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Project Summary

Prospects for Increasing the Direct Use of Coal in Industrial Boilers

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The report gives a comprehensive evaluation of factors (environmental, technical, economic, and institutional) influencing solid coal use in industrial boilers. Trends in coal use, recent legislative warrants, and technical and logistic problems in coal use at industrial plants are reviewed. Demographic aspects of the existing industrial boiler population are examined, and regional patterns in fuel consumption, boiler deployment, and the location of major energy consuming industries are identified. Six technologies and five alternate groups of the technologies are compared to the year 2000 on the basis of resource requirements and emissions. Technologies considered are conventional combustion in both a spreader-stoker boiler and with flue-gas desulfurization, fluidized-bed combustion, low-Btu gasification, and physical coal cleaning (alone and combined with the above technologies). Air emissions are further assessed from the perspective of existing air quality problems in industrial areas. Capital and annual costs for each technology are also compared. Sensitivity analysis is included to detail the extent to which varying operating parameters affect steam cost. Fuel choices are evaluated on industry- and region-specific bases. Finally, results of analyses are interpreted from the perspective of achieving environmental and energy goals.

This Project Summary was developed by EPA's Industrial Environmental Research Laboratory, Research Triangle Park, NC, to announce key findings of the research project that is fully documented in a separate report of the same title (see Project Report ordering information at back).

Introduction

Over 35 percent of the total U.S. energy budget is consumed in the industrial sector, an amount equivalent to 220* in 1978. Of that amount, 40 percent is devoted to producing process steam. Process steam is used to power machinery, heat chemical reactors, cook foods, distill liquids, provide reducing atmospheres, and so on. Process steam is the largest prime mover in the Nation's multifaceted industries. However, the use of process steam both in quantity and as a percentage of total energy use varies markedly between industries. For example, equipment manufacturing and the stone, clay, and glass industries use precious little steam; whereas the food and paper industries are among the largest users. Over 500,000 boilers produce steam for U.S. industries, ranging in size from small prefabricated "package" units to units large enough to rival those turning turbines in electric utilities. Boilers are deployed in every

*1Q = 1 quad - 1 quadrillion (10^{15}) British thermal units (Btu). One Q is roughly equivalent to over 170 million barrels of crude oil, or about 42 million short tons of bituminous coal, or about 1 trillion cubic feet of natural gas state and every industry, and they can be run with all types of energy carriers — solid, liquid, gas, and electric — and all fuels — coal, petroleum, natural gas, uranium, solar, wood, and waste. Thus the fuels and energy carriers used to raise steam in boilers represent a significant opportunity for substituting more plentiful energy supplies for those of increasing scarcity. Yet exercising such opportunities entails a host of considerations and impacts to the industries themselves, to the workers employed by them, to the populations living near the industries, and ultimately to the entire Nation.

As part of the national Coal Technology Assessment (CTA) program — an ongoing comprehensive assessment of the use of coal over the next several decades — a study of industrial boilers has been undertaken to examine possibilities for using a plentiful resource, coal, as a substitute for oil and natural gas supplies as a boiler fuel. The need to understand the potential for an increased use of coal comes naturally as a result of increasingly tight energy supplies and from the desire to reduce national dependence on imported supplies of energy.

Objectives of the Study

Four major objectives have guided the analysis of this study:

- To investigate any potential conflicts between a greatly expanded use of coal in industrial boilers and existing air quality standards.
- To assess regional differences in the consequences of coal use in industrial boilers.
- To identify and analyze, where appropriate, other constraints to the use of solid coal in industrial boilers, including such factors as space requirements, economics, convenience, industry attitudes, solid waste production, and resource requirements.
- To compare alternative coal-fired boiler technologies within these contexts.

Scope of the Study and Some Significant Findings

The conclusions of the CTA's study are based on a comparison of five technologies in terms of assumed coal use to the year 2000. The technologies were selected, after consultation with appropriate experts, as being likely candidates for burning coal in industrial boilers. Deployment rates were based on market penetration estimates. The technologies are: conventional combustion in a spreader-stoker boiler (CC); conventional combustion with a flue-gas desulfurization (FGD) system; fluidized-bed combustion (FBC); low-Btu gasification; and physical coal cleaning (PCC), alone and in combination with the above technologies. In view of the move to increase the use of coal, as exemplified by the Fuel Use Act of 1978, we assume 6Q as the energy content of coal used for industrial boilers in the year 2000. The increase in coal use involves both (1) additions to the total inventory of boilers, and (2) conversion and replacement of existing boilers that use other fuels.

Figure 1 displays the regional configuration used throughout the CTA program, including this report. Different in many respects from more familiar regional breakdowns — such as those used by the Bureau of the Census, the Department of Energy, and the Environmental Protection Agency — the CTA configuration is an attempt to present regional breakdowns that are consistent in terms of *energy usage.* Such consistency highlights differences in impacts from the use of coal.

Historical Overview of Industrial Use of Coal

Many of the factors that now constrain coal use in industry have precedents. The literature of the late 19th and early 20th centuries testifies to the difficulties in supplying coal to industrial users. While coal had become the predominant fuel in the U.S. in the early 20th century, its decline was precipitous when alternative fuels became available. For example, coal use in industry (excluding coking coal) has fallen from about 40 to 6 percent of total industrial use of energy within the last 30 years. The fall cannot be attributed strictly to lower fuel prices for oil and natural gas; rather, factors such as efficiency, convenience, reliability of supply, increased productivity from electrification, and certainly, cleanliness, were important variables. Furthermore, historical records attest to the fact that the concern over air pollution from the burning of coal is not a recent phenomenon. Air quality concerns date back for centuries. We note that periods of improving air quality are accompanied by public reluctance to accept additional pollution. The importance of such a reluctance should not be overlooked when a return to the inherently dirtier fuel of coal is being widely advocated.

National Policies Affecting the Use of Coal in Industrial Boilers

Major environmental acts including the Clean Air Act and Amendments of 1977 and the Resource Conservation and Recovery Act of 1976 are sum-

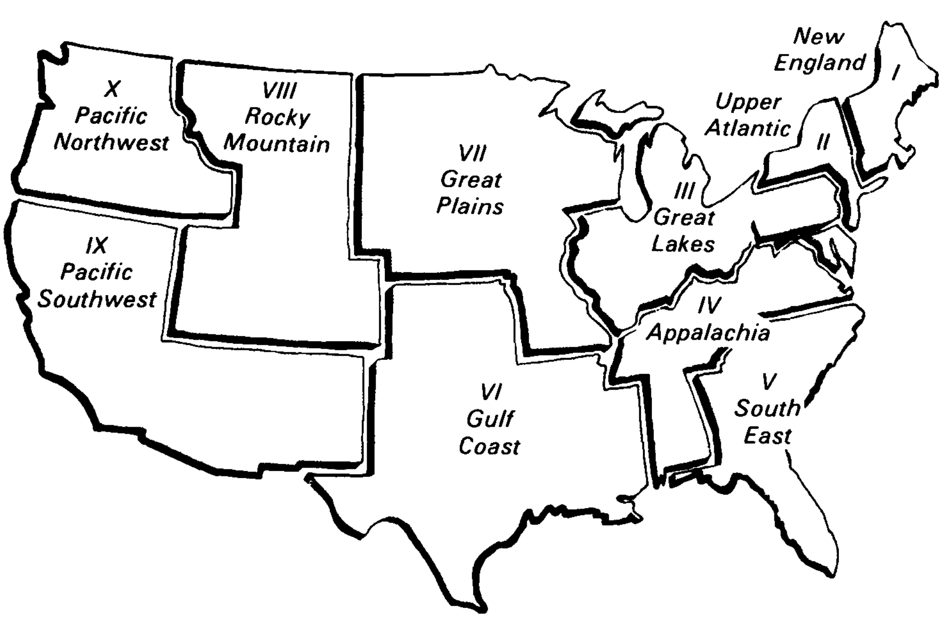

Figure 1. *Coal technology assessment (CTA) regions.*

marized, as well as the energy policy legislation of the Industrial and Power Plant Fuel Use Act and National Gas Policy Act of 1978. The latter two acts, both part of the National Energy Act, represent two different approaches to increasing coal use in industry and, as such, are critical backdrops to understanding present legislative thinking on how industry may be a vehicle to help steer the Nation through its current energy dilemma. And in the nexus between the four pieces of legislation, we begin to see the difficulties in balancing energy and environmental imperatives. Clearly, achieving the intent of the Fuel Use Act will be severely compromised because of exemptions granted from converting to coal where environmental regulations would be violated.

Technical and Logistical Factors Affecting the Industrial Use of Coal

The proportion of total industrial boiler capacity in the year 2000 that will be installed in manufacturing plants constructed after 1980 is expected to be quite small relative to existing boiler capacity. Thus, any substantial near-term increase in the use of coal for raising industrial steam will have to be accomplished through conversion or replacement of existing boilers fired by natural gas or oil. Conversion or replacement programs, however, may be impeded by a host of technical and logistical constraints. A comprehensive survey of the literature on these problems was undertaken.

A fundamental restriction upon the rapid substitution of coal for gas and oil in industry is the fact that coal cannot be burned in boilers that were originally designed to fire liquid or gaseous fuels. A switch to coal, therefore, involves the replacement of existing gas/oil units with new boilers capable of burning coal. Replacement, however, entails numerous changes in overall steam plant design, operation, and maintenance.

The municipal nature of industry means that space is at a premium. The land requirements for coal storage, handling, pollution control equipment, and waste disposal place coal at an immediate disadvantage to oil or natural gas; in many cases, the land needed to accommodate coal use may simply not exist. Another logistical aspect that must be accounted for by firms considering a switch to coal is transportation. Besides costs and reliability, deteriorating rolling stock and road beds are significant items for concern. Other features of coal supply are cause for concern as well.

Most industrial users will have difficulty in obtaining long-term supply contracts. The supply of spot market coal, which has traditionally been the source of coal for smaller users, may decline sharply over the next few decades. Coal enters the spot market from two sources: the smaller companies that produce specifically for it, and the surplus production from larger mines. Inflation, slack demand, capital availability, and competition from larger, mechanized strip mining operations, as well as the mounting complexities in planning, permitting, and meeting worker health and safety and reclamation requirements, have combined to reduce the number of small operators. At the same time, large mines are increasingly becoming captive or dedicated operations in order to prevent the costly production surpluses that in the past resulted from faulty projections of demand. For these reasons, industry tends to view the future supply and price of coal as being no more reliable than that of natural gas or oil. Until the general infrastructural organization has time to evolve in a fashion commensurate with the demands of industrial coal use, technical and logistical obstacles may severely constrain a widespread shift to coal by manufacturing industries.

The Current Role of Boilers in the Industrial Sector

Included are the most recent estimates of how energy is used by various industries, with which fuels, and with what technologies. Regional distribution of boilers and energy use is presented. Such detail is required to reflect the very heterogeneous picture that industry presents in terms of energy usage. We discover that aggregate national figures may be both misleading and an insufficient basis for the formulation of policies. For example, slightly over 60 percent of total industrial energy consumption in the U.S. occurs in 10 states. Figure 2 documents regional fuel use patterns, as well as changes that have historically occurred between 1963 and 1978. Further, four key industry groups account for 60 percent of industrial energy consumption; the same industries account for over 70 percent of the fuel burned in industrial boilers. The regional distribution of key industrial groups is displayed in Table 1. Not only are industries concentrated regionally, but 60 percent on the basis of fuel use are also located in municipal areas. Moreover, existing industries rely predominantly on natural gas (67 percent by fuel use), though regionally the percentages vary from 85 to 3 percent. Some regions still remain heavy users of coal in industry — over 50 percent in some cases. Finally, a little more than 1 percent of the large boilers in industry account for over 40 percent of capacity, again unevenly distributed on region- or industry-specific bases. Sensitivity to such factors is essential to assess the impacts of increasing the use of coal in industrial boilers. But data for a complete picture are lacking, particularly for the small boiler which are uneconomical for most coal use.

Boiler Technologies and the Framework for Their Analysis

The technologies investigated were noted previously. Units delivering 100,000 lb of steam per hour, roughly the current average size of industrial units based on energy consumed, were used as the standard for comparison. "Typical" Eastern and Western coals were also assigned. The level of demand that is assumed in the year 2000 is 6Q*, a high but justifiable assumption in the sense that it represents the intent of the Fuel Use Act. The consideration of coal use is restricted to the large boiler (>100,000 lb steam/hr) size range. This restriction is made for a number of reasons. First, adequate data for the present distribution of boilers only exist for the large boilers. Second, only larger boilers are subject to provisions of the Clean Air Act. Third, the larger boilers are the most cost-effective size for using coal. Our assumptions do, however, account for a slight reduction in capacity in smaller boilers (<100,000 lb steam/hr), consistent with a scenario that emphasizes a greater role for coal in large boilers.

Figure 3 summarizes the assumed year 2000 energy demand in industrial boilers. Between now and the year 2000, 75 percent of new capacity in large boilers (or roughly 3.5Q) is assumed to be fired by coal. It was assumed that 90 percent of present oil-fired capacity in large boilers will be

*6Q would come to about 252 million tons of coal, or about 5.5 times current industrial use of coal in boilers, representing a 7.2 percent increase per year in the growth of coal use.

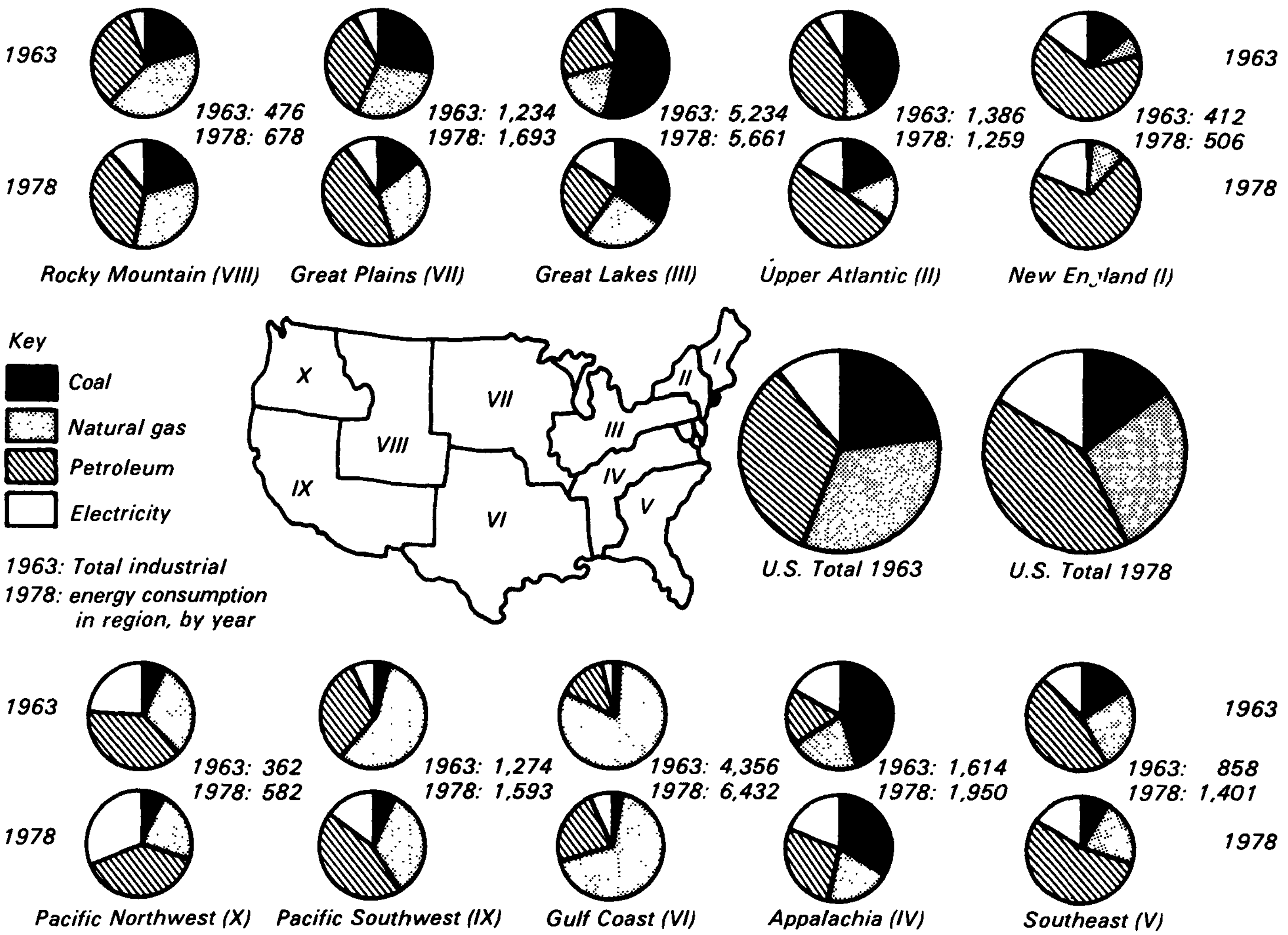

Figure 2. Regional fuel use patterns (1963 and 1978, 10^{12} BTU).

Table 1. Regional Shares of Industrial Energy Use (1977)

	Chemicals		Primary metals		Petroleum/coal		Paper		Stone/clay/glass		Food	
	Region %	Nation %	Region %	Nation %	Region %	Nation %	Region %	Nation %	Region %	Nation %	Region %	Nation %
New England	8	<1	6	<1	1	<1	34	7	7	3	5	3
Upper Atlantic	21	6	30	9	12	6	6	4	10	12	6	10
Great Lakes	10	10	49	57	10	19	4	10	8	33	3	20
Appalachia	30	11	29	12	3	2	17	15	6	10	3	6
Southeast	15	4	2	<1	<1	<1	45	25	6	6	5	7
Gulf Coast	52	59	5	6	27	52	6	16	3	14	2	11
Great Plains	16	3	9	2	6	2	16	7	12	9	17	17
Rocky Mountain	3	<1	51	4	26	3	<1	<1	9	3	7	3
Pacific Southwest	12	3	15	4	35	13	6	3	10	9	9	9
Pacific Northwest	7	<1	27	4	9	2	37	12	3	2	6	5

converted to, or replaced by, coal by the year 2000; though site-specific factors are also assumed to allow 10 percent of new capacity to be fired by oil. For natural gas, it was assumed that 50 percent of existing capacity in large boilers will be converted to coal, with 15 percent of new capacity being satisfied by natural gas. A minimum of roughly 3.5Q of coal-fired capacity in the year 2000 takes place at existing industrial sites. Of the approximately 2.5Q of new growth which is coal-fired, much of the amount may also occur at existing facilities, since capacity additions may be expected in many industries. Regional assignments of energy use are based on industry-specific growth projections. Further, the two "typical" coals used in the analysis were not uniformly applied to each region, since not all regions would have equal access to the two coal types.

Discharges to the environment and resource requirements were determined for all operations from mining through steam production. To compare technologies, a trajectory, or sequence of operations, was defined for each technology. Figure 4 presents the results of comparing SO_2 emissions, total solid waste production, and water requirements for four of the technologies considered. In addition to comparisons among technologies that provide the same level of steam output, discharge and resource comparisons are made among several "technology mixes," each of which in the aggregate would require 6 Q of coal in the year 2000. The technology mixes are as follows:

- Industrial Boilers in Year 2000. This is the "reference mix" for year 2000 because the level of application of each technology is that which is assumed to be achievable according to market penetration estimates that were provided by the sources of the study. In this and the subsequent technologies, the steam production is taken to be 4.8Q/yr; and the coal required, nominally 6Q/yr, varies with the technology mix.
- Clean All Eastern Coal — Year 2000. All Eastern coal, except that which is used in low-Btu gasification, is cleaned physically.
- High-Level FGD — Year 2000. All coal from conventional combustion of uncleaned coal is shifted to FGD.
- High Level of Low-Btu Gasification — Year 2000. All conventional combustion of uncleaned coal is replaced by low-Btu gasification.
- High Level of FBC. All combustion of uncleaned coal is replaced by FBC.

Results from comparing four of the five technology mixes for total SO_2 emissions, solid waste production, and water requirements are displayed in Figure 5.

Overall, energy use in all industrial boilers is assumed to increase at a rate of 1.5 percent per year between 1978 and 2000; energy use in large boilers is assumed to increase at a rate of 3.5 percent per year. The use of coal in large boilers increases at 8.4 percent per year. Whether U.S. industry can, in fact, increase coal use to such an extent is

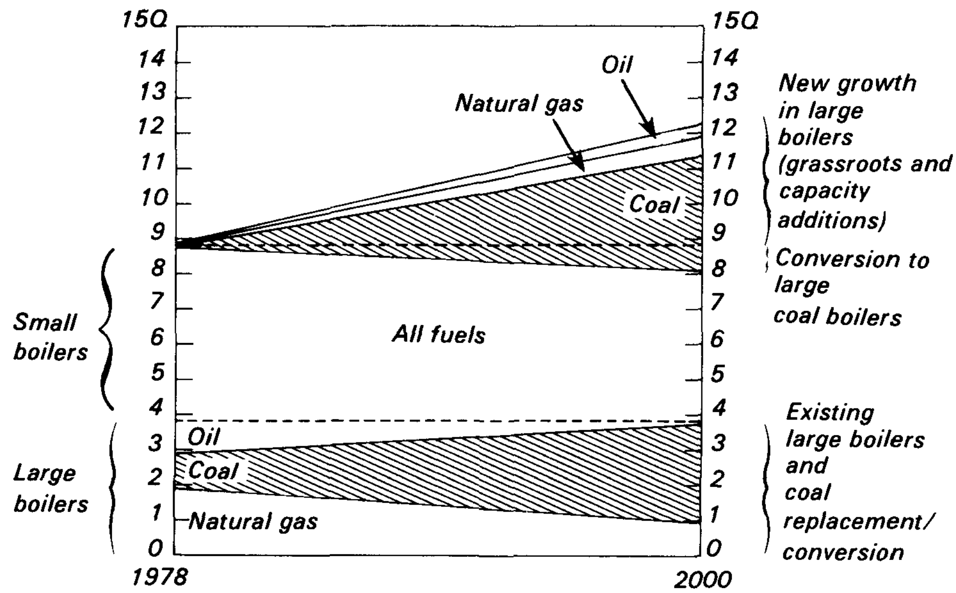

Figure 3. Summary of assumptions for industrial boilers.

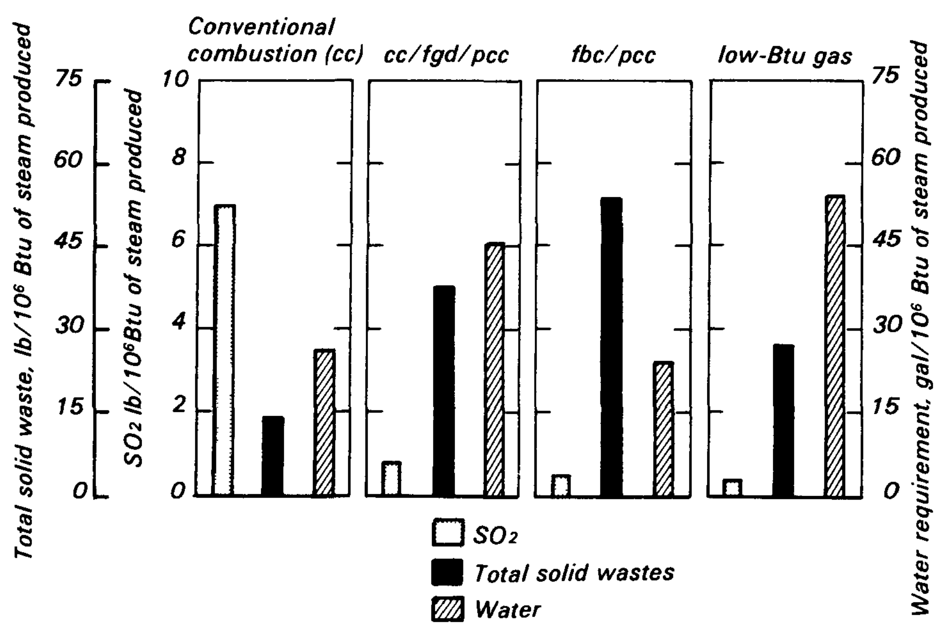

Figure 4. Direct comparison of SO_2 emissions, total solid waste production, and water requirements for four technologies.

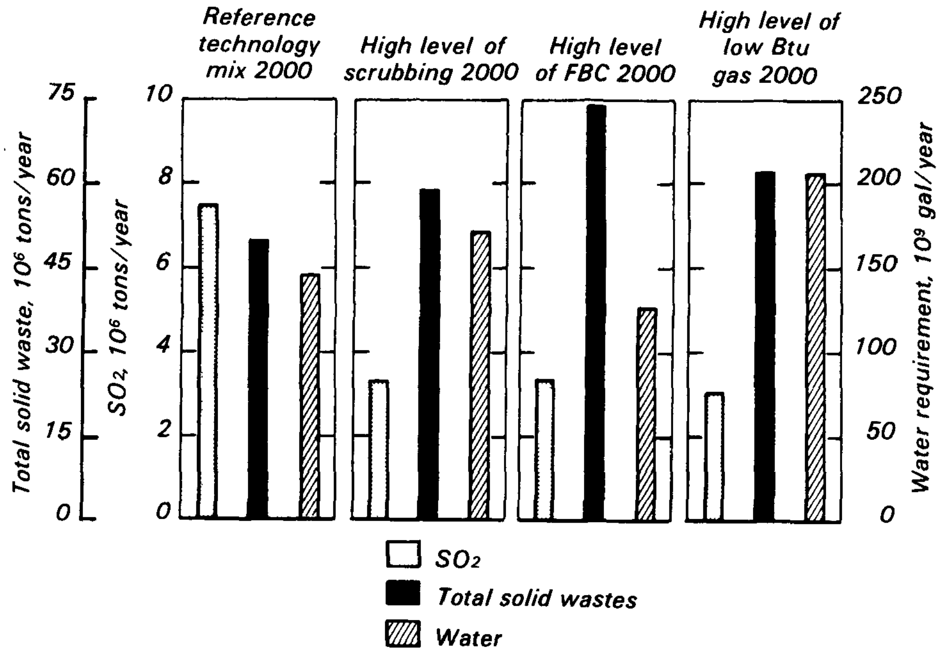

Figure 5. Total SO_2 emissions, solid waste production, and water requirements for four technology mixes in the year 2000.

tested, in part, by the analysis in the remaining chapters of the main report.

Perspectives on Air Quality

Certainly, one of the most serious concerns surrounding a widespread resurgence of the use of coal in industrial boilers is the potential of deteriorating air quality. As shown in Figure 6, at the year 2000 coal-use levels noted above, SO_2 emissions would increase to 7.5 million tons per year, or about half the present SO_2 emissions from the electric utility industry. Nationally, regions that now contain much industry and rely on natural gas, as exemplified by the Gulf Coast States, would experience the largest percentage and absolute increases in SO_2 and particulate (TSP) levels. Almost all regions would experience a degrading of air quality, should other sources of air emissions not be cleaned up sufficiently to counteract the emissions from coal-fired boilers in industry. This general trend of declining air quality can be seen in Figure 7.

Yet such coal-use levels may never be attained. First, a detailed analysis of half the present boiler capacity indicates that 65 to 70 percent of industrial facilities are located in "dirty air" nonattainment areas. Obtaining permits in such situations for coal-fired boilers will be difficult due to an apparent unwillingness of existing industries to trade their potential to reduce emissions to possibly competing industries. Furthermore, two-thirds of emissions from industrial boilers nationwide occur in municipal areas. This concentration makes industries highly visible and subject to local opposition should air quality be perceived to degrade. In all likelihood, the middle-sized industries are the most liable to such opposition. In any case, meeting the intent of the Fuel Use Act while keeping air clean appears to require massive relocation of existing industries, technological breakthroughs that are not now apparent, cleaning up existing nonindustrial sources to a degree not heretofore experienced, or nothing at all.

Resources Used and Solid Wastes Generated

Comprehensive pictures of the entire fuel cycle from mining the coal to producing the steam are presented. We discovered that conventional combustion requires the fewest resources, excepting water in the case of fluidized-bed combustion, and that low-Btu gasification requires the largest. Overall, the largest resource impact for the assumed year 2000 coal-use level would be an increase of 40 percent in mined-coal requirements over present domestic production. Increases in water and land requirements would roughly come to about 1 percent of present demands for all uses. Solid waste generation would markedly increase, with states along the Gulf Coast and Great Lakes bearing the largest burden. Such distributions are documented in Figure 8. In fact, 95 percent of the possible 50 million to 75 million additional tons of solid waste would occur in the central portions of the U.S. Compounding such increases is the fact that two-thirds of the waste would require disposal near municipal areas, or roughly an increase of 10 to 30 percent over the present amounts of disposed municipal wastes. Furthermore, much of the waste will be generated by industries that do not have experience in large-volume waste disposal.

Economic Factors Influencing Industrial Fuel Choice Decisions

Even with the recent rise in prices for natural gas and oil, coal-fired boilers have yet to demonstrate a clear cost advantage. Costs are addressed from three related perspectives. First, the cost of steam was compared from conventional and advanced coal technologies, and between conventional coal-fired boilers (equipped with flue-gas desulfurization) and boilers burning natural gas. Sensitivity analysis was included to detail the extent to which

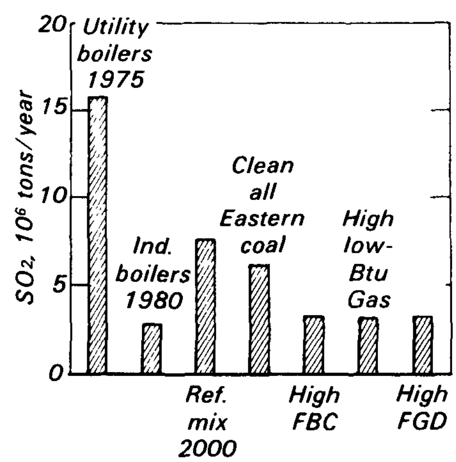

Figure 6. SO_2 emissions for various technology mixes in year 2000 compared with those from utility boilers in 1975 and with industrial boilers in 1980.

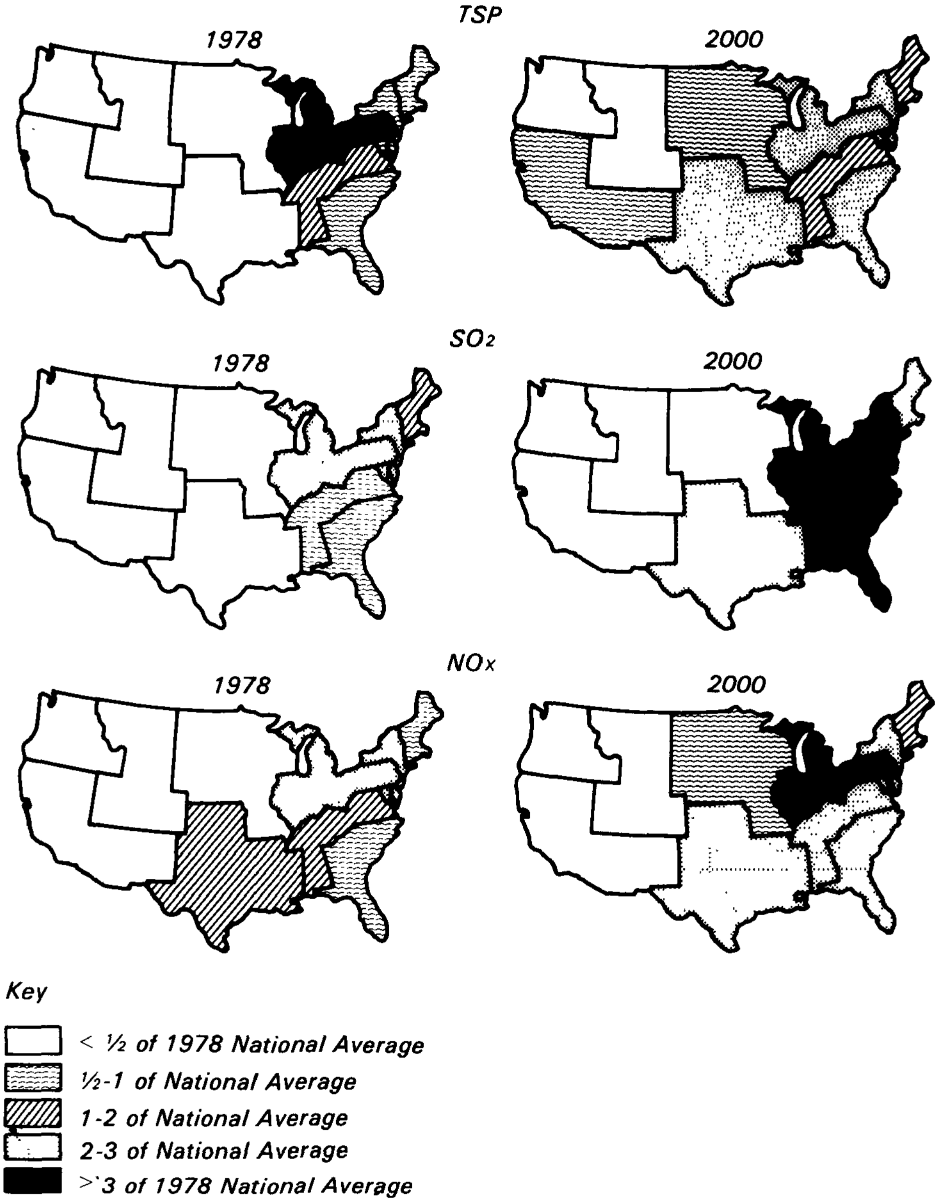

Figure 7. *Regional coal, oil, and NG industrial boiler emissions/m², 1978 basis.*

variations in boiler's size or operating parameters affect the cost of steam. Second, the modes by which economic factors external to steam costs influence boiler/fuel choice are described generally. Finally, fuel choice decisions are evaluated on an industry- and region-specific basis.

Comparative capital and steam costs for conventional and advanced coal technologies are depicted in Table 2. The use of cleaned coal increases the cost of steam only marginally above that for an uncontrolled conventional watertube boiler. Furthermore, when all the benefits of using cleaned coal are accounted for — lower waste disposal, transportation, and maintenance costs — the net cost of steam produced by a boiler equipped with FGD is the same whether cleaned or uncleaned coal is used; the same observation applies to FBC. For Eastern coals, FBC appears to be slightly less costly than FGD, while for Western coals the differential is greater. Capital costs for low-Btu gasification systems are 25 percent higher than any technology studied. Only at extremely high rates of capacity utilization could onsite low-Btu gasification become cost-effective for generating industrial process steam.

The much higher capital costs associated with coal-fired boilers place them at a substantial cost disadvantage compared to units designed to fire natural gas. Additionally, coal-based energy technologies exhibit severe economies of scale. The combined effect of these factors is to make coal-firing cost-effective only in large boilers that operate at high load factors where economies of scale can be reached and where capital costs can be spread over a maximum amount of steam production. The industrial sector, however, is characterized by a large number of small boilers operating at a fraction of rated capacity.

High capital costs are a significant disincentive for firms considering a switch to coal. For many industrial firms, steam costs constitute only a very small fraction of total plant-operating costs. As a result, investing limited capital resources in capital-intensive boiler systems cannot be economically justified even when such an investment would reduce annual energy costs. For those firms where the cost of steam represents a greater share of total operating costs, large capital investments to reduce annual energy expenditures will be viewed more favorably. In all industries, however, boiler system replacement or expansion projects must compete for capital with other business activities. Finally, the manifest inconveniences of using solid coal at manufacturing plants have at least the potential to raise substantially the effective costs of using coal compared to using other fuels.

Clearly then, the decision to burn coal as a boiler fuel can be influenced by a number of economic, technical, and institutional considerations. In order to gain some perspective on how these considerations may affect different industrial firms, an industry- and region-specific analysis of fuel/technology decisions was undertaken. In each case, it was assumed that an existing gas- or oil-fired boiler required replacement. The existing unit was assumed to have totally depreciated in value.

Six industries were considered: chemicals, petroleum, aluminum, steel, equipment manufacturing, and food processing. The analysis took into account industrial differences by employing industry-specific data on average boiler size, load factor, and expected

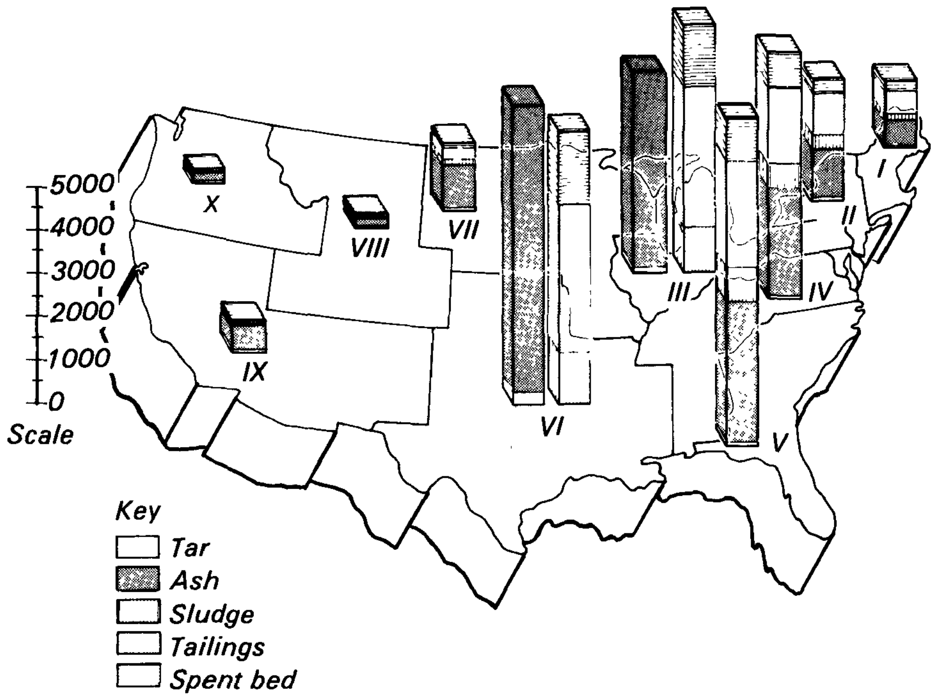

Figure 8. *Year 2000 SW discharges, annual basis, 10^3 tons, reference mix.*

Table 2. *Summary of Approximate Costs*[a]

	Eastern coal		Western coal	
Technology	Total capital investment, 10^6\$	Cost of steam, \$/10^6 Btu	Total capital investment, 10^6\$	Cost of steam, \$/10^6 Btu
Conventional combustion (CC)	8.80	7.43	10.57	7.77
CC with cleaned coal	8.96[b]	7.71	—	—
CC with FGD	10.12	9.79	11.82	9.21
CC/FGD with cleaned coal	10.20[b]	9.79	—	—
FBC	9.83	9.29	10.05	7.55
FBC with cleaned coal	9.99[b]	9.29	—	—
Low-Btu gasification plus boiler	12.80	12.57	11.77	10.74

[a]*Basis: boiler with a capacity of 100,000 lb/hr steam (approximately 125 x 10^6 Btu/hr fuel input) with a load factor of 45 percent.*
[b]*Includes proportional share of the capital cost of a large coal-cleaning plant supplying fifty 100,000-lb/hr steam plants.*

returns on invested capital, all of which influence the traditional analysis of capital, operating, maintenance, and fuel costs. In addition, regional differences were reflected in fuel costs and availability, as well as in the subjective probabilities that specific levels of price and fuel availability would occur. Probability functions were derived, for the most part, from interviews and thus were only intended to represent intra-industry perceptions. Eight possible outcomes, or scenarios, were constructed in terms of variations in fuel prices and expected levels of supply. For each scenario and for each industry/region grouping, the cost of steam from a gas-fired system was calculated as a percentage of an equivalent capacity coal-fired system.

A summary of the results is presented in Figure 9. The shaded portion incorporates the range of values calculated for each industry among eight scenarios. Under the assumptions employed in this analysis, only in the steel industry and in the petroleum refining industry in the Upper Atlantic Region does coal appear to represent a clearly cost-effective alternative. The steel industry, however, currently faces significant capital constraints and is located primarily in areas of poor air quality. Petroleum refineries are often sited in congested areas. For these industries, then, the apparent economic incentives to use coal may be overridden by other constraints. Large energy-intensive firms located along the Gulf Coast generally perceive only a marginal incentive to convert to coal due to the high cost of transporting coal to that region.

Conclusions

The historical imperatives that shaped the Nation's industrial development have given rise to a configuration of technical systems that is not amenable to a rapid shift to coal. Industries, for the most part, are concentrated in a few geographical areas. Such concentration has led to restrictions on the amount of space available to individual manufacturing plants and resulted in a close proximity between industries and areas of high population density. The concentration of industries and populations, with the concomitant concentration of transportation and commercial support systems, has caused the quality of the air in these areas to deteriorate seriously. Only recently has a public commitment to restore the quality of the environment in heavily industrialized and urbanized regions been made and translated into specific policy actions. In the last 25 years, much of the progress that has been made has arisen from a shift away from coal to cleaner fuels. Thus, a return to the widespread utilization of coal raises a potential contradiction between environmental and energy goals.

Other constraints to an increased use of coal in industrial boilers can be traced to historical factors as well. The progressive movement to small, packaged, and low-capital-cost boilers restricts the technical capability of existing equipment to use alternative fuels, especially coal. Changes in mining technology, policy initiatives designed to protect the health and safety of miners and to minimize environmental damage from mining operations, gradual changes in coal marketing and management practices, as well as deficiencies in existing transportation systems, cast serious doubts on the adequacy of the supply infrastructure to support a widespread shift to coal in industrial boilers.

All of the factors mentioned combine to levy a substantial cost penalty on coal users. Costs of control technology, waste disposal, land, boiler replacement, and transportation are often more than enough to offset the rapid increases in the price of natural gas and oil. More importantly, the capital intensiveness of coal technologies can raise an array of financial problems for industrial firms.

Each of these constraints appears to be rather intractable. To the degree that they arise from long-term historical trends, from conflicts with other public goals, and from imperatives of our economic system, the policy initiatives that are designed to provide a near-term and widespread shift to coal in industrial boilers will be severely compromised. A high level of coal use in industrial boilers does not appear to be technically, environmentally, economically, or politically feasible.

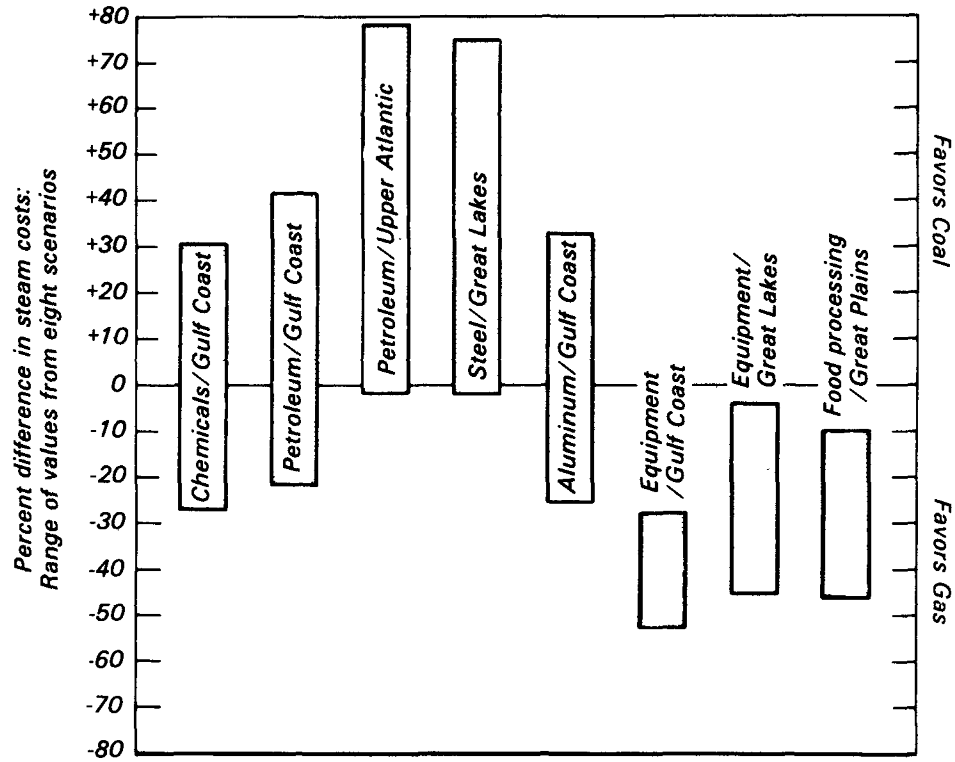

Figure 9. *Summary of fuel choice decision analysis.*

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The complete report, entitled "Prospects for Increasing the Direct Use of Coal in Industrial Boilers," (Order No. PB 82-232 380; Cost: $24.00, subject to change) will be available only from:

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