

** Raw Coal Analysis: 3.45% S; 26,772 kJ/kg; 23.90% ash; (2,576 $ngSO_2/J$)

\+ Percent Reduction in $ngSO_2/J$

TABLE 4-27. COSTS OF "BEST" SO_2 CONTROL TECHNIQUES FOR 44 MW COAL-FIRED BOILERS USING HIGH SULFUR EASTERN COAL

SYSTEM HIGH SULFUR EASTERN COAL: STANDARD BOILERS — Heat Input MW (MBTU/hr) **	STANDARD BOILERS — Type	TYPE AND LEVEL OF CONTROL	CONTROL EFFICIENCY+ (%)	ANNUALIZED COSTS $/MW(t) ($/MBTU/hr)	IMPACTS *: % INCREASE IN COSTS OVER UNCONTROLLED BOILER	IMPACTS *: % INCREASE IN COSTS OVER SIP-CONTROLLED BOILER
44 (150) 26,772 kJ/kg 3.45% S	Spreader Stoker	Raw Coal Uncontrolled	0	13.56 (3.97)	N.A.	N.A.
28,847 kJ/kg 1.54% S		SIP - 1,075 $ngSO_2/J$ Middling Prod. Level 5 pcc	58%	14.37 (4.21)	6.0	N.A.
"		Moderate 1,290 $ngSO_2/J$ Middling Prod. Level 5 pcc	58%	14.37 (4.21)	6.0	0
30,533 kJ/kg 0.98%		Optional Mod. 860 $ngSO_2/J$ Deep Cleaned Prod. Level 5 PCC	75%	15.12 (4.43)	11.5	5.2
30,533 kJ/kg 0.98%		Intermediate 645 $ngSO_2/J$ Deep Cleaned Prod. Level 5 PCC	75%	15.12 (4.43)	11.5	5.2
27,903 kJ/kg 0.73% S		Stringent 516 $ngSO_2/J$ ERDA Chemical CC	80%	19.13 (5.61)	41.1	33.1

* BASED ONLY ON ANNUALIZED COSTS

** Raw Coal Analysis: 3.45% S; 26,772 kJ/kg; 23.90% ash; (2,576 ng SO_2/J)

\+ Percent Reduction in $ngSO_2/J$

TABLE 4-28. COSTS OF "BEST" SO_2 CONTROL TECHNIQUES FOR 58.6 MW COAL-FIRED BOILERS USING HIGH SULFUR EASTERN COAL

SYSTEM HIGH SULFUR EASTERN COAL				ANNUALIZED COSTS $/MW(t) ($/MBTU/hr)	IMPACTS *	
STANDARD BOILERS: Heat Input MW (MBTU/hr) **	STANDARD BOILERS: Type	TYPE AND LEVEL OF CONTROL	CONTROL EFFICIENCY+ (%)		% INCREASE IN COSTS OVER UNCONTROLLED BOILER	% INCREASE IN COSTS OVER SIP-CONTROLLED BOILER
58.6 (200) 26,772 kJ/kg 3.45% S	Pulverized Coal fired	Raw Coal Uncontrolled	0	13.95 (4.09)	N.A.	N.A.
28,847 kJ/kg 1.54% S		SIP 1,075 $ngSO_2/J$ Middling Prod. Level 5-PCC	58%	14.97 (4.38)	7.3	N.A.
"		Moderate 1,290 $ngSO_2/J$ Middling Prod. Level 5-PCC	58%	14.97 (4.38)	7.3	0
30,533 kJ/kg 0.98% S		Optional Mod. 860 $ngSO_2/J$ Deep Cleaned Prod. Level 5 PCC	75%	15.72 (4.60)	12.7	5.0
30,533 kJ/kg 0.98%		Intermediate 645 $ngSO_2/J$ Deep Cleaned Prod. Level 5 PCC	75%	15.72 (4.60)	12.7	5.0
27,903 kJ/kg 0.73% S		Stringent 516 $ngSO_2/J$ ERDA Chemical CC	80%	19.74 (5.78)	42	31.9

* BASED ONLY ON ANNUALIZED COSTS

** Raw Coal Analysis: 3.45% S; 26,772 kJ/kg; 23.90% ash; (2,576 ng SO_2/J

\+ Percent Reduction in $ngSO_2/J$

TABLE 4-29. COSTS OF "BEST" SO_2 CONTROL TECHNIQUES FOR 117.2 MW COAL-FIRED BOILERS USING HIGH SULFUR EASTERN COAL

SYSTEM HIGH SULFUR EASTERN COAL				ANNUALIZED COSTS $/MW(t) ($/MBTU/hr)	IMPACTS *	
STANDARD BOILERS: Heat Input MW (MBTU/hr) **	STANDARD BOILERS: Type	TYPE AND LEVEL OF CONTROL	CONTROL EFFICIENCY+ (%)		% INCREASE IN COSTS OVER UNCONTROLLED BOILER	% INCREASE IN COSTS OVER SIP-CONTROLLED BOILER
118 (400) 26,772 kJ/kg 3.45% S	Pulverized Coal fired	Raw Coal Uncontrolled	0	12.79 (3.75)	N.A.	N.A.
28,847 kJ/kg 1.54% S		SIP 1,075 $ngSO_2/J$ Middling Prod. Level 5-PCC	58%	13.81 (4.05)	8.0	N.A.
		Moderate 1,290 $ngSO_2/J$ Middling Prod. Level 5-PCC	58%	13.81 (4.05)	8.0	0
30,533 kJ/kg 0.98% S		Optional Mod. 860 $ngSO_2/J$ Deep Cleaned Prod. Level 5 PCC	75%	14.56 (4.26)	13.8	5.4
30,533 kJ/kg 0.98%		Intermediate 645 $ngSO_2/J$ Deep Cleaned Prod. Level 5 PCC	75%	14.56 (4.26)	13.8	5.4
27,903 kJ/kg 0.73% S		Stringent 516 $ngSO_2/J$ ERDA Chemical CC	80%	18.57 (5.44)	45.3	34.5

* BASED ONLY ON ANNUALIZED COSTS

** Raw Coal Analysis: 3.45% S; 26,772 kJ/kg; 23.90% ash; 2,576 ng SO_2/J

\+ Percent Reduction in $ngSO_2/J$

TABLE 4-30. COSTS OF "BEST" SO_2 CONTROL TECHNIQUES FOR 8.8 MW COAL-FIRED BOILERS USING LOW SULFUR EASTERN COAL

SYSTEM LOW SULFUR EASTERN COAL				ANNUALIZED COSTS	IMPACTS *	
STANDARD BOILERS: Heat Input MW (MBTU/hr) **	STANDARD BOILERS: Type	TYPE AND LEVEL OF CONTROL	CONTROL EFFICIENCY+ (%)	\$/MW(t) (\$/MBTU/hr)	% INCREASE IN COSTS OVER UNCONTROLLED BOILER	% INCREASE IN COSTS OVER SIP-CONTROLLED BOILER
8.8 (30)	Underfeed Stoker Boiler	RAW	0	\$20.48 (\$6.00)	0	N.A.
		SIP - Control	0	" "	0	N.A.
		Moderate 1,290 $ngSO_2/J$ or 860 $ngSO_2/J$	0	" "	0	0
PCC 33,882 kJ/kg 0.89% S		Intermediate 645 $ngSO_2/J$ PCC-Level 4	30%	\$21.11 (\$6.19)	3.1%	3.1%
"		Stringent 516 $ngSO_2/J$ PCC-Level 4++	30%	\$21.11 (\$6.19)	3.1%	3.1%
CCC 36,130 kJ/kg 0.64% S		CCC-Gravichem	50%	\$21.79 (\$6.38)	6.4%	3.2%

* BASED ONLY ON ANNUALIZED COSTS

** Raw Coal: 1.18% S; 31,685 kJ/kg; 10.4% ash; (745 ng SO_2/J

\+ Percent reduction in $ngSO_2/J$

++ Physical coal cleaning product is 525 $ngSO_2/J$ without sulfur retention

TABLE 4-31. COSTS OF "BEST" SO_2 CONTROL TECHNIQUES FOR 22 MW COAL-FIRED BOILERS USING LOW SULFUR EASTERN COAL

SYSTEM LOW SULFUR EASTERN COAL				ANNUALIZED COSTS $/MW(t) ($/MBTU/hr)	IMPACTS *	
STANDARD BOILERS: Heat Input MW (MBTU/hr) **	STANDARD BOILERS: Type	TYPE AND LEVEL OF CONTROL	CONTROL EFFICIENCY+ (%)		% INCREASE IN COSTS OVER UNCONTROLLED BOILER	% INCREASE IN COSTS OVER SIP-CONTROLLED BOILER
22 (75)	Chain - Grate - Stoker	RAW	0	$16.17 ($4.74)	0	N.A.
		SIP - Control	0	"	0	N.A.
		Moderate: 1,290 $ngSO_2/J$ or 860 $ngSO_2/J$	0	"	0	0
PCC Coal 33,882 kJ/kg 0.89% S		Intermediate 645 $ngSO_2/J$ PCC-Level 4	30%	$16.81 ($4.92)	3.9%	3.9%
		Stringent 516 $ngSO_2/J$++ PCC-Level 4	30%	$16.81 ($4.92)	3.9%	3.9%
CCC Coal 36,130 kJ/kg 0.64% S		Chemical CC Gravichem	50%	$17.48 ($5.12)	8.1%	8.1%

* BASED ONLY ON ANNUALIZED COSTS
** Raw Coal: 1.18% S; 31,685 kJ/kg; 10.4% ash; (745 ng SO_2/J
\+ Percent Reduction in $ngSO_2/J$
++ PCC product is 525 $ngSO_2/J$ without sulfur retention

TABLE 4-32. COSTS OF "BEST" SO_2 CONTROL TECHNIQUES FOR 44 MW COAL-FIRED BOILERS USING LOW SULFUR EASTERN COAL

SYSTEM LOW SULFUR EASTERN COAL				ANNUALIZED COSTS	IMPACTS *	
STANDARD BOILERS: Heat Input MW (MBTU/hr) **	STANDARD BOILERS: Type	TYPE AND LEVEL OF CONTROL	CONTROL EFFICIENCY+ (%)	\$/MW(t) (\$/MBTU/hr)	% INCREASE IN COSTS OVER UNCONTROLLED BOILER	% INCREASE IN COSTS OVER SIP-CONTROLLED BOILER
44 (150)	Watertube Spreader Stoker	RAW	0	\$13.50 (\$3.96)	0	N.A.
		SIP-Control	0	" "	0	N.A.
		Moderate: 1,290 $ngSO_2/J$ or 860 $ngSO_2/J$	0	" "	0	0
PCC: 33,882 kJ/kg 0.89% S		Intermediate 645 $ngSO_2/J$ PCC-Level 4	30%	\$14.34 (\$4.20)	6.2%	6.2%
		Stringent 516 $ngSO_2/J$ PCC-Level 4++	30%	\$14.34 (\$4.20)	6.2%	6.2%
CCC: 36,130 kJ/kg 0.64% S		CCC - Gravichem	50%	\$15.02 (\$4.40)	11.2%	11.2%

* BASED ONLY ON ANNUALIZED COSTS

** Raw Coal: 1.18% S; 31,685 kJ/kg; 10.4% ash; (745 $ngSO_2/J$

\+ Percent Reduction in $ngSO_2/J$

\+\+ PCC product is 525 $ngSO_2/J$ without sulfur retention

TABLE 4-33. COSTS OF "BEST" SO_2 CONTROL TECHNIQUES FOR 58.6 MW COAL-FIRED BOILERS USING LOW SULFUR EASTERN COAL

SYSTEM LOW SULFUR EASTERN COAL				ANNUALIZED COSTS $/MW(t) ($/MBTU/hr)	IMPACTS *	
STANDARD BOILERS: Heat Input MW (MBTU/hr) **	STANDARD BOILERS: Type	TYPE AND LEVEL OF CONTROL	CONTROL EFFICIENCY+ (%)		% INCREASE IN COSTS OVER UNCONTROLLED BOILER	% INCREASE IN COSTS OVER SIP-CONTROLLED BOILER
58.6 (200)	Pulverized Coal-Fired	RAW	0	$13.91 ($4.08)	0	N.A.
		SIP - Control	0	" "	0	N.A.
		Moderate: 1,290 ng SO_2/J and 860 ngSO_2/J	0	" "	0	0
PCC 33,882 kJ/kg 0.89% S 4.1% ash		Intermediate 645 ng SO_2/J PCC-Level 4	30%	$14.83 ($4.35)	6.6%	6.6%
		Stringent 516 ngSO_2/J PCC-Level 4++	30%	$14.83 ($4.35)	6.6%	6.6%
CCC 36,130 kJ/kg 0.64% S 3.1% ash		CCC - Gravichem	50%	$15.51 ($4.54)	11.5%	11.5%

* BASED ONLY ON ANNUALIZED COSTS

** Raw Coal: 1.18% S; 31,685 kJ/kg; 10.4% ash; (745 ngSO_2/J)

\+ Percent Reduction in ngSO_2/J

++ PCC product is 525 ngSO_2/J without sulfur retention

TABLE 4-34. COSTS OF "BEST" SO CONTROL TECHNIQUES FOR 117.2 MW COAL-FIRED BOILERS USING LOW SULFUR EASTERN COAL.

SYSTEM LOW SULFUR EASTERN COAL				ANNUALIZED COSTS	IMPACTS *	
STANDARD BOILERS Heat Input MW (MBtu/hr) **	STANDARD BOILERS Type	TYPE AND LEVEL OF CONTROL	CONTROL EFFICIENCY+ (%)	$/MW(t) ($/MBtu/hr)	% INCREASE IN COSTS OVER UNCONTROLLED BOILER	% INCREASE IN COSTS OVER SIP-CONTROLLED BOILER
117.2 (400)	Pulverized Coal-Fired	RAW	0	$12.86 ($3.77)	0	N.A.
		SIP - Control	0	" "	0	N.A.
		Moderate: 1,290 ng SO_2/J and 860 ngSO_2/J	0	" "	0	0
PCC 33,882 kJ/kg 0.89% S 4.1% ash		Intermediate 645 ng SO_2/J PCC-Level 4	30%	$13.78 ($4.04)	7.2	7.2
		Stringent 516 ngSO_2/J PCC-Level 4++	30%	$13.78 ($4.04)	7.2	7.2
CCC 36,130 kJ/kg 0.64% S 3.1% ash		CCC - Gravichem	50%	$14.46 ($4.24)	12.4	12.4

* BASED ONLY ON ANNUALIZED COSTS

** Raw Coal: 1.18% S; 31,685 kJ/kg; 10.4% ash; (745 ngSO_2/J)

\+ Percent Reduction in ngSO_2/J

++ PCC product is 525 ngSO_2/J without sulfur retention

TABLE 4-35. COSTS OF "BEST" SO_2 CONTROL TECHNIQUES FOR 8.8 MW and 22 MW COAL-FIRED BOILERS USING LOW SULFUR WESTERN COAL

SYSTEM LOW SULFUR WESTERN COAL				ANNUALIZED COSTS	IMPACTS *	
STANDARD BOILERS		TYPE AND LEVEL OF CONTROL	CONTROL EFFICIENCY (%)	$/MW(t) ($/MBTU/hr)	% INCREASE IN COSTS OVER UNCONTROLLED BOILER	% INCREASE IN COSTS OVER SIP-CONTROLLED BOILER
Heat Input MW (MBTU/hr) **	Type					
8.8 (30)	Underfeed Stoker	RAW (744)	0	$21.39 ($6.27)	N.A.	N.A.
"	"	SIP-Control (1074)	0	$21.76*** ($6.39)	1.7%	N.A.
"	"	1,290 ngSO_2/J	0	" "	1.7%	0
		860 ngSO_2/J	0	" "	1.7%	0
"	"	645 ngSO_2/J	0	" "	1.7%	0
"	"	516 ngSO_2/J	0	" "	1.7%	0
22 (75)	Chain-Grate	RAW (744)	0	$16.81 ($4.93)	N.A.	N.A.
"	Stoker	SIP-Control (1074)	0	$17.18 ($5.03)	2.2%	N.A.
"	"	1,290 ngSO_2/J	0	" "	2.2%	0
		860 ngSO_2/J	0	" "	2.2%	0
"	"	645 ngSO_2/J	0	" "	2.2%	0
"	"	516 ngSO_2/J	0	" "	2.2%	0

* BASED ONLY ON ANNUALIZED COSTS

** 0.59% S; 26,270 kJ/kg; 24.8% ash - Raw Coal Analysis- (744 ng SO_2/J)

*** Increase due to particulate control

TABLE 4-36. COSTS OF "BEST" SO_2 CONTROL TECHNIQUES FOR 44 MW AND 58.6 AND 117.2 MW COAL-FIRED BOILERS USING LOW SULFUR WESTERN COAL

SYSTEM LOW SULFUR WESTERN COAL				ANNUALIZED COSTS	IMPACTS *	
STANDARD BOILERS		TYPE AND LEVEL OF CONTROL	CONTROL EFFICIENCY (%)	\$/MW(t) (\$/MBTU/hr)	% INCREASE IN COSTS OVER UNCONTROLLED BOILER	% INCREASE IN COSTS OVER SIP-CONTROLLED BOILER
Heat Input MW (MBTU/hr) **	Type					
44 (150)	Field erected, watertube, spreader stoker	RAW	0	\$13.74 (\$4.03)	N.A.	N.A.
"		SIP - Control	0	\$14.71 (\$4.31)	7.1%	N.A.
"		1,290 $ngSO_2/J$	0	" "	7.1%	0
"		860 $ngSO_2/J$	0	" "	7.1%	0
"		645 $ngSO_2/J$	0	" "	7.1%	0
"	"	516 $ngSO_2/J$	0	" "	7.1%	0
58.6 (200)	Field erected, watertube, pulverized coal	RAW	0	\$14.10 (\$4.13)	N.A.	N.A.
"		SIP - Control	0	\$15.13 (\$4.43)	7.3%	N.A.
"		1,290 $ngSO_2/J$	0	" "	7.3%	0
"		860 $ngSO_2/J$	0	" "	7.3%	0
"		645 $ngSO_2/J$	0	" "	7.3%	0
"	"	516 $ngSO_2/J$	0	" "	7.3%	0
117.2 (400)		RAW	0	\$12.95 (\$3.79)	N.A.	N.A.
		SIP - Control (1,074)	0	\$14.15 (\$4.15)	9.3%	0
		1,290 $ngSO_2/J$	0	" "	9.3%	0
		860 $ngSO_2/J$	0	" "	9.3%	0
		645 $ngSO_2/J$	0	" "	9.3%	0
		516 $ngSO_2/J$	0	" "	9.3%	0

* BASED ONLY ON ANNUALIZED COSTS

** 0.59% S; 24.8% ash; 26,270 kJ/kg - Raw Coal Analysis - (744 ng SO_2/J)

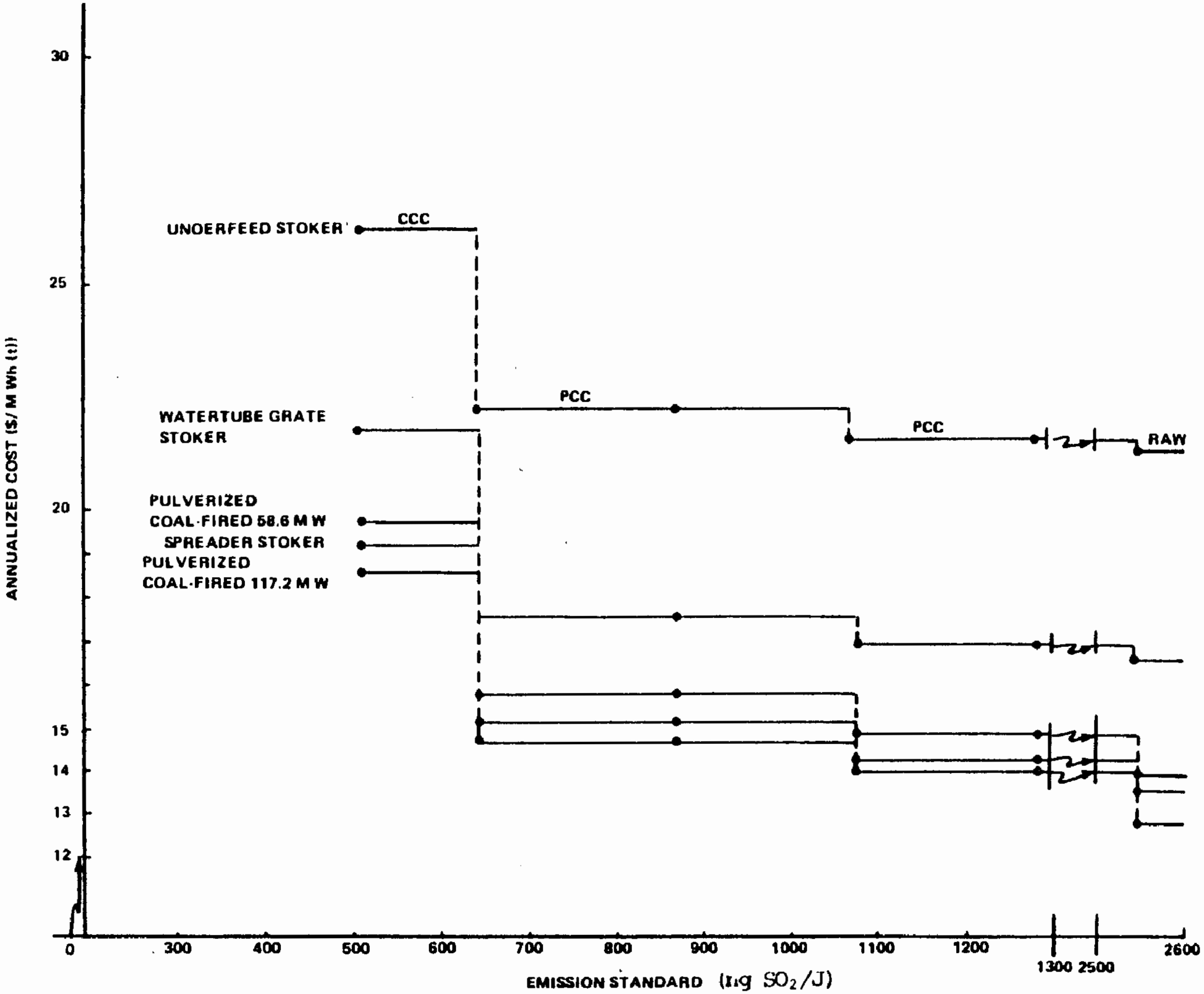

FIGURE 4-2 LEVEL-OF-CONTROL ANNUALIZED COST CURVES FOR HIGH SULFUR EASTERN COAL

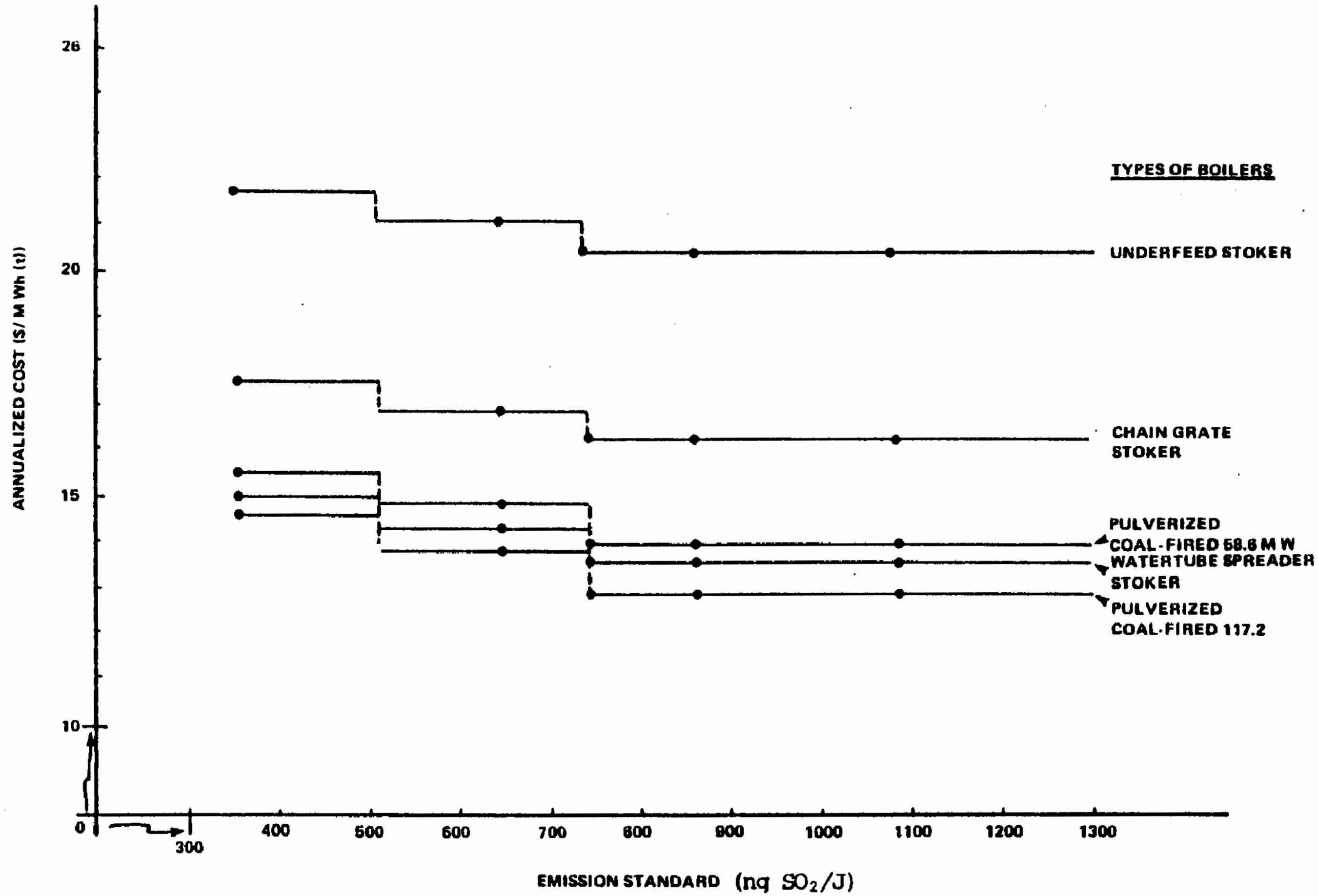

FIGURE 4-3 LEVEL-OF-CONTROL ANNUALIZED COST CURVES FOR LOW SULFUR EASTERN COAL

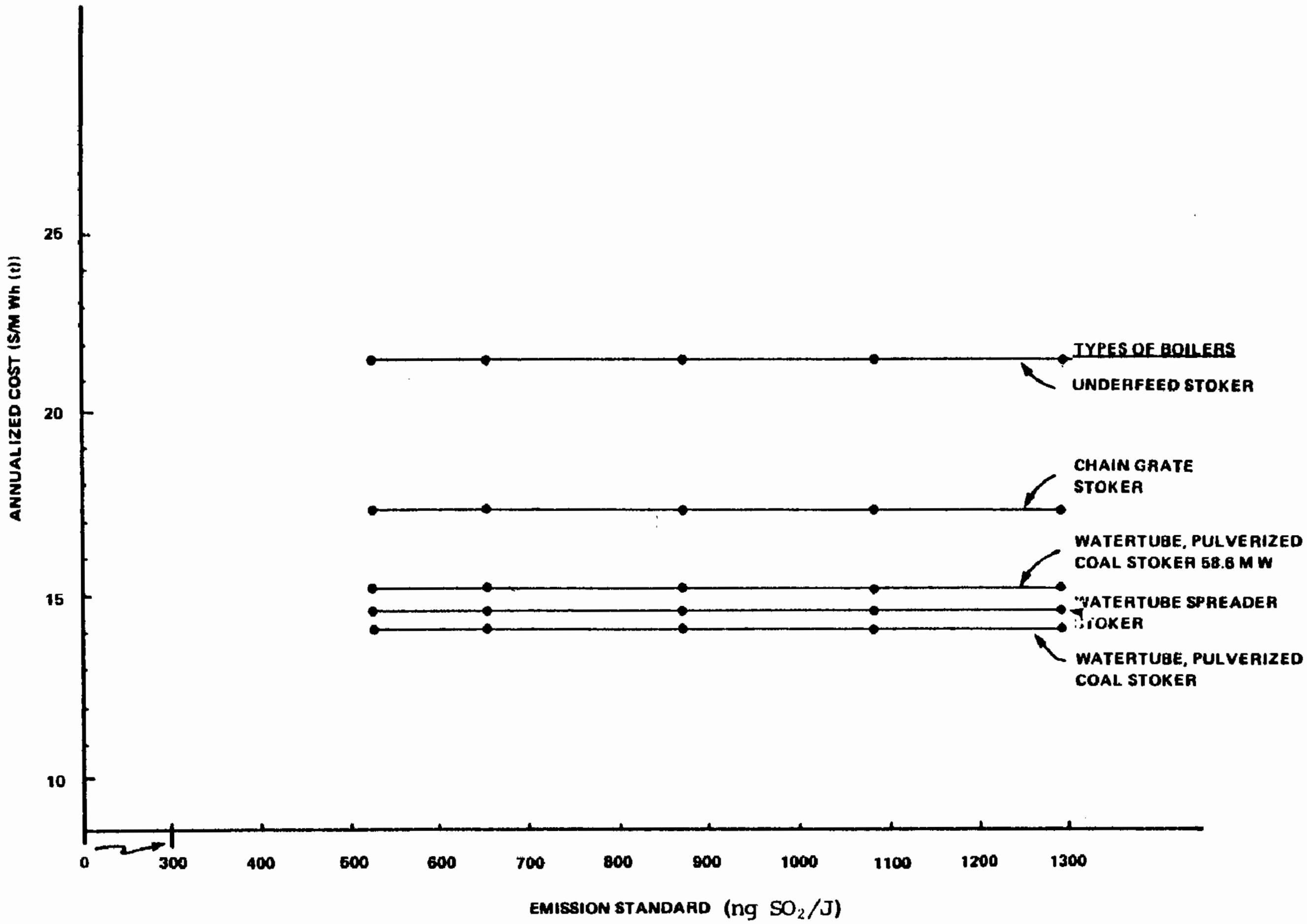

FIGURE 4-4 LEVEL-OF-CONTROL ANNUALIZED COST CURVES FOR LOW SULFUR WESTERN COAL

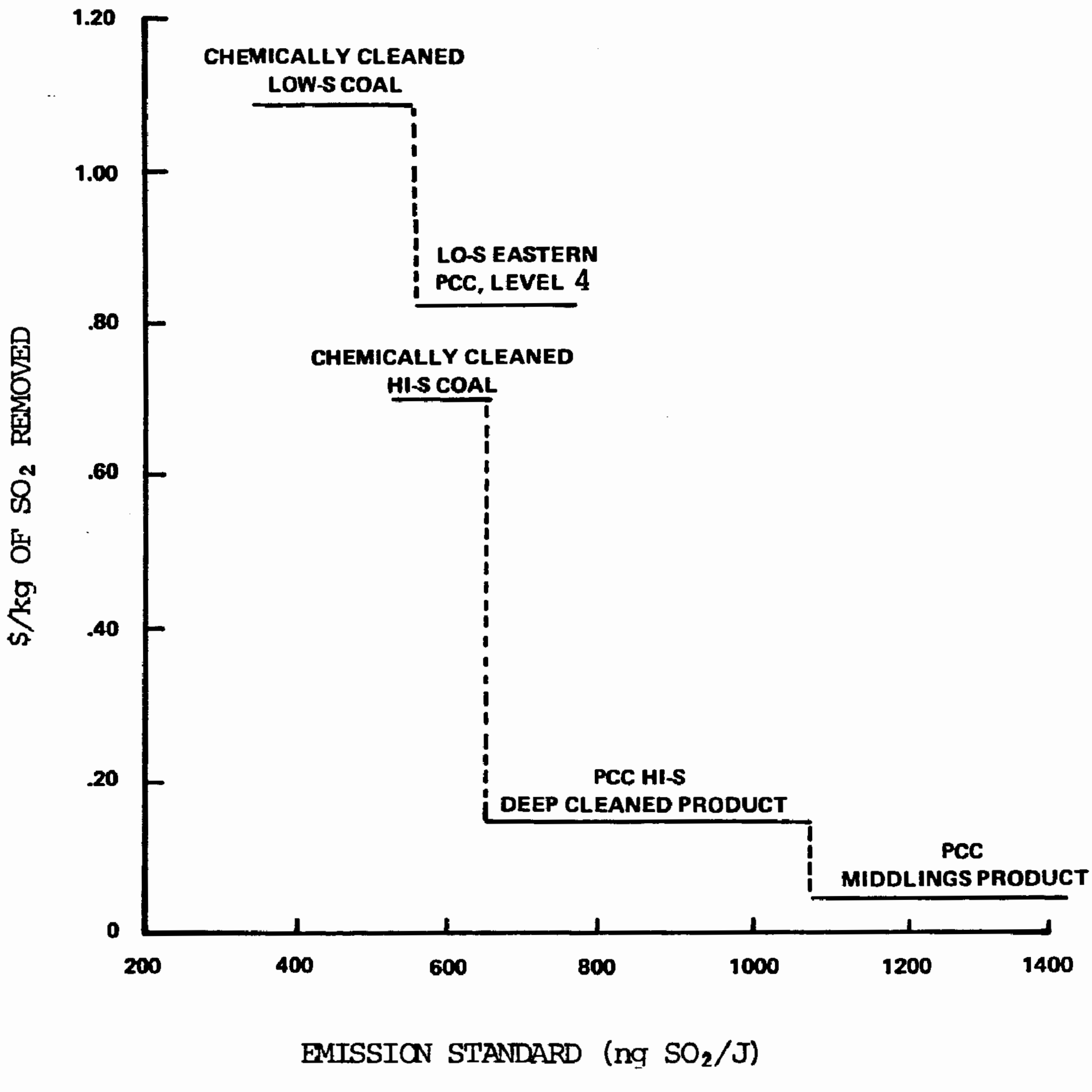

FIGURE 4-5 COST EFFECTIVENESS CURVES

The normalized costs are shown as step functions because the cost differential to attain less than optimum cleaning for any given beneficiation process is negligible. For example, the fuel cost to the boiler operator would not be significantly less if the deep cleaned coal (i.e., high sulfur eastern coal, cleaned to level 4) were only treated to produce 650 ng SO_2/J, instead of 525 ng SO_2/J, assuming the same equipment was used. On the other hand, a separate, distinct coal cleaning scheme could be designed to produce a deep cleaned product which would produce 650 ng SO_2/J. The fuel cost from this plant might be significantly less than the beneficiation plant presented in this study. It is not within the scope of this ITAR, however, to design the multiplicity of cleaning plants necessary to produce a relatively smooth cost curve. It is also noted that any cost curve would be unique to that particular coal being cleaned since the costs are a function of pyrite content, organic sulfur content, size distribution of pyritic material, ash content, moisture content, and washability characteristics (see Section 3).

This study only provides the costs required to attain optimal cleaning for each BSER and reference coal. The tables are based on 1978 annual operating costs for standard boilers provided by PEDCo.[40] Examples of the calculations to determine BSER costs are provided in Tables 4-37 through 4- 39.

The results of costing the BSER technologies reveal two major findings. First, for high sulfur eastern coal, physical coal cleaning is an exceptionally low cost control technology. That is, to meet moderate or SIP control levels, a 60 percent reduction in sulfur dioxide emissions per unit heat rate can be obtained with a 1 percent increase in annual operating costs. To comply with an optional moderate (860 ng SO_2/J) or intermediate control level (645 ng SO_2/J), a 75 percent reduction in sulfur dioxide emissions is required and can be obtained with only a 4-8 percent increase in operating costs. Stringent control levels cannot be met with physical coal cleaning which is reflected in the almost 30 percent increase in costs using chemical coal cleaning versus an uncontrolled boiler.

TABLE 4-37. EXAMPLE OF COSTS FOR BSER [41,42,43,44,45]

Basis: High sulfur eastern coal - 26,772 kJ/kg (as received);
3.40% sulfur; 23.4% ash

18.74 x 10^6 metric tons (2.0 x 10^6 tons) per year

3,333 hours per year operation

Capital amortized over 20 years @ 10% interest

Level 5 - Grass roots plant installation
73.3% weight yield, 87.5% heating value recovery

<u>Summary Values for Coal Cleaning Plant with the Two Product Streams Combined</u>

Installed Capital Cost: $18,123,100

Annual Operating Costs on Clean Coal Basis: $6,350,200 processing cost excluding coal cost

$40,350,200, including coal cost

$4.78/metric ton ($4.33/ton), excluding coal cost
$30.27/metric ton ($27.52/ton), including coal cost
$0.149/$10^6$ kJ ($0.158/$10^6$ BTU), excluding coal cost
$0.934/$10^6$ kJ ($0.988/$10^6$ BTU), including coal cost

TABLE 4-37. (Continued) PREPARATION PLANT CAPITAL REQUIREMENTS FOR HIGH SULFUR COAL (BSER)

RAW COAL STORAGE AND HANDLING	Mid 1977 prices
Raw Coal Storage Area 20,000 ton capacity with reclaiming feeders and tunnel	300,000
Raw Coal Belt to Rotary Breakers 42 inch wide - 200 feet @ $520 per foot	104,000
Tramp Iron Magnet over Raw Load Belt (explosion proof, self cleaning type)	20,000
Rotary Breaker 9 ft. diameter - 17 feet long	150,000
Surge Silo 5,000 ton capacity @ $110 per ton	550,000
Raw Coal Belt to Scalping Screen 42 inch wide - 250 feet @ $520 per foot	130,000
Raw Coal Scalping Screen and Structural Work for the Crusher and the Breaker	350,000
Raw Coal Crusher 2 @ $128,000 each	256,000
Raw Coal Belt to Plant 42 inch wide - 250 feet @ $520 per foot	130,000
Total Raw Coal Storage and Handling Cost	1,990,000

TABLE 4-37. (Continued) PREPARATION PLANT

Equipment Cost -

6 x 16 Foot Single Deck Screen 2 @ $15,000 each	30,000
Heavy Media Vessel Daniels DMS Washer	31,000
4 x 16 Foot Double Deck Vibrating Drain & Rinse Screens 4 @ $20,500 each	82,000
Crusher - McNally Split Mesh Geared Stocker Crusher	58,500
Centrifugal Dryer - Bird Model 1150 D	48,000
3 x 16 Foot Single Deck Vibrating Drain & Rinse Screen	12,000
Magnetic Separators for Heavy & Dilute Media 30 inch diameter - 10 feet long 6 @ $8,500 each	51,000
Sumps for Heavy & Dilute Media 4,000 gal - 1/4" steel 6 @ $14,000 each	84,000
6 x 16 Foot Single Deck Vibrating Desliming Screens 4 @ $19,000	76,000
Heavy Media Cyclone 24 inch diameter - w/Ni-Hand Liner 9 @ $6,000 each	54,000
Sieve Bends 5 feet wide - 80 inch, radius 6 @ $4,000 each	24,000
6 x 16 Foot Single Deck Vibrating Drain & Rinse Screens 6 @ $19,000	114,000
Sieve Bends 6 feet wide - 30 inch radius 2 @ $4,800 each	9,600
6 x 16 Foot Single Deck Vibrating Drain & Rinse Screens 2 @ $19,000	38,000
Clean Coal Centrifuge - Bird Model 1150 D 4 @ $48,000	192,000

TABLE 4-37.(Continued) PREPARATION PLANT

Sump - Heavy Media Cyclone Feed Sumps 7,000 gallon - 1/4 inch steel 2 @ $14,000 each	28,000
Sieve Bend 4 feet wide - 30 inch radius	3,200
3' x 16' Single Deck Vibrating Drain & Rinse Screen	12,000
Sieve Bend 6 feet wide - 80 inch radius	4,800
6' x 16' Single Deck Vibrating Drain & Rinse Screen	19,000
Clean Coal (3/8 x 28M) Centrifuge Screen-Bowl	110,000
Refuse (3/8 x 28M) Centrifuge Bird Model 1150 D	48,000
Sump - 28 M x 0 Cyclone Feed Sump 10,000 gallon - 1/4 inch steel 2 @ $18,000	36,000
Thickening Cyclone #1 14 inch diameter - w/rubber liner 15 @ $1,300 each	19,500
Sump - Cyclone #1 Underflow Sump 2,500 gallon - 1/4" steel 2 @ $10,000 each	20,000
Sump - Hydroclone Feed Sump 10,000 gallon - 1/4 inch steel 2 @ $18,000	36,000
Thickening Cyclone #2 14 inch diameter - w/rubber liner 5 @ $1,300 each	6,500
Hydroclones - 14 inch Diameter - w/Ni-Hand Liner & Refrax Underflow 10 @ $3,500 each	35,000
Sieve Bend 5 feet wide - 30 inch radius 10 @ $4,000 each	40,000

TABLE 4-37. (Continued) PREPARATION PLANT

Centrifuge Dryers - Screen Bowl	190,000
Clarifier - Emco Model B-90 90 feet in diameter	132,000
Disc Filter - 2,000 sq. ft.	130,000
Pumps for the Preparation Plant	150,000
Total Preparation Plant Equipment	1,924,000

Total Installed Cost of Preparation Plant Equipment

Including Site Preparation
Building Structure, Piping,
Electrical and Erection

1,924,100 x 2.35	4,521,600

The factor 2.35 for determining total direct capital costs from plant equipment costs was arrived from both Hoffman-Muntner Co. and Bechtel Corp. in their reports on preparation plant costs. The percent of breakdown of the total direct cost is provided below:

	PERCENTAGE
Plant Purchased Equipment	42.5
Building Structures	25.2
Piping	5.1
Electrical	11.6
Erection	15.5
	100

These factors do not include construction labor and field expenses which are considered indirect costs.

TABLE 4-37. (Continued)
MISCELLANEOUS FACILITIES AND EQUIPMENT:

Clean Coal Belt to #1 Fuel Silo 36 inch wide - 300 feet @ \$480 per foot	144,000
#7 Fuel Silo 10,000 ton capacity @ \$110 per ton	1,100,000
Clean Coal Belt to #2 Fuel Silo 36 inch wide - 300 feet @ \$480 per foot	144,000
#2 Fuel Silo 10,000 ton capacity @ \$110 per ton	1,100,000
Refuse Belt 36 inch wide - 300 feet @ \$480 per foot	144,000
Refuse Bin 2-100 ton capacity - fabricated plant	100,000
Coal Sampling System	300,000
Unit-Train Loading Facility	500,000
	3,532,000

SUMMARY OF TOTAL INSTALLED CAPITAL COST (MID 1977)

Raw Coal Storage and Handling	1,990,000
Preparation Plant	4,521,600
Miscellaneous Facilities and Equipment	3,532,000
	10,043,600

Factor for Escalating Direct Costs from Mid-1977 to Mid-1978 [46] = 8.0%

10,043,600 x 1.080 = Total Installed Capital Cost (Mid 1978) \$10,847,100

TABLE 4-37. (Continued)

TOTAL INSTALLED CAPITAL COST (June 30, 1978)

Total Direct Costs (equipment & installation)		10,847,100
Installation costs, indirect		
Engineering (10% of direct costs)	1,084,700	
Construction and field expense (10% of direct costs)	1,084,800	
Construction fees (10% of direct costs)	1,084,700	
Start-up (2% of direct costs)	217,000	
Performance tests (minimum $2,000)	--	
Total Indirect Costs		3,473,000
Contingencies (20% of direct and indirect costs)		2,864,000
Total Turnkey Costs (direct & indirect & contingencies)		17,184,100
Land		264,000
Working capital (25% of total direct operating costs)*		675,000
GRAND TOTAL (turnkey & land & working capital)		18,123,100

* Assumes 25% of operating and maintenance costs which include: utilities, chemicals, operating labor, maintenance and repairs, and disposal costs.

TABLE 4-38. SAMPLE CALCULATION FOR ESTIMATING ANNUAL OPERATING COSTS FOR HIGH SULFUR COAL (BSER)

ANNUALIZED COSTS (Mid 1978$)		
Direct Labor (18 man yrs x $23,700/yr)	426,600	
Supervision (3 man yrs x $30,400/yr)	91,200	
Maintenance Labor (10 man yrs x $23,700/yr)	237,000	
Maintenance Materials & Replacement Parts (7% of total turnkey costs)	1,202,900	
Electricity (25.8 mils/kwh x 2,318 kw	199,300	
Water ($0.15/$10^3$ gal x 8 l/sec (127 gpm)	3,800	
Waste Disposal $1.1/kkg ($1/ton)	433,200	
Chemicals (magn: 1,157 kkg @ $71.7/kkg ($65/ton)	83,000	
(floc: 5,290 kg @ $4.4 kg ($2/lb)	23,300	
TOTAL DIRECT COST		2,700,300
Payroll (30% of direct & indirect & maintenance labor)	226,400	
Plant Overhead (26% of direct, indirect & maintenance labor and maintenance, and chemicals)	536,600	
TOTAL OVERHEAD COST		763,000
Capital Recovery Factor (11.75% of total Turnkey Costs)	2,132,000	
G&A, Taxes & Insurance (4% of total Turnkey Costs)	687,400	
Interest on Working Capital (10% of W.C.)	67,500	
TOTAL CAPITAL CHARGES		2,886,900
TOTAL ANNUALIZED COSTS (excluding coal cost)		6,350,200
Cost Per Ton of Moisture Free Product		$4.33/ton
Cost Per 10^6 BTU of Moisture Free Product		$0.158/$10^6$ BTU
Raw Coal Cost, 1.8 x 10^6 kkg/yr @ $18.74/kkg ($17/ton)		34,000,000
TOTAL ANNUALIZED COST (including coal cost)		$40,350,200
Cost per kkg (ton) of Moisture Free Product		$30.34 ($27.52)
Cost per 10^6 kJ (10^6 BTU) of Moisture Free Product		$0.934 ($0.988)

TABLE 4-39. SAMPLE CALCULATION FOR COMPARATIVE COAL COSTS

Fuel Cost

Yield = 73.3% of raw coal; Middling = 38% Deep Cleaned Product = 35.3

$$\frac{\text{Total Annual Cost}}{\text{Total Clean Coal}} = \frac{\$40,350,200}{\left[\frac{2 \times 10^6 \text{ tons}}{\text{yr.}} \times .733\right]} = \$27.52/\text{ton} = \$30.34/\text{metric ton}$$

AVERAGE COAL COST = $30.34 /metric ton

However, the 2 products are not equal, so two prices must be provided.

Assume middling product at 12,400 BTU/lb (as received); 10.3% ash; and 1.54% sulfur is priced at spot market price for naturally-occurring equivalent coal (47)

$24/ton or $26.40/metric ton

At 38% yield - $2 \times 10^6 \times .38 = 0.76 \times 10^6$ TPY middling product

$0.76 \times 10^6 \times \$24 = \$18.2 \times 10^6$ per year revenue

Income: $\$40.4 \times 10^6$ (annual cost) - $\$18.2 \times 10^6$ (middlings revenue = $\$22.2 \times 10^6$

or deep cleaned product must yield $\$22.2 \times 10^6$ to break even

At 35.3% yield - $2 \times 10^6 \times .353 = 0.71 \times 10^6$ TPY Lo-S product

$$\frac{\$22.2 \times 10^5}{0.71 \times 10^6} = \$31.45/\text{ton}$$

At 5% profit = $33.02/ton - Value at Shipping = $36.32 /metric ton

$$\frac{\$33.02}{\text{ton}} \times \frac{\text{ton}}{2{,}000 \text{ lb.}} \times \frac{\text{lb}}{\underset{\text{(as received)}}{.01313 \times 10^6 \text{ BTU}}} = \$1.26 /10^6 \text{ BTU} = \$1.20/10^6 \text{kJ}$$

Value as fired: Same as 'shipping', except add $.10/ton for grinding at pulverized boiler

Ash Handling Cost Factor

ROM coal at 23.4% ash and 26,772 kJ/kg

$$\text{or } \frac{.234 \text{ g ash}}{\text{g coal}} \times \frac{\text{g coal}}{26.770 \text{ kJ}} = 8.74 \times 10^{-3} \text{ g ash/kJ}$$

Middling Product: 10.3% ash; 28,847 kJ/kg

$$\frac{.103 \text{ g ash}}{\text{g coal}} \times \frac{\text{g coal}}{28.84 \text{ kJ}} = 3.57 \times 10^{-3} \text{ g ash/kJ}$$

Low-sulfur product: 5.28% ash; 30,533 kJ/kg

$$\frac{.0528 \text{ g ash}}{\text{g coal}} \times \frac{\text{g coal}}{30.53 \text{ kJ}} = 1.73 \times 10^{-3} \text{ g ash/kJ}$$

TABLE 4-39. SAMPLE CALCULATION FOR COMPARATIVE COAL COSTS (Continued)

Ash Handling Factor:

Middling Product = $\frac{3.57}{8.74} \cong 0.40$

Low-S Product = $\frac{1.73}{8.76} = 0.20$

Industrial Boiler Operator Costs

Two values change over those provided by Acurex/PEDCo:

1) Fuel costs (increase)
2) Ash handling costs (decrease)

For 8.8 MW Underfeed Stoker

1) Fuel Cost Increase:

a) Middling coal:

$$\frac{\$24.00}{\text{ton}} \times \frac{\text{ton}}{2{,}000\ \text{lb.}} \times \frac{\text{lb}}{.0124 \times 10^6\ \text{BTU}} = \$.97/10^6\ \text{BTU}$$

$$\frac{\$.97}{10^6\ \text{BTU}} \times \frac{30 \times 10^6\ \text{BTU}}{\text{hr.}} \times \frac{8{,}760\ \text{hr}}{\text{yr.}} \times 0.6\ \text{C.F.} = \$152{,}600$$

- Raw Fuel Cost Provided by PEDCo	=	116,300
Clean Coal Cost Difference	+	$36,300

2) Bottom Ash Costs - Middling Product Reduces Value by 60%.

Raw Coal Bottm Ash Handling (PEDCo Cost)	=	$21,000
0.40 x $21,000	=	8,400
Bottom Ash Handling Cost Difference	=	-$12,600
SubTotal Increased Costs		$23,700
Increase Costs for Fly Ash: $4/ton x 1,670 tons/yr. of fly ash=		$ 6,700
Total Annual Costs = $952,300 + 23,700 + 6,700 =		$982,700

Annual Cost Basis: $/MW

$$\frac{\$982{,}700}{8.8\ \frac{\text{MW}}{\text{hr.}} \times \frac{8{,}760\ \text{hr.}}{\text{yr.}} \times .6} = \$21.25/\text{MW(t)}$$

For Table 4-36 :the low sulfur product coal costs are based on $\$1.26/10^6$ BTU and an ash handling factor of 0.2. The ERDA process costs are based on $\$2.11/10^6$ BTU and an ash handling factor of 0.75.

The second major finding is that physically and chemically cleaned low sulfur eastern coal can meet a stringent control level of 516 ng SO_2/J (1.2 lb $SO_2/10^6$ BTU) at relatively low increase in cost to the industrial boiler operator. This increase in annual cost is as low as 3 percent or as high as 9 percent, dependent upon control technology and size of the boiler. Because chemical coal cleaning is still in the development stage, the future cost to the boiler operator for chemically cleaned coal may be radically different than the values presented here.

4.2.2.1 Comparison of BSER Costs with Commercial Plants--

The capital cost and annual operating and maintenance cost for each BSER were compared to previous calculations and estimates from existing beneficiation plants to check the accuracy of the cost calculations. The report "An Engineering/Economic Analysis of Coal Preparation Plant Operation and Cost" prepared for the Department of Energy by Hoffman-Munter Corporation was used as the basis for the comparison.[47]

A general statement in the Hoffman-Munter report was that beneficiation plants cost between \$7,000-\$23,000 per ton-hour of coal input (mid-1977 dollars).[48] The normalized BSER capital costs were \$34,800/ton-hour for the multi-stream plant and \$30,000/ton-hour for the preparation plant designed for low sulfur eastern coal (mid 1978 dollars). The major differences in these costs were the inclusion of indirect installation costs (i.e., engineering, construction expenses, start-up costs, and performance tests), land costs and working capital costs in this study. If these two costs are excluded, the normalized costs decrease to \$26,200/ton-hour for the multi-stream plant and \$23,000/ton-hour for the low sulfur eastern coal preparation plant (mid-1978 dollars). Including one year inflation at 8 percent, the normalized costs appear to be in the correct range and conservatively high.

As a further check, the results of this study were compared to similar plants presented in the Hoffman-Munter study. The comparison is provided in Tables 4-40 and 4-41. These tables show that the BSER beneficiation plant costs are good estimates of actual plant costs.

TABLE 4-40. COST COMPARISON WITH LEVEL 4, HEAVY MEDIA PLANT USING HIGH SULFUR EASTERN COAL

Parameter	Hoffman-Muntner Actual Plant Costs (mid-1977)	ITAR Estimated Costs (mid-1978)
(Plant Description)	Heavy media process cleaning 900 TPH; 2-stage heavy media cyclone; fines cleaning by deister tables; thermal dryers.	Heavy media plant cleaning 600 TPH; 2-stage heavy media cyclone; fines cleaning by hydrocyclones; <u>no</u> thermal dryers.
Raw Coal Handling Equipment cost	\$1.2 million	\$2.1 million
Preparation Plant Equip.	\$2.6 million	\$2.1 million
Other Facilities (exclud. thermal dryer)	\$3.8 million	\$3.8 million
Total Installed Capital Cost per ton-hr. input	\$17,200	\$21,700
1978 Operation and Maintenance (excluding thermal dryer)	\$10.4 million	\$6.3 million
1978 O & M Cost per ton of clean coal	3.06	\$4.33

TABLE 4-41. COST COMPARISON WITH LEVEL 4, HEAVY MEDIA PLANT USING LOW SULFUR EASTERN COAL[50]

Parameter	Hoffman Muntner Actual Plant Costs (mid-1977 $)	ITAR Estimated Cost (mid-1978 $)
(Plant Description)	Heavy media process cleaning 600 TPH; Heavy media vessel for coarse separation; heavy media cyclone for middlings separation; flotation cells for fine coal cleaning; thermal dryers.	Heavy Media process cleaning 600 TPH; heavy media vessel for coarse coal; heavy media cyclone for middlings; hydrocyclones for fine coal dewatering; no thermal dryer.
Raw Coal Handling Equipment	$1.0 million	$2.1 million
Preparation Plant Equipment	$1.4 million	$1.9 million
Miscellaneous Equipment (excludes thermal dryer)	$2.9 million	$2.9 million
1978 Total installed capital cost per ton-hr. input (excludes thermal dryer)	$15,500	$19,100
1978 Operation and Maintenance (excluding thermal dryer)	$5.2 million	$5.3 million
1978 O&M per ton of clean coal	$4.54	$3.14

4.3 COST SUMMARY

Section 4.0 has presented the cost of complying with emission control levels for industrial boilers using naturally occurring or cleaned coal. The costs were found to be a combination of four costs: raw coal costs, cleaning/handling charges, transportation, and in-plant preparation and disposal. The raw coal costs are a function of the coal quality with respect to heating value, ash content, and sulfur content. The cleaning charges used in this ITAR are based on engineering estimates of cleaning plant operating costs. Boiler operator costs were assumed to be those presented by PEDCo Environmental with modifications made to fuel and waste disposal costs. In-plant preparation and disposal costs are primarily a function of heating value and ash content of the coal. Cleaned coal can reduce boiler size, coal handling throughput needs, and maintenance requirements. The decreased capital and operating costs associated with these reduced requirements are not included in this ITAR. However, the decrease in operating costs associated with less ash disposal is included.

Transportation costs were excluded from this analysis, although transportation has a major impact on which coal type is used. Transportation cost examples were presented in Section 4.1.1.5. A comparison of Tables 4-4 and 4-19 with Table 4-6 shows that transportation costs are of the same order of magnitude as raw and cleaned coal costs. Of special note is that the cost of transporting western coal to eastern markets is in the range of $15-24/kkg, while cleaning costs are only $3-5/kkg. From a cost standpoint it appears that cleaning local eastern and midwestern coals would be preferable to transporting western coals to eastern markets. This assumes, of course, that high sulfur coals can be cleaned to acceptable levels to meet environmental constraints.

The BSER operating cost for each industrial boiler size and reference coal type at various emission standard levels is presented in Table 4-42. On a $/MWh basis, the costs for each coal type and reference boiler are within 30 percent of one another and in most cases the cost differential is less than 10 percent. This further accentuates the fact that the BSER depends heavily on transportation costs and therefore on the location of the boiler.

TABLE 4-42. COST SUMMARY TABLE - BSER

Cost to industrial boiler operator is the combined cost of raw coal plus cleaning plus transportation plus boiler O&M. However, since the boiler location has not been specified for this study, transportation costs are excluded. Also particulate control costs (both capital and operating) are not included. It is our understanding that these costs will be included in future studies.

[Costs are in $/MWh(t)]

High Sulfur Eastern Coal

Boiler Size/ MW	Emission Control Level (ng SO_2/J) Uncontrolled	1290	1075	860	645	516
8.8	21.17	21.43	21.43	22.17	22.17	26.19
22	16.59	16.83	16.83	17.65	17.65	21.61
44	13.56	14.37	14.37	15.11	15.11	19.13
58.6	13.95	14.97	14.97	15.72	15.72	19.74
117.2	12.79	13.81	13.81	14.56	14.56	18.57

Low Sulfur Eastern Coal

Boiler Size/ MW	Emission Control Level (ng SO_2/J) Uncontrolled	1290	1075	860	645	516	CCC
8.8	20.48	20.48	20.48	20.48	21.11	21.11	21.79
22	16.17	16.17	16.17	16.17	16.80	16.80	17.48
44	13.50	13.50	13.50	13.50	14.34	14.34	15.02
58.6	13.91	13.91	13.91	13.91	14.83	14.83	15.51
117.2	12.86	12.86	12.86	12.86	13.78	13.78	14.46

Low Sulfur Western Coal

The costs for low sulfur western coal as a BSER are relevant for emission control levels greater than 450 ng SO_2/J:

Boiler Size	Uncontrolled	Controlled
8.8	21.39	21.76
22	16.81	17.18
44	13.74	14.71
56.8	14.10	15.13
117.2	12.95	14.15

SECTION 4

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2. Regional Energy System for the Planning and Optimization of National Scenarios. "Final Report, Clean Coal Energy: Source-to-Use Economics Project", ERDA-76-109, June 1976, Page 101.

3. Larry Broz (Acurex Corp.) Memo of October 23, 1978. Subject: "Industrial Boiler Project," PEDCo. Sec. 4.0, "Cost of New Boilers" for EPA/OAQPS Control Costs, pp. 4-11, 4-22, 4-31, 4-43, 4-46, 4-52, 4-55.

4. U.S. Department of Energy "An Engineering Economic Analysis of Coal Preparation Plant Operations and Costs" Prepared by Hoffman-Munter Corp., July, 1978. pp. 132-133.

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SECTION 5.0

ENERGY IMPACT OF CANDIDATES FOR BEST SYSTEM OF EMISSION REDUCTION

The purpose of this energy impacts section is to quantify and compare the energy requirements of the control technologies previously identified as Best Systems of Emission Reduction (BSER). The first portion of this section introduces the various energy uses or savings associated with each BSER. Where possible, these uses are quantified. In the second portion, the energy quantities are combined to characterize the energy usage for each BSER. Subsequent portions briefly discuss the potential for energy savings from each BSER, the factors which effect energy use by modified/reconstructed boilers, and the impacts on the BSER of government legislation which mandates fuel switching.

5.1 INTRODUCTION

In this section we compare the levels of energy consumed in two systems of coal used for industrial boilers--naturally occurring low-sulfur coals and cleaned coals.

The major energy-using activities considered are: transportation of coal, processing at mine mouth, coal cleaning, and postcombustion fly ash removal.

5.1.1 <u>Energy Involved in Transporting Coal</u>

Naturally Occurring Low Sulfur Coal--

The energy required to transport coal (as a fraction of the combustion energy in the coal) depends on the distance between origin and destination, the available routes, the mode of transportation, and the heating value of the delivered coal.

Table 5-1 presents estimated distances of transportation routes between the supply centers of seven coals and six industrial destinations. The

Table 5-1. DISTANCES, BY MODE, BETWEEN THE ORIGINS OF SUPPLY COALS AND DESTINATIONS
Km (mi)

		Origin						
		Low-Sulfur Coals						High-Sulfur Coal
Destination	Mode	Gillette, Wy.	Rock Springs, Wy.	Gallup, N.M.	Williston, N.D.	Buchanan, Va.	Las Animas, Co.	Butler, Pa.
Austin, Tx.	Water	0 (0)	0 (0)	0 (0)	0 (0)	2420 (1500)	0 (0)	2740 (1710)
	Rail	2440 (1510)	2240 (1400)	1780 (1105)	2630 (1630)	1050 (650)	1980 (1230)	780 (490)
	Total	2440 (1510)	2240 (1400)	1780 (1105)	2630 (1630)	3470 (2150)	1980 (1230)	3520 (2200)
Harrisburg, Pa.	Water	1590 (990)	1890 (1180)	1890 (1190)	1590 (980)	0 (0)	2480 (1540)	0 (0)
	Rail	2050 (1270)	2450 (1530)	2340 (1580)	1500 (930)	470 (290)	1220 (760)	460 (290)
	Total	3640 (2260)	4340 (2710)	4230 (2760)	3090 (1920)	470 (290)	3700 (2300)	460 (290)
Columbus, Oh.	Water	1340 (830)	1140 (700)	1140 (700)	1340 (830)	0 (0)	1720 (1070)	760 (470)
	Rail	1770 (1100)	2250 (1400)	2330 (1450)	1220 (760)	660 (410)	1010 (630)	130 (80)
	Total	3110 (1930)	3390 (2100)	3470 (2150)	2560 (1590)	660 (410)	2730 (1700)	890 (550)
Baton Rouge, La.	Water	1480 (920)	1480 (900)	1390 (860)	2520 (1570)	2420 (1500)	1390 (860)	2750 (1710)
	Rail	1960 (1220)	2060 (1280)	1500 (930)	960 (600)	340 (200)	1080 (670)	60 (40)
	Total	3440 (2140)	4540 (2180)	2890 (1790)	3480 (2170)	3760 (1710)	2470 (1530)	2810 (1750)
Sacramento, Ca.	Water	0 (0)	0 (0)	0 (0)	0 (0)	1560 (970)	0 (0)	1880 (1180)
	Rail	2540 (1580)	1420 (880)	1620 (1005)	2620 (1630)	3570 (2220)	2310 (1430)	3310 (2060)
	Total	2540 (1580)	1420 (880)	1620 (1005)	2620 (1630)	4130 (3190)	2310 (1430)	5210 (3240)
Springfield, Il.	Water	0 (0)	0 (0)	0 (0)	1040 (650)	1260 (780)	590 (330)	1890 (1180)
	Rail	2120 (1320)	2220 (1380)	2300 (1430)	1130 (700)	500 (310)	980 (610)	230 (140)
	Total	2120 (1320)	2220 (1380)	2300 (1430)	2170 (1350)	1760 (1090)	1570 (980)	2120 (1320)

routing, which includes the two major transportation modes--rail and water--gives preference to the water mode where possible, since it involves less energy and less cost than does the rail mode.

The energy required to transport low-sulfur coals, physically-cleaned coals, and chemically-cleaned coals to the reference destinations is presented in Tables 5-2, 5-3, and 5-4, respectively, as a fraction of the combustible energy in the delivered coal. The values are based upon the heating values of the coals (see Section 3.2.2), the routed distances on rail and water (see Table 5-1), and the average values of 2.62×10^5 Joules per kkg-km (366 BTU per ton-mile) by rail, and 2.12×10^5 Joules per kkg-km (296 BTU per ton-mile) by barge, values which include energy consumed in hauling and in loading and unloading operations.

Table 5-2, which presents values for the six representative low-sulfur coals (unprocessed), indicates a range of over an order-of-magnitude in the computed values of transportation-energy consumption, expressed as a percentage of the energy in the delivered coal. For example, transporting the low-sulfur coal from Buchanan, Virginia to Harrisburg, Pennsylvania consumes energy equal to about 0.4 percent of the coal's energy, while transporting lignite from Williston, North Dakota to Baton Rouge, Louisiana consumes energy equal to almost 5.0 percent of the combustible energy in the coal.

Similarly, for physical and chemical coal cleaning, the range of values of transportation energy as a percentage of the energy in the delivered coal, is somewhat greater than an order-of-magnitude, as shown in Tables 5-3 and 5-4.

Transportation Energy Consumed by BSER--

This subsection focuses upon the energy consumed during the transportation of the three reference coals selected in Section 3.0. The matrix in Table 5-5 summarizes the "Best System of SO_2 Emission Reduction," which permits compliance with four alternative SO_2 emission control levels when applied to the three coals.

A summary of the values of the energy consumed during transportation using the Best Systems of Emission Reduction is displayed in Table 5-6. For some demand centers, such as Austin, Texas, the energy consumed during transportation is approximately the same (i.e., about 2.0 to 2.5 percent)

Table 5-2. THE ENERGY CONSUMED IN TRANSPORTING LOW-SULFUR COAL TO INDUSTRIAL DEMAND CENTERS AS A PERCENTAGE OF THE COMBUSTIBLE ENERGY IN THE DELIVERED COAL†

	Origin					
Destination	Buchanan, Va.	Las Animas, Co.	Gillette, Wy.	Rock Springs, Wy.	Gallup, N.M.	Williston, N.D.
Austin, TX	2.51%	2.00%	3.26%	2.22%	2.02%	4.27%
Harrisburg, PA	0.39	3.25	4.46	3.94	4.62	4.53
Columbus, OH	0.55	2.42	3.82	3.13	3.69	3.75
Baton Rouge, LA	1.91	2.22	4.32	3.22	2.97	4.89
Sacramento, CA	4.04	2.32	3.40	1.40	1.84	4.26
Springfield, IL	1.23	1.47	2.84	2.22	2.62	3.20

† Values based upon (1) heating values of the coals (see section 3.2.2) (2) routed distances by railroad and barge (see Table 5-1), and (3) energy consumption rates of 2.62×10^5 J/kkg-km by railroad and 2.12×10^5 J/kkg-km by barge.

Table 5-3. THE ENERGY CONSUMED IN TRANSPORTING SELECTED PHYSICALLY CLEANED COALS TO INDUSTRIAL DEMAND CENTERS AS A PERCENTAGE OF THE COMBUSTIBLE ENERGY IN THE DELIVERED COAL†

	Origin of Physically Cleaned Coals and Level of Cleaning$^{\sigma}$		
	Low-S Eastern (Buchanan, VA)	High-S Eastern (Butler, PA)	
Destination	PCC Level 4	PCC Level 5 Middlings	PCC Level 5 Deep Cleaned
Austin, TX	2.18%	2.63%	2.59%
Harrisburg, PA	0.34	0.40	0.39
Columbus, OH	0.48	0.64	0.63
Baton Rouge, LA	1.66	2.00	1.97
Sacramento, CA	3.51	4.23	4.17
Springfield, IL	1.07	1.54	1.51

† Values based upon (1) heating values of the coals (see section 3.2.2), (2) routed distances by railroad and barge (see Table 5-1), and (3) energy consumption rates of 2.62×10^5 J/kkg-km by railroad and 2.12×10^5 J/kkg-km by barge.

σ The levels of PCC correspond to those described in section 3.2.1.2.

Table 5-4. THE ENERGY CONSUMED IN TRANSPORTING A CHEMICALLY-CLEANED COAL TO INDUSTRIAL DEMAND CENTERS AS A PERCENTAGE OF THE COMBUSTIBLE ENERGY IN THE DELIVERED COAL†

	High-S Eastern (Butler, PA)	
	CCC Process σ	
Destination	Gravichem	ERDA
Austin, TX	2.61	2.85
Harrisburg, PA	0.39	0.43
Columbus, OH	0.64	0.69
Baton Rouge, LA	1.99	2.17
Sacramento, CA	4.21	4.59
Springfield, IL	1.52	1.66

† Values based upon (1) heating values of the coals (see section 3.2.2), (2) routed distances by railroad and barge (see Table 3.2-3), and (3) energy consumption rates of 2.62×10^5 J/kkg-km by railroad and 2.12×10^5 J/kkg-km by barge.

σ The chemical coal cleaning processes are described in section 3.2.1.3.

TABLE 5-5. BEST SYSTEM OF EMISSION REDUCTION FOR THREE CANDIDATE COALS AND FIVE SO_2 EMISSION CONTROL LEVELS

Coal	SO_2 Emission Levels ng SO_2/J (lb/SO_2/10^6 BTU)				
	1,290 (3.0)	1,075 (2.5)	860 (2.0)	645 (1.5)	516 (1.2)
High Sulfur Eastern	PCC level 5 Middling	PCC level 5 Middling	PCC level 5 Deep Cleaned	PCC level 5 Deep Cleaned	CCC: ERDA
Low Sulfur Eastern	Raw Coal	Raw Coal	Raw Coal	PCC level 4	PCC level 4 CCC Gravichem
Low Sulfur Western	Raw Coal	Raw Coal	Raw Coal	Raw Coal	Raw Coal

TABLE 5-6. ENERGY CONSUMED DURING TRANSPORTATION WHEN THE "BEST SYSTEM OF EMISSION REDUCTION" IS APPLIED TO THREE COALS SELECTED AS CANDIDATES FOR COAL CLEANING AS A PERCENTAGE OF THE COMBUSTION ENERGY OF THE DELIVERED COAL

		Emission Level ng SO_2/J (lb $SO_2/10^6$ BTU)			
Destination	Coal Type ∞	1,290 (3.0)	860 (2.0)	645 (1.5)	516 (1.2)
Austin, TX	High-S Eastern	2.63%	2.59%	2.59%	2.85%
	Low-S Eastern	2.51	2.51	2.18	2.18
	Low-S Western	2.00	2.00	2.00	2.00
Harrisburg, PA	High-S Eastern	0.40	0.39	0.39	0.43
	Low-S Eastern	0.39	0.39	0.34	0.34
	Low-S Western	3.25	3.25	3.25	3.25
Columbus, OH	High-S Eastern	0.64	0.63	0.63	0.69
	Low-S Eastern	0.55	0.55	0.48	0.48
	Low-S Western	2.42	2.42	2.42	2.42
Baton Rouge, LA	High-S Eastern	2.00	1.97	1.97	2.17
	Low-S Eastern	1.91	1.91	1.66	1.66
	Low-S Western	2.22	2.22	2.22	2.22
Sacramento, CA	High-S Eastern	4.23	4.17	4.17	4.59
	Low-S Eastern	4.04	4.04	3.51	3.51
	Low-S Western	2.32	2.32	2.32	2.32
Springfield, IL	High-S Eastern	1.54	1.51	1.51	1.66
	Low-S Eastern	1.23	1.23	1.07	1.07
	Low-S Western	1.47	1.47	1.47	1.47

∞ These coal types are characterized in Section 3.2.2. The high sulfur eastern coal originates at Butler, PA., the low sulfur eastern coal at Buchanan, VA., the low sulfur western coal at Las Animas, CO.

regardless of the selected BSER. For other industrial centers, such as Harrisburg, PA., the range of values in transportation energy may differ by an order of magnitude (i.e., from about 0.3 to 3.0 percent).

The difference between the energy consumed in transporting raw coals and the energy used in transporting cleaned coals reflects the net energy enhancement of the coals resulting from the removal of ash during the cleaning process. Energy enhancement allows less coal (per unit weight) to satisfy boiler input heat requirements. The following percentages of coal-energy enhancement were used:

Coal Cleaning Process	kJ/kg Enhancement (%)
PCC: Level 5 Middlings	13.0
PCC: Level 5 Deep Cleaned	15.0
CCC: Gravichem	14.0
CCC: ERDA	4.4

5.1.2 Energy Elements for a Low Sulfur Coal Control System

The major energy elements involved with providing low sulfur coal to industrial boilers is the use of energy during transportation and during handling at the mine and industrial boiler.

The energy used for breakers at the mine is approximately 290 KW - based on a 7,250 metric ton/day plant. This value represents the energy utilized to reduce run-of-mine (ROM) coal to sizes acceptable for further processing or to satisfy the demand for specific top sizes. Breaking coal to a relatively homogeneous size range helps accomplish efficient coal handling and combustion.

5.1.3 Energy Usage by Physical Coal Cleaning Processes

5.1.3.1 Total Energy Use of PCC Plant Control System--

Because of the nature of physical coal cleaning most processes involve merely sizing and washing and are not energy intensive. There are no increased temperature or pressure requirements as would be required of chemical coal cleaning. Instead the operations which use significant amounts of energy are pulverizing, dewatering and thermal drying. Of these, pulverizing and dewatering require electrical energy while thermal drying requires fuel. Pulverizing systems utilize electrical energy for crushers and grinders. As is indicated by Table 5-7 the chosen Best Systems for Emission Reduction utilize 6.2 kJ/kg for a Level 4 plant and 15.5 kJ/kg for a Level 5 plant for pulverizing. For higher levels of cleaning more grinding and crushing are performed than for lower levels.

Dewatering systems require electrical energy for units such as centrifuges, vacuum filters and cyclones. Table 5-7 shows energy usages for dewatering as 5.3 kJ/kg of product for Level 4 and 14.2 kJ/kg of product for Level 5. The increased handling in higher levels of cleaning means a proportionate increase in size of the dewatering systems.

Electrical energy is also used for motors and pumps as well as for separation devices such as heavy media vessels and froth flotation. In addition, coal prepared for an industrial boiler must as a last step be screened or agglomerated to meet boiler specifications. This is a specific electrical energy requirement when preparing coals for industrial boilers.

As shown in Table 5-7 the total energy usage for the chosen PCC best systems are 18.3 kJ/kg of product for Level 4 and 50.7 kJ/kg of product for Level 5. The primary contributors to these usages are pumps, dewatering units and pulverizing units.

For a typical physical coal cleaning plant the last step in moisture removal is thermal drying. Hot air for drying is produced usually by burning cleaned coal but the fuel may also be oil. The chosen best systems did not include thermal drying due to the difficulty in meeting control levels. However, for a typical physical coal cleaning plant thermal drying represents the most energy intensive operation.

5.1.3.2 Energy Content Rejection and Enhancement--

The raw coal feed into a physical coal cleaning plant has a specific energy content. In processing, this energy content is split and appears in

TABLE 5-7 ENERGY ELEMENTS FOR "BEST" PHYSICAL COAL CLEANING SYSTEMS[2],[3],[4]

Coal Type	Best System of Emission Reduction (PCC)	Electrical Energy for Pulverizing kJ/kg (BTU/lb) Product	Electrical Energy for Dewatering kJ/kg (BTU/lb)	Miscellaneous Energy Users kJ/kg (BTU/lb)	Total Energy for Coal Preparation kJ/kg (BTU/lb)
High Sulfur Eastern	PCC - Level 5 "deep cleaned" coal	15.5 (6.6)	14.2 (6.1)	21.0 (9.0)	50.7 (21.7)
	PCC - Level 5 "middlings"	14.4 (6.17)	12.6 (5.4)	18.4 (7.9)	45.4 (19.5)
Low Sulfur Eastern	PCC - Level 4	6.2 (2.7)	5.3 (2.3)	6.8 (2.9)	18.3 (7.9)

the refuse as well as the cleaned coal product. Table 5-8 indicates the energy content of refuse and product for the five levels of physical coal cleaning using the high sulfur eastern coal as input.

As indicated by the table, energy content enhancement of the product increases with increasing levels of cleaning. For example, a Level 2 plant yields 28,917 kJ/kg of product, and Level 3 plant yields 30,278 kJ/kg of product. Three values represent an 8 percent and 13 percent increase (enhancement) of the energy content of the coal, respectively.

The rejection of useful energy in refuse represents the major energy consumer in physical coal cleaning. Usable energy is lost to the refuse by pyrite rejection in order to meet pollution control levels. Since Level 1 physical coal cleaning only involves crushing and sizing, little or no energy content is lost to refuse. However, for the other levels considerable energy loss exists. On the other hand, higher levels of cleaning increase enhancement and decrease reject energy content, making higher levels desirable relative to energy content of the fuel.

5.1.4 Energy Usage by Chemical Coal Cleaning

5.1.4.1 Energy Usage for the Cleaning Process--[5]

The primary energy users for physical coal cleaning, pulverizing, dewatering and thermal drying, are also significant users of energy in chemical coal cleaning. Pulverizing is an integral part of the chemical coal cleaning system and is accomplished by crushers, grinders and pulverizers. These units all require electrical energy, but due to variations in coal size requirements, the electrical energy expended for pulverizing may vary from system to system.

Dewatering operations utilize electrical energy in such units as vacuum filters, centrifuges and cyclones.

TABLE 5-8 ENERGY CONTENT REJECTION AND ENHANCEMENT IN PHYSICAL COAL CLEANING

Coal Type	Level of Cleaning	ROM Coal Energy Content* kJ/kg (BTU/lb)	Refuse Energy Content* kJ/kg (BTU/lb)	Clean Coal Energy Content* kJ/kg (BTU/lb)	% Energy Recovery
High Sulfur Eastern	1	26,716 (11,486)	0 (0)	27,260 (11,720)	100
	2	26,716 (11,486)	14,249 (6,126)	28,917 (12,432)	92
	3	26,716 (11,486)	16,030 (6,892)	30,278 (13,017)	85
	4	26,716 (11,486)	11,132 (4,786)	33,397 (14,358)	87.5
	5	26,716 (11,486)	9,716 (4,177)	31,513** (13,548)**	92

* As-Received Basis.
** Heating value of combined product. Level 5 will generate two product streams, a deep cleaned stream and a middling product.

Drying is accomplished with heat produced in a furnace. Usually, coal produced by the cleaning process is used for fuel although oil may also be used. This fuel use represents a major energy expenditure.

Among energy requirements for chemical coal cleaning,which do not exist for physical coal cleaning,are compressors for elevated pressure in reactors (electrical energy), heaters for reactors (fuel energy) and motors for mixers (electrical energy). In addition, because of the differences in chemical coal cleaning systems, there exist electrical energy requirements which are unique to individual systems. An example is the oxygen-nitrogen generation plant of the TRW Meyer's Process.

It would be appropriate to give energy usage values as was done for physical coal cleaning for units and processes in chemical coal cleaning. However, because chemical coal cleaning is still in the developmental stage, estimates for unit energy usage of full scale operations are not as readily attainable as for physical coal cleaning. Values for ERDA and Gravichem have been calculated for the entire process. The 209 kJ/kg of product expended by the ERDA process (Table 5-10) includes all elements discussed previously with major energy usage attributed to elevated temperature and pressure requirements in the reactors. The 61 kJ/kg of product expended by the Gravichem process is largely due to electrical energy requirements of the oxygen-nitrogen generation plant, as well as pulverizing, dewatering and thermal drying previously discussed. Note that 20 percent (12 kJ/kg) of the energy usage is due to the physical coal cleaning portion of this process.

5.1.4.2 Energy Content Rejection and Enhancement--

The removal of sulfur and coal diluents by chemical coal cleaning increases the energy content of the product coal. The actual amount of upgrading varies with the process and coal used. Table 5-9 shows the energy content of two reference coals after enhancement by two chemical coal cleaning processes. For the ERDA process only a 4 percent upgrading of energy content is achieved, whereas the Gravichem process yields a significantly higher upgrading of 14 percent.

TABLE 5-9. ENERGY BALANCE FOR CHEMICALLY CLEANED COAL

Coal Type	CCC Process	ROM Coal Energy Content kJ/kg (BTU/lb)	Cleaned Coal Energy Content kJ/kg (BTU/lb)	Refuse Energy Content kJ/kg (BTU/lb)	% Energy Recovery
High Sulfur Eastern	ERDA	26,772 (11,510)	28,507 (12,256)	16,031 (6,892)	94
Low Sulfur Eastern	Gravichem	31,685 (13,622)	36,132 (15,534)	14,116 (6,069)	91

Energy rejected in the refuse represents a major energy loss in chemical coal cleaning. As can be seen in Table 5-9, this energy loss is similar for both the processes chosen as best systems of emission reduction.

5.1.5 Energy Usage by the Candidate BSERs, External to the Boiler

Table 5-10 presents values for total energy usage by the chosen BSERs. These data will be used in Section 5.2 to determine the energy impacts on the reference boilers. Also presented in Table 5-10 are energy values for energy content rejection and enhancement. Overall energy content recovery consists of three energy elements, (1) energy for preparation, (2) energy content rejection, and (3) energy content enhancement.

5.1.6 Energy Differences Between Uncontrolled Boilers and Various Levels of Control

Energy usage varies with the level of control desired. For an uncontrolled boiler, energy is required only for transportation of the mined coal to the boiler and for handling of the coal at the boiler.

5.1.6.1 Energy Consumption/Decrease over Uncontrolled Boilers Using Low Sulfur Coal--

The major difference between energy consumed by uncontrolled and controlled boilers utilizing low sulfur coal is the energy required for particulate control.

In Section 5.2.1 we compute the electrical energy consumed in removing particulates from the flue gas following the combustion of selected cleaned and uncleaned coals in five reference boilers. The control devices are (1) electrostatic precipitators and (2) fabric filters.

5.1.6.2 Energy Savings of PCC and CCC over Uncontrolled Boilers--

When physically or chemically cleaned coal is used to meet specified control levels, the energy expended for transportation and handling is less than for uncleaned coal. This decrease is due to the removal in the cleaning process of those constituents having no energy value. Therefore less energy is expended for transporting and handling the same number of Joules in cleaned coal than in uncleaned coal.

Table 5-10. Energy Elements for Chosen Best Systems of Emission Reduction

Coal Type	Level of Control ng SO_2/J (lb $SO_2/10^6$ BTU	Best System of Emission Reduction	Energy for* Coal Preparation** kJ/kg Cleaned Coal (BTU/lb)	Refuse Energy Content kJ/kg (BTU/lb)	Clean Coal Energy Content kJ/kg (BTU/lb)	% Energy Recovery in Product
High Sulfur Eastern	Moderate 1,290 (3.0)	PCC-Level 5 Middlings	45.4 (19.5)	12,563 (5,401)	31,662 (13,612)	44.06 44.06
	Opt. Moderate 860 (2.0) or Intermediate 645 (1.5)	PCC-Level 5 deep cleaned coal	50.7 (21.7)	12,563 (5,401)	33,555 (14,426)	43.42
	Stringent 516 (1.2)	CCC-ERDA	209 (89.9)	16,031 (6,892)	28,507 (12,256)	94.00
Low Sulfur Eastern	Moderate 1,290 (3.0) or Opt. Moderate 860 (2.0)	Raw Coal	1.9 (0.8)	--	31,685 (13,622)	100.00
	Intermediate 645 (1.5)	PCC Level 4	18.3 (7.9)	20,139 (8,658)	33,883 (14,567)	89.83
	Stringent 516 (1.2)	PCC Level 4	18.3 (7.9)	20,139 (8,658)	33,883 (14,567)	89.83
		Gravichem	61 (26.2)	14,116 (6,069)	36,132 (15,534)	91
Low Sulfur Western	Moderate 1,290 (3.0)	Raw Coal	1.9 (0.8)	--	26,270 (11,294)	100.00
	Opt. Moderate 860 (2.0) or Intermediate 645 (1.5)	Raw Coal	1.9 (0.8)	--	26,270 (11,294)	100.00
	Stringent 516 (1.2)	Raw Coal	1.9 (0.8)	--	26,270 (11,294)	100.00

* Usually this would be fuel as well as electrical energy. For the chosen PCC BSER no thermal dryers exist and this value is only electrical energy.

** Based on 8,000 TPD feed

Not only are there energy usage advantages for transporting and handling cleaned coal, but these advantages become greater as the level of cleaning increases. Thus a Level 5 physically cleaned coal or a coal cleaned by the ERDA process would meet a more stringent control level and would require less energy expenditure for transportation and handling than a less rigorously cleaned coal.

Energy used for handling coal at the boiler site is also decreased if cleaned coal is used. The most energy intensive part of handling is grinding. Because beneficiated coal contains less mineral matter than raw coal, less energy is required to grind beneficiated coal. In addition, decreased hardness will increase the life of the grinder and cut down on maintenance of the grinder.

A primary disadvantage of physical and chemical coal cleaning over uncontrolled boilers is the loss to refuse of usable energy. In a boiler using raw coal, there is no loss of available heating value. However, this advantage of utilizing raw coal is lost when downtime and maintenance are analyzed.[6] Use of raw coal rather than cleaned coal increases the energy input for maintenance and increases the downtime. Thus in the long term, a boiler burning raw coal requires greater energy input due to handling than a boiler using beneficiated coal.[7]

As control levels become more stringent, the complexity and energy requirements of coal cleaning circuits increase. However with greater cleaning, the products become increasingly desirable for usage in boilers. In addition to advantages already pointed out, the cleaned products require less particulate control at the boiler site.

5.2 ENERGY IMPACT OF CONTROLS FOR COAL-FIRED BOILERS

This section presents the energy required to control particulates and sulfur dioxide for each BSER or the representative boilers. Section 5.2.2 presents the energy consumption values using the standard format, while Section 5.2.4 provides a comparison of the results. All values presented are based upon new facilities.

5.2.1 Energy Consumed in Controlling Emissions of Particulates During the Combustion of Selected Raw Low-Sulfur Coals and Cleaned Coals

This section presents the electrical energy requirements to control particulates from coal-burning industrial boilers. The three reference coals presented in Section 3.0, both raw and cleaned, are included in the analyses. The analyses provide insight into how particulate control energy consumption is affected by the removal of ash and sulfur during coal cleaning. The energy used in fly ash removal may also be compared with the energy consumed in transporting the seven sample coals to six selected destinations (see Section 5.1.1), and the energy consumed in cleaning three sample coals by means of several levels of physical and chemical coal cleaning (see Section 5.2.2).

The energy requirements of a particulate-control system depends upon the type of control system, characteristics of the coal feed, the applicable emission control level for particulates, and certain parameters associated with the boiler design and operation. The two major types of fly ash controls considered are: electrostatic precipitators (ESP) and fabric filters. The major relevant characteristics of the raw and cleaned coals used--heating value, ash, and sulfur content--are listed in Table 5-11. The emission control levels for particulates, which are based on EPA suggestions, are presented in Table 5-12. Relevant parameters of the five reference boilers--input energy rate, flue gas flow rate, capacity factor, and the quantity of fly ash formed during combustion as a percentage of coal ash--are shown in Table 5-13.

Table 5-11 SUMMARY OF CHARACTERISTICS OF REFERENCE RAW AND CLEANED COALS

	Coal Type			
Parameter	**High Sulfur Eastern**		**Low Sulfur Eastern**	**Low Sulfur Western**
Source Location (County)	Butler, PA		Buchanan, VA	Las Animas, CO
Raw Values				
Ash %	23.90		10.38	24.81
Sulfur %	3.45		1.18	0.59
Heating Value				
kJ/kg	26,772		31,685	26,270
(BTU/lb)	(11,510)		(13,622)	(11,294)
PCC Values	Middlings Product	Deep Cleaned Product		
Ash %	11.31	5.80	4.13	-
Sulfur %	1.69	1.08	0.89	-
Heating Value				
kJ/kg	31,662	33,555	33,883	-
(BTU/lb)	(13,612)	(14,426)	(14,567)	-
CCC Values	ERDA		Gravichem	ERDA
Ash %	17.5%		3.30%	18.6%
Sulfur %	0.73		0.50	0.25
Heating Value				
kJ/kg	27,903		36,132	27,437
(BTU/lb)	(11,996)		(15,534)	(11,796)

TABLE 5-12. PARTICULATE AND SO_2 EMISSION CONTROL LEVELS

Standard	Particulate Emissions		SO_2 Emissions	
	ng/J	($lb/10^6$ BTU)	ng/J	($lb/10^6$ BTU)
SIP	258	(0.6)	1,075	(2.5)
Moderate	108	(0.25)	1,290	(3.0)
Optional Moderate	108	(0.25)	860	(2.0)
Intermediate	43	(0.1)	645	(1.5)
Stringent	13	(0.03)	516	(1.2)

TABLE 5-13. RELEVANT CHARACTERISTICS OF THE REFERENCE COAL-FIRED INDUSTRIAL BOILERS

Boiler Type	Energy Input Rate MW(t) (10^6 BTU/hr)	Flue-Gas Flow Rate[15] Actual m^3/min (Actual ft^3/min)	Capacity Factor	Fly Ash as a Percentage of Coal Ash
Underfeed Stoker	8.8 (30)	350 (12,500)	60%	25%
Chain-Grate Stoker	22 (75)	900 (32,000)	60	25
Watertube Spreader Stoker	43 (150)	1,760 (63,000)	60	65
Watertube Pulverized-Coal Boiler	59 (200)	2,040 (73,000)	60	80
Watertube Pulverized-Coal Boiler	118 (400)	4,080 (146,000)	60	80

Electrical Energy Used by an Electrostatic Precipitator (ESP)

The required particulate collection efficiency is determined by the allowable emission factor for particulates, the ash content of the coal, and the percentage of coal ash converted to fly ash (listed for each boiler type in Table 5-13). Given a value for minimum collection efficiency, the area of an ESP's collecting surface (and, consequently, the required energy use) will increase as the sulfur content of the coal decreases. This relationship is illustrated in Figure 5-1 , in which collection efficiency is plotted against collection area for various values of the sulfur percentage by weight in the coal. By choosing the necessary collection area and knowing the flue gas flowrate, the required electrical energy is computed as shown in Table 5-14.

The results of the calculations of the energy consumed by the ESP using the selected coals and boilers are shown in Table 5-15. Values of energy required by the ESP are presented as electrical energy (assumed to be 33 percent of the primary energy). In comparing the ESP energy--before and after coal cleaning for the cleaned coals, we observe that:

- The high-sulfur eastern coal from Butler, Pa., requires more ESP energy after cleaning; and
- For cleaned low sulfur eastern coal the amount of energy required by the ESP is less than when raw coal is burned.

The electrical consumption by fabric filters is only a function of flue gas flowrate and is basically independent of coal characteristics. As a result the values presented by GCA Corporation, Section 5.0, Energy Impact of Candidates for Best Emission Control Systems, Draft Report[9] will be used in this report. The energy consumption values are shown in Table 5-16.

Figure 5-1

Relationship Between Collection Efficiency and ESP Collecting Surface Area to Gas Flow Ratio For Various Coal Sulfur Contents[10]

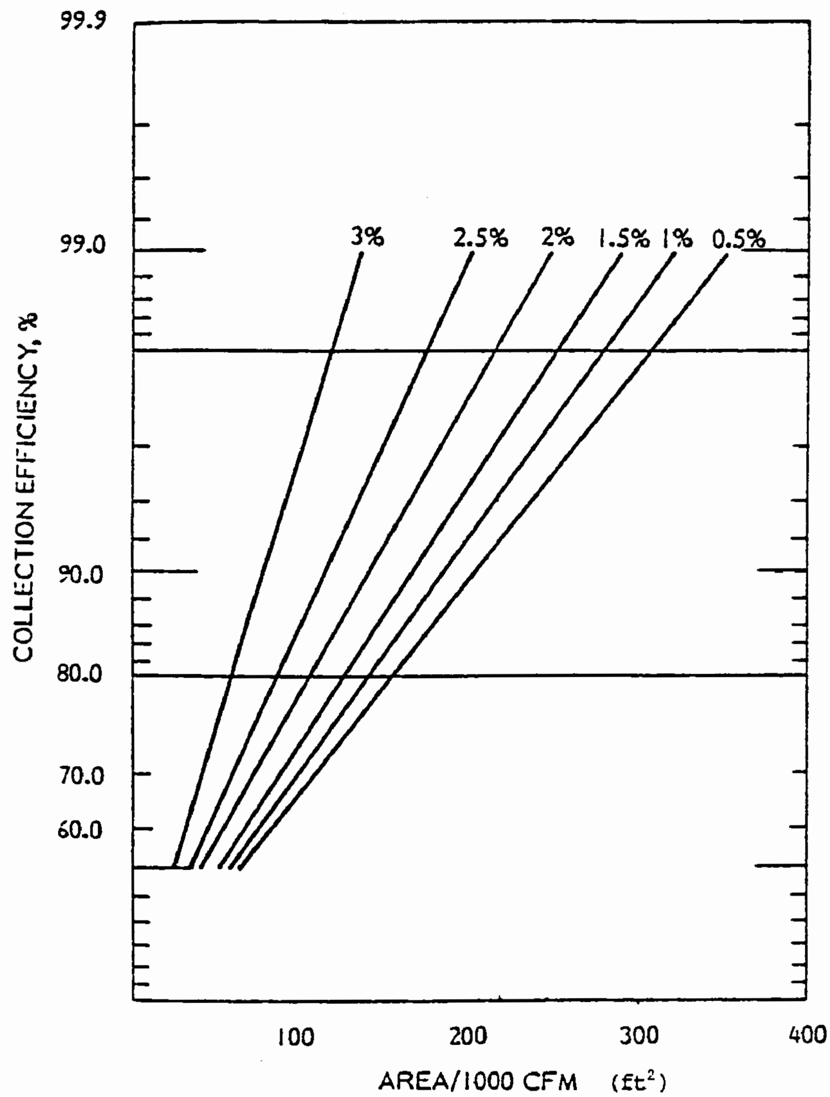

Table 5-14 ALGORITHM FOR COMPUTING THE RATE OF ELECTRICAL ENERGY USED BY AN ELECTROSTATIC PRECIPITATOR[11]

$$kW(e) = \frac{P_p \times Area}{e_r} + \frac{P_d \times k \times (Flow\ Rate)}{e_f}$$

The symbols are explained below:

Symbol	Description	Units	Value Used
kW(e)	ESP power consumption	KW	—
P_p	Electric power required to activate the ESP plates	KW/m^2	0.0215
Area	ESP collector area	m^2	See Figure 5-1
P_d	Pressure drop	cm of water	5.08
Flow Rate	Flue gas flow rate	m^3/min	See Table 5-13
k	Electrical power to run fans	KW/(cm water x m^3/min)	0.00278
e_r	Transformer - rectifier efficiency	—	0.6
e_f	Fan efficiency	—	0.6

TABLE 5-15. ESP REQUIREMENTS ON INDUSTRIAL BOILERS USING RAW COAL VERSUS USING THE BSER COAL[10],[11]

Type of Coal Feed	Control Level (lb/10^6 BTU)	Raw Coal + BSER	Collection Efficiency A	Collection Efficiency B	Collection Efficiency C	Collection Efficiency D	Collection Efficiency E	Energy Requirements of ESP (KW[e]) A	Energy Requirements of ESP (KW[e]) B	Energy Requirements of ESP (KW[e]) C	Energy Requirements of ESP (KW[e]) D	Energy Requirements of ESP (KW[e]) E
High Sulfur Eastern	SIP	Raw Coal	88.2	88.2	95.5	96.3	96.3	10	27	57	67	115
		Level 5-Mid	71.1	71.1	88.9	91.0	91.0	12	30	75	90	138
	Moderate	Raw Coal	95.1	95.1	98.1	98.5	98.5	11	29	58	70	118
		Level 5-Mid	88.0	88.0	95.4	96.2	96.2	14	37	94	108	157
	Optional Moderate	Raw Coal	95.1	95.1	98.1	98.5	98.5	11	29	58	70	118
		Level 5-D.C.	75.0	75.0	90.4	92.2	92.2	13	34	78	99	147
	Intermediate	Raw Coal	98.0	98.0	99.2	99.4	99.4	12	30	62	77	125
		Level 5-D.C.	90.0	90.0	96.2	96.9	96.9	16	40	100	120	169
	Stringent	Raw Coal	99.4	99.4	99.8	99.8	99.8	13	33	69	91	138
		ERDA	99.3	99.3	99.7	99.8	99.8	24	63	125	145	193
Low Sulfur Eastern	SIP	Raw Coal/(BSER)	68.4	68.4	87.9	90.1	90.1	12	31	77	89	138
	Moderate	Raw Coal/(BSER)	86.8	86.8	94.9	95.9	95.9	15	39	100	116	164
	Optional Moderate	Raw Coal	86.8	86.8	94.9	95.9	95.9	15	39	100	116	164
	Intermediate	Raw Coal	94.7	94.7	98.0	98.4	98.4	20	50	107	123	171
		Level 4	85.7	85.7	94.5	95.5	95.5	15	40	102	120	169
		Gravichem	80.0	80.0	92.3	93.8	93.8	15	37	92	118	166
	Stringent	Raw Coal	98.4	98.4	99.5	99.5	99.5	21	55	119	140	188
		Level 4	95.7	95.7	98.4	98.7	98.7	20	52	108	127	174
		Gravichem	94.0	94.0	97.7	98.1	98.1	21	53	110	130	178
Low Sulfur Western	SIP	Raw Coal/(BSER)	89.1	89.1	95.8	96.6	96.6	16	41	106	127	175
	Moderate	Raw Coal/(BSER)	95.5	95.5	98.3	98.6	98.6	21	54	112	130	178
	Optional Moderate	Raw Coal/(BSER)	95.5	95.5	98.3	98.6	98.6	21	54	112	130	178
	Intermediate	Raw Coal/(BSER)	98.2	98.2	99.3	99.4	99.4	22	58	125	145	193
	Stringent	Raw Coal/(BSER)	99.5	99.5	99.8	99.8	99.8	25	64	125	145	193

A - Underfeed Stoker Boiler: Heat Input 8.8MW (30 10^6 BTU/hr)

B - Watertube Chain Grate Stoker: Heat Input 22MW (75 10^6 BTU/hr)

C - Watertube Spreader Stoker: Heat Input 44MW (150 10^6 BTU/hr)

D - Watertube Pulverized Coal Fired: Heat Input 58.6MW (200 10^6 BTU/hr)

E - Watertube Pulverized Coal Fired: Heat Input 118 MW (400 x 10^6 BTU/hr.)

TABLE 5-16. ENERGY CONSUMED BY FABRIC FILTERS[11]

Boiler Type	COAL TYPE High Sulfur Eastern	Low Sulfur Eastern	Low Sulfur Western
Underfeed Stoker	16.4	15.6	16.0
Chain Grate Stoker	41.2	38.4	40.0
Spreader Stoker	82.6	77.6	80.1
Pulverized Coal (58.6MW)	95.4	90.2	93.2
Pulverized Coal (118MW)	190.8	180.4	186.4

(Values are in KW(e))

5.2.2 Overall Energy Consumption

For each coal type, reference boiler, and level of emission control, the energy consumption for the corresponding best system of emission reduction is presented in Tables 5-17 to 5-31. In every case the best system of emission reduction included an electrostatic precipitator. Electrostatic precipitators (ESP) were chosen because of their wide usage and because the energy consumed by ESP is representative of energies used for particulate control.

Tables 5-17 to 5-31 also present the control efficiency and type of energy consumed for each best system. The actual energy consumption values shown in the first column are the energy consumed per kilogram (pound) of product. The second column represents the kilowatt usage which varies with the boiler input. The boiler is assumed to operate at 100 percent efficiency. To determine annual KWh, the KW should be multiplied by 5,256 hours (i.e. 60% capacity factor).

The total energy consumed at each level of control is a summation of energy lost to refuse in the process (which takes into account heat content enhancement of the product), energy required to process coal at the preparation plant, and energy for particulate control. The percent increases in energy over uncontrolled and SIP-controlled boilers are calculated as indicated in a sample calculation shown in Table 5-32.

5.2.3 Level-of-Control Energy Graphs

Figures 5-2, 5-3, and 5-4, illustrate the energy consumed by four major types of boilers to meet various emission control levels as presented in Section 5.2.2. The three bar charts represent energy usage when burning high sulfur eastern, low sulfur eastern, and low sulfur western coal. These charts show an increase in the amount of energy consumed as emission control levels become increasingly stringent.

Figure 5-3 shows that the energy required to meet the various control levels greatly increases (over raw coal requirements) when using either physically

TABLE 5-17 ENERGY USAGE OF "BEST" CONTROL TECHNIQUES FOR 8.8 MW COAL-FIRED BOILERS USING HIGH SULFUR EASTERN COAL

SYSTEM HIGH SULFUR EASTERN COAL**					ENERGY CONSUMPTION		IMPACTS	
STANDARD BOILERS		TYPE AND LEVEL OF CONTROL	CONTROL EFFI-CIENCY+ (%)	ENERGY TYPE	ENERGY CONSUMED BY CONTROL		% INCREASE IN ENERGY OVER UNCONTROLLED BOILER	% INCREASE IN ENERGY OVER SIP-CONTROLLED BOILER
Fuel and Heat Input MW (10^6 BTU/hr)	Type				kJ/Kg (BTU/lb)	KW (Thermal)		
8.8 (30)	Underfeed Stoker	SIP						
28,842 kJ/kg		PCC - Level 5		Fuel$^{\alpha}$	4,568 (1,964)	1,392		
1.54% S		Middling.	58	Elec.	45.4 (19.5)	14		
10.30% Ash		ESP.	71	Elec.	114.2 (49.1)	34		
				Total	4727.6 (2033)	1,440	16.3	N.A.
		MODERATE						
28,842 kJ/kg		PCC-Level 5		Fuel$^{\alpha}$	4,568 (1,964)	1,392		
1.54% S		Middling.	58	Elec.	45.4 (19.5)	14		
10.30% Ash		ESP.	88	Elec.	141.8 (60.9)	43		
				Total	4,755 (2,044)	1,449	16.4	0.1%
30,533 kJ/kg		Optional Moderate						
0.98% S		PCC-Level 5	75	Fuel$^{\alpha}$	4,568 (1,964)	1,314		
5.28% Ash		Deep Cleaned Coal		Elec	50.7 (21.7)	15		
		ESP	75	Elec	139.1 (60.0)	40		
				Total	4,758 (2,046)	1,369	15.4	(.7%)*

* Indicates a decrease

** Raw Coal Analysis: 3.45% S; 23.90% Ash; 26,772 kJ/kg

\+ Percent Sulfur reduction in ng SO_2/J and percent Ash reduction in ng ash/J

α Energy rejected to preparation plant refuse

TABLE 5-17 ENERGY USAGE OF "BEST" CONTROL TECHNIQUES FOR 8.8 MW COAL-FIRED BOILERS USING HIGH SULFUR EASTERN COAL (continued)

SYSTEM HIGH SULFUR EASTERN COAL**					ENERGY CONSUMPTION		IMPACTS	
STANDARD BOILERS		TYPE AND LEVEL OF CONTROL	CONTROL EFFICIENCY+ (%)	ENERGY TYPE	ENERGY CONSUMED BY CONTROL		% INCREASE IN ENERGY OVER UNCONTROLLED BOILER	% INCREASE IN ENERGY OVER SIP-CONTROLLED BOILER
Fuel Input	Type				kJ/kg (BTU/lb)	KW (Thermal)		
30,533 kJ/kg .98% S 5.28% Ash		**INTERMEDIATE**						
		PCC-Level 5 Deep Cleaned Coal.	75	Fuel[α]	4,568 (1,964)	1,314		
				Elec.	50.7 (21.7)	15		
		ESP.	90	Elec.	163.7 (70.4)	47		
				Total	4,782 (2,056)	1,376	15.5	(0.6%)*
27,903 kJ/kg .73% S 20.74% Ash		**STRINGENT**						
		CCC-ERDA.	80	Fuel[α]	1782 (766)	561		
				Elec. & Fuel	209 (89.9)	65		
		ESP.	99	Elec.	232.4 (99.9)	73		
				Total	2,223 (955)	699	8.0	(7.1%)*

* Indicates a decrease
** Raw Coal Analysis: 3.45% S; 23.90% Ash; 26,772 kJ/kg
+ Percent Sulfur reduction in ng SO_2/J and percent Ash reduction in ng ash/J
α Energy rejected to preparation plant refuse

TABLE 5-18. ENERGY USAGE OF "BEST" CONTROL TECHNIQUES FOR 22 MW COAL-FIRED BOILERS USING HIGH SULFUR EASTERN COAL

SYSTEM HIGH SULFUR EASTERN COAL**					ENERGY CONSUMPTION		IMPACTS	
STANDARD BOILERS: Heat and Fuel Input MW (10^6 BTU/hr)	STANDARD BOILERS: TYPE	TYPE AND LEVEL OF CONTROL	CONTROL EFFI-CIENCY+ (%)	ENERGY TYPE	ENERGY CONSUMED BY CONTROL: kJ/kg (BTU/lb)	ENERGY CONSUMED BY CONTROL: KW (thermal)	% INCREASE IN ENERGY OVER UNCONTROLLED BOILER	% INCREASE IN ENERGY OVER SIP-CONTROLLED BOILER
22 (75)	Watertube Chain Grate Stoker	SIP						
28,842 kJ/kg 1.54% S 10.30% Ash				Fuel$^{\alpha}$	4,568 (1,964)	3,479		
		PCC-Level 5 Middling.	58	Elec.	45.4 (19.5)	34		
		ESP.	71	Elec.	117.0 (50.3)	89		
				Total	4,731 (2,034)	3,603	16.4%	N.A.
28,842 kJ/kg 1.54% S 10.30% Ash		MODERATE						
		PCC-Level 5		Fuel$^{\alpha}$	4,568 (1,964)	3,479		
		Middling.	58	Elec.	45.4 (19.5)	34		0.1%
		ESP.	88	Elec.	146.5 (63.0)	111		
				Total	4,760 (2,046)	3,624	16.5%	
30,533 kJ/kg .98% S 5.28% Ash		Optional Moderate						
		PCC-Level 5	75	Fuel$^{\alpha}$	4.568 (1964)	3,287		
		Deep Cleaned Coal		Elec	50.7 (21.7)	36		
		ESP	75	Elec	141.9 (61.2)	102		
				Total	4,761 (2,047)	3,425	15.6	(0.7%)*

* Indicates a decrease

** Raw Coal Analysis: 3.45% S; 23.90% Ash; 26,772 kJ/kg

+ Percent sulfur reduction in ng SO_2/J and percent ash reduction in ng ash/J.

α Energy rejected to preparation plant refuse

TABLE 5-18. ENERGY USAGE OF "BEST" CONTROL TECHNIQUES FOR 22 MW COAL-FIRED BOILERS USING HIGH SULFUR EASTERN COAL (continued)

SYSTEM HIGH SULFUR EASTERN COAL**					ENERGY CONSUMPTION		IMPACTS	
STANDARD BOILERS: Fuel Input	STANDARD BOILERS: TYPE	TYPE AND LEVEL OF CONTROL	CONTROL EFFICIENCY+ (%)	ENERGY TYPE	ENERGY CONSUMED BY CONTROL kJ/kg(BTU/lb)	ENERGY CONSUMED BY CONTROL KW (thermal)	% INCREASE IN ENERGY OVER UNCONTROLLED BOILER	% INCREASE IN ENERGY OVER SIP-CONTROLLED BOILER
30,533 kJ/kg .98% S 5.28% Ash		**INTERMEDIATE** PCC-Level 5 Deep Cleaned Coal.	75	Fuel $^{\alpha}$ Elec.	4,568 (1,964) 50.7 (21.7)	3,287 36		
		ESP	90	Elec	168.5 (72.4)	121		
				Total	4,787 (2,058)	3,444	15.7%	(0.6%)*
27,903 kJ/kg .73% S 20.74% Ash		**STRINGENT** CCC-ERDA	80	Fuel $^{\alpha}$ Elec.	1,782 (766) 209 (89.9)	1403 164		
		ESP	99.3	Fuel Elec.	239.3 (102.9)	188		
				Total	2,230 (959)	1,755	8.0%	(7.2%)*

* Indicates a decrease

** Raw Coal Analysis: 3.45% S; 23.90% Ash; 26,772 kJ/kg

\+ Percent sulfur reduction in ng SO_2/J and percent ash reduction in ng ash/J.

α Energy rejected to preparation plant refuse

TABLE 5-19. ENERGY USAGE OF "BEST" CONTROL TECHNIQUES FOR 44 MW COAL-FIRED BOILERS USING HIGH SULFUR EASTERN COAL

SYSTEM HIGH SULFUR EASTERN COAL**					ENERGY CONSUMPTION		IMPACTS	
STANDARD BOILERS: Heat and Fuel Input MW (10^6 BTU/hr)	STANDARD BOILERS: TYPE	TYPE AND LEVEL OF CONTROL	CONTROL EFFI-CIENCY+ (%)	ENERGY TYPE	ENERGY CONSUMED BY CONTROL kJ/kg (BTU/lb)	ENERGY CONSUMED BY CONTROL KW (thermal)	% INCREASE IN ENERGY OVER UNCONTROLLED BOILER	% INCREASE IN ENERGY OVER SIP-CONTROLLED BOILER
44 (150)	Spreader Stoker	SIP		Fuel$^{\alpha}$	4,568 (1,964)	6,959		
28,842 kJ/kg 1.54% S 10.30% ash		PCC-Level 5 Middling.	58	Elec.	45.4 (19.5)	69		
		ESP	89	Elec.	147.2 (63.3)	224	16.5%	N.A.
				Total	4,761 (2,047)	7,252		
28,842 kJ/kg 1.54% S 10.30% ash		MODERATE		Fuel$^{\alpha}$	4,568 (1,964)	6,959		
		PCC-Level 5 Middling.	58	Elec.	45.4 (19.5)	69		
		ESP	95	Elec.	184.3 (79.2)	280	16.6%	0.1%
				Total	4,798 (2,063)	7,309		
30,533 kJ/kg .98% S 5.28% ash		OPTIONAL MODERATE						
		PCC-Level 5 Deep Cleaned Coal	75	Fuel$^{\alpha}$	4,568 (1,964)	6,550		
				Elec.	50.7 (21.7)	72		
		ESP	90	Elec.	162.8 (70.2)	234	15.6%	(0.8%)*
				Total	4,781 (2,056)	6,856		
30,533 kJ/kg .98% S 5.28% ash		INTERMEDIATE						
		PCC-Level 5 deep cleaned coal	75	Fuel$^{\alpha}$	4,568 (1,964)	6,574		
				Elec.	50.7 (21.7)	72		
		ESP	96	Elec.	208.3 (89.5)	299	15.8%	(0.6)*
				Total	4,827 (2,075)	6,945		
27,903 kJ/kg .73% S 20.74% ash		STRINGENT		Fuel$^{\alpha}$	1,782 (766)	2,806		
		CCC-ERDA	80	ESP	209 (89.9)	329		
		ESP	99.7	Elec.	238.1 (102.4)	375	8.0%	7.3%
				Total	2,229 (958)	3,510		

* Indicates a decrease

** Raw Coal Analysis: 3.45% S; 23.90% Ash; 26,772 kJ/kg

\+ Percent sulfur reduction in ng SO_2/J and percent ash reduction in ng ash/J.

α Energy rejected to preparation plant refuse

TABLE 5-20. ENERGY USAGE OF "BEST" CONTROL TECHNIQUES FOR 58.6 MW COAL-FIRED BOILERS USING HIGH SULFUR EASTERN COAL

SYSTEM HIGH SULFUR EASTERN COAL**					ENERGY CONSUMPTION		IMPACTS	
STANDARD BOILERS: Heat and Fuel Input MW(10^6 BTU/hr)	STANDARD BOILERS: TYPE	TYPE AND LEVEL OF CONTROL	CONTROL EFFICIENCY+ (%)	ENERGY TYPE	ENERGY CONSUMED BY CONTROL: kJ/kg (BTU/lb)	ENERGY CONSUMED BY CONTROL: KW (thermal)	% INCREASE IN ENERGY OVER UNCONTROLLED BOILER	% INCREASE IN ENERGY OVER SIP-CONTROLLED BOILER
58.6 (200)	Pulverized Coal	SIP		Fuel$^\alpha$	4,568 (1,964)	9,279		
28,842 kJ/kg		PCC-Level 5						
1.54% S		Middling	58	Elec.	45.4 (19.5)	92		
10.30% ash		ESP	91	Elec.	133.3 (57.3)	270	16.4%	N.A.
				Total	4,747 (2,041)	9,641		
28,842 kJ/kg		MODERATE		Fuel$^\alpha$	4,568 (1,964)	9,279		
1.54% S		PCC-Level 5						
10.3% ash		Middling	58	Elec.	45.4 (19.5)	92		
		ESP	96	Elec.	159.6 (68.6)	325	16.5%	0.1%
				Total	4,773 (2,052)	9,696		
30,533 kJ/kg		OPTIONAL MODERATE						
0.98% S		PCC-Level 5	75	Fuel$^\alpha$	4,568 (1,964)	8,733		
5.28% ash		Deep Cleaned Coal		Elec.	50.7 (21.7)	97		
		ESP	92	Elec.	154.4 (66.6)	296	15.6%	(0.8%)*
				Total	4,773 (2,052)	9,126		
30,533 kJ/kg		INTERMEDIATE		Fuel$^\alpha$	4,568 (1,964)	8,764		
0.98% S		PCC-Level 5	75	Elec.	50.7 (21.7)	96		
5.28% ash		Deep cleaned coal		Elec.	188.4 (81.0)	361	15.7%	(0.6%)*
		ESP	97	Total	4,807 (2,067)	9,221		
57,903 kJ/kg		STRINGENT		Fuel$^\alpha$	1,782 (766)	3,741		
0.73% S		CCC-ERDA	80	E&F	209 (89.9)	439		
20.74%		ESP	99.8	Elec.	206.8 (88.9)	434	8.0%	(7.3%)
				Total	2,198 (945)	4,614		

* Indicates a decrease

** Raw Coal Analysis: 3.45% S; 23.90% Ash; 26,772 kJ/kg

+ Percent sulfur reduction in ng SO_2/J and percent ash reduction in ng ash/J.

α Energy rejected to preparation plant refuse

TABLE 5-21 ENERGY USAGE OF "BEST" CONTROL TECHNIQUES FOR 118 MW COAL-FIRED BOILERS USING HIGH SULFUR EASTERN COAL

SYSTEM HIGH SULFUR EASTERN COAL **					ENERGY CONSUMPTION		IMPACTS	
Standard Boiler: Fuel and Heat Input MW(10^6 BTU/hr.)	Standard Boiler: Type	Type and Level of Control	Control Ef- + ficiency Percent	Energy Type	Energy Consumed by Control: kJ/kg (BTU/lb)	Energy Consumed by Control: KW (thermal)	Percent Increase in Energy over Uncontrolled Boiler	Percent Increase in Energy over SIP Controlled Boiler
118 (400) 28,842 kJ/kg 1.54% S 10.30% Ash	Pulverized Coal	SIP PCC-Level 5 Middling ESP	 58 91	Fuel α Elec. Elec.	4,568 (1,964) 45.4 (19.5) 101.9 (43.8)	18,560 184 414	16.2%	NA
				TOTAL	4,715 (2,027)	19,158		
28,842 kJ/kg 1.54% S 10.3% Ash		Moderate PCC-Level 5 Middling ESP	 58 96	Fuel α Elec. Elec.	4,568 (1,964) 45.4 (19.5) 115.8 (49.8)	18,560 184 471	16.3%	.04%
				TOTAL	4,729 (2,033)	19,215		
30,533 kJ/kg 0.98% S 5.28 % Ash		Optional Moderate PCC-Level 5 Deep Clean Coal ESP	 75 92	Fuel α Elec. Elec.	4,568 (1,964) 50.7 (21.7) 114.9 (49.4)	17,466 205 441	15.3%	(0.8%)*
				TOTAL	4,734 (2,035)	18,112		
30,533 kJ/kg 0.98% S 5.20% Ash		Intermediate PCC-Level 5 Deep Clean Coal ESP	75 97	Fuel α Elec. Elec.	4,568 (1,964) 50.7 (21.7) 132.1 (56.8)	17,528 205 507	15.4%	(0.7%)*
				TOTAL	4,751 (2,043)	18,240		
57,903 0.73% S 20.74% Ash		Stringent CCC-ERDA ESP	80 99.8	Fuel α E&F Elec.	1,782 (766) 209 (89.9) 286.1 (123)	7,482 850 579	7.6%	(8.0%)*
				TOTAL	2,277 (979)	8,911		

* Indicates a decrease

** Raw Coal Analysis: 3.45% S; 23.90% Ash; 26,772 kJ/kg

\+ Percent Sulfur reduction in ng SO_2/J and percent ash reduction in ng ash/J

α Energy rejected to preparation plant refuse

TABLE 5-22 ENERGY USAGE OF "BEST" CONTROL TECHNIQUES FOR 8.8 MW COAL-FIRED BOILERS USING LOW SULFUR EASTERN COAL

SYSTEM LOW SULFUR EASTERN COAL**					ENERGY CONSUMPTION		IMPACTS	
STANDARD BOILERS: Heat and Fuel Input MW(10^6BTU/hr)	STANDARD BOILERS: TYPE	TYPE AND LEVEL OF CONTROL	CONTROL EFFI-CIENCY+ (%)	ENERGY TYPE	ENERGY CONSUMED BY CONTROL: kJ/kg (BTU/lb)	ENERGY CONSUMED BY CONTROL: KW (thermal)	% INCREASE IN ENERGY OVER UNCONTROLLED BOILER	% INCREASE IN ENERGY OVER SIP-CONTROLLED BOILER
8.8 (30) 31,685 kJ/kg 1.18% S 10.38% ash	Underfeed Stoker	SIP Raw coal ESP	 0 68	 Elec. Elec. Total	 1.9 (.8) 128.7 (55.3) 134.8 (57.9)	 < 1 35 36	0.4%	N.A.
31,685 kJ/kg 1.18% S 10.38% ash		MODERATE Raw coal ESP	 0 87	 Elec. Elec. Total	 1.9 (.8) 163.3 (70.2) 169.4 (72.8)	 < 1 45 46	0.5%	0.1%
31,685 kJ/kg 1.18% S 10.38% ash		OPTIONAL MODERATE Raw Caol ESP	 0 87	 Elec. Elec. Total	 1.9 (.8) 163.5 (70.5) 170 (73)	 < 1 45 46	0.5%	0.1%
PCC 33,882 kJ/kg 0.89% S 4.1% ash		INTERMEDIATE PCC-Level 4 ESP	 30 86	Fuel α Elec. Elec. Total	3,835 (1,649) 18.3 (7.9) 178 (76.5) 4,196 (1,733)	995 4 46 1,045	12.0%	11.5%
CCC 36,130 kJ/kg 0.64% S 3.1% ash		STRINGENT CCC-Gravichem ESP	 50 94	Fuel α E&F Elec. Total	3,573 (1,536) 57.2 (24.5) 255.3 (109.8) 3,886 (1,670.3)	869 14 62 945	10.7%	10.3%

** Raw Coal Analysis: 31,685 kJ/kg; 1.18% S; 10.38% ash

\+ Percent sulfur reduction in ng SO_2/J and percent ash reduction in ng ash/J.

α Energy rejected to preparation plant refuse

TABLE 5-23 ENERGY USAGE OF "BEST" CONTROL TECHNIQUES FOR 22 MW COAL-FIRED BOILERS USING LOW SULFUR EASTERN COAL

SYSTEM LOW SULFUR EASTERN COAL**					ENERGY CONSUMPTION		IMPACTS	
STANDARD BOILERS		TYPE AND LEVEL OF CONTROL	CONTROL EFFI-CIENCY+ (%)	ENERGY TYPE	ENERGY CONSUMED BY CONTROL		% INCREASE IN ENERGY OVER UNCONTROLLED BOILER	% INCREASE IN ENERGY OVER SIP-CONTROLLED BOILER
Heat and Fuel Input MW(10^6BTU/hr)	TYPE				kJ/kg (BTU/lb)	KW (thermal)		
22 (75) 31,685 kJ/kg 1.18% S 10.38% ash	Chain Grate Stoker	SIP Raw coal ESP	 0 68	Elec. Elec Total	1.9 (.8) 133.3 (57.3) 135.2 (58.1)	1 92 93	0.4%	N.A.
31,685 kJ/kg 1.18% S 10.38% ash		MODERATE Raw coal ESP	 0 87	Elec. Elec. Total	1.9 (.8) 167.9 (72.2) 169.8 (73.0)	1 116 117	0.5%	0.1%
31,685 kJ/kg 1.18% S 10.38% ash		OPTIONAL MODERATE Raw Coal ESP	 0 87	Elec. Elec. Total	1.9 (.8) 167.5 (72.2) 169 (73)	1 116 117	0.5%	0.1%
PCC 33,882 kJ/kg 0.89% S 4.1 % ash		INTERMEDIATE PCC-Level 4 ESP	 30 86	Fuel$^{\alpha}$ Elec. Elec. Total	3,835 (1,649) 18.3 (7.9) 184.6 (79.4) 4,038 (1,736)	2,486 14 119 2,619	11.9%	11.4%
CCC 36,130 kJ/kg 0.64% S 3.1% ash		STRINGENT CCC-Gravichem ESP	 50 94	Fuel$^{\alpha}$ F&E Elec. Total	3,573 (1,536) 57.2 (24.5) 262.7 (112.9) 3,893 (1,673)	2,172 37 159 2,369	10.8%	10.3%

** Raw Coal Analysis: 31,685 kJ/kg; 1.18% S; 10.38% ash
+ Percent sulfur reduction in ng SO_2/J and percent ash reduction in ng ash/J.
α Energy rejected to preparation plant refuse

TABLE 5-24. ENERGY USAGE OF "BEST" CONTROL TECHNIQUES FOR 44 MW COAL-FIRED BOILERS USING LOW SULFUR EASTERN COAL

SYSTEM LOW SULFUR EASTERN COAL**					ENERGY CONSUMPTION		IMPACTS	
STANDARD BOILERS: Heat 2nd Fuel Input MW(10^6BTU/hr)	STANDARD BOILERS: TYPE	TYPE AND LEVEL OF CONTROL	CONTROL EFFICIENCY+ (%)	ENERGY TYPE	ENERGY CONSUMED BY CONTROL: kJ/kg (BTU/lb)	ENERGY CONSUMED BY CONTROL: KW (thermal)	% INCREASE IN ENERGY OVER UNCONTROLLED BOILER	% INCREASE IN ENERGY OVER SIP-CONTROLLED BOILER
44 (150) 31,685 kJ/kg 1.18% S 10.38% ash	Spreader Stoker	SIP Raw coal ESP	 0 88	 Elec. Elec. Total	 1.9 (.8) 166.4 (71.5) 168.3 (72.3)	 2 230 232	0.5%	N.A.
31,685 kJ/kg 1.18% S 10.38% ash		MODERATE Raw coal ESP	 0 95	 Elec. Elec. Total	 1.9 (.8) 216.1 (92.9) 218.0 (93.7)	 2 299 301	0.7%	0.2%
31,685 kJ/kg 1.18% S 10.38% ash		OPTIONAL MODERATE Raw Coal ESP	 0 95	 Elec. Elec. Total	 1.9 (.8) 216.6 (93.3) 218.5 (94.1)	 2 300 302	0.7%	0.2%
PCC 33,882 kJ/kg 0.89% S 4.1% ash		INTERMEDIATE PCC-Level 4 ESP	 30 95	Fuel α Elec. Elec. Total	3,835 (1,649) 18.3 (7.9) 236.1 (101.4) 4,089 (1,758)	4,974 29 306 5,309	12.1%	11.5%
CCC 36,130 kJ/kg 0.64% S 3.1% ash		STRINGENT CCC-Gravichem ESP	 50 98	Fuel α E&F Elec. Total	3,573 (1,536) 57.2 (24.5) 272.1 (117.0) 3,902 (1,678)	4,345 74 330 4,749	10.8%	10.2%

** Raw Coal Analysis: 31,685 kJ/kg; 1.18% S; 10.38% ash
+ Percent sulfur reduction in ng SO_2/J and percent ash reduction in ng ash/J.
α Energy rejected to preparation plant refuse

TABLE 5-25. ENERGY USAGE OF "BEST" CONTROL TECHNIQUES FOR 58.6 MW COAL-FIRED BOILERS USING LOW SULFUR EASTERN COAL

SYSTEM LOW SULFUR EASTERN COAL**					ENERGY CONSUMPTION		IMPACTS	
STANDARD BOILERS Heat and Fuel Input MW(10^6 BTU/hr)	STANDARD BOILERS TYPE	TYPE AND LEVEL OF CONTROL	CONTROL EFFI-CIENCY+ (%)	ENERGY TYPE	ENERGY CONSUMED BY CONTROL kJ/kg (BTU/lb)	ENERGY CONSUMED BY CONTROL KW (thermal)	% INCREASE IN ENERGY OVER UNCONTROLLED BOILER	% INCREASE IN ENERGY OVER SIP-CONTROLLED BOILER
58.6 (200) 31,685 kJ/kg 1.18% S 10.38% ash	Pulverized Coal Fired	SIP Raw coal ESP	 0 90	 Elec. Elec. Total	 1.9 (.8) 144.4 (62.1) 146.3 (62.9)	 3 267 270	0.4%	N.A.
31,685 kJ/kg 1.18% S 10.38% ash		MODERATE Raw coal ESP	 0 96	 Elec. Elec. Total	 1.9 (.8) 187.7 (80.7) 189.6 (81.5)	 3 347 350	0.6%	0.6%
31,685 kJ/kg 1.18% S 10.38% ash		OPTIONAL MODERATE Raw Coal ESP	 0 96	 Elec. Elec. Total	 1.9 (.8) 187.9 (81) 190 (82)	 3 347 350	0.6%	0.6%
PCC 33,882 kJ/kg 0.89% S 4.1% ash		INTERMEDIATE PCC-Level 4 ESP	 30 96	Fuel α Elec. Elec. Total	3,835 (1,649) 18.3 (7.9) 209 (89.9) 4,062 (1,747)	6,632 38 361 7,031	12.0%	11.9%
CCC 36,130 kJ/kg 0.64% S 3.1% ash		STRINGENT CCC-Gravichem ESP	 50 98	Fuel α E&F Elec. Total	3,573 (1,536) 57.2 (24.5) 240.9 (103.5) 3,871 (1,664)	5,793 98 390 6,281	10.7%	10.7%

** Raw Coal Analysis: 31,685 kJ/kg; 1.18% S; 10.38% ash
+ Percent sulfur reduction in ng SO_2/J and percent ash reduction in ng ash/J.
α Energy rejected to preparation plant refuse

TABLE 5-26 ENERGY USAGE OF "BEST" CONTROL TECHNIQUES FOR 118 MW COAL-FIRED BOILERS USING LOW SULFUR EASTERN COAL

SYSTEM LOW SULFUR EASTERN COAL **					ENERGY CONSUMPTION		IMPACTS	
Standard Boiler: Heat Rate MW or (10^6 BTU/hr)	Standard Boiler: Type	Type and Level of Control	Control Ef- + ficiency Percent (%)	Energy Type	Energy Consumed by Control: kJ/kg (BTU/lb)	Energy Consumed by Control: KW (thermal)	Percent Increase in Energy over Uncontrolled Boiler	Percent Increase in Energy over SIP Controlled Boiler
118 (400) 31,685 kJ/kg 1.18 % S 10.38 % Ash	Pulverized Coal	SIP Raw Coal ESP	 0 90	 Elec. Elec. TOTAL	 1.9 (.8) 111.9 (48.1) 113.8 (48.9)	 7 414 421	0.3%	NA
31,685 kJ/kg 1.18% S 10.38%		Moderate Raw Coal ESP	 0 90	 Elec. Elec. TOTAL	 1.9 (.8) 133.0 (57.2) 134.9 (58.0)	 7 492 499	0.4%	0.6%
31,685 kJ/kg 1.18% S 10.38% Ash		Optional Moderate Raw Coal ESP	 0 96	 Elec. Elec. TOTAL	 1.9 (.8) 133.0 (57.2) 134.9 (58.0)	 7 492 499	0.4%	0.6%
PCC 33,882 kJ/kg 0.89% S 4.1% Ash		Intermediate PCC-Level 4 ESP	 30 96	Fuel α Elec. Elec. TOTAL	3,835 (1,649) 18.3 (7.9) 146.5 (63.0) 4,000 (1,720)	13,264 64 507 13,835	11.7%	10.2%
CCC 36,130 kJ/kg 0.64% S 3.1% Ash		Stringent CCC-Gravichem ESP	 50 98	Fuel α E & F Elec. TOTAL	3,573 (1,536) 57.2 (24.5) 164.7 (70.8) 3,795 (1,631)	11,586 185 534 12,305	10.4%	9.1%

** Raw Coal Analysis: 31,685 kJ/kg; 1.18% S; 10.38% ash
\+ Percent sulfur reduction in ng SO_2/J and percent ash reduction in ng ash/J.
α Energy rejected to preparation plant refuse

Table 5-27. ENERGY USAGE OF "BEST" CONTROL TECHNIQUES FOR 8.8 MW COAL-FIRED BOILERS USING LOW SULFUR WESTERN COAL

SYSTEM LOW SULFUR WESTERN COAL **					ENERGY CONSUMPTION		IMPACTS	
STANDARD BOILERS: Heat and Fuel Input MW (10^6 BTU/hr)	STANDARD BOILERS: Type	TYPE AND LEVEL OF CONTROL	CONTROL EFFICIENCY+ (%)	ENERGY TYPE	ENERGY CONSUMED BY CONTROL: kJ/Kg (BTU/1b)	ENERGY CONSUMED BY CONTROL: KW (thermal)	% INCREASE IN ENERGY OVER UNCONTROLLED BOILER	% INCREASE IN ENERGY OVER SIP-CONTROLLED BOILER
8.8 (30)	Underfeed Stoker	SIP						
26,270 kJ/kg		Raw	0	Elec.	1.9 (.8)	< 1		
0.59% S		ESP	89	Elec.	144.4 (62.1)	48		
24.8% Ash				Total	146.2 (62.9)	49	.6%	N.A.
		MODERATE						
		Raw Coal	0	Elec.	1.9 (.8)	< 1		
		ESP	96	Elec.	189.2 (81.4)	63		
				Total	191.0 (82.2)	64	.7%	.2%
		OPTIONAL MODERATE						
		Raw Coal	0	Elec.	1.9 (.8)	< 1		
		ESP	96	Elec	189.2 (81.4)	63	.7%	.2%
				Total	191 (82)	64		
		INTERMEDIATE						
		Raw Coal	0	Elec.	1.9 (.8)	< 1		
		ESP	98	Elec.	200.0 (86.0)	66		
				Total	201.8 (86.8)	67	.8%	.2%
		STRINGENT						
		Raw Coal	0	Elec.	1.9 (.8)	< 1		
		ESP	99.5	Elec.	222.4 (95.6)	74		
				Total	224.2 (96.4)	75	.9%	.3%

** Raw Coal Analysis: 0.59% S; 26,270 kJ/kg; 24.8% Ash

+ Percent Sulfur reduction in ng SO_2/J and percent Ash reduction in ng ash/J

Table 5-28. ENERGY USAGE OF "BEST" CONTROL TECHNIQUES FOR 22MW COAL-FIRED BOILERS USING LOW SULFUR WESTERN COAL

SYSTEM: LOW SULFUR WESTERN COAL**					ENERGY CONSUMPTION		IMPACTS	
STANDARD BOILERS: Heat and Fuel Input MW (10^6 BTU/hr)	STANDARD BOILERS: Type	TYPE AND LEVEL OF CONTROL	CONTROL EFFICIENCY+ (%)	ENERGY TYPE	ENERGY CONSUMED BY CONTROL: kJ/kg (BTU/lb)	ENERGY CONSUMED BY CONTROL: KW (thermal)	% INCREASE IN ENERGY OVER UNCONTROLLED BOILER	% INCREASE IN ENERGY OVER SIP-CONTROLLED BOILER
22 (75)	Chain Grate Stoker	SIP						
26,270 kJ/kg		Raw Coal	0	Elec.	1.9(.8)	1		
0.59% S		ESP	89	Elec.	148.5(63.9)	124		
24.8% Ash				Total	150.4(64.7)	125	.6%	NA
		MODERATE						
		Raw Coal	0	Elec.	1.9(.8)	1		
		ESP	96	Elec.	194.8(83.8)	162		
				Total	196.7(84.6)	163	.8%	.2%
		OPTIONAL MODERATE						
		Raw Coal	0	Elec.	1.9 (.8)	1		
		ESP	96	Elec.	196.7 (84.6)	163		
				Total	199 (85)	164	.7%	.2%
		INTERMEDIATE						
		Raw Coal	0	Elec.	1.9(.8)	1		
		ESP	98	Elec.	206.3(88.7)	172		
				Total	208.2(89.5)	173	.8%	.2%
		STRINGENT						
		Raw Coal	0	Elec.	1.9(.8)	1		
		ESP	99.5	Elec.	229.2(98.6)	191		
				Total	231.1(99.4)	192	.9%	.3%

** Raw Coal Analysis: 0.59% S; 26,270 kJ/kg; 24.8% Ash

\+ Percent sulfur reduction in ng SO_2/J and percent Ash reduction in ng ash/J

Table 5-29 ENERGY USAGE OF "BEST" CONTROL TECHNIQUES FOR 44MW COAL-FIRED BOILERS USING LOW SULFUR WESTERN COAL

SYSTEM LOW SULFUR WESTERN COAL**					ENERGY CONSUMPTION		IMPACTS	
STANDARD BOILERS: Heat and Fuel Input MW (10^6 BTU/hr)	STANDARD BOILERS: Type	TYPE AND LEVEL OF CONTROL	CONTROL EFFICIENCY+ (%)	ENERGY TYPE	ENERGY CONSUMED BY CONTROL: kJ/kg (BTU/lb)	ENERGY CONSUMED BY CONTROL: KW (thermal)	% INCREASE IN ENERGY OVER UNCONTROLLED BOILER	% INCREASE IN ENERGY OVER SIP-CONTROLLED BOILER
44 (150)	Spreader Stoker	SIP						
26,270 kJ/kg		Raw Coal	0	Elec.	1.9(.8)	3		
0.59% S		ESP	96	Elec.	(81.9)	318		
24.8% Ash				Total	1.9(82.7)	321	.7%	NA
		MODERATE						
		Raw Coal	0	Elec.	1.9(.8)	3		
		ESP	98	Elec.	201.7(86.7)	337		
				Total	203.6(87.5)	340	.8%	.04%
		OPTIONAL MODERATE						
		Raw Coal	0	Elec	1.9 (.8)	3		
			98	Elec.	201.7 (86.7)	337		
				Total	204 (88)	340	.8%	.04%
		INTERMEDIATE						
		Raw Coal	0	Elec.	1.9(.8)	3		
		ESP	99.3	Elec.	224.2(96.4)	375		
				Total	226.1(97.2)	378	.9%	.1%
		STRINGENT						
		Raw Coal	0	Elec.	1.9(.8)	3		
		ESP	99.8	Elec.	224.2(96.4)	375		
				Total	226.1(97.2)	378	.9%	.1%

** Raw Coal Analysis: 0.59% S; 26,270 kJ/kg; 24.8% Ash

\+ Percent sulfur reduction in ng SO_2/J and percent Ash reduction in ng ash/J

Table 5-30. ENERGY USAGE OF "BEST" CONTROL TECHNIQUES FOR 58.6MW COAL-FIRED BOILERS USING LOW SULFUR WESTERN COAL

SYSTEM: LOW SULFUR WESTERN** COAL					ENERGY CONSUMPTION		IMPACTS	
STANDARD BOILERS: Heat and Fuel Input MW (10^6 BTU/hr)	STANDARD BOILERS: Type	TYPE AND LEVEL OF CONTROL	CONTROL EFFICIENCY+ (%)	ENERGY TYPE	ENERGY CONSUMED BY CONTROL: kJ/Kg(BTU/lb)	ENERGY CONSUMED BY CONTROL: KW (thermal)	% INCREASE IN ENERGY OVER UNCONTROLLED BOILER	% INCREASE IN ENERGY OVER SIP-CONTROLLED BOILER
58.6 (200) 26,270 kJ/kg 0.59% S 24.8% Ash	Pulverized Coal	SIP						
		Raw Coal	0	Elec.	1.9(.8)	4		
		ESP	97	Elect.	170.3(73.2)	379		
				Total	172.2(74.0)	383	.6%	NA
		MODERATE						
		Raw Coal	0	Elec.	1.9(.8)	4		
		ESP	99	Elec.	175.1(75.3)	390		
				Total	177.0(76.1)	394	.7%	.02%
		OPTIONAL MODERATE						
		Raw Coal	0	Elec	1.9 (.8)	4		
		ESP	99	Elec.	175.5 (75.7	391		
				Total	177 (77)	395	.7%	.02%
		INTERMEDIATE						
		Raw Coal	0	Elec.	1.9(.8)	4		
		ESP	99.4	Elec.	194.7(83.7)	434		
				Total	196.6(84.5)	438	.7%	.09%
		STRINGENT						
		Raw Coal	0	Elec.	1.9(.8)	4		
		ESP	99.8	Elec.	194.7(83.7)	434		
				Total	196.6(84.5)	438	.7%	.09%

** Raw Coal Analysis: 0.59% S; 26,270 kJ/kg; 24.8% Ash

+ Percent sulfur reduction in ng SO_2/J and percent Ash reduction in ng ash/J

TABLE 5-31 ENERGY USAGE OF "BEST" CONTROL TECHNIQUES FOR 118 MW COAL-FIRED BOILERS USING LOW SULFUR WESTERN COAL

SYSTEM LOW SULFUR WESTERN COAL **					ENERGY CONSUMPTION		IMPACTS	
Standard Boiler: Heat Rate MW or (10^6 BTU/hr)	Standard Boiler: Type	Type and Level of Control	Control Ef- + ficiency Percent (%)	Energy Type	Energy Consumed by Control: kJ/kg (BTU/lb)	Energy Consumed by Control: KW (thermal)	Percent Increase in Energy over Uncontrolled Boiler	Percent Increase in Energy over SIP Controlled Boiler
118 (400)	Pulverized Coal	SIP						
26,270 kJ/kg		Raw Coal	0	Elec.	1.9 (.8)	8.3		
0.59% S		ESP	97	Elec.	117.7 (50.6)	525	0.4%	NA
24.8% Ash				TOTAL	119.6 (51.4)	533		
		Moderate						
		Raw Coal	0	Elec.	1.9 (.8)	8.3		
		ESP	99	Elec.	119.6 (51.4)	534	0.4%	.008%
				TOTAL	121.5 (52.2)	542		
		Optional Moderate						
		Raw Coal	0	Elec.	1.9 (.8)	8.3		
		ESP	99	Elec.	119.6 (51.4)	534	0.4%	.008%
				TOTAL	121.5 (52.5)	542		
		Intermediate						
		Raw Coal	0	Elec.	1.9 (.8)	8.3		
		ESP	99.4	Elec.	129.8 (55.8)	579	0.5%	.04%
				TOTAL	131.7 (56.6)	587		
		Stringent						
		Raw Coal	0	Elec.	1.9 (.8)	8.3		
		ESP	99.8	Elec.	129.8 (55.8)	579	0.5%	.04%
				TOTAL	131.7 (56.6)	587		

** Raw Coal Analysis: 0.59% S; 26,270 kJ/kg; 24.8% Ash
+ Percent sulfur reduction in ng SO_2/J and percent Ash reduction in ng ash/J.

TABLE 5-32. SAMPLE CALCULATIONS

Calculating energy consumed by control - 8.8MW underfeed stoker using high sulfur eastern coal to meet SIP level.

1) Fuel energy lost in refuse in PCC plant - Level 5, middling product

a) $$\frac{\text{Heat content in refuse}}{\text{lb product}} = \frac{\text{heat content of refuse} \times \text{refuse wt \%} \times \text{raw coal feedrate}}{\text{product coal feed rate}}$$

$$\frac{\text{Heat content in refuse}}{\text{lb product}} = \frac{5{,}401\ \frac{\text{BTU}}{\text{lb}} \times 0.2667 \times 8{,}000\ \frac{\text{ton}}{\text{day}}}{5{,}866\ \frac{\text{ton}}{\text{day}}} = 1{,}964\ \frac{\text{BTU}}{\text{lb}} = 4{,}568\ \text{kJ/kg}$$

b) Converting $\frac{\text{BTU}}{\text{lb}}$ to KW

$$\frac{\frac{\text{Heat content in refuse}}{\text{lb product}} \times \text{boiler input rate} \times .000293\ \frac{\text{KW}}{\text{BTU/hr}}}{\text{heat content of coal input to boiler}} = \text{KW}$$

$$\frac{1964\ \frac{\text{BTU}}{\text{lb}} \times 30\ \frac{10^6\ \text{BTU}}{\text{hr}} \times .000293\ \frac{\text{KW}}{\text{BTU/hr}}}{.012402\ \frac{10^6\ \text{BTU}}{\text{lb}}} = 1{,}392\ \text{KW}$$

2) Calculating electrical energy use in preparation.

Using the equipment list in Section 4, energy requirements for each unit in Level 5 were obtained and summed. From this value was subtracted energy usage values for those pieces which were only used for deep clean coal processing. The resulting energy value represented middling processing.

3) Calculating ESP electrical energy use.

Using methodology in Section 5.2.1 and resulting Table 5 - 15, electrical kilowatt usage was 11.6. Thermal kilowatt usage was 3 x 11.6 = 34.8KW. Conversion to BTU/hr is similar to first calculation.

4) Calculating % increase in energy over uncontrolled boiler.

$$\frac{\text{total energy consumed in control}}{\text{energy input to boiler}} = \frac{1.431\text{MW}}{8.8\text{MW}} = 16.3\%$$

5) Calculating % increase in energy over SIP-controlled boiler.

$$1 - \frac{\text{total energy consumed in control for SIP} + \text{energy input to boiler}}{\text{total energy consumed in control} + \text{energy input to boiler}}$$

$$1 - \frac{8.8 + 1.431\text{MW}}{8.8 + 1.439\text{MW}} = 0.1\%$$

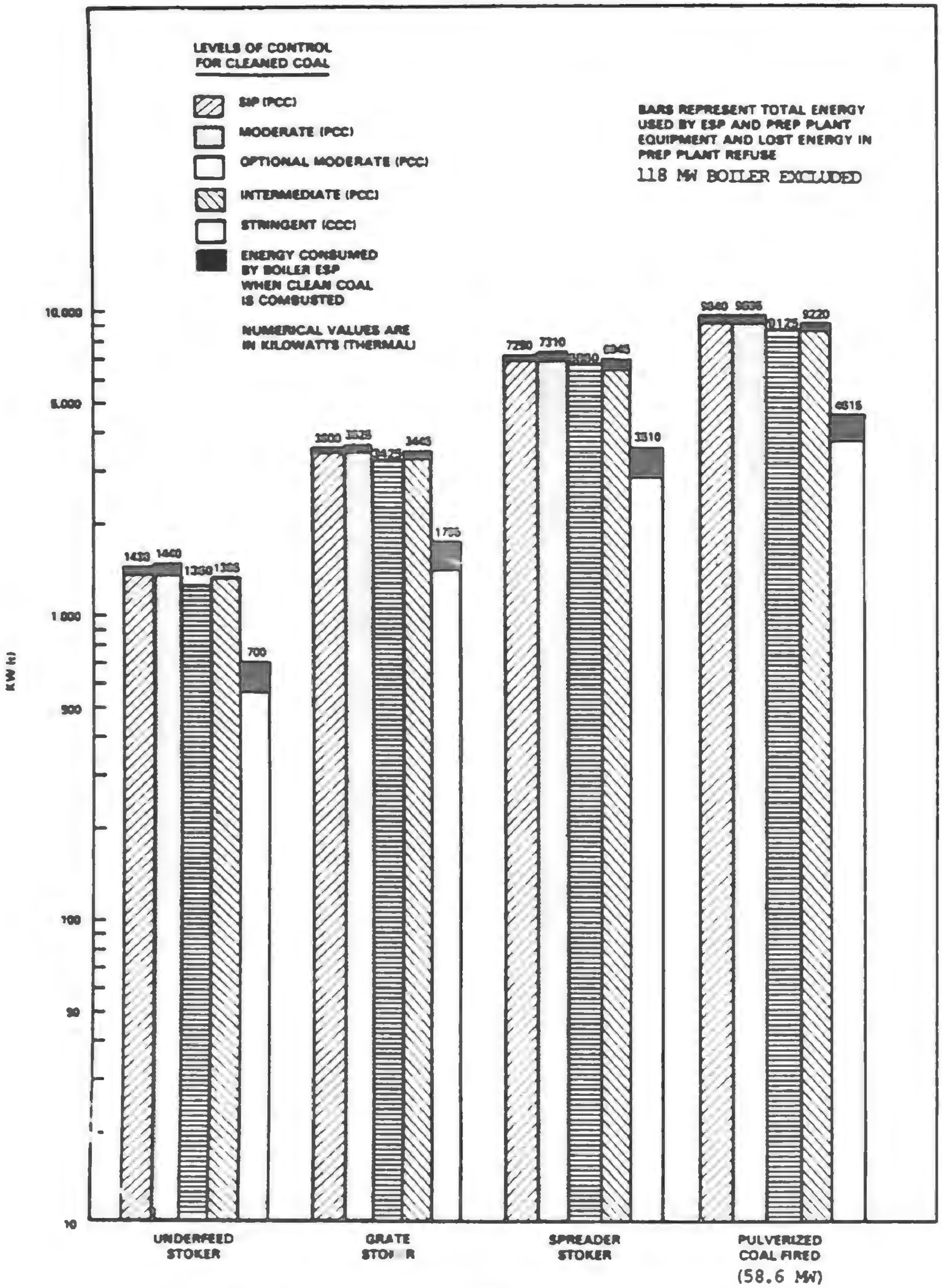

FIGURE 5-2 ENERGY CONSUMED USING HIGH SULFUR EASTERN COAL

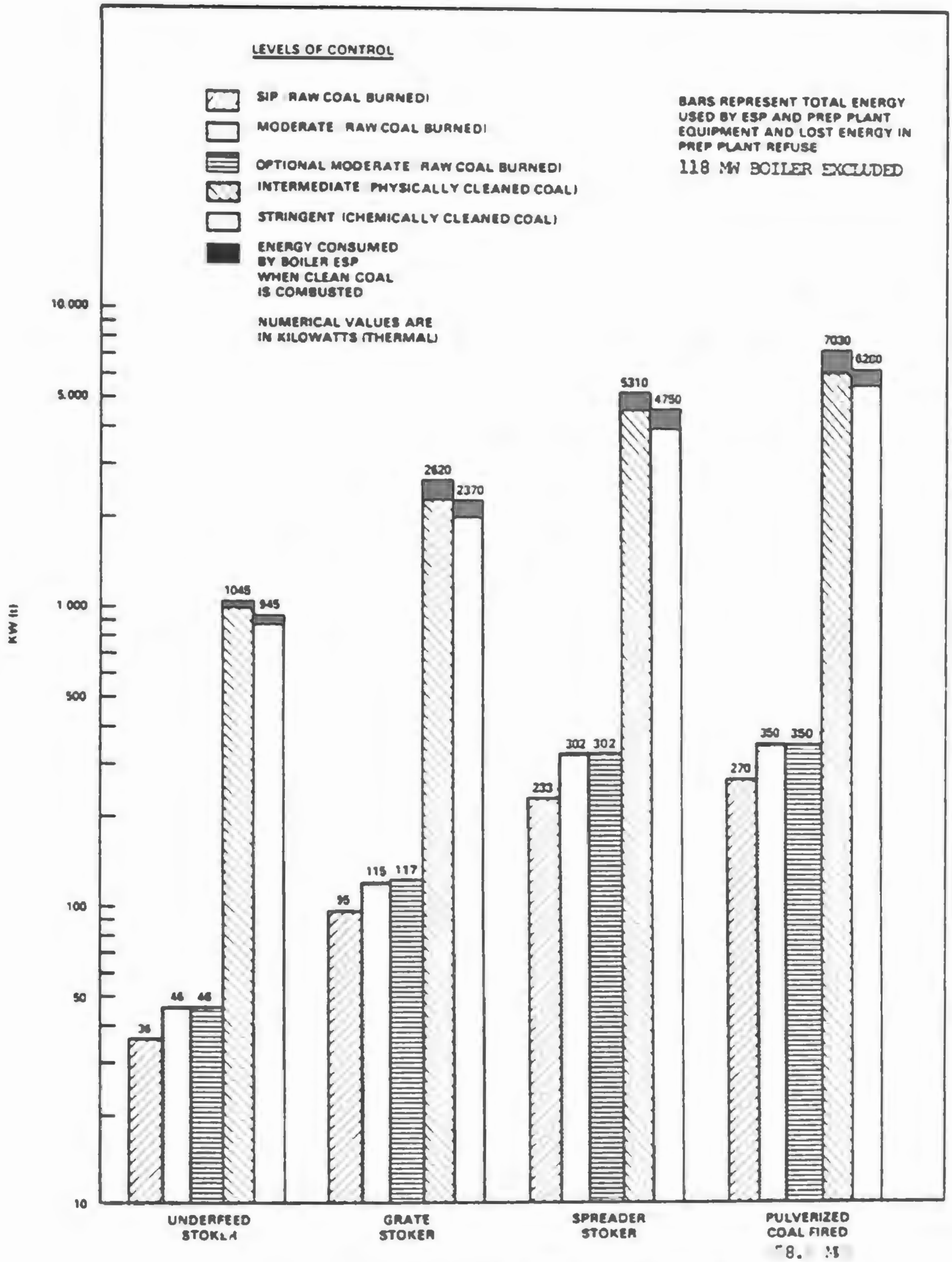

FIGURE 5-3 ENERGY CONSUMED USING LOW SULFUR EASTERN COAL

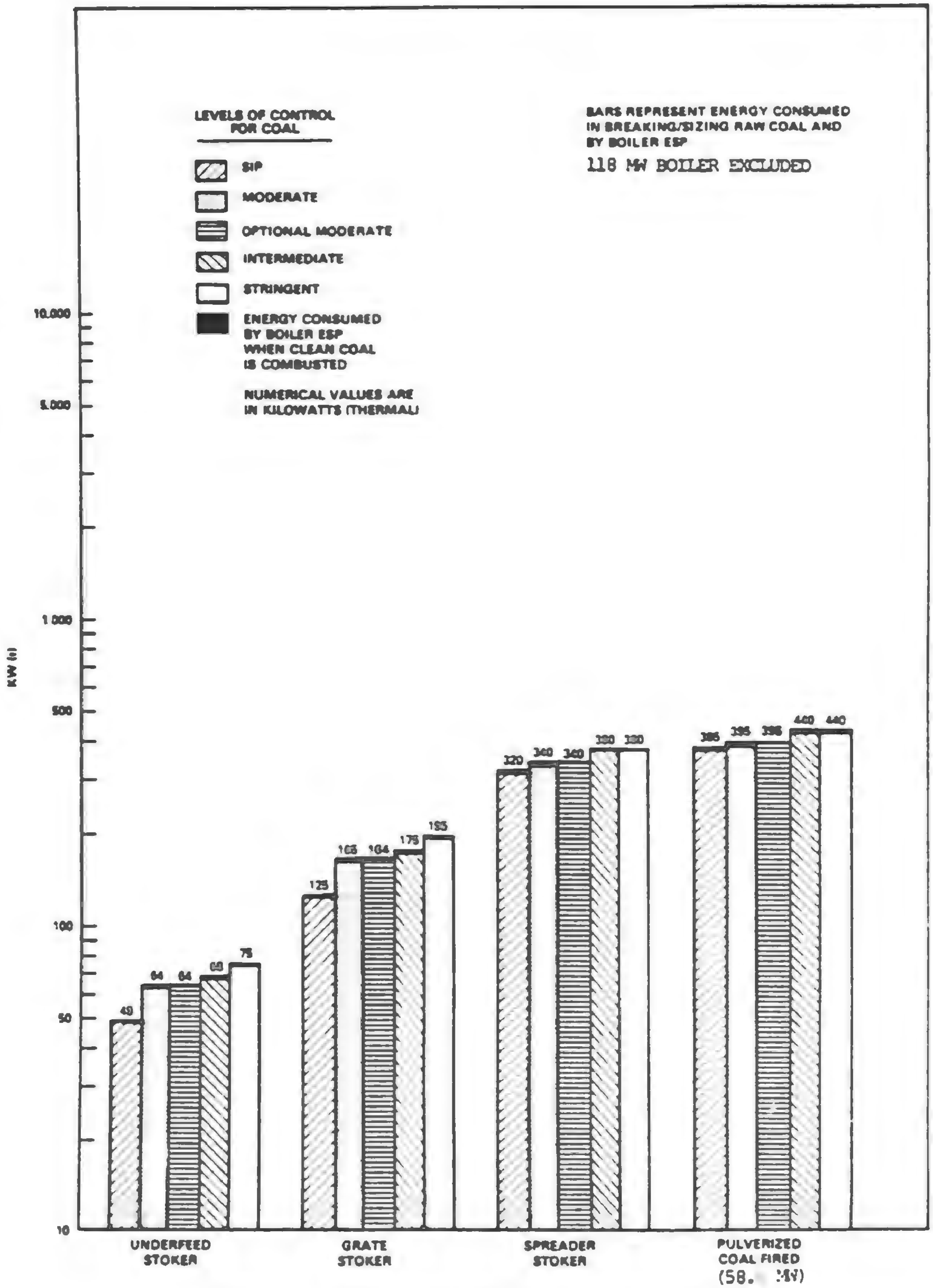

FIGURE 5-4 ENERGY USAGE USING LOW SULFUR WESTERN COAL

and chemically cleaned low sulfur eastern coal. The large increase in energy consumption is attributable to the energy lost in coal preparation plant refuse. Figure 5-4 shows raw low sulfur western coal requires the least amount of energy to meet the control levels and also shows a step-wise progression of the amount of energy required to meet increasingly strict controls. Figure 5-2 also shows this step-wise progression, however, the amount of energy required then using physically cleaned high sulfur coal is greater than for chemically cleaned coal. This occurs because less refuse is produced by chemical coal cleaning plants (i.e. higher yields) resulting in less energy lost to the refuse, and more energy remaining in the aggregated product coal.

5.2.4 Comparison of Energy Consumption Using Low Sulfur Coal, Physically Cleaned Coal and Chemically Cleaned Coal

As discussed in Section 5.1 the major energy elements differ for each control technology discussed. Section 5.2.2 shows the magnitude of the energy consumption between these elements. Expressed as a percent of the raw coal energy content, the difference in energy consumption can be estimated.

For low sulfur coal transport the energy consumed varies from 0.4-4.0 percent depending upon the coal source and its destination. Note on Table 5-6 that when a physically or chemically cleaned coal is transported the same distance as raw coal, the energy impact is less. For example, transporting raw low sulfur eastern coal to Austin, Texas consumes the equivalent of 2.51 percent of the coal's energy content. If that coal is cleaned at the mine and then shipped, the equivalent energy consumption is reduced to 2.18 percent. The transportation energy savings is over 10 percent.

Compared to transportation energy consumption, the energy spent in actually physically cleaning the coal is negligible. As a percent of the coal energy content, it is less than 0.05 percent. Chemically cleaning the coal involves considerably more energy, but as a percent of the coal energy content, it is equivalent to only 0.2-0.75 percent.

The major energy consumer is energy lost in the refuse of a coal cleaning plant. It is this loss of energy from the mined, raw coal which accounts for 95 percent of the energy consumption related to coal cleaning technology, including particulate control. As shown in the BSER energy usage tables, level 5 coal cleaning rejects almost 16 percent of the coal's energy content while level 4 rejects about 12 percent. For chemical coal cleaning the rejection energy is slightly lower, from 8-10 percent of the coal energy content.

The fourth energy element is particulate collection. Section 5.2.1 shows the absolute energy requirements for particulate control at various control levels using electrostatic precipitators. Note that raw high sulfur coal consumes less energy than cleaned coal for the same emission control level. This is a function of the ash resistivity increase due to lower sulfur content in the cleaned coal, which is dominant over the lower ash content. On the other hand, cleaning low sulfur eastern coal reduces energy requirements for particulate control. For the BSERs, the ESP consumes from 0.4-0.8 percent of the energy content in the specified low sulfur eastern coal and 0.6-0.9 percent for the low sulfur western coal.

In total, including transportation, using low sulfur western coal will consume from 3-6 percent of a coal's energy content to meet various emission control levels. If physically cleaned eastern coal is used, the consumption value is much higher at 14-18 percent. Chemical coal cleaning energy consumption is slightly lower at 9-12 percent of the input coal energy value.

The energy effectiveness with respect to SO_2 removal of the three control technologies is shown in Table 5-33. Transportation energy is not included in these values. For raw low sulfur coal the absolute value of energy consumed is provided, since there is actually no sulfur removed by using this control technique. The table shows that removal of additional amounts of sulfur is associated with an increase in the absolute amount of energy consumed (primarily energy lost to the refuse), but a decrease in the kilowatt per ng SO_2/J removed equivalent. This result is

TABLE 5-33. ENERGY USAGE EFFECTIVENESS

Boiler Input MBTU	Level of Control	High Sulfur Eastern Coal BSER	KW	KW/ ng SO_2/J removed	Low Sulfur Eastern Coal BSER	KW	KW/ ng SO_2/J removed	Low Sulfur Western Coal BSER	KW*
8.8	SIP	PCC-Lvl 5-mid	1,431	.95	Raw Coal	36	36*	Raw Coal	49
	Moderate	PCC-Lvl 5-mid	1,439	.96	Raw Coal	46	46*	Raw Coal	64
	Optional Moderate	PCC-Lvl 5-dc	1,358	.70	Raw Coal	46	46*	Raw Coal	64
	Intermed.	PCC-Lvl 5-dc	1,365	.71	PCC-Lvl 4	1,046	4.7	Raw Coal	68
	Stringent	CCC-ERDA	700	.34	CCC-Gravi.	946	2.5	Raw Coal	75
22	SIP	PCC-Lvl 5-mid	3,603	2.40	Raw Coal	94	94*	Raw Coal	126
	Moderate	PCC-Lvl 5-mid	3,625	2.42	Raw Coal	118	118*	Raw Coal	165
	Optional Moderate	PCC-Lvl 5-dc	3,425	1.77	Raw Coal	117	117*	Raw Coal	164
	Intermed.	PCC-Lvl 5-dc	3,444	1.78	PCC-Lvl 4	2,620	11.7	Raw Coal	174
	Stringent	CCC-ERDA	1,756	.85	CCC-Gravi.	2,369	6.4	Raw Coal	193
44	SIP	PCC-Lvl 5-mid	7,252	4.85	Raw Coal	233	233*	Raw Coal	233
	Moderate	PCC-Lvl 5-mid	7,309	4.89	Raw Coal	302	302*	Raw Coal	340
	Optional Moderate	PCC-Lvl 5-dc	6,856	3.55	Raw Coal	302	302*	Raw Coal	340
	Intermed.	PCC-Lvl 5-dc	6,946	3.59	PCC-Lvl 4	5,309	23.8	Raw Coal	378
	Stringent	CCC-ERDA	3,510	1.70	CCC-Gravi.	4,750	12.8	Raw Coal	378
58.6	SIP	PCC-Lvl 5-mid	9,642	6.45	Raw Coal	271	271*	Raw Coal	384
	Moderate	PCC-Lvl 5-mid	9,696	6.48	Raw Coal	351	351*	Raw Coal	395
	Optional Moderate	PCC-Lvl 5-dc	9,216	4.77	Raw Coal	350	350*	Raw Coal	395
	Intermed.	PCC-Lvl 5-dc	9,222	4.77	PCC-Lvl 4	7,032	31.5	Raw Coal	438
	Stringent	CCC-ERDA	4,614	2.24	CCC-Gravi.	6,282	16.9	Raw Coal	438
118	SIP	PCC-Lvl 5-mid	19,158	12.81	Raw Coal	421	421*	Raw Coal	533
	Moderate	PCC-Lvl 5-mid	19,215	12.85	Raw Coal	499	499*	Raw Coal	542
	Optional Moderate	PCC-Lvl 5-dc	18,112	9.37	Raw Coal	499	499*	Raw Coal	542
	Intermediate	PCC-Lvl 5-dc	18,240	9.43	PCC-Lvl 4	13,835	61.9	Raw Coal	587
	Stringent	CCC-ERDA	8,911	4.32	CCC-Gravi.	12,305	33.0	Raw Coal	587

* Indicates KW usage since no sulfur was removed

not surprising since the cleaning equipment required to increase sulfur removal is not energy intensive. Sulfur removal is limited by the amount and size of pyritic sulfur in the coal and a trade-off between coal yield and sulfur content; it is not limited by energy demand.

5.3 POTENTIAL FOR ENERGY SAVINGS

This section discusses some of the possible methods for reducing the amount of energy consumed by the control technologies being considered. For the low sulfur coal control technology the major potential energy savings would be in the area of transportation to the industrial boiler user. However, since transportation energy is not to be considered in this section no further discussion would be pertinent.

The chemical coal cleaning systems which have been proposed as BSERs are simply conceptual in design at the present time and therefore any further consideration of energy savings would be mainly conjecture. The physical coal cleaning systems which have been proposed are commercially available and several areas of energy reduction are potentially feasible.

5.3.1 Design of Physical Coal Cleaning Plants Without Thermal Driers

In recent years, an increase in mechanical mining methods has increased the amount of fine coal which the physical coal cleaning plant must process. This fine coal material will absorb and retain considerably more moisture during processing than the coarser fractions. This increased moisture content in the fine sizes often has required the coal preparation plant designer to specify thermal driers to remove excess moisture. There are two major benefits for using thermal driers, (1) a decrease in transportation costs and (2) a reduction of heat loss due to evaporation of surface moisture from the coal during the burning process. The major disadvantages to the thermal drying system are the high capital costs of the system compared to mechanical dewatering, the high energy costs, and the environmental problems associated with particulate emissions from the drier stacks. The energy savings associated with the elimination of thermal driers is on the order of 1% of the coal production per day.

The environmental problem associated with the particulate emissions has become a major factor in recent years in new plant design. In the past two years, permits have been denied for a number of new installations due to the inability of thermal drier pollution devices to meet particulate control levels. As a result, plant designers are carefully looking at alternative designs using more sophisticated mechanical dewatering systems and blending of coal product streams to achieve product coal specifications without thermal drying. The physical coal cleaning plant designs used in this report do not use thermal drying operations to achieve product moisture specifications.

5.3.2 Energy Recovery in Physical Coal Cleaning

The physical coal cleaning process changes the net energy value of coal in four major ways - by reducing the ash content, by increasing the moisture content, by reducing the pyritic sulfur content, and by rejecting some coal in refuse streams. The magnitude of these changes, and their relative impact upon the overall energy balance, is to a large extent controllable through design and operation of coal cleaning plants.

5.3.2.1 Factors Affecting Energy Recovery--

Ash Removal

Ash removal, or more correctly the removal of ash-forming minerals, improves the net energy balance. Except for pyritic sulfur (iron pyrite), the mineral impurities have no heating value so that their removal does not constitute an energy loss. By removing minerals, an energy benefit is achieved by avoiding the transportation requirements for inert materials, and by avoiding the sensible heat requirements (in the boiler) for inert materials. This energy benefit can be sizable, since the quantity removed by coal cleaning may amount to 15 or 20 percent of the total raw coal quantity.

Pyrite Removal

Pyritic sulfur (iron pyrite) is removed in coal cleaning plants for boiler-related emission reasons. Since iron pyrite does have a heating value, its intentional removal for environmental reasons prior to combustion is associated with an inherent energy penalty.

The heat of combustion of iron pyrite, FeS_2, is 6,894 kJ/kg (2,964 BTU/lb). Table 5-34 summarizes the inherent energy penalty of pre-combustion pyrite removal.

Moisture Content of Washed Coal

Physical coal cleaning processes result in increased moisture content of the product coal. As coal cleaning plant designs evolve to remove greater amounts of pyritic sulfur, fine coal cleaning circuits will become prevalent. The liberation of iron pyrite by further size reduction, and the separation of pyrite by washing fine size fractions, are the commonly-applied techniques. Since fine coal fractions have much greater quantities of surface moisture, the resultant energy penalties for transporting excess moisture and for evaporating excess moisture in the boiler become larger. Coal cleaning plant dewatering techniques (e.g. centrifugation or filtration) are effective in significantly reducing these moisture-related energy penalties, but thermal drying (with its comparatively large energy requirements) is necessary to achieve moisture levels in washed fine coal approximating the raw coal moisture levels.

Misplaced Material

Since commercial physical coal cleaning processes are less than theoretically perfect in partitioning organic coal from inorganic impurities, some coal with its desirable energy value is lost, as misplaced material, with the inorganic refuse streams. Fine coal cleaning circuits have the potential not only of separating and rejecting more liberated pyrite and ash, but also of recovering more liberated clean coal. Cleaning plant design techniques and unit processes for fine coal separations are useful for minimizing the energy penalties associated with misplaced clean coal.

5.3.2.2 Trade-Offs for Energy Recovery--

The first two factors discussed above have direct, easily discernible effects on energy use by cleaning plants. First, ash removal is a desirable process from every standpoint, since it provides lower transportation and

TABLE 5-34 ENERGY PENALTIES ASSOCIATED WITH PRE-COMBUSTION PYRITE REMOVAL

	Eastern High-Sulfur Coal	Eastern Low-Sulfur Coal	Western Low-Sulfur Coal
Percent Pyritic Sulfur	2.79	0.60	0.30
Percent Iron Pyrite (FeS_2)	5.22	1.12	0.56
Heating Value, kJ/kg Total Coal			
Total Coal	26,772	31,685	26,268
Iron Pyrite in Coal	360	77	39
Net (Coal less pyrite)	26,412	31,608	26,229
Percent of Total Heating Value in Iron Pyrite	1.34	0.24	0.15

coal handling costs , less ash handling and disposal costs and generally less slagging problems in the boiler leading to lower operation and maintenance costs. The energy benefit of ash removal is completely consistent with the above cost-benefits. The second straightforward relationship is with the pyrite removal factor. Emission goals necessitate the maximum removal of pyritic sulfur, with the implied result that any energy penalties from pyrite removal are acceptable.

For the other two factors, the relationship is not straightforward, but is largely dependent upon specific plant designs and plant operating characteristics. The magnitude of energy penalties from excess moisture and from misplaced clean coal are largely controllable, and may be viewed as the results of tradeoffs for particular commercial situations.

The plant designs and operating characteristics which affect the quantity of excess moisture in cleaned coal and the quantity of organic coal rejected in refuse streams are the result of economic tradeoffs. The criterion for selecting coal cleaning operations such as dewatering, drying, separation, and recovery, is least cost per unit of delivered clean coal (or maximum profit to the cleaning plant operator). The economic optimum does not necessarily coincide with an optimum based upon maximum net energy recovery. Several key ingredients are common to cost and energy: transportation costs are approximately proportional to transportation energy, and the economic value of rejected misplaced coal is approximately proportional to the energy value of this rejected coal. However, the economic tradeoffs are heavily influenced by capital amortization, which plays no role in energy tradeoffs.

Mechanical dewatering techniques (centrifugation, filtration) have a highly positive energy balance. The energy benefit of removing excess moisture, in terms of avoiding transportation and evaporation penalties, are much greater than the energy requirements for mechanical dewatering. Fortuitously, the cost tradeoff appears consistent with the energy tradeoff. The economic benefits, in terms of avoiding excess transportation charges and boiler evaporation penalties, are generally greater than the capital amortization and operating costs for mechanical dewatering.

Hence, mechanical dewatering appears desirable for both cost saving and energy recovery purposes.

Thermal drying of fine coal, however, is not clearly advantageous, assuming that much of the excess moisture in fine coal is first removed by mechanical dewatering. The incremental moisture removed by thermal drying reduces both transportation costs and transportation energy requirements. However, thermal drying requires considerably more energy (because of higher inefficiencies) than evaporation of moisture in the boiler. From an economic viewpoint, the capital and operating costs of thermal dryers are high, especially when stringent air pollution controls are required.

A fundamental characteristic of any single physical coal cleaning unit operation is that it may be designed and operated <u>either</u> by maximum removal of high-density inorganic impurities or for maximum recovery of clean coal; but not for achieving both goals. This characteristic arises from the presence of individual mid-gravity particles which report either to the clean coal fraction (if a high operating specific gravity is selected), thereby maximizing energy recovery; or to the refuse fraction (if a low operating specific gravity is selected), thereby maximizing impurity removal.

Several approaches are effective in minimizing the energy penalty of misplaced coal. One approach is finer size reduction, which liberates more of the impurities so that a lesser fraction of the individual particles fall in the mid-gravity range. Another approach is to use more efficient separation processes (which have a sharper partition curve). A third approach is to apply sequential processes or sequential circuits, where a first stage operated to achieve one of the alternate goals is followed by a second stage operated to achieve the other goal. For the sink from one heavy-media cyclone operated at a low specific gravity may then be the feed to a second heavy media cyclone operated at a high specific gravity - the first stage produces a "deep-cleaned" product and the second stage produces a middling product, while the products of both stages maximize the energy recovery. Similarly, an entire plant may be designed and operated to produce both a very clean coal product and a middling product.

Although these approaches minimize the energy penalty of misplaced coal, the designs and operating conditions are normally dictated by economics rather than by energy recovery. At some point, it becomes uneconomical to recover any more energy, and some coal is lost in the refuse streams.

5.4 IMPACTS OF SWITCHING FROM OIL-FIRED TO COAL-FIRED INDUSTRIAL BOILERS

It is not practical to modify existing oil-fired industrial boilers to burn coal. Such modification would entail substantial costs—for new pollution control facilities; for an air preheater; for additional space and facilities for receiving, storing, and handling coal; and for handling, storing, and disposing of residuals. Moreover, the required modifications would cause significant decreases in capacity rating; indeed, the capacity rating might drop by as much as two-thirds. Even oil-burning boilers that previously burned coal could encounter problems when reconverting: needed auxiliary equipment, space, and rail connections may have been removed; pollution control facilities might be inadequate; and the type of coal for which the boiler was designed might no longer be available.

For industrial firms, then, switching from oil to coal means installing new boilers—boilers expected to be subject to New Source Performance Standards (NSPS) for major air pollutants. In fact, for the whole universe of energy users nationally, increasing coal use by switching from oil or gas means primarily burning coal in new industrial boilers; electric utilities burning fossil fuels are already planning to use coal in new units; the other major sectors (transportation, residential, and commercial) cannot realistically be expected to burn coal in significant quantities.

There are perceived advantages to burning coal: first, coal is likely to be more available than oil or gas; and, second, the delivered price of coal is expected to be lower per unit of energy. The advantage of a lower annual fuel cost must be evaluated in terms of a tight money market and the fact that industries require a relatively high rate of return on investment. A chemical plant, for example, might expect payback in three to five years, while a utility (which can borrow more cheaply) may be able to wait 20 years. The advantage of lower fuel cost will, of course, be relatively greater in boilers with higher capacity factors.

The American Boiler Manufacturers Association predicted in 1977 that, in 1985, only 38 percent of the new boiler capacity with heat input ranging from about 30 to 90 Mw(t) (100-312 million BTU/hr) will burn oil or gas; the remainder will burn coal or waste.(12) One boiler vendor, whose estimates are based on a survey he conducted in 1976, predicted that close to 40 percent of the capacity of the fossil-fuel-fired boilers purchased over the next five years will have the capability to burn coal.(13) Both of these projected values are considerably higher than the current value of coal's percentage of industrial boiler fuel, which is about ten percent.

The recently passed National Energy Act (NEA) includes provisions that are intended to prohibit the burning of gas or oil in the majority of new industrial boilers, and to decrease the financial disadvantage of burning coal vis-a-vis oil or gas. Most dramatically, the NEA prohibits "large" new boilers—units with a heat input rate of at least 30 Mw(t) (100 million BTU/hr) or aggregations of units of total capacity exceeding 73 mw(t) (250 million BTU/hr)—from burning oil unless granted an exemption by DOE (on the basis of factors such as environmental degradation, economic hardship, and site limitations). By specifying "large" boilers the NEA will affect most new boiler capacity: in 1974, 3.9 quads of the approximately 4.3 quads of fuel consumed in industrial boilers were burned in "large" industrial boilers.(14)

5.5 SUMMARY

Table 5-35 summarizes the energy in kilowatts used by each BSER. These values show that the greatest energy user is physical coal cleaning with chemical coal cleaning consuming about 50% as much energy and low sulfur coal consuming only 5 percent of the PCC value. Figures 5-5, 5-6 and 5-7 represent energy usage versus Boiler Capacity for each BSER. Normalized on a percent basis (MW (+) energy used MW of boiler) these values also show that physical coal cleaning is the greatest energy user and that low sulfur coal consumes the least amount of energy, again only

TABLE 5-35. SUMMARY OF ENERGY CONSUMPTION BY BSERs

Boiler Type	Level of Control	Energy Consumption for High Sulfur Eastern Coal KW(t)	Energy Consumption for Low Sulfur Eastern Coal KW(t)	Energy Consumption for Low Sulfur Western Coal KW(t)
8.8 MW	SIP	1,431	36	49
	Moderate	1,439	46	64
	Optional Moderate	1,358	46	64
	Intermed.	1,365	1,046	68
	Stringent	700	946	75
22 MW	SIP	3,603	94	126
	Moderate	3,625	118	165
	Optional Moderate	3,425	117	164
	Intermed.	3,444	2,620	174
	Stringent	1,756	2,369	193
44 MW	SIP	7,252	233	322
	Moderate	7,309	302	340
	Optional Moderate	6,856	302	340
	Intermed.	6,946	5,309	378
	Stringent	3,510	4,750	378
58.6	SIP	9,642	271	384
	Moderate	9,696	351	395
	Optional Moderate	9,126	350	395
	Intermed.	9,222	7,032	438
	Stringent	4,614	6,282	438
118	SIP	19,158	421	533
	Moderate	19,215	499	542
	Optional Moderate	18,112	499	542
	Intermediate	18,240	13,835	587
	Stringent	8,911	12,305	587

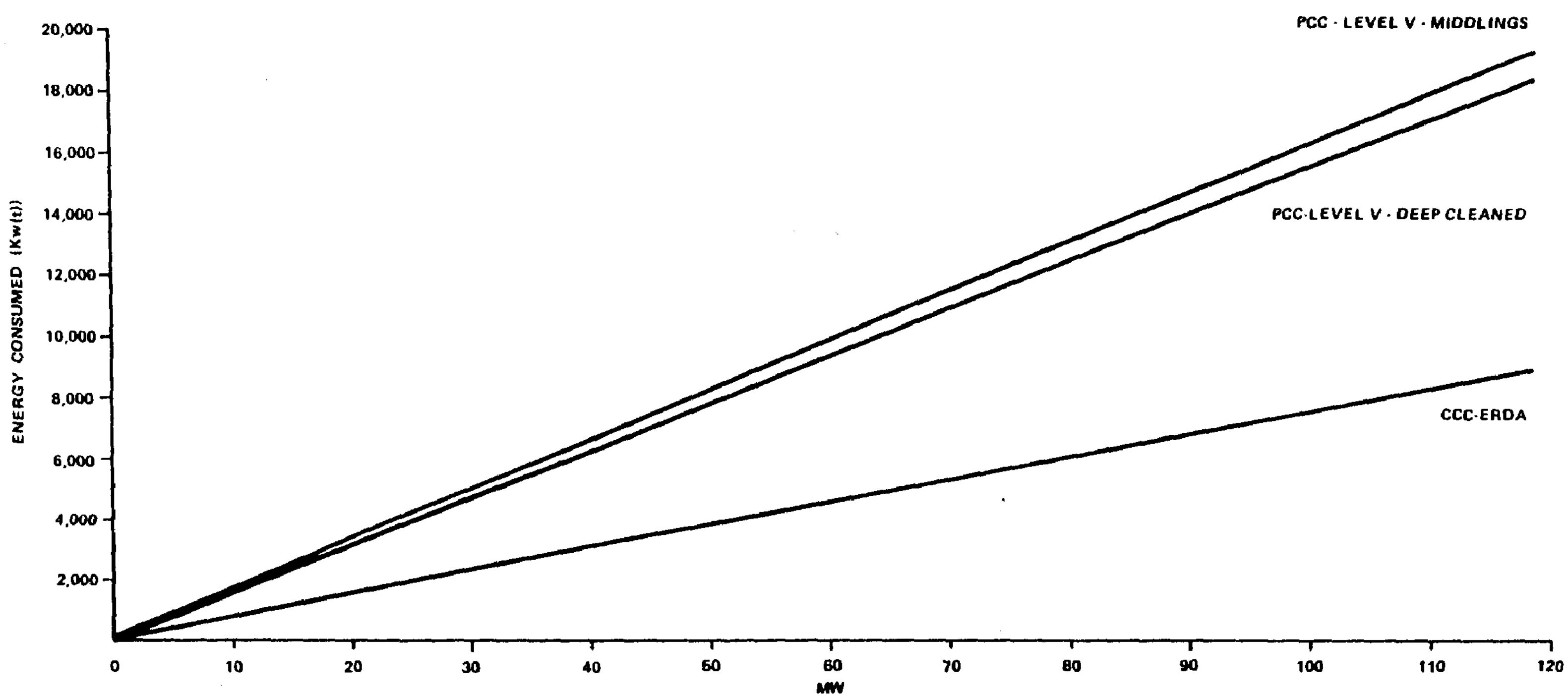

FIGURE 5-5 HIGH SULFUR EASTERN COAL ENERGY USAGE

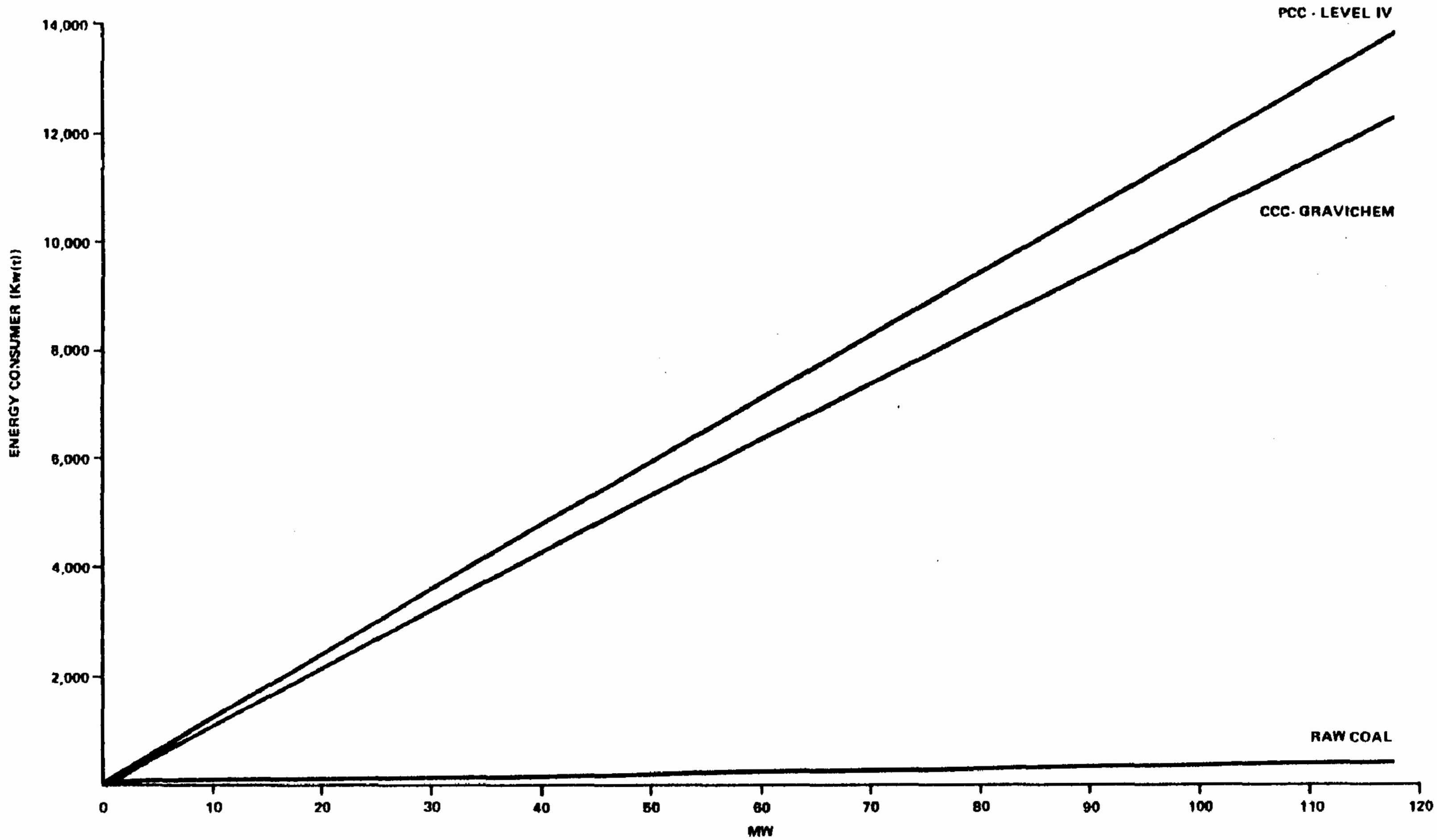

FIGURE 5-8 LOW SULFUR EASTERN COAL ENERGY USAGE

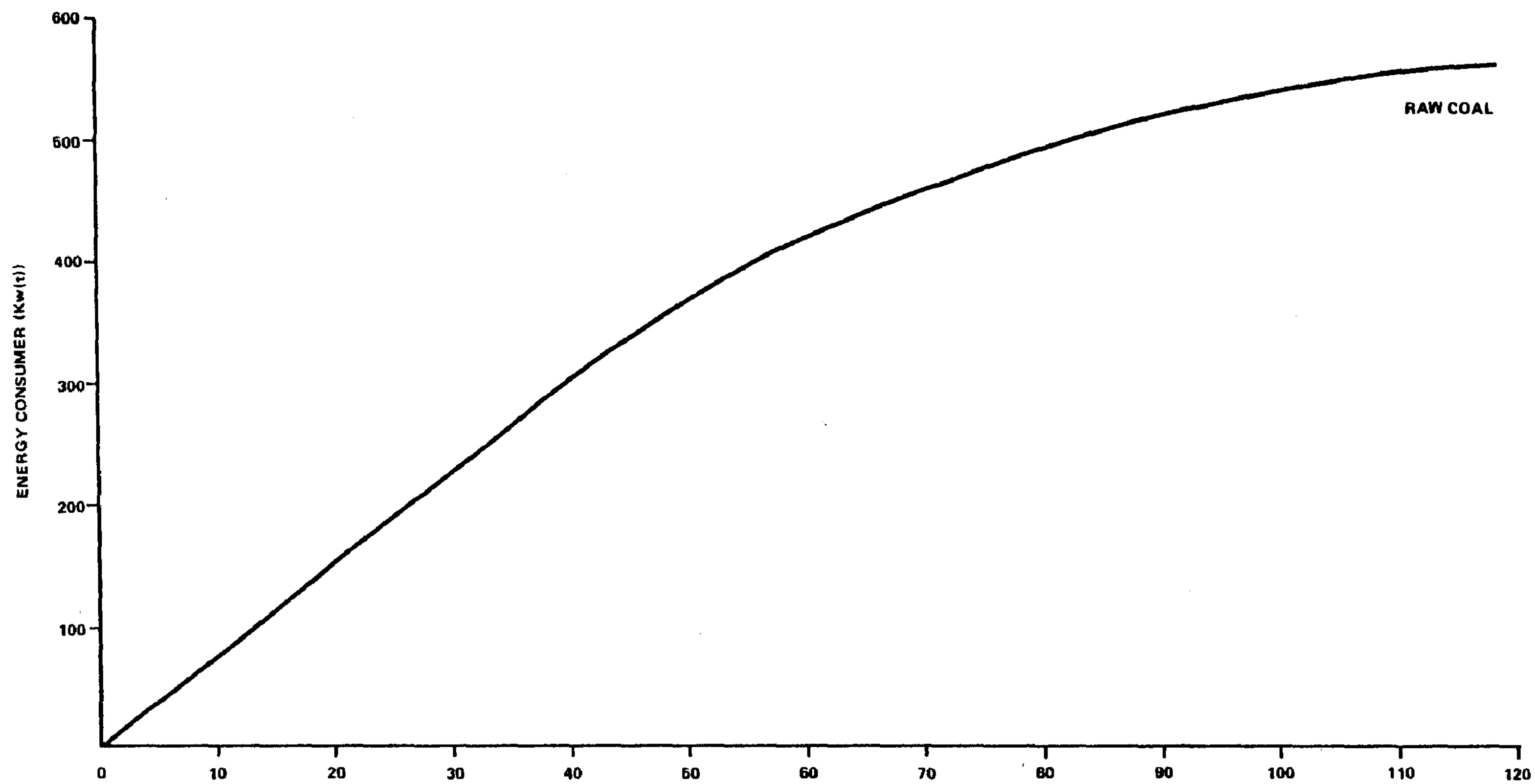

FIGURE 5-7 LOW SULFUR WESTERN COAL ENERGY USAGE

5 percent of the PCC value. The normalized values also show that the amount of energy consumed is not dependent upon the boiler capacity. The energy values remain constant for each BSER regardless of the boiler capacity.

The large differential between the energy consumed by PCC and the energy consumed by low sulfur coal is caused by rejection of energy to refuse in coal cleaning. The tradeoffs associated with the rejection of energy versus product coal energy content were discussed in Section 5.3. Note that decreased energy requirements for the boiler operator associated with decreased coal and ash handling, less boiler maintenance and increased boiler efficiency are not included in thss analysis. Although these values could not be quantified in this ITAR, there should be an attempt to do so in the CTAR.

An interesting result from the energy impact analyses of the three control technologies is the increased energy effectiveness as SO_2 removal requirements increase. (See Table 5-35.) This shows that coal cleaning is an energy effective SO_2 control technology.

SECTION 5.0

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SECTION 6.0

ENVIRONMENTAL IMPACT OF CANDIDATES FOR BEST EMISSION CONTROL SYSTEM

6.1 INTRODUCTION

Section 6 examines the environmental impacts of the best systems of emission reduction. Two kinds of environmental concerns are addressed. The first is the direct effect of atmospheric emissions from industrial boilers using raw and cleaned coal. The BSER candidates considered relate to various processes for reducing sulfur (and other) emissions during the combustion of coal in industrial boilers by the cleaning of coal, and this is where the opportunities lie for the greatest reductions in environmental impact. However, since the cleaning process has its own potential environmental impacts, it is also necessary to evaluate the candidate BSERs for the coal cleaning step. Thus, this assessment will compare the environmental impact of burning raw, uncleaned coal with the total impact from the cleaning of coal and the utilization of cleaned coal.

The environmental impacts will be addressed on a media specific basis by analyzing air emissions, liquid discharges and solid wastes separately. This analysis assumes that electrostatic precipitators are used for particulate control and there are no liquid discharges from industrial boilers burning raw coal. The analysis excludes environmental impacts from mining and transporting of coal and disposal of bottom ash and fly ash collected at the boiler.

The purpose of Section 6 is to quantify the emissions of major pollutants of concern and to discuss their generation and means of control. It should not be implied that analysis is all inclusive relative to minor emissions or trace elements. The amount of data available on the environmental impacts of coal cleaning is relatively scarce and there are many areas relative to cleaning plant emissions that are as yet not quantified. This analysis attempts to utilize existing data to the maximum extent possible and some of the results should be considered preliminary.

The results presented in Section 6.2, 6.3, and 6.4 basically show that the coal cleaning BSERs reduce air emissions while slightly increasing liquid wastes and doubling solid wastes. Specifically for air pollutants, coal cleaning reduces SO_2 emissions by 30-80 percent and reduces particulate loading in the flue gas by 60-85 percent. For NO_2, and CO, and hydrocarbons, coal cleaning provides a slight reduction in boiler emissions due to the increased heat energy of the fuel. Coal cleaning, however, does not remove NO_2, CO or hydrocarbons. The coal cleaning process itself may have a significant particulate emission if thermal driers are used, however, thermal drying was not included in the BSERs.

For liquid discharges the highest discharge concentration is for COD and the major trace element pollutant is iron. There are NPDES guidelines for TSS, iron, manganese and pH from coal cleaning plants which must be met and several unit operations are discussed which minimize these and other liquid effluents.

The major environmental impact from coal cleaning is the generation of large quantities of cleaning refuse, composed of minerals in the coal and some coal particles. Compared to the ash in the raw coal, the physical coal cleaning BSERs produce from 43-112 percent more solid wastes. Infiltration of contaminated water from the refuse piles and tailing ponds identified as a major environmental impact and several mitigative measures are presented.

6.2 ENVIRONMENTAL IMPACTS OF CONTROLS FOR COAL-FIRED BOILERS

6.2.1 Air Pollution

6.2.1.1 Derivation of Emission Rates--

Because coal cleaning processes affect the composition of the boiler fuel, the determination of boiler emission rates must be preceded by the systematic discussion and determination of the ultimate analyses of raw and cleaned coals. The combustion stoichiometry of each of the raw and cleaned coals is evaluated, as an intermediate step, before the boiler-specific and fuel-specific emission rates are determined.

Composition of Raw and Cleaned Coals

Table 6-1 lists the proximate and the ultimate analyses for each of the three representative raw coals considered: high sulfur eastern coal

TABLE 6-1 ANALYSIS OF RAW AND CLEANED COALS

			High-Sulfur Eastern Coal					Low-Sulfur Eastern Coal				Low-Sulfur Western Coal	
			Raw Coal	Deep-Cleaned PCC	Middling PCC	ERDA	Gravichem	Raw Coal	PCC Product	ERDA	Gravichem	Raw Coal	Product Coal
Proximate Analysis	As-Received	Moisture, %	5.0	9.0	8.89	5.0	5.0	2.0	7.47	2.0	2.0	2.5	7.22
		Ash, %	22.23	5.28	10.30	22.23	4.17	10.17	3.82	10.17	1.91	24.19	15.31
		Total S, %	3.23	0.98	1.54	0.71	1.05	1.16	0.82	0.38	0.55	0.58	0.60
		Pyritic S, %	2.65	-	-	0.27	0.32	0.59	-	0.04	0.29	0.29	-
		HV, kJ/kg	25,433	30,533	28,847	25,940	32,377	31,052	31,352	31,051	33,973	25,614	27,093
		HV, BTU/lb	10,934	13,127	12,402	11,152	13,919	13,350	13,479	13,350	14,606	11,012	11,648
	Dry Basis	Ash, %	23.40	5.80	11.31	23.40	4.39	10.38	4.13	10.38	1.95	24.81	16.50
		Total S, %	3.40	1.08	1.69	0.74	1.10	1.18	0.89	0.39	0.56	0.59	0.65
		Pyritic S, %	2.79	-	-	0.28	0.34	0.60	-	0.05	0.05	0.30	-
		HV, kJ/kg	26,772	33,555	31,662	27,305	34,081	31,685	33,883	31,685	34,666	26,268	29,201
		HV, BTU/lb	11,510	14,426	13,612	11,739	14,652	13,622	14,567	13,622	14,904	11,294	12,554
Ultimate Analysis (Estimated)	Dry Basis	C, %	65.58	80.59	76.04	65.58	81.85	76.10	81.38	76.10	83.25	63.09	70.13
		H, %	4.20	5.16	4.87	4.20	5.24	4.87	5.21	4.87	5.32	4.04	4.49
		S, %	3.40	1.08	1.69	0.74	1.10	1.18	0.89	0.39	0.56	0.59	0.65
		O, %	2.19	5.06	4.67	4.86	5.88	6.04	6.86	6.83	7.34	6.27	6.89
		N, %	1.23	1.51	1.42	1.23	1.53	1.43	1.53	1.43	1.57	1.20	1.34
		Ash, %	23.40	5.80	11.31	23.40	4.39	10.38	4.13	10.38	1.95	24.81	16.50
	Dry, Ash-Free Basis	C, %	85.61	85.55	85.74	85.61	85.61	84.91	84.89	84.91	84.91	83.91	83.99
		H, %	5.48	5.48	5.49	5.48	5.48	5.43	5.43	5.43	5.43	5.37	5.38
		S, %	4.44	1.15	1.91	0.96	1.16	1.32	0.93	0.44	0.57	0.78	0.78
		O, %	2.87	6.22	5.26	6.35	6.15	6.74	7.15	7.62	7.49	8.34	8.25
		N, %	1.60	1.60	1.60	1.60	1.60	1.60	1.60	1.60	1.60	1.60	1.60
		HV, kJ/kg	35,646	35,620	35,699	35,646	35,646	35,355	35,344	35,355	35,355	34,931	34,971
		HV, BTU/lb	15,325	15,314	15,348	15,325	15,325	15,200	15,195	15,200	15,200	15,021	15,035

(Upper Freeport Seam, Butler County, Pennsylvania); low sulfur eastern coal (Eagle Seam, Buchanan County, Virginia); and low sulfur western coal (Primero Seam, Las Animas County, Colorado). Also listed are the proximate and ultimate analyses for the clean coal products from the physical and chemical processes discussed in Section 3 of this ITAR. The proximate analyses are given both on an as-received basis and a dry basis; and the ultimate analyses are given both on a dry basis and on a dry, ash-free basis.

The proximate analyses for each of the three raw coals are actual values, as presented earlier in Table 3-12, and form the basis for the remainder of Table 6-1. The conversion from as-received percentages to dry-basis percentages is:

$$X_{\text{Dry Basis}} = \frac{X_{\text{As-Received Basis}}}{1 - (\text{Percent Moisture}/100)};$$

where X is either the percentage of ash, total sulfur, or pyritic sulfur; or is the heating value (HV).

Similarly, for the ultimate analysis,

$$X_{\text{Dry, Ash-Free Basis}} = \frac{X_{\text{Dry Basis}}}{1 - [\text{Percent Ash (Dry Basis)}/100]}$$

Ultimate analyses were not available for the three specific raw coals, and were therefore estimated. First, the percent carbon (dry, ash-free basis) was calculated using the Uehling relationship for bituminous coals,[1]

$$\text{Percent Carbon (Dry, Ash-Free Basis)} = 100 \; \frac{\text{Heating Value (Dry, Ash-Free Basis), BTU/lb}}{17{,}900 \text{ BTU/lb}}$$

This simple relationship for estimating the ultimate analysis from the experimentally-determined heating value has been found to be accurate to within 2 percent for coals within a given rank. As a test of this predictive relationship, it was applied to ten bituminous coals for which the ultimate analysis had been experimentally determined:[2]

Group	State	County	Analysis, Dry, Ash-Free Basis C,%	H,%	O,%	N,%	S,%	HV, BTU/lb	Ratio H:C	Predicted C,%
Low-Vol.	WV	McDowell	90.4	4.8	2.7	1.3	0.8	15,670	0.053	87.5
Low-Vol.	PA	Cambria	89.4	4.8	2.4	1.5	1.9	15,615	0.054	87.2
Med-Vol.	PA	Somerset	88.6	4.8	3.1	1.6	1.9	15,540	0.054	86.8
Med-Vol.	PA	Indiana	87.6	5.2	3.3	1.4	2.5	15,630	0.059	87.3
High-Vol.A	PA	Westmoreland	85.0	5.4	5.8	1.7	2.1	15,265	0.064	85.3
High-Vol.A	KY	Pike	85.5	5.5	6.7	1.6	0.7	15,370	0.064	85.9
High-Vol.A	OH	Belmont	80.9	5.7	7.4	1.4	4.6	14,730	0.070	82.3
High-Vol.B	IL	Williamson	80.5	5.5	9.1	1.6	3.3	14,430	0.068	80.6
High-Vol.B	UT	Emergy	79.8	5.6	11.8	1.7	1.1	14,260	0.070	79.7
High-Vol.C	IL	Vermillion	79.2	5.7	9.5	1.5	4.1	14,400	0.072	80.4

For these ten coals, the root-mean-square difference between the measured and predicted values for percent carbon is 1.4 percent, verifying the accuracy of the Uehling relationship for bituminous coals.

Another Uehling relationship is that the ratio of hydrogen to carbon varies little among coals of the same rank.[3] From the above data for the ten bituminous coals, a value of 0.064 was adopted for this ratio, and the percent hydrogen was derived for the three raw coals of Table 6-1 from the percent carbon values. An additional relationship from the above data is that the nitrogen percentage (on a dry, ash-free basis) is relatively constant - a value of 1.6 percent was used in Table 6-1.

With these three relationships, the values for carbon, hydrogen, and nitrogen on a dry, ash-free basis were developed for the three raw coals. Since the total percent sulfur was known, the oxygen percentage was derived by difference, enabling the entire ultimate analysis to be estimated.

Similarly, the starting points for the products of physical coal cleaning (PCC) processes were the proximate analyses previously given in Tables 3-16, 3-17, and 3-18. The moisture contents for the PCC products for the low sulfur eastern and low sulfur western coals, not previously reported, were derived from the material flows shown on Figures 3-7 and 3-10 by using the same inherent moisture contents as the respective raw coals and by using the following appropriate values for surface moisture (as a function of size consist):

Coal Type	Product Stream No.	Size Consist	Surface Moisture, %
Low Sulfur Eastern	1	3/8 x 28M	6.0
	2	28M x 0	15.0
	3	1 1/4 x 3/8	4.0
Low Sulfur Western	1	1/4 x 0	9.0
	2	1 1/4 x 3/8	4.0

Since the physical coal cleaning processes do not change the inherent character of the "pure" coal, it was assumed that the relationships previously developed for raw coal ultimate analyses (on a dry, ash-free basis) also apply to cleaned coals; enabling Table 6-1 to be developed for these physically-cleaned coals.

Several additional assumptions were necessarily made for Table 6-1 to be completed for chemical coal cleaning (CCC), since proximate analyses were not previously given for the CCC products. First, it was assumed that the CCC products were dried to the same moisture levels as the raw coal feeds. It was assumed that the ERDA process results in the same percent ash as the raw coal feeds, but that the Gravichem process results in a product with 0.25 (first step) x 0.75 (second step) = 0.1875 of the ash content of the raw coal feeds. Further, it was assumed that CCC products had the same heating value and percentages of carbon, hydrogen, and nitrogen (on a dry, ash-free basis) as the raw coal feeds.

In the removal of mineral constituents not containing sulfur, it has been determined that some trace elements tend to be associated with the coal fraction and some (most) with the mineral fraction.[4,5,6,7] These distribute themselves between the coal and the waste with the distribution varying as a function of the specific gravity at which the separation is made. These fractionation factors also vary significantly among different coals and no generalized average or "standard" values are possible. As a result, the calculation of possible trace element emissions from the boiler cannot be performed and no trace element emission values will be presented in this analysis. The study results and their implications are discussed further in Section 6.2.1.4.

Combustion Stoichiometry

The ultimate analyses for the raw and cleaned coals are presented on Table 6-2 on a common basis of one kilogram of moisture-free fuel. These values, in grams of each element per kilogram of dry fuel, were converted to gram atoms per kilogram, from which the stoichiometric air requirements and major combustion products (CO_2, H_2O, and SO_2) were derived. Further, the oxygen and nitrogen in the combustion gases, and then the total moles and standard volumes of combustion gas, were calculated for 0, 30, and 50 percent excess air.

Also included in Table 6-2, at the 30 and 50 percent excess air levels, are the number of gram moles of NO_2, CO, and hydrocarbons as CH_4, per kilogram of fuel burned. The values for each of these secondary products, at each level of excess air, are constant regardless of fuel type. This was directly derived from the PEDCo-provided design parameters for standard boilers, summarized in Table 6-3, which stated an emission rate for NO_x, CO, and CH_4 directly proportional to the fuel feed rate for each boiler.[9] The molar quantities per kilogram of fuel shown in Table 6-2 correspond to the weight percentages in Table 6-3.

It may be argued that the quantities of these secondary products should be based upon the thermodynamic combustion of each fuel with the appropriate quantities of excess air. A rigorous approach would be to derive the equilibrium flame temperature for each fuel/air case of Table 6-2 from the heat of combustion of one kilogram of each fuel, and the heat capacities (as a function of temperature) and corresponding quanti-

TABLE 6-2. COMBUSTION STOICHIOMETRY OF RAW AND CLEANED COALS
BASIS: ONE KILOGRAM OF MOISTURE-FREE COAL FEED

		High-Sulfur Eastern Coal					Low-Sulfur Eastern Coal				Low-Sulfur Western Coal	
		Raw Coal	Deep-Cleaned PCC	Middling PCC	ERDA	Gravichem	Raw Coal	PCC Product	ERDA	Gravichem	Raw Coal	PCC Product
Coal Feed Basis	gms C	655.8	805.9	760.4	655.8	818.5	761.0	813.8	761.0	832.5	630.9	701.3
	gms H	42.0	51.6	48.7	42.0	52.4	48.7	52.1	48.7	53.2	40.4	44.9
	gms S	34.0	10.8	16.9	7.4	11.0	11.8	8.9	3.9	5.6	5.9	6.5
	gms O	21.9	58.6	46.7	48.6	58.8	60.4	68.6	68.3	73.4	62.7	68.9
	gms N	12.3	15.1	14.2	12.3	15.3	14.3	15.3	14.3	15.7	12.0	13.4
	gms Ash	234.0	58.0	113.1	234.0	43.9	103.8	41.3	103.8	19.5	248.1	165.0
	gms H_2O	52.6	98.9	97.6	52.6	52.6	20.4	80.7	20.4	20.4	25.6	77.8
	gm atoms C	54.60	67.10	63.31	54.60	68.15	63.36	67.76	63.36	69.32	52.53	58.39
	gm atoms H	41.67	51.19	48.31	41.67	51.98	48.31	51.69	48.31	52.78	40.08	44.54
	gm atoms S	1.0603	0.3368	0.5270	0.2308	0.3430	0.3680	0.2776	0.1216	0.1746	0.1840	0.2027
	gm atoms O	1.37	3.66	2.92	3.04	3.68	3.78	4.29	4.27	4.59	3.92	4.31
	gm atoms N	0.88	1.08	1.01	0.88	1.09	1.02	1.09	1.02	1.12	0.86	0.96
	gm moles H_2O	2.92	5.49	5.42	2.92	2.92	1.13	4.48	1.13	1.13	1.42	4.32
Stoichiometric Dry Air	gm moles O_2	65.39	78.41	74.46	63.73	79.65	73.92	78.82	73.42	80.39	60.77	67.57
	gm moles N_2	246.00	294.96	280.10	239.74	299.63	278.06	296.49	276.21	302.44	228.63	254.20
	gm moles Air	311.39	373.37	354.5[illegible]	303.47	379.28	351.98	375.31	349.64	382.83	289.40	321.77
Combustion Products	gm moles CO_2	54.60	67.10	63.31	54.60	68.15	63.36	67.76	63.36	69.32	52.53	58.39
	gm moles H_2O	23.76	31.09	29.58	23.76	28.91	25.29	30.33	25.29	27.52	21.46	26.59
	gm moles SO_2	1.0603	0.3368	0.5270	0.2308	0.3430	0.3680	0.2776	0.1216	0.1746	0.1840	0.2027
Products At 0% Excess Air	gm moles N_2	246.44	295.50	280.61	240.18	300.18	278.57	297.04	276.72	303.00	229.06	254.68
	Total gm moles	325.9	394.0	374.0	318.8	397.6	367.6	395.4	365.5	400.0	302.9	339.9
	Total Std m^3	7.305	8.831	8.383	7.146	8.912	8.240	8.863	8.193	8.965	6.789	7.619
Products At 30% Excess Air	gm moles O_2	19.62	23.52	22.34	19.11	23.90	22.18	23.65	22.03	24.12	18.23	20.27
	gm moles N_2	320.24	383.99	364.64	312.10	390.06	362.01	386.01	359.58	393.73	297.62	330.93
	gm moles NO_2	0.1956	0.1956	0.1956	0.1956	0.1956	0.1956	0.1956	0.1956	0.1956	0.1956	0.1956
	gm moles CO	0.01785	0.01785	0.01785	0.01785	0.01785	0.01785	0.01785	0.01785	0.01785	0.01785	0.01785
	gm moles CH_4	0.00935	0.00935	0.00935	0.00935	0.00935	0.00935	0.00935	0.00935	0.00935	0.00935	0.00935
	Total gm moles	419.3	506.0	480.4	409.8	511.4	473.2	508.0	470.4	514.9	389.7	436.4
	Total Std m^3	9.398	11.342	10.768	9.186	11.463	10.607	11.387	10,544	11.541	8.735	9.782
Products At 50% Excess Air	gm moles O_2	32.70	39.21	37.23	31.87	39.83	36.96	39.41	36.71	40.20	30.39	33.79
	gm moles N_2	369.44	442.98	420.66	360.05	449.99	417.63	445.31	414.83	454.22	343.35	381.77
	gm moles NO_2	0.1630	0.1630	0.1630	0.1630	0.1630	0.1630	0.1630	0.1630	0.1630	0.1630	0.1630
	gm moles CO	0.03570	0.03570	0.03570	0.03570	0.03570	0.03570	0.03570	0.03570	0.03570	0.03570	0.03570
	gm moles CH_4	0.03117	0.03117	0.03117	0.03117	0.03117	0.03117	0.03117	0.03117	0.03117	0.03117	0.03117
	Total gm moles	481.6	580.7	551.3	470.5	587.2	543.6	583.1	540.3	591.4	447.6	500.7
	Total Std m^3	10.795	13.016	12.357	10.546	13.162	12.185	13.070	12.111	13.256	10.033	11.223

TABLE 6-3 . RELEVANT CHARACTERISTICS OF THE REFERENCE COAL-FIRED INDUSTRIAL BOILERS
Source: Acurex Design Parameters for Standard Boilers

Boiler Specifications					Uncontrolled Flue Gas Constituents				
No.	Boiler Type	Heat Input Rate		Excess Air, Percent	Flyash % of Coal Ash	SO_2, % of Coal SO_2	NO_x, % of Coal Feed	CO, % of Coal Feed	HC as CH_4, % of Coal Feed
		kW	10^6 BTU/hr						
1	Package, Water-tube, Underfeed Stoker	8,790	30	50	25.0	95.0	0.75	0.10	0.05
2	Package, Water-tube, Chain Grate	21,975	75	50	25.0	95.0	0.75	0.10	0.05
3	Field-Erected, Watertube, Spreader Stoker	43,950	150	50	65.0	95.0	0.75	0.10	0.05
4	Field-Erected, Watertube, Pulverized Coal	58,600	200	30	80.0	95.0	0.90	0.05	0.015

ties of the combustion products, including ash and moisture. The equilibrium constants for NO_2, NO, CO, and CH_4 may then be evaluated (from the free energy change) at that flame temperature, enabling the calculation of equilibrium concentrations of these secondary products. Short of this rigorous approach, it may also be argued that the quantities could be assumed directly proportional to the heat input rate for each boiler rather than to the fuel feed rate.

After consideration of these alternative approaches, the values for NO_x, CO, and CH_4 shown in Table 6-2 (and subsequently used to derive emission rates) were chosen to be consistent with the PEDCo values implicit in their "Design Parameters for Standard Boilers".[19]

Calculations of Emission Rates

Tables F-1 through F-4 in Appendix F, list the gross emission rates (for each pollutant and for each fuel), respectively, for each of the four standard industrial boilers. The derivation of each column in these tables begins with the calculation of the dry coal feed rate, kg/s, by dividing the boiler heat input rate in kJ/s by the dry coal heating value in kJ/kg. This dry coal feed rate is then the multiplier for the values in each column of Table 6-2 (which are based upon one kilogram of dry coal feed), to derive the rates shown in Tables F-1 through F-4.

The total ash values of Tables F-1 through F-4 are the quantities in the coal feed; the flyash values were derived from the fraction (specific to each boiler) defined by PEDCo and summarized in Table 6-3. Also in accordance with PEDCo, assumptions, the SO_2 values in Tables F-1 through F-4 are 95 percent of the stoichiometric quantities. [10]

Presentation of Emission Rates

The final results of these calculations are presented in Table 6-8. The uncontrolled case and the SIP case have been added to the BSER boiler/control level cases (defined in Table 3-22). Those boiler/control combinations in Tables F-1 through F-4 which were not selected as BSER combinations are not included in Table 6-4.

Table 6-4. Air Pollution Impacts from "Best" SO_2 and Particulate Control Techniques for Coal-Fired Boilers

SYSTEM								EMISSIONS									
Coal Type	Standard Boiler		Control Level	SO_2 Control		Particulate Pct. Reduction		SO_2		Particulates		NO_x		CO		HC as CH_4	
	Heat Input MW(10^6 Btu/hr)	Type		Type	Pct Reduction	Coal Cleaning	ESP	$\frac{g}{s}$	$\frac{ng}{J}$	$\frac{g}{s}$	$\frac{ng}{J}$	$\frac{g}{s}$	$\frac{ng}{J}$	$\frac{g}{s}$	$\frac{ng}{J}$	$\frac{g}{s}$	$\frac{ng}{J}$
High-Sulfur Eastern Coal	8.79(30)	Underfeed Stoker	Uncontrolled	Raw Coal	0	0	0	21.54	2451	19.62	2233	2.46	280	0.328	37.3	0.164	18.7
			SIP	PCCV Middling	57.1	58.3	71.1	8.91	1013	2.268	258.0	2.08	237	0.278	31.6	0.139	15.8
			Moderate	PCCV Middling	57.1	58.3	88.0	8.91	1013	0.945	107.5	2.08	237	0.278	31.6	0.139	15.8
			Intermediate	PCCV Deep-Cl.	74.1	79.8	90.1	5.37	611	0.378	43.0	1.97	223	0.262	29.8	0.131	14.9
			Stringent	CCC-ERDA	78.2	0	99.4	4.52	514	0.113	12.9	2.41	275				
	21.975(75)	Chain Grate	Uncontrolled	Raw Coal	0	0	0	53.84	2451	49.06	2233	6.16	280	0.822	37.3	0.411	18.7
			SIP	PCCV Middling	57.1	58.3	71.1	22.26	1013	5.670	258.0	5.20	237	0.695	31.6	0.347	15.8
			Moderate	PCCV Middling	57.1	58.3	88.0	22.26	1013	2.362	107.5	5.20	237	0.695	31.6	0.347	15.8
			Intermediate	PCCV Deep-Cl.	74.1	79.8	90.1	13.42	611	0.945	43.0	4.91	223	0.655	29.8	0.327	14.9
			Stringent	CCC-ERDA	78.2	0	99.4	11.31	514	0.283	12.9	6.04	275	0.804	36.6	0.403	18.3
	43.95(150)	Spreader Stoker	Uncontrolled	Raw Coal	0	0	0	107.68	2451	255.09	5806	12.32	280	1.643	37.3	0.822	18.7
			SIP	PCCV Middling	57.1	58.3	88.9	44.53	1013	11.339	258.0	10.41	237	1.389	31.6	0.695	15.8
			Moderate	PCCV Middling	57.1	58.3	95.4	44.53	1013	4.724	107.5	10.41	237	1.389	31.6	0.695	15.8
			Intermediate	PCCV Deep-Cl.	74.1	79.8	96.2	26.85	611	1.890	43.0	9.82	223	1.311	29.8	0.655	14.9
			Stringent	CCC-ERDA	78.2	0	99.8	22.61	514	0.567	12.9	12.07	275	1.611	36.6	0.805	18.3
	58.60(200)	Pulverized Coal	Uncontrolled	Raw Coal	0	0	0	143.57	2451	418.61	7146	19.71	336	1.095	18.7	0.328	5.60
			SIP	PCCV Middling	57.1	58.3	91.0	59.36	1013	15.119	258.0	16.65	284	0.924	15.8	0.278	4.74
			Moderate	PCCV Middling	57.1	58.3	96.2	59.36	1013	6.298	107.5	16.65	284	0.924	15.8	0.278	4.74
			Intermediate	PCCV Deep-Cl.	74.1	79.8	96.9	35.80	611	2.520	43.0	15.72	268	0.874	14.9	0.261	4.45
			Stringent	CCC-ERDA	78.2	0	99.8	30.15	514	0.756	12.9	19.31	330	1.073	18.3	0.322	5.49

Table 6-4. Air Pollution Impacts from "Best" SO_2 and Particulate Control Techniques for Coal-Fired Boilers (Con't)

Coal Type (SYSTEM)	Standard Boiler: Heat Input MW(10^6 Btu/hr)	Standard Boiler: Type	Control Level	SO_2 Control: Type	SO_2 Control: Pct. Reduction	Particulate Pct. Reduction: Coal Cleaning	Particulate Pct. Reduction: ESP	EMISSIONS SO_2 $\frac{g}{s}$	SO_2 $\frac{ng}{J}$	Particulates $\frac{g}{s}$	Particulates $\frac{ng}{J}$	NO_x $\frac{g}{s}$	NO_x $\frac{ng}{J}$	CO $\frac{g}{s}$	CO $\frac{ng}{J}$	HC as CH_4 $\frac{g}{s}$	HC as CH_4 $\frac{ng}{J}$
Low-Sulfur Eastern Coal	8.79(30)	Underfeed Stoker	Uncontrolled	Raw Coal	0	0	0	6.21	707	7.20	819.1	2.08	237	0.277	31.6	0.139	15.8
			SIP	Raw Coal	0	0	68.5	6.21	707	2.268	258.0	2.08	237	0.277	31.6	0.139	15.8
			Moderate	Raw Coal	0	0	86.9	6.21	707	0.945	107.5	2.08	237	0.277	31.6	0.139	15.8
			Intermediate	PCC IV	29.5	62.8	85.9	4.38	499	0.378	43.0	1.95	221	0.259	29.6	0.130	14.7
			Stringent	PCC IV	29.5	62.8	95.8	4.38	499	0.113	12.9	1.95	221	0.259	29.6	0.130	14.7
	21.975(75)	Chain Grate	Uncontrolled	Raw Coal	0	0	0	15.53	707	18.00	819.1	5.20	237	0.695	31.6	0.347	15.8
			SIP	Raw Coal	0	0	68.5	15.53	707	5.670	258.0	5.20	237	0.695	31.6	0.347	15.8
			Moderate	Raw Coal	0	0	86.9	15.53	707	2.362	107.5	5.20	237	0.695	31.6	0.347	15.8
			Intermediate	PCC IV	29.5	62.8	85.9	10.96	499	0.945	43.0	4.86	221	0.650	29.6	0.324	14.7
			Stringent	PCC IV	29.5	62.8	95.8	10.96	499	0.283	12.9	4.86	221	0.650	29.6	0.324	14.7
	43.95(150)	Spreader Stoker	Uncontrolled	Raw Coal	0	0	0	31.07	707	93.6	2130	10.40	237	1.386	31.6	0.693	15.8
			SIP	Raw Coal	0	0	87.9	31.07	707	11.339	258.0	10.40	237	1.386	31.6	0.693	15.8
			Moderate	Raw Coal	0	0	95.0	31.07	707	4.724	107.5	10.40	237	1.386	31.6	0.693	15.8
			Intermediate	PCC IV	29.5	62.8	94.6	21.92	499	1.890	43.0	9.73	221	1.297	29.6	0.648	14.7
			Stringent	PCC IV	29.5	62.8	98.4	21.92	499	0.567	12.9	9.73	221	1.297	29.6	0.648	14.7
	58.60(200)	Pulverized Coal	Uncontrolled	Raw Coal	0	0	0	41.43	707	153.6	2621	16.65	284	0.924	23.7	0.278	4.74
			SIP	Raw Coal	0	0	90.2	41.43	707	15.119	258.0	16.65	284	0.924	23.7	0.278	4.74
			Moderate	Raw Coal	0	0	95.9	41.43	707	6.298	107.5	16.65	284	0.924	23.7	0.278	4.74
			Intermediate	PCC IV	29.5	62.8	95.6	29.22	499	2.520	43.0	15.56	266	0.866	22.1	0.260	4.44
			Stringent	PCC IV	29.5	62.8	98.7	29.22	499	0.756	12.9	15.56	266	0.866	22.1	0.260	4.44

Table 6-4. Air Pollution Impacts from "Best" SO_2 and Particulate Control Techniques for Coal-Fired Boilers (Con't)

SYSTEM								EMISSIONS									
Coal Type	Standard Boiler		Control Level	SO_2 Control		Particulate Pct. Reduction		SO_2		Particulates		NO_x		CO		HC as CH_4	
	Heat Input MW(10^6 Btu/hr)	Type		Type	Pct. Reduction	Coal Cleaning	ESP	g/s	ng/J	g/s	ng/J	g/s	ng/J	g/s	ng/J	g/s	ng/J
Low-Sulfur Western Coal	8.79 (30)	Underfeed Stoker	Controlled	Raw Coal	0	0	0	3.75	426	20.75	2361	2.51	286	0.335	38.0	0.167	19.1
			SIP	Raw Coal	0	0	89.1	3.75	426	2.268	258.0	2.51	286	0.335	38.0	0.167	19.1
			Moderate	Raw Coal	0	0	95.4	3.75	426	0.945	107.5	2.51	286	0.335	38.0	0.167	19.1
			Intermediate	Raw Coal	0	0	98.2	3.75	426	0.378	43.0	2.51	286	0.335	38.0	0.167	19.1
			Stringent	Raw Coal	0	0	99.5	3.75	426	0.113	12.9	2.51	286	0.335	38.0	0.167	19.1
	21.975 (75)	Chain Gate	Uncontrolled	Raw Coal	0	0	0	9.37	426	51.89	2361	6.28	286	0.837	38.0	0.419	19.1
			SIP	Raw Coal	0	0	89.1	9.37	426	5.670	258.0	6.28	286	0.837	38.0	0.419	19.1
			Moderate	Raw Coal	0	0	95.4	9.37	426	2.362	107.5	6.28	286	0.837	38.0	0.419	19.1
			Intermediate	Raw Coal	0	0	98.2	9.37	426	0.945	43.0	6.28	286	0.837	38.0	0.419	19.1
			Stringent	Raw Coal	0	0	99.5	9.37	426	0.283	12.9	6.28	286	0.837	38.0	0.419	19.1
	43.95 (150)	Spreader Stoker	Uncontrolled	Raw Coal	0	0	0	18.74	426	269.8	6139	12.55	286	1.672	38.0	0.837	19.1
			SIP	Raw Coal	0	0	95.8	18.74	426	11.339	258.0	12.55	286	1.672	38.0	0.837	19.1
			Moderate	Raw Coal	0	0	98.2	18.74	426	4.724	107.5	12.55	286	1.672	38.0	0.837	19.1
			Intermediate	Raw Coal	0	0	99.3	18.74	426	1.890	43.0	12.55	286	1.672	38.0	0.837	19.1
			Stringent	Raw Coal	0	0	99.8	18.74	426	0.567	12.9	12.55	286	1.672	38.0	0.837	19.1
	58.60 (200)	Pulverized Coal	Uncontrolled	Raw Coal	0	0	0	24.99	426	442.8	4604	20.08	343	1.115	19.0	0.335	5.72
			SIP	Raw Coal	0	0	94.4	24.99	426	15.119	258.0	20.08	343	1.115	19.0	0.335	5.72
			Moderate	Raw Coal	0	0	97.7	24.99	426	6.298	107.5	20.08	343	1.115	19.0	0.335	5.72
			Intermediate	Raw Coal	0	0	99.1	24.99	426	2.520	43.0	20.08	343	1.115	19.0	0.335	5.72
			Stringent	Raw Coal	0	0	99.7	24.99	426	0.756	12.9	20.08	343	1.115	19.0	0.335	5.72

6.2.1.2 Discussion of Air Pollution Impacts--

Sulfur Dioxide

The SO_2 emissions data in Table 6-4 show that the stringent SO_2 emission control level of 516 ng/J (1.2 $lb/10^6$ BTU) may be achieved for the two Eastern representative coals through application of physical or chemical coal cleaning technologies. This stringent control level is directly achieved by the raw low sulfur western coal. The intermediate control level of 645 ng/J (1.5 $lb/10^6$ BTU) is met, for the Eastern coals, with physical coal cleaning technologies, without the necessity for chemical cleaning.

Particulates

Although physical and chemical coal cleaning technologies remove considerable quantities of ash from the coal, the residual amounts must still be controlled to meet the following control levels:

SIP	258.0 ng/J	(0.60 $lb/10^6$ BTU)
Moderate	107.5 ng/J	(0.25 $lb/10^6$ BTU)
Intermediate	43.0 ng/J	(0.10 $lb/10^6$ BTU)
Stringent	12.9 ng/J	(0.03 $lb/10^6$ BTU)

Table 6-4 lists two removal efficiences for particulates: the percent reduction of the raw coal ash content achieved by coal cleaning; and the percent reduction of the flyash required, by an ESP or other control, to meet the appropriate particulate emission control level. A third factor is the fraction of the fuel ash content which is removed as bottom ash: this boiler-specific factor, defined by PEDCo is in Table 6-3.

The particulate emission rates in Table 6-4 are equivalent to the appropriate emission control levels, implying that the effectiveness of post-combustion particulate control devices is tailored (through design and operation) to achieve these levels. Under this strategy, there is no differential air pollution particulate impact resulting from coal cleaning as a sulfur dioxide control technology.

Nitrogen Oxides, Carbon Monoxide, and Hydrocarbons

The section on combustion stoichiometry contained a brief discussion of the validity of the method for determining the emission rates for NO_x, CO, and hydrocarbons which are listed in Table 6-4. The selected method, based upon PEDco definitions of reference boiler design parameters, results in a reduction of emissions for these substances from removal of ash by coal cleaning processes. This calculated reduction in emissions approaches 20 percent in those cases where coal cleaning removes large quantities of ash.

However, the alternate estimating method - where emissions of NO_x, CO, and hydrocarbons are directly proportional to heat input rate rather than to coal feed rate - would result in no differential impact of coal cleaning. It is observed, from Tables F-1 through F-4, that for a given reference boiler (and its constant heat input rate), the total gram moles per second or standard cubic meters per second of gaseous emissions varies little with coal type and with level of cleaning. Moreover, the molar composition of the emissions also is fairly constant. With large quantities of excess air, the total heat capacity of the ash is a very small fraction of the total heat capacity of gaseous combustion products, so that varying quantities of ash should not have a significant effect upon the equilibrium flame temperature.

Based upon the above considerations, it is concluded that there is minimal differential impact of coal cleaning upon NO_x, CO, and hydrocarbons emissions.

Air Emission Sensitivity Analysis

Air emissions from the combustion of cleaned coal in various sized boilers, include SO_x, NO_x, CO, and HC. Progressive reduction of SO_x emissions from boilers is accomplished with increased cleaning of sulfur from the raw coal, however, as we stated above, there is minimal differential impact of coal cleaning upon NO_x, CO, and hydrocarbons emissions. Emission differences from different sized boilers are also minimal.

In the case of stoker fired boilers (8.8, 22, and 44 MW) the size of the boiler has a negligible effect upon the normalized quantity (i.e., ng/J) of emissions (see Table 6-5). The emission rate is inherent to the coal type used, whether it be raw or cleaned. The same scenario applies to pulverized fired boilers (58.6 and 73 MW and 118 MW) such that the levels of emissions per Joule remain constant for each boiler size. However, differences do exist in emission levels of pollutants between the two boiler types. For example, carbon monoxide and hydrocarbon emissions from coal combustion are noticeably lower from pulverized boilers than from stoker fired boilers (i.e., 50% lower for CO and 70% lower for Hydrocarbons). The opposite is true for NO_x emissions since emissions are 17% higher from pulverized boilers than from stoker fired boilers. SO_x emissions remain constant for both stoker and pulverized fired boilers.

6.2.1.3 Differential Impacts Compared to SIP-Controlled Boilers--

Table 6-6 lists the emissions at the SIP control level, taken directly from Table 6-4, and also lists the differential emissions for each coal type when BSER coal cleaning technologies are applied.

The reductions in particulate emissions, from the SIP control level to the moderate, intermediate and stringent control levels, are (respectively) 58 percent, 83 percent, and 95 percent. They are the same regardless of fuel type or boiler type and size; and are achieved by combinations of coal cleaning ash removal and post-combustion particulate control devices.

For other than particulate emissions, no reduction occurs between the SIP control level and the moderate control level. For all three coal types, the same control technologies and degrees of application were used for both levels. Moreover, since the raw low sulfur western coal meets the

TABLE 6-5. SENSITIVITY ANALYSIS

Emission Values Shown in Tables are Constants for Their Respective Boiler Types

I. Air Emissions (ng/J)

A. High Sulfur Eastern Coal

Type of Control		Stoker Boiler (8.8 MW, 22 MW, 44 MW)	Pulverized Boiler (58.6 MW, 73 MW, 118 MW)
SO_x:	Raw Coal	2451	2451
	PCC V Middlings	1013	1013
	PCC V Deep-Cl.	611	611
	CCC - ERDA	514	514
NO_x:	Raw Coal	275	336
	PCC V MID	237	284
	PCC V Deep-Cl.	223	268
	CCC - ERDA	275	330
CO:	Raw Coal	36.6	18.7
	PCC V MID	31.6	15.8
	PCC V Deep Cl.	29.8	14.9
	CCC - ERDA	36.6 *	18.3
HC:	Raw Coal	18.3	5.60
	PCC V MID.	15.8	4.74
	PCC V Deep Cl.	14.9	4.45
	CCC - ERDA	18.3 *	5.49

* Does not include 8.8 MW

TABLE 6-5. SENSITIVITY ANALYSIS (continued)

B. Low Sulfur Eastern Coal

Type of Control		Stoker Boiler (8.8 MW, 22 MW, 44 MW)	Pulverized Boiler (58.6 MW, 73 MW)
SO_x:	Raw Coal	707	707
	PCC IV	499	499
NO_x:	Raw Coal	237	284
	PCC IV	221	266
CO:	Raw Coal	31.6	23.7
	PCC IV	29.6	22.1
HC:	Raw Coal	15.8	4.74
	PCC IV	14.7	4.44

C. Low Sulfur Western Coal

Type of Control		Stoker Boiler (8.8 MW, 22 MW, 44 MW)	Pulverized Boiler (58.6 MW, 73 MW)
SO_x:	Raw Coal	426	426
NO_x:	Raw Coal	286	343
CO:	Raw Coal	38.0	19.0
HC:	Raw Coal	19.1	5.72

TABLE 6-6. DIFFERENTIAL IMPACTS COMPARED TO SIP - CONTROLLED BOILERS

Coal Type		High-Sulfur Eastern Coal				Low-Sulfur Eastern Coal				Low-Sulfur Western Coal			
Control Level	MW / Pollutant	8.8 / 30	22 / 75	44 / 150	58.6 / 200	8.8 / 30	22 / 75	44 / 150	58.6 / 200	8.8 / 30	22 / 75	44 / 150	58.6 / 200
Emissions at SIP Level ng/J	SO_2	1,013	1,013	1,013	1,013	707	707	707	708	426	426	426	426
	Part.	258	258	258	258	258	258	258	258	258	258	258	258
	NO_x	237	237	237	284	237	237	237	284	286	286	286	343
	CO	31.6	31.6	31.6	15.8	31.6	31.6	31.6	23.7	38.0	38.0	38.0	19.0
	HC	15.8	15.8	15.8	4.74	15.8	15.8	15.8	4.74	19.1	19.1	19.1	5.72
Emission Reductions at Moderate Level, ng/J	SO_2	0	0	0	0	0	0	0	0	0	0	0	0
	Part.	150.5	150.5	150.5	150.5	150.5	150.5	150.5	150.5	150.5	150.5	150.5	150.5
	NO_x	0	0	0	0	0	0	0	0	0	0	0	0
	CO	0	0	0	0	0	0	0	0	0	0	0	0
	HC	0	0	0	0	0	0	0	0	0	0	0	0
Emission Reductions at Intermediate Level ng/J	SO_2	402	402	402	402	208	208	208	208	0	0	0	0
	Part.	215	215	215	215	215	215	215	215	215	215	215	215
	NO_x	14	14	14	16	16	16	16	18	0	0	0	0
	CO	1.8	1.8	1.8	0.9	2.0	2.0	2.0	1.6	0	0	0	0
	HC	0.9	0.9	0.9	0.29	1.1	1.1	1.1	0.30	0	0	0	0
Emission Reductions at Stringent Level, ng/J	SO_2	499	499	499	499	208	208	208	208	0	0	0	0
	Part.	245.1	245.1	245.1	245.1	245.1	245.1	245.1	245.1	245.1	245.1	245.1	245.1
	NO_x	0	0	0	0	16	16	16	18	0	0	0	0
	CO	0	0	0	0	2.0	2.0	2.0	1.6	0	0	0	0
	HC	0	0	0	0	1.1	1.1	1.1	0.30	0	0	0	0

stringent emission level (for SO_2) without cleaning, no differential exists among all the control levels for SO_2, NO_x, CO, and hydrocarbons for this coal type.

At the intermediate control level, the SO_2 emission reductions compared to the SIP control level are 40 percent for the high sulfur eastern coal and 30 percent for the low sulfur eastern coal. The NO_x, CO, and hydrocarbon emission reductions are about 7 percent for both the high sulfur and low sulfur eastern coals.

At the stringent control level, the SO_2 emission reductions compared to the SIP control level are 49 percent for the high sulfur eastern coal and 30 percent (the same as the intermediate differential) for the low sulfur eastern coal. For the high sulfur eastern coal, no change occurs (between the SIP and stringent levels) in NO_x, CO, and hydrocarbon emissions, because the ERDA chemical coal cleaning technology employed to achieve the stringent SO_2 emission level is much less effective in reducing ash content than physical coal cleaning techniques. For the low sulfur eastern coal, the differentials in NO_x, CO, and hydrocarbon emissions are the same for the stringent level as for the intermediate level.

6.2.1.4 Further Reduction of Boiler Emissions—Sulfur Dioxide

In the preceding discussion the effectiveness of SO_2 controls by coal cleaning was shown to depend upon the washability characteristics of the raw coal and upon the level of coal cleaning technology selected. For controlling SO_2 emissions from the representative high sulfur eastern coal, the level of coal cleaning required to meet the stringent emission standard of 516 ng/J (1.20) lb/10^6 BTU) was close to the most advanced techniques available - chemical coal cleaning with removal of some organic sulfur as well as most pyritic sulfur. In this case, there is little potential (with presently-available technology) for further reducing the SO_2 emissions beyond the stringent control level.

However, coal cleaning could be more effective than shown in Tables 6-4 and 6-6 when applied to the two low-sulfur coal types. For the low-sulfur eastern coal, the stringent emission control level was achieved using level 4 physical coal cleaning technology. The application of deeper physical cleaning techniques or of chemical cleaning techniques to this representative raw coal could substantially reduce the SO_2 emissions. Based upon the calculations in Tables F-1 through F-4 the application of the ERDA chemical coal cleaning process to the low-sulfur eastern coal could result in a SO_2 emission level of 233 ng/J (0.54 lb/10^6BTU). For the low-sulfur western coal, an emissions level of 426 ng/J (0.99 lb/10^6BTU) was achieved without any cleaning. If deep physical coal cleaning or chemical coal cleaning technologies were applied to this raw coal, the SO_2 emissions might be reduced by 50 percent.

The potential for SO_2 emission reductions indicated by the above discussion may be extended, for any particular industrial boiler, through the application of fuel blending techniques. Some cleaned low-sulfur eastern coal or some low-sulfur western coal, for example, might be blended with deep physically-cleaned high-sulfur eastern coal to achieve the most stringent emission control levels with out necessitating the more costly chemical coal cleaning technologies.

Further, the application of pre-combustion coal cleaning technologies for SO_2 control does not preclude the use of other technologies (fluidized bed combustion or flue gas desulfurization) for achieving further SO_2 reductions. Alternatively, the application of a combination of technologies for achieving a stringent SO_2 emission control level might prove less costly than either alone.

Particulates

Table 6-4 lists the particulate emissions consistent with SIP, moderate, intermediate, and stringent control levels, and the required removal efficiencies of electrostatic precipitators (or other post-combustion control devices). Further reductions in particulates emissions may be achieved if higher ESP efficiencies are specified in the selection of such units.

Alternatively, lower particulates emissions may be achieved with an existing ESP unit by utilizing physical coal cleaning processes which remove greater percentages of the ash from the raw coal. Two applications are immediately evident from the "particulate percent removal-coal cleaning" column of Table 6-4. First, the zero-percent ash removal from low-sulfur western coal is a consequence of the fact that the stringent SO_2 control level is met without requiring coal cleaning. The high (24.81 percent) ash content of this raw coal could readily be reduced by more than 50 percent by physical coal cleaning techniques. This would reduce boiler particulate emissions without requiring increased ESP efficiency. Such ash removal via coal cleaning may be economically justified solely on the basis of reduced coal transportation costs.

Second, the stringent SO_2 control level is met for the high-sulfur eastern coal through application of the ERDA chemical coal cleaning process, which does not result in a high removal of ash from the raw coal. By using physical coal cleaning techniques prior to ERDA process, large reductions in coal ash (and thus in boiler particulate emissions for a given ESP efficiency) may be achieved. This initial cleaning step may be economically justified on the basis of reduced throughput requirements for chemical coal cleaning process equipment.

<u>Nitrogen Oxides, Carbon Monoxide, and Hydrocarbons</u>

The use of greater amounts of excess air in the boiler is a technique for reducing the emissions of carbon monoxide and hydrocarbons by promoting more complete combustion. However, this technique results in lower boiler efficiencies due to the greater heat loss in the flue gas. Boiler design and operation technology, including proper maintenance, are utilized for achieving more complete combustion and thereby reducing the CO and hydrocarbon emissions.

The emission factors specified by Acurex for the standard boilers, which are summarized in Table 6-3, include a higher NO_x emission at reduced excess air. This factor is 0.90 percent of the coal feed at 30 percent excess air, compared with 0.75 percent of the coal feed at 50 percent excess air. Equilibrium flame temperatures are higher at reduced quantities of excess air, resulting in a significantly higher equilibrium constant for the production of NO_x from nitrogen and oxygen. Since the rate of NO_x dissociation is normally not high enough to reestablish equilibrium upon cooling of the combustion gases, NO_x emissions are highly sensitive to the peak temperature experienced in the boiler. Effective NO_x controls currently used limit the peak temperature through two-stage combustion.

6.2.1.5 Emission of Toxic Substances--

The unburned hydrocarbons in boiler emissions include specific substances identified as potential carcinogens. These substances are the pyrolysis products of the polyaromatic hydrocarbons in the feed coal. The key towards minimizing emissions of hazardous organics is in achieving more complete combustion, through improved boiler design, operation and maintenance, and to some extent through the use of larger excess air quantities. To the extent that coal cleaning improves boiler operation by providing a fuel with much lower quantities of ash (and the subsequent slag), this technology might aid in the reduction of toxic organic substance emissions.

With regard to the air pollution impact of trace elements in coal, two partitioning processes must be considered: the fate of these elements in the coal cleaning process, which determines how much of each element originally in the raw coal reports in the clean coal product; and the fate of the elements in the combustion process, which determines how much of each element originally in the fuel reports in the particulate emissions from the boiler.

Several studies have been published on the distribution of trace elements in coal cleaning processes, Ruch, et.al.(11), Gluskoter, et.al.(12), and Schultz, et.al.(13) have reported that float-sink separation of mineral matter (including pyrite) from coal results in a general partitioning of heavy metals to the refuse (sink) fraction, leaving the clean coal (float) fraction with relatively lower heavy metal concentrations. However, the results are considerably different from one coal to another. Hamersma, et.al.(14) reported on the distribution of trace elements between refuse and cleaned coal in the Meyers chemical coal cleaning process, with results similar to those for physical coal cleaning separations. At this point in time, it is judged that trace element partitioning data exists on too few coal samples to quantitatively extrapolate the published data to the three reference coals considered in this study.

The second partitioning process is the distribution of trace elements between emissions (gaseous and emitted fly ash) and collected ash (bottom ash plus collected fly ash). Klein, et.al.[15] and Yost, et.al.[16] studied the pathways of trace elements through coal-fired boilers. The results indicate that those metals whose oxides are relatively volatile (arsenic, cadmium, lead, zinc, mercury) form smaller particles upon recondensation and are more likely to escape collection by an ESP. Again, the quantitative extrapolation of these results to the reference coals and to the reference industrial boilers is not justified at this point.

Qualitatively, however, it may be concluded that coal cleaning reduces the emissions of trace elements from coal-fired boilers via two mechanisms. First, the preliminary studies indicate that the coal cleaning processes reduce the concentration of many elements in the coal product. Second, the heating value enhancement of coal results in less fuel quantity required at a given boiler input heat rate. This means that lesser amounts of trace elements would be delivered to the boiler even if coal cleaning did not change the trace element concentration in the fuel.

6.2.1.6. Air Pollution Impacts from Coal Cleaning Plants—

Since all physical coal cleaning process unit operations, exluding crushing and sizing, for the three reference coals are wet operations, the major air pollution impact from these processes are the fugitive emissions from coal storage piles and from coal conveying and loading operations. A recent EPA-sponsored program[17] has developed factors for fugitive emissions from coal storage piles, based on an extensive field sampling program. The estimating equation takes into account major influencing parameters, including wind speed, surface area of the pile, coal density, and the regional precipitation-evaporation (P-E) index, all site-specific parameters. Thus, it is clear that universally-applicable emission factors cannot be developed. The average factor for all of the field data was reported to be 0.0065 g/kg (0.013 lb/ton) in storage per year. This value, however, should be used with caution because of large observed variations.

At this stage of development of chemical coal cleaning process, air pollution impacts have neither been formally identified nor quantified.

In recognition of the significant air pollution impacts from thermal dryers, none of the coal cleaning processes identified as BSERs in Section 3 have employed thermal drying. Instead, the clean coal product moisture content has been controlled to approximately 7 to 9 percent by mechanical dewatering (centrifuging) of individual clean coal streams, each of a different size consist, and then by blending the several streams in predetermined proportions.

A recent trade-off study of dewatering and drying, conducted by Versar, Inc. for EPA, determined that mechanical dewatering was generally preferable to thermal drying on economic grounds, without considering the environmental impacts of these alternative operations. For both economic and environmental reasons, therefore, thermal drying was not included in the Best Systems of Emission Reduction; and consequently, there are no air pollution impacts attributable to thermal drying.

6.3 WATER POLLUTION

6.3.1 Emissions of Water Pollutants from Coal Cleaning

Most coal cleaning operations are performed in aqueous media, which accumulate suspended and dissolved substances. The water pollutants directly associated with the cleaning of coal are primarily dissolved and suspended solids. The dissolved solids are mostly inorganic elements and compounds leached from the ash fraction during the cleaning process. Typically physical coal cleaning plants discharge refuse pond (i.e. recycle pond) overflow, and drainage from coal storage and refuse piles. Modern PCC plants attempt to maximize water recycle.

Data available are insufficient to define the composition and quantities of effluents as a function of coal type or coal cleaning process variations. The best data available are from an unpublished study by Versar performed for the EPA.[18] The objective of the study was to determine the best available technology (BAT) for wastewater pollutants from the coal mining and preparation point source category. As a part of this study, Versar was required to perform screening sampling and analysis for 65 classes of compounds.

In the screening sampling phase of this study, 18 coal preparation plants associated with mines were visited and wastewater samples were obtained from 7 of these facilities. In addition, samples of wastewater were obtained from auxiliary areas such as refuse pile drainage from 5 of these facilities. The results of the screening sampling phase are presented in Table 6-7 through 6-9 for cleaning levels 2 and 4.[19]

The process water raw waste characteristics of coal preparation plants depend upon the particular process or recovery technique used and possibly the coal processed. Since processing methods require an alkaline media for efficient and economic operation, process water does not appear to contain significant amounts of metallic minerals present in the raw coal. The principal pollutant in preparation plant water is suspended solids.

TABLE 6-7. ANALYSES OF WASTEWATERS AND TREATED STREAMS FROM LEVEL 2 PLANTS - WATER QUALITY AND METAL PARAMETERS

	Plant NC 10	Plant NC 17		Plant NC 22			
Parameter (mg/l)	Prep Plant Recycle Water	Slurry Pond Effluent	in (Kg/day)	Prep Plant Drag Tank Raw Water	in (Kg/day)	Slurry Pond Effluent	in (Kg/day)
Total Solids	850	530	4911	9,600	17,440	1,100	839.4
Total Suspended Solids	4.0	24	222.4	7,800	14,170	7.4	5.64
Total Volatile Solids	38	94	871	3,200	5,814	150	114.5
Volatile Suspended Solids	1.6	22	203.8	2,000	3,634	3.6	2.75
COD	4.0	31	287.2	4,861	8,831	20.6	15.72
TOC	2.0	25	231.6	1,130	2,053	3.2	2.44
pH	8.1	7.1	--	6.78	--	8.20	--
Metals (mg/l)	--	--	--	--	--	--	--
Aluminum	<0.099	0.747	6.92	300	545	<0.099	
Antimony	.002	<0.001		0.021	.038	0.001	.00076
Arsenic	.008	0.002	.01853	0.065	.118	0.007	.0053
Barium	.025	0.068	.6301	2.0	3.63	0.025	.019
Beryllium	<0.002	<0.002		<0.02		<0.002	
Boron	0.055	0.046	--	<0.050		0.085	.065
Cadmium	<0.02	<0.02		<0.20		<0.02	
Calcium	55.3	13.3	123.2	268	486.9	175	133.5
Chromium	<0.024	<0.024		0.44	.799	0.036	.0275
Cobalt	<0.01	<0.01		<0.10		<.01	
Copper	<.004	0.05	.0463	0.21	.382	0.03	.0229
Iron	0.181	0.487	4.512	3,000	5.45	0.183	.1396
Lead	<.06	<.06		<0.6		0.067	.05112
Magnesium	15.8	6.4	59.3	130	236.2	55.9	42.65
Manganese	<.01	<.024		2.0	3.63	0.025	.01908
Mercury	0.0004	0.0003	.0028	0.0003	.0005	<0.0001	
Molybdenum	0.029	<0.01		0.55		0.03	.023
Nickel	<.05	<.05		<0.50		<0.05	
Selenium	<0.001	<0.001		0.059	.11	0.012	--
Silver	<0.025	<0.025		<0.25		<0.025	
Sodium	163	97.0	898.8	53	96.3	44.5	33.96
Thallium	<0.001	0.003	.028	0.070	.127	<0.001	
Tin	<0.099	<0.099		<0.99		<0.099	
Titanium	0.016	<0.01		2.0	3.63	<0.01	
Vanadium	<0.099	<0.099	--	<0.99		<0.099	
Yttrium	<.01	<0.01		0.12	.218	<0.01	
Zinc	0.093	<0.025		0.81	1.47	0.039	.02976
Cyanide	<0.005	<0.005		<0.005		<0.005	
Phenol	<0.02	0.035	--	--	--	--	--

Note: Waterborne Raw Waste Loads are listed for plants NC 17 and NC 22 above. For plant NC 10, as these waters are recycled, there are no waterborne waste.

TABLE 6-8. ANALYSES OF WASTEWATERS AND TREATED STREAMS FROM LEVEL 4 PLANTS - WATER QUALITY AND METAL PARAMETERS.

	Plant NC 3				Plant NC 16
Classical Parameters (mg/l)	Prep Plant Slurry	Slurry Pond Effluent	in (Kg/day)	Clear Lake Prep Plant Recycle	Prep Plant Water Circuit
Total Solids	—	—	—	—	7,300
Total Suspended Solids	—	—	—	—	230
Total Volatile Solids	—	—	—	—	1,100
Volatile Suspended Solids	—	—	—	—	140
COD	—	—	—	—	396
TOC	—	—	—	—	43.2
pH	—	—	—	—	7.3
Metals (mg/l)	—	—	—	—	—
Aluminum	200	<0.099		<0.099	<0.099
Antimony	<0.1	<0.05		<0.05	0.003
Arsenic	<0.01	<0.002		<0.002	0.045
Barium	7.0	<0.005		<0.005	0.161
Beryllium	<0.02	<0.002		<0.002	<0.002
Boron	2.0	0.570	5.44	0.431	0.007
Cadmium	<0.2	<0.02		<0.02	<0.02
Calcium	947	202	1,927	218	39.6
Chromium	<0.24	0.103	.98	0.107	<0.024
Cobalt	<0.1	<0.01		<0.01	<0.01
Copper	0.27	<0.004		<0.004	<0.004
Iron	200	0.200	1.91	0.352	0.195
Lead	<0.6	<0.06		<0.06	<0.06
Magnesium	287	150	1,431	160	8.8
Manganese	2	0.024	.229	0.097	0.024
Mercury	<0.0005	<0.0005		<0.0005	0.002
Molybdenum	0.190	<0.01		<0.01	<0.01
Nickel	<0.5	<0.05		<0.05	<0.05
Selenium	0.05	<0.005		<0.005	0.002
Silver	<0.025	<0.025		<0.025	<0.025
Sodium	764	670	6,391	513	167
Thallium	<0.1	<0.1		<0.1	0.002
Tin	<0.99	<0.099		<0.099	<0.099
Titanium	3.0	0.012	.115	<0.01	<0.01
Vanadium	<0.99	<0.099		<0.099	<0.099
Yttrium	<0.1	0.013	.124	0.011	<0.01
Zinc	1.0	0.049	.47	0.026	<0.025
Cyanide	—	—	—	—	<0.005
Phenol	—	—	—	—	0.035

Note: Raw Waste Loads in kg/day are listed for the applicable streams of Plant NC 3. For the other streams at plant NC 3 and for plant NC 16, as these streams are not discharged, there are no waterborne effluents.

TABLE 6-9. ANALYSES OF WASTEWATERS AND TREATED STREAMS FROM LEVEL 4 PLANTS - WATER QUALITY AND METAL PARAMETERS.

	Plant NC 11	Plant NC 8	
Classical Parameters (mg/l)	Prep Plant Recycle Pond	Slurry Pond Effluent	in Kg/day
Total Solids	680	1200	24,980
Total Suspended Solids	50	5.4	112.4
Total Volatile Solids	100	100	2,082
Volatile Suspended Solids	5.6	1.8	37.5
COD	23.3	<2.0	
TOC	<1.0	<1.0	
pH	7.2	9.0	—
Metals (mg/l)			
Aluminum	<0.99	<0.099	
Antimony	<0.001	0.002	.042
Arsenic	0.002	0.014	.291
Barium	0.11	0.035	.729
Beryllium	<0.02	<0.002	
Boron	0.09	0.261	5.43
Cadmium	<0.2	<0.02	
Calcium	35.0	64.1	1,334
Chromium	2.0	<0.024	
Cobalt	<0.1	<0.01	
Copper	<0.04	<0.004	
Iron	9.0	0.271	5.64
Lead	<0.6	<0.06	
Magnesium	16.0	29.1	.854
Manganese	0.37	0.064	1.33
Mercury	0.0009	0.0006	.0125
Molybdenum	<0.1	0.041	.854
Nickel	0.53	<0.05	
Selenium	<0.001	<0.001	
Silver	<0.25	<0.025	
Sodium	67.0	226	4,705
Thallium	<0.001	0.001	.021
Tin	<0.99	<0.099	
Titanium	<0.1	0.011	.229
Vanadium	<0.99	<0.099	
Yttrium	<0.1	<0.01	
Zinc	<0.25	0.029	.604
Cyanide	<0.005	<0.005	
Phenol	<0.02	<0.02	

NOTE: Raw Waste Load (in kg/day) listed for Plant NC 8. For Plant NC 11, as the wastewater is recycled, there are no waterborne effluents.

Tables 6-7, 6-8 and 6-9 list the inorganic compounds present in wastewaters from coal preparation plants. Among the priority pollutants present are antimony, arsenic, asbestos, beryllium, cadmium, chromium, copper, cyanides, lead, mercury, nickel, selenium, thallium, and zinc compounds. The concentrations of most of these materials are quite low and many of these species are at least partially removable by the lime treatments normally given the wastewaters before discharge. Certain difficulties were encountered, however. In the analytical procedures used for this screening study, cadmium, lead, and silver have anomalous levels reported. Additional specific analyses must be made to provide more reliable data.

The wastewaters from coal storage, refuse piles, and coal preparation plant associated areas are characterized as being similar to the raw mine drainage at the mines served by the preparation plants. Geologic and geographic setting of the mine and the nature of the coal mined appear to determine the characteristics of these wastewaters. As the contents of these waste piles do not appear dependent on the plant processing operations used, all of these associated area wastewater problems will be treated as a whole and not subcategorized by plant process used. A listing of wastewater data for refuse piles for five of the facilities is given in Table 6-10.

6.3.1.1 Recycling—

In coal preparation plants and associated areas, the major control technology now in place is the recycle of process water. This technique is widely practiced and is effective in reducing wastewater discharges.

TABLE 6-10. ANALYSES OF REFUSE PILE WASTEWATERS - WATER QUALITY AND METAL PARAMETERS.

	NC 15			NC 14		NC 16	NC 17	NC 21
Classical Parameters (mg/l)	Refuse Pile Raw Water	In * Kg/ day	Refuse Pile Treated Effluent	Refuse Pile Raw Water	In * Kg/ day	Refuse Pile Runoff Non-Discharging Pond	Refuse Pile Non-Discharging Pond	Refuse Pile Raw Water
Total Solids	410	(11.17)	260	14,000	(229)	490	430	22,000
Total Suspended Solids	11.4	(.31)	62	39	(.4)	26.4	3.8	140
Total Volatile Solids	34	(.93)	36	2,600	(42.5)	86	66	2,900
Volatile Suspended Solids	2.2	(.06)	19.6	6.0	(.098)	4.9	<1.0	28.0
COD	15.5	(.42)	29.1	260	(4.25)	31.0	19.4	1,160
TOC	3.6	(.098)	5.5	19.3	(.32)	2.9	2.4	11.1
pH	4.0	--	9.7	6.5	--	7.7	7.2	2.4
Metals (mg/l)								
Aluminum	1.47	(.04)	<0.99	5.0	(.082)	<0.099	<0.099	800
Antimony	0.002	($5x10^{-5}$)	0.002	0.008	($1.3x10^{-4}$)	<0.001	<0.001	0.028
Arsenic	0.003	--	0.004	0.055	($9x10^{-4}$)	0.007	0.004	1.34
Barium	0.127	--	0.17	<0.05		0.649	0.009	<0.05
Beryllium	<0.002	--	<0.02	<0.02		<0.002	<0.002	0.22
Boron	0.024	--	0.11	1.000	(.016)	<0.005	0.028	<0.05
Cadmium	<0.02	--	<0.2	<0.2		<0.02	<0.02	<0.20
Calcium	26.5	(.73)	8.0	485	(7.93)	14.5	17.5	407
Chromium	<0.024		<0.24	0.43	($7x10^{-3}$)	<0.024	<0.024	0.98
Cobalt	0.038	($1x10^{-3}$)	<0.1	<0.1		<0.01	<0.01	4.0
Copper	0.006	($1.6x10^{-4}$)	<0.04	0.31	($5x10^{-3}$)	<0.004	<0.004	1.0
Iron	0.509	(.014)	1.0	2,000	(32.1)	0.123	0.103	9,000
Lead	<0.06		<0.6	<0.6		<0.06	<0.06	1.0
Magnesium	15.5	(.42)	3.0	420	(6.87)	3.7	11.3	490
Manganese	2.09	(0.56)	<0.2	30	(.49)	0.029	0.600	80.0
Mercury	0.0048	($1.3x10^{-4}$)	0.0043	0.0002	($3x10^{-6}$)	0.0003	0.0001	0.0011
Molybdenum	<0.01		<0.1	0.39	($6x10^{-3}$)	<0.01	0.112	2.0
Nickel	<0.05		<0.5	1.0	(.016)	<0.05	<0.05	10.0
Selenium	0.003	($8x10^{-5}$)	0.004	0.074	($1.2x10^{-3}$)	0.003	0.002	0.45
Silver	<0.025		<0.250	<0.25		<0.025	<0.025	<0.25
Sodium	38.8	(1.06)	65.0	913	(14.9)	55.4	139	413
Thallium	<0.001		<0.001	<0.001		<0.001	<0.001	0.014
Tin	<0.099		<0.99	<0.99		<0.099	<0.099	1.0
Titanium	0.014	($3x10^{-4}$)	<0.1	<0.1		<0.01	<0.01	<1.0
Vanadium	<0.099		<0.99	<0.99		<0.099	<0.099	<0.99
Yttrium	<0.01		<0.1	0.31	($5x10^{-3}$)	<0.01	<0.01	3.0
Zinc	0.168	($4.5x10^{-3}$)	<0.25	0.99	(.016)	<0.025	0.037	30.0
Cyanide	<0.005		<0.005	<0.005		<0.005	<0.005	<0.005
Phenols	<0.02	--	<0.035	<0.02		0.03	<0.02	<0.02

*Raw Waste Loads are given for those streams which are discharged either with or without subsequent treatment.

A major factor in achieving recycle of process water is the installation and operation of efficient dewatering equipment on preparation plant refuse streams, with consequent reduction of hydraulic loads on refuse impoundments.

Equipment in current use includes dewatering screens, Vor-Sivs, and centrifugal driers. The use of non-acidic water for preparation plant make-up probably reduces the quantities of priority pollutants present in the plant discharge and additionally protects the preparation plant equipment from corrosion.

6.3.1.2 Neutralization--

For associated area wastewaters, neutralization is generally the treatment of choice. This reduces the acidity and enhances the oxidation of iron from ferrous to ferric. Ferric hydroxide is less soluble and easier to settle than ferrous hydroxide. Adjustment of pH is important before aeration because the oxidization of the ferrous iron increases the hydrogen ion concentration.

Although there are many methods of neutralization, the two commonly employed are addition of lime or caustic soda. Lime neutralization involves making a slurry of lime, with either the acid water or treated water. This slurry is then added to the acid mine water in sufficient quantity to raise the pH to between eight and ten. Caustic soda neutralization, employed by a small percentage of the industry, achieves the same effect as lime addition. Although caustic soda neutralization has been shown to have a rapid reaction rate and quick response, it is relatively expensive and harder to handle than lime.

6.3.1.3 Neutralization Plus Settling--

After neutralization is complete, the precipitate (sludge) and the water may be separated by gravity settling. This may be done in either a clarifier with the use of thickeners or an earthen impoundment (settling pond). The iron precipitate (known as yellowboy) settles to the bottom of the lagoon and the clear water is discharged.

Settling ponds are generally very large in size - often from 114,000 to 303,000 cu m (30 to 80 million gallon) capacity - and are constructed by either damming a valley or digging a large hole. Settling ponds are large because sludge is collected in them. Some acid mine drainage treatment plants use two ponds. When one pond has reached capacity, flow is diverted to the second and the sludge in the first is either removed by dredging or allowed to undergo drying and compaction which greatly reduces the sludge volume. When the second pond is full, flow is returned to the first and the cycle is repeated.

6.3.2 Water Pollutants Discharged from BSER

Based upon the preliminary data provided in the above tables, we have attempted to estimate cleaning plant discharges for the classical parameters and several representative metals on a gram of pollutant per kkg of product coal basis. Direct slurry pond discharges are provided in Table 6-11. Refuse pile discharges are only indirectly a function of plant size and cannot be quantified. In addition modern cleaning plants do not discharge coal pile runoff without extensive treatment to meet the NPDES guidelines presented in Table 6-12.

For chemical coal cleaning processes, insufficient operating or environmental data is available to quantify either the amount or characteristics of chemical cleaning plant liquid discharges.

The primary pollutant and trace element discharges associated with each of the four reference boilers and eastern reference coals is provided in Tables 6-13 through 6-20. A sensitivity analysis follows in Table 6-21. Liquid wastes from mining and industrial boiler blowdown are not included. Western coal values are not presented because the tables only reflect liquid discharges from coal cleaning facilities and the Western coal BSER only involves using raw coal.

The table results show that water pollution levels are low from modern coal cleaning facilities. Chemical oxygen demand (COD) has the highest primary pollutant discharge value for each boiler and coal; iron discharges far exceed the values for any other trace metal. The discharges are directly proportional to the coal feed rate to the boiler, since coal cleaning liquid discharges cannot be allocated to various levels of cleaning and the values presented are normalized on a kkg of product coal basis.

TABLE 6-11. MEASURED LIQUID DISCHARGES FROM SELECTED PHYSICAL COAL CLEANING PLANTS

Parameter/Plant	NC-22S	NC-22V	NC-17S	NC-16S	Median Value
Effluent Flowrate ($\frac{\text{liters}}{\text{kkg}}$ of product)	75	75	851	54	75
Primary - (gm/kkg of coal product)					
Total Dissolved Solids	82	-	451	-	265
Total Suspended Solids	0.6	1.3	20	12	7
Total Volatile Solids	11	15	80	59	37
COD	1.6	1.5	26	21	11
TOC	0.2	0.5	21	2.3	1.9
pH	8.2	6.9	7.1	7.3	7.2
Major Elements (gm/kkg of product)					
Calcium	8.8	-	11	2.1	8.8
Magnesium	4.2	-	5.4	0.5	4.2
Sodium	3.3	-	83	9.0	9.0
Trace Elements (mg/kkg of product)					
Copper	2.3	0.6	43	< 0.2	1.5
Iron	14	-	410	11	14
Zinc	3	3	20	< 1	3
Manganese	1.8	-	20	1.3	1.8

TABLE 6-12. EFFLUENT GUIDELINES FOR COAL CLEANING PLANTS (20)

TSS, pH, iron and manganese are the only parameters for which NPDES standards exist for the coal industry. The limitations for these in preparation plant acid and alkaline waters are:

Effluent Characteristics	Acid Water Maximum for 1 Day (mg/l)	Average of Values for 30 Consecutive Days Shall not exceed (mg/l)
TSS	70.0	35.0
Iron total	6.0	3.0
Manganese total	4.0	2.0
pH	within the range of 6 to 9	

Effluent Characteristics	Alkaline Water Maximum for 1 Day (mg/l)	Average of Values for 30 Consecutive Days Shall not exceed (mg/l)
TSS	70.0	35.0
Iron total	6.0	3.0
pH	within the range of 6 to 9	

These standards are effective February 12, 1979.

TABLE 6-13. WATER POLLUTION IMPACTS FROM "BEST" SO_2 CONTROL TECHNIQUES FOR HIGH SULFUR EASTERN COAL-FIRED BOILERS.

SYSTEM				EMISSIONS			
Standard Boiler				Primary Pollutants		Trace Elements	
Heat Rate (MW or 10^6 BTU/hr)	Type	Control Level (Name, % of SO_2 Reduction	Type of Control	mg/s (lb/hr)	ng/J (lb/10^6 BTU)	Pollutant mg/s	Degree Change over Raw Coal
8.8 MW (30)	Underfeed Stoker	None 0%	Raw Coal	None	None	None	
		SIP and Moderate 58%	PCC Middlings	**			
						Fe=0.0043	*
				TSS=2.1 =(0.02)	=0.24 =(0.0007)	Zn=0.00093	*
				COD=3.4 =(0.03)	=0.39 =(0.001)	Cu=0.00046	*
				TOC=0.58 =(0.005) [pH=7.2]	=0.066 =(0.0002)	Mn=0.0006	*
				Ca=2.7 =(0.02)	=0.31 =(0.0007)		
				Na=2.8 =(0.02)	=0.32 =(0.0007)		
				Mg=1.3 =(0.01)	=0.15 =(0.0003)		
		Optional Moderate and Intermediate 75%	PCC Deep cleaned Product	5% decrease in the above values for the Middlings Product			*
		Stringent 80%	CCC ERDA	No Data	-	No data	

* Some increase in environmental effects compared to burning naturally-occurring coal with no controls.
** Discharge flow = 0.18 m^3/hr

TABLE 6-14 WATER POLLUTION IMPACTS FROM "BEST" SO_2 CONTROL TECHNIQUES FOR HIGH SULFUR EASTERN COAL-FIRED BOILERS

SYSTEM				EMISSIONS			
Standard Boiler				Primary Pollutants		Trace Elements	
Heat Rate (MW or 10^6 BTU/hr)	Type	Control Level (Name, % of SO_2 Reduction	Type of Control	mg/s (lb/hr)	ng/J (lb/10^6 BTU)	Pollutant mg/s	Degree Change over Raw Coal
22 (75)	Watertube Grate Stoker	None 0%	Raw Coal	None **	None	None	
		SIP and Moderate 58%	PCC Middlings	TSS=5.3 =(0.04) COD=8.4 =(0.07) TOC=1.5 =(0.01) [pH=7.2] Ca=6.7 =(0.05) Na=6.9 =(0.05) Mg=3.2 =(0.03)	= 0.24 = (0.0005) = 0.38 = (0.0009) = 0.07 = (0.0001) = 0.31 = (0.0007) = 0.31 = (0.0007) = 0.15 = (0.0004)	Fe=0.0107 Zn=0.0023 Cu=0.0011 Mn=0.0014	* * * *
		Optional Moderate and Intermediate 75%	PCC Deep Cleaned Product	5% decrease in the above values for the Middlins Product			*
		Stringent 80%	CCC ERDA	No Data	--	No Data	

* Some increase in environmental effects compared to burning naturally-occurring coal with no controls.
** Discharge flow = 0.18 m^3/hr

TABLE 6-15. WATER POLLUTION IMPACTS FROM "BEST" SO_2 CONTROL TECHNIQUES FOR HIGH SULFUR EASTERN COAL-FIRED BOILERS

SYSTEM				EMISSIONS			
Standard Boiler		Control Level (Name, % of SO_2 Reduction	Type of Control	Primary Pollutants		Trace Elements	
Heat Rate (MW or 10^6 BTU/hr)	Type			mg/s (lb/hr)	ng/J (lb/10^6 BTU)	Pollutant mg/s	Degree Change over Raw Coal
44 (150)	Spreader Stoker	None 0%	Raw coal	None	None	None	
		SIP and Moderate 58%	PCC Middlings	** TSS=10.7	=0.24 =(.0005)	Fe=.0214	*
				COD=16.8 =(.13)	=0.38 =(.0009)	Zn=.0046	*
				TOC=2.9 =(.023)	=.07 =(.0002)	Cu=.0023	*
				[pH=7.2]		Mn=.0028	*
				Ca=13.4 =(.11)	=.31 =(.0007)		
				Na=13.7 =(.11)	=.31 =(.0007)		
				Mg=6.4 =(.05)	=.15 =(.0003)		
		Optional Moderate and Intermediate 75%	PCC Deep cleaned Product	5% decrease in the above values for the middlings product			*

* Some increase in environmental effects compared to burning naturally-occurring coal with no controls.
** Discharge flow = 0.18 m^3/hr

TABLE 6-16. WATER POLLUTION IMPACTS FROM "BEST" SO_2 CONTROL TECHNIQUES FOR HIGH SULFUR EASTERN COAL-FIRED BOILERS

SYSTEM				EMISSIONS			
Standard Boiler		Control Level (Name, % of SO_2 Reduction	Type of Control	Primary Pollutants		Trace Elements	
Heat Rate (MW or 10^6 BTU/hr)	Type			mg/s (lb/hr)	ng/J (lb/10^6 BTU)	Pollutant mg/s	Degree Change over Raw Coal
58.6 (200)	Pulverized coal fired	None 0%	Raw coal	None	None	None	
		SIP and Moderate 58%	PCC Middlings	** TSS=14.2 =(.11)	.24 .0006	Fe=.0285	*
				COD=22.4 =(.18)	.38 .0009	Zn=.0061	*
				TOC=3.9 =(.03)	.07 .0002	Cu=.0031	*
				[pH=7.2]		Mn=.0037	*
				Ca=17.9 =(.14)	.31 .007		
				Na=18.3 =(.15)	.31 .0008		
				Mg=8.5 =(.07)	.15		
		Optional, Moderate and Intermediate 75%	PCC Deep Cleaned Product	5% decrease in the above values for the Middlings Product			

* Some increase in environmental effects compared to burning naturally-occurring coal with no controls.
** Discharge flow = 0.18 m^3/hr

TABLE 6-17. WATER POLLUTION IMPACTS FROM "BEST" SO_2 CONTROL TECHNIQUES FOR LOW SULFUR EASTERN COAL-FIRED BOILERS.

SYSTEM				EMISSIONS			
Standard Boiler				Primary Pollutants		Trace Elements	
Heat Rate (MW or 10^6 BTU/hr)	Type	Control Level (Name, % of SO_2 Reduction	Type of Control	mg/s (lb/hr)	ng/J (lb/10^6 BTU)	Pollutant mg/s	Degree Change over Raw Coal
8.8 (30)	Underfeed Stoker Boiler	None 0%	Raw Coal	None	None	None	
		SIP, Moderate and Optional Moderate, 0%	Raw Coal	None **	None	None	
		Intermediate and Stringent 30%	PCC Level 4 PCC Level 4	TSS=1.8 =(0.014) COD=2.8 =(0.022) TOC=0.5 =(0.004) [pH=7.2] Ca=2.3 =(0.018) Na=2.3 =(0.018) Mg=1.1 =(0.009)	= 0.20 = (0.0005) = 0.32 = (0.0007) = 0.06 = (0.0001) = 0.26 = (0.0006) = 0.26 = (0.0006) = 0.13 = (0.0003)	Cu=0.0004 Fe=0.0036 Mn=0.0005 Zn=0.0008	* * * *

* Some increase in environmental effects compared to burning naturally-occurring coal with no controls.
** Discharge flow = 0.18 m^3/hr

TABLE 6-18. WATER POLLUTION IMPACTS FROM "BEST" SO_2 CONTROL TECHNIQUES FOR LOW SULFUR EASTERN COAL-FIRED BOILERS.

SYSTEM				EMISSIONS			
Standard Boiler				Primary Pollutants		Trace Elements	
Heat Rate (MW or 10^6 BTU/hr)	Type	Control Level (Name, % of SO_2 Reduction	Type of Control	mg/s (lb/hr)	ng/J (lb/10^6 BTU)	Pollutant mg/s	Degree Change over Raw Coal
22 (75)	Watertube Grate Stoker	None 0%	Raw Coal	None	None	None	
		SIP, Moderate and Optional Moderate, 0%	Raw Coal	None **	None	None	
		Intermediate and Stringent 30%	PCC Level 4	TSS=4.5 =(.04)	.21 (.0005)	Cu=.0009	*
				COD=7.1 =(.06)	.32 (.0008)	Fe=.0091	*
				TOC=1.2 =(.01)	.06 (.0001)	Mn=.0012	*
				[pH=7.2]		Zn=.0020	*
				Ca=5.7 =(.05)	.26 (.0006)		
				Na=5.8 =(.05)	.27 (.0006)		
				Mg=2.7 =(.02)	.12 (.0003)		

* Some increase in environmental effects compared to burning naturally-occurring coal with no controls.
** Discharge flow = 0.18 m^3/hr

TABLE 6-19. WATER POLLUTION IMPACTS FROM "BEST" SO_2 CONTROL TECHNIQUES FOR LOW SULFUR EASTERN COAL-FIRED BOILERS.

SYSTEM				EMISSIONS			
Standard Boiler		Control Level (Name, % of SO_2 Reduction	Type of Control	Primary Pollutants		Trace Elements	
Heat Rate (MW or 10^6 BTU/hr)	Type			mg/s (lb/hr)	ng/J (lb/10^6 BTU)	Pollutant mg/s	Degree Change over Raw Coal
44 (150)	Spreader Stoker	None 0%	Raw Coal	None	None	None	
		SIP, Moderate, and Optional Moderate 0%	Raw Coal	None	None	None	
		Intermediate and Stringent 30%	PCC Level 4	** TSS=9.1 0(.07) COD=14.3 =(.11) TOC=2.5 =(.02) [pH=7.2] Ca=11.4 =(.09) Na=11.7 =(.09) Mg=5.5 =(.04)	 .21 (.0005) .32 (.008) .06 (.001) .26 (.006) .27 (.006) .12 (.003)	Cu=.0019 Fe=.0182 Mn=.0023 Zn=.0039	* * * *

* Some increase in environmental effects compared to burning naturally-occurring coal with no controls.
** Discharge flow = 0.18 m^3/hr

TABLE 6-20. WATER POLLUTION IMPACTS FROM "BEST" SO_2 CONTROL TECHNIQUES FOR LOW SULFUR EASTERN COAL-FIRED BOILERS.

SYSTEM				EMISSIONS			
Standard Boiler		Control Level (Name, % of SO_2 Reduction	Type of Control	Primary Pollutants		Trace Elements	
Heat Rate (MW or 10^6 BTU/hr)	Type			mg/s (lb/hr)	ng/J (lb/10^6 BTU)	Pollutant mg/s	Degree Change over Raw Coal
58.6 (200)	Pulverized Coal Fired	None 0%	Raw Coal	None	None	None	
		SIP, Moderate, and Optional Moderate 0%	Raw Coal	None	None	None	
		Intermediate and Stringent 30%	PCC Level 14	**			
				TSS=12.1 =(.10)	.21 (.005)	Cu=.0026	*
				COD=19.1 =(.15)	.32 (.0008)	Fe=.0242	*
				TOC=3.3 =(.03)	.06 (.001)	Mn=.0031	*
				[pH=7.2]		Zn=.0052	*
				Ca=15.2 =(.12)	.26 (.0006)		
				Na=15.6 =(.12)	.27 (.0006)		
				Mg=73 =(.06)	.12 (.0003)		

* Some increase in environmental effects compared to burning naturally-occurring coal with no controls.
** Discharge flow = 0.18 m^3/hr

TABLE 6-21. SENSITIVITY ANALYSIS OF WATER EMISSIONS FROM COAL CLEANING PLANTS

A. High Sulfur Eastern Coal

Emission values are constant for all boilers.

Type of Control	Primary Pollutants (ng/J)
Raw Coal	None
PCC-Middlings	TSS = 0.24
	COD = 0.39
	TOC = 0.07
	Ca = 0.31
	Na = 0.32
	Mg = 0.15
PCC-Deep Cleaned	TSS = 0.23
	COD = 0.37
	TOC = 0.07
	Ca = 0.29
	Na = 0.30
	Mg = 0.14
CCC-ERDA	No Data

B. Low Sulfur Eastern Coal

Emission values are constant for all boilers.

Type of Control	Primary Pollutants (ng/J)
Raw Coal	None
PCC-Level IV	TSS = 0.21
	COD = 0.32
	TOC = 0.06
	Ca = 0.26
	Na = 0.26
	Mg = 0.13

C. Western Values are not presented because the tables only reflect liquid discharges from coal cleaning facilities and the Western Coal BSER only involves using raw coal.

6.4 SOLID WASTES

Coal cleaning affects the amount of solid waste generated in that there is a greater production of waste at the point of coal preparation and less production at the point of use. The net effect is a greater production of solid waste. This is due to the large refuse rejection rate at the preparation plant. However, a major benefit to the industrial boiler user results. Coal cleaning greatly reduces the amounts of fly ash and bottom ash produced making the disposal problem much less at the boiler site. Also, there are several economic and environmental advantages which result. Air emissions of coal constituents which are volatilized upon combustion, e.g., sulfur oxides and mercury are minimized by their removal as solid wastes during coal cleaning.

With respect to SO_2, possibly the pollutant of most concern from the combustion of coal, there is the additional advantage from a solid waste viewpoint that removal of sulfur as FeS necessitates the disposal of a much smaller volume of waste than by the removal of sulfur as $CaSO_3$-1/2 H_2O and/or $CaSO_4 \cdot 2H_2O$ (and unreacted $CaCO_3$) if an FGD process is utilized.

The absolute quantities of non-volatile constituents, those which report to the ash upon combustion, are in actuality not reduced, but there are advantages in disposing of them at the preparation plant rather than at the user's site.

6.4.1 Solid Wastes from Physical Coal Cleaning

According to the Keystone Manual (1977), there are over 460 physical coal cleaning plants in the U.S. which can handle over 400 million tons of raw coal per year.[21] This resulted in an estimated 96 million tons of coal cleaning refuse.[22]

Coal refuse consists of waste coal, slate, carbonaceous and pyritic shales, and clays associated with coal seam. It has been estimated that about 25 percent of the raw coal mined is disposed of as waste. (Western coals surface mined from very thick beds, e.g., as in the Powder River Basin, will not have these percentages of wastes, but these coals are not currently subjected to coal cleaning.)

Coal refuse disposal involves two quite separate and distinct categories of material—a coarse (+ 28 mesh) refuse and a fine (-28 mesh) refuse. The coarse refuse is usually handled as a normal solid waste. The fine refuse is normally removed from the coal preparation plant as a thickener underflow slurry and pumped to an impoundment.

6.4.2 Solid Wastes from Chemical Coal Cleaning

Solid wastes, as such, are not directly produced by the ERDA, Meyers or Gravichem chemical coal cleaning processes; removal is by acid dissolution rather than by physical separation. Solid wastes are produced when the acid waste solutions are neutralized and precipitated with lime. Although removal of ash constituents by these chemical processes is evidently less than by physical cleaning processes, solid wastes from CCC plants cannot be readily quantified because of the undeveloped state of the technology. It is assumed for this study that the ERDA process removes 25 percent of the ash in the coal while the Gravichem process can remove 25 percent of the ash material after physical coal cleaning.[23]

6.4.3 Environmental Impacts from Cleaning Plant Solid Wastes

The mineral wastes from coal preparation and mine development constitute a major environmental problem. More than 3 billion tons of these materials have accumulated in the U.S., and the current annual rate of waste production of 100 million tons per year is expected to double within a decade. The total number of coal waste dumps is estimated to be between 3,000 and 5,000, of which half pose some type of health, environmental, or safety problem. Although it has been established that the drainage from coal refuse dumps is often highly contaminated with trace or inorganic elements, little is known about the quantities of undesirable elements released into the environment from this source.

Infiltration of contaminated water from tailings ponds containing fine solid wastes is an obvious environmental problem. Inclusion of an impervious bottom in the construction of such ponds is one mitigative measure; collection ditches or wells around the perimeter are another; and maintenance of the pH within the pond on the alkaline side will reduce the concentrations of many undesirable solutes.

Infiltration of rainfall and air into piles of coarse coal refuse promotes oxidation of the pyrites, creating an acid condition causing accelerated dissolution of contaminants. Principal mitigative measure is compaction and coverage with soil to minimize the chances for oxidation and percolation. This also reduces the possibility of fire, another major environmental problem with refuse piles.

6.4.4 Solid Waste Quantification for BSER Comparisons

Only solid waste quantities from each BSER will be presented in the environmental factor comparisons because of the lack of data on the constituents in coal cleaning refuse piles, the conflicting information on the fate of trace elements in the raw coal relative to cleaning plant refuse, bottom ash, or fly ash, and the difficulty in characterizing the impact of leachate on the environment.[13,14,15,16,17,18]

The amount of solids generated by the coal cleaning plants are calculated by:

$$SW = (1-Y)I$$

where:

SW is the quantity of solid wastes (kkg/day)

Y is the cleaning plant yield, and

I is the input coal quanitity to the cleaning plant (=7,250 kkg/day).

The above formula must be modified for use with the cleaning of high sulfur eastern coal because of the production of two products. The total refuse produced (1-Y) is split among the two products in proportion to the percent yield of each. To determine the quantity of solid waste generated when two products are produced, the following formula is used.

$$SW_1=(1-Y)\left(\frac{Y_1}{Y}\right)I$$

SW_1 is the quantity of solid waste attributed to product 1, (mg/s) (1-Y) is the refuse yield, Y_1 is the yield of product 1, Y is the total product yield, I is the input coal quantity to the cleaning plant (75,700 mg/s). To obtain SW_2, Y_2 is substituted for Y_1.

The values for solid wastes generated by coal cleaning and cleaned coal are provided in Tables 6-22 through 6-30 for each BSER. These values of solids generated by combustion at the boiler are calculated using the feed rate to the boiler (mg/s), the percent ash of the coals being burned and the percent of the total ash which goes to fly ash and bottom ash. The feed rate to the boiler is calculated using the following formula.

$$\text{Feed rate (mg/s)} = \frac{\text{Heat rate of boiler (BTU/hr.)}}{\text{Heat content of coal (BTU/lb)}} \quad \frac{126 \text{ mg/s}}{\text{BTU/lb}}$$

The percent ash of the coals being burned are found in Section 3 and the percents of the total ash which go to fly ash are shown in Table 5-13. The following formulae are used to calculate the amounts of fly ash and bottom ash generated upon combustion of the coal.

$$\text{Amount of Fly ash (mg/s)} = \text{Feed rate (mg/s)} \times \frac{\%\ \text{Ash}}{100} \times \frac{\%\ \text{Fly Ash of Total Ash}}{100}$$

$$\text{Amount of Bottom ash (mg/s)} = \text{Feed rate (mg/s)} \times \frac{\%\ \text{Ash}}{100} \times \frac{\%\ \text{Bottom Ash of Total Ash}}{100}$$

Note: 100 - (% Fly Ash of Total Ash) = % Bottom Ash of Total Ash

The high sulfur eastern coal results show an anamoly in that sulfur removal is inversely proportional to solid wastes generated. This is explained by the cleaned coal characteristics and the method for physically cleaning the coal. As shown in Figure 3-4, the deep cleaned and middlings cleaning circuits are relatively inseparable from a generation of refuse standpoint. If the refuse is attributed evenly to each product on a weight basis, then the higher heating value of the deep cleaned coal will produce less wastes from an energy basis: (i.e. ng/J). The ERDA process uses chemical reactions to extract pyritic and organic sulfur and, as a result, only generates small amounts of waste while removing about 25 percent of the incombustible materials and most of the pyritic sulfur in the coal. The results for low sulfur eastern coal are more consistent with the expectation that greater SO_2 control should be associated with increased solid waste generation. Note that the BSER physical and chemical coal cleaning methods produce over twice as much solid waste as the raw coal.

TABLE 6-22. SOLID WASTES FROM "BEST" SO_2 CONTROL TECHNIQUES FOR 8.8 MW COAL FIRED BOILERS

HIGH SULFUR EASTERN COAL

SYSTEM				EMISSIONS		
Standard Boiler		Control Level (Name, % of SO_2 Reduction	Type of Control	Solid Wastes		Percent Increase Over No Controls
Heat Rate (MW or 10^6 BTU/hr)	Type			mg/s (lb/hr)	ng/J (lb/10^6 BTU)	
8.8 (30)	Underfeed Stoker	None, 0%	Raw Coal	Type Cleaning 0		
				Bottom Ash 56.5 (448)	6,430 (15)	
				Fly Ash 19.6 (155)	2,233 (5)	
				Total Wastes 75.3 (597)	8,570 (20)	-
		Moderate 1,290 ng SO_2/J and	Middling	Cleaning 94 (750)	10,690 (25)	
		SIP 1,075 ng SO_2/J 58%	Middling	Bottom Ash 24 (190)	2,730 (6)	
				Fly Ash 8.0 (63)	910 (2)	
				Total Wastes 126 (1,000)	14,330 (33)	67%
		Optional Moderate and	Deep Cleaned Prod.	Cleaning 92 (730)	10,460 (24)	
		Intermediate 645 ng SO_2/J 75%	Deep Cleaned Prod.	Bottom Ash 11 (87)	1,250 (3)	
				Fly Ash 3.8 (30)	430 (1)	
				Total Wastes 107 (850)	12,140 (28)	42%
		Stringent 516 ng SO_2/J 80%	CCC ERDA	Cleaning 21 (167)	2,390 (5)	
				Bottom Ash 41 (325)	4,660 (11)	
				Fly Ash 14 (111)	1,590 (4)	
				Total Wastes 76 (603)	8,640 (20)	0%

TABLE 6-23. SOLID WASTES FROM "BEST" SO_2 CONTROL TECHNIQUES FOR 22 MW COAL FIRED BOILERS

HIGH SULFUR EASTERN COAL

SYSTEM				EMISSIONS		
Standard Boiler		Control Level (Name, % of SO_2 Reduction	Type of Control	Solid Wastes		Percent Increase Over No Controls
Heat Rate (MW or 10^6 BTU/hr)	Type			mg/s (lb/hr)	ng/J (lb/10^6 BTU)	
22 (75)	Chain-Grate Stoker	None, 0%	Raw Coal	Cleaning 0 Bottom Ash 141 (1,120) Fly Ash 49 (388) Total Ash 188 (1,490)	 6,415 (15) 2,233 (5) 8,555 (20)	—
		Moderate 1,290 ng SO_2/J and SIP 1,075 ng SO_2/J 58%	Middling Middling	Cleaning 236 (1,870) Bottom Ash 59 (470) Fly Ash 20 (160) Total Waste 315 (2,500)	 10,740 (25) 2,680 (6.3) 910 (2.1) 14,330 (33)	68%
		Optional Moderate 860 ng SO_2/J and Intermediate 75%	Deep Cleaned Prod. Deep Cleaned Prod.	Cleaning 230 (1,825) Bottom Ash 28 (220) Fly Ash 10 (80) Total Waste 268 (2,125)	 10,460 (24) 1,280 (2.9) 450 (1.1) 12,190 (28)	43%
		Stringent 516 ng SO_2/J 80%	CCC ERDA	Cleaning 52 (410) Bottom Ash 102 (810) Fly Ash 34 (270) Total Ash 188 (1,490)	 2,360 (5.5) 4,640 (11) 1,550 (3.6) 8,550 (20)	0%

TABLE 6-24. SOLID WASTES FROM "BEST" SO_2 CONTROL TECHNIQUES FOR 44 MW COAL FIRED BOILERS

HIGH SULFUR EASTERN COAL

SYSTEM				EMISSIONS		
Standard Boiler Heat Rate (MW or (10^6 BTU/hr)	Standard Boiler Type	Control Level (Name, % of SO_2 Reduction	Type of Control	Solid Wastes mg/s (lb/hr)	Solid Wastes ng/J (lb/10^6 BTU)	Percent Increase Over No Controls
44 (150)	Spreader Stoker	Uncontrolled 0%	Raw Coal	Cleaning 0 Bottom Ash 132 (1,050) Fly Ash 255 (2021) Total Ash 377 (2,990)	0 3,000 (7) 5,806 (13.5) 8,575 (20)	—
		Moderate 1,290 ng SO_2/J and SIP 1,075 ng SO_2/J 58%	Middling Product Middling Product	Cleaning 472 (3,750) Bottom Ash 55 (440) Fly Ash 102 (810) Total Waste 629 (5,000)	10,740 (25) 1,250 (3) 2,320 (5) 14,310 (33)	67%
		Optional Moderate 860 ng SO_2/J and Intermediate 645 ng SO_2/J 75%	Deep Cleaned Product Deep Cleaned Product	Cleaning 460 (3,650) Bottom Ash 26 (210) Fly Ash 50 (400) Total Waste 536 (4,260)	10,460 (24) 590 (1.4) 1,140 (2.6) 12,190 (28)	42%
		Stringent 516 ng SO_2/J 80%	Chemically Cleaned-ERDA	Cleaning 105 (830) Bottom Ash 95 (760) Fly Ash 177 (1400) Total Waste 377 (2,990)	2,390 (5.5) 2,160 (5.1) 4,030 (9.3) 8,580 (20)	0%

TABLE 6-25. SOLID WASTE FROM "BEST" SO_2 CONTROL TECHNIQUES FOR 58.6 MW COAL FIRED BOILERS

HIGH SULFUR EASTERN COAL

SYSTEM				EMISSIONS		
Standard Boiler		Control Level (Name, % of SO_2 Reduction	Type of Control	Solid Wastes		Percent Increase Over No Controls
Heat Rate (MW or (10^6 BTU/hr)	Type			mg/s (lb/hr)	ng/J (lb/10^6 BTU)	
58.6 (200)	Pulverized	Uncontrolled 0%	Raw Coal	Cleaning 0	0	
				Bottom Ash 100 (790)	1,710 (4)	
				Fly Ash 418 (3,313)	7,146 (16.6)	
				Total Ash 500 (3,970)	8,530 (20)	—
		Moderate 1,290 ng SO_2/J and SIP 1,075 ng SO_2/J 58%	Middling Middling	Cleaning 630 (5,000)	10,750 (25)	
				Bottom Ash 40 (320)	680 (1.6)	
				Fly Ash 170 (1,350)	2,900 (6.7)	
				Total Waste 840 (6,670)	14,330 (33)	68%
		Optional Moderate 860 ng SO_2/J and Intermediate 645 ng SO_2/J 75%	Deep Cleaned	Cleaning 610 (4,840)	10,410 (24)	
				Bottom Ash 20 (160)	340 (0.8)	
				Fly Ash 80 (640)	1,360 (3.2)	
				Total Waste 710 (5,640)	12,110 (28)	42%
		Stringent 516 ng SO_2/J 80%	Chemically Cleaned	Cleaning 140 (1,110)	2,390 (5.6)	
				Bottom Ash 70 (560)	1,190 (2.8)	
				Fly Ash 290 (2,300)	4,950 (11.5)	
				Total Waste 500 (3,970)	8,530 (20)	0%

TABLE 6-26. SOLID WASTE FROM "BEST" SO_2 CONTROL TECHNIQUES FOR 8.8 MW COAL FIRED BOILERS

LOW SULFUR EASTERN COAL

SYSTEM				EMISSIONS		
Standard Boiler		Control Level (Name, % of SO_2 Reduction	Type of Control	Solid Wastes		Percent Increase Over No Controls
Heat Rate MW or (10^6 BTU/hr)	Type			mg/s (lb/hr)	ng/J (lb/10^6 BTU)	
8.8 (30)	Underfeed Stoker	Uncontrolled 0%	Raw Coal	Cleaning 0		
		SIP 1,075 ng SO_2/J	Raw Coal	Bottom Ash 21.6 (171)	2,450 (5.7)	
		Moderate 1,290 ng SO_2/J	Raw Coal	Fly Ash 7.2 (57)	820 (1.9)	
		Optional Moderate 860 ng SO_2/J 0%	Raw Coal	Total Ash 28.8 (228)	3,270 (7.6)	—
		Intermediate 645 ng SO_2/J and Stringent 516 ng SO_2/J 30%	PCC Level 4 PCC Level 4	Cleaning 50 (400)	5,690 (13)	
				Bottom Ash 8 (60)	920 (2)	
				Fly Ash 2.7 (20)	310 (0.7)	
				Total Waste 61 (480)	6,920 (16)	112%
		Stringent 516 ng SO_2/J 50%	CCC Gravichem	Cleaning 63 (500)	7,160 (17)	
				Bottom Ash 4 (30)	450 (1)	
				Fly Ash 1 (8)	110 (0.3)	
				Total Waste 68 (540)	7,720 (18)	136%

TABLE 6-27. SOLID WASTE FROM "BEST" SO_2 CONTROL TECHNIQUES FOR 22 MW COAL FIRED BOILERS

LOW SULFUR EASTERN COAL

SYSTEM				EMISSIONS		
Standard Boiler		Control Level (Name, % of SO_2 Reduction	Type of Control	Solid Wastes		Percent Increase Over No Controls
Heat Rate MW or (10^6 BTU/hr)	Type			mg/s (lb/hr)	ng/J (lb/10^6 BTU)	
22 (75)	Chain- Grate Stoker	Uncontrolled, 0% and SIP 1,075 ng SO_2/J and Moderate 1,290 ng SO_2/J and Opt. Mod. 860 ng SO_2/J 0%	Raw Coal Raw Coal Raw Coal Raw Coal	Cleaning 0 Bottom Ash 54 (430) Fly Ash 18 (140) Total Ash 72 (570)	 0 2,460 (5.7) 820 (1.9) 3,280 (7.6)	—
-		Intermediate 645 ng SO_2/J and Stringent 516 ng SO_2/J 30%	PCC Level 4 PCC Level 4	Cleaning 125 (990) Bottom Ash 20 (160) Fly Ash 7 (60) Total Waste 152 (1,210)	 5,690 (13) 910 (2.1) 320 (0.8) 6,920 (16)	111%
		Stringent 516 ng SO_2/J	CCC Gravichem	Cleaning 160 (1,270) Bottom Ash 9 (70) Fly Ash 3 (20) Total Waste 172 (1,360)	 7,280 (17) 410 (1) 140 (0.3) 7,830 (18)	139%

TABLE 6-28. SOLID WASTE FROM "BEST" SO_2 CONTROL TECHNIQUES FOR 44 MW COAL FIRED BOILERS

LOW SULFUR EASTERN COAL

SYSTEM				EMISSIONS		
Standard Boiler		Control Level (Name, % of SO_2 Reduction	Type of Control	Solid Wastes		Percent Increase Over No Controls
Heat Rate MW or (10^6 BTU/hr)	Type			mg/s (lb/hr)	ng/J (lb/10^6 BTU)	
44 (150)	Spreader Stoker	Uncontrolled 0% SIP 1,075 ng SO_2/J and Moderate 1,290 ng SO_2/J and Opt. Moderate 860 ng SO_2/J 0%	Raw Coal Raw Coal Raw Coal Raw Coal	Cleaning 0 Bottom Ash 50 (400) Fly Ash 94 (750) Total Ash 144 (1,150)	1,140 (2.7) 2,140 (5) 3,280 (7.7)	—
		Intermediate 645 ng SO_2/J and Stringent 516 ng SO_2/J 30%	PCC Level 4 PCC Level 4	Cleaning 250 (1,980) Bottom Ash 19 (150) Fly Ash 35 (290) Total Waste 304 (2,420)	5,690 (13) 430 (1) 800 (2) 6,920 (16)	111%
		Stringent 516 ng SO_2/J 50%	CCC Gravichem	Cleaning 320 (2,540) Bottom Ash 8 (60) Fly Ash 16 (130) Total Waste 345 (2740)	7,280 (17) 180 (0.4) 260 (0.9) 7,830 (18)	140%

TABLE 6-29. SOLID WASTE FROM "BEST" SO_2 CONTROL TECHNIQUES FOR 58.6 MW COAL FIRED BOILERS

LOW SULFUR EASTERN COAL

SYSTEM				EMISSIONS		
Standard Boiler		Control Level (Name, % of SO_2 Reduction	Type of Control	Solid Wastes		Percent Increase Over No Controls
Heat Rate MW or (10^6 BTU/hr)	Type			mg/s (lb/hr)	ng/J (lb/10^6 BTU)	
58.6 (200)	Pulverized	Uncontrolled 0%	Raw Coal	Cleaning 0	0	
		SIP 1,075 ng SO_2/J and	Raw Coal	Bottom Ash 38 (300)	650 (1.5)	
		Moderate 1,290 ng SO_2/J and	Raw Coal	Fly Ash 154 (1,220)	2,630 (6.1)	
		Opt. Moderate 860 ng SO_2/J	Raw Coal	Total Ash 192 (1,520)	3,280 (7.6)	—
		Intermediate 645 ng SO_2/J and	PCC Level 4	Cleaning 334 (2,650)	5,700 (13)	
		Stringent 516 ng SO_2/J 30%	PCC Level 4	Bottom Ash 14 (110)	240 (0.5)	
				Fly Ash 57 (450)	970 (2.2)	
				Total Waste 405 (3,210)	6,910 (16)	111%
		Stringent 516 ng SO_2/J 50%	CCC Gravichem	Cleaning 420 (3,330)	7,170 (16.6)	
				Bottom Ash 7 (60)	120 (0.3)	
				Fly Ash 26 (210)	440 (1)	
				Total Waste 455 (3,600)	7,730 (18)	137%

TABLE 6-30. SOLID WASTE FROM "BEST" SO_2 CONTROL TECHNIQUES FOR 8.8 MW COAL FIRED BOILERS

LOW SULFUR WESTERN COAL

SYSTEM				EMISSIONS		
Standard Boiler		Control Level (Name, % of SO_2 Reduction	Type of Control	Solid Wastes		Percent Increase Over No. Controls
Heat Rate MW or (10^6 BTU/hr)	Type			mg/s (lb/hr)	ng/J (lb/10^6 BTU)	
8.8 (30)	Underfeed Stoker	All 0%	Raw Coal	Bottom Ash 62 (490)	7,050 (16)	None
				Fly Ash 21 (170)	2,390 (16)	
				Total Ash 83 (660)	9,440 (22)	
22 (75)	Chain-Grate Stoker	All 0%	Raw Coal	Bottom Ash 156 (1,240)	7,100 (16.5)	None
				Fly Ash 52 (410)	2,370 (5.5)	
				Total Ash 208 (1,650)	9,470 (22)	
44 (150)	Spreader Stoker	All 0%	Raw Coal	Bottom Ash 145 (1,150)	3,300 (7.7)	None
				Fly Ash 270 (2,140)	6,140 (14.3)	
				Total Ash 415 (3,290)	9,440 (22)	
58.6 (200)	Pulverized	All 0%	Raw Coal	Bottom Ash 111 (880)	1,890 (4.4)	None
				Fly Ash 443 (3,520)	7,560 (17.6)	
				Total Ash 554 (4,400)	9,450 (22)	

Solid waste discharges from each of the boilers, expressed as ng/J, remain constant in value, regardless of size or type of boiler. Figures 6-1 and 6-2 show cleaning wastes versus percent sulfur in coal and ash removed versus percent sulfur in coal, respectively. Normalized amounts of cleaning waste are not affected by boiler size or type, but only by the sulfur content of the coal cleaned. Figure 1 shows that as the sulfur content of the coal being cleaned decreases, the amount of wastes also decreases. Figure 2 shows that the amount of ash removed by cleaning also depends upon the sulfur content of the raw coal. As in Figure 1, the amount of ash removed with sulfur content decreases. In general, the emissions (in ng/J) using a standard coal are less dependent upon the size of the boiler, as they are on the inherent characteristics of the coal being utilized.

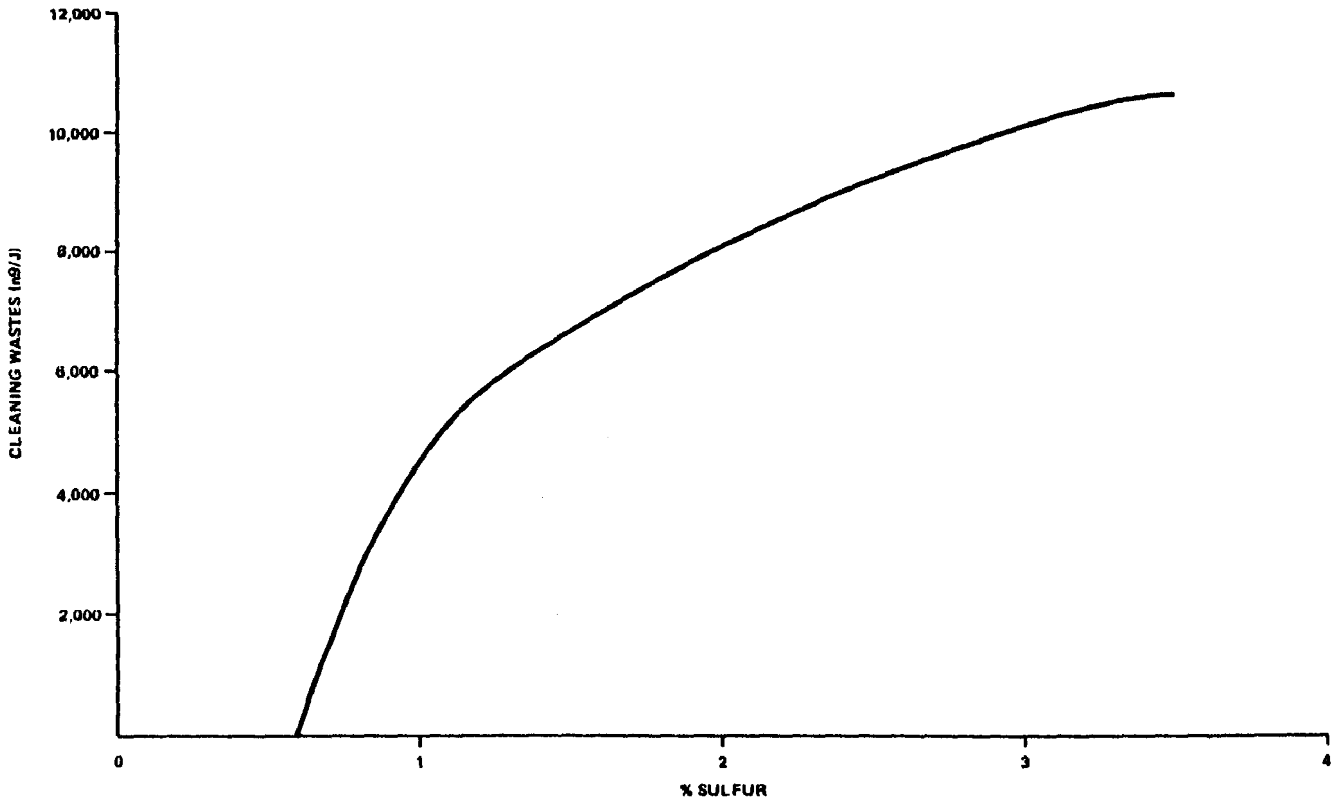

FIGURE 6-1 CLEANING WASTES VS. % SULFUR OF COAL BURNED

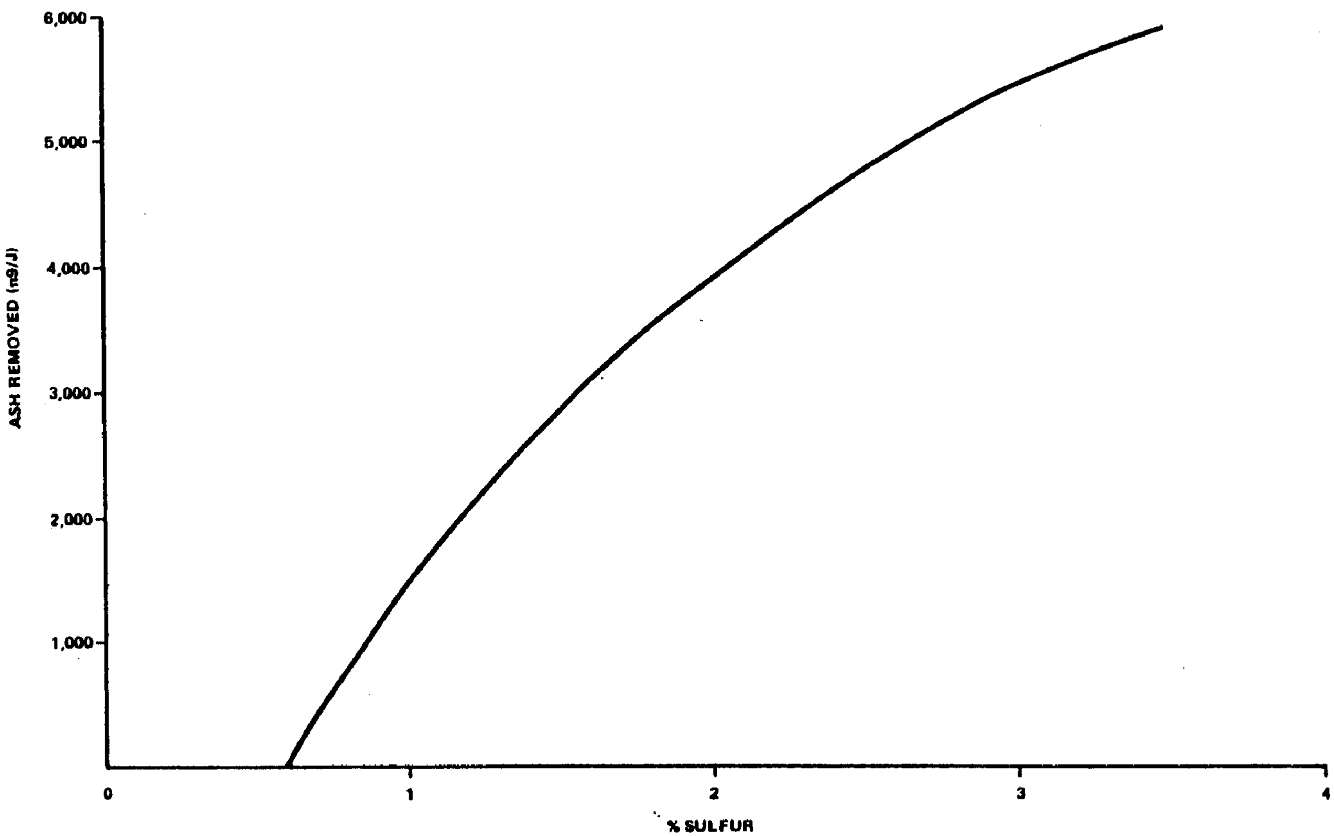

FIGURE 6-2 ASH REMOVED VS. % SULFUR OF COAL BURNED

SECTION 6.0

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SECTION 7.0

EMISSION SOURCE TEST DATA

7.1 INTRODUCTION

The intent of Section 7.0 is to present actual emissions test data from industrial boilers using the control technology. For this ITAR, it means measuring SO_2, particulates, and/or NO_x emissions from industrial boilers burning physically or chemically cleaned coal. To truly test the control technology, it is required that the boiler initially burn an unwashed coal and then burn a washed coal. To our knowledge only one such test was performed, in 1968 by TVA on identical 200 MW boilers.(1) This test, however, only studied relative maintenance cost advantages of washed coal and did not provide comparable emission measurements.

As an alternative, since emission factors for various boilers have been determined in AP-42,(2) input fuel characteristics (sulfur and ash content) will give an accurate estimate of boiler emissions. Therefore, if actual measured cleaned product coal characteristics are compared to the raw (feed) coal, emission control capabilities can be established. The precedent for using feed coal and product coal characteristics to determine percent sulfur removal is provided as Appendix A, Reference Method 19, to the proposed NSPS for electric utility steam generating units.(3) The principle behind this method is that fuel analyses of sulfur content and BTU content taken before and after fuel pretreatment systems allow calculation of percent sulfur dioxide reduction (ng/J). Consistent with this approach, Versar has recently completed a study of the capability of physical coal cleaning to reduce emissions by sulfur removal and BTU enhancement using measured fuel characteristics data provided by U.S. coal companies and the EPA.(4) The data were expected to provide guidance to EPA Office of Air Quality Planring and Standards on sulfur dioxide emission control and attenuation of sulfur variability in coal achieved by cleaning plants of different types, as well as satisfy the requirements of ORD.

7.2 PROJECT METHODOLOGY

Three tasks were performed to accomplish the study. Collection of existing coal cleaning data was the first task. The second task involved checking the data, converting the raw data to quantity of SO_2 per unit heat value, and performing straightforward statistical calculations. The third task was to analyze the data to determine important relationships and relevant trends.

7.2.1 Data Acquisition

Existing preparation plant data were solicited from coal cleaning plant owners. This was accomplished through the National Coal Association who contacted a selected list of companies which operate cleaning plants in different coal regions of the U.S. In total, the selected companies operate 111 preparation plants, which represent over 25 percent of all U.S. plants. In addition, Versar requested data from one coal company not in the NCA which operates 4 preparation plants in the Alabama region.

In response to the NCA request, Versar received data from 46 plants operated by eight coal companies. Since multiple lot information was requested and received, Versar was provided with 114 paired feed and product data points.

Versar also obtained EPA-collected data from a 1972 air pollution study of coal preparation plants.[4] These data included 1972 annual average feed and product values from 130 coal preparation plants.

A third data source was the commercial coal cleaning plant test program being conducted by Versar and its subcontractor Denver Equipment Division of Joy Manufacturing Company under EPA Contract 68-02-2199. At the time of this study, three sets of 5-day test results were available for analysis.

Sufficient data for statistical analyses were received for three coal regions - Northern Appalachia, Southern Appalachia, and Eastern Midwest.

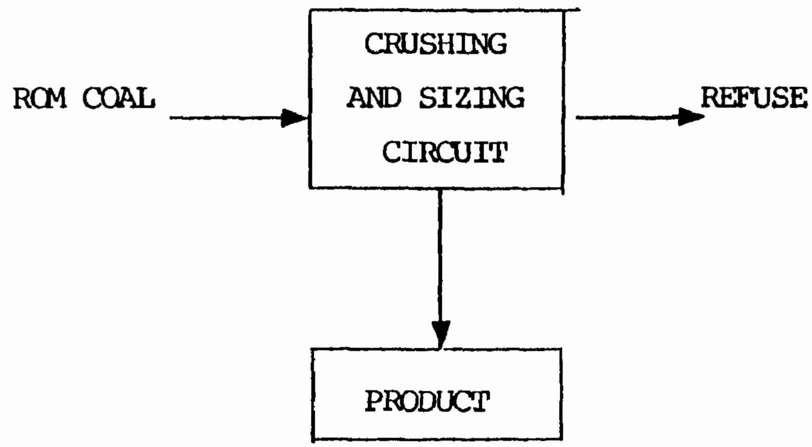
Preparation plants were categorized by four general cleaning levels. Generic flow diagrams of these cleaning levels are shown on Figures 7-1 through 7-4. (These figures are generically equivalent to Figures 2-16 through 2-19 in Section 2.0). Level I coal preparation consists of crushing and sizing to remove large pieces of rock and overburden and to size to product specifications. Level II coal preparation starts by crushing the coal then sizing at approximately 9.2 mm (3/8 inch); the plus 9.2 mm material is processed in a coarse coal washing system such as a jig or dense medium vessel, while the minus 9.2 mm material is not cleaned, but simply blended with the clean product or sent to refuse.

Coal preparation levels III and IV process finer sizes of coal than the first two levels, and subsequently achieve greater rejection of ash and sulfur with subsequent BTU enhancement. Both of these levels process the plus 9.2 mm material with a coarse coal washing system while the 9.2 mm by 28 mesh fraction is processed by a fine coal washing system consisting of a heavy media cyclone or washing table. Coal preparation level III processes the minus 28 mesh material with a hydrocyclone circuit which will recover about 50 percent of the minus 28 mesh feed. Coal preparation level IV processes the minus 28 mesh material with a froth flotation circuit to achieve deep cleaning and enhanced product recovery.

7.2.2 Data Accuracy - Sampling Methods

To provide an understanding of the reliability and accuracy of the data provided, the coal companies were asked to describe their sampling methods. Several coal company representatives remarked that specific coal sampling procedures differ at each plant relative to how the sample is taken, its frequency, the method for producing a composite sample and where the feed and product coals are sampled. A general description, however, could be provided in most cases.

For feed coal, infrequent, manual sampling is the norm. The terms 'occasionally', 'weekly', 'only when we have problems', and 'periodically' were used to describe typical feed coal sample frequency. In a majority



LEVEL 1

FIGURE 7-1. LEVEL I PLANT

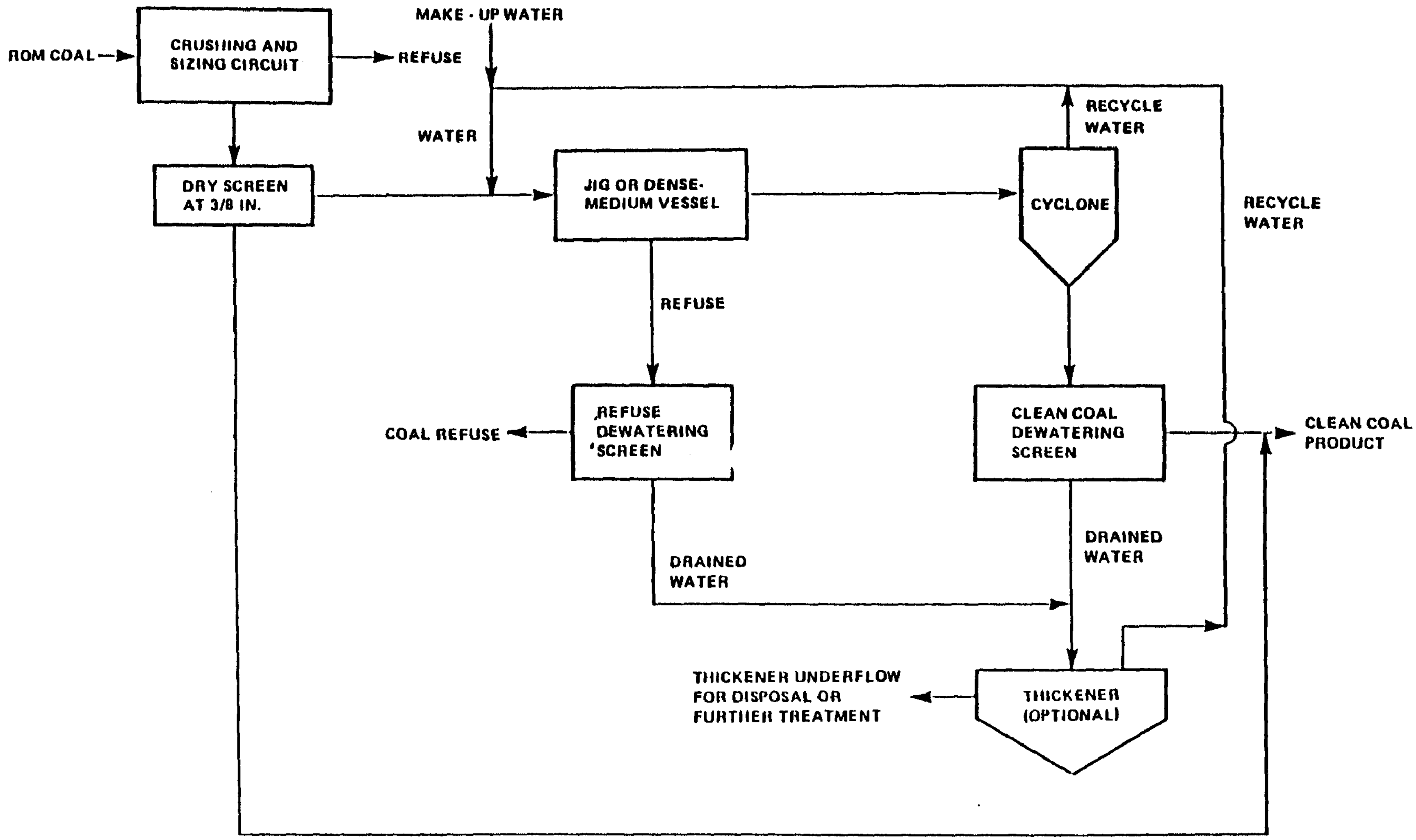


FIGURE 7-2. LEVEL II PLANT

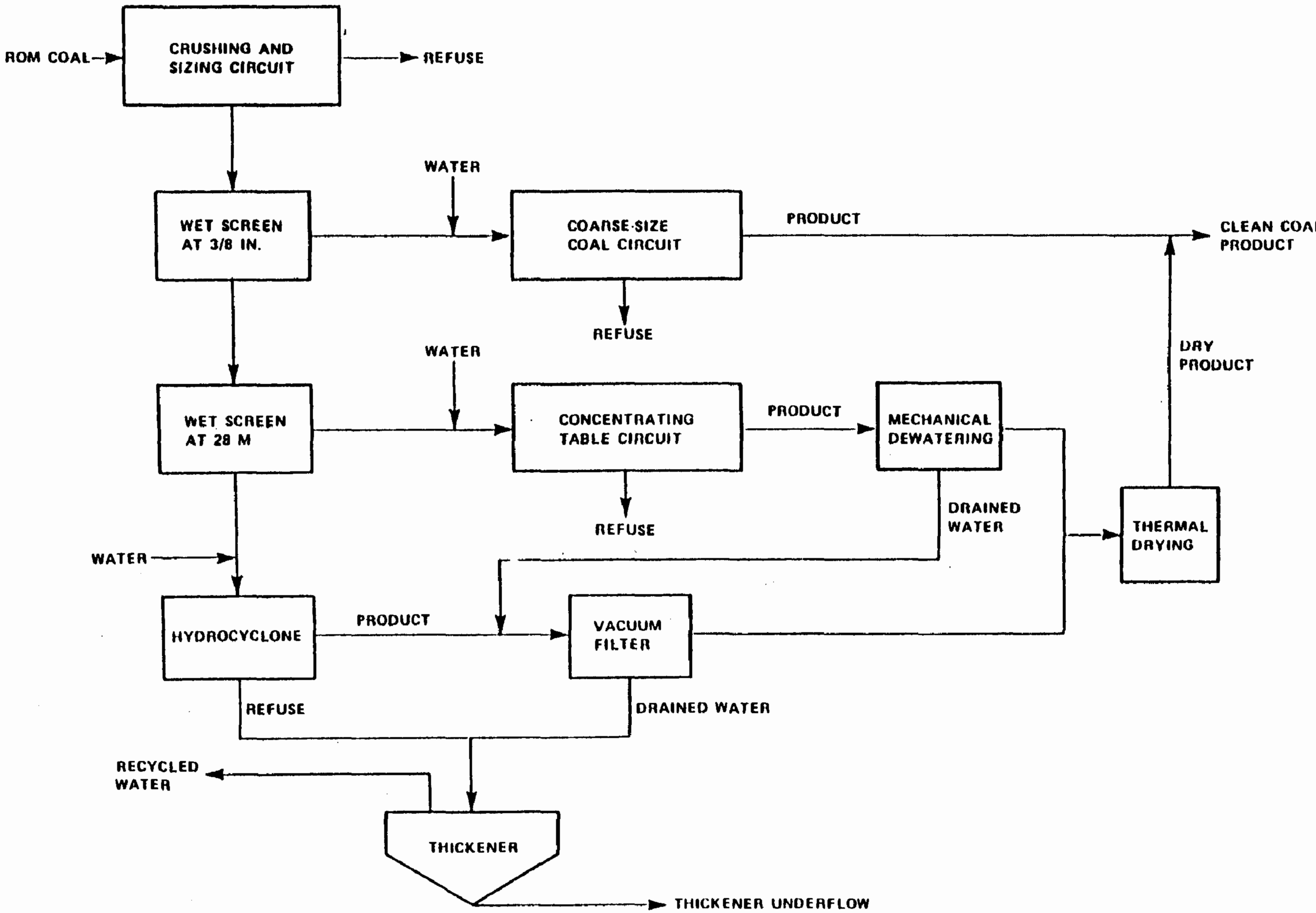


FIGURE 7-3. LEVEL III PLANT

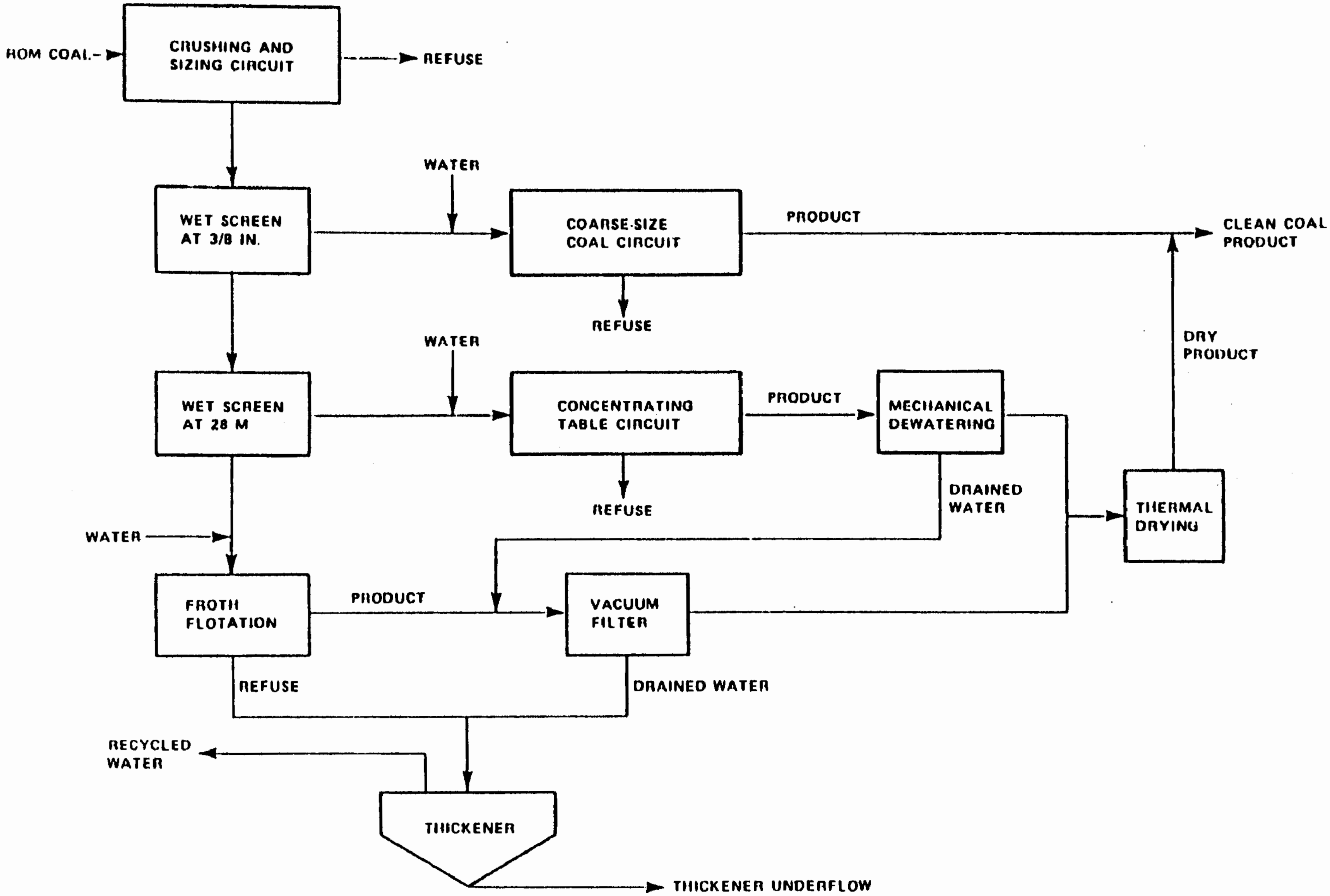


FIGURE 7-4. LEVEL IV PLANT

of the cases, the feed coal belt is stopped and an American Standards and Testing Method (ASTM) belt sample is taken. The sample is a good dependable representation of the input coal at that time, however, it should not be considered a reliable value for feed coal in the short- and medium-term. This was an overriding factor that led some of the coal companies to send monthly and yearly average values, rather than the daily, weekly, or lot shipment information requested. The feed coal values provided to Versar were generally weighted averages of feed coal belt sample analyses.

In contrast, the product coal is extensively sampled and analyzed. The coal companies typically take a one or two hour composite sample of the product, if the plant has an automatic sampler, or will manually sample unit train carloads or barges according to ASTM sampling procedures. The automatically sampled composites consist of individual samples taken at 5-15 minute intervals. The manual samples are usually taken off a conveyor discharge as the railroad car or barge is loaded.

The frequency of product sampling is somewhat determined by the origin of the coal feed to the preparation plant. For a mine mouth coal cleaning plant only one composite sample per day may be analyzed; at the other extreme, where specifications are tight and contract coal is blended and cleaned, the composite samples may be taken and analyzed every 30 minutes. Where possible, Versar has specified data which were received from plants with automatic product samplers.

Although the testing and analysis procedures were not explicitly provided by the coal companies it is normal practice for coal preparation plants to use or specify ASTM methods. For heat content, ASTM method D2015 was used and for total sulfur content, ASTM D3177 was the method used.

7.2.3 Statistical Procedures

The coal preparation plant data, as received, were checked for completeness and consistency with the information requested. A complete data set included feed and product sulfur content (dry), BTU-content (dry), and lot size, and general information on the source of coal (seam, county, and state) and level of cleaning. The data set was then categorized by coal region, cleaning level, seam, and lot size. For average monthly data the information was often supplied on a ton per day (TPD) basis, the 'lot size' was calculated by multiplying the TPD by 22 working days per month.

After categorizing all the data received, the arithmetic mean (μ), standard deviation (σ), and relative standard deviation (RSD) were calculated for each category and subcategory. The mean and standard deviation values presented were determined from the entire data set, rather than averaging subset values,which is an incorrect statistical procedure.

To use these sample statistics as an estimate of the universe statistics, the central limit theorem is assumed to hold. That is, the universe coal parameter distributions were assumed to be normally distributed and therefore the sampling distribution of the mean derived from each distribution also is normally distributed. Also the expected value of the sampling distribution of the mean is equal in value to the universe mean.

Another statistical analysis was determination of the relationship between feed and product coals on a weight of sulfur dioxide per unit heat input basis. Another relationship studied included reduction in ng SO_2/J RSD, from feed to product.

An analysis that was attempted but which did not yield meaningful results was the reduction of μ, σ, and RSD by coal cleaning on a regional basis. The heterogeneity of the coal in each region causes the data sets to lose their normal distribution characteristics when many seams are aggregated. Since a regional ng SO_2/J distribution depends on which seams are incorporated and how much data from each seam is included, the distribution will differ significantly depending on the input data used. The data provided and analysis results, therefore, should not be considered representative of the region. A theoretical study analyzing the universal coal data in each region would be representative; however there was insufficient actual cleaning information to treat the universal data set in each region from this study.

7.3 DATA PRESENTATION AND ANALYSIS

A general breakdown of the data received is presented in Table 7-1. A listing of the data is provided in Appendix C. Although only four of the six coal regions were represented by the data provided, the information was diverse relative to coal seam, cleaning level, coal use (metallurgical and steam), and sulfur content. To supplement the data from the coal companies, Versar has included for this study the results of three sampling and analysis tests from its EPA Contract 68-01-2199. These results are also provided in Appendix C.

7.3.1 Analysis of Individual Physical Coal Cleaning Plants

The approach taken to analyze sulfur removal capabilities by coal cleaning plants was to begin with individual plants. For each plant with sufficient feed and product coal data the mean (μ), standard deviation (σ), and relative standard deviation (RSD) were calculated to determine the variation in sulfur removal for the most constant situation (i.e. only feed coal characteristics change). Data analyses for the nine individual plants are provided in Tables 7-2 through 7-10.

The nine individual plants show that sulfur content per unit heat content (i.e. ng SO_2/J) is treated by the coal preparation process. This occurs even though the plants were primarily designed to remove refuse and ash in their attempt to increase BTU content and are not designed specifically to remove sulfur. Sulfur removal percentages ranged from 18.3 to 48.3. On absolute terms, a sulfur reduction equivalent of 150 ng SO_2/J was attained on the lowest sulfur coal (Plant I) and 1,400 ng SO_2/J was provided on one of the highest sulfur coals (Plant D).

Significantly, in all nine plants the standard deviation (i.e. sulfur variability) in ng SO_2/J was reduced and in eight of the nine plants the RSD decreased. Figure 7-5 shows the magnitude of the decrease in RSD between the feed and product for nine coal cleaning plants, each operating

TABLE 7-1. CLASSIFICATION OF DATA RECEIVED FROM COAL COMPANIES AND TESTING BY VERSAR/JOY-DENVER

NO. OF DATA SETS = 129

REGIONAL DISTRIBUTION

N. Appalachia	=	39
S. Appalachia	=	40
E. Midwest	=	45
Alabama	=	5

CLEANING LEVEL

N. Appalachia	S. Appalachia	E. Midwest	Alabama
Level 1 = 2	Level 1 = 0	Level 1 = 4	Level 4 = 5
Level 2 = 7	Level 2 = 3	Level 2 = 22	
Level 3 = 22	Level 3 = 14	Level 3 = 18	
Level 4 = 8	Level 4 = 23	Level 4 = 1	

SULFUR CONTENT OF FEED COAL

>3%	=	61
1-3%	=	35
<1%	=	33

SULFUR CONTENT OF FEED COAL BY REGION

	>3%	1-3%	<1%
N. Appalachia	19	18	2
S. Appalachia	0	12	28
E. Midwest	42	2	1
Alabama		3	2

LOT QUANTITY (METRIC TONS) - DATA SETS IN EACH RANGE

≥500,000	=	5
100,000-499,999	=	49
10,000- 99,999	=	44
1,000- 9,999	=	18
<999	=	13

TABLE 7-2A. MONTHLY AVERAGE SULFUR REDUCTION BY A LEVEL II CLEANING PLANT - ILLINOIS NO. 6 COAL - (SI Units)

PLANT A

COAL USE	LOT QUANTITY* (metric tons)	FEED %S	FEED kJ/kg	FEED ng SO_2/J	PRODUCT %S	PRODUCT kJ/kg	PRODUCT ng SO_2/J
Steam	169,462	3.98	25,893	3,078.8	3.64	28,130	2,592.9
Steam	339,826	4.27	25,117	3,405.6	3.93	28,130	2,799.3
Steam	313,257	4.74	25,465	3,728.1	3.83	27,986	2,743.4
Steam	331,132	4.72	25,609	3,693.7	3.94	28,070	2,812.2
Steam	318,613	4.10	25,490	3,225.0	3.83	28,098	2,730.5
Steam	267,310	4.45	24,463	3,646.4	3.71	28,035	2,653.1
Steam	271,923	4.87	24,008	4,063.5	4.40	28,652	3,078.8
Steam	272,630	5.16	24,947	4,145.2	4.34	28,608	3,040.1
Steam	289,303	5.05	25,528	3,964.6	4.44	28,822	3,087.4
Steam	254,843	5.44	25,027	4,355.9	4.46	28,706	3,113.2
Steam	275,065	4.98	24,272	4,110.8	4.42	28,582	3,100.3
Steam	221,743	5.20	25,083	4,153.8	4.29	28,640	3,001.4

FEED (ng SO_2/J)

$\mu = 3,796.9$ $\sigma = 404.2$ RSD = 0.106

PRODUCT (ng SO_2/J)

$\mu = 2,898.2$ $\sigma = 193.5$ RSD = 0.067

SULFUR REMOVAL (%)

$\mu = 23.4$ $\sigma = 5.86$ RSD = .25

* Monthly Coal Throughput
Product sampled mechanically

TABLE 7-2B. MONTHLY AVERAGE SULFUR REDUCTION BY A LEVEL II CLEANING PLANT - ILLINOIS NO. 6 COAL - (English Units)

PLANT A

		FEED			PRODUCT		
COAL USE	LOT QUANTITY* (tons)	%S	BTU/lb	lb SO_2/ 10^6BTU	%S	BTU/lb	lb SO_2/ 10^6BTU
Steam	186,838	3.98	11,113	7.16	3.64	12,073	6.03
Steam	374,670	4.27	10,780	7.92	3.93	12,073	6.51
Steam	345,377	4.74	10,929	8.67	3.83	12,011	6.38
Steam	365,085	4.72	10,991	8.59	3.94	12,047	6.54
Steam	351,282	4.10	10,940	7.50	3.83	12,059	6.35
Steam	294,719	4.45	10,499	8.48	3.71	12,032	6.17
Steam	299,805	4.87	10,304	9.45	4.40	12,297	7.16
Steam	300,584	5.16	10.707	9.64	4.34	12,278	7.07
Steam	318,967	5.05	10,956	9.22	4.44	12,370	7.18
Steam	280,974	5.44	10,741	10.13	4.46	12,320	7.24
Steam	303,269	4.98	10,417	9.56	4.42	12,267	7.21
Steam	244,479	5.20	10,765	9.66	4.29	12,292	6.98

FEED (lbs $SO_2/10^6$BTU)

$\mu = 8.83$ $\sigma = 0.94$ RSD = 0.106

PRODUCT (lbs $SO_2/10^6$BTU)

$\mu = 6.74$ $\sigma = 0.45$ RSD = 0.067

SULFUR REMOVAL (%)

$\mu = 23.4$ $\sigma = 5.86$ RSD = .25

* Monthly Coal Throughput

Product sampled mechanically

TABLE 7-3A. MONTHLY AVERAGE SULFUR REDUCTION BY A LEVEL II CLEANING PLANT - KENTUCKY #9 and #14 - (SI Units)

PLANT B

	Feed			Product		
Quantity* (metric tons)	%S	kJ/kg	ng SO_2/J	%S	kJ/kg	ng SO_2/J
184,913	4.17	25,712	3,250.8	3.21	30,411	2,115.6
162,692	4.64	27,557	3,375.5	3.23	30,437	2,124.2
189,817	4.08	27,981	2,919.7	3.24	30,360	2,137.1
183,209	3.96	24,533	3,233.6	3.14	32,450	1,939.3
266,168	3.98	27,054	2,949.8	3.13	30,236	2,072.6
180,382	4.13	25,430	3,255.1	3.18	30,187	2,111.3

Coal Use: Steam

Feed (ng SO_2/J)

μ = 3,164.8 σ = 191.78 RSD = 0.061

Product (ng SO_2/J)

μ = 2,085.5 σ = 43.43 RSD = 0.021

Sulfur Removal (%)

μ = 33.2 σ = 4.26 RSD = 0.128

* Monthly Coal Throughput
Product sampled mechanically

TABLE 7-3B. MONTHLY AVERAGE SULFUR REDUCTION BY A LEVEL II CLEANING PLANT - KENTUCKY #9 and #14 - (English Units)

Lot Quantity (tons) *	Feed %S	Feed BTU/lb	Feed lb SO_2/10^6BTU	Product %S	Product BTU/lb	Product lb SO_2/10^6BTU
203,873	4.17	11,035	7.56	3.21	13,052	4.92
179,374	4.64	11,827	7.85	3.23	13,063	4.94
209,280	4.08	12,009	6.79	3.24	13,030	4.97
201,994	3.96	10,529	7.52	3.14	13,927	4.51
293,460	3.98	11,611	6.86	3.13	12,977	4.82
198,878	4.13	10,914	7.57	3.18	12,956	4.91

Coal Use: Steam

Feed (lbs $SO_2/10^6$BTU)

$\mu = 7.36$ $\sigma = 0.446$ RSD = 0.061

Product (lbs $SO_2/10^6$BTU)

$\mu = 4.85$ $\sigma = 0.101$ RSD = 0.021

Sulfur Removal (%)

$\mu = 33.2$ $\sigma = 4.26$ RSD = 0.128

* Monthly Coal Throughput

Product sampled mechanically

TABLE 7-4A. MONTHLY AVERAGE SULFUR REDUCTION BY A LEVEL II CLEANING PLANT - KENTUCKY #9 - (SI Units)

PLANT C

	FEED			PRODUCT		
Lot Quantity (metric tons)*	%S	kJ/kg	ng SO_2/J	%S	kJ/kg	ng SO_2/J
113,068	4.72	29,002	3,263.7	3.40	30,339	2,244.6
105,246	4.07	28,857	2,825.1	3.40	30,013	2,270.4
92,494	3.99	28,004	2,855.2	3.36	30,278	2,223.1
83,306	3.96	27,177	2,919.7	3.30	30,285	2,184.4
81,723	5.05	28,319	3,573.3	3.35	30,183	2,223.1
68,479	3.93	29,656	2,657.4	3.38	30,262	2,236.0

Coal Use: Steam

Feed (ng SO_2/J)

$\mu =$ 3,014.3 $\sigma =$ 342.3 RSD = 0.114

Product (ng SO_2/J)

$\mu =$ 2,231.7 $\sigma =$ 28.0 RSD = 0.012

Sulfur Removal (%)

$\mu =$ 25.2 $\sigma =$ 7.96% RSD = 0.316

* Product sampled manually

TABLE 7-4B. MONTHLY AVERAGE SULFUR REDUCTION BY A LEVEL II CLEANING PLANT - KENTUCKY #9- (English Units)

PLANT C

	Feed			Product		
LOT QUANTITY (tons) *	%S	BTU/lb	lb SO_2/10^6BTU	%S	BTU/lb	lb SO_2/10^6BTU
124,662	4.72	12,447	7.59	3.40	13,021	5.22
116,037	4.07	12,385	6.57	3.40	12,881	5.28
101,978	3.99	12,019	6.64	3.36	12,995	5.17
91,848	3.96	11,664	6.79	3.30	12,998	5.08
90,102	5.05	12,154	8.31	3.35	12,954	5.17
75,501	3.93	12,728	6.18	3.38	12,988	5.20

Coal Use: Steam

Feed (lbs $SO_2/10^6$BTU)

$\mu = 7.01$ $\sigma = 0.796$ RSD = 0.114

Product (lbs $SO_2/10^6$BTU)

$\mu = 5.19$ $\sigma = 0.065$ RSD = 0.012

Sulfur Removal (%)

$\mu = 25.2$ $\sigma = 7.96$ RSD = 0.316

*Product sampled manually

TABLE 7-5A. MONTHLY AVERAGE SULFUR REDUCTION FOR A LEVEL 2 COAL CLEANING PLANT - KENTUCKY Nos. 11 and 12 - (SI Units)

PLANT D

LOT QUANTITY (metric tons)*	FEED %S	FEED kJ/kg	FEED ng SO_2/J	PRODUCT %S	PRODUCT kJ/kg	PRODUCT ng SO_2/J
264,129	3.99	25,171	3,177.7	3.31	29,246	2,266.1
224,563	4.25	22,883	3,719.5	3.39	29,113	2,334.9
234,109	3.77	24,675	3,061.6	3.29	29,435	2,240.3
156,950	-	-	-	3.20	29,565	2,167.2
182,844	-	-	-	3.15	29,572	2,132.8
179,810	5.03	22,992	4,381.7	2.97	29,899	1,990.9

Coal Use: Steam

Feed (ng SO_2/J)

$\mu = 3,586.2$ $\sigma = 602.0$ RSD = 0.168

Product (ng SO_2/J)

$\mu = 2,188.7$ $\sigma = 114.0$ RSD = 0.052

Sulfur Removal (%)

$\mu = 36.83$ $\sigma = 12.89$ RSD = 0.350

*Product sampled manually

TABLE 7-5B. MONTHLY AVERAGE SULFUR REDUCTION FOR A LEVEL 2 COAL CLEANING PLANT - KENTUCKY Nos. 11 and 12 - (English Units)

PLANT D

LOT QUANTITY (tons) *	FEED %S	FEED BTU/lb	FEED lb SO_2/ 10^6BTU	PRODUCT %S	PRODUCT BTU/lb	PRODUCT lb SO_2/ 10^6BTU
291,212	3.99	10,803	7.39	3.31	12,552	5.27
247,589	4.25	9,821	8.65	3.39	12,495	5.43
258,113	3.77	10,590	7.12	3.29	12,633	5.21
173,043	-	-	-	3.20	12,689	5.04
201,592	-	-	-	3.15	12,692	4.96
198,247	5.03	9,868	10.19	2.97	12,832	4.63

Coal Use: Steam

Feed (lb $SO_2/10^6$BTU)

$\mu = 8.34$ $\sigma = 1.40$ RSD = 0.168

Product (lb $SO_2/10^6$BTU)

$\mu = 5.09$ $\sigma = 0.265$ RSD = 0.052

Sulfur Removal (%)

$\mu = 36.83$ $\sigma = 12.89$ RSD = 0.350

*Product sampled manually

TABLE 7-6A. MONTHLY AVERAGE SULFUR REDUCTION BY A LEVEL II CLEANING PLANT - MIDDLE KITTANING (Ohio No. 6) - (SI Units)

PLANT E

COAL USE	LOT QUANTITY (metric tons)*	FEED %S	FEED kJ/ng	FEED ng SO_2/J	PRODUCT %S	PRODUCT kJ/ng	PRODUCT ng SO_2/J
Steam	154,565	4.07	25,756	3,164.8	3.03	29,111	2,085.5
Steam	138,162	3.73	27,180	2,747.7	2.86	29,041	1,973.7
Steam	162,063	3.98	26,047	3,061.6	3.06	29,037	2,111.3
Steam	145,074	4.46	25,029	3,569.0	3.05	28,992	2,107.0
Steam	189,246	3.96	25,248	3,143.3	3.06	29,044	2,111.3
Steam	163,255	3.45	25,465	2,713.3	2.99	28,957	2,068.3

Feed (ng SO_2/J)

$\mu = 3,065.9$ $\sigma = 322.9$ RSD = 0.105

Product (ng SO_2/J)

$\mu = 2,076.9$ $\sigma = 37.4$ RSD = 0.018

Sulfur Removal (%)

$\mu = 32.0$ $\sigma = 5.91$ RSD = 0.185

*Product sampled manually

TABLE 7-6B. MONTHLY AVERAGE SULFUR REDUCTION BY A LEVEL II CLEANING PLANT - MIDDLE KITTANING (Ohio No. 6) - (English Units)

PLANT E

		FEED			PRODUCT		
COAL USE	LOT QUANTITY (tons) *	%S	BTU/lb	lb SO_2/ 10^6BTU	%S	BTU lb	lb SO_2/ 10^6BTU
Steam	170,413	4.07	11,054	7.36	3.03	12,494	4.85
Steam	152,329	3.73	11,665	6.39	2.86	12,464	4.59
Steam	178,680	3.98	11,179	7.12	3.06	12,462	4.91
Steam	159,949	4.46	10,742	8.30	3.05	12,443	4.90
Steam	208,650	3.96	10,836	7.31	3.06	12,465	4.91
Steam	179,994	3.45	10,929	6.31	2.99	12,428	4.81

Feed (lbs $SO_2/10^6$BTU)

$\mu = 7.13$ $\sigma = 0.751$ RSD = 0.105

Product (lbs $SO_2/10^6$BTU)

$\mu = 4.83$ $\sigma = 0.087$ RSD - .018

Sulfur Removal (%)

$\mu = 32.0$ $\sigma = 5.91$ RSD = 0.185

*Product sampled manually

TABLE 7-7A. ANNUAL AVERAGE SULFUR REDUCTION BY A LEVEL 3 CLEANING PLANT - OHIO COAL - (SI Units)

PLANT F

	FEED			PRODUCT *		
SEAM	%S	kJ/kg	ng SO_2/J	%S	kJ/kg	ng SO_2/J
#8	3.28	22,524	2919.7	3.96	30,831	2575.7
LF	2.92	21,313	2743.4	2.94	32,203	1827.5
#8	2.05	21,750	1887.7	2.78	31,502	1767.3
LF	2.55	27,459	1861.9	2.34	32,571	1440.5
#8	5.09	28,622	3564.7	3.59	31,294	2300.5
#9	2.51	28,885	1741.5	2.15	30,024	1436.2
#9	3.02	29,130	2076.9	2.51	30,462	1651.2
#8	2.67	29,498	1814.6	2.33	32,282	1444.8

SEAM: Pittsburgh #8 and #9; Lower Freeport #6A ('D' Coal)

Coal Use: Steam

Feed

μ = 2326.3 ng SO_2/J σ = 670.8 ng SO_2/J   RSD = 0.288

Product

μ = 1806.0 ng SO_2/J σ = 426.1 ng SO_2/J   RSD = 0.236

Sulfur Removal

μ = 21.0% σ = 9.85%   RSD = 0.469

*Product sampled manually

TABLE 7-7B. ANNUAL AVERAGE SULFUR REDUCTION BY A LEVEL 3 CLEANING PLANT - OHIO COAL - (English Units)

	FEED			PRODUCT*		
SEAM	%S	BTU/lb	lb SO_2/10^6BTU	%S	BTU/lb	lb SO_2/10^6BTU
#8	3.28	9,667	6.79	3.96	13,232	5.99
LF	2.92	9,147	6.38	2.94	13,821	4.25
#8	2.05	9,335	4.39	2.78	13,520	4.11
LF	2.55	11,785	4.33	2.34	13,979	3.35
#8	5.09	12,284	8.29	3.59	13,431	5.35
#9	2.51	12,397	4.05	2.15	12,886	3.34
#9	3.02	12,502	4.83	2.51	13,074	3.84
#8	2.67	12,660	4.22	2.33	13,855	3.36

SEAM: Pittsburgh #8 and #9; Lower Freeport #6A ('D' Coal)

Coal Use: Steam

Feed (lbs SO_2/10^6BTU)

$\mu = 5.41$ $\sigma = 1.56$ RSD = 0.288

Product (lbs SO_2/10^6BTU)

$\mu = 4.20$ $\sigma = 0.991$ RSD = 0.236

Sulfur Removal

$\mu = 21.0\%$ $\sigma = 9.85\%$ RSD = 0.469

*Product sampled manually

TABLE 7-8A. DAILY AVERAGE SULFUR REDUCTION BY A LEVEL III CLEANING PLANT - LOWER KITTANING - 5 DAY TESTS* (SI Units)

	FEED			PRODUCT		
Day	%S	kJ/kg	ng SO_2/J	%S	kJ/kg	ng SO_2/J
1	2.80	31,420	1,784.5	1.11	34,069	653.6
2	2.24	30,008	1,496.4	1.20	33,200	722.4
3	1.84	28,198	1,307.2	1.22	32,960	739.6
4	1.46	29,491	993.3	0.82	33,533	490.2
5	1.38	31,756	872.9	0.99	33,634	589.1

Lot Size = 581 metric tons

Coal Use: Metallurgical

Feed (ng SO_2/J)

μ = 1,290 σ_x = 369.8 RSD = 0.29

Product (ng SO_2/J)

μ = 640.7 σ_x = 103.2 RSD = 0.16

Sulfur Removal (%)

μ = 48.3 σ = 11.4 RSD = 0.237

Seam Coal

Lower Freeport - Kittaning B,C,D,E

*Grab sample taken every 15 minutes over four hour period per day

TABLE 7-8B. DAILY AVERAGE SULFUR REDUCTION BY A LEVEL III CLEANING PLANT - LOWER KITTANING - 5 DAY TESTS-*

(English Units)

PLANT G

	Feed			Product		
DAY	%S	BTU/lb	lb SO_2/ 10^6BTU	%S	BTU/lb	lb SO_2/ 10^6BTU
1	2.80	13,485	4.15	1.11	14,622	1.52
2	2.24	12,879	3.48	1.20	14,249	1.68
3	1.84	12,102	3.04	1.22	14,146	1.72
4	1.46	12,657	2.31	0.82	14,392	1.14
5	1.38	13,629	2.03	0.99	14,435	1.37

Lot Size = 640 Tons

Coal Use: Metallurgical

Feed (lbs $SO_2/10^6$BTU)

$\mu = 3.00$ $\sigma_x = .86$ RSD = 0.29

Product (lbs $SO_2/10^6$BTU)

$\mu = 1.49$ $\sigma_x = .24$ RSD = 0.16

Sulfur Removal (%)

$\mu = 48.3$ $\sigma = 11.4$ RSD = 0.237

Seam Coal

Lower Freeport - Kittaning B,C,D,E

*Grab sample taken every 15 minutes over four hour period per day

TABLE 7-9A. DAILY AVERAGE SULFUR REDUCTION BY A LEVEL III PLANT - SOUTH WESTERN VIRGINIA SEAMS - 5 DAY TESTS - (SI Units)*

PLANT H

	FEED			PRODUCT		
Day	%S	kJ/kg	ng SO_2/J	%S	kJ/kg	ng SO_2/J
1	1.24	25,243	984.7	1.48	33,997	872.9
2	.92	24,178	761.1	1.31	33,666	778.3
3	.82	22,766	722.4	0.89	33,226	537.5
4	1.15	21,394	1,075.0	1.06	33,617	640.7
5	1.10	22,722	971.8	1.10	34,074	645.0

Lot Size = 2,395 - 2,503 metric tons per day

Coal Use: Steam

Feed (ng SO_2/J)

μ = 903.0 σ_x = 154.8 RSD = 0.17

Product (ng SO_2/J)

μ = 696.6 σ_x = 133.3 RSD = 0.19

Sulfur Removal (%)

μ = 21.7 σ = 17.2 RSD = .793

Seam Coal	% Feed
Elkhorn-Rider	12.5
Lyons	12.5
Dorchester	25.0
Norton	25.0
Clintwood	25.0

* Grab sample taken every 15 minutes over four hour period per day

TABLE 7-9B. DAILY AVERAGE SULFUR REDUCTION BY A LEVEL III PLANT - SOUTH WESTERN VIRGINIA SEAMS - 5 DAY TESTS *

	Feed			Product		
DAY	%S	BTU/lb	lb SO_2/ 10^6BTU	%S	BTU/lb	lb SO_2/ 10^6BTU
1	1.24	10,834	2.29	1.48	14,591	2.03
2	.92	10,377	1.77	1.31	14,449	1.81
3	.82	9,771	1.68	0.89	14,260	1.25
4	1.15	9,182	2.50	1.06	14,428	1.49
5	1.10	9,782	2.26	1.10	14,624	1.50

Lot Size = 2,640-2,760 Tons Per Day

Coal Use: Steam

Feed (lbs $SO_2/10^6$BTU)

$\mu = 2.10$ $\sigma_x = .36$ RSD = 0.17

Produce (lbs $SO_2/10^6$BTU)

$\mu = 1.62$ $\sigma_x = .31$ RSD = 0.19

Sulfur Removal (%)

$\mu = 21.7$ $\sigma = 17.2$ RSD = .793

Seam Coal	% Feed
Elkhorn-Rider	12.5
Lyons	12.5
Dorchester	25.0
Norton	25.0
Clintwood	25.0

*Grab sample taken every 15 minutes over four hour period per day

TABLE 7-10A. DAILY AVERAGE SULFUR REDUCTION BY A LEVEL III * CLEANING PLANT - REFUSE COAL - 5 DAY TESTS - (Metric Units)

PLANT I

	FEED			PRODUCT		
Day	%S	kJ/kg	ng SO_2/J	%S	kJ/kg	ng SO_2/J
1	.603	16,466	735.3	.948	31,555	602.0
2	.637	18,936	675.1	.835	30,854	541.8
3	1.099	21,166	1,040.6	1.009	30,083	670.8
4	.570	20,206	563.3	.830	31,066	533.2
5	.582	18,377	636.4	.850	30,716	554.7

Lot Size = 544 metric tons

Coal Use: Metallurgical

Feed (ng SO_2/J)

μ = 731.0 σ_x = 184.9 RSD = 0.25

Product (ng SO_2/J)

μ = 580.5 σ_x = 55.9 RSD = 0.099

Sulfur Removal (%)

μ = 18.3 σ = 11.1 RSD = 0.605

GOB Coal (Refuse)

*Grab sample taken every 15 minutes over four hour period per day

TABLE 7-10B. DAILY AVERAGE SULFUR REDUCTION BY A LEVEL III CLEANING PLANT - REFUSE COAL - 5 DAY TESTS - *
(English Units)

	FEED			PRODUCT		
DAY	%S	BTU/lb	lb SO_2/ 10^6BTU	%S	BTU/lb	lb SO_2/ 10^6BTU
1	.603	7,067	1.71	.948	13,543	1.40
2	.637	8,127	1.57	.835	13,242	1.26
3	1.099	9,084	2.42	1.009	12,911	1.56
4	.570	8,672	1.31	.830	13,333	1.24
5	.582	7,887	1.48	.850	13,183	1.29

Lot Size = 600 Tons

Coal Use: Metallurgical

Feed (lbs $SO_2/10^6$BTU)

$\mu = 1.70$ $\sigma_x = .43$ RSD = 0.25

Product (lbs $SO_2/10^6$BTU)

$\mu = 1.35$ $\sigma_x = .13$ RSD = 0.099

Sulfur Removal

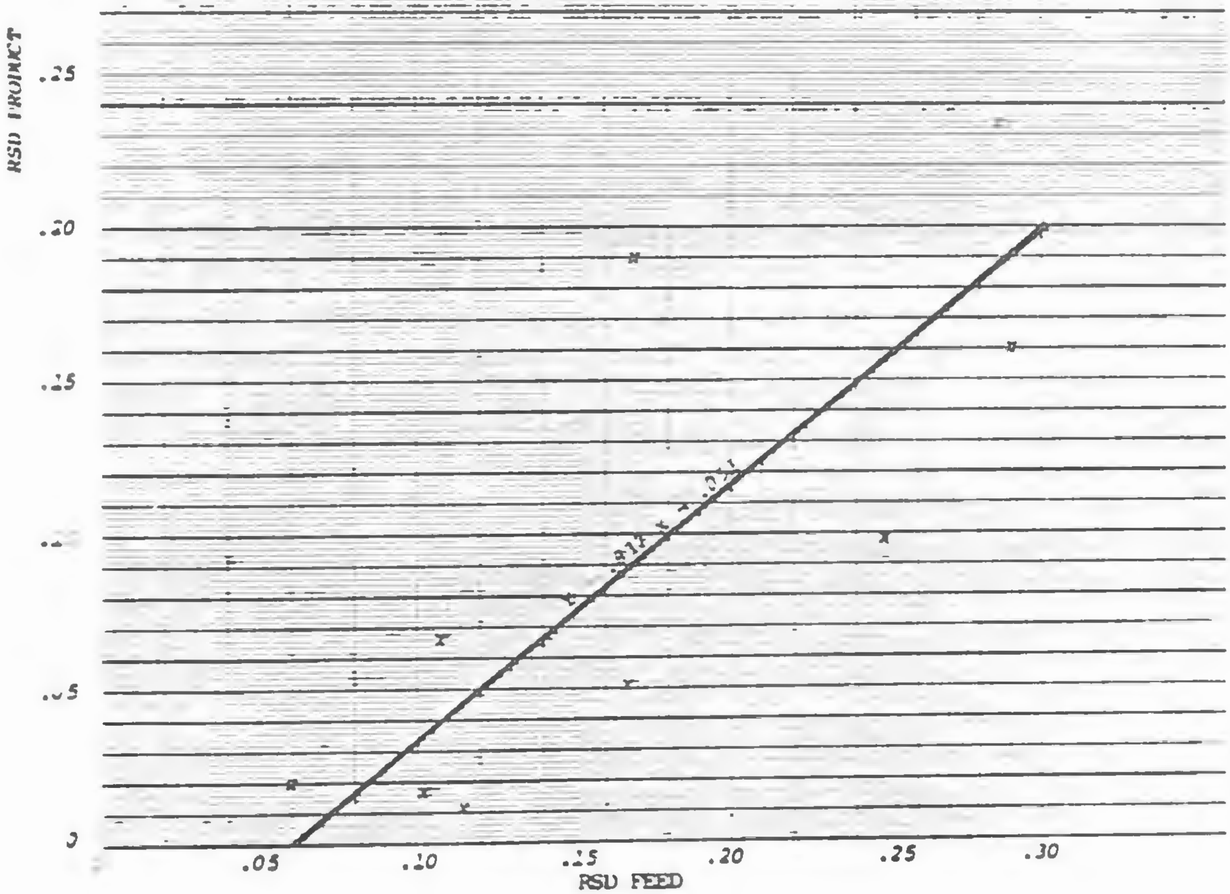
$\mu = 18.3\%$ $\sigma = 11.1\%$ RSD = 0.605

GOB Coal (Refuse)

* Grab sample taken every 15 minutes over four hour period per day

FIGURE 7-5

RELATIONSHIP BETWEEN FEED AND PRODUCT RELATIVE STANDARD DEVIATION (RSD) FOR INDIVIDUAL COAL CLEANING PLANTS



on a different seam. The "line of best fit" equation is:

$$RSD_P = .837\ RSD_F - .051$$

where RSD_P = Relative Standard Deviation of the product coal

RSD_F = Relative Standard Deviation of the feed coal

This equation indicates that the expected value of the RSD_P is less than 0.05 of the RSD_F. The Office of Air Quality Planning and Standards (OAQPS) uses the value for both raw coal and cleaned coal of RSD = 0.15 in its calculations concerning sulfur dioxide emissions. Based on this equation, derived from the percent reduction of RSD at these nine plants, a corresponding value for RSD_P = 0.080 should be used if a value of RSD_F = 0.15 is applied to the raw coal.

It is significant that the two preparation plants that did not provide at least 35% reduction of RSD were cleaning blends of coal or various coals during the time period studied (i.e. Plant F cleans three different seam coals and Plant H cleans a blend of five different coals).

7.3.2 Analysis of Aggregated Data—By Seam and Cleaning Level

As mentioned above, sulfur and BTU content feed and product coal data were received on 46 preparation plants. For the majority of these plants only one value was given for feed and product characteristics, so analyses of in-plant variation is not possible. For the data tables in Appendix A, the final column presents percent removal in terms of ng SO_2/ J.

To examine plant capabilities, but avoid aggregating all the data, Versar analyzed the information on a seam and cleaning level basis within each region. For example, Plant A is a level 3 cleaning plant beneficiating Illinois #6 coal. Versar was provided with cleaning data from eight other plants that receive Illinois #6 coal, of which five also have level 3 cleaning. Tables 7-11 through 7-14 present sulfur removal by seam and cleaning level for each region for data received from the coal companies and Versar's field test results.

TABLE 7-11. EASTERN MIDWEST COAL SULFUR REDUCTION BY SEAM AND CLEANING LEVEL

SEAM	Cleaning Level 1	2	3	4	Average Reduction Levels 2-4	Pts.
Illinois #6	5.6/3	36.3/2	26.7/16	34.9/1	28%	22
Illinois/Indiana #2 & #3		43.4/2			43%	2
Illinois #5			23.4/2		23%	2
Kentucky #9	0/1	29.2/12			29%	13
Kentucky #11 & #12		36.8/6			37%	6
Weighted Averages	4.2/4	33.2/22	26.3/18	34.9/1	30%	45

Values shown are percent reduction in ng SO_2/ J/No. of data points.

TABLE 7-12. NORTHERN APPALACHIA COAL SULFUR REDUCTION BY SEAM AND CLEANING LEVEL

SEAM	Cleaning Level 1	2	3	4	Average Reduction Levels 2-4	Data Points
Pittsburgh, #8	(0/1)	21.5/1	30.6/13	29.8/3	30%	17
#9			19.0/2		19%	2
Middle Kittaning (#6)		32.0/6		49.2/2	36%	8
Lower Freeport (#6A)			23.0/2		23%	2
Lower Kittaning			48.4/5*	45.4/1	48%	6
Upper Freeport				35.1/2	35%	2
Weighted Averages	(0/1)	30.1/7	32.9/2	37.9/8	33%	37

Values shown are percent reduction in ng SO_2/J/No. of data points.

*Blend of B,C,D,E , 'B' predominates

TABLE 7-13. SOUTHERN APPALACHIA COAL SULFUR REDUCTION BY SEAM AND CLEANING LEVEL

SEAM	Cleaning Level 1	2	3	4	Average Reduction Levels 2-4	Data Points
Cedar Grove	N.D.	11.3/3		-25.0/1	2%	4
Jewell	N.D.	N.D.	N.D.	34.0/4	34%	4
Pocahontas 3 & 4	N.D.	N.D.	N.D.	39.4/3	39%	3
Sewell	N.D.	N.D.	11.5/1	54.1/2	40%	3
Various Seams	N.D.	0/2	14.3/12	29.3/14	N.D.	N.D.
Weighted Averages	N.D.	2.6/5	14.1/13	31.2/24	23%	42

Values shown are percent reduction in ng SO_2/ J/No. of data points.

TABLE 7-14. ALABAMA COAL SULFUR REDUCTION BY CLEANING LEVEL

SEAM	Cleaning Level 1	2	3	4	Average Reduction Levels 2-4	Data Points
Mary Lee	N.D.	N.D.	N.D.	40.1/3	40%	3
Blue Creek	N.D.	N.D.	N.D.	42.8/2	43%	2
Weighted Averages	N.D.	N.D.	N.D.	41.1/5	41%	5

Values shown are percent reduction in ng SO_2/ J/No. of data points.

N.D. = No Data

By cleaning level, the ng SO_2/J removed was no definitive trend, except in Southern Appalachia where deep cleaning of the fine coal (cleaning level 4) almost doubles the reduction of SO_2 per unit heat over level 3. Generally, however, the difference between cleaning levels 2, 3, and 4 is negligible relative to reduction capabilities.

The tables also show that reduction varies for seams in the same region. This is due to the varying pyrite quantities in each seam which can be removed by beneficiation. The variation is striking between the Southern Appalachian Cedar Grove seam, which allows only small percentage reductions, and the Pocahontas Nos. 3 and 4 and Sewell seams which allow at least 40 percent reduction in ng SO_2/J.

Percent removal of ng SO_2/J is relatively constant in the four coal regions analyzed. Reduction in SO_2 emissions per unit heat ranges from 25% in Southern Appalachia to 41% in Alabama. The average reduction is about 30% for all regions.

As a supplement to the data received from the coal companies and Versar tests, data were obtained from the 1972 EPA survey of coal preparation plants.[5] About half the plants surveyed provided both ROM and product coal information. The data taken from the survey and compiled were: code # of plant, name of plant/mine, coal company, location (county, state, region), operating capacity for raw and clean coal (T/hr), cleaning level, and BTU, ash, total sulfur (S_{tot}), pyritic sulfur (S_p) and organic sulfur (S_o) for ROM and product usage (Utility, Metallurgical, other). A complete listing of the data is provided in Appendix D. The data consisted of annual average information for each plant. As a result analysis of sulfur reduction within individual preparation plants was not possible. Also, since seam origin for the run-of-mine coal was not provided, analyses on a seam basis could not be performed. The major utility of the data was to calculate the reduction of ng SO_2/J on a cleaning level and regional basis. Table 7-15 summarizes the results.

TABLE 7-15. SULFUR EMISSION REDUCTION DATA BASED ON THE 1972 EPA SURVEY

NON-METALLURGICAL COAL

Region	Cleaning Level 2	Cleaning Level 3	Cleaning Level 4	Mean Removal Levels 2-4	Total Data Points
	(Percentage ng SO_2/J Reduction/ No. of Points)				
N. Appalachia	17.2/10	25.5/2	35.5/8	26.1	20
S. Appalachian	20.7/8	7.4/10	16.2/14	14.8	32
E. Midwest	28.4/3	16.4/8	20.7/3	21.8	14
METALLURGICAL COAL					
N. Appalachian	37.8/3	40.9/2	46.7/5	41.8	10
S. Appalachian	34.5/2	16.5/8	28.6/27	26.5	37
E. Midwest	1.95/1	-1.73/1	16.6/3	5.61	5
Western	0	0	9/2	3.00	2
COMBINED					
N. Appalachian	22.0/13	33.2/4	39.8/13	31%	30
S. Appalachian	23.5/10	11.4/18	24.4/41	21%	69
E. Midwest	21.3/4	14.4/9	18.6/6	17%	19

A comparison of the coal company provided data and EPA 1972 survey data shows considerable consistency. For example, on Northern Appalachian coal for cleaning levels 3 and 4 (and the mean reduction for all cleaning levels) the results for the two sets of data are within two percent. The Southern Appalachian coal results are not as consistent by individual cleaning level, but the mean reduction values for cleaning levels 2, 3 and 4 combined are within four percent. Eastern Midwest coal is the least consistent with a difference between the two data sets of 11-16 percent.

All regions and data sets, except the 1972 Eastern Midwest coal cleaning information, show that deep cleaning through a fine coal circuit (i.e. cleaning level 4) reduces the most ng SO_2/J of the four cleaning levels. Cleaning level 1 provides the least.

Because of its consistency with long-term average data, we conclude that the coal company provided data can be used to estimate the capability of coal cleaning to remove sulfur and enhance energy content.

7.4 CONCLUSIONS

The analysis of the collected data supports the following conclusions:

- Physical coal cleaning is an effective sulfur dioxide control technology. The ng SO_2/J value of the coal is significantly reduced by coal cleaning. The average reductions achieved for different coal regions using coal company-provided data were 33% for Northern Appalachian coals, 23% for Southern Appalachian coals, and 30% for Eastern Midwest coals.
- In terms of ng SO_2/J, preparation plants reduced the mean, standard deviation, and relative standard deviation of the product coal as compared to feed coal in almost every case. The only exceptions were several plants cleaning low sulfur Southern Appalachian coal.

- The difference in reduction of lbs $SO_2/10^6$BTU between cleaning levels 2, 3, and 4 is small, although cleaning level 4 (deep cleaning) always showed the greatest reduction on a regional basis.

- RSD reduction between feed coal and product coal is only valid for individual cleaning plant results and should not be aggregated by seam or region.

SECTION 7.0

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APPENDIX A

DOCUMENTATION FOR THE RESERVE PROCESS ASSESSMENT MODEL

Documentation

To simulate the desulfurization potential of physical coal cleaning a generalized approach was taken. The methodology characterized the entire U.S. reserve base via 36,000 composite coal analyses showing total weight, percent ash, percent sulfur, and BTU content. In addition, each reserve base record was associated with one float-sink analysis as reported by Cavallaro, Johnson, and Deurbrouck in RI8118.(1) The mathematical approach adopted allows the characteristics of the cleaned coal to be obtained from those of the raw coal by scaling the raw coal characteristics by factors dependent on the cleaning process involved and the washability - analysis of the raw coal.

The data used in this study were as follows:

- 587 sets of washability analyses for coal from sample mines in the U.S. as reported by Cavallaro, Johnston, and Deurbrouck.(2)
- The reserve base of U.S. coal, consisting of 3,167 records specifying the weight of each resource for both strip and underground coal, together with the maximum, minimum, and mean levels of the major constituents of the coal in that resource. These data are consistent with those summarized in Thomson and York(3) and Hamilton, White and Matson.(4)
- Approximately 50,000 detailed sample coal analyses taken from the coal data base of the U.S. Bureau of Mines in Denver, Colorado. These data include the composition of each sample in terms of its ash, sulfur, and heat content.

Given these three sets of data as a starting point, the first step in the analysis was to overlay them into a single data base which contained 36,000 coal resource records and which had the following information for each:

- The location in terms of its region, state, county, and bed.
- The weight in tons of both strip and underground coal.
- The mean percent by weight of ash, organic sulfur, and pyritic sulfur.

- The mean heat content expressed in BTU/lb.
- The float-sink distribution of the coal characteristics.

The coal reserve resources and the washability data of RI8118 are each specified by state, bed and county; however, there is not an exact correspondence between reserves and washability data since for many of the reserves there are no washability data. To determine the desulfurization by physical cleaning processes of coal resources having no washability data, the reserve resources were assigned washability data in the following manner:

- If one or more state, bed and county matches are found between a given reserve and the washability data, the reserve is assigned that washability data set which has coal composition closest (in the least squares sense) to the composition of the reserve. If no composition data are given for that reserve source, the resource is subdivided into as many parts as there are matching washability data sets and each part is assigned one of the washability analyses.
- If there are no state, bed and county matches between a given reserve resource and the washability data, look for state, bed and region matches. Assign the reserve the matching washability data as in the above.
- If no matches occur in either of the above, look for state and county matches. Assign the reserve the matching washability data as in the first mentioned bullet.
- If no matches occur in the above, assign the reserve the washability data from other beds in the same state and region as in the first mentioned bullet.
- For some states there are no washability analyses at all; reserve resources in those states are assigned washability data from other states in the same region as follows: assign

North Carolina	to	Virginia
Michigan	to	All states in the Eastern Midwest region
Texas	to	Oklahoma
South Dakota	to	North Dakota
Idaho		
Oregon	to	Montana and Wyoming
Washington		

Assign the reserve washability data of the relevant state or states by the least squares method described in the first paragraph above.

In this manner all the coal reserves are assigned washability data. However, since no washability data existed in RI 8118 for Alaskan coal or for Pennsylvania anthracite coal, these reserves were not included.

The analytical data file consists of approximately 50,000 records each of which gives coal composition data for a reserve resource sample. These sample analysis data were overlaid with the reserve base to obtain coal composition data for each reserve resource. Each resource has several sample analyses corresponding to it and, in the absence of any method of assigning weights to the different analyses for the same resource, all were weighted equally. The variation in the samples for a given resource was taken into account by dividing all the coal in that reserve resource into as many parts as there are corresponding sample analyses and each part was assigned the composition of one of the samples. For those reserves that have composition data given on the reserves file and on the analysis file it was assumed that the mean of all the sample analyses should be equal to the composition data given on the reserves tape; if necessary the sample analysis data was scaled to make this so. Reserves having no composition data given on the reserves file were assigned the coal composition given by the RI 8118 washability data. Reserves having composition data given on the reserves file but no sample analysis used the coal composition given on the reserves file.

By overlaying the coal reserves file and the analysis file in this manner an expanded reserves file of approximately 36,000 records was obtained, each record consisting of resource identification (by state, bed and county), weight of coal for both strip and underground, and the composition of the coal. The reason 36,000 records were obtained, and not 50,000 as on the original analysis file, was because a number of the sample analyses either do not correspond to any of the reserve resources or correspond to a given resource which shows no coal available in both strip and underground reserve. For a given state, bed and county group there are several records on the file each having the same weight of reserves (such that the total adds up to the actual weight in the resource) but having possibly different composition data corresponding to the different sample analyses for that resource. The sulfur content of the coal is given in the coal reserves file and in the analysis file only as total sulfur content; this was divided into pyritic and organic sulfur in the ratio in which these two occur in the washability data that corresponds to that resource.

To implement the effect of the cleaning processes on the reserve resources, use has been made of the fact that a single washability analysis corresponds to many records on the overlaid reserves data file. The methodology developed can treat any cleaning process that is of one of the following specific types.

1. A physical cleaning process;
2. A chemical cleaning process that removes specified percentages of the characteristics of the raw coal (ash, pyritic sulfur, organic sulfur);
3. A chemical cleaning process that reduces the levels of the characteristics to given threshold values;
4. Combinations of 1 and 3 or combinations of 2 and 3;
5. A blend of the product coal from two of the above process; and
6. One of processes 1-4 on the coal product of another of processes 1-4.

Reductions in the weight and energy per unit mass of the coal by given percentages can be specified directly for processes of types 2 and 3 and for processes of type 1 as operating penalties over and above the reductions caused by the physical separation process. Physical cleaning processes are restricted by the RI 8118 washability data to top sizes of 1-1/2 inches, 3/8 inch or 14 mesh, and to specific gravity fractions of float -1.3, 1.3-1.4, 1.4-1.6 or the sink from 1.6.

A physical coal cleaning process can be specified by the top size to which the coal is crushed before separation plus the following quantities for each specific gravity fraction:

- The percent ash removed;
- The percent pyritic sulfur removed;
- The percent organic sulfur removed;
- The percent BTU/lb recovery; and
- The percent weight recovery (=0.0 for a specific gravity fraction which is discarded).

No allowance was made for process inefficiency (misplaced material) in this analysis of available reserves. These quantities are in addition to the amount of each characteristic that is removed by the physical separation process. A cleaning process of type 2 can be expressed in terms of the above five quantities alone. A cleaning process of type 3 can be expressed in terms of the above quantities together with threshold values for those characteristics that are reduced to threshold levels.

Given such a specification of a cleaning process of type 1 or 2 and the file of the RI 8118 washability data, it is possible to construct an array (Ti,j,k) which fully characterizes the cleaning of coal from a particular state, bed and county group by the cleaning process. Here i corresponds to the index of the washability data (determined from the state, bed and county group), j corresponds to the cleaning process under consideration, and k corresponds to the characteristics of the coal that are subject to change by cleaning (weight, ash, pyritic sulfur, organic sulfur, and BTU/lb). On cleaning by process j a sample of raw coal having state, bed and county group corresponding to washability index i and characteristics R(k), one obtains cleaned coal having characteristics

$$C(k) = R(k) x T(i,j,k).$$

Thus the effect of a cleaning process on coal of a given washability is obtained simply by scaling the characteristics of the coal by the relevant factors from the T array. Chemical cleaning, which reduces characteristics to threshold values (type 3 processes), can be simulated by reducing the relevant characteristics after scaling by the T factors.

The array (Ti,j,k) is computed as follows. For a type 2 cleaning process j the specification of the process described above completely determines the T matrix. The process specification gives the proportion D(k) of characteristic k of the feed coal that appears in the cleaned coal. If

k=1 corresponds to weight
k=2 corresponds to ash content
k=3 corresponds to pyritic sulfur content
k=4 corresponds to organic sulfur content
k=5 corresponds to BTU/lb for the coal

then

$T(i,j,1)=D(1)$
$T(i,j,k)=D(k)/D(1), \qquad k=2,3,4,5$

This is independent of the washability index i.

For a type 1 process the proportion $P(\ell,k)$ of the feed coal in specific gravity fraction ℓ and having characteristic k that appears in the cleaned coal is given by the washability data for the feed coal. Any additional reduction in the levels of the characteristics is given by the process specification and can be expressed as $D(\ell,k)$. Combining these two, the proportion of the feed coal appearing in the product is

$$\sum_{\ell} P(\ell,k) x D(\ell,k)$$

where the summation is over the four specific gravity fractions of the RI 8118 washability data. Then

$$T(i,j,1)=\sum_{\ell} P(\ell,1)xD(\ell,1)$$

and

$$T(i,j,k)=\sum_{\ell} P(\ell,k)xD(\ell,k)/T(i,j,1), \qquad k=2,3,4,5.$$

Having constructed this T matrix from the specifications of the cleaning processes and the washability data, it is combined with the overlaid reserves and analytical data file. The characteristics of the raw coal from each of the 36,000 reserve resource records on the file are scaled by the appropriate factors from the T matrix to obtain the characteristics of that coal after cleaning by each of the processes. Any reduction in characteristic values to threshold values for a type 3 process is done at this stage. A new file is created consisting of 36,000 records as before but now each record contains not just the reserve levels and characteristics of the raw coal but those values also for the processed coal for each cleaning process. This file is then used to assess the desulfurization potential of the coal reserves.

APPENDIX A REFERENCES

1. Cavallaro, J.A., Johnston, M.T., and Deurbrouck, A.W., "Sulfur Reduction Potential of the Coals of the United States", U.S. Bureau of Mines, RI 8118 (1976).

2. Ibid.

3. Thomas, R.D., and York, H.F., "The Reserve Base of U.S. Coals by Sulfur Content, The Eastern States", IC 8680, U.S. Bureau of Mines, Washington, D.C. (1975), 537 pp.

4. Hamilton, P.A., White, D.H., and Matson, T.K., "The Reserve Base of U.S. Coals by Sulfur Content, The Western States", IC 8693, U.S. Bureau of Mines, Washington, D.C. (1975), 322 pp.

APPENDIX B

LEVELIZED COSTS FOR LOW SULFUR COALS

LEVELIZED COST CALCULATIONS

The levelized cost is equivalent to a fixed current-dollar cost during each year of the economic lifetime of a facility. Because of the positive market rate of interest, the levelized cost of a facility in any year of operation must be discounted back to a base year. The sum of the levelized costs discounted back to the base year during each year of operation is called the *present discount value* of the cost.

Since the annual current-value cost is generally not constant, the present discounted value is, in fact, the sum of a series of discounted <u>variable</u> costs. One can form a series of terms representing equivalent <u>fixed</u> annual costs discounted back to the base year, such that the sum of the terms equals the present discount value. It is the equivalent fixed annual cost of this series that is defined as the *levelized cost.*

In mathematical terms, the procedure for calculating the present discount value and the levelized cost is described in the following two steps:

1. Find the <u>present discount value</u>, PDV, of the costs:

$$PDV = \sum_{n=0}^{N} \frac{C_n}{(1+d)^n}, \text{ where}$$

$C_n = C_i \prod_{n=1,N} (1+p)^n$ = the cost of the variable being evaluated in current dollars in the n^{th} year.

d = the average discount rate during the economic lifetime.

C_i = the cost of the variable being evaluated in the initial year.

p = the average price escalation.

2. Find the levelized cost, LC, (the equivalent constant annual cost) such that the PDV computed on the basis of LC will be equal to the PDV found in step 1 above:

The levelized cost is equivalent to a fixed current-dollar cost during each year of the economic lifetime of a facility. Because of the positive market rate of interest, the levelized cost of a facility in any year of operation must be discounted back to the base year. The sum of the levelized costs discounted back to the base year during each year of operation is called the present discounted value (PDV) of the cost. Furthermore, the contribution of the levelized cost to the PDV in the base year (n=1) will decrease as n increases. The total PDV is equal to the sum of the discounted values of the levelized cost for all years throughout the lifetime of the facility.

In fact, there is not generally a constant annual real cost; the PDV is a sum of discounted real costs that vary from year to year. The levelized cost (the equivalent fixed yearly real cost) is found by first finding the value of the PDV for a base year, and then equating this value to a sum of a series of terms, each of which is the levelized cost discounted back to the base year at an average discount rate. In mathematical terms, the procedure for calculating PDV and levelized cost is described in the following two steps:

$$PDV = LC \sum_{n=o}^{N} \frac{1}{(1+d)^n}$$

$$LC = \frac{d\ (1+d)^N}{(1+d)^N - 1}\ PDV.$$

An equivalent way of expressing the levelized cost (LC) is to multiply the cost in the initial year by the *levelization factor* (LF):

$$LF = \left[\frac{d(1 + d)^N}{(1 + d)^N - 1}\right]\left[\frac{1 + p}{d - p}\right]\left[1 - \left(\frac{1 + p}{1 + d}\right)^N\right].$$

The first factor in the above equation is often referred to as the capital recovery factor (CRF).

For capital costs there are additional charges associated with an investment beyond the initial ones levelized by applying the above equations. Taxes, insurance and general and administrative expenses required for capital equipment should be accounted for as well, usually by applying a *fixed charge rate* to the initial investment amount to arrive at a total levelized cost associated with capital expenditure. The fixed charge rate is defined as:

FCR = CRF + TAX + INS + G&A

where

FCR = fixed charge rate

CRF = capital recovery factor = $\frac{d\,(1 + d)^N}{(1+d)^N - 1}$

INS = insurance and real estate taxes as a levelized percent of the initial investment

G&A = general and administrative expenses as a levelized percent of the initial investment.

The values presented as *levelized costs* in the following tables are the sum of (1) the levelized capital costs found by multiplying the initial investment costs by the fixed charge rate, and (2) the levelized operating and maintenance (O&M) costs, found by multiplying the first-year O&M costs by the appropriate levelizing factor.

The fixed charge rates and levelization factors, and the values upon which they are based, are listed in Table B-1 for the four major types of industrial coal-burning boilers considered in this study. The levelized coal costs are obtained by applying levelizing factors to the annual coal costs (see Table 4-3): 2.57 to the field-erected boilers, 2.13 to the 30 MW packaged boiler.

The computation and results of levelizing the low-sulfur coal costs are presented in Tables B-2 through B-7.

TABLE B-1. VALUES USED IN THE COST ANALYSIS OF LOW-SULFUR-COAL-COMBUSTION

ITEM \ Boiler Type	Packaged Watertube: Underfeed Stoker	Field Erected Watertube: • Spreader Stoker • Chain-Grate Stoker • Pulverized Coal
Investment Life	30 years	45 years
Operating Cost Escalation Rate	7%	7%
Discount Rate	10%	10%
Levelization Factor	2.13	2.57
Capital Recovery Factor	10.61%	10.14%
Other Fixed Charges	4%	4%
Fixed Charge Rate	14.61%	14.14%

Table B-2. ANNUALIZED AND LEVELIZED FUEL COSTS (1978 $) AND FUEL INPUTS BY BOILER-TYPE CAPACITY*

Boiler Capacity (Feed rate) / Coal Source	8.8 MW (30 X 10^6 BTU/hr) $/Year Annual (Levelized)	8.8 MW Kkg/Year	44 MW (150 X 10^6 BTU/hr) $/Year Annual (Levelized)	44 MW Kkg/year	58.6 MW (200 X 10^6 BTU/hr) $/Year Annual (Levelized)	58.6 MW Kkg/year
Buchanan, VA (Low-Sulfur Eastern)	165,600 (425,600)	5,250	828,000 (2,128,000)	26,300	1,109,000 (2,850,100)	35,200
Las Animas, CO	121,400 (312,000)	6,260	607,000 (1,556,000)	31,300	813,400 (2,090,400)	41,900
Williston, ND	78,740 (202,400)	10,200	393,700 (1,011,800)	51,000	527,560 (1,355,800)	68,300
Gillette, WY	57,800 (148,500	8,410	289,000 (742,700)	42,000	387,300 (995,400)	68,300
Rock Springs, WY	99,100 (254,700)	6,210	495,500 (1,273,400)	31,000	664,000 (1,706,500)	41,600
Gallup, NM	188,800 (305,300)	6,350	594,000 (1,526,500)	31,800	796,000 (2,045,700)	42,500

* Costs are based upon (1) spot prices, f.o.b. mine, in $/GJ (see Table 4-4) and (2) capacity factor equal to 0.6. Except where indicated otherwise, the levelized costs apply to field-erected water-tube boiler; a levelization factor of 2.57 is applied (see Table 4-3).

Table B-3. THE COMPUTATION OF ANNUALIZED AND LEVELIZED COSTS FOR THE STANDARD BOILERS (1978$) (EXCLUDING COAL COSTS)

	Boiler Type:	Package Watertube 30 X 10^6 BTU/hr		Field-Erected Watertube 75 X 10^6 BTU/hr		Field-Erected Watertube 150 X 10^6 BTU/hr		Field-Erected Watertube 200 X 10^6 BTU/hr	
	Coal Type:	Eastern low-sulfur	Subbit.	Eastern low-sulfur	Subbit.	Eastern low-sulfur	Subbit.	Eastern low-sulfur	Subbit.
1	Direct Costs (less fuel)	442,700	496,500	773,300	864,400	1,101,500	1,267,100	1,404,500	1,610,700
2	Overhead	178,300	185,200	177,300	434,500	377,400	400,200	386,400	415,100
3	O&M Costs (excluding fuel)	621,000	681,700	950,600	1,298,900	1,478,900	1,667,300	1,790,900	2,025,800
4	Levelized O&M Cost (excluding fuel)	1,322,730	1,452,021	2,443,042	3,338,173	3,800,773	4,284,961	4,602,613	5,206,306
5	Capital Charges (levelized)[f]	260,400	345,800	629,000	692,300	1,161,400	1,519,000	1,549,100	1,992,800
6	Annualized Cost (excluding fuel)	881,400	1,027,500	1,579,600	1,991,200	2,640,300	3,186,300	3,340,000	4,018,600
7	Levelized Cost (excluding fuel)	1,583,130	1,797,821	3,072,042	4,030,473	4,962,173	5,803,961	6,151,713	7,199,106

Table B-4. ESTIMATED COSTS (1978 \$) OF BURNING LOW-SULFUR COALS
BOILER TYPE: PACKAGED WATERTUBE, UNDERFEED STOKER †
8.8 MW (30 X 10^6 BTU/hr); 150 PSIG/sat.temp.

Coal Source	Coal Type σ	Standard within Which Uncontrolled Emissions Fall		Yearly Costs (1978 \$)	
		ng SO_2/J	(lb $SO_2/10^6$ BTU) ω	Annualized Cost	Levelized Costs
Buchanan, Va.	B	860	(2.0	1,047,500	2,008,700
Las Animas, Co.	B	516	(1.2)	1,075,800	1,895,130
Williston, N.D.	Lignite	1,075	(2.5) SIP	1,106,200	2,000,200
Gillette, Wy.	SB	860	(2.0)	1,085,300	1,946,300
Rock Springs, Wy.	B	645	(1.5)	1,053,500	1,837,800
Gallup, N.M.	SB	860	(2.0)	1,146,300	2,103,100

† The costs here (annualized and levelized) are found by adding the yearly fuel costs (annual and levelized) in Table B-2 to the yearly boiler costs excluding fuel costs (annualized and levelized) in Table B-3.

σ The bituminous coals are assumed to be burned in boilers constructed to burn "eastern low sulfur coal"; the subbituminous coal and lignite are assumed to be burned in boilers constructed to burn "sub-bituminous coal" (see Table B-3).

ω These are the most stringent of five SO_2 standards considered here, which the uncontrolled SO_2 emissions from each coal can meet. The standards (ng SO_2/J) are 516, 645, 860, 1,075, 1,290. We assume no retention of sulfur as SO_2 in the boiler.

Table B-5. ESTIMATED COSTS (1978 \$) OF BURNING LOW-SULFUR COALS
BOILER TYPE: FIELD-ERECTED WATERTUBE
22 MW (75 X 10^6 BTU/hr); 150 PSIG/sat.temp. †

Coal Source	Coal Type σ	Standard within Which Uncontrolled Emissions Fall		Costs (1978\$)	
		$ngSO_2/J$	($lb\ SO_2/10^6$ BTU) ∞	Annualized Cost	Levelized Costs
Buchanan, Va.	B	860	(2.0	1,993,600	4,136,000
Las Animas, Co.	B	516	(1.2)	2,088,900	3,850,000
Williston, N.D.	Lignite	1,075	(2.5) SIP	2,188,000	4,536,400
Gillette, Wy.	SB	860	(2.0)	2,135,700	4,401,800
Rock Springs, Wy.	B	645	(1.5)	2,033,200	3,708,700
Gallup, N.M.	SB	860	(2.0)	2,288,200	4,793,700

† The costs here (annualized and levelized) are found by adding the yearly fuel costs (annual and levelized) in Table B-2 to the yearly boiler costs excluding fuel costs (annualized and levelized) in Table B-3.

σ The bituminous coals are assumed to be burned in boilers constructed to burn "eastern low-sulfur coal;" the subbituminous coal and lignite are assumed to be burned in boilers constructed to burn "subbituminous coal" (see Table B-3).

∞ These are the most stringent of five SO_2 standards considered here, which the uncontrolled SO_2 emissions from each coal can meet. The standards ($ngSO_2/J$) are 516,645, 860, 1,075, 1,290. We assume no retention of sulfur as SO_2 in the boiler.

Table B-6. ESTIMATED COSTS (1978 $) OF BURNING LOW-SULFUR COALS
BOILER TYPE: FIELD-ERECTED WATERTUBE
44 MW (150 X 10^6 BTU/hr); 450 PSIG/600°F [†]

Coal Source	Coal Type [σ]	Standard within Which Uncontrolled Emissions Fall		Costs (1978$)	
		$ngSO_2/J$	(lb $SO_2/10^6$ BTU) [ω]	Annualized Cost	Levelized Costs
Buchanan, Va.	B	860	(2.0)	3,468,300	7,090,200
Las Animas, Co.	B	516	(1.2)	3,520,300	6,518,200
Williston, N.D.	Lignite	1,075	(2.5) SIP	3,580,000	6,815,800
Gillette, Wy.	SB	860	(2.0)	3,475,300	6,546,700
Rock Springs, Wy.	B	645	(1.5)	3,408,800	6,235,600
Gallup, N.M.	SB	860	(2.0)	3,780,300	7,330,500

† The costs here (annualized and levelized) are found by adding the yearly fuel costs (annual and levelized) in Table B-2 to the yearly boiler costs excluding fuel costs (annualized and levelized) in Table B-3.

σ The bituminous coals are assumed to be burned in boilers constructed to burn "eastern low-sulfur coal;" the subbituminous coal and lignite are assumed to be burned in boilers constructed to burn "subbituminous coal" (see Table B-3).

ω These are the most stringent of five SO_2 standards considered here, which the uncontrolled SO_2 emissions from each coal can meet. The standards ($ngSO_2/J$) are 516, 645, 860, 1075, 1290. We assume no retention of sulfur as SO_2 in the boiler.

TABLE B-7. ESTIMATED COSTS (1978 $) OF BURNING LOW SULFUR COALS
BOILER TYPE: FIELD-[illegible] WATERTUBE
58.6 MW (200 BTU/HR): [illegible]/750°F *

Coal Source	Coal Type†	Standard within which Uncontrolled Emissions [illegible] ng SO_2/J	(lb SO_2/10^6 Btu)	Yearly Costs (1978 $) Annualized	Levelized Costs
Buchanan, VA	B	[illegible]	[illegible]	[illegible]	[illegible],830
Las Animas, CO	B	516	[illegible]	4,4[illegible],700	[illegible]
Williston, ND	Lignite	1,075	(2.5)	4,54[illegible],200	[illegible]
Gillette, WY	SB	860	(2.0)	[illegible],900	[illegible]
Rock Springs, WY	B	645	(1.5)	4,343,300	7,858,200
Gallup, NM	SB	860	(2.0)	[illegible]	[illegible],800

* The costs here (annualized and levelized) are found by adding the yearly [illegible] and levelized) in Table B-2 to the yearly boiler costs excluding fuel costs (annualized and levelized) in Table B-3.

† The bituminous coals are assumed to be burned in boilers constructed to burn "eastern low sulfur coal"; the subbituminous coal and lignite are assumed to be burned in boilers constructed to burn "subbituminous coal" (see Table B-3).

V These are the most stringent of five SO_2 standards considered here, which the uncontrolled SO_2 emissions from each coal can meet. The standards (ng SO_2/J) are 516, 645, 860, 1,075, 1,290. We assume no retention of sulfur as SO_2 in the boiler.

APPENDIX C

REGIONAL LISTING OF COAL COMPANY-PROVIDED DATA

FEED AND PRODUCT COAL QUALITY FOR N. APPALACHIAN

REGION AND PLANT NO.	SEAM	COUNTY	STATE	CLEANING LEVEL	(TONS) PRODUCT LOT QUANTITY	ROM BTU/LB	ROM % SULFUR	PRODUCT METALLURGICAL BTU/LB	PRODUCT METALLURGICAL % SULFUR	PRODUCT STEAM BTU/LB	PRODUCT STEAM % SULFUR	LBS $SO_2/10^6$ BTU'S ROM	LBS $SO_2/10^6$ BTU'S PRODUCT	% REDUCTION LBS $SO_2/10^6$ BTU'S
N. Appalachian - #44	U.F.	Allegheny	Pa.	4	95,000	11,730	1.84			14,030	1.28	3.14	1.82	42.0
N. Appalachian - #44	U.F.	Allegheny	Pa.	4	120,000	10,810	1.67	14,130	1.57			3.09	2.22	28.2
N. Appalachian - #45	U.F.	Somerset	Pa.	4	84,000	10,000	1.31	14,450	1.03			2.62	1.43	45.4
N. Appalachian - #52	L.F.6A	Harrison	W.Va.	3	288,000	9,147	2.92			13,821	2.94	6.38	4.25	33.4
N. Appalachian - #52	L.F.6A	Harrison	W.Va.	3	288,000	11,785	2.55			13,979	2.34	4.33	3.35	22.6
N. Appalachian - #52	Pitt	Belmont	Ohio	3	288,000	9,667	3.28			13,232	3.96	6.79	5.99	11.8
N. Appalachian - #52	Pitt	Harrison	W.Va.	3	288,000	9,335	2.05			13,520	2.78	4.39	4.11	6.4
N. Appalachian - #52	Pitt	Harrison	W.Va.	3	288,000	12,284	5.09			13,431	3.59	8.29	5.35	35.5
N. Appalachian - #52	Pitt	Belmont	Ohio	3	288,000	12,397	2.51			12,886	2.15	4.05	3.34	17.5
N. Appalachian - #52	Pitt	Belmont	Ohio	3	288,000	12,502	3.02			13,074	2.51	4.83	3.84	20.5
N. Appalachian - #52	Pitt	Harrison	W.Va.	3	288,000	12,660	2.67			13,855	2.33	4.22	3.36	20.4
N. Appalachian - #43	Pgh	Washington	Pa.	4	192,000	9,770	1.55	14,040	1.55			3.17	2.21	30.3
N. Appalachian - #43	Pgh	Washington	Pa.	4	240,000	10,060	2.0			13,680	1.92	3.98	2.81	29.4
N. Appalachian - #46	Pgh	Marshall	W.Va.	2	240,000	10,940	4.97			12,660	4.52	9.09	7.14	21.5
N. Appalachian - #47	Pgh	Marshall	W.Va.	1	190,000	12,800	2.8			12,800	2.8	4.38	4.38	0
N. Appalachian - #48	Pgh	Marion	W.Va.	3	288,000	13,360	3.46			13,980	2.72	5.18	3.89	24.9
N. Appalachian - #49	Pgh	Harrison	W.Va.	4	240,000	13,260	4.30			14,010	3.2	6.49	4.57	29.6
N. Appalachian - #50	Pgh	Marion	W.Va.	3	144,000	12,460	4.24			13,940	3.27	6.81	4.69	31.1
N. Appalachian - #50	Pgh	Harrison	W.Va.	3	120,000	13,140	3.61			14,010	2.8	5.49	4.00	27.2
N. Appalachian - #20	Ohio#6	Perry	Ohio	2	170,413	11,054	4.07			12,494	3.03	7.46	4.85	35.1
N. Appalachian - #20	Ohio#6	Perry	Ohio	2	152,329	11,665	3.73			12,464	2.86	6.40	4.60	28.1
N. Appalachian - #20	Ohio#6	Perry	Ohio	2	178,680	11,179	3.98			12,462	3.06	7.12	4.91	31.0
N. Appalachian - #20	Ohio#6	Perry	Ohio	2	159,949	10,742	4.46			12,443	3.05	8.30	4.90	41.0
N. Appalachian - #20	Ohio#6	Perry	Ohio	2	208,650	10,836	3.96			12,465	3.06	7.31	4.91	32.9
N. Appalachian - #20	Ohio#6	Perry	Ohio	2	179,994	10,929	3.45			12,428	2.99	6.31	4.81	23.8
N. Appalachian - #22	Pitt#8	Belmont	Ohio	2	900,000	10,105	4.89			11,790	3.66	9.68	6.21	35.8
N. Appalachian - #22	Pitt#8	Belmont	Ohio	2	1,000,000	10,105	4.89			12,048	3.34	9.68	5.54	42.8
N. Appalachian - #23	Pitt#8	Monroe	Ohio	3	1,000,000	10,105	4.89			12,359	3.36	9.68	5.44	43.8
N. Appalachian - #23	Pitt#8	Belmont	Ohio	3	700,000	10,105	4.89			12,292	3.46	9.68	5.63	41.8
N. Appalachian - #23	Pitt#8	Belmont	Ohio	3	1,200,000	10,105	4.89			12,863	4.23	9.68	6.58	31.7
N. Appalachian - #23	Pitt#8	Monroe	Ohio	3	300,000	10,105	4.89			12,407	3.31	9.68	5.33	44.9
N. Appalachian - #36	Sewell	Nicholas	W.Va.	4	49,200	11,236	.85	14,452	.80			1.51	1.10	27.1
N. Appalachian - #37	Sewell	Nicholas	W.Va.	3	53,000	12,432	.70	14,148	.71			1.13	1.0	11.5
N. Appalachian - #38	M.Kittan	Upshur	W.Va.	4	27,000	10,626	1.93	13,822	1.02			3.63	1.47	59.5
N. Appalachian - #38	M.Kittan	Upshur	W.Va.	4	8,400	10,626	1.93			12,416	1.38	3.63	2.22	38.8

FEED AND PRODUCT COAL QUALITY FOR N. APPALACHIAN

REGION AND PLANT NO.	SEAM	COUNTY	STATE	CLEANING LEVEL	(TONS) PRODUCT LOT QUANTITY	ROM		PRODUCT				LBS $SO_2/10^6$ BTU'S		% REDUCTION LBS $SO_2/10^6$ BTU'S
								METALLURGICAL		STEAM				
						BTU/LB	% SULF	BTU/LB	% SULF	BTU/LB	% SULF	ROM	PRODUCT	
N. Appalachian - #53	L.Kitt			3	640	13,485	2.80	14,622	1.11			4.15	1.52	63.4
N. Appalachian - #53	L.Kitt			3	640	12,879	2.24	14,249	1.20			3.48	1.68	51.6
N. Appalachian - #53	L.Kitt			3	640	12,102	1.84	14,146	1.22			3.04	1.72	43.3
N. Appalachian - #53	L.Kitt			3	640	12,657	1.46	14,392	0.82			2.31	1.14	50.6
N. Appalachian - #53	L.Kitt			3	640	13,629	1.38	14,435	0.99			2.03	1.37	32.3

FEED AND PRODUCT COAL QUALITY FOR S. APPALACHIAN

REGION AND PLANT NO.	SEAM	COUNTY	STATE	CLEANING LEVEL	(TONS) PRODUCT LOT QUANTITY	ROM BTU/LB	ROM % SULF	PRODUCT METALLURGICAL BTU/LB	PRODUCT METALLURGICAL % SULF	PRODUCT STEAM BTU/LB	PRODUCT STEAM % SULF	LBS $SO_2/10^6$ BTU'S ROM	LBS $SO_2/10^6$ BTU'S PRODUCT	% REDUCTION LBS $SO_2/10^6$ BTU'S
S. Appalachian - #11	Sewell	Raleigh	W.Va.	4	75,000	4,823	1.28	14,190	.75			5.31	1.06	80.1
S. Appalachian - #11	Beckley	Raleigh	W.Va.	4	66,000	5,000	1.25	13,975	.75			5.00	1.07	78.5
S. Appalachian - #12	Poca-3	Raleigh	W.Va.	4	96,000	6,129	1.18	14,250	.72			3.85	1.01	73.8
S. Appalachian - #13	Cedar Grove	Boone	W.Va.	4	75,000	11,307	.50	13,614	.75			.88	1.10	(+24.6)
S. Appalachian - #14	Stock-ton	Boone	W.Va.	4	24,000	11,159	.65	13,285	.69			1.16	1.04	10.8
S. Appalachian - #15	Marker	Wise	W.Va.	4	69,000	7,675	.60			14,120	.70	1.56	.99	36.5
S. Appalachian - #15	Toggart	Wise	W.Va.	4	63,000	10,040	.75			14,170	.62	1.50	.87	41.4
S. Appalachian - #15	Dorches-ter	Wise	W.Va.	4	84,000	9,240	.97			12,800	1.0	2.10	1.56	25.6
S. Appalachian - #21	SWVA	Wise	W.Va.	3	2,700	10,834	1.2			14,591	1.48	2.21	2.03	8.2
S. Appalachian - #21	SWVA	Wise	W.Va.	3	2,700	10,377	0.92			14,449	1.31	1.77	1.81	(+2.4)
S. Appalachian - #21	SWVA	Wise	W.Va.	3	2,700	9,771	0.82			14,260	0.89	1.68	1.25	25.6
S. Appalachian - #21	SWVA	Wise	W.Va.	3	2,700	9,182	0.61			14,428	1.06	1.33	1.47	(+10.5)
S. Appalachian - #21	SWVA	Wise	W.Va.	3	2,700	9,752	1.1			14,624	1.1	2.26	1.50	33.4
S. Appalachian - #24	Various	Dickenson	W.Va.	3	95,500	10,500	.70	14,381	.75			1.33	1.04	21.8
S. Appalachian - #24	Various	Dickenson	W.Va.	3	7,200	10,500	.70			12,463	.80	1.33	1.28	3.7
S. Appalachian - #25	Tiller	Russell	W.Va.	4	74,000	11,326	.42	14,387	.53			0.74	0.74	
S. Appalachian - #26	Various	Russell	W.Va.	4	132,000	9,055	.60	14,355	.70			1.32	0.97	26.0
S. Appalachian - #26	Various	Russell	W.Va.	4	56,600	9,055	.60			12,446	.69	1.32	1.11	15.9
S. Appalachian - #27	Raven	Buchanan	W.Va.	4		10,779	.55	15,032	.59			1.02	0.78	23.5
S. Appalachian - #28	L.Jewell	Buchanan	W.Va.	4	42,000	9,947	.64	14,463	.62			1.28	0.86	32.8
S. Appalachian - #28	L.Jewell	Buchanan	W.Va.	4	6,500	9,947	.64			13,031	.66	1.28	1.01	21.1
S. Appalachian - #29	Jewell	Buchanan	W.Va.	4	48,000	8,010	.76	15,056	.75			1.89	0.99	47.6
S. Appalachian - #29	L.Jewell	Buchanan	W.Va.	4	55,000	9,484	.73	14,494	.73			1.54	1.01	34.4
S. Appalachian - #30	Various	Pike	W.Va.	4	68,400	13,589	.78	14,397	.66			1.15	0.92	20.0
S. Appalachian - #31	Various	Logan	W.Va.	3	84,000	9,342	.66	13,979	.72			1.41	1.03	26.9
S. Appalachian - #31	Various	Logan	W.Va.	3	3,600	9,342	.66			11,402	.84	1.41	1.47	(+4.2)
S. Appalachian - #32	Warfield	Logan	W.Va.	2	44,600	12,410	1.1	13,730	.99			1.77	1.44	18.6
S. Appalachian - #32	Warfield	Logan	W.Va.	2	30,000	12,410	1.1			12,394	1.32	1.77	2.13	(+20.3)
S. Appalachian - #33	Cedar Grove	Logan	W.Va.	2	23,000	12,710	1.7	14,156	1.3			2.67	1.83	31.5

FEED AND PRODUCT COAL QUALITY FOR S. APPALACHIAN

REGION AND PLANT NO.	SEAM	COUNTY	STATE	CLEANING LEVEL	(TONS) PRODUCT LOT QUANTITY	ROM		PRODUCT				LBS $SO_2/10^6$ BTU'S		% REDUCTION LBS $SO_2/10^6$ BTU'S
								METALLURGICAL		STEAM				
						BTU/LB	% SULF	BTU/LB	% SULF	BTU/LB	% SULF	ROM	PRODUCT	
S. Appalachian - #33	Cedar Grove	Logan	W.Va.	2	16,000	12,710	1.7			12,836	1.71	2.67	2.66	0.3
S. Appalachian - #33	Cedar Grove	Logan	W.Va.	2	7,000	12,710	1.7			12,712	1.66	2.67	2.61	2.2
S. Appalachian - #34	Beckley	Wyoming	W.Va.	4		9,779	.58	14,611	.65			1.18	.89	24.6
S. Appalachian - #34	Various	Wyoming	W.Va.	4		9,021	1.10	14,624	1.06			2.44	1.45	40.6
S. Appalachian - #35	Poc 3&4	Wyoming	W.Va.	4	47,500	10,816	.67	14,402	.68			1.24	.94	23.8
S. Appalachian - #35	Poc 3	Wyoming	W.Va.	4	480	10,816	.67			13,242	.66	1.24	.99	20.2
S. Appalachian - #54	Refuse	Wyoming	W.Va.	3	600	7,067	.603	13,543	.948			1.71	1.40	18.0
S. Appalachian - #54	Refuse	Wyoming	W.Va.	3	600	8,127	.637	13,242	.835			1.57	1.26	19.7
S. Appalachian - #54	Refuse	Wyoming	W.Va.	3	600	9,084	1.099	12,911	1.099			2.42	1.56	35.5
S. Appalachian - #54	Refuse	Wyoming	W.Va.	3	600	8,672	.570	13,333	.830			1.31	1.25	5.3
S. Appalachian - #54	Refuse	Wyoming	W.Va.	3	600	7,887	.582	13,183	.850			1.48	1.29	12.8

FEED AND PRODUCT COAL QUALITY FOR ALABAMA

REGION AND PLANT NO.	SEAM	COUNTY	STATE	CLEANING LEVEL	(TONS) PRODUCT LOT QUANTITY	ROM		PRODUCT				LBS $SO_2/10^6$ BTU'S		% REDUCTION LBS $SO_2/10^6$ BTU'S
								METALLURGICAL		STEAM				
						BTU/LB	% STOT	BTU/LB	% STOT	BTU/LB	% STOT	ROM	PRODUCT	
Alabama - #39	Mary Le	Jefferson	Al.	4	60-70	10,160	.62	13,960	.72			1.22	1.03	15.6
Alabama - #40	NEMO	Jefferson	Al.	4	60-70	9,600	1.66	13,759	1.13			3.46	1.64	52.6
Alabama - #41	Blue Creek	Jefferson	Al.	4	1,500	12,150	.77	14,258	.60			1.26	.84	33.3
Alabama - #42	Blue Creek	Tuscal	Al.	4	4,000	9,400	1.2	13,964	.85			2.55	1.22	52.2
Alabama - #42	Mary Le	Tuscal	Al.	4	4,000	9,400	1.2	13,064	.85			2.55	1.22	52.2

FEED AND PRODUCT COAL QUALITY FOR E. MIDWEST

REGION AND PLANT NO.	SEAM	COUNTY	STATE	CLEANING LEVEL	(TONS) PRODUCT LOT QUANTITY	ROM		PRODUCT				LBS $SO_2/10^6$ BTU'S		% REDUCTION LBS $SO_2/10^6$ BTU'S
								METALLURGICAL		STEAM				
						BTU/LB	% STOT	BTU/LB	% STOT	BTU/LB	% STOT	ROM	PRODUCT	
E. Midwest - #5	IND #6	Warrick	Indiana	3	16,000	9,652	3.56	11,036	2.89			7.38	5.24	29.0
E. Midwest - #6	IND #3	Clay	Indiana	2	8,100	8,797	5.10	10,988	4.13			11.59	7.52	35.2
E. Midwest - #9	IND #6,7	Sullivan	Indiana	2	5,800	9,354	2.28	10,838	1.52			4.87	2.80	42.5
E. Midwest - #4	KY #9	Hopkins	Kentucky	1	-	11,100	4.10	11,100	4.10			7.40	7.40	-
E. Midwest - #16	KY #9,14	Ohio	Kentucky	2	203,873	11,035	4.17			13,052	3.21	7.56	4.92	34.9
E. Midwest - #16	KY #9,14	Ohio	Kentucky	2	179,374	11,827	4.64			13,063	3.23	7.85	4.95	37.0
E. Midwest - #16	KY #9,14	Ohio	Kentucky	2	209,280	12,009	4.08			13,030	3.24	6.80	4.97	26.9
E. Midwest - #16	KY #9,14	Ohio	Kentucky	2	201,994	10,529	3.96			13,927	3.14	7.52	4.51	40.0
E. Midwest - #16	KY #9,14	Ohio	Kentucky	2	293,460	11,611	3.98			12,977	3.13	6.86	4.82	29.6
E. Midwest - #16	KY #9,14	Ohio	Kentucky	2	198,878	10,914	4.13			12,956	3.18	7.57	4.91	35.1
E. Midwest - #17	KY #9	Ohio	Kentucky	2	124,662	12,447	4.72			13,021	3.40	7.58	5.22	31.1
E. Midwest - #17	KY #9	Ohio	Kentucky	2	116,037	12,385	4.07			12,887	3.40	6.57	5.28	19.7
E. Midwest - #17	KY #9	Ohio	Kentucky	2	101,978	12,019	3.99			12,995	3.36	6.64	5.17	22.1
E. Midwest - #17	KY #9	Ohio	Kentucky	2	91,848	11,664	3.96			12,998	3.30	6.79	5.08	25.2
E. Midwest - #17	KY #9	Ohio	Kentucky	2	90,102	12,154	5.05			12,954	3.35	8.31	5.17	37.8
E. Midwest - #17	KY #9	Ohio	Kentucky	2	75,501	12,728	3.93			12,998	3.38	6.18	5.20	15.8
E. Midwest - #19	KY #11, #12	Muhlenburg	Kentucky	2	291,212	10,803	3.99			12,552	3.31	7.39	5.27	28.6
E. Midwest - #19	KY #11, #12	Muhlenburg	Kentucky	2	247,589	9,821	4.25			12,495	3.39	8.65	5.43	37.3
E. Midwest - #19	KY #11, #12	Muhlenburg	Kentucky	2	258,113	10,590	3.77			12,633	3.29	7.12	5.21	26.8
E. Midwest - #19	KY #11, #12	Muhlenburg	Kentucky	2	173,043	-	-			12,689	3.20	-	5.04	
E. Midwest - #19	KY #11, #12	Muhlenburg	Kentucky	2	201,592	-	-			12,692	3.15	-	4.96	
E. Midwest - #19	KY #11, #12	Muhlenburg	Kentucky	2	198,247	9,868	5.03			12,832	2.97	10.20	4.63	54.6

FEED AND PRODUCT COAL QUALITY FOR E. MIDWEST

REGION AND PLANT NO.	SEAM	COUNTY	STATE	CLEANING LEVEL	(TONS) PRODUCT LOT QUANTITY	ROM		PRODUCT				LBS $SO_2/10^6$ BTU'S		% REDUCTION LBS $SO_2/10^6$ BTU'S
								METALLURGICAL		STEAM				
						BTU/LB	% SULF	BTU/LB	% SULF	BTU/LB	% SULF	ROM	PRODUCT	
E. Midwest - #18	ILL #6	Christian	Illinois	3	197,683	10,765	5.20			12,292	4.29	9.66	6.98	26.79
E. Midwest - #1	ILL #6	Douglas	Illinois	1	-	10,750	3.0	11,000	2.75			5.58	5.00	10.39
E. Midwest - #2	ILL #6	Randolph	Illinois	4	-	10,300	4.35	11,100	3.00			8.45	5.40	36.09
E. Midwest - #3	ILL #6	Williamson	Illinois	3	-	11,000	3.40	11,800	2.40			6.18	4.07	34.14
E. Midwest - #7	ILL #6	Saline	Illinois	3	8,600	10,023	3.93	11,773	2.38			7.84	4.04	48.47
E. Midwest - #8	ILL #5,6	Perry	Illinois	2	11,500	10,092	4.25	10,981	3.18			8.42	5.79	31.24
E. Midwest - #10	ILL #2	Fulton		2	4,000	9,488	4.62	11,081	2.68			9.74	4.84	50.30
E. Midwest - #18	ILL #6	Randolph	Illinois	3	150,234	11,113	3.98			12,073	3.64	7.16	6.03	15.78
E. Midwest - #18	ILL #6	Randolph	Illinois	3	315,719	10,780	4.27			12,073	3.93	7.92	6.51	17.80
E. Midwest - #18	ILL #6	Randolph	Illinois	3	29[illegible],914	10,929	4.74			12,011	3.83	8.67	6.38	26.41
E. Midwest - #18	ILL #6	Randolph	Illinois	3	320,532	10,991	4.72			12,047	3.94	8.59	6.54	23.86
E. Midwest - #18	ILL #6	Randolph	Illinois	3	294,042	10,940	4.10			12,059	3.83	7.50	6.35	15.33
E. Midwest - #18	ILL #6	Randolph	Illinois	3	246,346	10,499	4.45			12,032	3.71	8.48	6.17	27.24
E. Midwest - #18	ILL #6	Christian	Illinois	3	237,056	10,304	4.87			12,297	4.40	9.45	7.16	24.23
E. Midwest - #18	ILL #6	Christian	Illinois	3	244,514	10,707	5.16			12,278	4.34	9.64	7.07	26.66
E. Midwest - #18	ILL #6	Christian	Illinois	3	251,592	10,956	5.05			12,370	4.44	9.22	7.18	22.12
E. Midwest - #18	ILL #6	Christian	Illinois	3	226,517	10,741	5.44			12,320	4.46	10.13	7.24	28.53
E. Midwest - #18	ILL #6	Christian	Illinois	3	242,190	10,417	4.98			12,267	4.42	9.56	7.21	24.58
E. Midwest - #51	ILL #5	Fulton		3	240,000	10,940	3.46			12,600	3.15	6.33	5.00	21.01
E. Midwest -	ILL #6	Montgomery	Illinois	1	240,000	10,837	4.25					7.84		
E. Midwest - #51	ILL #6	Perry	Illinois	3	240,000	10,911	4.49			12,637	3.17	8.23	5.02	39.00
E. Midwest - #51	ILL #5	Randolph		3	120,000	10,937	4.83			12,681	4.16	8.83	6.56	25.71
E. Midwest - #51	ILL #6	Perry	Illinois	3	240,000	10,985	4.75			12,543	3.38	8.65	5.39	37.69
E. Midwest -	ILL #6	Jackson	Illinois	1	170,000	12,070	1.2					1.99		

APPENDIX D

LISTING OF UNPUBLISHED 1972 EPA SURVEY DATA

ON COAL PREPARATION PLANTS

TABLE 1: Coal Cleaning Plant Feed And Product Coal Data From The 1972 EPA Air Pollution Survey

Control #	Level of Cleaning	Thermal Dryers	Operating Capacity (T/hr.)		Run of Mine Coal					Product Usage Coal											
										Utility					Other						
			Raw	Clean	BTU	Ash	Stot	Sp	So	BTU	Ash	Stot	Sp	So	BTU	Ash	Stot	Sp	So		
149	4	Yes	825	700	12117	22.0	1.04	.39	.65						14700	5.5	.9	.18	.72		
150	3	Yes	600	500	11650	24.5	1.04	.44	.60	13349	13.5	1.0	.39	.61							
151	4	Yes	350	200	9123	42.0	.66	.03	.63												
002	3	No																			
015	2	No		850	11500	18.11	4.49			12487	11.66	3.37			12487	11.66	3.37				
005	3	No	500	404	10461	25.76	3.4	2.18	1.22	12833	11.0	2.5			13252	8.6	2.4				
018	3	No	600	480	12250	15.0	4.48	2.45	2.03	13485	7.0	3.8	1.96	1.84	13525	6.7	3.75	1.95	1.80		
019	3	No	450	340	12311	12.21	4.04			12644	10.96	3.41			12644	10.96	3.41				
021	1	No	250	1000	12550	13.0	4.0	2.2	1.8	13100	9.3	3.5	1.8	1.7							
022	1	No	600	500	12750	11.8	3.9	2.0	1.8	13200	8.6	3.3	1.6	1.6							
032	2	No																			
045	2	No	288	260	13035	11.2	4.44	2.84	1.57	13364	9.4	4.14	2.43	1.69							
046	2	No	288	260	13009	11.6	5.52	3.48	2.0	13275	10.0	5.05	2.92	2.11							
049	1	No				6.6	2.05	1.54	.51												
058	2	No								13600	8.5	2.8			13600	8.5	2.8				
071	4	No																			
092	2	No	100	80	13140	14.12	2.13	1.29	.84	14017	9.78	1.58	.8	.78							
107	4	No	500	350	12500	2.5	1.1														

TABLE 1: (Continued)

Control #	Level of Cleaning	Thermal Dryers	Operating Capacity (T/hr.) Raw	Clean	Run of Mine Coal BTU	Ash	Stot	Sp	So	Product Usage: Coal — Utility BTU	Ash	Stot	Sp	So	Other BTU	Ash	Stot	Sp	So
174	4	Yes	600	510	14000	12.0	.60	.30	.30						14500	5.3	.60	.30	.30
179	4	Yes	515	387	8600	40.0	1.5	.7	.7	12100	18.0	1.3	.4	.7					
180	4	Yes	375	206	10731	27	1.15	.25	.90										
181	3	Yes	352	275	12201	17	.85	.28	.57										
187	4	Yes	404	245	10860	24.95	.78												
188	4	No	300	195	11675	18.85	1.17												
191	3	Yes	1000	750	12200	15.9	4.5	3.1	1.4	13300	10.52	2.76	2.04	0.72					
192	4	Yes	500	400	12300	15.5	4.0	3.65	1.35	13500	7.0	2.65	1.95	.70					
204A	4	Yes			14000	15.0	.7												
205	3	Yes	750	575						13400	6.9	3.3	1.8	1.1	13400	6.9	3.3	1.8	1.1
117	4	Yes	800	500	12000	21.5	.8												
118	4	Yes	800	560		17.5	1.21			14300	5.9	.9							
123	4	Yes	350	247	11242	27	1.5	.54	.96	13336	13.4	1.37	.41	.96					
126	3	Yes	700	525	14400	5.0	.86			13500	9.5	.95							
128	3	Yes	450	325	11990	19.8	.7			13595	7.0	.80			14072	6.2	.79		
130	4	Yes	437	350	12800	13.8	3.8	.80	3.0	15400	7.2	3.0	.63	2.37					
144	4	Yes	825	700	13299	12.3	3.28	1.78	1.49	14072	7.2	2.52	.8	1.71	14216	6.6	2.21	.75	1.45
148	4	Yes	550	350	11065	28.1	.82	.18	.63										

TABLE 1: (Continued)

Control #	Level of Cleaning	Thermal Dryers	Operating Capacity (T/hr.) Raw	Operating Capacity (T/hr.) Clean	Run of Mine Coal BTU	Ash	Stot	Sp	So	Product Usage Coal: Utility BTU	Ash	Stot	Sp	So	Product Usage Coal: Other BTU	Ash	Stot	Sp	So
010	N/A	No	570	400	10070	27	5.0	2.7	2.3	12400	12	4.0	1.5	2.5	12400	12	4.0	1.5	2.5
011	N/A	No	980	700	11899	13.6	3.65	2.65	.9						13104	8.4	3.0	2.3	0.9
012	N/A	No	1400	1000	10070	27	5.0	2.7	2.3	12400	12	4.0	1.5	2.5	12400	12	4.0	1.5	2.5
013	2	No	853	607	10678	27.72	5.6	4.1	1.5	12800	13	4.0	2.4	1.6	12800	13	4.0	2.4	1.6
016	3	Yes	300	1000	11500	18.11	4.49			10916	12.33	3.53							
033	4	Yes	330	250	15300	22.0	.58	.17	.41										
037	2	No	300	225	11500	10.0	1.0			12500	7.5	1.0							
047	N/A	No	1260	1000	11233	20.1	4.9	3.13	1.77	12322	13.0	2.84	1.42	1.42	12322	13.0	2.84	1.42	1.42
050	2	No	475	355		31	3.8	2.0	1.8	12580	13.5	3.7	1.75	1.9					
056	3	Yes	220	206															
066	1	No	300	250	11931	23.0	3.2	2.75	0.45										
067	N/A	No	200	175	12429	18	3.5			13660	11.4	1.95							
095	3	Yes	650	490	12871	18	.78			13724	1.4	.65							
096	4	No	650	468	11856	18	.58												
097	4	Yes	1500	900	11315	27	.73	.22	.51	12800	17	.59	.12	.47	14250	7.5	.59	.12	.47
106	4	Yes	420	315	12024	18	.60	.18	.42										
114	N/A	No	400	300	11100	20	1.4			12000	15.5	1.3							
152	4	Yes	825	700	12973	14.5	3.6	2.6	0.9	14096	7.2	2.8	1.99	0.8					
153	4	Yes			12663	16.8	3.69	2.94	0.75										

TABLE 1: (Continued)

Control #	Level of Cleaning	Thermal Dryers	Operating Capacity (T/Hr.) Raw	Operating Capacity (T/Hr.) Clean	Run of Mine Coal BTU	Ash	Stot	Sp	So	Product Usage Coal: Utility BTU	Ash	Stot	Sp	So	Other BTU	Ash	Stot	Sp	So
131	N/A	No																	
138	2	No																	
141	2	No																	
162	4	No																	
164	4	No																	
165	2	No																	
197	2	No	250	200															
199	2	No	300	240		28.0					18.5	1.1							
201	2	No				31.0					20.0	.98							
213	2	No	550	484	13100	11.0	1.7			13400	8.0	1.4							
217	4	No	500	275															

TABLE 1: (Continued)

Control #	Level of Cleaning	Thermal Dryers	Operating Capacity (T/Hr.) Raw	Clean	Run of Mine Coal BTU	Ash	Stot	Sp	So	Product Usage Coal: Utility BTU	Ash	Stot	Sp	So	Other BTU	Ash	Stot	Sp	So
065	2	No	300	240	13172	16.1	1.45	0.80	0.65						14687	6.2	1.07	0.47	0.60
069	2	No	1500	975	0982	37.10	4.84			11868	19.95	2.69							
081	3	No	174	138						12516	18.75	3.01							
083	NA	No			11500	21.1	3.24	2.1	1.11	12350	16.0	2.30	1.20	1.11					
088	1	No	225	180	12065	15	1.5	1.0	0.5	12942	10.5	1.5	1.0	0.5					
090	NA	No	60	54	13250	12	3			13250	12	3							
093	2	No	250	199	14180	8.81	1.80	1.20	0.60	14186	8.17	1.27	0.67	0.60	14210	8.12	1.36	0.81	0.55
110	2	No	200	200	12600	12	0.6			12963	8.36	0.56			13922	4.82	0.54		
116	2	No	90	88	13600	3.21	0.6								13850	2.32	0.6		
127	2	No	600	450	12370	19.67	1.48			13900	9.30	1.16			14150	6.28	1.00		
145	1	No	538	386	12207	22.4	0.57	0.05	0.52										
155	3	Yes	200	140	13200	16	0.80	0.68	0.12	12900	9	0.70	0.59	0.11	Same as utility				
156	2	No	200	175	13000	15.0	1.95												
157	2	No	300	275	13385	12.5	1.95			14000	8.5	1.55			Same as utility				
170	2	No	150	135	11816	23.85	3.50	3.25	0.25	12448	19.78	3.50	3.12	0.38	Same as utility				
176	NA	No			11000	20	2.0			12000	12	2.0			Same as utility				
177	2	No	300	250	13307	10.50	1.13			14150	7.00	0.90			14600	3.70	0.90		
182	NA	No	225	200	14300	17.0	0.70	0.65	0.05										

TABLE E1: (Continued)

Control #	Level of Cleaning	Thermal Dryers	Operating Capacity (T/hr.) Raw	Clean	Run of Mine Coal BTU	Ash	Stot	Sp	So	Product Usage Coal: Utility BTU	Ash	Stot	Sp	So	Other BTU	Ash	Stot	Sp	So
136	4	Yes																		
137	3	Yes																		
139	4	Yes																		
140	4	Yes																		
142	N/A	Yes																		
143A	4	Yes																		

TABLE C1: (Continued)

Control #	Level of Cleaning	Thermal Dryers	Operating Capacity (T/hr.) Raw	Operating Capacity (T/hr.) Clean	Run of Mine Coal BTU	Ash	Stot	Sp	So	Product Usage: Coal Utility BTU	Ash	Stot	Sp	So	Other BTU	Ash	Stot	Sp	So
068	3	Yes	200	160	12931	15.33	1.23			13511	13.02	1.16			same as utility				
073	N/A	Yes																	
098	4	Yes																	
099	4	Yes																	
100	4	Yes																	
101	4	Yes																	
102	4	Yes																	
115	4	Yes	600	360	11006	25.05	0.95			13934	8.4	0.79							
121	4	Yes	550	358	11600	24.18	0.86												
122	4	Yes	550	368	14260	7.1	0.8												
125	N/A	Yes																	
129	4	Yes	550	400	11727	23.35	0.87			13321	12.50	0.85							
132	3	Yes																	
133	N/A	Yes																	
134	3	Yes																	

TABLE .1: (Continued)

Control #	Level of Cleaning	Thermal Dryers	Operating Capacity (T/hr.) Raw	Clean	Run of Mine Coal BTU	Ash	Stot	Sp	So	Product Usage Coal: Utility BTU	Ash	Stot	Sp	So	Other BTU	Ash	Stot	Sp	So
001	3	Yes	450	387	12672	12.71	3.43			11298	10.18	2.48							
006	4	Yes	1200	912	13192	9.4	1.82	1.11	0.71	13600	7.0	1.40			12800	12.0	1.40		
009	4	Yes	1000	950	13200	8.8	1.2	0.6	0.6						13300	7.8	1.1	0.5	0.6
014	3	Yes	1000	750						13440	8.50	2.50	1.25	1.25	13480	8.30	2.28	1.14	1.14
023	3	Yes	450	338	11000	20.0	0.65	0.26	0.39						13000	6.0	0.62	0.25	0.37
024	3	Yes	200	150	12000	15.0	1.00	0.40	0.60						13700	3.5	0.90	0.30	0.60
025	4	Yes		525	13000	20.0	0.75			13800	7.4	0.72			14100	5.25	0.65		
030	3	Yes								13800	6.5	1.00	0.20	0.80					
031	3	Yes								13500	7.0	1.00	0.20	0.80					
034	4	Yes	1250	800	10500	25	1.03			13276	10.1	0.90							
035	N/A	Yes	520	350	13000	12.0				13100	6.50	0.88							
038	4	Yes				18.30	0.90												
042	N/A	Yes																	
043	3	Yes																	
044A	N/A	Yes			12570	6.28	3.42			13292	6.64	3.62							
057	4	Yes	1500	1370	11700	20.0	2.0	1.4	0.6	12643	17.8	1.06							
062	3	Yes																	

TABLE 1: (Continued)

Control #	Level of Cleaning	Thermal Dryers	Operating Capacity (T/Hr.) Raw	Operating Capacity (T/Hr.) Clean	Run of Mine Coal BTU	Run of Mine Coal Ash	Run of Mine Coal Stot	Run of Mine Coal Sp	Run of Mine Coal So	Product Usage Coal: Utility BTU	Utility Ash	Utility Stot	Utility Sp	Utility So	Product Usage Coal: Other BTU	Other Ash	Other Stot	Other Sp	Other So
027	3	No	150	120	13800	5	0.70			13000	4	0.70			13800	3	0.70		
029	2	No								1200	12	1.5	0.5	1.0					
052	NA	No	70	50	10636	29.2	5.14			13385	14.4	3.13							
053	4	No	300	240	13000	16.0	2.0	1.20	0.80	13900	10.0	1.80	1.0	0.80					
060	NA	No	350	225	15261	9.0	0.99	0.67	0.32	15261	9.0	0.99	0.67	0.32	Same as utility				
063	NA	No	70	65		10-11	1.0-1.5												

TABLE 1: (Continued)

Control #	Level of Cleaning	Thermal Dryers	Operating Capacity (T/Hr.) Raw	Clean	Run of Mine Coal BTU	Ash	Stot	Sp	So	Product Usage Coal: Utility BTU	Ash	Stot	Sp	So	Other BTU	Ash	Stot	Sp	So
207	4	Yes	400	220	10249	35.0	0.60	0.04	0.56										
208	3				12677	10.8	1.10	0.38	0.85	11800	17.0	1.50			13071	9.5	1.20		
209	3	Yes	550	357	12500	30	0.05	0.74	0.11										
210	3	Yes								12310	7.35	0.92	0.18	0.74					
215	4	Yes			13000	12	0.68	0.20	0.48										
216	4	Yes	250	167	12200	21.2	1.18	0.38	0.80										
218	4	Yes	400	208	10250	30	0.60	0.18	0.42	13104	16.0	0.60	0.18	0.42					
004	4	No	1200	1044	12677	10.8	1.10	0.38	0.85	11800	17.0	1.50			13071	9.5	1.20		
085	2	No	300	255	13300	14	1.7	1.2	0.5	14000	10	1.3	0.8	0.5					
008	2	No	1000	600	12300	14.2	2.1	1.4	0.7	2700	12.1	1.8	1.0	0.8					
064	2	No	150	130	13000	10	1.5			3000	8	2.0							
072	NA	No			11500	18	6			3000	9.5	3.2							
075	2	No	150	100	2200	15	1.2			2800	11	1.0							
094	2	No	75	68	2500	16	4.0	1.0	3.0	12800	14	3.0	0	3.0					
111	NA	No	60	54	3500	12.0	1.2								13900	8.55	1.21		
020	2	No	70	56	1676	8.98	1.24												

TABLE 1: (Continued)

Control #	Level of Cleaning	Thermal Dryers	Operating Capacity (T/Hr.)		Run of Mine Coal					Product Usage Coal: Utility					Product Usage Coal: Other				
			Raw	Clean	BTU	Ash	Stot	Sp	So	BTU	Ash	Stot	Sp	So	BTU	Ash	Stot	Sp	So
159	4	Yes								13500	7.5	0.90	0.18	0.72					
161	4									13000	9.5	1.00	0.20	0.80					
166	4	Yes																	
167	4	Yes																	
171	3	Yes								13250	6.75	0.70	0.14	0.56					
172	3	Yes	400	275															
175	3	Yes	600	420	10195	30.05	0.90	0		13154	12.55	0.80	0						
189	4	Yes	1772	1539	12007	21.61	0.57	0.10	0.47										
190	4	Yes	1060	800	12150	10.30	0.59	0.10	0.49										
195	4	Yes	500	400	13158	14.00	0.78	0.56	0.22										
196	4	Yes	500	400	12852	16.00	0.80	0.55	0.25	12540	16.00	0.84	0.24	0.60					
198	3	Yes	325	255		45.00					17.00	1.08							
200	3	Yes	430	290		23.00				12175	19.50	1.12							
202	3	Yes	350	240	11745	24.5	0.72			12340	18.0	1.0							
203	4	Yes								13000	8.0	0.75	0.15	0.60					
206	4	Yes	650		13250	12.50	1.20	0.35	0.65						14850	2.50	0.90	0.15	0.65

APPENDIX E

DETAILED COAL COSTS

SUMMARY OF TOTAL DIRECT COSTS (Mid 1978 Dollars)

	Physical Coal Cleaning		Chemical Coal Cleaning		
	High Sulfur Eastern Coal	Low Sulfur Eastern Coal	ERDA Process	Meyers Process	Gravichem Process
Raw Coal Storage and Handling	2,147,000	2,149,000			
Preparation Plant Equipment Cost	(2,076,000)	(1,913,000)			
Total Cost of Preparation Plant	4,882,000	4,496,000			
Miscellaneous Facilities and Equipment	3,818,000	2,884,000			
Total Direct Cost	10,847,000	9,529,000	136,728,000	99,432,000	39,344,000

SUMMARY OF TOTAL INSTALLED CAPITAL COSTS (Mid 1978 Dollars)

	High Sulfur Eastern Coal	Low Sulfur Eastern Coal	ERDA Process	Meyers Process	Gravichem Process
Total Direct Costs (equipment and installation)	10,847,000	9,529,000	136,728,000	99,432,000	39,344,000
Total Indirect Cost	3,473,000	3,049,000	43,775,000	31,818,000	12,593,000
Contingencies	2,864,000	2,516,000	36,097,000	26,250,000	10,387,000
Total Turnkey Costs	17,184,000	15,094,000	216,580,000	157,500,000	62,324,000
Land	264,000	264,000	120,000	120,000	120,000
Working Capital	675,000	566,000	7,931,500	5,973,000	2,430,000
Grand Total (turnkey and land and working capital)	18,123,000	15,975,000	224,631,500	163,593,000	64,874,000

ANNUAL OPERATING COSTS (Mid 1978 Dollars)

	Physical Coal Cleaning		Chemical Coal Cleaning				
					Gravichem Process		
	High Sulfur Eastern Coal	Low Sulfur Eastern Coal	ERDA Process	Meyer's Process	Physical	Chemical	Total
Direct Cost							
Direct Labor	426,600	237,000	688,000	2,190,000	260,700	722,000	982,700
Supervision	91,200	91,200	92,000	212,000	60,800	91,000	151,800
Maintenance Labor	237,000	142,200	--	--	142,200	--	142,200
Maintenance Supplies and Replacement Parts	1,202,900	1,056,600	10,829,000	7,875,000	687,600	2,625,000	3,312,600
Power	199,300	315,100	12,885,000	5,200,000	83,400	1,734,000	1,817,400
Water	3,800	7,400	288,000	2,484,000	900	828,800	829,700
Waste Disposal	433,200	323,300	240,000	1,275,000	319,700	425,000	744,700
Chemicals	106,300	90,300	6,704,000	4,655,000	2,200	1,735,000	1,737,200
TOTAL DIRECT COST	2,700,300	2,263,100	31,726,000	23,891,000	1,557,500	8,160,800	9,718,300
Overhead							
Payroll	226,400	141,100	234,000	720,000	--	--	383,000
Plant	536,600	420,400	4,761,000	3,880,000	--	--	1,645,000
TOTAL OVERHEAD COST	763,000	561,500	4,995,000	4,600,000	--	--	2,028,000
Capital Charges							
G&A, Taxes & Insurance	687,400	603,800	8,663,000	6,300,000	--	--	2,493,000
Capital Recovery	2,132,000	1,773,500	25,448,000	18,500,000	--	--	7,358,000
TOTAL CAPITAL CHARGES	2,886,900	2,434,300	34,111,000	24,800,000	--	--	9,851,000
TOTAL ANNUAL COSTS*	6,350,200	5,258,900	70,832,000	53,291,000	--	--	21,597,300

*Excludes cost of raw coal.

SUMMARY OF TOTAL DIRECT COST (Equipment and Installation)
Physical Coal Cleaning-High Sulfur Eastern Coal (Mid 1978)

Raw Coal Storage and Handling		2,147,000
Preparation Plant Equipment Cost	2,076,0000	
Total Cost of Preparation Plant		4,882,000
Miscellaneous Facilities and Equipment		3,818,000
TOTAL DIRECT COST		10,847,000

SUMMARY OF TOTAL INSTALLED CAPITAL COST-Physical Coal Cleaning-
High Sulfur Eastern Coal (Mid 1978)

Total Direct Costs (equipment and installation)	10,847,000
Total Indirect Costs	3,473,000
Contingencies	2,864,000
Total Turnkey Costs	17,184,000
Land	--
Working Capital	675,000
GRAND TOTAL (turnkey & land & working capital)	18,123,000

Annual Operating Costs
Physical Coal Cleaning - High Sulfur Eastern Coal (Mid 1978)

Direct Cost	
Direct Labor	426,600
Supervision	91,200
Maintenance Labor	237,000
Maintenance supplies and replacement parts	1,202,900
Power	199,300
Water	3,800
Waste Disposal	433,200
Chemicals	106,300
Total Direct Cost	2,700,300
Overhead	
Payroll	226,400
Plant	536,600
Total Overhead Cost	763,000
Capital Charges	
G & A, taxes and insurance	687,400
Capital recovery	2,132,000
Total Capital Charges (including interest on working capital of $67,000)	2,886,900
Total Annual Costs*	6,350,200

*excludes cost of raw coal

Summary of Total Direct Cost (Equipment and Installation)
Physical Coal Cleaning Plant - Low Sulfur Eastern Coal (Mid 1978)

Raw Coal Storage and Handling		2,149,000
Preparation Plant Equipment Cost	1,913,000	
Total Installed Cost of Preparation Plant		4,496,000
Miscellaneous Facilities and Equipment		2,884,000
Total Direct Cost		9,529,000

Summary of Total Installed Capital Cost
Physical Coal Cleaning Plant - Low Sulfur Eastern Coal (Mid 1978)

Total Direct Costs (equipment and installation)	9,529,000
Total Indirect Costs	3,449,000
Contingencies	2,516,000
Total Turnkey Costs	15,094,000
Land	264,000
Working Capital	566,000
Grand Total (turnkey + land + working capital)	15,975,000

Annual Operating Costs

Physical Coal Cleaning Plant - Low Sulfur Eastern Coal (Mid 1978)

Direct Cost	
Direct Labor (10 man yr. x $23,700/man yr.)	237,000
Supervision (3 man yr. x $30,400/man yr.)	91,200
Maintenance Labor (6 man yr. x $23,700/man yr.)	142,200
Maintenance Supplies and Replacement Parts	1,056,600
Power (25.8 mils/kwh x 3,673 kw x 3,325 hrs/yr)	315,100
Water	7,400
Waste Disposal ($1/ton)	323,300
Chemicals	90,300
Total Direct Cost	2,263,100
Overhead	
Payroll	141,100
Plant	420,400
Total Overhead Cost	561,500
Capital Charges	
G & A, taxes and insurance	603,800
Capital recovery	1,773,500
Total Capital Charges (includes interest on working capital of $57,000)	2,434,300
Total Annualized Costs*	5,258,900

*excludes cost of raw coal

Summary of Total Installed Capital Cost

ERDA Chemical Coal Cleaning Process - (Mid 1978)

Total Direct Costs (equipment and installation)	136,728,000
Total Indirect Costs	43,755,000
Contingencies	36,097,000
Total Turnkey Costs	216,580,000
Land	120,000
Working Capital	7,931,500
Grand Total (turnkey + land + working capital)	224,631,500

Annual Operating Costs - ERDA Chemical Coal Cleaning Process
(Mid 1978)

Direct Cost	
Direct labor	688,000
Supervision	92,000
Maintenance labor	—
Maintenance supplies and replacement parts	10,829,000
Power	12,885,000
Water	288,000
Waste Disposal	240,000
Chemicals	6,704,000
Total Direct Costs	31,726,000
Overhead	
Payroll	234,000
Plant	4,761,000
Total Overhead Cost	4,995,000
Capital Charges	
G&A, Taxes and Insurance	8,663,000
Capital recovery	25,448,000
Total Capital Charges	34,111,000
Total Annual Costs*	70,832,000

* Excludes Cost of Raw Coal

Summary of Total Installed Capital Cost - Meyers Chemical Coal Cleaning Process (Mid 1978)

Total Direct Costs (equipment and installation)	99,432,000
Total Indirect Costs	31,818,000
Contingencies	26,250,000
Total Turnkey Costs	157,500,000
Land	120,000
Working Capital	5,973,000
Grand Total (turnkey + land + working capital)	163,593,000

Annual Operating Costs - Meyers Chemical Coal Cleaning Process
(Mid 1978)

Direct Cost	
Direct labor	2,190,000
Supervision	212,000
Maintenance labor	-
Maintenance supplies and replacement parts	7,875,000
Power	5,200,000
Water	2,484,000
Waste Disposal	1,275,000
Chemicals	4,655,000
Total Direct Costs	23,891,000
Overhead	
Payroll	720,000
Plant	3,880,000
Total Overhead Cost	4,600,000
Capital Charges	
G&A, taxes and insurance	6,300,000
Capital recovery	18,500,000
Total Capital Charges	24,800,000
Total Annual Costs*	53,291,000

* Excludes Cost of Raw Coal

Summary of Total Installed Capital Cost

Gravichem Coal Cleaning Plant - (Mid 1978)

Total Direct Costs (equipment and installation)	39,344,000
Total Indirect Costs	12,593,000
Contingencies	10,387,000
Total Turnkey Costs	62,324,000
Land	120,000
Working Capital	2,430,000
Grand Total (turnkey + land + working capital)	64,874,000

Annual Operating Costs

Gravichem Coal Cleaning Process - (Mid 1978)

Direct Cost	Chemical	Physical	Total
Direct labor	722,000	260,700	982,700
Supervision	91,000	60,800	151,800
Maintenance labor	-	142,200	142,200
Maintenance supplies and replacement parts	2,625,000	687,600	3,312,600
Power	1,734,000	83,400	1,817,400
Water	828,800	900	829,700
Waste Disposal	425,000	319,700	744,700
Chemicals	1,735,000	2,200	1,737,200
Total Direct Costs	8,160,800	1,557,500	9,718,300
Overhead			
Payroll			385,000
Plant			1,645,000
Total Overhead Cost			2,028,000
Capital Charges			
G & A, taxes, and insurance			2,493,000
Capital recovery			7,358,000
Total Capital Charges			9,851,000
Total Annual Costs*			21,597,300

*excludes cost of raw coal

APPENDIX F

EMISSIONS FROM REFERENCE BOILER'S NO. 1-4

TABLE F-1. EMISSIONS FROM REFERENCE BOILER NO. 1 PACKAGE, WATERTUBE, UNDERFEED STOCKER

8.79 MW = 8,790 kJ/S (30 x 10^6 BTU/hr) Input; 50% Excess Air

	High-Sulfur Eastern Coal					Low-Sulfur Eastern Coal				Low-Sulfur Western Coal	
	Raw Coal	Deep-Cleaned PCC	Middling PCC	ERDA	Gravichem	Raw Coal	PCC Product	ERDA	Gravichem	Raw Coal	PCC Product
Dry HV, kJ/kg	27,305	33,555	31,662	27,305	34,081	31,685	33,883	31,685	34,666	26,268	29,201
Dry Coal Feed, kg/S	0.3219	0.2620	0.2776	0.3219	0.2579	0.2774	0.2594	0.2774	0.2536	0.3346	0.3010
Total Ash, g/S	75.32	15.20	31.40	75.32	11.32	28.79	10.71	28.79	4.95	83.01	49.67
Fly ash, g/S	18.83	3.80	7.85	18.83	2.83	7.20	2.68	7.20	1.24	20.75	12.42
Gaseous Emissions, gm moles/sec: CO_2	17.58	17.58	17.57	17.58	17.58	17.58	17.58	17.58	17.58	17.58	17.58
H_2O	7.65	8.15	8.21	8.21	7.46	7.02	7.87	7.02	6.98	7.18	8.00
SO_2*	0.3242	0.0838	0.1390	0.0706	0.0840	0.0970	0.0684	0.0320	0.0421	0.0585	0.0580
O_2	10.53	10.27	10.34	10.26	10.27	10.25	10.22	10.18	10.19	10.17	10.17
N_2	118.92	116.06	116.78	115.90	116.05	115.85	115.51	115.07	115.19	114.88	114.91
NO_2	0.05247	0.04271	0.04525	0.05247	0.04203	0.04522	0.04228	0.04522	0.04134	0.05454	0.04906
CO	0.01149	0.00935	0.00991	0.01149	0.00921	0.00990	0.00926	0.00990	0.00905	0.01195	0.01075
CH_4	0.01003	0.00817	0.00865	0.01003	0.00804	0.00865	0.00809	0.00865	0.00790	0.01043	0.00938
Total	155.03	152.14	153.04	151.45	151.44	150.79	151.26	149.88	149.98	149.77	150.71
Gaseous Emissions, gm/sec: SO_2*	20.77	5.37	8.91	4.52	5.38	6.21	4.38	2.05	2.70	3.75	3.72
NO_2	2.41	1.97	2.08	2.41	1.93	2.08	1.95	2.08	1.90	2.51	2.26
CO	0.322	0.262	0.278	0.322	0.258	0.277	0.259	0.277	0.253	0.335	0.301
CH_4	0.161	0.131	0.139	0.161	0.129	0.139	0.130	0.139	0.127	0.167	0.150
Flue Gas: Temp, °K	478	450	450	450	450	450	450	450	450	450	450
Std m^3/sec	3.475	3.410	3.430	3.395	3.394	3.380	3.390	3.360	3.362	3.357	3.378
Actual m^3/sec	6.075	5.614	5.647	5.590	5.588	5.565	5.581	5.532	5.535	5.527	5.562

* 95% of Stoichiometric Quantity

TABLE F-2. EMISSIONS FROM REFERENCE BOILER NO. 2 PACKAGE, WATERTUBE, CHAIN GRATE

21.975 MW = 21,975 kJ/S (75 x 10^6 BTU/hr) Input; 50% Excess Air

		High-Sulfur Eastern Coal					Low-Sulfur Eastern Coal				Low-Sulfur Western Coal	
		Raw Coal	Deep-Cleaned PCC	Middling PCC	ERDA	Gravichem	Raw Coal	PCC Product	ERDA	Gravichem	Raw Coal	PCC Product
Dry HV, kJ/kg		27,305	33,555	31.662	27,305	34,081	31,685	33,883	31,685	34,666	26,268	29,201
Dry Coal Feed, kg/S		0.8048	0.6549	0.6940	0.8048	0.6448	0.6935	0.6486	0.6935	0.6339	0.8366	0.7525
Total Ash, g/S		188.32	37.98	78.49	188.32	28.31	71.99	26.79	71.99	12.36	207.56	124.16
Fly ash, g/S		47.08	9.50	19.62	47.08	7.08	18.00	6.70	18.00	3.09	51.89	31.04
Gaseous Emissions, gm moles/sec	CO_2	43.94	43.94	43.94	43.94	43.94	43.94	43.95	43.94	43.94	43.95	43.94
	H_2O	19.12	20.36	20.53	19.12	18.64	17.54	19.67	17.54	17.44	17.95	20.01
	SO_2*	0.8107	0.2095	0.3475	0.1765	0.2101	0.2424	0.1710	0.0801	0.1051	0.1462	0.1449
	O_2	26.32	25.68	25.84	25.65	25.68	25.63	25.56	25.46	25.48	25.42	25.43
	N_2	297.33	290.11	291.94	289.77	290.15	289.63	288.83	287.68	287.93	287.25	287.28
	NO_2	0.1312	0.1067	0.1131	0.1312	0.1051	0.1130	0.1057	0.1130	0.1033	0.1364	0.1227
	CO	0.0287	0.0234	0.0248	0.0287	0.0230	0.0248	0.0232	0.0248	0.0226	0.0299	0.0269
	CH_4	0.0251	0.0204	0.0216	0.0251	0.0201	0.0216	0.0202	0.0216	0.0198	0.0261	0.0235
	Total	387.6	380.3	382.6	378.7	378.6	377.0	378.2	374.7	374.9	374.5	376.8
Gaseous Emissions, gm/sec	SO_2*	51.94	13.42	22.26	11.31	13.46	15.53	10.96	5.13	6.73	9.37	9.28
	NO_2	6.04	4.91	5.20	6.04	4.84	5.20	4.86	5.20	4.75	6.28	5.65
	CO	0.804	0.655	0.695	0.804	0.644	0.695	0.650	0.695	0.633	0.837	0.753
	CH_4	0.403	0.327	0.347	0.403	0.322	0.347	0.324	0.347	0.318	0.419	0.377
Flue Gas	Temp, °K	478	450	450	450	450	450	450	450	450	450	450
	Std m^3/sec	8.688	8.524	8.576	8.487	8.487	8.450	8.477	8.399	8.403	8.394	8.445
	Actual m^3/sec	15.188	14.034	14.120	13.973	13.973	13.912	13.957	13.828	13.835	13.820	13.904

* 95% of Stoichiometric Quantity

TABLE F-3. EMISSIONS FROM REFERENCE BOILER NO. 3 FIELD-ERECTED, WATERTUBE, SPREADER STOKER

43.95 MW = 43,950 kJ/S (150 x 10^6 BTU/hr) Input; 50% Excess Air

	High-Sulfur Eastern Coal					Low-Sulfur Eastern Coal				Low-Sulfur Western Coal	
	Raw Coal	Deep-Cleaned PCC	Middling PCC	ERDA	Gravichem	Raw Coal	PCC Product	ERDA	Gravichem	Raw Coal	PCC Product
Dry HV, kJ/kg	27,305	33,555	31,662	27,305	34,081	31,685	33,883	31,685	34,666	26,268	29,201
Dry Coal Feed, kg/S	1.6096	1.3098	1.3881	1.6096	1.2896	1.3871	1.2971	1.3871	1.2678	1.6731	1.5051
Total Ash, g/S	376.6	76.0	157.0	376.6	56.6	144.0	53.6	144.0	24.7	415.1	248.3
Fly ash, g/S	244.8	49.4	102.0	244.8	36.8	93.6	34.8	93.6	16.1	269.8	161.4
Gaseous Emissions, gm moles/sec: CO_2	87.88	87.89	87.88	87.88	87.89	87.89	87.89	87.89	87.88	87.89	87.88
H_2O	38.24	40.72	41.06	38.24	37.28	35.08	39.34	35.08	34.89	35.90	40.02
SO_2*	1.6213	0.4191	0.6950	0.3529	0.4202	0.4849	0.3421	0.1602	0.2103	0.2925	0.2898
O_2	52.63	51.36	51.68	51.30	51.36	51.27	51.12	50.92	50.97	50.85	50.86
N_2	594.65	580.22	583.92	579.54	580.31	579.29	577.61	575.41	575.86	574.46	574.60
NO_2	0.2624	0.2135	0.2263	0.2624	0.2102	0.2261	0.2114	0.2261	0.2067	0.2727	0.2453
CO	0.0575	0.0468	0.0496	0.0575	0.0460	0.0495	0.0463	0.0495	0.0453	0.0597	0.0537
CH_4	0.0502	0.0408	0.0433	0.0502	0.0402	0.0432	0.0404	0.0432	0.0395	0.0522	0.0469
Total	775.2	760.6	765.3	757.3	757.3	754.0	756.3	749.5	749.8	748.9	753.6
Gaseous Emissions, gm/sec: SO_2*	103.87	26.85	44.53	22.61	26.92	31.07	21.92	10.26	13.47	18.74	18.57
NO_2	12.07	9.82	10.41	12.07	9.67	10.40	9.73	10.40	9.51	12.55	11.29
CO	1.611	1.311	1.389	1.611	1.288	1.386	1.297	1.386	1.269	1.672	1.504
CH_4	0.805	0.655	0.695	0.805	0.645	0.693	0.648	0.693	0.634	0.837	0.752
Flue Gas: Temp, °K	478	450	450	450	450	450	450	450	450	450	450
Std m^3/sec	17.376	17.048	17.153	16.975	16.974	16.902	16.953	16.799	16.806	16.786	16.892
Actual m^3/sec	30.376	28.068	28.241	27.948	27.946	27.828	27.912	27.658	27.670	27.637	27.811

* 95% of Stoichiometric Quantity

Table F-4. Emissions from Reference Boiler No. 4
Field-Erected, Watertube, Pulverized Coal
58.60 MW = 58,600 KJ/S (200 x 10^6 Btu/hr) Input; 30% Excess Air

	High-Sulfur Eastern Coal					Low-Sulfur Eastern Coal				Low-Sulfur Western Coal	
	Raw Coal	Deep-Cleaned PCC	Middling PCC	ERDA	Gravichem	Raw Coal	PCC Product	ERDA	Gravichem	Raw Coal	PCC Product
Dry HV, kJ/kg	27,305	33,555	31,662	27,305	34,081	31,685	33,883	31,685	34,666	26,268	29,201
Dry Coal Feed, kg/S	2.1461	1.7464	1.8508	2.1461	1.7194	1.8495	1.7295	1.8495	1.6904	2.2309	2.0068
Total Ash, g/S	502.2	101.3	209.3	502.2	75.5	192.0	71.4	192.0	33.0	553.5	331.1
Fly ash, g/S	401.7	81.0	167.5	401.7	60.4	153.6	57.1	153.6	26.4	442.8	264.9
Gaseous Emissions, gm moles/sec: CO_2	117.18	117.18	117.17	117.18	117.18	117.18	117.19	117.18	117.18	117.19	117.18
H_2O	50.99	54.30	54.75	50.99	49.71	46.77	52.46	46.77	46.52	47.88	53.36
SO_2*	2.1617	0.5588	0.9266	0.4706	0.5603	0.6466	0.4561	0.2137	0.2951	0.3900	0.3864
O_2	42.11	41.08	41.35	41.01	41.09	41.02	40.90	40.74	40.77	40.67	40.68
N_2	687.27	670.60	674.88	669.80	670.67	669.54	667.60	665.04	665.56	663.96	664.11
NO_2	0.4198	0.3416	0.3620	0.4198	0.3363	0.3618	0.3383	0.3618	0.3306	0.4364	0.3925
CO	0.0383	0.0312	0.0330	0.0383	0.0307	0.0330	0.0309	0.0330	0.0302	0.0398	0.0358
CH_4	0.0201	0.0163	0.0173	0.0201	0.0161	0.0173	0.0162	0.0173	0.0158	0.0209	0.0188
Total	899.9	883.7	889.1	879.5	879.3	875.2	878.6	870.0	870.4	869.4	875.8
Gaseous Emissions, gm/sec: SO_2*	138.49	35.80	59.36	30.15	35.90	41.43	29.22	13.69	18.91	24.99	24.76
NO_2	19.31	15.72	16.65	19.31	15.47	16.65	15.56	16.65	15.21	20.08	18.06
CO	1.073	0.874	0.924	1.073	0.860	0.924	0.866	0.924	0.846	1.115	1.003
CH_4	0.322	0.261	0.278	0.322	0.258	0.278	0.260	0.278	0.253	0.335	0.302
Flue Gas: Temp, °K	478	450	450	450	450	450	450	450	450	450	450
Std m^3/sec	20.169	19.808	19.929	19.714	19.709	19.618	19.694	19.501	19.509	19.487	19.631
Actual m^3/sec	35.259	32.612	32.811	32.457	32.449	32.299	32.424	32.107	32.120	32.084	32.321

*95% of Stoichiometric Quantity

APPENDIX G

ANALYSIS OF AN EASTERN MEDIUM SULFUR COAL

Lower Kittanning Coal, Cambria, Pa.

A medium sulfur coal (Lower kittanning, Cambria, Pa.) has been analyzed to provide a comparison of performance factors on a variety of boiler types and sizes.

Included in this Appendix is:

- the design and costing basis;
- washability data for the determination of the performance of a physical coal cleaning operation on the medium sulfur coal;
- a cost analysis for the candidate control systems;
- an energy impact analysis of the candidate control systems; and
- an environmental impact analysis of the candidate control systems.

DESIGN AND COSTING BASIS

The major design criteria used for the preparation of the flow sheets for each coal are summarized as follows:

- Plant input in each case is 544 metric tons per hour (600 tons per hour);
- Annual capacity throughput is 1.81 million metric tons (2.0 million tons) based upon a 13.3 hour operating day and 250 operating days per year;
- In all cases, the plant is located at the mine mouth, and all resources such as coal, water, power, etc. are assumed readily available;
- Coal storage loading conveyors and product loading equipment is assumed to be part of the mine and has not been duplicated;
- All process equipment used is commercially available and proven;
- Actual equipment performance partition factors have been used to adjust raw coal washability characteristics to performance guaranteed specifications; and
- Design of pollution control facilities is based upon federal new source performance regulations - EPA standards for air and water quality, MESA regulations for refuse disposal, and MESA/OSHA noise limitations.
- Annualized costs are presented on a cost for beneficiation basis [dollars/ton of clean coal] excluding costs for coal lost to refuse.

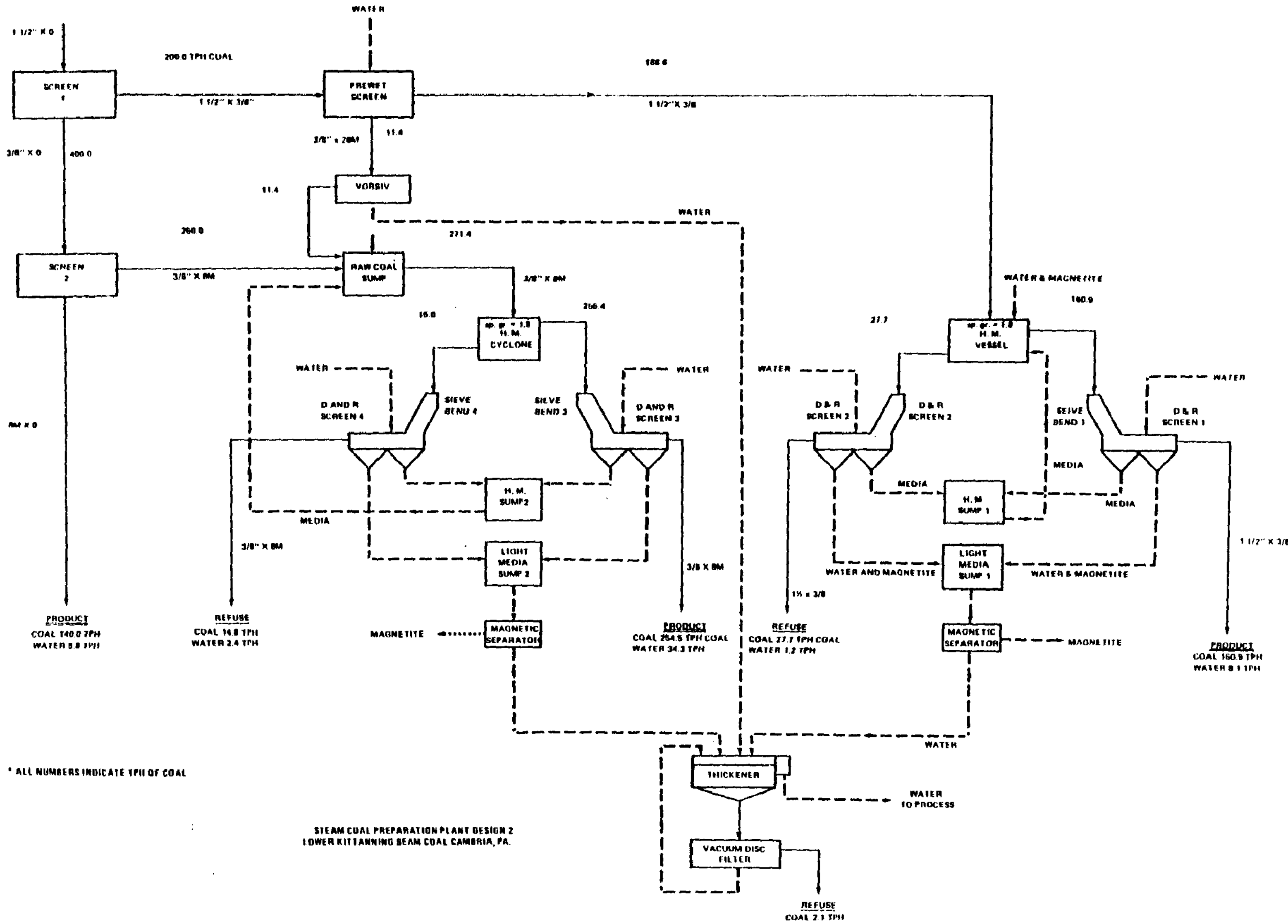

Figure G-1. A level 3 coal preparation flowsheet for beneficiation of a medium sulfur eastern coal for steam fuel purposes.

TABLE G-1 PRODUCT SPECIFICATION
Lower Kittanning Coal - Design #2

A. CHEMICAL SPECIFICATIONS OF FEED AND PRODUCT

	FEED	PRODUCT
Ash, %+	12.8	8.7
Total S, %+	1.86	1.22
Pyritic S, %+	1.34	0.67
Heating Value, (BTU/LB)+	13,508	14,139
Moisture, %	3.5	9.3
LBS $SO_2/10^6$ BTU	2.75	1.72

+ Moisture free basis

B. PLANT PRODUCT FLOW

SIZE	COAL (TPH)	WATER (TPH)	TOTAL (TPH)	% MOISTURE
1¼" x 3/8"	160.9	8.1	169.0	4.8
3/8" x 8M	254.5	43.0	297.5	14.5
8M x 0	140.0	5.8	145.8	4.0
TOTAL	555.4	56.9	611.4	9.3

Weight Yield $= \frac{555.4}{600} \times 100 = 92.6\%$

Moisture Content of Product $= \frac{56.9}{611.4} \times 100 = 9.3\%$

BTU Recovery = 96.9%

TABLE G-2.

COAL WASHABILITY ANALYSIS FOR LOWER KITTANNING SEAM

CAMBRIA, PENNSYLVANIA

SPEC GRAVITY	DIRECT PERCENT (DRY BASIS) WEIGHT %	ASH %	BTU/ LB.	PYRITIC SULFUR,%	TOTAL SULFUR,%	CUMULATIVE PERCENT (DRY BASIS) WEIGHT %	ASH %	BTU/ LB.	PYRITIC SULFUR,%	TOTAL SULFUR,%	LB SO2/ MIL. BTU
1-1/2 BY 3/4	12.4					12.4					
FLOAT- 1.30	25.3	3.6	14934.	0.19	0.82	25.3	3.6	14934.	0.19	0.82	1.10
1.30 - 1.35	15.6	7.0	14408.	0.41	0.97	40.9	4.9	14733.	0.27	0.88	1.19
1.35 - 1.40	8.2	11.9	13648.	0.66	1.23	49.1	6.1	14552.	0.34	0.94	1.29
1.40 - 1.50	6.1	18.5	12626.	1.52	2.01	55.2	7.4	14339.	0.47	1.05	1.47
1.50 - 1.60	5.5	30.7	10736.	1.57	1.79	60.7	9.5	14013.	0.57	1.12	1.60
1.60 - 1.90	18.8	45.3	8474.	1.83	2.02	79.5	18.0	12703.	0.87	1.33	2.10
1.90 - 2.20	2.5	49.8	7777.	12.48	12.48	82.0	19.0	12553.	1.22	1.67	2.67
2.20 - 2.50	7.9	75.2	3842.	6.41	6.44	89.9	23.9	11787.	1.68	2.09	3.55
2.50 - 2.80	8.8	83.6	2541.	4.57	4.57	98.7	29.2	10963.	1.93	2.31	4.22
2.80 - SINK	1.3	60.6	6104.	36.02	37.05	100.0	29.6	10900.	2.38	2.77	5.07
3/4 BY 3/8	19.0					31.4					
FLOAT- 1.30	52.0	3.8	14903.	0.24	0.85	52.0	3.8	14903.	0.24	0.85	1.14
1.30 - 1.35	17.1	8.0	14253.	0.46	1.00	69.1	4.8	14742.	0.29	0.89	1.20
1.35 - 1.40	5.0	12.9	13494.	1.00	1.51	74.1	5.4	14658.	0.34	0.93	1.27
1.40 - 1.50	5.3	19.4	12487.	1.49	1.93	79.4	6.3	14513.	0.42	1.00	1.37
1.50 - 1.60	3.6	28.5	11077.	1.99	2.39	83.0	7.3	14364.	0.49	1.06	1.47
1.60 - 1.90	8.3	46.1	8350.	3.11	3.26	91.3	10.8	13817.	0.73	1.26	1.82
1.90 - 2.20	1.6	53.1	7266.	11.22	11.28	92.9	11.5	13704.	0.91	1.43	2.09
2.20 - 2.50	3.0	72.9	4198.	7.27	7.41	95.9	13.5	13407.	1.11	1.62	2.41
2.50 - 2.80	3.0	82.4	2727.	5.90	5.90	98.9	15.5	13083.	1.25	1.75	2.67
2.80 - SINK	1.1	61.9	5902.	37.63	37.73	100.0	16.1	13004.	1.65	2.14	3.29
3/8 BY 28	55.7					87.1					
FLOAT- 1.30	69.2	2.8	15058.	0.13	0.72	69.2	2.8	15058.	0.13	0.72	0.96
1.30 - 1.35	13.0	7.2	14377.	0.32	0.86	82.2	3.5	14950.	0.16	0.74	0.99
1.35 - 1.40	3.8	11.1	13772.	0.70	1.15	86.0	3.8	14898.	0.18	0.76	1.02
1.40 - 1.50	3.0	16.9	12874.	1.23	1.62	89.0	4.3	14830.	0.22	0.79	1.06
1.50 - 1.60	1.7	25.8	11495.	1.94	2.45	90.7	4.7	14768.	0.25	0.82	1.11
1.60 - 1.90	4.4	45.2	8490.	3.77	4.15	95.1	6.6	14477.	0.41	0.97	1.35
1.90 - 2.20	1.0	53.0	7281.	7.48	7.64	96.1	7.0	14402.	0.49	1.04	1.45
2.20 - 2.50	1.2	70.3	4601.	7.83	8.08	97.3	7.8	14281.	0.58	1.13	1.58
2.50 - 2.80	1.7	80.4	3036.	6.77	6.77	99.0	9.1	14088.	0.68	1.23	1.74
2.80 - SINK	1.0	60.5	6119.	38.51	38.51	100.0	9.6	14009.	1.06	1.60	2.28
28 BY 100	12.9					100.0					
FLOAT- 1.30	77.2	2.6	15089.	0.28	0.92	77.2	2.6	15089.	0.28	0.92	1.22
1.30 - 1.35	8.6	7.7	14299.	0.40	1.01	85.8	3.1	15010.	0.29	0.93	1.24
1.35 - 1.40	3.1	12.5	13556.	0.73	1.16	88.9	3.4	14959.	0.31	0.94	1.25
1.40 - 1.50	2.4	17.5	12781.	1.14	1.64	91.3	3.8	14902.	0.33	0.96	1.28
1.50 - 1.60	1.4	23.4	11867.	1.64	2.19	92.7	4.1	14856.	0.35	0.97	1.31
1.60 - 1.90	2.6	36.7	9806.	2.31	2.67	95.3	5.0	14718.	0.40	1.02	1.39
1.90 - 2.20	1.0	55.0	6971.	3.65	4.19	96.3	5.5	14638.	0.44	1.05	1.44
2.20 - 2.50	1.1	66.5	5190.	6.29	6.84	97.4	6.2	14531.	0.50	1.12	1.54
2.50 - 2.80	1.3	77.5	3486.	6.73	6.93	98.7	7.1	14386.	0.58	1.20	1.66
2.80 - SINK	1.3	62.9	5748.	37.78	37.78	100.0	7.9	14273.	1.07	1.67	2.34

TABLE G-3 PREPARATION PLANT EQUIPMENT (Mid 1978 $)

Lower Kittanning Coal - Design #2

UNIT	NUMBER	SIZE & DESCRIPTION	TOTAL
Raw Coal Sizing Screen 1	3 units	8'x20', Single Deck, Dry, Vibrating, Inclined	69,900
Raw Coal Sizing Screen 2	6 units	8'x20', Single Deck, Dry, Vibrating, Inclined	139,800
Prewet Screen	2 units	6'x14', Single Deck, Wet, Vibrating, Horizontal	33,800
Heavy Media Vessel	1 unit	10' Ø	210,000
Heavy Media Cyclone	3 units	26' Ø	30,300
Vor-Siv	1 unit	Model 2500	15,500
Sieve Bend 1	2 units	60" radius, 5' wide	8,900
Sieve Bend 2	1 unit	30" radius, 4' wide	2,500
Sieve Bend 3	5 units	60" radius, 5' wide	15,000
Sieve Bend 4	1 unit	30" radius, 2' wide	1,900
Drain & Rinse Screen 1	2 units	5'x16', Single Deck, Wet, Vibrating, Horizontal	42,400
Drain & Rinse Screen 2	1 unit	3'x16', Single Deck, Wet, Vibrating, Horizontal	15,700
Drain & Rinse Screen 3	5 units	8'x16', Single Deck, Wet, Vibrating, Horizontal	128,500
Drain & Rinse Screen 4	1 unit	3'x16', Single Deck, Wet, Vibrating, Horizontal	15,700
Vacuum Disc Filter	1 unit	11' Ø, 6 Discs	75,600
Magnetic Separator 1	2 units	30"x6'	13,800
Magnetic Separator 2	2 units	30"x8'	17,400
Raw Coal Sump	6 units		60,000
Heavy Media Sump 1	3 units		30,000
Heavy Media Sump 2	4 units		40,000
Light Media Sump 1	1 unit		10,000
Light Media Sump 2	2 units		20,000
Pumps			74,200
		TOTAL EQUIPMENT COST (FOB)	1,070,900
		FREIGHT (2% of total equipment cost)	21,400
		TOTAL COST (Not Installed)	1,092,300

TABLE G-3. CAPITAL COSTS FOR RAW COAL STORAGE AND HANDLING (Mid 1978 $)

Lower Kittanning Coal - Design #2

(Continued)

Raw Coal Storage Area (10,000 ton avg.; 20,000 ton max. capacity, stacking tube, 4 withdrawal areas, 4 reciprocating feeders of tunnel) (40 hp) = =	463,000
Belt Conveyor from raw coal storage to scalping tower (42" wide, 250 ft. center to center, 60 ft. elevation, 75 hp motor) $560/ft x 250 ft. =	140,000
Scalping Screen (8' x 20', vibrating, double deck, inclined, 2 x 25 = 50 hp motor) $30,000/1.08 ≅	28,000
Rotary Breaker (12'Ø x 27' long) $165,000/1.08 =	153,000
Scalping Tower, Rotary Breaker Motor (100 hp), Hopper/ Chute & Rock Bin, 28,000 + 153,000 =	181,000
Belt Conveyor from Scalping Tower to Process (42" wide, 250 ft. center to center, 60 ft. elevation, 75 hp motor) $562/ft. x 250 ft. =	140,000
Tramp Iron Magnet (Explosion Proof, Self Cleaning)	22,000
TOTAL INSTALLED COST	$1,127,000

TABLE G-4 CAPITAL COST FOR CLEAN COAL & REFUSE EQUIPMENT (Mid 1978 $)
Lower Kittanning Coal - Design #2

Thickener (77 ft. diameter)	=	143,000
Refuse Belt (24", 200 ft.)	=	88,000
Refuse Bin (Limit of 250 ton capacity)	=	60,000
Coal Sampling System	=	324,000
Refuse Handling Equipment		
1 Truck at 80,000 each	=	80,000
1 Dozer at 160,000 each	=	160,000
TOTAL INSTALLED COST		$855,000

TABLE G-5 SUMMARY OF CAPITAL COSTS (Mid 1978 $)
Lower Kittanning Coal - Design #2

Raw Coal Storage and Handling		1,127,000	
Preparation Plant Equipment Cost	1,092,300		
Total Cost of Prep. Plant (2.35 x Prep. Plant Equipment Cost)		2,567,000	
Miscellaneous Facilities and Equipment		855,000	
TOTAL DIRECT COSTS			$4,549,000
INSTALLATION COSTS, INDIRECT			
Engineering (10% of direct costs)		455,000	
Construction & Field Expense (10% of direct costs)		455,000	
Construction Fees (10% of direct costs)		455,000	
TOTAL INDIRECT COSTS			$1,365,000
CONTINGENCIES (25% of direct & indirect costs) (includes start-up and performance tests)			1,479,000
TOTAL TURNKEY COSTS			$7,393,000
LAND			264,000
WORKING CAPITAL (25% of direct operating costs)			402,000
GRAND TOTAL			$8,059,000

TABLE G-6 ANNUALIZED COSTS (Mid-1978$)
Lower Kittanning Coal - Design #2

Direct Labor (18 man yr. x $23,700/man yr.)	426,600	
Supervision (2 man yr. x $30,400/man yr.)	60,800	
Maintenance Labor (8 man yr. x $23,700/man yr.)	189,600	
Maintenance Materials & Replacement Parts (7% of total turnkey costs)	517,500	
Electricity (25.8 mils/kwh 1,980 kw x 3,325 $\frac{h}{yr}$)	169,600	
Water ($0.15/$10^3$ gal. x 27.1 x 10^6 gal/yr.)	4,100	
Waste Disposal ($1/ton x 1.633 x 10^5 tons/yr.)	163,300	
Chemicals (magn: 1,140 ton/yr. x $65/ton) (floc: 0.52 ton/yr. x $3,000 ton)	75,700	
TOTAL DIRECT COST		$1,607,200
Payroll (30% of direct & indirect & maintenance labor)	203,100	
Plant Overhead (26% of direct supervision, maintenance labor and maintenance, and chemicals)	330,300	
TOTAL OVERHEAD COST		$533,400
Capital Recovery Factor (11.75% of total Turnkey Costs)	868,700	
G&A, Taxes & Insurance (4% of total Turnkey Costs)	295,700	
Interest on Working Capital (10% of W.C.)	40,200	
TOTAL CAPITAL CHARGES		$1,204,600
TOTAL ANNUALIZED COSTS		$3,345,200
Cost Per Ton of Moisture Free Product		1.81
Cost Per 10^6 BTU of Product		0.064

TABLE G-7. ENERGY FACTORS

Lower Kittanning Coal - Design #2

Energy loss in refuse:	0.908 x 10^6 BTU/Ton Product (MF Basis)
Energy consumption in plant:	0.012 x 10^6 BTU/Ton Product
TOTAL	0.920 x 10^6 BTU/Ton Product
or;	460 BTU/lb product

TABLE G-8. ENVIRONMENTAL FACTORS

Lower Kittanning Coal - Design #2

A. SOLID WASTE

	Solid (TPH)	Water (TPH)	Total (TPH)
From Disc Filter	2.1	0.9	3.0
D&R Screen 2	27.7	1.2	28.9
D&R Screen 4	14.8	2.4	17.2
TOTAL	44.6	4.5	49.1

$$\text{Tons of Refuse (Dry Basis)/Ton of Product} = \frac{44.6}{555.4} = 0.080$$

TABLE G-8. (Continued)

B. WATER DISCHARGE PARAMETERS

Assume Effluent Flowrate = 75 liters/kkg of product

Primary Pollutants			
Total Dissolved Solids	(265 g/kkg of product)	=	133,523 gm/hr.
Total Suspended Solids	(7 g/kkg of product)	=	3,527 gm/hr.
Total Volatile Solids	(37 g/kkg of product)	=	18,642 gm/hr.
COD	(41 g/kkg of product)	=	5,542 gm/hr.
TOC	(1.9 g/kkg of product)	=	957 gm/hr.
Major Elemental Pollutants			
Calcium	(8.8 g/kkg of product)	=	4,434 gm/hr.
Magnesium	(4.2 g/kkg of product)	=	2,116 gm/hr.
Sodium	(9.0 g/kkg of product)	=	4,535 gm/hr.
Trace Element Pollutants			
Copper	(1.5 mg/kkg of product)	=	756 mg/hr.
Iron	(14 mg/kkg of product)	=	7,054 mg/hr.
Zinc	(3 mg/kkg of product)	=	1,512 mg/hr.
Manganese	(1.8 mg/kkg of product)	=	907 mg/hr.

TABLE G-9.

COSTS OF "BEST" SO_2 CONTROL TECHNIQUES FOR 22MW COAL-FIRED BOILERS USING MEDIUM SULFUR COAL

SYSTEM				ANNUAL COSTS	IMPACTS *	
STANDARD BOILERS: Heat Input MW (MBTU/hr) **	STANDARD BOILERS: Type	TYPE AND LEVEL OF CONTROL	CONTROL EFFICIENCY+ (%)	$/MW(t) ($/MBTU/hr)	% INCREASE IN COSTS OVER UNCONTROLLED BOILER	% INCREASE IN COSTS OVER SIP-CONTROLLED BOILER
22 (75) PCC Coal 32,887 kJ/kg 1.22% S 8.7% Ash	Chain - Grate - Stoker	Raw	0	16.07 (4.71)	--	--
		Moderate 1290 ng SO_2/J SIP - Control	0 37%	16.23 (4.75) 16.60 (4.86)	1.0 3.3	-- --
		Optional Moderate 860 ng SO_2/J	37%	16.60 (4.86)	3.3	--
		Intermediate 645 ng SO_2/J PCC-Level 4				
		Stringent 516 ng SO_2/J PCC-Level 4	56% (assumed)	Not Available		

* BASED ONLY ON ANNUAL COSTS
** Raw Coal: 1.86% S; 31,420 kJ/kg; 12.6% Ash; (1,184 ng SO_2/J)
\+ Percent Reduction in ng SO_2/J

TABLE G-10.

COSTS OF "BEST" SO_2 CONTROL TECHNIQUES FOR 117.2MW COAL-FIRED BOILERS USING MEDIUM SULFUR COAL

SYSTEM				ANNUAL COSTS	IMPACTS *	
STANDARD BOILERS		TYPE AND LEVEL OF CONTROL	CONTROL EFFICIENCY+ (%)	\$/MW(t) (\$/MBTU/hr)	% INCREASE IN COSTS OVER UNCONTROLLED BOILER	% INCREASE IN COSTS OVER SIP-CONTROLLED BOILER
Heat Input MW (MBTU/hr) **	Type					
117.2 (400) PCC Coal 32,887 kJ/kg 1.22% S 8.7% Ash	Chain - Grate - Stoker	Raw	0	12.72 (3.73)	--	--
		Moderate	0	13.36 (3.91)	5%	--
		1290 ng SO_2/J SIP - Control	37%	13.73 (4.02)	8	--
		Optional Moderate 860 ng SO_2/J	37%	13.73 (4.02)	8	--
		Intermediate 645 ng SO_2/J PCC-Level 4	56%			
		Stringent 516 ng SO_2/J PCC-Level 4	56%	Not Available		

* BASED ONLY ON ANNUAL COSTS
** Raw Coal: 1.86% S; 31,420 kJ/kg; 12.6% Ash (1,184 ng SO_2/J)
+ Percent Reduction in ng SO_2/J

TABLE G-11.

Energy Usage of "Best" Control Techniques for 8.8 MW Coal-Fired Boilers Using Medium Sulfur Coal

SYSTEM					ENERGY CONSUMPTION		IMPACTS	
Standard Boiler		Type and Level of Control	Control Ef- ficiency Percent	Energy Type	Energy Consumed by Control		Percent Increase in Energy over Uncontrolled Boiler	Percent Increase in Energy over SIP Controlled Boiler
Heat Rate MW or (10^6 BTU/hr)	Type				kJ/kg (BTU/lb)	kw(thermal)		
8.8 (30)	Underfeed Stoker	Moderate						
		Raw Coal	0				0.5	(3.0)
		ESP	89.5	Elec.	153 (65.8)	42.9		
				TOTAL				
		SIP		Fuel	1,056(454.1)	282.3		
		PCC Level 3	35.3	Elec.	14(6.0)	3.7		
		ESP	60.4	Elec.	127(54.6)	33.8	3.6	NA
				TOTAL	1,197(514.7)	319.8		
		Optional Moderate		Fuel	1,056(454.1)	282.3		
		PCC Level 3	35.3	Elec.	14(6.0)	3.7		
		ESP	84.5	Elec.	153(65.8)	42.8	3.7	0.1
				TOTAL	1,223(525.9)	328.8		
		Intermediate		Fuel	1,885(810.6)	508.2		
		CCC ERDA	25	Elec.	209(89.9)	56.4		
		ESP	94.1	Elec.	208(89.4)	56.2	7.1	3.3
				TOTAL	2,302(989.9)	620.8		
		Stringent		Fuel	1,885(810.6)	508.2		
		CCC ERDA	25	Elec.	209(89.9)	56.4		
		ESP	98.5	Elec.	244(104.8)	65.8	7.2	3.4
				TOTAL	2,338(1005.3)	630.4		

TABLE G-12.

Energy Usage of "Best" Control Techniques for 22 MW Coal-Fired Boilers Using Medium Sulfur Coal

SYSTEM					ENERGY CONSUMPTION		IMPACTS	
Standard Boiler		Type and Level of Control	Control Efficiency Percent	Energy Type	Energy Consumed by Control		Percent Increase in Energy over Uncontrolled Boiler	Percent Increase in Energy over SIP Controlled Boiler
Heat Rate MW or (10^6 BTU/hr)	Type				kJ/kg (BTU/lb)	kw(thermal)		
22 (75)	Chain Grate Stoker	Moderate						
		Raw Coal	0					
		ESP	89.5	Elec.	151 64.9	105.3	0.5	(3.0)
		SIP		Fuel	1,056 (454.1)	704.4		
		PCC Level 3	35.3	Elec.	14 (6.0)	9.3		
		ESP	60.7	Elec.	125 (53.8)	83.7	3.6	NA
				TOTAL	1,185 (513.9)	797.4		
		Optional Moderate		Fuel	1,056 (454.1)	704.4		
		PCC Level 3	35.3	Elec.	14 (6.0)	9.3		
		ESP	83.4	Elec.	167 (71.8)	111.6	3.8	0.1
				TOTAL	1,237 (531.9)	825.3		
		Intermediate		Fuel	1,885 (810.6)	1,264.4		
		CCC ERDA	25	Elec.	209 (89.9)	140.2		
		ESP	94.6	Elec.	222 (95.5)	148.8	7.1	3.3
				TOTAL	2,316 (996)	1,553.4		
		Stringent		Fuel	1,885 (810.6)	1,264.4		
		CCC ERDA	25	Elec.	209 (89.9)	140.2		
		ESP	98.2	Elec.	247 (106.2)	165.6	7.1	3.4
				TOTAL	2,341 (1,006.7)	1,570.2		

TABLE G-13.

Energy Usage of "Best" Control Techniques for 44 MW Coal-Fired Boilers Using Medium Sulfur Coal

SYSTEM					ENERGY CONSUMPTION		IMPACTS	
Standard Boiler: Heat Rate MW or (10^6 BTU/hr)	Standard Boiler: Type	Type and Level of Control	Control Efficiency Percent	Energy Type	Energy Consumed by Control: kJ/kg (BTU/lb)	Energy Consumed by Control: kw(thermal)	Percent Increase in Energy over Uncontrolled Boiler	Percent Increase in Energy over SIP Controlled Boiler
44 (150)	Spreader Stoker	Moderate						
		Raw Coal	0					
		ESP	96.2	Elec.	189 (81.3)	264.48	.6	(3.0)
				TOTAL				
		SIP		Fuel	1,056 (454.1)	1,411.72		
		PCC Level 3	35.3	Elec	14 (6.0)	18.71		
		ESP	85.0	Elec.	161 (69.2)	215.73	3.7	NA
				TOTAL	1,231 (529.3)	1,646.16		
		Optional Moderate		Fuel	1,056 (454.1)	1,411.72		
		PCC Level 3	35.3	Elec.	14 (6.0)	18.71		
		ESP	93.8	Elec.	184 (79.1)	246.18	3.8	0.1
				TOTAL	1,254 (539.2)	1,676.61		
		Intermediate		Fuel	1,885 (810.6)	2,533.85		
		CCC ERDA	25	Elec.	209 (89.9)	280.94		
		ESP	97.8	Elec.	235 (101.0)	316.29	7.1	3.3
				TOTAL	2,329 (1,001.5)	3,131.08		
		Stringent		Fuel	1,885 (810.6)	2,533.85		
		CCC ERDA	25	Elec.	209 (89.9)	280.94		
		ESP	99.3	Elec.	251 (108.0)	337.62	7.2	3.3
				TOTAL	2,345 (1,008.5)	3,152.41		

TABLE G-14.

ENERGY USAGE OF "BEST" CONTROL TECHNIQUES FOR 58.6 MW COAL-FIRED BOILERS USING MEDIUM SULFUR COAL

SYSTEM					ENERGY CONSUMPTION		IMPACTS	
Standard Boiler		Type and Level of Control	Control Ef-ficiency Percent	Energy Type	Energy Consumed by Control		Percent Increase in Energy over Uncontrolled Boiler	Percent Increase in Energy over SIP Controlled Boiler
Heat Rate MW or (10^6 BTU/hr)	Type				kJ/kg (BTU/lb)	kw(thermal)		
58.6 (200)	Pulverized	Moderate						
		Raw Coal	-					
		ESP	96.7	Elec.	162 (69.9)	303.0	0.5	(3.1)
		SIP		Fuel	1,056 (454.1)	1,881.3		
		PCC Level 3	35.3	Elec.	14 (6.0)	24.9		
		ESP	87.8	Elec.	152 (65.2)	270.0	3.7	NA
				TOTAL	1,222 (525.3)	2,176.2		
		Optional Moderate		Fuel	1,056 (454.1)	1,881.3		
		PCC Level 3	35.3	Elec.	14 (6.0)	24.9		
		ESP	94.9	Elec.	182 (78.3)	324.2	3.8	0.1
				TOTAL	1,252 (538.4)	2,230.4		
		Intermediate		Fuel	1,885 (810.6)	3,379.2		
		CCC ERDA	25	Elec.	209 (89.9)	374.7		
		ESP	98.3	Elec.	204 (87.7)	366.5	7.0	3.2
				TOTAL	2,298 (988.2)	4,120.4		
		Stringent		Fuel	1,885 (810.6)	3,379.2		
		CCC ERDA	25	Elec.	209 (89.9)	374.7		
		ESP	99.4	Elec.	222 (95.5)	398.3	7.1	3.3
				TOTAL	2,316 (996)	4,152.2		

TABLE G-15.

ENERGY USAGE OF "BEST" CONTROL TECHNIQUES FOR 117.2 MW COAL-FIRED BOILERS USING MEDIUM SULFUR COAL

SYSTEM					ENERGY CONSUMPTION		IMPACTS	
Standard Boiler: Heat Rate MW or (10^6 BTU/hr)	Standard Boiler: Type	Type and Level of Control	Control Ef-ficiency Percent	Energy Type	Energy Consumed by Control: kJ/kg (BTU/lb)	Energy Consumed by Control: kw(thermal)	Percent Increase in Energy over Uncontrolled Boiler	Percent Increase in Energy over SIP Controlled Boiler
118 (400)	Pulverized	Moderate						
		Raw Coal	-					
		ESP	96.7	Elec.	168 (72.2)	627.1	.5	(3.0)
		SIP		Fuel	1,056 (454.1)	3,762.6		
		PCC Level 3	35.3	Elec.	14 (6.0)	49.9		
		ESP	87.8	Elec.	144 (62.0)	514.1	3.7	NA
				TOTAL	1,214 (522.1)	4,326.6		
		Optional Moderate		Fuel	1,056 (454.1)	3,762.6		
		PCC Level 3	35.3	Elec.	14 (6.0)	49.9		
		ESP	94.9	Elec.	184 (79.1)	655.4	3.8	0.1
				TOTAL	1,254 (539.2)	4,467.9		
		Intermediate		Fuel	1,885 (810.6)	6,758.3		
		CCC ERDA	25	Elec.	209 (89.9)	749.3		
		ESP	98.3	Elec.	202 (87.1)	726.0	7.0	3.2
				TOTAL	2,296 (987.6)	8,233.6		
		Stringent		Fuel	1,885 (810.6)	6,758.3		
		CCC ERDA	25	Elec.	209 (89.9)	749.3		
		ESP	99.5	Elec.	244 (104.9)	874.3	7.1	3.3
				TOTAL	2,338 (1,005.4)	8,381.9		

TABLE G-16.

Air Pollution Impacts from "Best" SO_2 and Particulate Control Techniques for Medium Sulfur Coal-Fired Boilers.

SYSTEM							EMISSIONS									
Standard Boiler		Control Level (Name, % of SO_2 Reduction)	SO_2 Control		Particulate Pct. Reduction		SO_2		Particulates		NO_x		CO		HC as CH_4	
Heat Rate (MW or 10^6 BTU/hr)	Type		Type of Control	PCT. Reduction	Coal Cleaning	ESP	g/s	ng/J	g/s	ng/J	g/s	ng/J	g/s	ng/J	g/s	ng/J
8.8 (30)	Underfeed Stoker	Uncontrolled	Raw Coal	0	0	0	10.44	1,188	9.0	1,024	2.0	230	0.28	31.9	0.145	16.5
		Moderate	Raw Coal	0	0	89.5	10.44	1,188	0.9	107.5	2.0	230	0.28	31.9	0.145	16.5
		SIP	PCC Level 3	37.7	35.3	60.4	6.5	740	2.3	258	1.9	215	0.27	30.4	0.133	15.1
		Optional Moderate	PCC Level 3	37.7	35.3	84.5	6.5	740	0.9	107.5	1.9	215	0.27	30.4	0.133	15.1
		Intermediate	CCC ERDA	56.9	25	94.1	4.5	510	0.4	43	2.0	230	0.28	31.9	0.145	16.5
		Stringent	CCC ERDA	56.9	25	98.5	4.5	510	0.1	12.9	2.0	230	0.28	31.9	0.145	16.5
22 (75)	Chain Grate	Uncontrolled	Raw Coal	0	0	0	25.9	1,188	22.3	1,024	5.1	230	0.68	31.9	0.363	16.5
		Moderate	Raw Coal	0	0	89.5	25.9	1,188	2.4	107.5	5.1	230	0.68	31.9	0.363	16.5
		SIP	PCC Level 3	37.7	35.3	60.7	16.3	740	5.7	258	4.7	215	0.67	30.4	0.332	15.1
		Optional Moderate	PCC Level 3	37.7	35.3	83.4	16.3	740	2.4	107.5	4.7	215	0.67	30.4	0.332	15.1
		Intermediate	CCC ERDA	56.9	25	94.6	11.2	510	0.9	43	5.1	230	0.68	31.9	0.363	16.5
		Stringent	CCC ERDA	56.9	25	98.2	11.2	510	0.3	12.9	5.1	230	0.68	31.9	0.363	16.5
44 (150)	Spreader Stoker	Uncontrolled	Raw Coal	0	0	0	51.8	1,188	116.2	2,644	10.1	230	1.4	31.9	0.725	16.5
		Moderate	Raw Coal	0	0	96.2	51.8	1,188	4.7	107.5	10.1	230	1.4	31.9	0.725	16.5
		SIP	PCC Level 3	37.7	35.3	85.0	32.6	740	11.3	258	9.4	215	1.34	30.4	0.664	15.1
		Optional	PCC Level 3	37.7	35.3	93.8	32.6	740	4.7	107.5	9.4	215	1.34	30.4	0.664	15.1
		Intermediate	CCC ERDA	56.9	25	97.8	22.4	510	1.9	43	10.1	230	1.4	31.9	0.725	16.5
		Stringent	CCC ERDA	56.9	25	99.3	22.4	510	0.6	12.9	10.1	230	1.4	31.9	0.725	16.5
58.6 (200)	Pulverized	Uncontrolled	Raw Coal	0	0	0	69.3	1,188	190.9	3257.0	16.2	276	0.93	15.9	0.287	4.9
		Moderate	Raw Coal	0	0	96.7	69.3	1,188	6.3	107.5	16.2	276	0.93	15.9	0.287	4.9
		SIP	PCC Level 3	37.7	35.3	87.8	43.4	740	15.1	258.0	15.1	258	0.89	15.2	0.264	4.5
		Optional Moderate	PCC Level 3	37.7	35.3	94.9	43.4	740	6.3	107.5	15.1	258	0.89	15.2	0.264	4.5
		Intermediate	CCC ERDA	56.9	25	98.3	29.9	510	2.5	43.0	16.2	276	0.93	15.9	0.287	4.9
		Stringent	CCC ERDA	56.9	25	99.4	29.9	510	0.8	12.9	16.2	276	0.93	15.9	0.287	4.9
118 (400)	Pulverized	Uncontrolled	Raw Coal	0	0	0	138.7	1,188	381.7	3,257.0	32.3	276	1.86	15.9	0.574	4.9
		Moderate	Raw Coal	0	0	96.7	138.7	1,188	12.6	107.5	32.3	276	1.86	15.9	0.574	4.9
		SIP	PCC Level 3	37.7	35.3	87.8	86.8	740	30.2	258.0	30.2	258	1.78	15.2	0.527	4.5
		Optional Moderate	PCC Level 3	37.7	35.3	94.9	86.8	750	12.6	107.5	30.2	258	1.78	15.2	0.527	4.5
		Intermediate	CCC ERDA	56.9	25	98.3	59.8	510	5.0	43.0	32.3	276	1.86	15.9	0.574	4.9
		Stringent	CCC ERDA	56.9	25	99.5	59.8	510	1.5	12.9	32.3	276	1.86	15.9	0.574	4.9

TABLE G-17.

WATER POLLUTION IMPACTS FROM "BEST" SO_2 CONTROL TECHNIQUES FOR MEDIUM SULFUR COAL-FIRED BOILERS

SYSTEM				EMISSIONS			
Standard Boiler				Primary Pollutants		Trace Elements	
Heat Rate MW or (10^6 BTU/hr)	Type	Control Level (Name, % of SO_2 Reduction	Type of Control	mg/s (lb/hr)	ng/J (lb/10^6 BTU)	Pollutant mg/s	Change over Raw Coal*
8.8 (30)	Underfeed Stoker	None 0%	Raw Coal	None **	—	None	
		Moderate 0%	Raw Coal	None	—	None	
		SIP and Optional Moderate 37%	PCC Level 3	TSS = 1.87 =(0.015)	= 0.215 =(0.0005)	Fe = 0.0037	*
				COD = 2.94 =(0.023)	= 0.33 =(0.0008)	Zn = 0.0008	*
				TOC = 0.51 =(0.004)	= 0.057 =(0.0001)	Cu = 0.0004	*
						Mn = 0.00048	*
				[pH = 7.2]			
				Ca = 2.35 =(0.019)	= 0.272 =(0.0006)		
				Na = 2.41 =(0.02)	= 0.286 =(0.0007)		
				Mg = 1.12 =(0.009)	= 0.13 =(0.0003)		
		Intermediate and Stringent 56%	CCC	No Data	—	No Data	–

* Some increase in environmental effects compared to burning naturally-occurring coal with no controls.

** Discharge flow = 0.18 m^3/hr.

TABLE G-17.

WATER POLLUTION IMPACTS FROM "BEST" SO_2 CONTROL TECHNIQUES FOR MEDIUM SULFUR COAL-FIRED BOILERS

(continued)

SYSTEM				EMISSIONS			
Standard Boiler: Heat Rate MW or (10^6 BTU/hr)	Standard Boiler: Type	Control Level (Name, % of SO_2 Reduction	Type of Control	Primary Pollutants: mg/s (lb/hr)	Primary Pollutants: ng/J (lb/10^6 BTU)	Trace Elements: Pollutant mg/s	Trace Elements: Change over Raw Coal*
22 (75)	Watertube Grate Stoker	None 0%	Raw Coal	None **	---	None	
		Moderate 0%	Raw Coal	None	---	None	
		SIP and Optional Moderate 37%	PCC Level 3	TSS = 4.66 =(0.037)	= 0.212 = (0.0005)	Fe = 0.0093	*
				COD = 7.33 =(0.058)	= 0.332 = (0.0008)	Zn = 0.002	*
				TOC = 1.26	= 0.06	Cu = 0.001	*
				=(0.001)	= (0.0001)	Mn = 0.0012	*
				[pH 7.2]			
				Ca = 5.86 =(0.047)	= 0.269 = (0.0006)		
				Na = 6.0 =(0.048)	= 0.275 = (0.0006)		
				Mg = 2.8 =(0.022)	= 0.126 = (0.0003)		
		Intermediate and Stringent 56%	CCC	No Data	---	No Data	---

* Some increase in environmental effects compared to buring naturally-occurring coal with no controls.

** Discharge flow = 0.18 m^3/hr.

TABLE G-17.

WATER POLLUTION IMPACTS FROM "BEST" SO_2 CONTROL TECHNIQUES
FOR MEDIUM SULFUR COAL-FIRED BOILERS

(continued)

SYSTEM				EMISSIONS			
Standard Boiler				Primary Pollutants		Trace Elements	
Heat Rate MW or (10^6 BTU/hr)	Type	Control Level (Name, % of SO_2 Reduction	Type of Control	mg/s (lb/hr)	ng/J (lb/10^6 BTU)	Pollutant mg/s	Change over Raw Coal*
44 (150)	Spreader Stoker	None 0%	Raw Coal	None	---	None	
		Moderate 0%	Raw Coal	None	---	None	
		SIP and Optional Moderate 37%	PCC Level 3	TSS = 9.35 =(0.074)	= 0.212 = 0.0005	Fe = 0.018	*
				COD = 14.7 =(0.116)	= 0.332 = (0.0008)	Zn = 0.004	*
				TOC = 2.54 =(0.02)	= 0.057 = (0.0001)	Cu = 0.002 Mn = 0.0024	* *
				[pH = 7.2]			
				Ca = 11.8 =(0.093)	= 0.266 = (0.0006)		
				Na = 12.0 =(0.095)	= 0.272 = (0.0006)		
				Mg = 5.61 =(0.044)	= 0.126 = (0.0003)		
		Intermediate and Stringent 56%	CCC	No Data	---	No Data	---

TABLE G-17.

WATER POLLUTION IMPACTS FROM "BEST" SO_2 CONTROL TECHNIQUES
FOR MEDIUM SULFUR COAL-FIRED BOILERS

(continued)

SYSTEM				EMISSIONS			
Standard Boiler				Primary Pollutants		Trace Elements	
Heat Rate MW or (10^6 BTU/hr)	Type	Control Level (Name, % of SO_2 Reduction	Type of Control	mg/s (lb/hr)	ng/J (lb/10^6 BTU)	Pollutant mg/s	Change over Raw Coal*
58.6 (200)	Pulverized Coal Fired	None 0%	Raw Coal	None **	---	None	
		Moderate 0%	Raw Coal	None	---	None	
		SIP and Optional Moderate 37%	PCC Level 3	TSS = 12.4	= 0.211		
				=(0.098)	= (0.0005)	Fe = 0.0249	*
				COD = 19.6	= 0.333	Zn = 0.0053	*
				=(0.155)	= (0.0008)		
				TOC = 3.38	= 0.056	Cu = 0.0027	*
				=(0.026)	= (0.0001)		
				[pH = 7.2]		Mn = 0.0032	*
				Ca = 15.6	= 0.266		
				=(0.124)	= (0.0006)		
				Na = 16.0	= 0.273		
				=(0.127)	= (0.0006)		
				Mg = 7.48	= 0.127		
				=(0.059)	= (0.0003)		
		Intermediate and Stringent 56%	CCC	No Data	---	No Data	---

* Some increase in environmental effects compared to burning naturally-occurring coal with no controls.

** Discharge flow = 0.18 m^3/hr.

TABLE G-17.

WATER POLLUTION IMPACTS FROM "BEST" SO_2 CONTROL TECHNIQUES FOR MEDIUM SULFUR COAL-FIRED BOILERS

(continued)

SYSTEM				EMISSIONS			
Standard Boiler				Primary Pollutants		Trace Elements	
Heat Rate MW or (10^6 BTU/hr)	Type	Control Level (Name, % of SO_2 Reduction	Type of Control	mg/s (lb/hr)	ng/J (lb/10^6 BTU)	Pollutant mg/s	Change over Raw Coal*
118 (400)	Pulverized Coal Fired	None 0%	Raw Coal	None **	---	None	
		Moderate 0%	Raw Coal	None	---	None	
		SIP and Optional Moderate 37%	PCC Level 3	TSS = 24.9 =(0.197)	= 0.212 = (0.0005)	Fe = 0.0498	*
				COD = 39.2 =(0.311)	= 0.334 = (0.0008)	Zn = 0.0106	*
				TOC = 6.76 =(0.053)	= 0.056 = (0.0001)	Cu = 0.0053	*
				[pH = 7.2]		Mn = 0.0064	*
				Ca = 31.3 =(0.248)	= 0.266 = (0.0006)		
				Na = 32.1 =(0.254)	= 0.273 = (0.0006)		
				Mg = 15.0 =(0.118)	= 0.126 = (0.0003)		
		Intermediate and Stringent 56%	CCC	No Data	---	No Data	---

* Some increase in environmental effects compared to burning naturally-occurring coal with no controls.

** Discharge flow = 0.18 m^3/hr.

TABLE G-18.

Solid Wastes from "Best" SO_2 Control Techniques for Coal-Fired Boilers
Medium Sulfur Coal

(continued)

SYSTEM				EMISSIONS			
Standard Boiler Heat Rate (MW or 10^6 BTU/hr)	Standard Boiler Type	Control Level (Name, % of SO_2 Reduction	Type of Control	Solid Waste g/s (lb/hr)	Solid Waste ng/J (lb/10^6 BTU)	Percent Increase over NO controls	Percent Increase over SIP controls
8.8 (30)	Underfeed Stoker	Uncontrolled 0%	Raw Coal	Cleaning 0			
		Moderate 1,290 ng SO_2/J	Raw Coal	Bottom Ash 26.8(212.5)	1,032(2.4)		
				Fly Ash 9.0 (71.4)	3,053 (7.1)		
				Total Ash 35.8(283.9)	4,085 (9.5)	---	—
		SIP 1,075 ng SO_2/J	PCC Level 3	Cleaning 21.4(169.7)	2,451 (5.7)		
		Optional Moderate 860 ng SO_2/J 37%	PCC Level 3	Bottom Ash 17.4(138.0)	1,978(4.6)		
				Fly Ash 5.8(46.0)	645(1.5)		
				Total Waste 44.6(353.7)	5,074(11.8)	24.2%	—
		Intermediate 645 ng SO_2/J	CCC ERDA	Cleaning 8.9(70.6)	1,032(2.4)		
				Bottom Ash 20.2(160.2)	2,279 (5.3)		
		Stringent 516 ng SO_2/J 56%	CCC ERDA	Fly Ash 6.7(53.1)	774(1.8)		
				Total Waste 35.8(283.9)	4,085(9.5)	0	19.7%

TABLE G-18.

Solid Wastes from "Best" SO_2 Control Techniques for Coal-Fired Boilers
Medium Sulfur Coal

(continued)

SYSTEM				EMISSIONS			
Standard Boiler		Control Level (Name, % of SO_2 Reduction	Type of Control	Solid Waste		Percent Increase over NO controls	Percent Increase over SIP controls
Heat Rate (MW or 10^6 BTU/hr)	Type			g/s (lb/hr)	ng/J (lb/10^6 BTU)		
22(75)	Chain Grate Stoker	Uncontrolled 0%	Raw Coal	Cleaning 0			
				Bottom Ash 66.9(530.5)	3,053(7.1)		
		Moderate 1,290 ng SO_2/J	Raw Coal	Fly Ash 22.3(176.8)	989 (2.3)		
				Total Ash 89.2(707.3)	4,042 (9.4)		
		SIP 1,075 ng SO /J	PCC Level 3	Cleaning 53.3(422.7)	2,408 (5.6)		
				Bottom Ash 43.5(344.9)	1,978(4.6)		
		Optional Moderate 860 ng SO_2/J 37%	PCC Level 3	Fly Ash 14.5(115.0)	645 (1.5)		
				Total Waste 111.3(882.6)	5,031(11.7)	24.2%	
		Intermediate 645 ng SO /J	CCC ERDA	Cleaning 22.3(176.8)	989 (2.3)		
				Bottom Ash 50.2(398.1)	2,279 (5.3)		
		Stringent 516 ng SO_2/J 56%	CCC ERDA	Fly Ash 16.7(132.4)	774(1.8)	0%	19.9%
				Total Waste 89.2(707.3)	4,042 (9.4)		

TABLE G-18.

Solid Wastes from "Best" SO_2 Control Techniques for Coal-Fired Boilers
Medium Sulfur Coal

(continued)

SYSTEM				EMISSIONS			
Standard Boiler		Control Level (Name, % of SO_2 Reduction	Type of Control	Solid Waste		Percent Increase over NO controls	Percent Increase over SIP controls
Heat Rate (MW or 10^6 BTU/hr)	Type			g/s (lb/hr)	ng/J ($lb/10^6$ BTU)		
44 (150)	Spreader Stoker	Uncontrolled 0% Moderate 1,290 ng SO_2/J	Raw Coal Raw Coal	Cleaning 0 Bottom Ash 62.6(496.4) Fly Ash 116.2(921.5) Total Ash 178.8(1,417.9)	 1,419(3.3) 2,623(6.1) 4,042(9.4)		
		SIP 1,075 ng SO_2/J Optional Moderate 860 ng SO_2/J 37%	PCC Level 3 PCC Level 3	Cleaning 106.9(847.7) Bottom Ash 40.7(322.8) Fly Ash 75.5(598.7) Total Waste 223.1(1,769)	 2,408(5.6) 946 (2.2) 1,720(4.0) 5,074 (11.8)	25.5%	
		Intermediate 645 ng SO_2/J Stringent 516 ng SO_2/J 56%	CCC ERDA CCC ERDA	Cleaning 44.7(354.5) Bottom Ash 46.9(371.9) Fly Ash 87.2(691.5) Total Waste 178.8(1,418)	 1,032(2.4) 1,075(2.5) 1,978(4.6) 4,085(9.5)	1.1%	19.1%

TABLE G-18.

Solid Wastes from "Best" SO_2 Control Techniques for Coal-Fired Boilers
Medium Sulfur Coal

(continued)

SYSTEM				EMISSIONS			
Standard Boiler		Control Level (Name, % of SO_2 Reduction	Type of Control	Solid Waste		Percent Increase over NO controls	Percent Increase over SIP controls
Heat Rate (MW or 10^6 BTU/hr)	Type			g/s (lb/hr)	ng/J (lb/10^6 BTU)		
58.6	Pulverized	Uncontrolled	Raw Coal	Cleaning			
(200)		0%		0			
		Moderate	Raw Coal	Bottom Ash			
		1,290 ng SO /J		47.7(378.3)	817 (1.9)		
				Fly Ash			
				190.9(1,514)	3,268(7.6)		
				Total Ash			
				238.6(1,892)	4,085(9.5)		
		SIP	PCC	Cleaning			
		1,075 ng SO /J	Level 3	142.4(1,129)	2,451 (5.7)		
		Optional Moderate	PCC	Bottom Ash			
		860 ng SO /J	Level 3	31.0(245.8)	516 (1.2)		
		37%		Fly Ash			
				124.0(983.3)	2,107 (4.9)		
				Total Waste			
				297.4(2,358.4)	5,074(11.8)	24.2%	
		Intermediate	CCC	Cleaning			
		645 ng SO /J	ERDA	59.6(472.6)	1,032(2.4)		
		Stringent	CCC	Bottom Ash			
		516 ng SO /J	ERDA	35.8(283.9)	602 (1.4)		
		56%		Fly Ash			
				143.2 (1,136)	2,451(5.7)		
				Total Waste			
				238.6(1,892)	4,085(9.5)	0	19.1%

TABLE G-18.

Solid Wastes from "Best" SO_2 Control Techniques for Coal-Fired Boilers

Medium Sulfur Coal

(continued)

SYSTEM				EMISSIONS			
Standard Boiler Heat Rate (MW or 10^6 BTU/hr)	Standard Boiler Type	Control Level (Name, % of SO_2 Reduction)	Type of Control	Solid Waste g/s (lb/hr)	Solid Waste ng/J (lb/10^6 BTU)	Percent Increase over NO controls	Percent Increase over SIP controls
118	Pulverized	Uncontrolled	Raw Coal	Cleaning			
(400)		0%		0			
		Moderate	Raw Coal	Bottom Ash			
		1,290 ng SO_2/J		95.4(756.5)	817 (1.9)		
				Fly Ash			
				381.8(3,028)	3,268 (7.6)		
				Total Ash			
				477.2(3,784)	1,085 (9.5)		
		SIP	POC	Cleaning			
		1,075 ng SO_2/J	Level 3	284.9(2,259	3) 2,451(5.7)		
		Optional Moderate	POC	Bottom Ash			
		860 ng SO_2/J	Level 3	62.0(491.7)	516 (1.2)		
		37%		Fly Ash			
				247.8(1,965	0)2,107(4.9)		
				Total Waste			
				594.7(4,716	0)5,074(11.8)	24.2%	
		Intermediate	CCC	Cleaning			
		645 ng SO_2/J	ERDA	119.3(946.0	1,032(2.4)		
		Stringent	CCC	Bottom Ash			
		516 ng SO_2/J	ERDA	71.6(567.8)	602(1.4)		
		56%		Fly Ash			
				286.3(2,270	4)2,451(5.7)		
				Total Waste			
				477.2(3,784	2)4,085(9.5)	0%	19.1%

TECHNICAL REPORT DATA
(Please read Instructions on the reverse before completing)

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15. SUPPLEMENTARY NOTES IERL-RTP project officer is James D. Kilgroe, Mail Drop 61, 919/541-2851.

16. ABSTRACT The report assesses the use of three pollution control technologies--low sulfur coals, physical coal cleaning (PCC), and chemical coal cleaning (CCC)--to comply with SO2 emission regulations. It is one of a series to be used in determining the technological basis for a new source performance standard for industrial boilers. Candidate systems were selected after consideration of 7 naturally occurring low sulfur coals, 5 levels of sulfur removal by PCC, and desulfurization by 11 CCC processes. The best systems of emission reduction were identified for three coals at each of five emission control levels. Low sulfur western coal can meet all emission levels down to 516 ng SO2/J without cleaning. Uncleaned low sulfur eastern coal can achieve emission levels above 860 ng SO2/J; when physically cleaned, this coal can be used to meet an emission level of 516 ng SO2/J. High sulfur coal can be cleaned to meet emission levels of 645 ng SO2/J and higher; for this coal, CCC must be used to produce fuels capable of complying with an emission limit of 516 ng SO2/J. These findings apply only to the coals evaluated; in general, each coal has a distinctly different desulfurization potential. For regulatory purposes this assessment must be viewed as preliminary, pending results of a more extensive examination of impacts called for under Section 111 of the Clean Air Act Amendments.

17. KEY WORDS AND DOCUMENT ANALYSIS

a. DESCRIPTORS		b. IDENTIFIERS/OPEN ENDED TERMS	c. COSATI Field/Group	
Pollution	Sulfur Dioxide	Pollution Control	13B	07B
Assessments		Stationary Sources	14B	
Boilers		Industrial Boilers	13A	
Coal		Low Sulfur Coal	21D	
Cleaning			13H	
Coal Preparation			08I	

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