LOW-RANK COAL STUDY

NATIONAL NEEDS FOR RESOURCE DEVELOPMENT

MASTER**REGULATORY, ENVIRONMENTAL,
AND MARKET ANALYSES**Dist-179
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LOW-RANK COAL STUDY
National Needs for Resource Development

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Walnut Creek, California

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PREFACE

This is volume four of a six-volume "Low-Rank Coal Study." Overall, the report presents a comprehensive analysis of the technical, environmental, and economic constraints to expanded development of U.S. lignite, subbituminous coal, and peat resources. The primary objective of the study was to propose a comprehensive national research, development, and demonstration (RD&D) program focusing on technology development for enhanced utilization of these resources. The report is organized as follows:^a

- Volume 1 - Executive Summary
- Volume 2 - Resource Characterization
- Volume 3 - Technology Evaluation
- Volume 4 - Regulatory, Environmental,
and Market Analyses
- Volume 5 - RD&D Program Evaluation
- Volume 6 - Peat

This study was directed by the Grand Forks Energy Technology Center (GFETC), which has the lead mission within the Department of Energy for technology "applications for low-rank coals." G. H. Gronhovd (Director) and E.A. Sondreal (Deputy Director) of GFETC provided technical direction and review of all aspects of the study. The work was performed by Energy Resources Company, Inc. (ERCO) under a contract initiated on May 16, 1979, and completed on September 30, 1980. The study approach is summarized in Table P-1, which shows the eight major contract tasks and the approximate percentage allocation of funds to each. The study schedule is summarized on Figure P-1.

Because of the scope and complexity of the effort, GFETC enlisted a task force of recognized experts on the technical and regional issues germane to the study. These individuals are listed in Table P-2; their contributions to the quality and direction of the study were highly significant. The task force met with the study team at four critical points to review interim results and to lead working groups which established the emphasis, priorities, and methodologies for the analysis. Primarily through the efforts of the task force members, useful data inputs and critiques of working draft materials were received from a number of organizations as the study progressed.

Individual contacts and contributions made during the course of the study are too numerous to list. The following (in addition to the task force members) contributed significantly to the review of part or all of the document: G.H. Gronhovd, E.A. Sondreal, W.G. Willson, and H.H. Schobert of GFETC; W.R. Kube of the University of North Dakota and GFETC; S. Alpert, K. Clifford, S. Ehrlich, T. Lund, C. Aulisio, D. Giovanni, and R. Wolk of the Electric Power Research Institute; W. McCurdy, S. Freedman, L. Miller, M. Kopstein, L. Ludwig, E. Burwell, W. Schmidt, M.N. Rosenthal, J. Nardella, and J. Turner of DOE; W.R. Kaiser of the University of Texas at Austin; and P. Averitt (retired) of the U.S. Geological Survey.

^a Volumes 2 through 5 address lignite and subbituminous coal; Volume 6 addresses peat; and Volume 1 summarizes the conclusions and recommendations of the total study.

Figure P-1

Low-Rank Coal Study Schedule

Table P-1

Major Tasks in the Low-Rank Coal Study

1. Low-Rank Coal Development Scenarios (6%) 1.1 Literature Review 1.2 Technology Definitions 1.3 Regulatory/Environmental/Market Definitions 1.4 Low-Rank Coal Data Base 2. Resource Characterization (8%) 2.1 Occurrence 2.2 Properties/Characteristics 2.3 Classification 3. Technology Evaluation (42%) 3.1 Extraction 3.2 Transportation Systems 3.3 Preparation, Handling, and Storage 3.4 Processing and Utilization 3.5 Environmental Control Technology 4. Regulatory Requirements/Constraints (4%) 4.1 Definition 4.2 Roadmap 4.3 Effects on Development	5. Environmental Impact Analysis (3%) 5.1 Land Use/Reclamation 5.2 Air Quality 5.3 Water Quality 5.4 Ecological Effects 5.5 Socio-Economic Effects 6. Market Analysis (6%) 6.1 Existing Markets and Penetrations 6.2 Potential Markets 7. RD&D Program Evaluation (11%) 7.1 Definition and Priorities 7.2 Review of Current RD&D Programs 7.3 Cost and Impact Analysis 8. Task Force Utilization (20%) 8.1 Development Scenarios Evaluation 8.2 Technical Analysis Evaluation 8.3 RD&D Program Definition 8.4 RD&D Program Impacts and Recommendations

Table P-2

Low-Rank Coal Study
Task Force Participants

<u>Participant</u>	<u>Affiliation</u>
1. Dr. Martin A. Elliott Houston, Texas	Consultant, Texas Eastern Gas Transmission Co.
2. Professor George R. Hill Salt Lake City, Utah	University of Utah Department of Chemical Engineering
3. Mr. James Jonakin Birmingham, Alabama	Consulting Engineer (Retired from Combustion Engineering, Inc.)
4. Mr. Paul W. Crutchfield and Mr. David J. Beecy Washington, D.C.	U.S. Department of Energy Office of Policy and Planning
5. Professor Donald E. Severson Grand Forks, North Dakota	University of North Dakota Department of Chemical Engineering
6. Mr. David M. White Austin, Texas	Texas Energy and Natural Resources Advisory Council
7. Mr. Kurt Yeager and Dr. Charles R. McGowin Palo Alto, California	Electric Power Research Institute

The ERCO Program Manager on this effort was Dr. John Kotowski. Mr. George Wiltsee was the Assistant Program Manager and Technical Director. Other ERCO personnel who provided major contributions to the effort include Paul Goodson, Randall Smith, Wayne Simmons, Barbara Acker, Jeffrey Feerer, Timothy Buscheck, and Myron Burr. In addition, special thanks should be extended to Lydia Felix and Jennifer Spinello of the administrative staff for their support and assistance in the preparation of this report.

ABSTRACT

The regulatory, environmental, and market constraints to development of U.S. low-rank coal resources are analyzed. Government-imposed environmental and regulatory requirements are among the most important factors that determine the markets for low-rank coal and the technology used in the extraction, delivery, and utilization systems. Both state and federal controls are examined, in light of available data on impacts and effluents associated with major low-rank coal development efforts.

The market analysis examines both the penetration of existing markets by low-rank coal and the evolution of potential markets in the future. The electric utility industry consumes about 99 percent of the total low-rank coal production. This use in utility boilers rose dramatically in the 1970's and is expected to continue to grow rapidly. In the late 1980's, and 1990's, industrial direct use of low-rank coal and the production of synthetic fuels are expected to start growing as major new markets.

4.1 INTRODUCTION AND SUMMARY

The primary factors affecting the development of low-rank coals are government regulations, environmental impacts, and competition with other fuels. These three factors are closely related, as the detailed examinations of each of them (presented in the three following major sections of this volume) reveal.

Regulatory controls and permitting requirements are imposed on coal development and utilization projects by all levels of government -- Federal, state, and local. These controls for the most part respond to environmental, health, and safety concerns. In general, air quality, water quality, and water quantity issues are the most significant ones affecting low-rank coal projects. However, the issues of land use and productivity, solid waste disposal, noise, and public safety are very significant as well.

The major Federal controls on low-rank coal development are imposed through the following legislation:

1. The Surface Mining Control and Reclamation Act, which establishes requirements for effective reclamation of mined lands.
2. Clean Water Act, which specifies the cleanup and discharge requirements for water pollutants, and the associated permitting system.
3. The Resource Conservation and Recovery Act, which governs the disposal of discarded materials such as fly ash and scrubber sludge, and defines the procedures that must be followed with respect to hazardous wastes.
4. The Clean Air Act (and Amendments), which establishes both New Source Performance Standards for emissions of air pollutants, and ambient air quality (concentration) standards for regions.
5. The Endangered Species Act, which governs the preservation of ecosystems of endangered or threatened plant and wildlife species.
6. The Toxic Substances Control Act, which regulates the manufacture, processing, distribution, use and disposal of a list of priority (toxic) pollutants.

7. The National Environmental Policy Act, which governs the preparation of Environmental Impact Statements.
8. The Occupational Safety and Health Act, which places limits on worker exposure to dangerous substances or situations.
9. The Mine Safety and Health Act, which establishes standards and inspection procedures to protect the safety and health of miners.

Many of these Federal regulatory programs are implemented by state programs which are at least as stringent as the Federal standards. For example, California, Montana, North Dakota, Texas, and other states have air quality regulations that are significantly different from or are more stringent than the National Ambient Air Quality Standards.

Permitting requirements for major energy projects have become extremely time-consuming and costly. These requirements are specific to the state and local agencies involved, and in some cases are project-specific as well. Several recent examples, such as the Great Plains Gasification Associates SNG plant in North Dakota and the Twin Oaks electric power plant in Texas, are evaluated to serve as examples of permitting procedures. In the case of the gasification project, seven federal permits, 25 state permits and 10 county and local permits had to be obtained -- over a period of seven years.

The environmental impacts associated with low-rank coal development can be very significant. Surface mines affect the appearance and subsequent use of the land. Technology for mined land reclamation has been developed rapidly in response to recent regulatory requirements. Other, generally less significant surface mining impacts are dust, noise, and vibration problems, water diversion, and water contamination.

Huge quantities of western subbituminous coal are shipped long distances by unit train, or train and barge combinations. Heavy train traffic disrupts communities and causes grade crossing safety problems. Fugitive dust emissions from loading/unloading facilities and from open coal cars represent a relatively minor impact caused by low-rank coal transportation. If slurry pipelines become a significant transport mode in the future, a major issue of water allocation will be raised if water is to be supplied from one of the arid or semi-arid low-rank coal regions.

Coal preparation, handling, and storage systems create relatively minor impacts: fugitive dust emissions which can be readily controlled by collection and cleanup systems, and water quality problems if leaching occurs from storage piles.

Major environmental impacts affecting air, water, and land are

associated with coal combustion and conversion systems, unless very effective environmental control systems are employed. The major air emissions of concern are SO₂, NO_x, and particulate matter (fly ash). Carbon monoxide and unburned hydrocarbons are also emitted to some extent, as are a wide variety of trace elements that occur in minute concentrations in the coal. In the future, regional and global effects of acid rain and CO₂ buildup are going to become significant problems.

Water consumption by coal combustion and conversion facilities tends to be very high. As the use of coal expands to make up for declining oil and gas use, this will become a limiting constraint in some areas of the country. Water quality is not a major issue with conventional coal combustion technology, but it is with coal gasification and liquefaction processes, which produce highly contaminated wastewater streams.

Solid wastes are produced from combustion and conversion processes in very large quantities. Impacts of ash and sludge disposal on ground-water quality have not been thoroughly quantified as yet. Disposal methods are still evolving in response to changing standards.

The only significant market for low-rank coals at the present time is the electric utility industry. During the 1970's, the use of both lignite and subbituminous coal in utility boilers grew very dramatically. This growth was in response to a number of factors, including: 1) the fact that low-rank coals became the lowest-cost fossil fuel available to utilities; 2) large-scale surface mining and combustion technologies were developed that allowed considerable economies of scale to be obtained; 3) long-distance power transmission opened up major markets to some of the low-rank coal resources found in sparsely populated areas; 4) SO₂ emission standards caused many utilities to burn low-sulfur western coal rather than install scrubbers; and 5) OPEC oil price hikes led to the initiation of massive lignite power generation projects in Texas.

The future markets for low-rank coals are expected to continue evolving along similar lines. Utilities will continue to dominate as the major low-rank coal users, eventually phasing in advanced technologies such as integrated gasification/combined cycle plants or fluidized bed combustors. Industrial direct use of low-rank coal is likely to become significant in the late 1980's, with Texas being the most likely proving ground. Synthetic fuels from low-rank coal will be produced in large quantities starting in the 1990's.

Overall, it is expected that low-rank coal production, which accounted for only 1-2 percent of total coal production prior to 1970, and 21 percent in 1978, will account for about half of a greatly expanded total coal production figure by the end of this century. Major challenges will be faced in accomplishing that growth within the bounds of the environmental and regulatory constraints.

4.2 REGULATORY ANALYSIS

Governmental control on energy projects is a crucial consideration in development of Western low-rank coals. Regulatory control is a function of public concern over local, regional, and national environmental and economic issues. These issues result in legislative philosophy which could potentially constrain coal resource development by imposing unattainable environmental standards and other regulatory controls. The overall milieu in which proposed development efforts and RD&D programs will operate is defined in this chapter by examining the constraining effects of present and future regulations.

Regional and local regulations are fairly consistent, at least in philosophy, across the United States. Thus, it is prudent that this study focus only on important low-rank coal resource regions to simplify the regulatory analysis. Two regions were chosen for study: The Northern Great Plains, which consists of Montana, North Dakota, and Wyoming; and the Gulf Coast, particularly the state of Texas. These regions were chosen because major portions of the resource and thus most of the low-rank coal development projects have been located and will continue to occur in these areas. In addition, many of the necessary environmental studies have been performed for these regions, which provides a strong data base for analysis.

The objective of this section is to discuss present and future regulatory controls on potential low-rank coal development and utilization. Material is presented in four sub-sections as described below.

First, the environmental issues associated with low-rank coal development are summarized in order to understand the evolution of present regulatory controls (Note that the issues presented here are only summaries; detailed discussions of particular low-rank coal process effluents and impacts are in Section 4.3, Environmental Impact Analysis.)

Second, those regulatory controls that respond to environmental, health, and safety impacts from low-rank coal utilization are described. These descriptions are general summaries of the federal laws and regulations, with specific references to low-rank coal applications wherever possible.

A comparison of the various state and federal environmental regulations which affects the utilization of low-rank coals is presented in the third subsection.

The fourth subsection traces two actual permitting histories still underway, one a lignite-fired utility generating station in Texas, the other a lignite gasification plant in North Dakota. The gasification plant history is especially interesting since the facility will be the first commercial-scale high-BTU gasification complex in the United States. Also included in this subsection are the regulatory agencies and their associated regulations and permits which are required of a coal-fired power plant currently being permitted in California.

Finally, the direction and evolution of regulatory controls are ascertained by matching issues with a regulatory forecast in order to estimate the severity of probable future regulatory constraints.

Table 4.2.1 presents an overview of the major Federal environmental regulations that presently impact low-rank coal development. Future impacts are estimated based upon current trends in the particular permitting and regulatory procedures.

4.2.1 Environmental Issues Affecting Regulations

The environmental issues that will arise from low-rank coal development can best be summarized by using a systems approach such as that illustrated on Figure 4.2.1. Extraction of low-rank coal in the Western United States will be primarily through surface mining. Transportation of the mined coal to a distant facility will utilize railways, barges, and slurry pipelines. Transport of mined coal to a minemouth facility will utilize trucks and/or conveyors. Facilities for coal preparation will process coal for enhanced utilization in liquefaction, gasification, or direct combustion plants.

The utilization processes can be centered at the minemouth, or spread out over hundreds of miles. Concentration of facilities in one locality will intensify environmental issues on a local and regional level, while separation of facilities requires consideration of multiple state and local issues.

The major types of environmental issues for each system component are shown on Figure 4.2.2. Air Quality, water quality, and water quantity are the most significant environmental issues. At the present time, Federal siting policies affecting low-rank coal burning facilities are centered around the NEPA Environmental Impact Statement process and the preconstruction review of new facilities under the Clean Air Act Amendments of 1977. There are also requirements for permits under the Clean Water Act, including NPDES and Corps of Engineers "dredge and fill" permits, but these do not usually constrain the time schedule for completing a new facility. Future permitting requirements under the Resource Conservation and Recovery Act will be at least as significant as air and water pollution controls are today. Each of the environmental issues is discussed in the following sections.

Quantification of environmental impacts is discussed in Section 4.3.

4.2.1.1 Air Quality

Surface mining operations create air quality problems primarily from increased dust levels. Blasting and removal of overburden, ore and overburden hauling, crushing and loading the coal, and wind erosion of exposed surfaces produce large quantities of fine particles. Air quality problems are exacerbated when several mines are concentrated in one area.

Table 4.2.1

Federal Environmental Regulations and Impacts

Page 1 of 5

Law/Regulation	Current Limits	Future Regulations	
		Expected Impacts	Worst Impacts
<u>Clean Air Act</u> - New Source Performance standards (NSPS)	<p>The 1979 standards limit SO₂, NO_x and particulate emissions from electric utility steam generating units that burn subbituminous coal and lignite (250 million BTU/hr or more heat input):</p> <p>SO₂: 1.20 lb/10⁶ BTU with 90% reduction in potential SO₂ emissions, or 70% reduction when emissions are below 0.6 lb/10⁶ BTU</p> <p>NO_x: 0.50 lb/10⁶ BTU for subbituminous coal 0.60 lb/10⁶ BTU for lignite; 0.80 lb/10⁶ BTU for cyclone-fired boilers using lignite from N.D., S.D., and Montana.</p> <p>particulate: 0.03 lb/10⁶ BTU</p> <p>No NSPS explicitly set for synfuel facilities. However, utility NSPS would be applicable, which allow for alternative standards for emerging energy technologies. These existing standards also will apply to power generation facilities providing electricity to the synfuel plant.</p>	<p>NSPS are to be set by EPA on best adequately demonstrated technology and reviewed every 4 years.</p>	<p>LAER could force NSPS to become more stringent over time. Mining, storage and handling NSPS could be developed.</p>

Table 4.2.1 (continued)
Federal Environmental Regulations and Impacts

Law/Regulation	Current Limits	Future Regulations	
		Expected Impacts	Worst Impacts
- Prevention of significant deterioration (PSD)	Air quality increments for TSP and SO ₂ are required in Class I, II, III areas. The use of best available control technology (BACT) plus one year of air quality monitoring is normally required for all new sources.	Increments for NO _x , and more stringent requirements for BACT as control technology develops.	Needed air quality increments may become unavailable. The number of protected Class I areas may increase. BACT could become extremely cost/energy intensive.
- Nonattainment (NA)	New sources locating in areas exceeding the NAAQS must utilize lowest achievable emission rate (LAER) technology and offset emissions by cleaning up existing sources.	States will determine LAER, and run the emission offset program.	LAER may become prohibitively expensive, and needed emission offsets may be unavailable.
- Visibility	New sources locating near Class I areas must undergo air quality related values review. Federal Land Managers must approve the sources siting to protect air quality related values.	New sources locating near Class I areas may have to implement controls beyond BACT.	New sources locating in Class II or III areas may be found to be impacting visibility in Class I areas. The siting of multi-facilities near Class I areas may be impacted.
- NESHAPS National Emission Standards for Hazardous Air Pollutants	No hazardous pollutant standards for synfuel facilities have been established.	We know of no EPA plans to establish hazardous pollutants emission standards for synfuel facilities.	Hazardous emission substances may be later identified which need to be controlled.
- Effluent	None	EPA will develop by early 1980's effluent guidelines for coal liquefaction.	Close to zero discharge already expected.

Table 4.2.1 (continued)

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Federal Environmental Regulations and Impacts

Law/Regulation	Current Limits	Future Regulations	
		Expected Impacts	Worst Impacts
<u>Clean Water Act</u> <u>(NPDES)</u> <ul style="list-style-type: none"> - Point source discharge permits under NPDES system - Water Quality Standards 	<p>State and stream specific permitting limits.</p> <p>States develop standards for stream segments for various pollutants. Technologies currently plan for zero discharge.</p>	<p>Limits become more severe.</p> <p>Localized implementation details not defined.</p>	<p>Goal is economic zero discharge.</p> <p>Water-quality limited areas may be differentially constrained.</p>
<u>Toxic Substances Control Act</u> <ul style="list-style-type: none"> - Control of new substances introduced into commerce 	<p>Requires premanufacture notification to EPA if product is toxic.</p>	<p>Future ratchetting of restriction.</p>	<p>Long-term uncertainty.</p>
<u>National Environmental Policy Act</u>	<p>Requires EIS's to be prepared for all major Federal actions significantly affecting the quality of the human environment.</p>		<p>Permitting delays due to intervenors.</p>
<u>Safe Drinking Water Act</u> <ul style="list-style-type: none"> - Underground injection guidelines 	<p>Proposed guidelines not finalized nor are state programs defined.</p>	<p>State plans must reflect regulations at least as stringent as the final guidelines.</p>	<p>Water limited areas could impose more stringent monitoring, increased impact would be small other than timing.</p>

Table 4.2.1 (continued)
Federal Environmental Regulations and Impacts

Law/Regulation	Current Limits	Future Regulations	
		Expected Impacts	Worst Impacts
- Sole source aquifer designations	Federal program has designated about 10 aquifers to be sole source; siting requirements in such areas are more stringent than other areas, and subject to EPA review.	Extension of designations to other areas.	Extension of designation to areas that are rich in resources causing increased locational constraints and more severe regulatory controls under SMCRA, SDWA.
<u>Occupational Safety and Health Act</u>	Worker exposure to: Carcinogens Noise Vibration Heat Dust Fumes Danger from explosives	May make existing requirements more stringent.	Cost of control; best practices may escalate; interaction of OSHA; TSCA regulations could increase problems.
<u>Endangered Species Act</u>	Identification of endangered fish, plant and wildlife species is required.	No increase in impacts expected.	Site specific opportunity losses.
<u>Resource Conservation and Recovery Act (RCRA)</u>	EPA has proposed regulations for disposal of hazardous and non-hazardous wastes. Restricts siting of disposal facilities.	Portions of liquefaction wastes may be identified as hazardous.	All solid wastes from liquefaction operations are identified as hazardous.
<u>Surface Mining Control and Reclamation Act (SMCRA)</u>	Regulations restrict surface mining on alluvial valley floors (AVF), potential farmland areas.		Increased protection of farmlands; reclamation failures could restrict areas.
<u>Fish and Wildlife Coordination Act</u>	Any facility which modifies a body of water for cooling water purposes must provide for the conservation, maintenance, and management of fish and wildlife resources.		

Table 4.2.1 (continued)

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Federal Environmental Regulations and Impacts

Law/Regulation	Current Limits	Future Regulations	
		Expected Impacts	Worst Impacts
<u>Wilderness Act of 1964 DOE</u>	DOE regulations prohibit new mining in wilderness areas after January 1, 1984 unless prior leasing arrangements made with DOI.		
<u>Federal Coal Mine Safety and Health Act of 1977</u>	Establishes health and safety standards relating to construction, operation and maintenance of underground and surface mining facilities. Compliance regulated by Department of Labor (MSHA).		
<u>Federal Land Policy and Management Act of 1976</u>	Establishes land management plans and guidelines for right-of-way permits.		
Source: Adapted from	Reference 2		

Figure 4.2.1

Low-Rank Coal Utilization System

Figure 4.2.2.

Environmental Issues in Low-Rank Coal Development

	<u>Air Quality</u>	<u>Water Quality</u>	<u>Water Quantity</u>	<u>Land Produc- tivity</u>	<u>Solid Waste Disposal</u>	<u>Land Use</u>	<u>Noise</u>	<u>Public Safety</u>
Extraction	●	●	●	●	◐	◐	◐	◐
Transportation	○	○	●*	○	○	●	◐	◐
Preparation & Storage	●	◐	○	○	◐	○	○	○
Conversion	●	●	●	○	◐	○	○	○
Converted Coal Transportation	○	○	●*	○	○	●	◐	●
Energy Production	●	◐	●	○	◐	◐	○	○

Major Issue (special legislation for coal expected)

Significant Issue

Minor Issue (minor or weaker legislation)

*

Slurry Pipeline Issue

Coal preparation facilities can have a wide range of environmental impacts depending on the techniques used. Thermal dryers and coal cleaning release particulate matter as well as small amounts of HC, SO_x, NO_x, and CO. Comminution releases significant quantities of fine particles, and storage piles can release dust due to wind effects.

The most significant adverse effects of coal conversion plant operations are on the air quality. The high-volume air pollution sources in a gasification or liquefaction process are: 1) carbon dioxide vent streams, 2) tail gas from sulfur plants, 3) flue gas from utility boilers, and 4) air and moisture effluents from cooling towers. Air emissions from any specific plant will depend heavily on the processes and environmental controls utilized, and will also depend to some extent on the type of coal used. Transportation systems for product gases or liquids from coal conversion plants would have negligible air quality impacts.

The major air emission source from an energy production facility (e.g., a utility boiler) is the flue gas stream, which contains regulated amounts of SO_x, NO_x, and particulate matter. Large volumes of CO₂ are released, which is a long-range concern for all fossil fuels. Trace amounts of unburned hydrocarbons, CO, and potentially toxic trace elements found in coal are also released.

4.2.1.2 Water Quality

Water quality of surface and subterranean flows may be degraded as a result of surface mining operations. Storage piles with steeply sloped ridges and little or no vegetative cover are highly susceptible to erosion. Erosion of storage piles can cause increased levels of dissolved salts, trace metals, and sediment loads in downslope streams. Intermittent stream flows in semi-arid lands can hamper the natural flushing of these pollutants and substantially reduce local water quality. Groundwater supplies can also become contaminated due to percolation of salts and trace metals through the highly permeable spoil. Mining will also alter existing drainage patterns, creating new gullies and altering stream locations. Aquifers may be intercepted in the mining operation, causing mixing of groundwater layers of varying quality. Dewatering of mines can further contaminate surface water with groundwater of low quality.

Coal preparation and storage facilities also raise water quality issues, primarily from leaching of trace metals from storage piles. Significant water quality degradation is also expected from wastewater treatment plants associated with preparation processes which use solvents to achieve mineral matter control. Primary wastewater effluents will contain dissolved solids, suspended solids, various organics, soluble salts, and trace metals.

Water quality issues also arise in planning coal conversion facilities. Discharge from wastewater treatment plants will potentially cause lowered water quality. The exact effects of these pollutants on riparian and instream ecology are not completely known. Sulfur compounds will decrease stream pH by forming acids. Compounds such as sulfur ions,

phenols, and amines cause odor and taste problems. Increased turbidity from particulates and tars can bury fish eggs and food sources, and cause physiological changes in fish as evidenced by high mortality, low reproductive potential, and decreased lifespan. Organic compounds increase oxygen demand, decreasing the biological carrying capacity of the stream. Trace elements may be mutagenic, cause reproductive failure, and may render fish species, especially carnivores, unsafe for human or animal consumption.

The conventional production of energy requires water for condenser cooling, which may then be released into surface water at a higher temperature. Discharges of warm water will generally change the types, species, diversity, and number of fish found downstream, typically resulting in less valuable species. Leaching of groundwater contaminants from ash and sludge disposal sites is another area of growing concern.

4.2.1.3 Water Quantity

The major effect associated with coal extraction on the quantity of water available results from the physical removal of the coal. Near-surface coal beds often serve as major aquifers. Removal of the coal alters the level and movement of groundwater in and around the area of mining operations. The specific changes that may occur vary considerably by location, depending primarily on the continuity of the coal bed and on the dip of the coal bed being mined in relation to the mining pit. When the mining operation is moving up the dip of the bed, the mining pit will be a drainage area if the bed or any of the overlying strata is an aquifer. Mining will lower the water table in the unmined portion of the bed and possibly destroy the natural outflow area of the aquifer. When the mining operation is moving down the dip of the bed, some of the natural recharge of precipitation into the bed may be interrupted. If the dip is relatively slight and the bed is thick, some discharge could occur as well. When the conditions for drainage exist, drainage is likely to persist throughout the period of mining operations. Once mining ceases, if the final cut is not backfilled, the discharge will fill the mining pit until an equilibrium is reached. If the cut is backfilled, a barrier of low permeability may be created, raising the water table.

Surface water flows may be affected in several ways. Because the spoil piles are likely to be more porous and permeable than the surrounding unblasted overburden, infiltration of precipitation into aquifers and subsequent discharges into surface streams may increase. However, if a hardpan forms on the surface of the spoil piles, runoff will increase, resulting in a more variable stream flow. Mining of alluvial valley floors will disrupt the alluvial aquifer, reducing downstream surface flow.

When the water table is lowered as a result of mining operations, those living in the immediate area may suffer losses. The geographic extent of this effect will vary with the continuity of the bed. At one extreme, a minable bed could be confined to the area of mining operations by faulting, erosion, or pinch-outs; at the other, it could extend for

miles. Inhabitants of the area using groundwater may be forced to drill deeper wells to maintain current supplies or to develop other sources of water, or, if these alternatives are not feasible, they may have to reduce farming and ranching operations because of a reduction in water supplies. If natural outflows and other surface flows are disrupted, downstream surface water users may also have to seek more expensive alternative sources or operate with less supply.¹

Operation of coal-related transportation facilities does not raise water quantity issues, except in the case of slurry pipelines. Slurry pipelines use substantial amounts of water and may affect water availability to other users. Surface water users will have less water than previously available to them or will have to incur additional costs to maintain previous consumptive levels. Water tables may be lowered, resulting in increased costs to other groundwater users.

The manufacture of synthetic fuels from coal can require large quantities of water. Water is needed primarily for cooling, and also as a source of hydrogen in the conversion process. The amount of water consumed in the process depends on the difference between hydrogen/carbon ratios in the coal and in the products. Theoretically, the minimum amount of water to supply this hydrogen in a gasification process is about nine gallons per million BTU. Chemical water requirements for direct liquefaction will be only a fifth or less of the requirements of a gasification process.²

Both conversion plants and thermal electric power generating stations require large quantities of cooling water. Power plants using wet cooling systems utilize more than three times the cooling water required for liquefaction and more than twice the amount required for gasification, per net unit of useful energy produced.

4.2.1.4 Land Productivity

Change in land productivity is a major environmental issue of low-rank coal extraction. Removal of vegetation makes forage, cover, and food unavailable for wildlife. The topsoil is either destroyed in the mining process by mixing with the overburden or its pre-mining level of productivity is reduced at least temporarily. Natural or induced revegetation may occur after mining, but in semi-arid land this process can be a long-term one. Disturbance of natural vegetation and topsoil often allows undesirable exotic species to gain a foothold in competition with native flora. Destruction of vegetation allows accelerated erosion, which can result in siltation of surface streams.

4.2.1.5 Solid Waste Disposal

The issue of solid waste disposal concerns possible contamination of groundwater through leaching from disposal sites. The solid waste consists chiefly of ash and residues from sulfur removal, and from mine

tailings. Leachate from solid wastes generated from low-rank coals development can be highly alkaline and may contain a variety of trace elements. Cumulative volumes produced depend on the choice of fuel and the SO₂ removal method; acreage needed for disposal could be as high as 66 square miles for lignite development in Texas alone.³ The probability of groundwater being contaminated by waste leachate varies from site to site, with the nature of the wastes, and with the pre-disposal treatment.

4.2.1.6 Other Environmental Issues

Other environmental issues which may impact low-rank coal development are concerned with land use priorities, noise pollution, and safety of the general public. Development of low-rank coals will pre-empt large quantities of land from other uses for at least the duration of the extraction or utilization project. Transportation of coal requires permanent right-of-way acquisition for railways, access roads, and pipeline routes. Electric transmission lines require permanent right-of-way, which may limit urban development and some agricultural uses. Noise issues may arise from mining operations such as blasting and hauling, and in transportation of coal and converted coal on unit trains and trucks. Finally, worker and public safety issues will exist in all coal mining, transportation, and utilization areas.

4.2.2 Current Regulatory Constraints

The major Federal legislation that currently imposes constraints on low-rank coal development projects is summarized in Figure 4.2.3 and in the following discussions.

4.2.2.1 Surface Mining Control and Reclamation Act (SMCRA)

The Surface Mining Control and Reclamation Act of 1977 (30 USC 1201) was enacted to ensure effective reclamation of all affected lands. Regulatory authority can be assumed by individual state governments as long as the state imposed regulations meet the minimum requirements established by SMRCA. Applicants must obtain a permit from the regulatory authority prior to any mining operations. As part of the permit application procedure, a reclamation plan must be filed and a performance bond posted to assure the success and completion of the reclamation program.

Figure 4.2.3

Major Regulatory Constraints

	<u>SMCRA</u>	<u>CWA</u>	<u>RCRA</u>	<u>CAA</u>	<u>ESA</u>	<u>TSCA</u>	<u>State Siting Laws</u>
Extraction	X	X	X	X	X		
Transportation			X				X
Preparation & Storage		X	X	X			X
Conversion		X	X	X		X	X
Converted Coal Transportation			X			X	X
Energy Production		X	X	X		X	

SMCRA = Surface Mining Control and Reclamation Act

CWA = Clean Water Act

RCRA = Resource Conservation and Recovery Act

CAA = Clean Air Act

ESA = Endangered Species Act

TSCA = Toxic Substances Control Act

The requirements and specifications of the permitting procedure, reclamation plan, and the performance bond are summarized in the following paragraphs.

1. Permitting (Sec. 506)

- a. An issued permit is valid for a term not to exceed five years.
- b. The permit shall be terminated if the permittee has not commenced mining operations within three years of issuance. With respect to coal mined for a synfuel facility or a "specific major electric generating facility," the mining operations are considered commenced when construction of the synthetic fuel or generating facility is initiated.
- c. Any valid permit can be renewed for the area within the boundaries of the existing permitted operation. Application for renewal shall be made at least 120 days prior to the expiration of the valid permit.
- d. Permits will be granted for mining operations that disturb prime farmland if the regulatory authority finds in writing that the operator has the technical capability to restore such a mined area, within a reasonable time, to equivalent or higher levels of yield as non-mined prime farmland in the surrounding area under equivalent levels of management (Sec. 510).

Permits for surface coal mining in the West (by definition, west of the 100° west meridian longitude) may be denied if the proposed operation will mine alluvial valley floors presently supporting significant agricultural production (Sec. 510). This particular regulation within the Surface Mining Control and Reclamation Act of 1977 could affect more than half of the uncommitted federal lands in the coal-rich area around Gillette, Wyoming, according to a recent internal Bureau of Land Management (BLM) report.⁷

2. Reclamation Plan (Sec. 508)

As part of the permit application, the permittee shall submit a reclamation plan that includes the provisions listed below. These provisions parallel the General Performance Standards of all surface coal mining and reclamation operations as established in Section 515 of SMCRA; the reclamation plan itemizes each action to make sure the permittee addresses every requirement.

The reclamation plan must include:

- a. identification of lands subject to mining operations, and the sequence that individual mine areas will be permitted;
- b. the condition of the land prior to mining operations, covering
 1. existing uses, if any
 2. capability for other possible land uses, including agriculture
 3. a soil survey analysis
- c. the proposed use of the land following reclamation
- d. methods for implementing the post-mining land use
- e. proposed engineering techniques to be used in both mining and reclamation operations, to assure proper drainage, backfilling, grading, and revegetation
- f. the consideration given to maximum coal recovery so as to minimize additional land disturbance
- g. detailed timetable of every major step in the Reclamation plan
- h. the consideration given to making mining and reclamation plans consistent with surface owner plans
- i. compliance with applicable health and safety standards
- j. a description of measures taken to assure to protection of
 1. surface and groundwater quality, both on and off site, from mining and reclamation effects
 2. present water user rights
 3. surface and groundwater quantities.

3. Performance Bonds (Sec. 509).

Performance bonds are required of the mining operators to assure that any surface mining operation will not be terminated prior to the successful completion of the reclamation plan. The amount of the bond shall be sufficient for completion of the reclamation plan if the work had to be performed by the regulatory authority in the event of forfeiture. In no case shall the bond for the entire area under one permit be less than \$10,000.

SMCRA can constrain and in some cases prevent surface mining in certain areas. Much of the land suitable for mining is characterized as arid and frequently the reclamation efforts are extremely difficult or can fail altogether. Recently, the government has been tightening the environmental protection performance standards for reclamation due to failures in the field.

4.2.2.2 Clean Water Act (CWA)

Section 2 of P.L. 92-500, commonly referred to as the Federal Water Pollution Control Act (FWPCA), was amended in 1977, and with other independent provisions, retitled 95-217 (33 U.S.C. Sec. 1251 et seq.), The Clean Water Act (CWA).

The objective of this Act is to restore and maintain the chemical, physical, and biological integrity of the nation's waters. To meet this objective, the Act defines six goals:

1. eliminate discharge of pollutants into navigable waters by 1985;
2. achieve by July 1, 1983, an interim goal of water quality which protects and propagates fish, shellfish, and wildlife, and provides for recreation in and on the water;
3. prohibit discharge of toxic pollutants in toxic amounts;
4. provide federal financial assistance to construct publicly owned waste treatment works;
5. develop and implement areawide waste treatment, management, and planning processes to assure adequate control of pollutant sources in each state;
6. support RD & D efforts to develop technology necessary to eliminate the discharge of pollutants into the navigable waters, waters of the contiguous zone, and the oceans.

The CWA makes it unlawful to discharge any pollutant into navigable waters by any person unless the discharge is in compliance with the Act. The National Pollutant Discharge Elimination System (NPDES) is the permitting system associated with the CWA, and the Environmental Protection Agency (EPA) issues NPDES permits if the discharge meets the requirements of both the EPA and CWA. Applicants must certify that the pending operation applies the best practicable control technology currently available for the control of water pollutant discharges. In the case of discharge into a publicly owned treatment works, the Act requires compliance with any applicable pretreatment requirement.

No license or permit will be granted if the certification has been denied by the regulatory authority. Any person willfully or negligently violating applicable regulations is subject to a fine of \$2,500 to \$25,000 per day of violation, or imprisonment up to one year, or both. Repeat offenders are subject to up to \$50,000 per day of violation and/or two years in prison.

The NPDES permitting authority can be delegated to state agencies if the state program is approved by the EPA.

The CWA requires EPA to establish national standards of performance for point sources of discharge. The standards reflect the application of the best available technology economically achievable which results in further progress towards the national goal of eliminating the discharge of all pollutants. After promulgation of a standard of performance for a certain industry (including steam electric power plants), new sources cannot be operated in violation of the appropriate standard of performance. These standards of performance include thermal discharges.

The EPA has not as yet established standards of performance for synthetic fuel processing. A total package of effluent guidelines will be proposed in the near future.

Non-point sources of pollutants are also regulated by EPA. The EPA must establish guidelines for processes and procedures for control from non-point sources, including:

1. agricultural and silvicultural activities, including runoff from fields and crop and forest lands;
2. mining activities, including runoff and siltation from new, currently operating, and abandoned surface and underground mines;
3. all construction activity, including runoff from the facilities resulting from such construction.
4. the disposal of pollutants in wells or in subsurface excavations;

5. saltwater intrusion resulting from reductions of fresh water flow from any cause including extraction of ground water, irrigation, obstruction, and diversion; and
6. changes in the movement, flow, or circulation of any navigable waters or ground waters, including changes caused by the construction of dams, levees, channels, causeways, or flow diversion facilities. 33 U.S.C.A. Sec. 1314e (Supp. 1977).

The term "runoff" refers to storm or other waters draining from a site in an uncontrolled manner and not normally collected in a pipe or other point source to be discharged into navigable waters.

The CWA requires each state to establish an Areawide Waste Management Plan that identifies areas within a state that, as a result of urban-industrial concentrations, have substantial water quality control problems (Sec. 208). The governor must designate a planning agency to develop an areawide waste treatment plan for each area. The plan must set forth procedures and methods for controlling non-point source pollution, and must contain economic, social, and environmental impact assessments.

The CWA can restrict mining activity in areas where water quality standards are or might be violated. In order to comply with the new source performance standards expensive control procedures and methods are required, which can seriously impact the economics of the project.

4.2.2.3 Resource Conservation and Recovery Act (RCRA)

RCRA was enacted to provide technical and financial assistance for the development of management plans and facilities for the recovery of energy and other resources from discarded materials and for the safe disposal of discarded materials. This includes - and emphasizes - disposal regulation and management of hazardous wastes.

Many questions and ambiguities regarding interpretations of RCRA were resolved in May, 1980, when the EPA released detailed regulations regarding hazardous waste handling. These recent interpretations (19 May, 1980 Federal Register, Vol 45, No.98) clarified "Subtitle C - Hazardous Waste Management," which, when fully implemented, will provide "cradle-to-grave" regulation for hazardous wastes. Generators and transporters of hazardous waste must track such wastes by way of:

1. proper record keeping and reporting
2. a manifest system to track shipments
3. proper labeling and containment
4. delivery to approved treatment, storage, and disposal (TSD) facilities.

RCRA encourages individual states to develop and enforce their own solid waste/hazardous waste programs. The EPA will authorize state programs in lieu of federal authority as long as the state program meets or exceeds the minimum regulations and administrative requirements. Due to the recent development of these regulations, however, EPA does not anticipate many state programs in the immediate future.

The list of hazardous wastes includes several compounds that are by-products of coal conversion facilities. These include phenols, benzene, and certain trace elements. Effluents from coal combustion processes such as fly ash, bottom ash and slag, and flue gas emission control wastes are not listed as hazardous wastes and are therefore exempt from the otherwise required monitoring and permitting activities. Though not considered hazardous, generators of such combustion by-products must still follow proper disposal practices for landfilling and ponding of solid wastes as described in Section 1008 of RCRA.

4.2.2.4 Clean Air Act (CAA)

The Clean Air Act (CAA) Amendments of 1977 establish, among other things, pollutant emission ceilings for new, modified, or reconstructed facilities. These New Source Performance Standards (NSPS) limit emissions of sulfur dioxide (SO₂), particulate matter, nitrous oxides (NO_x), fluorides, hydrogen sulfate (H₂SO₄), and carbon monoxide (CO) from new or modified stationary sources. "Stationary source" means any building, structure, facility, or installation which emits or may emit any air pollutant regulated by the CAA. There are approximately twenty categories of stationary sources identified and covered by the NSPS.

The NSPS announced by EPA in the Federal Register on June 11, 1979 (40 CFR Part 60, Subpart Da), are summarized on Table 4.2.2. These revisions were promulgated in order to meet the purposes of the 1977 amendments to the Clean Air Act. One such purpose was: "The standards to the extent practical must force new sources to burn high-sulfur fuel thus freeing low-sulfur fuel for use in existing sources where it is harder to control emissions and where low-sulfur fuel is needed for compliance". In order to accomplish this purpose the House of Representatives initiated revisions to the Clean Air Act as follows:

1. NSPS must be based on the "best technological" control system. The insertion of the word "technological" precludes a NSPS based solely as the use of low-sulfur fuels.
2. NSPS for fossil-fuel-fired sources must require a "percentage reduction" in emissions, compared to the emissions that would result from burning untreated fuels.

The resulting SO₂ standards will effectively make eastern and midwestern high-rank coals more competitive with low-sulfur, low-rank coals, and therefore could slow the growth of low-rank coal utilization by midwestern electric utilities.

Table 4.2.2

**New Stationary Source Performance Standards
For Electric Utility Steam Generating Units, December 1971 and June 1979**

<u>Pollutant</u>		<u>December 1971 Standards</u>	<u>June 1979 Standards</u>
SO ₂ :	Emission limit	1.2 lb/10 ⁶ BTU	1.2 lb/10 ⁶ BTU (based on a 30-day rolling average)
	Reduction in potential emissions		90% when emissions are 0.6 lb/10 ⁶ BTU or greater 70% when emissions are less than 0.6 lb/10 ⁶ BTU
Particulate Matter:	Emission limit	0.1 lb/10 ⁶ BTU	0.03 lb/10 ⁶ BTU
	Opacity of emission	20%	20% (based on a 6-minute average)
			Based on a 30-day rolling average:
NO _x :	Emission limits	(i) 0.70 lb/10 ⁶ from the combustion of coals except lignite.	(i) 0.50 lb/10 ⁶ BTU from the combustion of subbituminous coal, shale oil, or any solid, liquid, or gaseous fuel derived from coal.
		(ii) 0.80 lb/10 ⁶ BTU from the combustion in a cyclone furnace of any fuel containing more than 25 percent, by weight, lignite which has been mined in North Dakota, or Montana.	(ii) 0.80 lb/10 ⁶ BTU from combustion in a slag tap furnace of any fuel containing more than 25 percent, by weight, lignite which has been mined in N. Dakota, S. Dakota, or Montana.
		(iii) Combustion of a fuel containing more than 25 percent, by weight, coal refuse is exempt from the NO _x standards and monitoring requirements.	(iii) Combustion of a fuel containing more than 25 percent, by weight, coal refuse is exempt from the NO _x standards & monitoring requirements.
		(iv) 0.60 lb/10 ⁶ BTU from the combustion of lignite except as stipulated in (ii) above.	(iv) 0.60 lb/10 ⁶ BTU from the combustion of any solid fuel not specified in (i), (ii), or (iii) above.

- Notes: 1. These standards apply to electric utility steam generating units capable of combusting more than 73 megawatts heat input (250 million BTU/hour) of fossil fuel.
2. A major difference between the December 1971 and June 1979 NSPS is in compliance testing. The June 1979 NSPS require continuous stack monitoring and a 30-day rolling average for the SO₂ and NO_x emissions. The December 1971 required that emission monitoring only be performed at the beginning of plant operation and thereafter when the EPA deemed it necessary.

In addition to source emission standards, the application of state and regional air quality standards can restrict the siting of new stationary sources. The EPA under the Clean Air Act of 1977 set National Ambient Air Quality Standards (NAAQS) to protect public health and welfare. The six contaminants so covered presently are sulfur oxides, suspended particulates, carbon monoxide, oxidants, hydrocarbons, and nitrous oxides. The CAA requires that each state implement its own air quality standards at least as stringent as the NAAQS, and develop regulations for air pollution control. Table 4.2.3 presents the NAAQS that affect coal conversion.

State Implementation Plans (SIP) must provide for the attainment of air-quality standards by certain deadlines. Depending on the geographic and demographic location of pollutant sources, certain areas possess an air quality cleaner than the ambient air quality standards; conversely, some atmospheric areas contain pollutant concentrations above the allowable standards.

For atmospheric areas cleaner than required by ambient standards, SIPs must include a program to prevent the significant deterioration (PSD) of air quality. Depending on the degree of allowable deterioration, areas are classified as Class I, II, III. Class I areas are the most restrictive and are generally national memorials and wilderness areas. The basic intent of the PSD regulations is to keep "clean air clean." This is accomplished by placing limitations on the amount the air quality can be degraded (i.e., increments) above what is termed the "baseline concentration." Baseline concentration is defined as the ambient air quality concentration level reflecting actual air quality as of August 7, 1977, minus concentrations attributable to major PSD sources which commenced construction after January 6, 1975. Table 4.2.4 lists the allowable increments for each air quality classification.

The PSD regulations use a two-tiered analysis which allows for the evaluation of any proposed facilities for potential emissions (first-tier) and allowable (controlled) emissions (second-tier). A source included in the 28 "major emitting facility" source categories having potential emissions of greater than 100 tons/year for one or more pollutants (250 tons/year for those sources outside the 28 source categories) is considered to be a major source. As such, it qualifies for the first-tier review.

A major source under PSD's first-tier review must meet all applicable emission limitations under the State Implementation Plan, and all Federal standards of performance under 40 CFR 60 (NSPS).

To determine whether a source is subject to the second-tier review, it is necessary to ascertain a source's "allowable emissions." The allowable emission rate is calculated using the maximum rated capacity of the source. Air pollution control devices may be taken into account, since they may be required as part of NSPS, part of the SIP, or made a condition

Table 4.2.3

National Ambient Air Quality Standards

Pollutant	Averaging Time	Primary Standard Levels	Secondary Standard Levels
SO ₂	Annual (arithmetic mean)	80mg/m ³ (0.03 ppm)	---
	24 hour*	365mg/m ³ (0.14 ppm)	---
	3 hour*	---	1300mg/m ³ (0.5 ppm)
Particulate Matter	Annual (geometric mean)	75mg/m ³	60mg/m ³
	24 hour*	260mg/m ³	150mg/m ³
NO _x	Annual (arithmetic mean)	100mg/m ³ (0.05 ppm)	100mg/m ³ (0.05 ppm)

*Not to be exceeded more than once per year

Table 4.2.4

New Prevention of Significant Deterioration of Air Quality
Increments and Ceilings
Clean Air Act Amendments of 1977

Pollutants	Maximum Allowable Increase ^a (in micrograms per cubic meter)		
	Class I	Class II	Class III
Particulate Matter			
Annual Geometric Mean	5	19	37
24-Hour Maximum	10	37	75
Sulfur Dioxide			
Annual Arithmetic Mean	2	20	40
24-Hour Maximum	5	91	182
3-Hour Maximum	25	512	700

^aMaximum allowable increases over baseline concentrations not to be exceeded more than once per year.

of the EPA permit.

Sources whose "allowable emission rate" is greater than 50 tons/year, 1000 pounds/day, or 100 pounds/hour, whichever is the most stringent, are then subject to the second-tier review. Any source falling below these allowable emission rates would then be granted a permit under PSD, and allowed to construct.

Sources subject to the second-tier review must apply "Best Available Control Technology" (BACT) for each applicable pollutant and undergo an air quality analysis. BACT means an emission limit or control technology representing the maximum degree of reduction with respect to a particular source and pollutant, taking into account: energy, environmental and economic impacts, and technical feasibility. This determination is made by EPA, but demonstration made by the applicant will be considered.

Such demonstrations must follow the Guidelines for BACT, published by the EPA, and must evaluate the type of technologies which are available for the type of source and pollutant under consideration. Since various technologies are undergoing continual development, it follows that projects in the future may be required to meet more stringent emission limits or use more advanced control equipment, as determined by the EPA.

BACT is to be determined on a case-by-case basis rather than automatically applying a Federal New Source Performance Standard (NSPS), as was the case under the previous regulation. The Act places the responsibility of determining BACT with the state once an acceptable SIP is approved. Determination of BACT is based on environmental and economic impacts and other costs associated with application of alternate control systems. Congress implied that the state would determine the relative weight given to each type of impact.

It is important to note that the allowable emission rate does not take into account emission offsets. That is, if a source causes emission reductions at some of its facilities, resulting in the net emissions falling below 50 tons/year, this would not necessarily exempt the source from the second-tier review. The allowable emission rate is examined in light of the new or modified facility only. However, if an emission offset is achieved that results in zero emissions, or results in an emission decrease, an air quality analysis would not be required, and in specific instances, the BACT requirement would be dropped.

BACT exemptions occur only if (1) a zero increase (or a net decrease) occurs at the source itself and (2) the facilities in question are not new or are to be reconstructed.

A reconstructed facility is one whose modification costs exceed 50 percent of the capital cost for a comparable new facility. Thus, for sources which are being modified, and for which zero increase or a net decrease will occur, BACT will not be required. For new or reconstructed facilities, BACT will be required regardless of the offsets achieved.

If after application of BACT, the pollutant levels are greater than the second-tier cut-off levels, an air quality analysis must be performed. Like EPA's former New Source Review regulations, (which PSD has in large part replaced), the PSD regulations require that a source demonstrate that no violations of the NAAQS for NO₂, CO and HC will occur. For SO₂ and particulate matter, it is necessary to demonstrate that the concentrations attributable to the source do not exceed the increments for the particular Class for the area in which the project would be located.

Concentration predictions are accomplished through the use of air quality models. The EPA requires that sources include details of modeling analyses in the evaluation of the projected impacts. They also require that any models used for evaluating impacts for a PSD permit shall be EPA approved.

It should be pointed out that these regulations are pollutant specific. That is, the regulations apply only for those pollutants whose emissions are greater than the designated cut-off rates mentioned above. For example, a petroleum refinery might have potential emissions of sulfur dioxide of approximately 120 tons/year, while all other pollutants might be below 100 tons/year. In such an instance, the source is subject to PSD review only for SO₂. Similarly, for sources outside of the 28 source categories, PSD review applies only for those pollutants which exceed 250 tons/year potential emissions. In areas that are already over standard, SIPs must indicate that these areas are on a program of eventual compliance. The initial review of a proposed major emitting facility in a non-attainment area requires evaluation of potential emissions. No further review is required if the source demonstrates that maximum potential emissions are less than 100 tons/year. This must apply to any criteria pollutant before the application of any control technology. In the event that the source exhibits the potential to emit 100 tons/year or more of any criteria pollutant the interpretive ruling applies (Federal Register 21 December 1976). This review step establishes the basic criteria for the maximum allowable emission rate not to exceed 50 tons/year. No further review is required if this criteria is satisfied after the application of control technology. On the other hand, "Lowest Achievable Emission Rate" (LAER) technology must be utilized for the particular pollutants that cannot attain the 50 ton/year limit after application of standard control technology. Additionally, emission offsets must be obtained in order to ensure that there is a positive net gain toward achieving the primary air quality standards.

LAER, like BACT, is considered on a case-by-case basis. However, energy, environmental, and economic impacts are not considered in the technology selection. LAER is selected from proven, state-of-the-art systems which provide the highest pollutant removal efficiencies under the proposed operating conditions.

The EPA has recently drafted proposed revisions to their PSD

regulations as well as to the Interpretative Ruling. These proposed regulations were published in the 5 September 1979 Federal Register. The proposed changes to these regulations resulted from a court opinion issued by the U.S. Court of Appeals for the District of Columbia Circuit on 18 June 1979. The Court ruled on a number of actions brought against EPA by both industry and environmental groups. These groups contested specific sections of the final PSD regulations which were published on 19 June 1978.

The only regulations affected by the Court's decision are the PSD regulations. However, the EPA is also proposing to revise the Interpretative Ruling (IR). This is because several of the Clean Air Act definitions and other concepts addressed in the court case (Alabama Power) are also relevant to the Clean Air Act requirement of non-attainment areas.

In the new regulations, the definition of potential emissions now may take into account air pollution control equipment, where before it did not. Thus, many new sources will be able to "get under" the cut-offs imposed by PSD and IR. Also, the PSD regulations are "source specific" rather than pollutant specific. That is, if one pollutant is greater than the applicable 100/250 tons/year potential emission cut-off, this acts as a trigger which would subject all pollutants emitted by the source in significant amounts to PSD review. PSD would thus apply even for non-attainment pollutants. What this would mean for such pollutants is, in general, monitoring. The IR will remain pollutant specific.

Although the regulation does not define "significant increase," the background discussion of the PSD regulations provides a listing of guideline De Minimis cut-off levels for all pollutants regulated under the Act (see Table 4.2.5). These would be used for determining what is significant net increase. Further, De Minimis significance levels for ambient concentrations have also been provided (See Table 4.2.6) and are designed to determine whether a full-blown modeling effort is necessary for pollutants emitted in significant but "non-major" amounts (i.e., greater than the De Minimis emission level, but less than the 100/250 tons/yr cut-off). If initial screening models indicate that concentrations fall below the De Minimis concentration levels, EPA will require no further modeling.

The definition of "modification" is also more stringent. These regulations would subject changes in the design or operation of a major stationary source to PSD or the IR if there is a "significant net increase" in the potential emissions of a pollutant for which the source is major.

In determining increases from modifications the new PSD regulations now allow for consideration of emission decreases occurring within the facility. This "bubble concept" enables facilities with multi-process pollutant sources to offset unavoidable increases from one source with an equivalent reduction at another. If there is no net pollutant increase from the facility as a whole, there is technically no modification and the source would not be subject to review. There are, however, certain restrictions. A facility with a state-approved bubble plan may offset only

Table 4.2.5

Guidelines for Significant Emission Rates
Proposed PSD Regulations - September 5, 1979

<u>Pollutant</u>	<u>Emission Rate</u>
Carbon Monoxide	100 tons per year
Nitrogen Dioxide	10 tons per year
Total Suspended Particulates	10 tons per year
Sulfur Dioxide	10 tons per year
Ozone	10 tons per year of volatile organic compounds
Lead	1 ton per year
Mercury	1 ton per year
Beryllium	0.004 ton per year
Asbestos	1 ton per year
Fluorides	0.02 ton per year
Sulfuric Acid Mist	1 ton per year
Vinyl Chloride	1 ton per year
Total Reduced Sulfur	
Hydrogen Sulfide	10 tons per year
Methyl Mercaptan	10 tons per year
Dimethyl Sulfide	10 tons per year
Dimethyl Disulfide	10 tons per year
Reduced Sulfur Compounds	
Hydrogen Sulfide (see above)	
Carbon Disulfide	10 tons per year
Carbonyl Sulfide	10 tons per year

Table 4.2.6

Guidelines for Significant Ambient Air Quality Impact
Proposed PSD Regulations-September 5, 1979

<u>Pollutant</u>	<u>Air Quality Impact</u>
Carbon Monoxide	500 $\mu\text{g}/\text{m}^3$, 8-hour average
Nitrogen Dioxide	1 $\mu\text{g}/\text{m}^3$, annual
Total Suspended Particulates	5 $\mu\text{g}/\text{m}^3$, 24-hour
Sulfur Dioxide	5 μm^3 , 24-hour
Ozone	-- a
Lead	.03 $\mu\text{g}/\text{m}^3$, 3-month
Mercury	0.1 $\mu\text{g}/\text{m}^3$, 24-hour
Beryllium	.005 $\mu\text{g}/\text{m}^3$, 24-hour
Asbestos	1 $\mu\text{g}/\text{m}^3$, 24-hour
Fluorides	.01 $\mu\text{g}/\text{m}^3$, 24-hour
Sulfuric Acid Mist	1 $\mu\text{g}/\text{m}^3$, 24-hour
Vinyl Chloride	1 $\mu\text{g}/\text{m}^3$, maximum value
Total Reduced Sulfur	
Hydrogen Sulfide	1 $\mu\text{g}/\text{m}^3$, 1-hour
Methyl Mercaptan	.5 $\mu\text{g}/\text{m}^3$, 1-hour
Dimethyl Sulfide	.5 $\mu\text{g}/\text{m}^3$, 1-hour
Dimethyl Disulfide	2 $\mu\text{g}/\text{m}^3$, 1-hour
Reduced Sulfur Compounds	
Hydrogen Sulfide (see above)	
Carbon Disulfide	200 $\mu\text{g}/\text{m}^3$, 1-hour
Carbonyl Sulfide	200 $\mu\text{g}/\text{m}^3$, 1-hour

^a No de minimis air quality level is proposed for ozone. However, any net increase of 100 tons per year of volatile organic compounds subject to PSD would require the performance of an ambient impact analysis, including the gathering of ambient air quality data.

pollutants of the same type; thus, it may not exchange reduced sulfur oxide emissions from one source for reduced hydrocarbon emissions from another source within the plant. Further, control of non-hazardous emissions may not be traded for control of hazardous pollutants.

Offset capacities can be traded between different plants in the same area as long as the trade involves the same pollutant.

The various requirements of the Clean Air Act may, in some cases, constrain the development of low-rank coals. First, a company must pay the cost penalties associated with emission limitations and the establishment of baseline data for PSD requirements. Then, it must either satisfy the PSD requirements in attainment areas or obtain offsets in non-attainment areas. Many companies may be unwilling to sell offsets to other companies since that could stop their own projected growth. This will tend to penalize small utilities or industries, or those which might move into an area. The large existing utilities or industries, in an area will tend to have a greater ability to add new capacity, by reducing emissions from their own existing facilities.

4.2.2.5 Endangered Species Act

The purpose of the Endangered Species Act is to conserve ecosystems of endangered or threatened plant and wildlife species. These species are identified on a list published by the Secretary of the Interior at least once every five years. The Act specifically forbids the importation or exportation of any of the species identified in any manner. The Act further prohibits any development that would "impact" an endangered or threatened species. Impact is defined here as a reduction in food supply or available water, a reduction in habitat cover, or any physical changes, which can result in toxicological effects.

The major impact to an industrial applicant, occurs when an endangered species is identified on site once a project is well under way. Since the particular species cannot, without Congressional action, be moved, projects must be stopped or may be significantly delayed while resolution of the problem is sought. Economic considerations can be staggering should projects be discontinued or slowed at late stages of development.

4.2.2.6 Toxic Substances Control Act (TSCA)

The Toxic Substances Control Act regulates the manufacture, processing, distribution, use and disposal of a list of priority pollutants specified by the U.S. Environmental Protection Agency. The list is shown on Table 4.2.7. The EPA administrator can:

1. require a prohibition of the manufacture, processing, or distribution of any substance on the list;

Table 4.2.7
Priority List of Toxic Substances

Acenaphthene	Bis(2-chloroethoxy) methane	Tetrachloroethylene
* Acrolein	Methylene chloride (dichloro- methane)	* Toluene
Acrylonitrile	Methyl chloride (chloromethane)	Trichloroethylene
* Benzene	Methyl bromide (bromomethane)	Vinyl chloride (chloroethylene)
Benzidine	Bromoform (tribromomethane)	Aldrin
* Carbon tetrachloride (tetrachloro- methane)	Dichlorobromomethane	Dieldrin
* Chlorobenzene	Trichlorofluoromethane	Chlordane (technical mixture and metabolites)
* 1,2,4-Trichlorobenzene	Dichlorodifluoromethane	4,4'-DDT
* Hexachlorobenzene	Chlorodibromomethane	4,4'-DDE (p,p' - DDX)
* 1,2-Dichloroethane	Hexachlorobutadiene	4,4'-DDD (p,p' - TDE)
* 1,1,1-Trichloroethane	Hexachlorocyclopentadiene	α -Endosulfan
* Hexachloroethane	Isophorene	β -Endosulfan
* 1,1-Dichloroethane	* Naphthalene	Endrin
* 1,1,2-Trichloroethane	Nitrobenzene	Endrin aldehyde
* 1,1,2-Tetrachloroethane	2-Nitrophenol	Endrin ketone
* Chloroethane	4-Nitrophenol	Heptachlor
* Bis(Chloromethyl) ether	2,4-Dinitrophenol	Heptachlor epoxide
* Bis(2-chloroethyl) ether	4,6-Dinitro-o-cresol	α -Hexachlorocyclohexane
* 2-Chloroethyl vinyl ether (mixed)	* N-nitrosodimethylamine	β -Hexachlorocyclohexane
2-Chlorohaphthalene	* N-nitrosodiphenylamine	γ -Hexachlorocyclohexane (lindane)
* 2,4,6-Trichlorophenol	* N-nitrosodi-n-propylamine	δ -Hexachlorocyclohexane
4-Chloro-m-cresol	* Pentachlorophenol	* Polychlorinated biphenyl (Arochlor 1242)
* Chloroform (trichloromethane)	* Phenol	* Polychlorinated biphenyl (Arochlor 1254)
* 2-Chlorophenol	Bis(2-ethylhexyl) phthalate	Toxaphene
* 1,2-Dichlorobenzene	Butylbenzyl phthalate	* Antimony (total)
* 1,3-Dichlorobenzene	Di-n-butyl phthalate	* Arsenic (total)
* 1,4-Dichlorobenzene	Diethyl phthalate	* Asbestos (fibro)
3,3-Dichlorobenzidine	Dimethyl phthalate	* Beryllium (total)
1,1-Dichloroethylene	1,2-Benzanthracene	* Cadmium (total)
1,1-Trans-dichloroethylene	3,4-Benzopyrene	* Chromium (total)
* 2,4-Dichlorophenol	3,4-Benzofluoranthene	* Copper (total)
1,2-Dichloropropane	11,12-Benzofluoranthene	* Cyanide (total)
1,3-Dichloropropylene (1,3-Dichloro- propene)	Chrysene	* Lead (total)
2,4-Dimethylphenol	Acenaphthylene	* Lead (total)
2,4-Dinitrotoluene	* Anthracene	* Mercury (total)
2,6-Dinitrotoluene	1,12-Benzoperlyene	* Nickel (total)
1,2-Diphenylhydrazine	Fluorene	* Selenium
Ethylbenzene	* Phenanthrene	* Silver (total)
Fluoranthene	1,2,5,6-Dibenzanthracene	* Thallium (total)
4-Chlorophenylphenyl ether	Indeno(1,2,3-c,d) pyrene	* Zinc (total)
4-Bromophenylphenyl ether	Pyrene	* Vanadium (total)
Bis-(2-chloroisopropyl) ether	2,3,7,8-Tetrachlorodibenzo-p- dioxin (TCDD)	* Ethylenediaminetetraacetate (EDTA)

*Substances most likely to be present in utility effluents based on preliminary data and literature survey.

Source: Reference 8

2. limit the total amount (or concentration) of the toxic substance that can be manufactured, processed or distributed;
3. require warning labels;
4. require complete records of manufacturing and processing;
5. regulate the use of disposal.

These requirements impact most industrial facilities. Since toxic substances can be present in power plant effluents, there will be heavy restrictions and careful documentation required.

The TSCA empowers EPA to inspect any facility producing, processing, or distributing chemical substances. Such an inspection requires written notice to the facility operator; a separate notice is required for each inspection, but not for each entry made during the time period covered by the inspection.

Any person who violates the requirements and regulations of TSCA is liable for a civil penalty up to \$25,000 per day of violation. In addition, criminal charges may be imposed as a fine up to \$25,000 per day of violation, or imprisonment for up to one year.

Synthetic fuel processes produce source by-products that require monitoring under the TSCA regulations. For example, coal gasification liquor effluents contain high concentrations of tars, oils, phenols, naphthas, sulfur and nitrogen compounds, and dissolved solids. Liquefaction processes create a sour water by-product containing ammonia, hydrogen sulfide, and dissolved organics such as phenols and cresols. For the major identified pollutants, commercial control technology is available, yet costly.

4.2.2.7 Federal Energy Regulatory Commission (FERC)

The FERC rules on an application for a Certificate of Public Convenience and Necessity. The certificate determines the allowable method for financing the project (i.e., its economic viability) based on a tariff regulating the terms of the product sale. The FERC process can be both time consuming and expensive, as illustrated by the example of the North Dakota Gasification facility. Complete economic and environmental studies are required as well as extensive hearings by the FERC.

4.2.2.8 National Environmental Policy Act (NEPA)

NEPA requires that any Federal action which will significantly affect the environment must be evaluated through an EIS. Construction and operation of a facility by a utility is not a significant Federal action; however, the issuance of a FERC certificate of convenience and necessity is

a significant Federal action. Hence, an EIS will almost always be required. However, the identification of significant impacts to various environmental parameters does not mean that a facility cannot be built. The EIS can be thought of as an environmental accounting system whereby the public is informed of the environmental costs of a proposed action. No quantitative standards of pollution control have to be met for the EIS to be completed. The EIS process will develop in the 1980's as part of the preconstruction review process. It will begin to encompass broader perspectives including the possible regional environmental impact of the plant and its system, including: 1) impact on long-range transport, acid deposition, and visibility degradation hundreds of miles away, 2) impact on CO₂ concentration, and 3) inventory of all toxic pollutants coming from the plant. The EIS will provide basic data on the plant and will complement and supplement on-line environmental and energy systems.

4.2.2.9 Occupational Safety and Health Act (OSHA)

OSHA places limits on the exposure of workers to the following:

1. Carcinogens
2. Noise
3. Vibration
4. Heat
5. Dust
6. Fumes
7. Danger from explosives

Properly designed and operated facilities should not be greatly affected by these regulations. In coal liquefaction plants, exposure of workers to possibly carcinogenic liquids will have to be carefully controlled.

4.2.2.10 Mine Safety and Health Act of 1977 (MSHA)

The purpose of MSHA is to promote health and safety standards in the coal mining industry. The Department of Labor can inspect any interstate coal mining operation to insure that mining is done in a safe manner. Under this Act, coal miners can refuse to work where he (she) believes he (she) could be killed or seriously injured, and remain immune to firing or discrimination from the employer. This walkaway provision is not contained in the legislation that set up OSHA.

Although MSHA was originally enacted to protect underground coal miners, it applies equivalent regulatory authority to surface coal mining activities.

4.2.3 State Environmental Regulations

In order to assess the environmental regulations that might constrain or impede the increased future utilization of low-rank coal, a survey of the regulations of 22 selected states was performed.^a These states were chosen for their present, planned, and/or potential use of low-rank coal. Information concerning each state's regulations and standards for reclamation air quality, water quality, and solid waste disposal was compiled and analyzed for differences. Few of the states contacted had specific regulations for coal gasification and liquefaction. Those states that had handled or were handling such plants treated them as conventional coal-fired plants and/or on a case-by-case basis.

4.2.3.1 Mined Land Reclamation Requirements

A large portion of the land underlain by strippable coal deposits is owned by the federal government. Federal laws have been passed to regulate reclamation on land subject to federal coal leases. Where state laws are in conflict with federal laws regarding reclamation requirements, the conflicts are resolved by the principle that the more stringent laws shall prevail. The progression of state legislation and administrative action runs from "acts" to "rules and regulations" to "technical guidelines" (see Table 4.2.8). Montana and Wyoming, as yet, are the only states which have completed this progression.

Table 4.2.9 presents the required actions and standards set in the state mined land reclamation programs. All states with reclamation laws follow a similar procedure in examining a mine operator's credentials and plans, and in requiring a surety bond before a permit is issued. Differences exist in some specifics such as time periods for renewal, number and amount of bonds, and information required for licensing. To safeguard against forfeiture, state agencies in Colorado, Montana, South Dakota and Wyoming have set bonding fees at a level to cover expected reclamation costs. In other states, except Arizona, the bonding amounts and release times are left to the discretion of the enforcement agencies. Colorado, Montana, and Wyoming also apply bonding requirements to exploration disturbance.

Most states have detailed specifications for handling and conserving topsoil, backfilling, and grading spoils, meeting slope requirements and handling toxic or waste materials. States also usually have regulations for air, water, and noise pollution and aesthetic degradation

^aThis survey was conducted mainly by telephone during the month of August 1980. Appropriate personnel in each of the state offices which were responsible for the air and water quality and solid waste disposal programs were interviewed. (A list of those personnel is available upon request.)

Table 4.2.8
State Mined Land Reclamation Programs in the West

Page 1 of 2

Subregion and State	State of program development			Title of act(s) (year effective)	Administering agency(ies)	State Law	
	Act(s)	Rules and Regulations	Technical Guidelines			Mineral or Commodity Covered	Rules vary by mining method
Northern Great Plains							
Montana	X	X	X (Partial)	(1) Montana Strip & Under- ground Mine Reclamation Act (1973), (2) Open Cut Mining Act (1973), and (3) Montana Hard-Rock Mining Reclamation Act (1971); amended 1974-75	Dept. of State Lands	Act (1) Coal and uranium Act (2) bentonite, clay, phosphate rock, scoria, and sand and gravel; Act (3) other minerals	--
North Dakota	X	X	--	North Dakota Century Code; Reclamation of Strip-Mined Land (1969), amended 1971, 1973, 1975	Public Service Commission	Coal	--
South Dakota	X	X	--	Surface Mining Land Reclamation Act (19710, as amended 1973-76	Dept. of Agriculture	All minerals	--
Wyoming	X	X	X (Partial)	Wyoming Environmental Quality Act (1973); amended 1974-75	Dept. of Environmental Quality	All minerals	Rules vary by soft rock mining or hard rock mining
Rocky Mountain							
Colorado	X	X	--	Colorado Mined Land Recla- mation Act (1973) as amended (1976)	Mined Land Reclamation Board, Dept. of Natural Resources	All minerals excluding oil, gas, and geothermal	--

Continued--

Table 4.2.8 (Continued)

State Mined Land Reclamation Programs in the West

Page 2 of 2

Subregion and State	State of program development			Title of act(s) (year effective)	Administering agency(ies)	State Law	
	Act(s)	Rules and Regulations	Technical Guidelines			Mineral or Commodity Covered	Rules vary by mining method
Rocky Mountain continued							
New Mexico	X	X	--	New Mexico Coal Surface Mining Act (1972)	Bureau of Mines and Minerals	Coal	--
Utah	X	X	--	Utah Mined Land Reclamation Act (1975)	Board and Division of, Oil, Gas and Mining, Dept. of Natural Resources	All minerals excluding geothermal, oil, and gas	--
Arizona	The State of Arizona applies standard reclamation requirements to State lands as a condition of mineral leases. Arizona also contains Federal lands where reclamation requirements are a condition of mineral leases. Some local units of government use land-use controls (such as zoning) and activity permits (such as minerals proceeding) to encourage reclamation. In the absence of State law, Federal lands are subject to Federal regulations.						
Pacific							
Washington	X	X	--	Surface-Mined Land Reclamation Act (1970)	Dept. of Natural Resources	All minerals	Quarries are handled as special cases
Alaska	Mining in the State of Alaska is on Indian, Federal and/or State lands; case-by-case State regulatory decisions and/or Federal coal leasing regulations apply.						

Source: Reference 10

Note: -- = no specific treatment of the topic in the acts, although the subject may be addressed in regulations, administrative orders, or in extant professional practices of that State.

X = a requirement or program element exists.

Table 4.2.9

Actions Required and Standards Set in State Mined Land Reclamation Programs, July 1977

Subregion and State	Reclamation Bonding 1/ Amount	Release Time	Reclamation of Exploration Disturbance	Control of water flow and quality	Conserve and Replace Topsoil	Backfill and Grade	Reduce Highwall or Pitwall	Bury or Neutralize Toxic Wastes	Revegetate for Beneficial Use	Other Rules or Remarks
Northern Great Plains										
Montana	Not less than \$200 per acre with \$2,000 minimum. Based on estimate of Reclamation costs.	Partial release upon approval of department; bond will not be released prior to 5 years from initial planting.	As soon as possible. Topsoil removal required for prospecting activities. May require planting of annual crop to control erosion.	Act (1) specific criteria, e.g.--pH range of 6. to 9.	Removal of stockpiling precede each step of operation. Topsoil removal required for prospecting activities.	Act (1) grade to < 20%, within 90 days after department has determined the operation	Slope of face will be < 20 percent.	Act (1), backfill with 8 feet of overburden. Soil and overburden analyses required.	Suitable, permanent, diverse and primarily native species.	Effluent standards conform with criteria of State Dept. of Environmental Sciences.
North Dakota	\$1,500 for each acre affected. (Minimum)	5 years after termination of permit; partial release may be affected for separate tasks.	X	X	Replace all available plant growth material, up to 5 feet of thickness.	Approximate original contour, or serve approved end use.	Slope of face will be $\leq$ 35 percent.	Requires pH, sodium adsorption ratio electrical conductivity texture (by feel).	X	Remedy any impairment to domestic or livestock water supply.

See footnote at end of table.

Continued--

Table 4.2.9 (Continued)

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Actions Required and Standards Set in State Mined Land Reclamation Programs, July 1977

Subregion and State	Reclamation Bonding 1/ Amount	Release Time	Reclamation: cf Exploration Disturbance	Control water flow and quality	Conserve and Replace Topsoil	Backfill and Grade	Reduce Highwall or Pitwall	Bury or Neutralize Toxic Wastes	Revegetate for Beneficial Use	Other Rules or Remarks
Northern Great Plains continued										
South Dakota	An amount sufficient to cover the costs of reclamation.	Upon approval of department.	X	X	X	"Achieve contour most beneficial to the proposed land use."	Slope will be $\leq 14^\circ$.	With 8 feet of topsoil or suitable overburden.	To create self-regenerative growth without irrigation.	Noxious weeds must be controlled.
Wyoming	Amount equal to estimated cost of reclaiming affected land. In no event will bond be less than \$10,000 issued annually.	75 percent may be released upon completion. Minimum balance of \$10,000 held for an additional 5 years.	Must meet with approval of administrator.	X	Topsoil unless non-existent; protect from erosion and toxicity, use most suitable plant growth minerals.	Approximate original contour; terrace; or serve approved end use.	Stabilize slope; minimize effect on landscape.	X	X	Delay mining for archeological or paleontological surveys; reclaim according to approved plans.

See footnote at end of table

Continued--

Table 4.2.9 (Continued)

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Actions Required and Standards Set in State Mined Land Reclamation Programs, July 1977

Subregion and State	Reclamation Bonding 1/ Amount	Release Time	Reclamation: of Exploration Disturbance	Control water flow and quality	Conserve and Replace Topsoil	Backfill and Grade	Reduce Highwall or Pitwall	Bury or Neutralize Toxic Wastes	Revegetate for Beneficial Use	Other Rules or Remarks
Rocky Mountain Colorado	:Depends upon type, costs and extent of reclama- tion acti- vities, posted before prospect- ing; maxi- mum \$2,000 per acre, \$25,000 for State- wide pros- pecting.	Upon approval of board.	Upon approval of board. Bonding re- quired.	X	X	Final con- tour appropriate to selected land use.	--	X	Diverse, permanent vegetative cover capa- ble of re- vegetation, and at least equal in extent as surround- ing area.	Exemptions are ob- tained for areas un- suitable (infeasi- ble) for corrective actions, each phase must be completed 5 years after initiation.

See footnote at end of table

Continued--

Table 4.2.9 (Continued)

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Actions Required and Standards Set in State Mined Land Reclamation Programs, July 1977

Subregion and State	Reclamation Banding 1/ Amount Release Time		Reclamation: of Exploration Disturbance	Control water flow and quality	Conserve and Replace Topsoil	Backfill and Grade	Reduce Highwall or Pitwall	Bury or Neutralize Toxic Wastes	Revegetate for Beneficial Use	Other Rules or Remarks
Rocky Mountain continued										
New Mexico	Required at the discre- tion of the Commis- sion.	Upon approval of the Commission.	--	X	--	Topography will be "gently undulating" or consis- tent with proposed end use.	--	--	To serve selected end use.	--
Utah	Depends up- on type, extent and costs per se not required; no maximum or minimum.	Upon approval of department.	X	X	--	X (Where practical.)	--	X	X .. (Priority to non- noxious, native species.)	Program implemen- tation recognizes site speci- fic (unique) conditions.
Arizona	No State law (Federal regulations apply).									

See footnote at end of table.

Continued--

Table 4.2.9 (Continued)

Page 5 of 5

Actions Required and Standards Set in State Mined Land Reclamation Programs, July 1977

Subregion and State	Reclamation Bonding 1/ Amount	Release Time	Reclamation: of Exploration Disturbance	Control water flow and quality	Conserve and Replace Topsoil	Backfill and Grade	Reduce Highwall or Pitwall	Bury or Neutralize Toxic Wastes	Revegetate for Beneficial Use	Other Rules or Remarks
Pacific										
Washington	Required at the discre- tion of depart- ment, no maximum or minimum.	Upon approval of department.	--	X	--	Conform to surrounding land area.	Grade of well < 66 per- cent. (uncon- solidated) and < 45 percent (rock).	With 2 feet of clean fill.	X	Other state regulations apply to water rights, flood plains, and fish and wild- life.
Alaska	No State law (Federal regulations apply).									

Source: Reference 10

Note: -- = no specific treatment of the topic in the acts, although the subject may be addressed in regulations, administrative orders, or in extant professional practices of that State.

X = a requirement or program element exists.

1/ In addition to bonding, various fees for licensing and mining permits are levied on the mine operator. Since the fees are nominal, they are omitted.

of the landscape. Revegetation and reclamation guidelines in the arid western states are fairly flexible and left open to the interpretation of the enforcing agencies because of the dearth of information concerning the time periods required for revegetation in such conditions. Montana's more stringent reclamation laws, however, have been more specific in requiring that reclamation include the establishment of "primarily native species".¹⁰

4.2.3.2 Air Quality Regulations

A comparison of the state air quality regulations and standards is presented in Table 4.2.10. (The federal air quality regulations were presented in Tables 4.2.3, 4.2.4, and 4.2.5.)

Those states which have ambient air quality standards that are significantly different from or are more stringent than the National Ambient Air Quality Standards are:

SO₂: CA, MN, MT, NM, ND, TX, WA, WY

PM : CA, MT, TX

NO_x: CA, ND, SD

The most stringent state standards appear to be California's SO₂ standard of 131 mg/m³ (24 hour average) and Texas' particulate matter standard of 100 mg/m³ (5 hour average).

The states with the most stringent NSPS are CA, CO, WY which require BACT on all new sources. Of those states with approved PSD programs only North Dakota was found to have more stringent increments than the federal PSD regulations: Class II areas - Particulate matter, annual = 10 mg/m³, 24 hour = 30 mg/m³; SO₂, annual = 15 mg/m³

4.2.3.3 Water Quality Regulations

Under the provisions of the Clean Water Act, any discharge must be permitted through the National Pollutant Discharge Elimination System (NPDES). This permitting system may be administered by a state upon approval by the EPA. Sources of discharge are required to at least meet the criteria of the NPDES permit and may also have to meet the state regulations if the state is not administering the NPDES. Some states have more stringent regulations (depending on stream classification) than the NPDES, which would also have to be met. Those states which have NPDES permitting authority are: CA, CO, MN, ND, and WA.

The federal regulations regarding thermal discharges are non-specific and essentially leave that authority to the states. Hence, there is a great deal of difference among the states on the issue of thermal discharges.

Table 4.2.10

State Air Quality Regulations, August 1980

Page 1 of 6

State	Ambient Air Quality Standards			PSD	NSPS	Special Considerations
	SO ₂	Particulate Matter	NO _x			
Arizona	Same as both levels	annual = 75mg/m ³ 24 hr = 150mg/m ³	same ²	Adopted EPA regulations; in approval process	Currently outdated; plans to adopt regulation similar to federal NSPS	
Arkansas	same	same	same	In technical review process	same ³	
California	24 hr = 60mg/m ³ 1 hr = 1310mg/m ³	annual = 60mg/m ³ 24 hr = 100mg/m ³	1 hr = 0.25 ppm	In program development process	BACT required on all new sources. In general, more stringent than federal NSPS.	For a coal plant being permitted in the San Francisco Bay Area, BACT was defined as 95 percent flue gas control for SO ₂ , 0.005 lb/MMBTU for particulate matter (equivalent to 99.9+ percent control); and 0.15 lb/MMBTU for NO _x (pushing for selective catalytic reduction).

Table 4.2.10 (Continued)

State Air Quality Regulations, August 1980

Page 2 of 6

State	Ambient Air Quality Standards			PSD	NSPS	Special Considerations
	SO ₂	Particulate Matter	NO _x			
Colorado	same as both levels	same as both levels	same	In approval process	(4)	State is permitting facilities in non-attainment (NA) areas. (EPA is presently permitting in attainment areas.) Therefore, since some state NO _x standards are less stringent than the EPA standards, the state would request that operators building in the NA areas to voluntarily comply with the EPA standards. After the state gets PSD program approval this situation should be remedied
Idaho	same	same	same	In program development process.		Similar to federal standards, but applied on a case-by-case basis and, hence, can be more stringent. BACT required on all new units. Max. coal sulfur content of 1 percent. (5)

Table 4.2.10. (Continued)

State Air Quality Regulations, August 1980

Page 3 of 6

State	Ambient Air Quality Standards			PSD	NSPS	Special Considerations
	SO ₂	Particulate Matter	No _x			
Illinois	same	same	same	Approved program	Same except for CO regulation: 200 ppm corrected to 50 percent excess air for boilers of more than 10 MMBTU/hr.	
Kansas	same	same	same	No program development yet.	Federal standards are more stringent than state standards.	
Louisiana	same as both levels	same as both levels	same	No program development yet.	same	
Minnesota	annual = 60 mc/m ³ 24 hr = 0.1 ppm 3 hr = 0.25 ppm	same	same	Approved program	same	Claim is that state PSD program is quicker than the EPA program
Missouri	same as secondary levels	same as secondary levels	same	In approval process	same	
Montana	annual = 0.02 ppm 24 hr = 0.10 ppm ⁽⁶⁾ 1 hr = 0.25 ppm ⁽⁷⁾	annual = 75 mg/m ³ 24 hr = 200 mg/m ³ ⁽⁸⁾	same	In approval process	same	
Nebraska	same	same	same	Approved program	same	
Nevada	same	same as secondary levels	same	In program development process.	same	

Table 4.2.10 (Continued)

State Air Quality Regulations, August 1980

Page 4 of 6

State	Ambient Air Quality Standards			PSD	NSPS	Special Considerations
	SO ₂	Particulate Matter	No _x			
New Mexico	annual = 0.02 ppm 24 hr. = 0.1 ppm	same as secondary levels	same	In approval process.	Same except SO ₂ standard: 0.34 lb/MMBTU	
North Dakota	annual = 60mg/m ³ 24 hr. = 260mg/m ³ 1 hr. = 715mg/m ³	same as secondary levels	annual = 100mg/m ³	Approved program. More stringent increments.	Same	PSD increments Class II areas: SO ₂ : annual = 15mg/m ³ 24 hr. = 91mg/m ³ 3 hr. = 512 mg/m ³ PM: annual = 10mg/m ³ 24 hr. = 30mg/m ³
Oklahoma	same	same	same	In technical review process.	same	
Oregon	same as secondary levels	same as secondary levels	same as secondary levels	Approved program.		
South Dakota	same	same as secondary levels	annual = 100mg/m ³ 24 hr. = 250mg/m ³	In program development	same	
Texas	30 min = 0.40 ppm(10)	5 hr. = 10Cmg/m ³ 3 hr. = 20Cmg/m ³ 1 hr. = 40Cmg/m ³	same	In program development process.	Same except BACT determined on a case-by-case basis.	
Washington	1 hr. = 0.40 ppm(1) additional hr. = 0.25 ppm(11)	same	same	In program development process.	same	

Table 4.2.10 (Continued)
State Air Quality Regulations, August 1980

Page 5 of 6

State	Ambient Air Quality Standards			PSD	NSPS	Special Considerations
	SO ₂	Particulate Matter	No _x			
Wisconsin	same	same	same	In approval process.	same	
Wyoming	annual = 60mg/m ³ 24 hr. = 260mg/m ³ (1) 3 hr. = 1300mg/m ³ (1)	same as secondary levels	same	Approved program	Same except BACT required on all new sources.	

- 1) Not to be exceeded more than once per year.
- 2) Same under "Ambient Air Quality Standards" means the state standard is the same as the federal primary standard level.
- 3) (See original.)
- 4) Colorado NSPS:
 - SO₂:
 - (i) 1.2 lbs/MMBTU for sources with a coal heat input of less than 25 MMBTU/hr.
 - (ii) 0.4 lbs/MMBTU for sources with a coal heat input of 250 MMBTU/hr. or greater.
 - (iii) 1.2 lbs/MMBTU for sources converted from other fuels to coal.
 - NO_x:
 - (i) 0.70 lb/MMBTU heat input derived from solid fossil fuel or solid fossil fuel and wood residue (except lignite or a solid fossil fuel containing 25 percent, by weight, or more of coal refuse).
 - (ii) 0.60 lb/MMBTU heat input derived from lignite or lignite and wood residue (except as noted in standard (iii) below.)
 - (iii) 0.80 lb/MMBTU heat input derived from lignite which is mined in North Dakota, South Dakota, or Montana and which is burned in a cyclone-fired unit.
- 5) Maximum coal sulfur content may be changed to allow scrubbing to 1 percent.
- 6) Not to be exceeded more than 1 percent of the days in any 3 month period.
- 7) Not to be exceeded more than once in any 4 consecutive days.
- 8) Not to be exceeded more than 1 percent of the days in a year.
- 9) Not to be exceeded more than 1 percent of the time in any 3 month period.
- 10) Some Texas counties are more stringent with standards of 0.32 ppm and 0.28 ppm.
- 11) Not to be exceeded more than twice in any 7 day period.

Those states that have no thermal pollution regulations are: IL, NM, and AZ. New Mexico and Arizona don't require such regulation since the scarcity of water in these states prevents it from being used as a once through coolant from streams. Plants in these states as well as Wyoming usually use cooling towers, ponds, or air cooling. The steam generating facility at the mouth of the largest coal field in the world, located in Wyoming, is air cooled. Most of the plants in Kansas are also cooled with cooling towers or ponds.

The states of Oregon and Idaho have the most stringent thermal regulations. Off-stream cooling is required in Oregon and the temperature differences allowed in the streams and rivers of Idaho are minimal.

Those states with less stringent but by no means less detailed thermal regulations are: AR, CA, CO, KS, LA, MN, MO, MT, NV, ND, OK, SD, TX, WA, and WI.

The thermal discharge regulations of these states can be very complex and extensive. The regulations are, in most cases, site-specific and must be applied on a case-by-case basis.

In summary, the regulation of physical pollutants from source discharges is regulated first by the EPA (or a state with NPDES authority) then the state regulations must be met also. The thermal discharge regulations are essentially left entirely up to the individual states for their own administration.

4.2.3.4 Solid Waste Disposal Regulations

States generally regulate only the disposal of utility wastes, utilizing a permit or plan approval system. Unlike the RCRA hazardous waste regulations, states have not adopted a "cradle-to-grave" approach. Texas, however, does have a manifest system for tracking wastes disposed of off-site.

State regulations for the disposal of utility wastes take three forms:

1. site selection,
2. facility design, and
3. facility operation.

Many states have specific site selection regulations regarding location of disposal sites in environmentally sensitive areas such as floodplains, wetlands, and recharge zones for sole source aquifers. In many cases, the location of disposal sites is prohibited in these areas.

For utility wastes, however, it is more common that states will require special consideration and perhaps more stringent design criteria for disposal in sensitive areas without prohibiting such use.

Approval of disposal facility design is usually done on a case-by-case basis. Design parameters vary from state to state and depend on the waste and site characteristics. These parameters include:

1. Distance between the bottom of the landfill and the high groundwater table.
2. Distance from the landfill to public water supplies.
3. Thickness and permeability of bottom liners.
4. Distance between landfill edge and property line.
5. Distance between landfill and surface water.

These parameters are varied according to toxicity of the waste leachate, the suitability of the natural soils for buffering the leachate, the difference between rainfall and evaporation, and the existing quality and use of the ambient groundwater.

The major requirements imposed by states on facility operation involve monitoring around the site as well as leachate monitoring and collection. The extent of these requirements varies depending upon an evaluation by the state agency of what is necessary to protect the environment.

Regulations on the closure of utility waste disposal sites vary with the level of responsibility a utility is required to assume for the site after it is closed. Because utility wastes are most often not considered hazardous, the utility must simply close the site in accordance with applicable landfill guidelines. Some states will require that the utility continue to monitor the site for short periods until it has been determined that the site has been closed properly. More stringent states have gone a step further and required utilities to be financially responsible for the site for a longer period after closure. This financial responsibility is ensured either through the purchase of a bond prior to operation of the site or by requiring continuous contributions to a fund as the site is filled. The money is then returned when it is determined that the site has been closed in an environmentally acceptable manner.¹²

Under the Hazardous Waste Management System of the Resource Conservation and Recovery act, EPA on May 19, 1980 announced that it has excluded fly ash waste, bottom ash waste, slag waste, and flue gas emission control waste from the hazardous waste classification. This exclusion is viewed as temporary by EPA officials pending a more thorough determination of the toxicity of the waste constituents. Such a determination is difficult due to the variable composition of different coals. In the absence of specific federal regulations regarding coal wastes, the states have assumed authority and have dealt with the issue in basically three different ways:

- (1) little or no regulation,
- (2) disposal regulation,
- (3) stringent disposal regulation.

The degree of regulation is in large part due to the hydrogeologic and climatic conditions of the disposal sites. Of the three states which have little or no regulation (LA, NM, OR), two (NM, OR) have power plants only in arid areas and, therefore, have not deemed a great deal of regulation necessary. New Mexico's only regulation is that these wastes be disposed of on the land of the generator. Oregon's major concern appears to be with the radioactivity of such wastes; the state is currently deciding if coal wastes should be on the state's radio-active materials list. Until this issue is decided the Radiation Control Office of the Oregon Health Division will test representative coal waste samples on a case-by-case basis.

Those states which have regulations significantly more stringent than the federal regulations are: CA, MN, ND, WA, and WY. California does not recognize the EPA exclusion of coal wastes from the hazardous waste list because some constituents of the wastes (heavy metals) are generally considered hazardous. The states of Minnesota and Wyoming explicitly require leachate tests to determine the heavy metal concentration and, thereby, the disposal requirements for the wastes. Wyoming also tests the coal wastes for radioactivity. Each of these states require hydrogeologic assessments, ground water monitoring and possibly disposal site liners of clay or an impermeable material. The states of Washington and North Dakota both require that there be no discharge from disposal sites and that a leachate collection system be used. The rationale for the North Dakota "no discharge" regulation is to prevent the arsenic-laden leachate of the North Dakota lignite from reaching the ground water.

The other states (AZ, AR, CO, ID, IL, KS, MO, MT, NB, NV, OK, SD, TX, WI) have essentially adopted the EPA's position (coal waste is not a hazard waste). They do, however, require hydrogeologic assessments and possibly well monitoring. The tests are then used on a case-by-case site-specific basis to determine the actual requirements of a disposal site (i.e., liners, covers, runoff, etc.).

In general, the issue of solid wastes from coal plants is recognized by most states to warrant some regulation. The degree of the regulation depends on climatic and hydrogeologic considerations as well as the

toxicity of the solid waste constituents. It appears also that many of the states surveyed are awaiting EPA's final pronouncement as to the dangers posed by coal wastes before they take more specific action toward developing their own regulations and guidelines.

4.2.4 Permitting Procedures

Because of the variations in state-specific permitting requirements for low-rank coal facilities, no attempt has been made to develop a general permitting procedure applicable to all facilities throughout the nation. Instead, three specific examples of recent permitting processes are presented here to illustrate the similarities as well as the variations in requirements.

The first example delineates the history of the Great Plains Coal Gasification Project, a joint venture in North Dakota by several gas companies, and the first commercial-scale project of its kind in the U.S. The second example represents current Texas regulations applied to the Twin Oaks Power Plant, owned by the Texas Utilities Company. Both the North Dakota gasification plant and the Texas power plant are scheduled to begin operations in 1984. Another Texas power plant, the Big Brown Plant, is discussed to illustrate the increase in permitting requirements since its start-up in 1972. The third example is Pacific Gas and Electric Company's planned Montezuma coal-fired power plant in California.

When comparing the differing requirements of these states, it is interesting to note that no local permits were required for the Texas facilities; one city and nine county permits were needed for the gasification project in North Dakota; and in California, 19 state agencies and 5 local agencies have laws, ordinances, or standards applicable to permitting the power plant.

For the Twin Oaks plant and the North Dakota Gasification plant, ten years will have elapsed between project initiation and start-up; for the Montezuma plant, fifteen years will have elapsed. These time lags are associated with projects started six years ago; the time requirements for permitting projects initiated in 1980 appear to be similar but may be somewhat longer. Section 4.4 of this report presents an estimation of future Texas permitting considerations, and some recommendations for the streamlining of the entire permitting process.

4.2.4.1 Great Plains Coal Gasification Project

Background of the Project Development

American Natural Resources Company (ANR), like other gas companies, began investigating alternative sources of gas in the late 1960's. Several scenarios, including synthetic natural gas (SNG) from coal, appeared to be

the most suitable sources of long term gas supply for American Natural, and so the company began to develop a coal gasification project in the early 1970's. Many interesting developments have occurred since the conception of the plan, as discussed in the following paragraphs.⁴

The initial concept was to use SNG from Lurgi coal gasification plants to substantially supplement dwindling natural gas supplies. In 1972, an agreement was reached with the North American Coal Corporation, in which they would lease a major portion of their North Dakota lignite deposits to ANR. A subsidiary of North American, the Coteau Properties Company was formed to maintain and acquire coal leases and to perform the actual mining for ANR.

In 1973, an application was made to the North Dakota State Water Commission for rights to 68,000 acre feet per year of water, sufficient for operation of four plants, each producing 250 MM SCFD of SNG. Four such base loaded plants supplying a total of 1 billion SCFD would have provided approximately 40 percent of the ANR systems gas requirements for a zero growth situation.

In early 1974, the State Water Commission granted a conditional water permit for 17,000 acre feet per year equal to the estimated requirements of one 250 MM SCFD plant. This permit along with rapidly escalating plant costs narrowed the project scope to a single plant capable of supplying about 10 percent of the company's needs.

In 1975, the subsidiary, ANG Coal Gasification Company, was formed to own and operate the gas plant and the ANG project name became known.

As the project developed and the ANG executive management more fully evaluated the problems of financing, the socioeconomic impact on the area, and the difficulties of attracting large construction forces to North Dakota, a decision was made in 1976 to build the plant in two phases. That is, construction and operation of a Phase I, 125 MM SCFD plant, followed by the later construction and operation of the 125 MM SCFD phase II. The phasing concept reduced the initial gas volumes to 5 percent of the system requirements.

During the same year, a contract was signed with the Basin Electric Power Cooperative of Bismarck, North Dakota to proceed on a joint plant concept basis. Basin Electric is presently building two 450 MW generating units immediately adjacent to the gasification plant site and will sell power across the fence to Great Plains while purchasing coal fines from the gas plant. Additional mutual benefits to both parties are the common usage of such facilities as the coal mine, water intake and water pipeline, the railroad, access roads and a common drainage system.

In late 1976, financing plans suffered a setback when a proposed federal loan guarantee program for supplemental fuel projects failed to pass congress. Peoples Gas Company of Chicago was asked to join the project as co-owners and to contribute funds needed to maintain the engineering and permitting schedules. In March of 1977, Peoples became full partners, sharing all costs and receiving rights to 50 percent of the plant gas production.

Financial problems continued to plague the project, and after considering methods of foreign financing as well as waiting for a federal loan guarantee bill which still is not operative, it was determined that the only viable means to finance the project was through a Federal Energy Regulatory Commission (FERC) Certificate of Public Convenience and Necessity that would in effect provide loan guarantees. That is, in the event of non-completion or abandonment due to force majeure or governmental action, the outstanding debt would be recovered from the systems' customers. However, the customers would not be liable for technical failures or cost overruns. This approach was generally not favored by the FERC staff or consumer advocate groups.

The Department of Energy suggested forming a consortium of 4 to 5 companies to reduce the individual risk and increase the number of rate paying customers. It was hoped that this approach would increase the chances for securing an acceptable FERC certificate. In response to DOE's suggestion and support, ANG approached DOE with letters of intent from five prospective consortium members. The companies involved are:

1. Columbia Gas Transmission Corporation of Wilmington, Delaware
2. Michigan Wisconsin Pipe Line Company (American Natural Resources) of Detroit, Michigan
3. Natural Gas Pipeline Company of American (Peoples Gas) of Chicago, Illinois
4. Tennessee Gas Pipeline Company (Division of Tenneco, Inc.) of Houston, Texas
5. Transcontinental Gas Pipe Line Corporation of Houston, Texas

The combined systems of the above companies supply gas to thirty states and approximately one-third of all the interstate pipeline customers in the country. The abandonment risk to the average individual domestic customer would be less than two dollars per month for a five year duration under the worst circumstances. This followed exactly the DOE recommended approach, and DOE then promised their full support of the project.

As a result, the Great Plains Gasification Associates was legally formed in August of 1978. Each company owns 20 percent of the plant and receives an equivalent of 20 percent of the gas; however, the ANG Coal Gasification Company continues as the project administrator and eventually will operate the plant.

It is interesting to note that with the formation of the five company consortium, only 1 percent of ANG's system requirements will be met by the gasification project, as compared to the initial concept contribution of 40 percent. Also, the project that had started out as a major source of high BTU gas for ANR customers has in a few years been converted into a commercial sized demonstration plant for the whole natural gas industry.

Plant Siting

The proposed location for the phased gasification project is in Mercer County, roughly midway between Garrison Reservoirs (Lake Sakakawea) and the town of Beulah, North Dakota. At this location in the Williston Basin, the plant will draw upon North Dakota's Fort Union formations for its lignite fuel supply. The plant will be tied into existing pipeline networks through a 20" pipeline, 365 miles long, to be constructed from the plant site to the Great Lakes Gas Transmission Company's system at Thief River Falls, Minnesota. From this point, SNG will be transported to Crystal Falls, Michigan, where the gas will then be distributed to the member companies of the consortium by displacement.

Permitting Requirements for the Great Plains Gasification Project

Listed below is the status of major permits required for the Great Plains project:⁴

1. Water Permit, North Dakota State Water Commission. An appropriation of state water, issued in 1974 subject to conditions as determined by the Commission - 17,000 acre ft/yr.
2. Construction Permit, North Dakota State Department of Health. Originally applied for in 1975; revised in 1977; received in 1978. Subject to conditions and limitations on amounts of air emissions. An analysis performed by the Health Department showed the full-sized plant complied with all air quality regulations.
3. Site Compatibility Certificate, North Dakota Public Service Commission. Applied for in 1976; received in late 1977. The purpose of this certificate is to assure that site location is optimized with respect to competing land uses and natural resources. Minimizing adverse social and economic impact is an equally important objective of the certification procedure.
4. NPDES Permit (National Pollutants Discharge Elimination System), North Dakota State Department of Health. Applied for in 1977; a letter of concurrence was issued, since the actual permit is not required until the plant is completed. This permit covers the deep well disposal system and will be expanded to include the discharge of clean stormwater runoff and treated sanitary effluent.
5. Section 10 Permit, Corps of Engineers. Applied for in 1974; was received in 1978. This permit allows for the construction of the water intake facility in Lake Sakakawea.

6. Environmental Impact Statement, Bureau of Reclamation. Process begun 1975; a final EIS issued in 1978. Bureau of Reclamation was the lead agency in preparing the EIS which was required by the Corps of Engineers, Federal Energy Regulatory Commission, Department of Interior and several state agencies.
7. Solid Waste Disposal, North Dakota State Department of Health. The ash from the gasifiers will be returned to the mine for burial. Final application will be made when a detailed mining/reclamation plan is complete.
8. Certificate of Public Convenience and Necessity, Federal Energy Regulatory Commission. Application first filed in 1975; modified several times; hearing concluded in 1978; and the final decision was delivered in late 1979. This certificate determines the allowable method of financing and the economic viability of the project based on a tariff regulating the terms of gas sales.
9. Local Permits, County Commission. Permits have been obtained for perimeter drainage, road access, plant site zoning, and conditional use permit for the gas plant, water pump station and railroad spur. Also being processed are permits for inplant drainage and the construction camp.

The Certificate of Public Convenience and Necessity from FERC was the final major permit required for the project. The inability to obtain this certificate on a timely basis resulted in the reduction and delay of detailed engineering work in November of 1978.

On November 21, 1979, FERC approved the project. Barring any court appeals,^a the North Dakota Gasification Project will be the first commercial-sized synthetic fuels plant built in the U.S.

Forty-two formal permits and approvals were required to construct the Coal Gasification facility in North Dakota. The number would have been greater had the state Department of Health not received authority from the U.S. Environmental Protection Agency to administer all Federal environmental permit programs in the state. Seven federal permits, 25 state permits and 10 county and local permits were required for the plant. This does not include the nine additional permits required for the coal mine, which

^aIn April 1980, a suit was filed with the U.S. Court of Appeals by General Motors Corporation and state agencies from New York, Michigan, and Ohio, asking that FERC's decision to allow the consortium to pass the risk along to their customers be overturned. Instead, the suit asks the Court to rule that the bank syndicate financing the project be protected by Federal loan guarantees. (Business Week, May 12, 1980, p. 29.)

brings the total for the project to 51. Figure 4.2.4 tracks the permitting history of the gasification project. The permitting actually started in 1973 with the water appropriation and ended in November of 1979 with the FERC certification. The total permitting process, therefore, required approximately 82 months.

4.2.4.2 The Regulatory Roadmap for Lignite Power Plant Siting in Texas⁵

The process of permitting a lignite fired power plant in Texas is a dynamic activity which changes with the enactment of new laws and the implementation of new regulations. To emphasize the dynamic and changing nature of the permitting process, a comparison of two Texas Utilities Company Power Plants is presented.

Big Brown - Permitting Requirements of the 1960's

The first lignite fired power plant built in Texas since the Sandoz Plant (owned by Alcoa) in 1953 was the Big Brown Plant of Texas Utilities Company which was completed in 1972. Located in Freestone County, the Big Brown Plant consists of two 575 Mw capacity generators and uses lignite from the Wilcox formation for fuel. The lignite is mined at a Texas Utilities owned and operated surface mine located within a few miles of the power plant.

Big Brown requested its initial permits in 1968, prior to the enactment of the National Environmental Policy Act of 1969 and the watershed of environmental legislation which followed. As shown in Table 4.2.11, the Big Brown Plant required a total of six permits - five from the State of Texas related to water rights and water quality and a registration of stack and boiler heights with the U.S. Federal Aviation Administration. All six of these permits were of either a siting or design nature rather than for operating conditions. Total time between the initial request for permits and the completion of plant construction was four years. Three periodic facility inspections were called for after facility startup.

Twin Oaks - Permitting Requirements of the 1970's

In addition to the Big Brown Plant (1150 Mw), Texas Utilities currently has lignite-fired power plants in Titus County (Monticello Plant - 1900 Mw) and in Panola County (Martin Lake Plant - 2250 Mw in operation and 750 Mw under construction). The next lignite-fired power plant scheduled to come on line for Texas Utilities is the Twin Oaks Plant located in Robertson County. Designed to consist of two 750 Mw units, Twin Oaks was originally scheduled to start operation in 1981 and like the other lignite fired plants in the Texas Utilities system, would use surface mined lignite from the Wilcox formation. Because of the slowing in demand growth for electric power, the need for power from the Twin Oaks Plant has been delayed such that its design startup date is now 1984.

Regulatory Permitting Requirements for the Great Plains Coal Gasification Project:

Figure 4.2.4 (continued).

Regulatory Permitting Requirements for the Great Plains Coal Gasification Project

Page 2 of 2

Permit Description	Commission/ Agency	1974	1975	1976	1977	1978	1979	1980
		J A S O N D	J F M A M J J A S O N D	J F M A M J J A S O N D	J F M A M J J A S O N D	J F M A M J J A S O N D	J F M A M J J A S O N D	J F M A M J J A S O N D
County/Local								
1. Road Access	County Comm.							
2. Plant Site Re-zoning	County Comm.							
3. Perimeter Drainage	Water Mgmt.Dis.							
4-7. Conditioned Use Permits-Gas Plant	County Comm.							
- Railroad Spur	County Comm.							
- Water Pipeline	County Comm.							
- Water Pump Station	County Comm.							
- Construction Camp	City Council							
9. In-plant Drainage	Water Mgmt.Dis.							
10. Sewage Disposal	Co. Sanitation							

Legend:

	estimated.	▽
Filing	actual	▼
	refiling	◻
	estimated	○
Approval	preliminary	●
	final	●
	expires	●

Source: Reference 9

Table 4.2.11

Big Brown Permitting Requirements

State Regulatory Controls

1. Water rights permit for plant water requirements from Texas Water Rights Commission.
2. Dam construction permit for cooling reservoir from Texas Water Rights Commission.
3. Supplemental water rights permit for purchase of water from others from Texas Water Rights Commission.
4. Dam construction plans and specifications approval from Texas Water Rights Commission.
5. Water quality permit for plant discharge from Texas Water Quality Board.

-64- Federal Regulatory Controls

1. Stack and boiler height registration from Federal Aviation Administration.

State Operating Inspections

1. Water discharge permit compliance inspection by Texas Water Quality Board.
2. Water use permit compliance inspection by Texas Water Rights Commission.

Federal Operating Inspection

1. Mine safety inspection by Mine Enforcement and Safety Administration

Of the power plants currently in design and construction by Texas Utilities, the Twin Oaks Plant provides the best example of the changes in state and Federal permitting requirements over the last 10 years. In comparison to Big Brown's six permits, current regulations suggest that the Twin Oaks Plant will be subjected to the review process for 17 permits, 12 from the state and five from Federal agencies. Two additional Federal permits have been waived. Although only one of the 19 permits is defined as an operating permit, the number of operating inspections has increased from 3 to 11. Conspicuous by their absence are local requirements commonly found in other states. Except for zoning powers imposed within municipal boundaries, neither city nor county government have any direct control over facility permitting or operation. Table 4.2.12 lists the permit and inspection requirements to which Twin Oaks will be subjected and their status as of September 1, 1979.

A comparison of the expansion in permitting and inspection requirements between 1968 and 1978 is shown in Table 4.2.13. Important to note in this expansion of requirements is that rather than taking four years to move from the utility's decision to build the plant to actual startup (as with Big Brown), Twin Oaks will take ten years to complete this process. Of this additional six years, Texas Utilities estimates that four years are attributable to added permitting requirements with the remaining two years due to the decline in electricity demand growth. Figure 4.2.5 presents a graphical history of the previous and current permitting activity for the Twin Oaks project.

4.2.4.3 The Pacific Gas and Electric Montezuma Project

Pacific Gas and Electric Company which operates throughout most of Northern California has plans to build a coal-fired power plant of two units in Solano County. This will be the first coal-fired power plant in California. This project was chosen to illustrate the permitting process for fossil-fuel-fired power plants in California. Table 4.2.14 lists the federal, state, regional and local regulatory agencies and their respective regulations, laws, ordinances, and standards which affect the permitting of the Montezuma project.

The air pollution BACT for this plant was defined to be:

SO₂: 95% flue gas control

PM: 0.005 lb/MMBtu (equivalent to 99.9+ percent control)

NO_x: 0.15 lb/MMBtu (pushing for selective catalytic reduction)

The standards are some of the most stringent standards, if not the most stringent, of any of the states. Table 4.2.15 is a schedule of the required permits for the Montezuma Project. No dates are listed on the schedule because of changes in the plant operation dates. The siting permit process was started in 1974. The Notice of Intent was filed with the California Air Resources Board in December of 1977. The plant's two units are scheduled for completion in 1989 and 1990, almost three years behind schedule.¹¹

Table 4.2.12

Twin Oaks Permitting Requirements

Page 1 of 3

State Regulatory Controls

1. Water rights permit for plant water requirements from Texas Water Rights Commission. ^aPermit requested May 20, 1974; granted November 8, 1974.
2. Dam construction permit for cooling reservoir from Texas Water Rights Commission. Permit requested May 20, 1974; granted November 8, 1974.
3. Supplemental water rights permit for purchase of water from existing water rights holders from Texas Water Rights Commission. Permit requested June 21, 1974; granted November 8, 1974.
4. Dam construction plans and specifications approval from Texas Water Rights Commission. Approval requested March 1, 1975; granted September 6, 1976.
5. Water quality permit for plant discharge from Texas Water Quality Board. Permit requested April 18, 1975; granted February 25, 1976.
6. Solid Waste disposal permit from Texas Water Quality Board. Permit requested April 18, 1975; granted February 25, 1975.
7. Air quality permits for fuel handling, emission control, and solid waste handling systems from Texas Air Control Board. Permits requested December 31, 1975; granted February 28, 1978.
8. Certification of need for facility from Texas Public Utility Commission. Certification requested March 1, 1976; granted August 30, 1976.
9. Air quality control equipment plans and specifications approval from Texas Air Control Board for (1) NO_x control. Approval requested; (2) SO₂ and particulates. No action to date.
10. Mining permit from Surface Mining Division of Texas Railroad Commission. No action to date.
11. Water quality permit for mine discharge from Texas Department of Water Resources. No action to date.
12. Air quality control equipment operating permits from Texas Air Control Board. Required within 90 days after equipment performance certification test.

a. On September 1, 1977 the Texas Water Rights Commission Quality Board, and Water Development Board were consolidated into a single agency, the Texas Department of Water Resources.

Table 4.2.12 (continued)
Twin Oaks Permitting Requirements

Page 2 of 3

State Operating Inspections

1. Water discharge compliance inspection by Texas Department of Water Resources.
2. Water use compliance inspection by Texas Department of Water Resources.
3. Air emission compliance inspection by Texas Air Control Board.
4. Solid waste disposal compliance inspection by Texas Department of Water Resources.
5. Mining compliance inspection by Surface Mining Division of Texas Railroad Commission.

-67- Federal Operating Inspections

1. NPDES compliance inspection for plant by the Environmental Protection Agency.
2. NPDES compliance inspection for mine by Environmental Protection Agency.
3. PSD compliance inspection by the Environmental Protection Agency.
4. Mining compliance inspection by the Office of Surface Mining.
5. Plant safety inspection by the Occupational Safety and Health Administration.
6. Mine safety inspection by the Mine Safety and Health Administration.

Source: Reference 5

Table 4.2.12 (continued)

Twin Oaks Permitting Requirements

Federal Regulatory Controls

Page 3 of 3

1. National Pollutant Discharge Elimination System (NPDES) permit for water discharges from plant from Environmental Protection Agency. Permit requested June 3, 1975; Environmental Impact Statement (EIS) in preparation.
2. NPDES permit for water discharge from mine from Environmental Protection Agency. Permit requested December 5, 1977; approval pending.
3. Discharge of dredge and fill material into navigable waterway permit (Section 404 of Federal Water Pollution Control Act Amendments of 1972) from Corp of Engineers waived because median flow of impounded stream less than 5 cubic feet per second.
4. Prevention of Significant Deterioration (PSD) air quality permit from Environmental Protection Agency. Permit requested June 20, 1977; granted September 22, 1977.
5. Stack and boiler height registration from Federal Aviation Administration. Registration requested January 15, 1978; granted May 4, 1978.
6. Mining permit from Office of Surface Mining of Department of Interior. Waived until June 3, 1980 in lieu of state mining permit from Railroad Commission under authority of OSM Interim Rules.
7. Hazardous waste disposal permit from Environmental Protection Agency. Pending determination of waste disposal requirements for ash and scrubber sludge.

Table 4.2.13

Comparison of 1968 vs. 1978 Regulatory Requirements,
State of Texas

Permit and Inspection Requirements	Responsible Agency	State		Fed	
		1968	1978	1968	1978
<u>Siting & Planning Requirements</u>					
Water Rights	TDWR	0	0		
Dam Construction	TDWR	0	0		
Supplemental Water Rights	TDWR	0	0		
Need for Facility	TPUC		0		
Ambient Air Quality	TACB		0		
Dredge & Fill	USCOE				0
PSD Approval	USEPA				0
<u>Design Requirements</u>					
Dam Plans & Specifications	TDWR	0	0		
Water Quality	TDWR	0	0		
Air Quality Control Equipment	TACB		0		
NPDES Plant Discharge	USEPA				0
NPDES Mine Discharge	USEPA				0
FAA Registration	USFAA			0	0
<u>Construction Requirements</u>					
Mine	TRRC		0		
Solid Waste Disposal	TDWR		0		
Mine	USOSM				0
Hazardous Waste Disposal	USEPA				0
<u>Operating Requirements</u>					
Air Quality Control Equipment	TACB		0		
Water Quality	TDWR	X	X		
Water Use	TDWR	X	X		
Air Emissions	TACB		X		
Solid Waste	TDWR		X		
Mining	TRRC		X		
NPDES Plant Discharge	USEPA				X
NPDES Mine Discharge	USEPA				X
PSD	USEPA				X
Mining	USOSM				X
Occupational Plant Safety	USOSHA				X
Occupational Mine Safety	USMSHA			X	X

TDWR-Texas Department of Water Resources; TPUC-Texas Public Utility Commission; TACB-Texas Air Control Board; TRRC-Texas Railroad Commission, Surface Mining Division; USCOE-U.S. Corps of Engineers; USEPA-U.S. Environmental Protection Agency; USFAA-U.S. Federal Aviation Administration; USOSM-U.S. Department of Interior, Office of Surface Mining; USOSHA-U.S. Occupational Safety and Health Administration; USMSHA-U.S. Mine Safety and Health Administration

0-Permit; X-Inspection

Source: Reference 5

Figure 4.2.5

Twin Oaks Power Plant (Texas) Permitting Schedule

Permit Description	Commission / Agency	1974												1975												1976												1977												1978												1979																																			
		J	F	M	A	M	J	J	A	S	O	N	D	J	F	M	A	M	J	J	A	S	O	N	D	J	F	M	A	M	J	J	A	S	O	N	D	J	F	M	A	M	J	J	A	S	O	N	D	J	F	M	A	M	J	J	A	S	O	N	D																																				
<u>Federal</u>																																																																																																	
1. Water Discharge Permit (NPDES), Plant	EPA																																																	(pending)																																															
2. Water Discharge Permit (NPDES), Mine	EPA																																																	(pending)																																															
3. Navigable Waterway Discharge	Corp of Eng	Waived because median flow of impounded stream less than 5 ft ³ /sec																																																																																															
4. PSD Air Quality Permit	EPA																																																																																																
5. Structure over Reg. Height	FAA																																																																																																
6. Mining Permit	OSM; DOI	Waived until June 3, 1980, in lieu of state mining permit from RR Comm.																																																																																															
7. Hazardous Waste Disposal	EPA	pending determination of waste disposal requirements for ash & scrubber sludge																																																																																															
<u>State</u>																																																																																																	
1. Water Rights Permit, Plant	TWRC																																																																																																
2. Cooling Reservoir Dam Const. Permit	TWRC																																																																																																
3. Supplemental Water Rights, Existing Holders	TWRC																																																																																																
4. Dam Plan and Specs Approval	TWRC																																																																																																
5. Plant Discharge Water Quality Permit	TWQB																																																																																																
6. Solid Waste Disposal Permit	TWQB																																																																																																
7. Air Quality Permits	TACB																																																																																																
8. Certification of Need	TPUC																																																																																																
9. Air Quality Control Equip. Plans & Specs Approval	PUC																																																																																																
10. Mining Permit	TRRC																																																																																																
11. Mine Discharge Water Quality Permit	TRRC																																																																																																
12. Air Quality Control Equip. Operating Permits	TACB	Required within 90 days after equipment performance certification test																																																																																															

TWRC - Texas Water Rights Commission
 TWQB - Texas Water Quality Board
 TACB - Texas Air Control Board
 TPUC - Texas Public Utility Commission
 TRRC - Texas Railroad Commission

Source: Reference 5

Table 4.2.14

Page 1 of 7

Federal, State, Regional, and Local Agencies
Whose Regulations or Laws, Ordinances, and Standards
are Applicable to the Montezuma Site and Related Facilities

<u>Federal Agencies</u>	<u>Standard or Regulations</u>	<u>Applicability of Standard or Regulation</u>	<u>1-Power Plant 2-Transmission 3-Rail 4-Waste Disposal</u>	<u>Contact</u>
Environmental Protection Agency	42 U.S.C. Sec. 1857C-6	Prevention of significant deterioration; Ambient Air Quality Standards; New Source Review; New Source Performance Standards for Stationary Sources; National Emission Standards for Hazardous Air Pollutants. (implemented by Bay Area Air Quality Management District)	1	Paul De Falco Regional Administrator, EPA Region IX 215 Fremont Street San Francisco, CA 94106
Federal Aviation Administration	49 U.S.C. Sec. 1348 14 C.F.R. Sec. 77.1 <u>et. seq.</u>	Establishes standards for determining obstructions in navigable airspace	1.2	Robert C. Young Western Region - FAA P.O. Box 92007 World Way Postal Center Los Angeles, CA 90009
Federal Communication Commission	47 C.F.R. Sec. 15, 91, 94	Establishes standards covering interference from incidental radio transmissions from devices such as transmission lines; standards to the operation of radio equipment for industrial uses; and operation of private operational - fixed microwave radio facilities	2	Eugene C. Bowler 2025 M. Street N.W. Washington, DC 20554
Fish and Wildlife Service	National Environmental Protection Act; The Endangered Species Act; The Rivers & Harbor Act of 1899; The Federal Water Pollution Control Act; The Migratory Bird Act;		1, 2, 3, 4	William Sweeney Area Manager 2800 Cottage Way Room E-2740 Sacramento, CA 95825

Table 4.2.14 (continued)

Page 2 of 7

<u>Federal Agencies</u>	<u>Standard or Regulations</u>	<u>Applicability of Standard or Regulation</u>	<u>1-Power Plant</u> <u>2-Transmission</u> <u>3-Rail</u> <u>4-Waste Disposal</u>	<u>Contact</u>
U.S. Army, Corp of Engineers	The Estuarine Protection Act of 1968; The Anadromous Fish Act; The Fish and Wildlife Act of 1956; The Fish and Wildlife Coordination Act; Powerline Transmission Corridor Policy 33 U.S.C. Sec. 403 et. seq. 33 C.F.R. 209.120	Regulating structures and work affecting navigable waters of the United States (may require prior approval of other agencies)	1, 2, 3	James C. Wolfe San Francisco District - Corp of Engineers 211 Main Street San Francisco, CA 94105

Table 4.2.14 (continued)

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State Agencies	Standard or Regulation	Applicability of Standard or Regulation	1-Power Plant 2-Transmission 3-Rail 4-Waste Disposal	Contact
California Air Resources Board	Health & Safety Code Sec. 40000 <u>et. seq.</u>	Ambient Air Quality Standards (implemented by Bay Area Air Quality Management District)	1	Thomas C. Austin Executive Officer
California Division of Industrial Safety	Labor Code Sec. 7520 <u>et. seq.</u>	Inspects and administers safety regulations at tanks	1	
California Public Utilities Commission	Public Utilities Code Sec. 1001, California Public Utilities Commission G.O. 131; 12F (rail) 26D (transmission)	Certificate of Public Convenience & Necessity, Safety Standards for transmission lines and railroads	1, 2, 3, 4	Utilities Division 350 McAllister Street San Francisco, CA 94109
California Regional Water Quality Control Board - Central Valley Region	23 U.S.C. Sec. 1342 23 California Administrative Code Sec. 2200, 13360, 14040 <u>et. seq.</u>	Waste discharge requirements under NPDES permits; waste disposal to land; approval of best technology for cooling water intake structure	1, 4	James Robertson 3201 "S" Street Sacramento, CA 95816
Department of Fish & Game	Fish & Game Code Sec. 1601	Projects which divert, obstruct or change the natural flow or bed of a river	1, 3	E. C. Fullerton Director 1416 - 9th Street Sacramento, CA 95814
Department of Food & Agriculture		Policy opposing use of agricultural quality water for power plant cooling		Vashek Cervinka 1220 "N" Street Sacramento, CA 95814
Department of Health Service - Hazardous Materials Management Section	Health & Safety Code Division 20, Chapter 6.5	Disposal of fly ash; bottom ash, desulfurization sludge and other miscellaneous plant wastes, if wastes are classified as hazardous	4	Harvey F. Collins Acting Chief 1420 - 5th Street Sacramento, CA 95814
Department of Industrial Relations	Occupational Safety and Health Act of 1970 Title 8 of the California Administrative Code	Specifies standards and safety orders pertaining to occupational safety and health		

Table 4.2.14 (continued)

Page 4 of 7

State Agencies	Standard or Regulation	Applicability of Standard or Regulation	1-Power Plant 2-Transmission 3-Rail 4-Waste Disposal	Contact
Department of Transportation, Division of Aeronautics	Public Utilities Code 21656-21660	Permit Authority over the construction of any object which may constitute an obstacle or hazard to air navigation		
Department of Transportation	Streets and Highways Code Sec. 670	Authorizes encroachments in state highways	4	Ms. Adriana Giantureo 1120 North Street CALTRANS Sacramento, CA 95814
Reclamation Districts 341	23 California Administrative Code Sec. 16; Water Code 18710	Protection of the levees, embankments, canals, and tributaries of the Sacramento and San Joaquin Rivers and all of the overflow basins, thereof within the respective local districts.	2	W. Rossini Superintendent Star Route Isleton, CA 95641
San Francisco Bay Conservation and Development Commission (BCDC)	Governmental Code Sec. E6610	Within the 100-foot shoreline band or the 5-foot contour within marsh areas	1, 3	M. Wilmar 30 Van Ness Avenue San Francisco, CA 94102
"	Suisun Marsh Preservation Act of 1977	Within secondary management area	1, 3	"
State Energy Resources Conservation and Development Commission	Public Resources Code Sec. 25500 <u>et. seq.</u>	Certifies sites and facilities for thermal power plants	1, 2, 3, 4	
State Historic Preservation Office	National Historic Preservation Act 1966 Executive Order 11593 dated May 13, 1971 36 CFR Sec. 800 Reservoir Salvage Act of 1960 as amended by Historical and Archaeological Preservation Act NAPA of 1974			

Table 4.2.14 (continued)

<u>State Agencies</u>	<u>Standard or Regulation</u>	<u>Applicability of Standard or Regulation</u>	<u>1-Power Plant 2-Transmission 3-Rail 4-Waste Disposal</u>	<u>Contact</u>
State Lands Commission	Public Resources Code Sec. 6001 <u>et. seq.</u> 2 California Administrative Code Sec. 1900 <u>et. seq.</u>	Enforcement of environmental controls over state-owned lands, protect and establish titles to tide and submerged state lands, and establish the best use of state lands	1, 2	W. T. Northrop 1807 - 13th Street Sacramento, CA 95825
State Reclamation Board	Water Code Sec. 8710 23 California Administrative Code Sec. 19	Protection of the levees, embankments, canals, and tributaries of the Sacramento and San Joaquin Rivers and all of the overflow basins thereof	2	Paul Clifton 1416 Ninth Street Sacramento, CA 95814
State Solid Waste Management Board	Solid Waste Management and Resource Recovery Government Code Title 7.3 Sec. 66700-68052	Disposal of fly ash, bottom ash, desulfurization sludge and other miscellaneous plant wastes, if wastes are not classified as hazardous	4	Albert A. Marino Executive Officer 825 "K" Street Suite 300 Sacramento, CA
State Water Resources Control Board	33 U.S.C. Sec. 1341, 1344	Certification that dredging projects conform with applicable State Water Quality Standards	1, 3	James A. Robertson Central Valley RWQCB 3201 "S" Street Sacramento, CA 95816
Native American Heritage Commission	Public Resources Code Sec. 5097.9	Provides for preservation of and access to sites of sacred and social significance to Native American people		

Table 4.2.14 (continued)

1-Power Plant
2-Transmission
3-Rail
4-Waste Disposal

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<u>Local/Regional</u>	<u>Standard or Regulation</u>	<u>Applicability of Standard or Regulation</u>		<u>Contact</u>
Alameda County	Alameda County Zoning Ordinance #67-119 - Sec. 8-60.1	County Planning Commission Approval	2	William Fraley 399 Elmhurst Hayward, CA 94544
Bay Area Air Quality Management District (BAAQMD)	Regulations 2, 3, & 7	Enforces emissions limitation; Implements Ambient Air Quality Standards, New Source Performance Standards, New Source Review, Standards for Hazardous Air Pollutants	1	Milton Feldstein APC Officer 939 Ellis Street San Francisco, CA 94109
Contra Costa County	Contra Costa County Zoning Ordinance #2 - Sec. 8120	County Planning Staff Approval	2	Anthony A. Dehaesus Planning Director Admin. Building, North Wing P.O. Box 951 Martinez, CA 94553
Sacramento County	Sacramento County Zoning Ordinance #1111 - Sec. 23.14.010	County Planning Commission Approval	2	Lance Bailey Planning Director 700 "H" Street Sacramento, CA 95814
Solano County	Solano County Zoning Ordinance #28	County Planning Commission Approval	1, 3, 4	Clayne Munk Planning Director Courthouse Fairfield, CA 94533
Solano County	Solano County Zoning Ordinance #28 - Sec. 27	Use Permit - County Planning Commission	1, 3, 4	"
Solano County	Solano County Zoning Ordinance #28 - Sec. 24	County Planning Commission Approval	1, 2, 3	"
Solano County	Solano County Zoning Ordinance #28 - Sec. 27	Use Permit for Work Camps	1, 2, 3	"
Solano County	Solano County Public Works Code	Grading & Building Permits	1, 3, 4	Eugene Knapp Public Works Director Courthouse Fairfield, CA 94533
Solano County	Streets and Highways Code Sections 1450, 1460-1469	Authorizes encroachments in county roads	1, 3, 4	"

Table 4.2.14 (continued)

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<u>Local/Regional</u>	<u>Standard or Regulation</u>	<u>Applicability of Standard or Regulation</u>	1-Power Plant 2-Transmission 3-Rail 4-Waste Disposal	<u>Contact</u>
Solano County	Solano County Health Ordinance #405	Disposal Permit	1, 4	David Eubank 355 Tuolumne Vallejo, CA 94590
Solano County	"Proposed" Suisun Marsh Local Protection Program	Design Standards to be incorporated into grading and use permits	1, 3	Clayne Munk Planning Director Courthouse Fairfield, CA 94533

Source: Reference 11

Table 4.2.15

Montezuma 1 and 2 Permit Schedule
PGandE Permits

Page 1 of 2

Permit	Agency	Filing Date	Date Approval Expected
Certificate to Construct and Operate	California Energy Commission		
Certificate of Public Convenience and Necessity	California Public Utilities Commission		
Authority to Construct*	Bay Area Air Quality Management District		
Permit to Operate*	Bay Area Air Quality Management District		
Prevention of Significant Deterioration	Environmental Protection Agency		
License to Construct and Operate Electronic Transmitting Equipment	Federal Communication Commission		
Certificate of Conformance with Water Quality Standards	California Regional Water Quality Control Board - Central Valley Region		
NPDES Permit	California Regional Water Quality Control Board - Central Valley Region		
Waste Discharge Require- ments for Solid Waste Disposal Site	California Regional Water Quality Control Board - Central Valley Region		

Table 4.2.15 (continued)

Page 2 of 2

Permit	Agency	Filing Date	Date Approval Expected
Hazardous Waste Facility Permit	Department of Health Services - Hazardous Materials Management Section		
Solid Waste Disposal Site Permit	State Solid Waste Management Board		
Use Permit*	Solano County		
Grading Permit*	Solano County		
Building Permit*	Solano County		
Sanitation Permit*	Solano County		

Source: Reference 11

*Includes agencies which would have jurisdiction but for the exclusive permitting authority of the Energy Commission.

4.2.5 Proposed and Anticipated Regulations

As national energy and environmental conflicts intensify in the 1980's, several changes may be expected in the permitting processes affecting low-rank coal utilization. These changes can be anticipated in three general categories: 1) New regulatory areas and constraints; 2) changes in state/federal relationships and responsibilities; and 3) restructuring of state permitting processes. New areas of regulatory involvement which may develop over the next decade include: 1) expanded consideration of land use and aesthetics, either explicitly or through existing permits; 2) increased consideration of fine particulate matter, sulfates, and radioactive air emissions; 3) redefinition of water allocation procedures as conflicts between existing uses and future low-rank coal developments become better defined; and 4) expanded analyses of the need for power and financial impacts prior to certification of facility need.

While these topics apply to all potential low-rank coal regions, the following discussion exemplifies state permitting recommendations by using Texas policy proposals and goals.⁵

Historically, Texas has had little enthusiasm for land use regulation; the consideration of land use and aesthetics would be a totally new area for state involvement. As a result of other regulatory programs such as PSD, future consideration of this topic will be more likely, however. Although land use is the one area of environmental regulation not explicitly covered by existing regulations, it is perhaps more likely that future activities in this area will be accomplished through existing regulations rather than enactment of new laws. The other three areas of increased regulatory involvement would logically occur through the expansion of existing programs as well. While the total number of permits required as a result of changes may not increase, it is likely that the time from initial utility planning to plant completion will be further extended, due primarily to a lengthier process for allocation of water and certification of need for power.

Texas state government has placed substantial importance on the state obtaining delegation of federal regulatory programs in order to minimize duplication of permitting requirements and to maximize state control over the development of the state's resources. While the majority of federal programs have been delegated to the state, federal control still exists over the following: 1) NPDES permits; 2) PSD permits; 3) surface mining permits; and 4) solid waste disposal programs. The surface mining and solid waste disposal programs are still pending final adoption of the state's proposed program and completion of the federal guidelines, respectively.

Assuming all four of these programs are delegated to the state, federal permitting would be limited to the Corps of Engineers Section 404 permit for dredge and fill operations in navigable waterways and the Federal Aviation Administration requirement for registration of boiler and stack height. In that these permits would still be required, issued by the state rather than by a federal agency, it is uncertain whether any significant shortening of planning requirements or time would occur.

Texas has been historically reluctant to restructure or expand state regulatory programs except where it is clearly perceived that the existing approach is not working or is duplicative and that a change will improve the situation. Given this approach it is unlikely that any major effort will be made to establish a central siting authority with overall permitting responsibility. It is possible, however, that changes will be made within the framework of the existing system where duplication in responsibility occurs. The one area where this is most noticeable is in the regulation of water effluents from surface mines. With the resolution of the state/federal conflict over NPDES permitting discussed above, it is likely that the overlap between the Railroad Commission and the Department of Resources will be eliminated.

Assuming all of the above changes in the permitting process are made and that no major new permitting requirements develop, Figure 4.2.6 provides an estimate of the permitting schedule for the 1980's. As shown, the length of time from the utility's decision to proceed until plant startup is eight years. Because of their location on the permitting schedule, any lengthening of the permitting process for need of facility certification or water rights allocation, as discussed above, will increase the length of overall project schedule proportionately. Follow-up inspections (as shown previously in Table 4.2.13) would occur after startup, except for the Environmental Protection Agency and Office of Surface Mining permits delegated to the state.

Figure 4.2.6

Projected 1980's Permitting Schedule for Texas Power Plants

¹Includes PSD.

⁴NO_x controls.

²Includes NPDES.

⁵SO₂ and particulate controls.

³Includes RCRA

Source: Reference 5

References - Section 4.2

1. Nehring, R., B. Zycher, and J. Wharton. Coal Development and Government Regulation in the Northern Great Plains: A Preliminary Report, Rand Corporation R-1981-NSF/RC August, 1976.
2. Environmental Analysis of Synthetic Liquid Fuels, U.S. DOE, DOE/EV-0044, July, 1979.
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4.2.6 SELECTED REFERENCES

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This report addresses the impacts associated with three levels of potential synthetic fuel production to the year 1990. The 90 page report includes sections on technology assessments; regulatory analysis; and environmental analysis and siting constraints. The section on environmental and resource-oriented laws and regulations contains an extensive tabular summary of federal environmental regulations and impacts on synfuel technologies.

2. Nehring, Richard, Benjamin Zycher, and Joseph Wharton. Coal Development and Government Regulation in the Northern Great Plains: A Preliminary Report, The Rand Corporation, R-1981-NSF/RC, August 1976.

This report is part of an examination of coal development in the Northern Great Plains, the emerging regulation of such development and the relationships between the two. This particular case was chosen for study because (a) Northern Great Plains coal promises to be an important source of energy supplies for the United States between 1975 and 2000, (b) a major surge in coal development in the region is imminent, and (c) the case offers a rich complexity, providing many insights and lessons that could be usefully applied in other major energy developments in the future.

This preliminary report presents an easily read overview of relevant topics, classified into the following sections: Regulatory overview; regional coal resources; adverse effects of regional coal development and existing regulation remedies; and emerging conflicts, both in new technologies and in regulatory authority.

4.3 ENVIRONMENTAL IMPACT ANALYSIS

The global effects from low-rank coal utilization are not specifically known. As with most anthropogenic effluents, the impacts on plant and animal interactions occur slowly, as absolute values of contaminants gradually accrue over scores of years. By the time the impacts reach a level of human detection the degrading effects may be impossible to reverse, and are in any case economically and technically prohibitive to stop.

Legislation enacted during the past decade has initiated regulatory constraints and performance standards on coal utilization as intended protectorates of the nation's air, land, and water resources. In response to these constraints, technologies have been developed and improved that can contain the potentially harmful emissions from mining, storage, and conversion processes (see Chapter 3 - Technology Evaluation sections on Environmental Control Technology). Unfortunately, many environmental control technologies cannot eliminate effluents; instead they create a mass of new material comprised of concentrated effluents that would otherwise be dispersed by winds or waters. Only incineration, and to a lesser degree biological degradation, actually destroy effluents - and these processes can only eliminate certain organic wastes. In the case of flue gas desulfurization, the SO_2 removed from the gas is chemically bound within a dry solid, a highly viscous sludge, or as a dissolved solid in solution. The favorable results of cleaner air are somewhat offset by disposal of the solid and liquid residues. Proper storage of these residuals must prevent leaching of chemicals into groundwater and surface water systems, and will in any case require substantial, long-term acreage commitments for use as disposal sites.

Another major gaseous emission from coal (as well as all other fossil fuel) combustion facilities is carbon dioxide (CO_2). There are presently no regulations and no control technologies pertaining to CO_2 containment, nor are any anticipated in the near future. CO_2 as a compound is a vital link in the earth's ecological cycle, so its release from combustion plants is of no chemical concern. However, the potential global-warming problems (referred to as the "greenhouse" effect) arise from the sheer volumes of CO_2 released into the atmosphere over time. Conventional CO_2 "sinks," such as the surface layers of oceans and expansive vegetated areas, will not be able to absorb all of the CO_2 emitted, hence the expected CO_2 emissions will remain in the atmosphere. Although the CO_2 issue is receiving considerable public attention, the long-term impacts (albeit largely unknown) are not expected to reach irreversible proportions until sometime in the next century.

The push for more low-rank coal utilization draws attention to the expansive Western U.S. - an area rich in mineral resources that include subbituminous coal and lignite, and an area possessing majestic

natural beauty and fragile deserts. The limited water resources are vital to the various ecosystems throughout the West, as well as for agricultural, municipal, and industrial demands. Expanded low-rank coal utilization throughout the West will produce significant environmental impacts, both in absolute and relative terms, since most of the associated effluents will be released in quantities far above existing ambient levels.

This chapter discusses process emissions and environmental impacts for each major operational step in the low-rank coal fuel cycle. The four steps are: 1) Extraction; 2) Transportation; 3) Preparation, Handling, and Storage; and 4) Processing and Utilization. The environmental analysis is included in the overall Western Low-Rank Coal development report as a complement to previous sections. A thorough analysis of all the potential impacts would be voluminous in itself and hence outside the scope of this project. If more information is desired, references cited at the end of this chapter can provide substantial material in greater detail.

4.3.1 Extraction

The most significant environmental impact associated with the extraction of U.S. low-rank coal resources is the reclamation of surface-mined coal lands. Many of the subbituminous and lignite deposits in the West lie under semi-arid and overgrazed pasture land subject to severe temperature extremes and little precipitation. Successful reclamation planning begins with the initial mining plan and the development of dedicated ecological management. Reclamation in the Gulf Coast Region is blessed, in some places, by adequate rainfall and suitable topsoil for rapid revegetation. However, aquifer disruption due to mining can cause potential water quality and quantity problems for parts of the state. Many state studies have investigated various solutions to specific reclamation problems, and the results of several are presented in this sub-section.

Besides reclamation impacts, the act of strip mining creates its own environmental disruptions, such as: dust problems, noise and vibration, water diversions, and water contamination. These impacts are also overviewed in the following pages.

It is interesting to note that several impacts associated with low-rank coal extraction do not lend themselves to conventional environmental control technologies. This is especially true for groundwater disruption and contamination. The only effective "control" is deciding not to mine at that site and proceeding with mining activities only where groundwater systems will not be encountered. Such a decision would face sensitive, yet powerful opposition from energy concerns, and would probably be overturned due to the skeptical nature of long-term impact predictions.

4.3.1.1 Noise and Vibration

Sources of noise in surface mining operations include heavy earth moving trucks and shovels, conveyors, and blasting charges. Machinery noise is a continuous and very localized impact, and can be easily mitigated by improved exhaust mufflers and/or employee-worn ear protection. The goal of blasting is to get maximum fragmentation of the consolidated overburden material with optimum drilling and blasting cost. Blasting, however, produces intermittent and powerful shock waves that can have much longer range impacts on off-site structures and people.

A variety of complaints have always been received by industry pertaining to blasting. Since World War II, the population explosion and urban sprawl have acted to bring industry and the public into closer physical contact. In many cases, structures were built on property adjacent to surface mining operations. As a result, the number of complaints increased drastically and constituted a major problem.

Some complaints registered are legitimate claims of damage from blasting vibrations. The advances in blasting technology and a more knowledgeable blasting profession have minimized real structural damages. However, vibration levels that are completely safe for structures may be annoying and unpleasant for people. Though no actual damage is done, air blast pressures may cause windows to rattle and the loud noise can be intolerable. Repeated vibrations, such as those from a nearby mine, may eventually cause damage.

Control of vibration damage to natural scenic formations is a very important environmental consideration in surface mining in the West. These wind-eroded formations are very fragile, and damage as far as one-fourth of a mile from the operation has been noted.¹

4.3.1.2 Dust

Fugitive dust can arise from blasting operations, coal haul roads, spoil piles, and from virtually every operation that moves overburden or coal. Dust emission problems can be ameliorated in many cases by watering dusty haul roads and containing blast fragments with appropriate shields.

4.3.1.3 Aquifer Disruption, Water Contamination

Near surface deposits of low-rank coals are often associated with the areal groundwater systems. Such coal beds are either stratified near important aquifers, or else the bed itself comprises a major groundwater

system. The initial process of removing coal from a seam associated with an aquifer allows the groundwater to discharge into the mine pit, which would necessitate pumping the water into nearby surface streams. Addition of flow into these ephemeral stream channels can cause erosion and changes in water quality.

Surface mining destroys any highly permeable layers (aquifers) that may have existed prior to mining and forms, after reclamation efforts, a highly mixed hydrological system having lower permeability. Flow patterns through these backfilled aquifers would be changed, and could possibly alter nearby irrigational and municipal water well flows to the point of zero flow.

It is not known to what extent previous aquifer characteristics might be restored. One suggestion is that sorted gravels topping a tight clay layer might restore the aquifer, but the necessary research on this and other possibilities has yet to be performed.² However, until the social and economic value of water resources becomes as valuable as coal resources, any mining plan designed to selectively remove and replace all aquifers will be of such expense that it would preclude the economic recovery of the resource.

Another concern associated with the permeability change in reclaimed overburden is the potential for groundwater contamination resulting from acid mine drainage. In one Texas test pit study, the premining permeability was on the order of 10^{-2} cm/sec. However, the reclaimed test pit permeability was 10^{-4} cm/sec immediately after reclamation and 10^{-5} cm/sec 6 months later. These field studies were made 35 ft below the surface. In laboratory studies run on silt-clay and sand-clay mixtures the ultimate permeability was as low as 10^{-8} cm/sec when tested at overburden pressures that would exist below 20 ft.³⁰

The voids in the overburden formed by mining are not immediately filled with groundwater. Seepage cannot occur until the section is saturated, a process that may require many years to complete. For example, a 100 ft original highwall that expands to 125 ft after mining (25 percent swell factor) requires 187.5 gal per square foot or 25 acre-feet of water per acre of reclaimed land to reach saturation. The wettest spot in the world receives only about 18 acre-feet per year (assuming no evaporation losses it would require about 1 1/2 years to provide the required volume of water). During this time, a significant amount of redensification together with a corresponding decrease in permeability will have occurred.

In addition to the time required to saturate the overburden, it takes time for the overburden to oxidize and form acidic conditions. With decreasing permeability over time and the time dependent processes to form

oxidized conditions, groundwater pollution is naturally minimized. In coarse grained (fine sand) overburden the higher permeability is associated with more inert materials (quartz) so that pollution forming conditions are lessened. The clays and shales, associated with acid forming and oxidation pollution problems, have very low hydraulic characteristics. The net effect is that the geologic and hydrologic conditions and the present strip-ming methodology in the Gulf Coast lignite deposits have a generally low groundwater pollution risk.³⁰

4.3.1.4 Water Requirements for Mining

Industrial water requirements for surface mining operations are small and do not present serious problems of aquifer depletion or competition with existing uses. Both in the northern Great Plains and Southwest, the principal consumptive use of water in the mining operation is in dust control on access and haul roads. The most common source of this water is the surface and groundwater that accumulates in mine sumps. Quantities used depend on such factors as weather, length of road networks, and location of the mine with respect to aquifers and surface drainage.²

Auxiliary water requirements for domestic and sanitation purposes at a typical surface mining operation such as that at Decker, Montana will seldom exceed 5,000 gallons per day. Most of the shallow aquifers in the West will yield 7,200 gallons per day, which is adequate for these needs.²

4.3.1.5 Land Reclamation

Surface mining drastically alters the ecological characteristics of the area disturbed and in some cases has a decided effect on surrounding areas. Vegetation is removed, topographic features and characteristics are changed, and the original geologic overburden profiles are destroyed. Spoil banks generally are a heterogeneous mixture of rock fragments, rock particles, and soil-sized material that, once backfilled into the mining pit, bear no resemblance to "soil" as known to agriculture.

The physical composition as well as the chemical content of the spoil is extremely variable. In some areas both the rock and shale over a coal seam may contain pyritic materials which, when exposed to air, form sulfide compounds that are not only detrimental to plant growth but may prevent it entirely.³

During mining and before rehabilitation is begun stockpiles of topsoil, overburden, and raw spoil banks are subject to wind and fluvial erosion. Excessive siltation of local streams and ponds is a potential damaging impact from improper spoil management. In mining areas that possess quality topsoils (suitable for vegetation support and moisture

retention), the soil layer is segregated from the underlying, lower quality overburden and stored for eventual reapplication during reclamation. However, the values derived from reapplying the topsoil are often decreased by the process of stockpiling; the revegetative potential may be lost before it is placed on the spoils.²

Once the mined area is backfilled with the spoil, the resulting mass has been "fluffed," or swelled, up to about 1 1/2 times its original volume due to blasting and unconsolidation of the formerly packed strata. The spoil retains none of the discrete layers of the original overburden and hence severely alters the hydrologic permeability of the reclaimed area. Surface runoff, moisture retention, and groundwater flow characteristics are all affected. This can not only cause on-site ecological impacts, but also affects downstream watershed activity and possibly groundwater well flows.

In areas where surface mining disrupts agricultural activities, the reapplied topsoil (stockpiled during mining) behaves like plowed virgin land - releasing many nutrients and promoting rapid growth. Dr. Robert Curry (University of Montana) elaborates on this problem:

"This [behavior of reapplied topsoil] makes for high farm yields for several years . . . , but it defeats the natural nutrient cycling mechanisms and will ultimately result in a reduced vigor, reduced population stability, and retarded succession relative to adjacent undisturbed areas."⁴

Conversely, some mining activities in the West occur on arid, low quality solids. The underlying strata may contain layers of overburden possessing characteristics higher in quality than the topsoil and could potentially improve the post-mining utilization of the reclaimed area. Unfortunately, existing regulations in some states prohibit the reclamation process from shifting the layers of overburden.⁵

The principal determinant of successful soil formation and plant growth is soil moisture, not rainfall. In the arid west, rainfall bears relatively little relationship to soil moisture, and the highest evaporation rates occur during the growing season. These considerations must be applied when evaluating other climatic data for rehabilitation potentials.

Besides the chemical and biological parameters associated with proper reclamation, the physical and topographic factors of the spoil play an important part in controlling erosion and encouraging new vegetation. Some of these factors are described below.¹

Topographic Factors: Slope - The length and percent of slope are important factors in erosion control and vegetative establishment. A general rule-of-thumb is that as the percent of slope doubles, soil loss increases 2.6 times, and as the length of slope is doubled, soil loss increases 3.0 times. Thus as the steepness and length of slope increase, the amount of erosion and soil loss increase, making it difficult to revegetate these areas (i.e., steep and/or long outslopes, highwalls, and upgraded spoil banks).

Steepness of slope affects all land uses and machinery operation. A 30 percent slope is maximum for farm use such as pasture, hay-land or row crops. Precautions must be taken to control erosion on sloping areas regardless of use. Diversions or terraces that break the slope length and remove runoff to a safe outlet also help in preventing stream siltation and damage to adjoining lands.

Aspect - The direction in which a slope faces is known as aspect. Slopes facing north and east are generally cool and moist and are not too difficult to vegetate. Survival and growth on the hotter, drier south- and west-facing sites is generally poor. Temperatures average about 10 to 12 degrees higher on bare slopes having southern or western exposures than on slopes with northern or eastern exposures.

Physical Properties: Physical properties for the most part present less of a revegetation problem than do chemical properties. With proper spoil segregation, placement, and topsoiling, the problem can be minimized. The major problem will occur on orphan lands where the spoil is a mixture of the entire overburden and is usually of coarse texture, stony and will not function to retain water at the surface, as required for a good vegetative cover.

Stoniness - Stoniness affects all land uses, particularly the operation of machinery for tree planting, tillage, and management activities. Mine spoil has been divided into four classes of stoniness (Table 4.3.1.1) in order to evaluate the land use potential and treatment needed to stabilize and vegetate them for future use.

Table 4.3.1.1

Mine Spoils Classified According to Stoniness

<u>Stoniness Class</u>	<u>Criteria</u>	<u>Tillage Potential</u>
1. Non stony	<0.01% stones and boulders	Can be tilled
2. Stony	0.01-15% stones and boulders	Tillage limited, can be mowed for hay, pasture
3. Very stony	15-50% stones and boulders	Treat by hand
4. Extremely stony	>50% stones and boulders	Cannot use equipment

Source: Reference 6

Texture - Texture refers to the particle-size distribution of sand, silt, and clay in spoil; it influences vegetation mainly through its effects on spoil moisture, aeration, and compaction. Sandy-type spoil has good aeration but poor moisture holding capacity. Clay-type spoil compacts easily and in some instances is impervious to water percolation and root penetration. Silty loams are the best spoil material for revegetation and provide very favorable moisture conditions.

Color - Spoil material may vary in color from very light to almost black. Because of these color differences, temperature and spoil moisture may constitute serious problems. Temperatures in excess of 150°F have been recorded on spoil surfaces composed of dark shales. High temperatures are especially intense on south and west exposures and can be deadly to recently germinated or young plants.

Nutrients - Most mine spoils are characterized by a low level or lack of nitrogen, phosphorous, and organic matter. Nutrients such as potassium or other trace elements may also be lacking, but not to the relative frequency of nitrogen and phosphorus.

The factors affecting land reclamation procedures are so regional in nature (local geology, geography, climate, water resources, soil qualities, etc.) that a general discussion has limited value. Therefore, the remainder of this section on land reclamation is divided into specific (though brief) regional discussions according to major variations in the aforementioned factors.

Gulf Coast Region

Lignite mining in the Gulf Coast Region can avoid many of the problems associated with coal mining in the western low-rank coal areas. For many areas in Texas, the physical and chemical characteristics of soils are not much different from the underlying rocks and therefore, segregation of topsoil is not required.⁷

Texas lignite mining has only recently developed into a major growing industry, and offers a unique opportunity to preplan mining operations to minimize or avoid environmental degradation. Much of the mining in Texas will occur in the Pineywoods and the Post Oak Savannah vegetational regions of the state, both of which receive adequate rainfall (35-50 inches/yr) for revegetation.⁸

The Big Brown steam electric power plant is located in the Post Oak Savannah vegetational region. Completed in 1972, it was built as a mine-mouth plant near Fairfield, Texas, and near Wilcox Group lignite deposits. Before the promulgation of mine land reclamation laws and

regulations, Texas Utilities Company embarked on a precedential plan to restore the mining area to productive and pleasant acreage. Various soil samples were obtained and an ecological overview of the pre-mined area was conducted to establish a baseline for future reclamation work. An environmental research program coordinated by the university and the company was developed to conduct continued and varied research projects in the mining area.⁹ It was at the Big Brown site that soil analyses determined that topsoil segregation was unnecessary.

The Big Brown study indicates that land reclamation in the Piney Woods and Post Oak Savannah areas can be accomplished with relative ease due to such factors as adequate rainfall. However, lignite deposits do occur in drier southern areas of the state and reclamation could prove more difficult unless proper planning is initiated prior to, or at least early in the mining operation. Reclamation is far less costly and has a far higher chance of success if the effort begins during the development of the mining plan.¹⁰

Western Low-Rank Coal Regions

The coal lands of the western United States are quite different from others in the nation. They occur primarily in sparsely populated, mostly arid environments. Droughts are common and annual precipitation is more often below the average than above it. When precipitation does occur, it may come as high intensity, short duration storms or as snowfall when plants are dormant. Extreme fluctuations in both annual and seasonal temperatures are to be expected. Daytime soil temperature may reach levels that will desiccate seedling plants. Only hardy organisms that tolerate temperature extremes can survive the summer heat and winter cold. Wind, unimpeded by dense vegetation, drives sand and soil particles into tender plants and dries the soil.²

North Dakota

Wali and Freeman (reference 31) documented diversity and abundance of plant species, and soil physical and chemical properties at five mine sites in North Dakota where spoils ranged in age from 0 to 53 years. Based on numeric prevalence, only 50 plant species were found at mined sites as compared with 111 at the unmined sites, and the diversity in species between mined and unmined areas was considerable. The predominance of xeric species and many bare or sparsely vegetated areas, even at the oldest mine site, suggest that many native species have not adapted to severe environmental conditions even after 53 years. This implies that without proper treatment, the time required for revegetation could extend for many years, perhaps decades.³¹

Reclamation attempts in the Northern Great Plains have had highest success in terms of plant cover establishment where non-native species have been used. However, no experimental plots or reclamation attempts have been carried out for sufficiently long periods to test their abilities to withstand the drought, wind, and erosive conditions that sometimes occur. Thus, long term stability data are wholly lacking and the response of non-native species to natural conditions is not clearly known. Current experimentation with native species suffers in that insufficient attention has been given to the critical relationships between the degree of soil development and the degree of survival of native species under conditions of stress.¹⁰

New Mexico

Revegetation of surface mined spoil areas in the San Juan Basin of New Mexico poses some very difficult problems. The primary obstacle is the very low and erratic precipitation that makes the probability of successful revegetation very low without some form of irrigation. This need for additional water raises issues concerning the trade-offs between using the water for reclamation and for other areawide uses such as agriculture.

Another obstacle to the establishment of vegetation is the nature of the surface soil. Most of the soils developed on pediment surfaces and badlands are unsuitable for plant growth because they have a high sodium absorption ratio (SAR), low hydraulic conductivity, and are generally high in salts. The sandy material would be suitable for topdressing the spoils if adequate measures are taken to attain a suitable stand of vegetation and to prevent wind erosion until the vegetation is well established. After a suitable stand of vegetation is obtained, good range management practices and conservative grazing must be followed for several years to prevent degradation of the site.¹¹

Montana

The primary reclamation effort in Montana low-rank coal fields is the control of erosion. Erosion as a process results from two major driving forces: wind and water. Wind erosion in the Northern Plains area occurs somewhat continuously throughout the year. The detachment and movement of surface soil particles is sometimes hardly noticeable at a given moment, yet over a period of weeks or even days it is sufficient to destroy new seedlings by covering them with a fine layer of dusty soil.

Water erosion, however, occurs more sporadically than wind erosion due primarily to upstream snow melting in late spring or sudden summer thunderstorms. Minimizing erosion can be accomplished with organic mulches, live plant materials, or chemical surfactants or palliatives.

Of these methods, the establishment of living plants to protect the surface, to physically hold the soil in place, and to aid infiltration is by far the most effective.¹²

Several surface configurations have been extensively tested on spoil reclamation lands in Montana. They include deep chiseling, gouging and dozer basins. Deep chiseling is applicable on level or slight gradients; gouging on slightly steeper areas; and dozer basins on the steepest slopes. Dozer basins are an extreme treatment accomplished with a large single blade while gouging is a moderate treatment placed with a multiple disc implement powered by a farm tractor. Gouging techniques allowed storage of more water in the upper four feet of soil, and resulted in greater plant survival than chiseling or dozer basins.¹²

Summary

The following summary conditions are adapted from Curry¹³ and are intended to apply to all arid western lands where evaporation exceeds precipitation.¹⁰

1. Successful reclamation should be defined as restoration to a state under which vegetative cover and nutrient cycles are as 'closed' as before man-caused disturbance. In many instances in the arid west, such a goal cannot be attained within a period acceptable to mankind but in those instances, one should accept only those reclamation efforts that lead to natural progressive succession toward the desired state of closure.
2. Stable soil-vegetation relationships imply sub-climax vegetative cover that is adapted to the range of extremes, not means, of climatic and hydrologic conditions that may reasonably be expected to exist for a period of several thousand years.
3. Introduced species may permit increased rates of succession to a more stable community and may aid in construction of a soil but, ultimately, one would anticipate that the dominant cover should be made up of native species of those particular genotypes that have evolved in the area being reclaimed. This means that a nursery or seed source of these genotypic varieties must be available and must be site-specific to those particular sites being revegetated, not just to the northern great plains or a particular coal region.

4. The key to successful reclamation is not in the management of the ground cover, but in the biogeochemical management of the soil/plant combination best adapted to the site. This means that one should not necessarily strive toward most rapid growth or most vigorous green, but should attempt to achieve that combination of plants, soils, animals, and soil microorganisms that will permit longterm adaptation to expectable extremes of site climatic and other stress conditions.
5. It should be recognized that soil is a living biogeochemical substrate and cannot simply be stored in a pile during mining to be spread back over the recontoured spoils. Soil is composed of partly weathered and stratified minerals, delicately bound mineral nutrients that are available to plants upon demand but not available to leaching rainwaters, and living and dead organic substances and organisms that participate in the nutrient cycling between plants, atmosphere, and substrate. Each 2-4 inch segment of the top 1-2 feet of soil should be collected and maintained in viable condition and stratigraphic order if it is to be used most effectively for reclamation attempts.

Respreding topsoil over recontoured ground has demonstrably increased rates of restoration of arid lands. However, part of the reason for this increase is that the homogenized topsoil behaves just as do freshly plowed virgin lands. Its nutrient balance and storage structures are broken and it thus releases its nutrients in excess to rainwaters or irrigation, thus producing vigorous plant growth, especially of non-native species and weeds that habituate disturbed sites. Ultimately, initial high productivity gives way to reduced vigor, reduced population stability, increased susceptibility to pests and disease, and retarded succession. Thus 30-50 years hence in the high northern great plains, reclaimed lands will demonstrate less vigor and productivity than sites where weathering balances have been maintained in progressive states.

6. Use of water and fertilizer in reclamation efforts should be carefully planned so that biogeochemical conditions are not produced that are incompatible with those to which native plant communities must ultimately adapt. This requires that geochemical consequences of fertilization and irrigation are at least as well understood as biochemical consequences.
7. Reclamation implies replacement of the original water-holding capacity of a soil. If original soil structure and density could be maintained, such is not generally possible with large-scale earth moving equipment so reconstruction of soils with soil amendments becomes necessary. Soil organisms serve an important function for soil dilation and should be reintroduced with necessary food sources such as sewage sludge or agricultural wastes. Negative side effects of introduction of organic matter and change of soil pH profile should be fully understood.

Table 4.3.1.2 shows one estimate of the possibility of reaching the stated objectives in a "reasonable" time for various climatic conditions. Whether specific sites have higher or lower probabilities will depend on environmental assessments made for each site. For example, (see table) if a site is reshaped and is left to whatever plants will volunteer, only sites in the Ponderosa Pine and Mixedgrass Plains zones have a moderate chance of being revegetated in a reasonable time. Even when existing technology is applied properly, there is only a low probability for successful revegetation in the desert. The chance for revegetation in sagebrush is moderate. However, the chances of approaching the original ecosystem are only moderate even on the best of sites, and there is no probability of complete restoration anywhere. An almost endless number of alternative land use objectives (recreation sites, airports, waste disposal areas, etc.) can be selected that have a moderate to high chance of success anywhere.²

4.3.2 Transportation

Four modes of transportation used in the movement of low-rank coals are discussed in this sub-section: Trucks, barges, railroads (unit trains), and coal slurry pipelines. Though not in common use today, slurry pipelines are being seriously considered for long distance shipments of coal, and their development faces considerable environmental, economic, and legislative hurdles. Truck and barge-related impacts are real yet relatively minor when compared to rail shipment impacts. Future increases in coal utilization will exacerbate impacts from all of these transportation modes.

Table 4.3.1.2

Probability of Reaching Rehabilitation Objective
(High, Moderate, Low, Zero)

Rehabilitation Objective	Vegetative Zones			
	Desert	Sagebrush Foothills	Mixedgrass Plains	Ponderosa Pine & Mountain Brush
National Sacrifice Areas (Abandon the Spoils)	H	H	H	H
Shape Site to Avoid Aesthetic Insult	H	H	H	H
Shape Site and Expect Natural Vegetation to Stabilize the Environment	L	L	M	M
Establish Stable Vegetation by Using Best Technology	L	M	H	H
Approach Conditions and Values of Original Ecosystems	L	L	M	M
Complete Restoration of All Site Values	0	0	0	0
Reach Alternate Land Use Objective (e.g., airports, solar energy arrays, banana plantations, etc.)	0-H	0-H	0-H	0-H
Approximate % of Western Strippable Coal Reserve in Zone	11	27	41	21

Source: Reference 2

4.3.2.1 Railroad Transport

The substantial increase in unit coal trains required to transport new coal production will result in major social and environmental disruptions in many communities through which they move. Many towns in the West have been built around both sides of the tracks, hence railroad rights-of-way often divide major portions of towns. With most rail lines built at ground level, passing trains will temporarily sever towns, disrupting traffic on local streets and delaying essential hospital, fire, and police services. In some communities, in addition to acting as physical barriers, rail lines have come to represent social boundaries as well. In these instances, increased train traffic may have the effect of further isolating certain sectors of the community while adding to an already unsatisfactory community environment.¹³

The disruptions to the normal activities of affected communities would seem to be tolerable in cases where unit trains pass through towns only two or three times a day. However, should traffic increase to 35 trains per day,^a the total passby time for one day will jump to approximately 1.8 hours at train speeds of 20 miles per hour, and 7.2 hours at 5 miles per hour. In the latter case, the affected communities would in effect be severed for more than one-quarter of the day, clearly an intolerable situation in any town.¹³ Grade separations should therefore be considered where this type of problem is significant.

Increased rail traffic could cause problems in rural areas where the land is primarily used for ranching and farming. Railroad companies often erect "sheep-tight" fences along the tracks to keep free-ranging animals away from speeding trains. These fences, along with frequent unit train traffic, will prevent ranchers from crossing railroad tracks with their herds. This impact, however, is somewhat mitigated or tempered both by cattle passes built in new rail lines, and the fact that old rail lines often parallel highways, which block the passage of cattle independently of rail activity.¹⁴

Increased rail traffic will clearly magnify rail-highway grade crossing problems, although quantifying the incremental increase in deaths and injuries resulting from increased unit train transport is speculative at best. In any case, accident rates would be reduced by the installation of more traffic protection equipment along unit train rail routes.

Other environmental impacts associated with unit train shipments include combustion effluents from the diesel locomotive engines. These

^aTraffic on Burlington Northern's rail segment between Alliance and Lincoln, Nebraska, is expected to jump from 5 unit trains per day in 1975 to approximately 35 per day in 1980 (reference 13).

effluents will be distributed all along the shipment route, potentially polluting numerous towns and rural acreage. On the other hand, train passage is a relatively isolated event with definite opportunity for pollutant dispersal during the intervals between train passages. Diesel-electric locomotives emit carbon monoxide (CO), Hydrocarbons (HCs), nitrogen oxides (chiefly nitric oxide(NO)), particulates, and other pollutants during line-haul operations. The amount of each pollutant emitted depends upon several factors, including fuel composition and heating value, load, grade and use or lack of abatement equipment.

Fugitive dust emissions are another potential effluent from rail transport loading and unloading operations, as well as from blowoff during transit. The potential is not significant, however. Modern train loading facilities confine dust emissions to an area extending a few feet from the storage silos. Workers control the loading from within sealed enclosures and are not exposed to the dust. Coal losses appear to be negligible compared to the volume loaded. Coal losses during transit are so negligible as to be undetectable. Local officials in Wyoming and Colorado, which have appreciable coal train traffic, report that they have received no complaints of fugitive coal dust emissions.¹⁴

4.3.2.2 Barge Transport

Barge transport is not a transportation option in the U.S. low-rank coal regions. However, these coals are shipped to almost every corner of the midwest, and rail-to-barge shipments of subbituminous coals from the West are becoming more and more commonplace. With this method of transportation, unit trains carry coal from subbituminous mines in the Northern Great Plains across the midwest to barge-loading ports on the Great Lakes or on large navigable rivers. Barges then carry the coal to points north along the Lakes, or south along the Mississippi or other rivers.

Anticipated increases in barge traffic may disrupt or damage other commercial and non-commercial uses of the waterway. Possible consequences from expanded coal barge traffic are briefly discussed below.¹³

Dredging. The most important problem associated with channel dredging, which is required to maintain proper channel depth, is disposal of the dredge spoil. Spoil is pumped along the riverbanks and may destroy backwater wetlands, marshes, and sloughs, and their resident organisms. Dredging is in part a function of river traffic. Every effort should be made to minimize the impact of increased dredging that would occur as a result of increases in coal barge traffic.

Turbidity. Barge traffic turbidity churns up river bottom sediments, destroying bottom organisms and aquatic habitat, releasing pollutants present in bottom deposits, and reducing light penetration necessary for the photosynthesis production process. The destruction of

aquatic organisms may in turn affect shoreline organisms and wildlife by disruption of the natural food chain. Shoreline ecosystems may be impacted by barge wave wash, which tends to erode riverbanks and islands. The degree of turbidity is a function of river traffic, channel depth, sediment size, number of islands, and river width.

Water Quality. Oil discharges from tugs are a potential source of water pollution. Cargo spills are not likely to be a significant problem of increased coal transportation.

Shoreline Development. Increased barge traffic may induce shoreline development to provide additional barge-related services, resulting in secondary impacts such as industrial discharge, oil discharges from pleasure craft, destruction of environmentally sensitive areas, and reduction in shoreline property available for other land uses.

Air and Noise Pollution. Air and noise pollution from increased barge transportation are less likely to increase to a significant extent compared to other environmental variables, though it should be noted that any increase in tows will increase air pollution emissions and noise from tugs. This problem is much less severe for waterways than for other modes of transportation, suggesting that there are environmental as well as economic trade-offs between the modes.

Future low-rank coal barge traffic increases resulting from anticipated plant conversion or expansion on rivers of the inland waterway system will be minimal. The environmentally critical upper Mississippi River will be affected little, if at all, as western coal will be transhipped to barges at Duluth, Minnesota, St. Louis, and Metropolis, Illinois.¹³

4.3.2.3 Onsite Trucks and Conveyor Belts

The predominant use of large trucks for coal hauling in the low-rank coal regions is localized at the mine site. Large capacity, off-road trucks are used for short distance hauls, generally from the shovel or dragline to the storage or loading area. Rarely do truckloads of coal enter towns in the regions, as in the eastern coal regions in the U.S. Therefore, the impacts of truck transportation in the low-rank coal regions are relatively insignificant. Possible impacts associated with truck transport include: Fugitive dust, both from dry haul roads and coal loading and unloading operations; high-level noise from loading/unloading operations and from the giant engines on the trucks; and locally concentrated air emissions from the truck engine exhaust.

4.3.2.4 Slurry Pipeline

Predominant among the environmental issues concerning slurry pipelines is the issue of water supply. Citizens in arid coal source areas question the wisdom of exporting water to states where water is more abundant, and have expressed fears that increased pumping of groundwater for certain slurry pipeline projects would adversely affect the aquifers on which many people depend.¹⁵ As an example, water-requirements for a proposed Wyoming-to-Texas slurry pipeline range from 13,000 to 20,000 acre-feet/year, depending on best and worst-case scenarios. Thirty-five million tons of coal per year would be shipped via such a pipeline.¹⁴

The demand for western water to supply coal slurry pipeline projects competes with simultaneous plans for increased energy development, including mining, electric power generation, coal gasification and liquefaction, and shale oil exploitation. In the potential western coal slurry pipeline origin areas, demand projected for the 1985-2000 period exceeds the legally available supply. In the case of the Bighorn River in Montana, for example, the combination of present uses, signed contracts for U.S. Bureau of Reclamation water, and applications for future appropriations exceeds the state's compact share of the rivers flow by over 450,000 acre-feet/year. Demands in the entire Montana portion of the Yellowstone River Basin (to which the Bighorn is Tributary) will reach the legally available supply by the year 2000.¹⁶ Similarly, according to some projections, the area around Gillette, Wyoming, would have (without a slurry pipeline) a deficit of over 100,000 acre-feet/year by 2000, unless water were imported.¹⁷

Coal slurry pipelines could use surface water in these areas, but only at the expense of growth in the existing and new uses. Groundwater could in some cases reduce the deficit, but not the competition. Groundwater extraction has its own limitations as well. Assuming it were physically possible and economical to withdraw enough groundwater to overcome the projected deficit, withdrawals would exceed the present estimated recharge rate, so that the consequences of groundwater "mining" would have to be considered.¹⁴

There is currently one operating coal slurry pipeline in the U.S. In operation since 1970, it carries more than 5 1/2 million tons/year of coal from the Black Mesa mine (considered bituminous or subbituminous by conflicting reports) in Arizona to the 1500 MW Mohave power plant near Laughlin, Nevada. The power plant utilizes recovered and treated slurry water in the cooling systems, thereby alleviating some of the high volume water requirements associated with such facilities. Unfortunately, this successful, yet specific solution offers no potential relief of water demand for the proposed pipeline routes; regardless of the end-use of reclaimed slurry water, the thousands of acre feet of water would continue to leave the water-starved areas in Wyoming and Montana.

The major operational impact of coal slurry pipelines with disruptive effects on biological communities is accidental spills of slurry. There are three principal ways by which a slurry spill could occur along the transmission route: 1) pipeline rupture due to excessive pressure; 2) breakage resulting when the pipeline is accidentally struck by digging equipment; and 3) washout of the pipeline during a flood. Under the relatively high pressures of coal slurry in portions of the pipe, small leaks will normally develop quickly into major ruptures. The quantity of slurry released to the environment will depend upon the flow rate pressure, burial depth, overburden density, time for detection and pipeline shutdown, and proximity of holding ponds. Pipelines have been constructed with reserve holding ponds along the way. Using this approach, the slurry flow would be arrested in event of spill and the offending section of pipeline evacuated into the pond.

Only one coal slurry pipeline spill has been recorded, and the environmental impacts, primarily land and water impacts, are therefore only speculative. Presumably, the coal particles will be filtered from the water by the top few feet of soil. The effect of the coal in the soil upon plant growth is unknown. The impact of a spill into streams depends upon the relative flows of the stream and the spill. Coal sludge could temporarily harm aerobic benthic organisms, hamper fish feeding, smother eggs and larvae, and adversely affect spawning. Temperature changes and coal sludge could result in fish kills as well. These impacts, however, are not likely to be severe.¹⁴

There are several beneficial environmental and social impacts associated with coal slurry pipelines, especially when this transportation mode is compared to alternatives such as unit trains. Slurry pipelines will not disrupt western and midwestern towns as will unit trains. Noise impacts will be so different from unit trains as to make comparisons almost meaningless; while noise associated with trains stems from a continuous, yet moving source (locomotive engines and train wheels), pipelines are essentially silent except for the stationary pumping stations. These stations will be spaced at average intervals of approximately 75 miles,¹⁵ and will be located away from urban areas. Train/highway crossing accidents will, of course, be reduced if coal is moved by pipeline instead of by train.

Pipeline operations will have an indirect and relatively minor impact upon air quality if the electricity required to run pumps, slurry preparation equipment, and dewatering facilities is generated by combustion of fossil fuels.

4.3.3 Preparation, Handling, and Storage

Of all the environmental impacts associated with low-rank coal development, the ones resulting from preparation, handling, and storage activities are among the most easily rectified. Dust emissions and coal pile leaching are the primary impacts of crushing, loading, and storage activities. Coal washing, a common practice with bituminous coals is not presently used with subbituminous coal and lignite. However, there is a possibility that changes in mining practices and depletion of the highest quality reserves will create a need for some low-rank coal cleaning as time goes by. Each of these topics is discussed in the following paragraphs.

Dust emissions occur whenever coal is handled: crushing, transporting to storage silos or open stockpiles, and comminution. Fine coal particles easily become airborne in moderate winds and can be transported several miles from the site. Coal dust has a documented association with increases in lung diseases in humans, based on underground coal miner health in eastern bituminous mines. Fugitive dust emissions can be readily controlled by vacuum vents and baghouses, located wherever handling operations may produce excessive dust.

Coal storage, if uncovered, can be the source of fugitive dust as well as water contaminants. High winds can carry coal dust away from storage areas; rainfall can penetrate piles and leach out toxic trace elements and salts, carrying them into nearby water systems.

The slacking nature of low-rank coal (the tendency to form dust when exposed to the atmosphere) aggravates the fugitive dust emission problem. Operators using low-rank coal have learned to follow special handling and storage procedures to keep dust and spontaneous heating problems under control.

Impacts from storage piles can be mitigated with the application of coatings to seal the surface of the stockpile. This prevents water penetration and reduces air circulation through the pile. Coatings presently being evaluated include compositions formed by pulverized coal and waxes or plastics.¹⁸ More conventional mitigating measures involve careful shaping and handling of stockpiles.¹⁹ By using various sizes of the coal to be stored, piles can be formed that maximize water runoff with little water penetration. Dust emissions are reduced by covering the pile with a layer of coal chunks too large to be blown away by high winds.

Effluents resulting from coal cleaning activities include solid, liquid, and gaseous emissions.

Solid wastes: Coarse refuse from jigs and dense-medium vessels; fine refuse from air tables and hydrocarbons; sludge from clarification circuits; magnetite from dense-medium processes; and chemical reagents from froth flotation processes. These effluents can constitute quantities equal to one-fourth of the coal feed, and require controlled disposal practices to avoid leaching.

Liquids: The quantities of water used in coal cleaning range from 180 to 1800 gallons per ton of coal. Most of this process water is recirculated, but some is inevitably lost and may contain magnetite or potentially toxic or noxious chemical reagents. Suspended and dissolved solids are also present.

Air Emissions: With pneumatic cleaning systems, ambient air is used to separate coal from refuse. The exhaust air contains about 260 pounds of dust per ton of feed coal, although dust collection devices are used to control emissions to acceptable levels.

4.3.4 Processing and Utilization

The term "conversion" is considered in this sub-section as including conventional combustion, fluidized-bed combustion (FBC), coal gasification, coal liquefaction, and pyrolysis. Effluents from these coal conversion operations are for the most part quantified, yet the full extent of their impacts are not completely understood. (Little quantified data is available for FBC and pyrolysis processes.) This discussion first presents a summary listing of the available quantified estimates of effluents and land requirements associated with conversion activities, followed by estimates of potential impacts from these effluents.

Details concerning the processes and any available environmental control technologies can be found in appropriate sections in Chapter 3.

4.3.4.1 Coal Conversion Effluents

Tables 4.3.4.1 through 4.3.4.6 present estimates of gaseous and liquid emissions, water consumption, solid waste emissions, and land requirements for various low-rank coal conversion processes. The reader is cautioned that many of these estimates are based on process- and site-specific development scenarios. For this reason, quantity estimates are given as ranges.

Table 4.3.4.1

Air Emissions For Conversion Facilities^a
(pounds per hour)

Conversion Facility	Particulates	SO ₂	NO _x	CO	HC
Typical Size Power Plant ^b (3000 MWe)	1110-3010	4350-14000 ^c	14320-21080	1330-2170	400-650
Lurgi Gasification (250 MMcfd)	430-510	400-680	2325-2810	310-370	45-60
Synthane Gasification (250 MMcfd)	205-635	240-970	930-2110	160-200	20-60
Synthoil Liquefaction (100,000 bbl/day)	315-755	940-1180	1350-5770	220-1350	1660-4610

bbl = barrels
CO = carbon monoxide
HC = hydrocarbons
MMcfd = million cubic feet/day

MWe = megawatts-electric
NO_x = oxides of nitrogen
SO₂ = sulfur dioxide

^aThese numbers represent the range of emissions found in site specific scenarios; the facilities are assumed to be operating at a full load.

^b99 percent particulate removal and 80 percent SO₂ removal.

^cHad scrubbers not been hypothesized for the power plants, these numbers would be about five times larger.

Source: Reference 5

Table 4.3.4.2

Water Consumption of Coal Combustion/Conversion Facilities
for Subbituminous Coal and Lignite Feedstocks

Process	Size ^a	Net Water Consumption			
		(acre feet/year)		(gal/10 ⁶ BTU)	
		Subbituminous	Lignite	Subbituminous	Lignite
Combustion/Generation	3000 MWe	23880-29820			
Per BTU (th) ^b				43-54	
Per BTU (e) ^b				127-159	
Gasification ^c	250 MMscfd				
Lurgi		3350-7170	1670-5470	14-30	7-24
Synthane		3820-6690	3110-5740	16-28	13-24
Hygas		3590-5500	3590-5020	15-23	15-21
Bigas		-- --	3820-6450	- -	16-27
Liquefaction ^d	50,000 bbl/d				
Synthoil		3120-6860	4050-5920	10-22	13-19

bbl = barrels

Btu = British thermal units
(th-thermal and e-electric)

MMscfd = million standard cubic feet per day

MWe = megawatts-electric

^aLoad factors are: 70 percent for electric power; 90 percent for gasification and liquefaction processing.

^bPer Btu; thermal refers to the coal, per Btu; electric refers to the electricity. 34 percent efficiency is assumed.

^cThe heating value of the product is assumed to be 950 Btu's/standard cubic feet.

^dThe heating value of the product is assumed to be 6.29×10^6 Btu's/bbl.

Source: References 5 and 32

Cooling is the largest single water consumer for energy conversion technologies. Cooling water requirements can be reduced with the use of wet/dry rather than wet cooling processes. Over 60 percent of the cooling water needs could be eliminated by wet/dry techniques, as indicated in Table 4.3.4.3.

Table 4.3.4.3

Water Use Reduction Using Wet/Dry Cooling

Technology	Size	Fraction of Water Use for Cooling (%) ^a	Maximum Water Use Reduction Using Wet/Dry Cooling	
			%	Acre-Feet Per Year ^b
Power Generation	3,000 MWe	80-91	60-78	16,230-17,940
Lurgi Gasification	250 MMscfd	53-96	40-72	2,230-2,540
Synthane Gasification	250 MMscfd	65-70	49-53	3,840-4,220
Synthoil Liquefaction	100,000 bbl/day	67-87	50-65	5,880-6,550

bbl = barrels

MMscfd = million standard cubic feet per day

MWe = megawatts-electric

^aPower generation load factor is 70 percent; for synthetic fuels, 90 percent. This includes water use in mining.

^bRange in amount of water saved is due to site-specific variations.

Source: Reference 20

Table 4.3.4.4
Liquid Effluents from Conversion Facilities

Technology	Size	Load Factor	Wet-Solids Tons/Day	Pounds/10 ⁶ Btu in Product
Power Generation ^a	3,000 MWe	70%	3,140-14,510	(e) 33-152 (th) 11-52
Lurgi Gasification ^b	250 MMscfd	90%	1,960-8,220	18-77
Synthane Gasification ^b	250 MMscfd	90%	1,950-7,780	18-73
Synthoil Liquefaction ^c	100,000 bbl/day	90%	3,380-14,540	12-51

bbl = barrels

Btu = British thermal unit

MMscfd = million standard cubic feet per day

MWe = megawatts-electric

^aPer Btu (th) refers to the coal; per Btu (e) refers to the electricity.
34 percent efficiency is assumed.

^bAssumed heating value of product to be 950 Btu/ft³.

^cAssumed heating value of product to be 6.29 x 10⁶ Btu's/bbl.

Source: Reference 20

Table 4.3.4.5

Land Use by Conversion Facilities

<u>Conversion Facility</u>	<u>Typical Size (acres/30-year life of facility)</u>
Power Plant (3000 MWe)	2,400
Lurgi Gas (250 MMcfd)	805
Synthane Gas (250 MMcfd)	805
Synthoil Oil (100,000 bbl/day)	2,060

bbl = barrels

MMcfd = million cubic feet per day

MWe = megawatts-electric

Source: Reference 5

Table 4.3.4.6
Solid Waste from Conversion Facilities

Technology	Size	Load Factor	Dry-Solids Tons/Day ^a	Pounds/10 ⁶ Btu in Product
Power Generation ^b	3,000 MWe	70%	1,810-9,850	(e) 19-103 (th) 6-35
Lurgi Gasification ^c	250 MMscfd	90%	1,380-6,120	13-57
Synthane Gasification ^c	250 MMscfd	90%	1,390-6,010	13-56
Synthoil Liquefaction ^d	100,000 bbl/day	90%	2,540-11,140	9-39

bbl = barrels
 Btu = British thermal unit
 MMscfd = million standard cubic feet per day
 MWe = megawatts-electric

^aThe range of values is that found at six sites analyzed.

^bPer Btu (th) refers to the coal; per Btu (e) refers to the electricity.
 34 percent efficiency is assumed.

^cAssumed heating value of product to be 950 Btu's per cubic foot.

^dAssumed heating value of product to be 6.29×10^6 Btu's/bbl.

Source: Reference 20

4.3.4.2 Atmospheric Effluent Impacts

Sulfur Dioxide

Sulfur dioxide as a pollutant has been the subject of more investigation than any other single pollutant. Power plants (not specifically coal-fired) are the largest single source of sulfur pollution in the country, being responsible for some 65 percent of the approximately 30 million tons of sulfur oxides emitted each year.³⁴ The pollutant is capable of traveling great distances in the atmosphere, thereby increasing its effect as an air contaminant. The majority of SO_2 is removed from the atmosphere via rainout and washout and is deposited on soil, water and vegetation. However, while in the atmosphere, SO_2 may undergo significant chemical reactions such as the gas phase oxidation to sulfur trioxide and the subsequent dissolution in water droplets to form sulfuric acid.²¹

Some of the sulfuric acid in turn reacts with metallic ions or other substances in the air to form sulfate compounds, which remain in the air as submicron-size particulates. There is growing evidence that it is the aerosol or "mist" containing sulfuric acid and metallic sulfates, and not the SO_2 itself, that is the major culprit in sulfur pollution.³³

A related environmental impact receiving considerable public attention is the phenomenon known as "acid rain." Acid rain is defined as any precipitation having a pH of less than 5.6. It is produced when SO_2 is oxidized to H_2SO_4 in the presence of atmospheric moisture.²² Acid rain problems have been reported not only in the U.S. and Canada, but also in other North Atlantic countries, including Greenland and Sweden.

A series of studies in Sweden in the 1960s demonstrated conclusively that numerous lakes and streams in relatively pristine areas of the country had become highly acid. In many, fish populations had been destroyed or severely damaged.³⁵

One Swedish case study estimated that in some parts of Scandinavia the acidity of rainfall had increased as much as 200-fold since 1956. These findings dramatized both intensity and the large regional scale of atmospheric sulfur problems in the atmosphere, and they led to remarkable cooperative international studies by the OECD.^a These studies have documented sources of sulfur emissions, transport in the atmosphere, chemical transformations of sulfur occurring during transport, the distribution of sulfate in the atmosphere, deposition of sulfur in various forms throughout the region, and injury to vegetation and to fish in streams and lakes. They clearly confirm that a large part of the acidity of the rainfall is related to sulfates in the atmosphere produced by chemical transformations of sulfur dioxide emitted hundreds of miles away.

^aOrganization for Economic Cooperation and Development.

High acidity has also been observed in some Canadian lakes downwind from the high sulfur emissions of smelters in the large Sudbury mining district in Ontario. Because concentrated sulfur emissions have long been known to damage vegetation and waters severely in the immediate vicinity of smelters, these observations do not necessarily indicate longer distances of transport. However, comparison of the acidity of a lake in the Adirondacks, far from any sulfur emission sources, reveal that the pH dropped from a range of 6.6-7.2 in 1938 to a range of 3.9-5.8 in 1960.³⁶ By 1970, observations at a number of sites in the Finger Lakes region of New York showed that the pH was about 3.9 on average, with even lower values in the summer.^a Since about half the increased acidity was due to sulfates (the other half being nitric and hydrochloric acid) and since there were no significant local sources of sulfur, the report suggested that sulfates were probably transported from quite distant areas, such as the Ohio valley.³⁶

The existence of high sulfate levels and of acid rain far from known sources has also been confirmed by a variety of regional and global measurements in Scandinavia, New England, and elsewhere. In some instances specific air masses containing high SO₂ and sulfate concentrations have been followed for days as they move hundreds of miles. Over the open Atlantic Ocean in the northern midlatitudes, the ratio of SO₂ to sulfates (mostly natural sodium sulfate from sea salt) has been increasing and is now strikingly higher than the normal background ratio over the oceans. Analyses of yearly snow layers from inland Greenland ice indicate that the sulfate content has increased about threefold, from 0.06 µg/liter before the nineteenth century to 0.2 µg/liter in 1977.³⁷ Thus, the evidence is persuasive that sulfur dioxide and sulfates are increasing in the atmosphere and travel over distances of many hundreds of miles, where they may impair visibility, adversely affect ecological systems or materials, or damage human health.

American and European observers have also noted that while mean concentrations of sulfur dioxide, sulfate, or acid levels in the air expressed as annual or monthly averages provide useful synoptic pictures, not infrequently the movement of air masses and particular weather conditions produce abrupt increases in sulfates and in the acidity of rain, unrelated to local SO₂ levels. Such changes in meteorological factors may give rise to spurious correlations or may mask real correlations between long-term trends in sulfur emissions and sulfate levels over a broad region.³⁸ And they certainly call into question management methods based on predicting and/or preventing any specific local ambient concentrations.

^aAccording to an article by Likens (reference 39), a survey of Adirondack lakes between 1929 and 1937 found that 4 percent of these lakes had pH values below 5.0 and contained no fish. A survey of these same lakes in the 1970's revealed that 51 percent now have pH values below 5.0, and 90 percent are devoid of fish.

Acute damage to both agricultural and forest plants from sulfur dioxide emissions has been extensively documented. Obvious phytotoxic effects such as foliar injury occur in many sensitive plants when SO_2 concentrations exceed about 0.5 ppm for 1 hour.²³ Chronic effects such as reduced growth or reproductive rates may occur at even lower concentrations over extended periods of time. According to one report,²⁴ the mean annual local concentration of SO_2 need only exceed 0.01 to 0.08 ppm for obvious injury to occur.

Nitrogen Oxides

In contrast to sulfur dioxide, most global nitrogen oxide (NO_x) emissions originate from natural sources. One report contends that natural emissions of nitrogen dioxide and nitric oxide are 15 times as high as emissions of anthropogenic origin.²⁵ However, urban concentrations of NO are due largely (90%) to automobile emissions, and total 8.1 million tons per year. Full combustion produces 10 million tons/year in the U.S. alone.²² No specific impacts from NO_x emissions from low-rank coal conversion facilities have been documented.

Nitrogen dioxide can be phytotoxic at high levels, but exposure, dose, and response information is sparse. Because atmospheric concentrations of nitric oxide or of nitrogen dioxide sufficient to cause acute plant damage rarely occur, chronic exposures may be more important than acute exposures.²² As a single pollutant, NO_2 at many parts per million will not injure plants if exposures are for a few minutes; however, reduced vigor may be expected at continuous levels of 5 to 10 ppm. The acute injuries which develop in many kinds of plants exposed to nitrogen dioxide resemble those produced by sulfur dioxide.²⁶

In the atmosphere, much of the nitrogen oxide may be converted to the very toxic intermediate, peroxyacetyl nitrate (PAN); and the most likely final product is nitric acid, a powerful oxidizing agent and strong acid. The nitric acid presumably reacts with other contaminants of the air to form nitrates. Although nitrates in the atmosphere have been relatively little studied, one report from the Los Angeles basin showed ammonium nitrate to comprise 10 to 15 percent of the total suspended particulates.⁴⁰ Nitric acid has been identified spectroscopically in the Los Angeles air, along with the related nitrogen compounds formaldehyde and formic acid. Nitric acid and its salts are therefore of concern with respect to health effects of inhaled particulates and as contributors to acid rain.

For these reasons, the nitrogen oxide air pollution problem is about as complex as the sulfur dioxide problem. Nitrogen dioxide ambient levels may or may not be a good indicator of the health and other effects of PAN, nitric acid, oxidants, and nitrates; and reducing nitrogen oxide emissions will have uncertain effects on the ambient concentrations of

NO₂ and related compounds. Ambient levels of any of these substances will be influenced by emissions hundreds of miles away. There is no simple way to say that emissions at a certain point will or will not cause any particular effects at any particular point.³³

Particulates

The status of particulate control technology is such that the total mass of fly ash emitted from coal-fired power plants can be adequately controlled by increasing the size and/or power input of conventional collection equipment. Removal efficiencies greater than 99.5 percent are not uncommon, yet are at the same time misleading in their alleged success. Most conventional control equipment decreases in particulate collection efficiency as particle size decreases. Below about 2 microns, the collection efficiency of most devices decreases significantly. Unfortunately, particulate in this size range is the most serious from an air pollution and health hazard standpoint since it remains suspended in the air, can penetrate deep into the lungs, and has a high surface area for catalytic activity and/or sorption of gaseous pollutants. These small particles account for about 2 percent of the total mass emission; yet, in terms of numbers of particles, they can exceed the particulate population making up the remaining 98 percent of the fly ash mass.⁴¹

Very little work has been done to improve the small particle collection efficiency of control equipment or to develop equipment specifically dealing with this problem. Federal emission standards are being formulated to address the fine particulate problem. Current standards do not take into account the relative toxicities of different types of particulate matter. The properties and composition of the fine particles in low-rank coal fly ash have not been well characterized. However, they are believed to differ from the high-rank coal fine particulate properties because of the unique forms of finely dispersed mineral matter in low-rank coals, and such factors as the volatilization of sodium.

Trace Elements

Many trace elements present in coal combustion fly ash concentrate on the particle surface. This concentration is known to increase with decreasing particle size, particularly with trace metals such as lead and vanadium.⁴² Therefore, since the smaller, respirable particles (<5 microns) contain the higher trace element concentrations, the toxic impact on living tissue (e.g., lung tissue) may be more severe than previously anticipated on the basis of bulk analysis.⁴³

The amounts of elements mobilized into the atmosphere as a result of weathering and coal combustion are estimated in Table 4.3.4.7. Some of the more toxic elements are shown to be mobilized into the atmosphere in greater amounts from weathering than from coal combustion.

Table 4.3.4.7

Amounts of Elements Mobilized into the Atmosphere as a Result
of Weathering Processes and Coal Combustion

Element		Coal Concentration ^{a,b} (ppm)	Coal Combustion Mobilization ^{b,c} (X 10 ⁹ g/year)	Weathering Mobilization (X 10 ⁹ g/year)	
				River Flow ^d	Sediments ^e
Lithium	Li	65	9	110	12
Beryllium	Be	7.0 ^f	0.41		5.6
Boron	B	116 ^f	10.5	360	
Sodium	Na	2,000	280	230,000	57,000
Magnesium	Mg	2,000	280	148,000	42,000
Aluminum	Al	10,000	1,400	14,000	140,000
Phosphorus	P	500	70	720	
Sulfur	S	20,000	2,800	140,000	
Chlorine	Cl	1,000	140	280,000	
Potassium	K	1,000	140	83,000	48,000
Calcium	Ca	10,000	1,400	540,000	70,000
Scandium	Sc	5	0.7	0.14	10
Titanium	Ti	591 ^f	70	108	9,000
Vanadium	V	16 ^f	3.5	32	280
Chromium	Cr	7 ^f	1.4	36	200
Manganese	Mn	50	7	250	2,000
Iron	Fe	10,000	1,400	24,000	100,000
Cobalt	Co	2.7 ^f	0.7	7.2	8
Nickel	Ni	7.2 ^f	2.1	11	160
Copper	Cu	15	2.1	250	80
Zinc	Zn	59 ^f	7	720	80
Gallium	Ga	5.5 ^f	1	3	30
Germanium	Ge	1.6 ^f	0.7		12
Arsenic	As	3 ^f	0.7	72	
Selenium	Se	.73 ^f	0.42	7.2	
Rubidium	Rb	100	14	36	600
Strontium	Sr	500	70	1,800	600
Yttrium	Y	13 ^f	1.4	25	60
Molybdenum	Mo	1.7 ^f	0.7	36	28
Silver	Ag	0.5	0.07	11	0.03
Cadmium	Cd	2.1 ^f			0.5
Tin	Sn	0.9 ^f	0.28		11
Barium	Ba	500	70	360	500
Lanthanum	La	9.5 ^f	1.4	7.2	40
Cesium	Ce	11.5	1.6	2.2	90
Praseodymium	Pr	2.2	0.31	1.1	11
Neodymium	Nd	4.7	0.65	7.2	50
Samarium	Sm	1.6	0.22	1.1	13
Europium	Eu	0.7	0.1	0.25	2.1
Gadolinium	Gd	1.6	0.22	1.4	13
Terbium	Tb	0.3	0.042	0.29	
Holmium	Ho	0.3	0.042	0.36	2.3
Erbium	Er	0.6	0.085	1.8	5.0
Thulium	Tm	0.1	0.014	0.32	0.4
Ytterbium	Yb	0.5	0.07	1.8	5.3
Lutetium	Lu	0.07	0.01	0.29	1.5
Rhenium	Re	0.05	0.007		0.001
Mercury	Hg	0.1 ^f	0.0017	2.5	1.0
Lead	Pb	7.2 ^f	3.5	110	21
Bismuth	B	5.5	0.75		0.6
Uranium	U	1.0	0.14	11	8

^aThese average values were obtained from a review of published values for the abundances of elements in coal and fuel oils. Wide variations exist for a given element and the figures are presented as reasonable estimates from available data.

^bCoal and lignite are combined in this representation.

^cBased upon 1967 production figures.

^dIn the main, calculated from the data of Turekian (as cited in reference 45).

^eIn the main, calculated from the data of Goldberg (as cited in reference 45).

^fThese values are from reference 46 and represent Northern Great Plains and/or Powder River Basin coal analyses. The remaining values in the column represent averages from many different coals.

Source: References 45,46

It is difficult to quantify a level of toxicity for trace element emissions since the effect of any trace metal depends upon the organism in question, the dosage, and the chemical form of the trace metal absorbed. Certain trace metals are considered carcinogenic only when they exist in particular forms. The level of dosage may have varying effects on toxicity and on the detection of damage. For example, the toxicity of substances at high concentrations and short term exposure is more easily observed because the symptoms produced are often definite and acute; exposure to emissions from utility boiler stacks is usually long term and at relatively low levels, and the pathological processes arising from such exposure may be unnoticed, or misdiagnosed.⁴⁴

There has been recent concern over the amount of radioactive material that may be emitted to the atmosphere from coal combustion. Results from one study⁴⁷ indicate that concentration of radionuclides in coal from 18 Western mines (19 coal seams) varies widely, both within and between mines. The concentration of radionuclides in Western coal being mined today is roughly comparable to that of Eastern coal and is slightly below the average for all U.S. coal. A radionuclide balance from a power plant burning Western coal indicated that over 80 percent of uranium-234, uranium-238, and lead-210 present in the feed coal remained with the fly ash. An additional 8 to 9 percent remained with bottom ash. The impacts from these emissions, however, are no real cause for alarm; environmental deposition of radionuclides from stack emissions was estimated by atmospheric dispersion modeling to be 0.1 to 1.0 percent of measured background.⁴⁷

Hydrocarbons

Hydrocarbon emissions result from incomplete combustion processes, waste streams from synthetic fuel facilities, and from vapor leaks around pump seals and piping networks. Hydrocarbon emissions from coal conversion facilities are difficult to estimate quantitatively, although some qualitative analyses of the emissions have been documented.^{21,22}

Coal liquefaction processes produce a waste stream containing potentially carcinogenic multi-ring organic compounds that will require strict monitoring and control. Both liquefaction and gasification processes produce organic waste streams containing dissolved phenols, but these effluents typically remain in the water phase and do not constitute atmospheric emissions. Generally, organic waste streams can be effectively destroyed by proper incineration, and by adequate maintenance of system components to minimize leaks.

4.3.4.3 Water Effluent Impacts

Water is used in large quantity in most coal combustion and conversion processes. As illustrated earlier in Table 4.3.4.2, direct combustion for electric power generation requires more water than any of the synthetic fuel technologies. This is true whether the water requirement is measured on a total volume basis, or in terms of equivalent energy output. The predominant usage of these water volumes is for process cooling (refer to Table 4.3.4.3).

Cooling towers accumulate mineral deposits due to evaporation and the addition of corrosion inhibitors. It is therefore necessary to discharge, either continuously or intermittently, a fraction of the circulating water (usually less than 1% of the flow). This blowdown contains high concentrations of suspended and dissolved solids and sometimes significant amounts of residual chlorine. It may also contain chromium, zinc, phosphate, or other corrosion inhibitors and biocides in excess of effluent standards. This water can be treated and reused as cooling tower makeup water, reused as scrubber makeup, or discharged.

Wastewaters are produced in coal conversion processes when: 1) gases are scrubbed to remove soluble contaminants, quenched to control operating temperatures, compressed, or dehydrated; 2) steam used in the units cools and condenses or is reformed during methanation or hydro-treating; or when 3) slags and ash are water-quenched for slurry removal.

In coal gasification plants, there are four key process water effluent streams with various levels of quality. The dirtiest water stream is the foul process condensate recovered after gasification. Streams of intermediate cleanliness are those recovered after shift conversion and gas purification. The water of reaction stream from methanation is quite clean. Not every gasification plant has all of these streams, however.

The quality of the foul process condensate is directly linked to the gasifier process as defined by its operating variables, and to the rank of coal. Table 4.3.4.8 indicates a very broad measure of off-gas cleanliness for different gasifier types based on operating temperature. Other process variables that affect the effluent quality are: gas residence time, heatup rate of the coal, and gas-solid mixing.⁴⁸

In terms of effluent water treatment in synthetic fuel plants, chemical contaminants are the most numerous and generally the most difficult to remove. The chemical pollutants may be either organic or inorganic. Among the most important categories of inorganic pollutants are soluble gases, acids and bases, hardness, heavy metals, and soluble salts. The foul process condensates from all gasification reactors, except those operating at high temperature (e.g. Koppers-Totzek), contain large amounts

Table 4.3.4.8

Gasifier Characteristics

Type	Temperature (1500 ^o -3500 ^o F)	CH ₄ (0-15 mol%)	H ₂ /CO ^a (0.4-2.5)	Conversion Eff. (65-80%)	Product Gas Cleanliness
Entrained Flow	High	Generally Little	Low- Medium	Lower	Clean
Fixed Bed	Intermediate	Medium	Medium- High	Upper	Dirty
Fluidized Bed ^b	Low	Can Be High	Medium- High	Upper	Intermediate

^aOxygen-blown and excluding CO₂ Acceptor.

^bExcluding hydrogen-blown gasifier.

of dissolved ammonia formed from nitrogen in the coal. Ammonia is usually present in such high concentrations that releasing it to the atmosphere, as in a cooling tower, would emit a highly noxious odor. Ammonia can be corrosive to copper piping and inhibit biological decomposition of the organic contaminants. Gasifier condensates also contain large quantities of the dissolved acid gas carbon dioxide and smaller quantities of hydrogen sulfide. In hard alkaline waters high in calcium, the scale forming compound calcium carbonate will precipitate, which can seriously impair the effectiveness of heat transfer surfaces.⁴⁸

Organic contaminants are present in all foul process condensates in large quantities. Among the most prominent are phenols (carbolic acid), cresols, and "fatty" organic acids (carboxylic acids). Some of the organic matter may be removed by biological decomposition. However, many of the organic compounds found in the effluent process streams cannot or can only very slowly biologically decompose. These organics are "refractory" in that they resist biological decomposition. Under suitable conditions, they can be chemically oxidized to CO₂ and water. Phenols, which can be easily biodegraded when diluted, are toxic in high concentrations and inhibit biological oxidation.⁴⁸

Effluents from coal liquefaction and pyrolysis processes are not significantly different from those resulting in gasification. In fact,

the Fischer-Tropsch process produces nearly identical effluents as Lurgi gasification plants because coal is first gasified (Lurgi) prior to Fischer-Tropsch synthesis.

All of the foul process condensates recovered from liquefaction and low to intermediate temperature gasification plants have a high chemical oxygen demand (COD), up to 30,000 mg/l, and a high biochemical oxygen demand (BOD), up to 20,000 mg/l. They all share the need to remove large quantities of phenol, roughly 3,000 to 10,000 mg/l, and large quantities of ammonia in the range of 3,000 to 16,000 mg/l or more, depending on the process and the coal.⁴⁸

To remove or destroy phenol and other organic matter, many possible procedures exist including solvent extraction, adsorption on carbon or synthetic polymers, biological or chemical oxidation, and others. Ammonia and the acid gases carbon dioxide and hydrogen sulfide are not difficult to separate by fractional distillation due to their volatility. These processes are described in Section 3.5.3.4, Coal Gasification Environmental Control Technology.

Water Consumption

Where groundwater supplies are used for conversion facility process water and cooling, the quality of local aquifers may be affected due to any of the following:

- Intrusion of poor-quality water into the aquifer caused by excessive pumping
- Groundwater contamination due to subsurface disposal of wastewaters
- Groundwater contamination associated with solid waste disposal

These potential impacts would be indirect consequences of low-rank coal utilization, occurring gradually and usually detectable only after years of disruption. Because of the subtle - albeit irreversible - nature of these water concerns, it may be difficult to justify immediate controls on groundwater impaction.

Thermal Effluents

Utility steam-electric power plants burning low-rank coals convert about 1/3 of the coal's energy into electricity. The remainder of the

energy is lost as low-grade heat. Normal power plant practice is to remove this heat by circulating river or ocean water through the plant as a coolant, or by evaporating water in huge cooling towers. The latter process is more common where water is scarce or where the thermal increase in diverted river (or ocean) waters could significantly alter the local aquatic ecosystem.

Thermal discharges that increase river temperature by only 100F or so will invariably alter the plant and animal populations, potentially disrupting balanced food cycles and spawning habitats. Discharges of warm water typically result in less valuable species of fishes. Warm air releases from cooling towers also contain high moisture levels and can create localized changes in weather behavior.

4.3.4.4 Solid Waste Impacts

Solid wastes are produced during all coal combustion/conversion activities and include the following materials:

- fly ash from conventional and fluidized-bed combustion (FBC)
- bottom ash or slag (combustion)
- solids from flue gas particulate and SO₂ control equipment
- mineral matter (remaining from liquefaction)

The major solid waste problems from coal combustion result from fly ash collected in particulate control devices, bottom ash or slag, and the large quantities of dry solids or sludges produced from SO₂ scrubbers. FBC units do not require flue gas scrubbing systems like conventional combustors, yet the bed material must be continually refreshed if SO₂ control is to remain effective. Because of the need for fresh bed material, an equivalently sized (MW output) FBC unit can produce up to five times as much bottom ash (this includes spent bed material) as is produced by conventional combustion.

The major solid waste streams in coal gasification plants are coal cleaning refuse, bottom ash or slag, and waste water sludge. Liquefaction effluents consist mainly of mineral matter from the coal feedstock. Indirect liquefaction processes will discharge an ash or slag from the gasification stage. Other solid wastes will include spent catalysts, organic sludge from wastewater treatment, and inorganic sludge from flue gas desulfurization or evaporation ponds.

Disposal of these solid wastes in an environmentally sound manner is a difficult and increasingly significant problem as the quantities of these effluents continue to grow. The use of the word "disposal" is somewhat misleading in that these wastes are merely stored, as safely as possible, not necessarily disposed of in terms of ultimate removal. Ocean dumping and old mine dumping are "disposal" techniques currently practiced to a small degree, yet even these methods of removal are not complete solutions.

The selection and design of a disposal site is the most important task associated with solid waste and scrubber sludge disposal. Although the total surface acreage needed for disposal is large, the main concerns involve the leaching of contaminants from disposal sites into rivers and aquifers. These contaminants are not readily eliminated, but careful design and maintenance of storage areas can isolate these wastes from water routes, thus minimizing the impact on aquatic life and water quality.

Liquor disposed of in unlined sludge ponds and landfills will either evaporate, percolate down through the sludge and subsoil and potentially to an underlying aquifer, or overflow the pond. Additional rainfall in-flow will add to the total liquor volume unless covered.

Flue gas desulfurization sludge, in its untreated form, is fine-grained, highly water-retentive, low in structural load-bearing capability and tends to fluidize when disturbed. The principal contaminants in wastewater occluded in the waste solids include dissolved solids (primarily sulfates), chemical-oxygen demand due to sulfites, and soluble heavy-metal trace elements. The solids also contain leachable salts that are potentially toxic.²⁹

Commercial fixation has been developed as one approach to both water and land deterioration problems associated with solid wastes and sludges. Other alternatives more traditionally used in other industrial waste disposal operations include:

- pond liners
- landfill sealants
- surface and ground water flow diversion
- leachate collection systems

These environmental control technologies are discussed in considerable detail in Section 3.5.1.2.2 Direct Combustion, Solid Wastes.

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Eighteen authors contributed to this report, which is based on a symposium held at the University of North Dakota in 1975. These authors present state-specific reclamation activities-successes and failures. The report is an excellent source of recent empirical data on soil and vegetation types, and the effects of irrigation and fertilizer on reclamation attempts.

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This is a progress report of a three year technology assessment of the development of six energy resources (coal, geothermal, natural gas, oil, oil shale, and uranium) in eight western states (Arizona, Colorado, Montana, New Mexico, North Dakota, South Dakota, Utah, and Wyoming) during the period from the present to the year 2000. Volume I describes the purpose and conduct of the study, summarizes the results of the analyses conducted during the first year, and outlines plans for the remainder of the project. In Volume II, more detailed analytical results are presented. Six chapters report on the analysis of the likely impacts of deploying typical energy resource development technologies at sites representative of the kinds of conditions likely to be encountered in the eight-state study area. A seventh chapter focuses on the impacts likely to occur if western energy resources are developed at three different levels from the present to the year 2000.

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Ten chapters cover, in great detail, pertinent topics that include: coal characteristics, chemistry, petrography; conversion process descriptions; process effluents and related control technologies; environmental interactions of hydrocarbons, trace elements, sulfur oxides and nitrogen oxides; microbial interactions of organic and inorganic compounds; plant interactions; animal-bioenvironmental effects; and human metabolism and biological effects. The two volumes represent an invaluable reference document for highly technical and biological analyses of coal utilization impacts.

4.4 MARKET ANALYSIS

4.4.1 Existing Markets for Low-Rank Coal

The use of low-rank coals in the United States has been limited by several factors:

1. The major deposits are located relatively far from the industrial and population centers; long-distance coal (or electricity) transportation is very costly.
2. Convenience and cleanliness of oil, gas, and electricity have excluded coal (of all ranks) from direct use in the vast majority of industrial, commercial, residential, and transportation markets.
3. Unsuitability of low-rank coal as coking fuel excludes it from the one remaining major industrial market for bituminous coal.

Because of these factors, low-rank coals accounted for a very small portion of the 400-600 million tons per year of coal produced and used in the U.S. between 1920 and 1970. This was in spite of the fact that many of the low-rank coal reserves could be mined at a fraction (roughly one-half) of the cost per Btu of eastern bituminous coal.

In the period between 1960 and 1973, several technological and regulatory developments changed the relative economics of low-rank coal use by the electric utility industry:

1. Very large pulverized-coal-fired boilers, as well as extremely large strip mining machines, were perfected; these allowed the industry to realize the economics of scale required to make low-rank coal use competitive.
2. Electric power transmission systems and reliability councils developed to the point that vast regions of the U.S. became interconnected and interdependent; thus, minemouth power plants could serve a wide market area.
3. Limits were placed on emissions of SO₂ from coal-fired plants; this created a huge demand in the midwest for low-sulfur western coal, despite the high transportation costs.
4. OPEC radically raised the price of oil, and gas prices followed; this created a strong incentive to switch from these fuels to coal for power generation, particularly in Texas.

As a result of these developments, low-rank coal use by the electric utilities began growing at unprecedented rates in the 1970's. This growth rate (15-20 percent per year) will continue at least through 1985 based on current construction plans. Lignite, with its 35-45 percent moisture content, continues to be a regional fuel, used almost exclusively within the borders of the Fort Union and Gulf Lignite Regions. Subbituminous coal is also used to some extent within its major areas of occurrence (San Juan and Powder River Regions); much more dramatic has been the increase in shipments of low-sulfur subbituminous coal from the Powder River Basin to midwestern utilities.

The evolution of these major markets for low-rank coal to their current status is discussed below in three sections: first, the overall historical development is reviewed in section 4.4.1.1; second, the three major participating industries (coal producers, electric utilities, and railroads) are described in section 4.4.1.2; and third, the specific regional aspects of the existing markets are discussed in section 4.4.1.3.

Because of the 8-10 year lead time required for construction of new generating capacity, the "existing" markets are defined here as including units planned for startup through about 1985. Section 4.4.2 addresses the potential markets for low-rank coal beyond that year.

Finally, it should be noted that industrial markets for low-rank coal do currently exist. Quantitative data are difficult to obtain, but it is roughly estimated that at most, 1-2 million tons per year of subbituminous coal and lignite (or about 1 percent of total production) are being consumed in small boiler plants, cement kilns, etc. Most of this use is local, but some subbituminous coal does get shipped to nearby states for small consumers. In general it remains true today that industrial and commercial fuel users do not find coal competitive with oil or gas, despite the rapidly changing prices of these fuels. Coal handling and environmental control costs are major impediments, and investments in coal facilities are generally perceived as risky. Because of the insignificant size of existing low-rank markets other than electric utilities, these are not discussed further until Section 4.4.2.

4.4.1.1 Historical Overview

The history of coal production in the United States has been strongly influenced by the state of the economy and the supply and price of competitive fuels. Prior to industrialization in the U.S., wood was the major fuel source and coal was used mostly for blacksmith furnaces. The emergence of the railroads after 1830 greatly stimulated the infant coal industry. Not only did the railroads provide a means of transporting coal to the market centers but they also became important consumers themselves. In addition, the availability of fuel nurtured the growth of fuel-burning industries. The growth of the railroads also created a demand for the iron and steel industries which in turn became dependent upon coking coals.

With the onset of the industrial revolution, coal became a preferred fuel for household, commercial and industrial use, and toward the end of the nineteenth century coal became the primary fuel for steam-generated electricity. During the last half of the nineteenth century and up until the end of World War I, coal production doubled almost every decade. In 1918 production reached a peak of 678 million tons. The advent of cheaper petroleum and natural gas and the Great Depression caused coal production to dip to a low of 359 million tons in 1932. After a slow recovery in the 1930's, production increased rapidly during World War II. This expansion peaked at 688 million tons in 1947.

After World War II, coal markets were again displaced by cheaper, cleaner, and more convenient oil and natural gas. The railroads converted almost exclusively to diesel fuels and households chose oil, natural gas, and electricity for fuels. As a result coal production declined to a low of 420 million tons in 1961. Increased demand for coal by electric utilities and improved strip mining technology helped to increase production substantially until in 1970, 612 million tons of bituminous coal and anthracite were produced, the highest production figure since 1947. In the early 1970's production declined slightly and has steadily risen since then to a high for bituminous coal production of 689 million tons in 1977.

The production and consumption of coal in the U.S., as shown in Figure 4.4.1.1, has generally fluctuated between 400 and 600 million tons annually for roughly 50 years. This trend combined with the trend of rapidly rising production and consumption of energy in the U.S. (Figure 4.4.1.2) has resulted in a decreasing proportion of the total U.S. energy production supplied by coal (Figure 4.4.1.3). Coal consumption in 1978 was 18.1 percent of total U.S. primary energy consumption as compared to about 75 percent in 1925. Figure 4.4.1.3 indicates that the increased emphasis on petroleum and natural gas is primarily responsible for this shifting of consumption and production trends.

As noted previously, the coal market itself has also experienced shifting consumption trends. Coal use during the early 1940's was distributed fairly evenly among the retail, manufacturing, coking, railroad, and electric utility industries (Figure 4.4.1.4). This diversity in coal consumption changed substantially during the late 1940's through the 1960's (Figure 4.4.1.5). The loss of the railroad market, the reduction in the retail market and steel industry consumption reductions due to improvements in technology were offset by the growth of coal use by the electric utilities. Electric utility use of coal increased tenfold in less than 40 years to almost 500 million tons annually in 1977. The consumption of coal by electric utilities in 1975 far outranked all other uses of coal, accounting for 73 percent of domestic consumption. Electric utilities increased their coal use from 296 million tons in 1968 to 404 million tons in 1975, a 37 percent increase. The only other major user of coal in 1975 was the industrial sector (manufacturing and steel industries) with 108 million tons.

Figure 4.4.1.1

U.S. Trends in Bituminous
Coal Production and Consumption

Source: Reference 1

Figure 4.4.1.2

Annual Production and Consumption
of Energy in the U.S., 1900 - 1973

Source: Reference 3

Figure 4.4.1.3

Percentage of Annual U.S. Production
of Energy Supplied by Mineral Fuels,
Waterpower, and Nuclear Power, 1900-1973

Source: Reference 3

Figure 4.4.1.4

U.S. Percentage Consumption of Bituminous Coal and Lignite
In 1943, 1953, 1963, and 1973 by Consumer Class

Source: U.S. Bureau of Mines Minerals Yearbooks as cited in Reference 3.

Figure 4.4.1.5

U.S. Coal Consumption
By Consumer Class, 1950-1975

Source: Reference 2

Low-Rank Coals

Historical data on coal production and use do not generally indicate the classification by rank. However, reasonable approximations can be made by virtue of the geographic occurrence of the low-rank coals in the western regions of the country. The distribution of cumulative coal production among the states before 1974 is shown in Figure 4.4.1.6. States west of the Mississippi River accounted for only 8.5 percent of the total coal produced up to 1974. Roughly one-half of this production was bituminous coal, so that on a cumulative basis it is estimated that only about four percent of the coal produced in the U.S. prior to 1974 was low-rank coal.

The historical growth of low-rank coal production is shown in Table 4.4.1.1. This information is approximate, since actual production-by-rank statistics are not available, and several of the western states have both high- and low-rank coals. Low-rank coal production as a percentage of total coal produced has increased from 1.0 percent to 20.9 percent in the twenty-year period between 1958 and 1978. In the past decade, the trend has clearly been a rapid increase in the production of low-rank coal. In the ten-year period between 1968 and 1978, low-rank coal production increased at an average annual rate of 28 percent while total coal production grew at an average annual rate of 2.0 percent.

The only significant market for this low-rank coal production has been the electric utilities. With allowances for inconsistencies in data and rank classifications by different sources, the amount of low-rank coal delivered to utilities essentially matches the amount of low-rank coal produced each year. (Approximately 1-2 million tons of low-rank coal are used in the major producing areas as industrial and commercial fuel.) In contrast, about 60-65 percent of the annual production of bituminous coal is delivered to electric utilities; the remainder is used in the industrial markets mentioned previously. The very rapid growth of the utility market for low-rank coal is illustrated in Tables 4.4.1.2 and 4.4.1.3. These show the total deliveries and annual growth rates (in Btu), respectively, of the various ranks of coal to the electric utilities during the period 1974-1978. During this period, the use of low-rank coals by electric utilities grew at an average (compound) rate of almost 20 percent per year.

Two of the primary factors responsible for this very rapid penetration of the electric utility market by low-rank coals are shown on Table 4.4.1.2: low sulfur content, and low cost of the low-rank coals compared to bituminous coal. During the 1970's, air emission regulations required stack gas scrubbers on plants burning coal that would release more than 1.2 lb SO₂ per million Btu. This greatly enhanced the economic attractiveness of low-sulfur, low-rank coals which could meet the standards without scrubbers. This cost advantage is in addition to the generally lower extraction costs of low-rank coals, which are reflected in the 37-75¢/million Btu differential shown in the table between bituminous coal and the low-rank coals. (To some extent, these cost advantages are offset by higher plant capital and operating costs because low-rank coals generally require larger boilers and coal feeding systems than bituminous coals require for the same heat load.)

Figure 4.4.1.6

Percentage Distribution, by States
Of Cumulative Coal Production in the U.S. to January 1, 1974

Source: Reference 3

Table 4.4.1.1

U.S. Low-Rank Coal Production, 1953-1978, by State,
(thousand short tons)

Year	Alaska	Colorado	Montana	New Mexico	North Dakota	Texas	Washington	Wyoming	Production		Low-Rank Coal Percentage of Total Production
									Low-Rank	Total (2)	
1953	NA ¹	830	1873	514	2803	NA	690	2098	8808	457290	1.9
1954	NA	639	1491	123	NA	NA	619	1132	4004	391706	1.0
1955	NA	734	1247	201	3102	NA	610	1171	7065	464633	1.5
1956	NA	715	846	158	2815	NA	473	1021	6028	500874	1.2
1957	NA	674	413	137	2516	NA	360	847	4947	492704	1.0
1958	NA	625	305	117	2314	NA	252	652	4265	410446	1.0
1959	NA	911	345	148	2413	NA	242	791	4850	412028	1.2
1960	NA	753	313	295	2525	NA	228	1012	5126	415512	1.2
1961	NA	903	371	412	2726	NA	191	1265	5868	402977	1.5
1962	NA	800	382	677	2733	NA	235	1285	6112	422149	1.4
1963	853	831	343	1945	2399	NA	190	1562	8123	458928	1.8
1964	745	866	346	2969	2637	NA	68	1551	9182	486998	1.9
1965	893	810	364	3212	2732	NA	55	1630	9696	512088	1.9
1966	927	780	419	2480	3543	NA	59	1835	10043	533881	1.9
1967	925	683	371	3117	4156	NA	59	1794	11105	552626	2.0
1968	NA	711	519	3086	4487	NA	178	1915	10896	545245	2.1
1969	NA	625	1030	4024	4704	NA	58	2301	12742	560505	2.4
1970	NA	638	3447	6625	5639	NA	37	3813	20199	602932	3.5
1971	NA	533	7064	7358	6075	NA	1134	4574	26738	552192	5.0
1972	668	796	8221	7423	6632	4045	2634	6677	37096	595386	6.2
1973	694	696	10725	8162	6906	6944	3270	9795	47192	591738	8.0
1974	700	766	14106	8453	7463	7684	3913	14658	57743	603406	9.6
1975	766	5247	22054	7907	8515	11002	3743	18139	77373	648438	11.9
1976	706	3551	26231	8784	11102	14063	4109	25285	93831	678685	13.8
1977	705	4191	27226	9975	12028	15865	5057	42409	117456	691344	17.0
1978	731	5967	26600	11369	14028	20020	4708	55412	138835	665127	20.9
Total	9310	35255	156652	99671	126993	79623	33172	204624	745300	13649838	5.5

¹Data not available.²Excluding anthracite.

Source: Reference 6

Table 4.4.1.2

Grades of Coal Delivered to Electric Utilities, 1974-1978

	<u>Quantity</u> <u>1000 Ton</u>	<u>% of Total</u>	<u>Avg. Btu</u> <u>Per Pound</u>	<u>Avg. %</u> <u>Sulfur</u>	<u>Avg. Price</u> <u>¢/Million Btu</u>
<u>1974</u>					
Bituminous	324,815	84.4	11,263	2.55	76.0
Sub-bituminous	47,354	12.3	9,375	0.54	39.2
Lignite	11,444	3.0	6,889	0.64	20.0
Anthracite	<u>1,255</u>	<u>0.3</u>	<u>8,600</u>	<u>0.65</u>	<u>43.2</u>
Total	384,868	100.0	10,892	2.24	70.9
<u>1975</u>					
Bituminous	357,319	82.8	11,279	2.53	87.0
Sub-bituminous	56,578	13.1	9,232	0.56	49.9
Lignite	16,345	3.8	6,534	0.63	27.2
Anthracite	<u>1,286</u>	<u>0.3</u>	<u>8,532</u>	<u>0.57</u>	<u>52.8</u>
Total	431,528	100.0	10,822	2.19	81.4
<u>1976</u>					
Bituminous	364,227	80.1	11,407	2.44	91.0
Sub-bituminous	67,309	14.8	9,242	0.57	56.3
Lignite	22,211	4.9	6,509	0.63	32.3
Anthracite	<u>1,111</u>	<u>0.2</u>	<u>8,763</u>	<u>0.64</u>	<u>57.7</u>
Total	454,858	100.0	10,841	2.07	84.8
<u>1977</u>					
Bituminous	379,960	77.5	11,371	2.35	101.9
Sub-bituminous	85,295	17.4	9,216	0.55	66.5
Lignite	23,979	4.9	6,582	0.65	40.8
Anthracite	<u>1,182</u>	<u>0.2</u>	<u>8,622</u>	<u>0.69</u>	<u>57.8</u>
Total	490,415	100.0	10,756	1.90	94.7
<u>1978</u>					
Bituminous	354,019	74.4	11,368	2.2	121.8
Sub-bituminous	90,519	19.0	9,169	0.57	79.1
Lignite	30,611	6.4	6,605	0.68	45.0
Anthracite	<u>1,019</u>	<u>0.2</u>	<u>8,552</u>	<u>0.67</u>	<u>66.7</u>
Total	476,169	100.0	10,638	1.80	111.6

Source: Reference 5

Table 4.4.1.3

Growth Rates of Coal Delivered to Electric
Utilities, 1974-1978, Btu Basis
(percent growth over preceding year)

	<u>Lignite</u>	<u>Subbituminous</u>	<u>Bituminous</u>	<u>Low-Rank Coal</u>	<u>All Coal</u>
1975	35.4	17.7	10.2	20.4	11.4
1976	35.0	19.0	3.1	21.8	5.6
1977	9.3	26.4	4.0	23.2	7.0
1978	27.8	5.6	(6.9)	9.3	(4.0)
Average (Compound) Annual Rate, 1974-1978	26.5	16.9	2.5	18.5	4.8

Source: Reference 5

Another indication of the cost advantage of low-rank coals to electric utilities in certain regions is given by the data in Table 4.4.1.4. The delivered prices of coal, oil and natural gas to electric utilities are compared on a Btu basis. The regions where low-rank coals are heavily utilized are the Mountain, Pacific, and West South Central, and (to a lesser extent) the West North Central Region. The delivered coal cost is seen to be lowest in these regions, and in general, the differentials between the cost of coal and the costs of oil and gas are greatest in these regions. (Again, different plant capital and operating costs for the different fuels must be accounted for when comparing these delivered fuel prices. Because of differences in boiler size, fuel handling, and environmental control equipment, it has been estimated that the price of coal requiring a scrubber must be 80¢/million Btu less than the price of low-sulfur oil and about 90¢/million Btu less than the price of gas to be competitive in a large utility plant.)²

These and other factors contributing to the penetration of the utility market by low-rank coals are analyzed in the following sections. First, the major industries involved -- coal producers, utilities, and railroads -- are described in Section 4.4.1.2. Second, the existing regional markets for lignite and subbituminous coal are examined separately in Section 4.4.1.3.

Table 4.4.1.4

Delivered Fuel Prices to Electric Utilities,
by Region, April 1977 and May 1978
(cents per 10⁶ Btu)

Region	April 1977			May 1978		
	Coal	Oil	Gas	Coal	Oil	Gas
New England	127.9	218.5	200.1	146.8	195.3	184.3
Middle Atlantic	102.5	230.8	155.4	118.7	207.8	162.5
East North Central	93.9	256.3	184.7	116.6	262.0	191.7
West North Central	72.5	298.7	96.0	86.6	189.3	118.5
South Atlantic	108.4	217.8	85.7	129.1	198.4	112.3
East South Central	96.5	180.5	154.7	116.2	182.8	155.2
West South Central	60.2	200.3	113.7	69.0	182.0	135.8
Mountain	42.4	220.6	134.9	51.3	226.1	150.2
Pacific	70.8	235.8	204.5	78.3	250.3	220.4
National Average	90.1	226.2	125.6	110.6	209.6	143.5

Source: Department of Energy, Monthly Energy Review, October 1978, p. 82,
as cited in reference 2.

References - Section 4.4.1.1

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2. Landsberg, H.H., et al. Energy: The Next Twenty Years, Ballinger, 1979.
3. Averitt, P. Coal Resources of the United States, January 1, 1974, Geological Survey Bulletin 1412, 1975.
4. Mineral Facts and Problems, Bureau of Mines Bulletin 667, 1976.
5. Energy Data Report: Cost and Quality of Fuels for Electric Utility Plants - 1978 and 1979, DOE/EIA-0191 (78) October 1979.
6. U.S. Bureau of Mines Minerals Yearbook, as cited by the National Coal Association; Colorado Bureau of Mines; Wyoming Geological Survey; New Mexico Department of Energy and Minerals.

4.4.1.2 Industry Analysis

There are three dominant industries involved in the current low-rank coal markets: the coal producers, the electric utilities, and the railroads. The following subsections present some general background information on these industries, particularly with respect to their recent financial performance, and the factors that may affect the abilities of these industries to expand the use of low-rank coals. In general, the mining companies are healthy and appear to be capable of significant growth. The increasing participation of major oil and gas companies in the coal producing business is one factor contributing to this strength. The railroads and utilities, however, have serious problems with profitability and hence the ability to raise capital for expansion.

4.4.1.2.1 The Coal Mining Industry^{1,2,3}

Throughout most of its history, it has been easy to enter the coal industry. Coal reserves are very large and widely distributed and before mechanization of the mines took hold in the mid-1950s, the capital required to open a mine was small. Small operators were able to enter the market when demand was high and leave without major losses when coal requirements declined. As a result, the industry consisted of a large number of small operators and a few companies that had a large share of the total production.

By increasing capital requirements, mechanization of the mines made entry into coal mining more difficult. While the number of operating mines had normally ranged from 5,500 to 9,000, starting in about 1955 the number declined steadily until it was down to about 4,700 in 1973. The effects of the OPEC oil embargo and the impending wage negotiations between coal industry management and the United Mine Workers created a sudden demand for coal and brief reversal. Prices escalated, and a number of new small mines entered the market, so that by 1976 there were 6,200 mines operating. Small mines, however, will be unable to compete under normal market conditions. Moreover, the impact of the Surface Mining Act of 1977 on both strip and underground mines will adversely affect costs at small, older mines much more than at some of the new large ones.

Although the number of small mines and independent operators remains large, a major portion of the total coal is now produced by a small number of large companies. Table 4.4.1.5 indicates the breakdown of coal company sizes in 1973. In 1977, the largest 15 producers yielded 40 percent of national output; two were independent, five were owned by oil companies, five by steel companies or utilities, and three by conglomerates.

Another change relates to ownership patterns. For many years the ownership of coal mines was largely of two types - companies engaged only in coal mining and the captive coal mines owned by the steel companies that supplied the coking coal needed for their steelmaking operations.

Table 4.4.1.5
Breakdown of Coal Company Sizes (1973)

<u>Tons Mined</u>	<u>Number of Companies</u>	<u>Total Tons Produced in 1973</u>	<u>Percent of Total 1973 Production</u>	<u>Average Tons Mined Per Company</u>
Over 3 million	30	362,300,000	61.2%	12,066,000
2-3 million	19	45,700,000	7.7	2,405,000
1-2 million	30	39,500,000	6.7	1,326,000
.5-1 million	53	36,400,000	6.1	687,000
.3-.5 million	96	35,600,000	6.0	371,000
.1-.3 million	300	52,000,000	8.8	173,000
Less than 100,000	<u>3,172</u>	<u>20,200,000</u>	3.5	64,000
	3,700	592,000,000		

Source: Reference 4

Ownership patterns have changed dramatically since the early 1960s when Consolidation Coal Company was acquired by Continental Oil Company. Electric utilities, the largest coal consumers, are now increasing their share of captive coal, and this trend is expected to accelerate. Table 4.4.1.6 lists the electric utilities with captive coal production as of 1978. Many of these companies utilize western low-rank coals.

In 1977, utilities mined about 14.5 percent of their own coal consumption, up from about 9 percent in 1973. Moreover, 86 percent of all coal shipped to utilities in 1975 was under long-term contracts. Long-term contracts are usually written for 2 years' duration or more, with "market reopener" clauses allowing for price adjustments as the market price for comparable coal rises or falls, and with force majeure clauses allowing for termination in the face of uncontrollable or unforeseen events such as strikes, new regulations, or coal seam depletion.

In 1977, the Federal Power Commission predicted that by 1985 utility coal consumption would rise to 770 million tons and that the amount produced by the utilities themselves ("captive coal") would triple from the 1975 level, reaching 145 million tons, or almost 19 percent of utility coal consumption. Some maintain that this vertical integration allows utilities to manipulate supplies and production costs to justify rate increases and expand profits. The utilities counter that mine ownership makes them better able to hold down the cost of electricity to their customers.

Horizontal integration, the acquisition of coal mines by gas and oil companies, has proceeded faster than vertical integration and has received more attention. Fifteen oil and gas companies mined 161 million tons of coal in 1976, including 125 million tons of steam coal. This amounted to 24 percent of national production and 35 percent of all non-captive steam coal. The principal investors in coal reserves and leases in recent years have been oil and gas companies, which now make up 6 of the top 10 reserve holders. Oil and gas companies account for about 40 percent of planned new capacity, and while they are not expected to undertake all of the planned expansion, they are expected to produce 260-360 million tons of new steam coal in 1986, bringing their share of nonmetallurgical, nonexport production to 48 percent. Seven companies account for two thirds of the capacity additions planned by oil and gas firms. Table 4.4.1.7 lists the coal producers owned by oil and gas companies in 1976.

The phenomenon of horizontal integration raises charges and counterclaims similar to those in the case of utilities. Critics maintain that control of competing energy sources by a small group of firms allows self-interested manipulation of supplies and prices. Oil and gas companies maintain that their presence in the coal mining industry brings needed management expertise and capital.

Table 4.4.1.6

Captive Coal Production By
Electric Utilities, 1978

<u>Name of Operating Company</u>	<u>Name of Controlling or Parent Company</u>	<u>Location or Operation</u>	<u>1978 Production, Tons</u>
1. Texas Utilities Co.	Texas Utilities Co.	Texas	(est) 16,000,000
2. Western Energy Co.	Montana Power Co.	Montana	10,576,000
3. Windsor Power House Coal Co. Southern Ohio Coal Central Ohio Coal Co. Southern Appalachian Coal Co. Cedar Coal Co. Central Appalachian Coal Co.	American Elec. Power Co. NERCO; Peter Kiewit Sons Co. Montana-Dakota Util., Co. Pacific Power & Lt. Co. Washington Wt. Power Co. NERCO Idaho Power Co.	Ohio; W. Va. Montana N.D.; Montana Washington Wyoming	9,289,109 5,059,107 4,700,000 4,536,822 3,450,360
4. Knife River Coal Mining Co.	NERCO	Wyoming	3,358,899
5. Washington Irrig. & Develop Co.	Utah Power & Lt. Co.	Utah	2,544,789
6. Decker Coal Co.	Pennsylvania Power & Lt. Co.	Pennsylvania	2,113,804
7. Bridger Coal Co.	Public Service Co. N. Mexico	New Mexico	2,100,000
8. Glen Rock Coal Co.	Duke Power Co.	Pennsylvania	1,723,000
9. American Coal Co.	Black Hills Power & Lt. Co.	Wyoming	1,478,549
10. Pennsylvania Mines Corp.	Iowa Pub. Serv. Co.	Wyoming	1,215,196
11. Western Coal Co.	Columbus & Sou. Ohio Elec. Co.	Ohio	1,007,995
12. Eastover Mining Co.	Duquesne Lt. Co.	Pennsylvania	699,126
13. Wyodak Resources Devel. Co.	Ohio Edison Co.	Ohio	113,959
14. Energy Development Co.			
15. Peabody Coal Co. (Simco-Peabody Mine) Joint Venture with Simco, Inc.			
16. Duquesne Light Co.			
17. Ohio Edison Co.			
		TOTAL	69,966,715

Source: Reference 5

Table 4.4.1.7

Oil and Gas Company Ownership of Coal Producers
 (in millions of tons produced, 1976)

<u>Coal Company</u>	<u>Parent Company</u>	<u>1976 Production</u>
Consolidation Coal	Continental Oil	55.9
AMAX Coal	Standard Oil of California (20.6%)	23.1
Arch Mineral	Ashland Oil-Hunt Oil	18.0
Island Creek	Occidental Petroleum	17.6
Old Ben	SOMIO	9.7
Eastern Associated Coal	Eastern Gas & Fuel	8.0
Pittsburg & Midway	Gulf Oil	7.9
Zeigler Coal	Houston Natural Gas	5.2
Falcon Coal	Diamond Shamrock	5.2
MAPCO	MAPCO	3.9
Valley Camp	Quaker State	3.6
Monterey Coal	EXXON	2.8
Youghioghney & Ohio	Panhandle Eastern	2.1
Southern Utah Fuel	Coastal States	1.0
Hawley Fuel	Belco	.9
Braztah	McCulloch Oil	.5
Tesoro Coal	Tesoro	.4
Tosco Mining	TOSCO	.4
Belva	International Mining and Petroleum	.3
Husky Industries	Husky Oil	.1
TOTAL		166.6

Source: Reference 3

By and large, coal is sold not nationally, but rather in regional markets according to type of coal. When broken down by region and type, coal becomes a concentrated industry. Although more than 3000 companies operated more than 6000 mines in 1976, the top four companies in the Midwest produced 65 percent of the coal there; in the Northern Plains, 38 percent; in the Southwest, 64 percent; and in Appalachia, 22 percent (a figure that is probably understated since northern and southern Appalachia are actually two separate markets). By 1985, estimates the Department of Energy, the top four noncaptive producers will supply 47 percent of new, noncaptive utility supply now under contract, and the top eight will supply 71 percent.

The level of concentration in Montana and Wyoming in 1975 was estimated to reach 70 percent of output in those two states for the top four producers and 92 percent for the top eight. In addition, the boards of the top coal companies exhibit widespread interlocking with the boards of other coal companies and with the boards of major banks and coal consumers.

The dominance of long-term contracts, concentrated markets, and board interlocks carry with them possible implications of noncompetitive power and behavior that could be damaging to the economy. However, the detailed study required to explore these implications has not been done.

The rapid transformation of the structure of the coal industry was accompanied in the early 1970s by an even more rapid change in the industry's gross income and profitability. While output rose 14 percent from 1972 to 1976, the minemouth value of coal produced rose 187 percent, from \$4.6 billion in 1972 to \$13.2 billion in 1976. From an average of less than 11 percent in the 1950-1970 period, coal companies' return on net worth rose to an estimated 30 percent in 1974 and was 21 percent in 1976. The labor costs of coal dropped from 58 percent of total value received in 1950 to 20 percent in 1974; the labor cost share is estimated to lie in the 25-30 percent range today. Conglomerates do not show separate earnings for their coal operations; however, the financial statements of the two major independent coal companies (the Pittston Corporation and North American Coal) show that after 1973, despite their erratic output and declining labor productivity, the companies' total net income and net income per employee increased sharply. The net coal income of 24 large producers rose 400 percent from \$128 million in 1971 to \$639 million in 1974.

Return on investment and profits have declined for many coal companies since 1978 because of strikes and demand softness for certain coals (particularly in the east and midwest). The western low-rank coal producing industry has remained strong even in this temporary soft coal market period, although growth rates during 1979 and 1980 have slowed.⁶ To some extent, this strength has been at the expense of midwestern or eastern coal producers as utilities have been forced to switch to lower-sulfur coal. Overall, the chances are good that for most companies, the difficulties of 1979-1980 should prove to be a temporary phenomenon.

It is difficult to foresee the implications of the changes in industrial structure or of the rising profitability of the coal industry. Undoubtedly concentration and horizontal integration, operating under the shelter of world oil and gas prices governed by the petroleum cartel, will lead to higher prices for coal. Moreover, producers will be much less willing to resist increased labor demands than in the past. Thus, coal prices will tend to follow closely world petroleum prices, suitably discounted for the greater cost of burning coal as compared with fluid fuels. On the positive side, continued high profitability of the industry, and capital availability from the oil and gas companies, will make possible a higher rate of introduction of new technology, and thus rapid improvements in productivity, safety, and responsible environmental behavior could ensue. It will also be easier to enforce environmental, health, and safety regulations against a concentrated industry, both because large units are easier to monitor, and because the companies will be able to pass along internalized social costs to consumers. It may be that these beneficial effects will outweigh the greater ability of large companies to resist regulation through the courts and through lobbying the political process. Obviously, however, the coal industry is undergoing dramatic structural changes, and these are likely to accelerate in the future as the coal market inevitably expands.

4.4.1.2.2 The Electric Utility Industry

The electric utility industry is the most capital-intensive industry in the U.S. For example, the steel, chemical and automobile manufacturing industries require approximately twelve, ten and seven months of sales revenue to equal net (depreciated) assets. By comparison, the utility industry requires approximately three to four years of sales revenues to match the industry's annual net tangible investment.⁷

Despite the recent drop in the growth in demand for electricity from its historical rate of 7 percent to approximately 4-5 percent, almost \$60 billion of new construction has been completed in the past three years. This investment corresponds to approximately one-seventh of all new private industrial construction in the country. The trends to capital intensiveness and large capital needs are expected to continue for a long period of time in light of the economies of scale for base load coal and nuclear facilities.

The historical trend to larger facilities is illustrated in Table 4.4.1.8 for fossil-fueled steam plants. Despite an absolute decline of 43 plants from 1950 to 1977, capacity has increased 640 percent, due to the increase in the number of plants of greater than 500 MW capacity. There has also been a significant increase in the percentage of capacity of units greater than 500 MW and an increase in the average size of units from approximately 700 MW in 1955 to 1000 MW in the mid-1970s.

Table 4.4.1.8

Privately-Owned Electric Utility Generating Plants
Fossil-Fueled Steam Plants

	Number Under 100 MW (average MW)	Number 100-500 MW (average MW)	Number Greater Than 500 MW (average MW)	Percent Capacity Greater Than 500 MW	Total Number Plants	Total Capacity (1000 MW)
1950	543 (24.6)	Σ 141 (221.8)		?	684	44.6
1955	451 (30.1)	224 (225.9)	16 (693.6)	14.7	691	75.3
1960	362 (32.0)	298 (253.)	47 (698.6)	27.4	707	119.8
1965	255 (36.4)	309 (260.2)	89 (780.4)	43.7	653	159.1
1970	220 (37.5)	299 (258.)	153 (896.)	61.6	672	222.4
1971	215 (36.9)	297 (256.)	180 (908.3)	66.1	692	247.4
1972	207 (37.3)	282 (258.9)	182 (950.8)	68.2	671	253.8
1973	195 (38.5)	274 (260.9)	195 (1011.8)	71.4	664	276.2
1974	182 (39.6)	276 (262.3)	213 (988.3)	72.6	671	290.1
1975	164 (41.5)	267 (262.2)	227 (1000.4)	74.8	658	303.8
1976	159 (41.5)	257 (261.9)	243 (997.5)	76.6	659	316.3
1977	148 (40.5)	244 (261.5)	249 (1045.4)	78.9	641	330.1

Sources: Adapted from Statistical Abstracts of the United States, 1978, U.S. Department of Commerce, Bureau of the Census and Edison Electric Institute, Statistical Handbook, 1978.

Cost Trends

While the plants are getting larger, the per-unit cost of production is also increasing despite the economies of scale. Ever-increasing needs for safety in the nuclear segment and for cleaner emissions in the coal-fired segment have added substantially to the costs. Siting, certification, construction, and other problems have added unexpected and costly delays to the completion of plants and delivery of electricity. Inflation in the power construction index for the Pacific Geographic Division was a compounded 8.8 percent from January 1968 to January 1978 and 11.9 percent for the last five years versus 6.2 percent and 7.9 percent in the Consumer Price Index for the comparable period of time. Inflation, delays, and safety/environmental demands have pushed the costs for coal and nuclear facilities from \$144 and \$165 per KW respectively in 1970 to an anticipated cost of \$1,096 and \$1,861 per KW for facilities expected to go on line in 1987.⁸

The contribution of mandated environmental control technology to these cost increases has been estimated by EPRI.⁹ The capital cost of a typical coal-fired unit beginning design and engineering in 1979 is about \$800/KW. About 40 percent of this investment is directed to environmental control requirements. More stringent requirements planned during the next 5 years will increase environmental control's share to 50-60 percent of a total cost of \$1000-1400/KW. The EPRI estimates for the 1978 and 1985 environmental control costs associated with a 1000-MW plant are shown in Tables 4.4.1.9 and 4.4.1.10. Interestingly, the 1978 plant requires about the same investment for environmental controls whether the coal is high-sulfur Illinois bituminous or low-sulfur Wyoming subbituminous (although the 30-year levelized cost for the low-rank coal-derived electricity is considerably lower when O&M charges are included). The prediction for the 1985 "stringent standards" case, however, shows about 25 percent lower capital costs for environmental controls for the subbituminous coal compared to the bituminous coal. This causes the 30-year levelized cost advantage for the low-rank coal to increase substantially.

Utility Ratemaking

In return for obtaining a local monopoly on the production of electric power, the revenues and profits of the electric utility industry are controlled by public regulatory agencies. The purpose of the controls is to prevent utilities from obtaining monopoly profits, to ensure non-discriminatory rate structures and at the same time to guarantee an adequate return on investment so that there is sufficient capital available to produce the capacity needed for adequate and reliable service. The local state regulatory agencies or public utility commissions (PUC's) control the sale of electricity to the ultimate consumer. The Federal Energy Regulatory Commission (FERC) controls the rates of wholesale electricity sold across state lines.

Table 4.4.1.9

Environmental Control Costs at Coal-Fired Power Plants
1978 Environmental Control Requirements
 2x500 MW Plants, Wisconsin Location, Costs in 1978\$

Coal:	<u>Illinois</u> <u>Bituminous</u>	<u>Wyoming</u> <u>Sub-bituminous</u>
% S	4.0	0.48
% Ash	16.0	6.4
Btu/lb	10,100	8020

	Total Investment \$/kwa	30-Year Levelized mills/kWh ^b	Total Investment \$/kwa	30-Year Levelized mills/kWh ^b
Electrostatic Precipitator	62	1.9	131	4.0
Lime/Limestone SO ₂ Scrubber	136	13.7	104	7.5
Solid Waste Disposal	46	2.4	21	0.9
NO _x Control	10	0.5	10	0.5
Wet Cooling Tower	35	1.1	35	1.1
Water	15	1.5	15	1.5
Noise Control	12	0.4	12	0.4
	<u>316</u>	<u>21.5</u>	<u>328</u>	<u>15.9</u>

^aIncludes plant investment and 16.6% Allowance for Funds During Construction (AFDC)

^bLevelized over 30 years at 6% inflation rate and 10% discount rate; includes fixed and variable O and M and 18% fixed charges.

Source: Reference 9

Table 4.4.1.10

Summary of Estimated Costs of 1985 Environmental
Control and Potential Cost Savings

	<u>Costs in 1978\$</u>			
	1985 Stringent Standards			
	<u>With Current Technology</u>		<u>With R and D Improvements</u>	
	<u>\$/kwa</u>	<u>30-Year Levelized mills/kWh^b</u>	<u>\$/kwa</u>	<u>30-Year Levelized mills/kWh^b</u>
Baghouse/ESP	131-62	4-2	91-43	3-1
SO ₂ Scrubber	120-168	9-14	118-158	8-15
Solid Waste Disposal	47-167	3-8	10-29	2-4
NO _x Control	45-80	8-9	40-70	6-7
Plant Cooling	280-340	9-11	135-180	4-6
Water	20-30	2-5	15-25	1-3
Noise Control	<u>30-60</u>	<u>1-2</u>	<u>25-50</u>	<u>1-2</u>
Total Range	*673-907**	*36-51**	*434-555**	*25-39**

*Wyoming Sub-Bituminous

**Illinois Bituminous

2x500 MW plants, Wisconsin Location

^aIncludes plant investment and 16.6% Allowance for Funds During Construction (AFDC).

^bLevelized over 30 years at 6% inflation rate and 10% discount rate; includes fixed and variable O and M and 18% fixed charges.

Source: Reference 9

When an electric utility files for a rate increase, the matter is typically settled by the state regulatory agency within the format of an adjudicatory proceeding, that is, a rate case. The rate case is divided into two parts. The "revenue requirement," or what the utility is allowed to earn is established first; the rate schedules are then approved to meet the revenue requirement.

The revenue requirement is usually expressed in formula form as follows:

$$RR = E + d + T + (V-D)R, \text{ in which}$$

- RR = Revenue requirement
- E = Operating expenses
- d = Annual depreciation expense
- T = Taxes, including income taxes
- V = Gross valuation of the property
- D = Accrued depreciation
- R = Rate of return
- (V-D) = Rate base (net valuation)
- (V-D)R = Return, amount of profit, expressed as earnings allowed on the rate base.

In most cases the expenses (E) used in the rate case are based on the previous year's costs. In the 1960's when utilities were experiencing declining marginal costs, the use of the previous year's expense data caused no problem for utilities; recently, however, due to inflation and increasing marginal costs the expenses of the previous year tend to significantly lag the current year's costs. The problem is aggravated by the time lag involved in the rate case itself. The hearing process takes six months to a year and has become further delayed due to a large increase in the number of cases seeking rate increases. One of the largest inflating expenses, the fuel, has received an automatic fuel adjustment escalator in some states, but costs still lag revenues even in these cases.

The gross valuation of the property (V) is a subject of much controversy. Unless a PUC permits construction work in progress (CWIP) the assets considered in the rate case are only productive assets, as opposed to assets under construction. To offset this effect, the value of the assets can be somewhat inflated (for rate base rather than tax purposes) by the capitalization of the Allowance for Funds Used During Construction (AFUDC) if permitted by the local PUC. The value of V is effectively determined by the PUC rather than strictly by the balance sheet of the utility.

The rate of return (R) when multiplied by the allowed rate base (V-D) determines the absolute level of profit. This profit can be used to pay preferred and common dividends as well as be employed to generate new productive capacity. The rate of return should be high enough so that capital can be raised either internally (retained earnings) or externally in the capital markets. On the other hand, the rate should not be too high in order to protect the public from monopolistic profits.

Due to inflation and revenue rate adjustment lag, mentioned previously, current costs frequently exceed projected costs. In addition to rate adjustment lags, many PUC's have denied rate increase requests outright and the average increase nationally is running around 50 percent to 60 percent of the original requests. For example, the cost (per 100 kWh sold) has increased in the five year period from 1973 to 1978 at a compounded rate of approximately 16.5 percent per year while revenues for the same period have increased at only 14.1 percent.

The total revenues received are based on the number of kWh sold times the rate allowed per kWh. The number of kWh assumed to be sold in the rate of return formula is based on a forecast for electric demand for the year following the base year. The recently observed demand elasticity for electricity is much higher than most utilities or PUC's had anticipated (despite the fact that competing energy sources have also inflated) and as a result demand has been lower than originally forecast. Since all expenses are not strictly variable (e.g., interest expenses, depreciation, etc.) the resulting reduction in actual consumption of kWh from forecast has resulted in a larger reduction of total revenues than of costs.

Utility Industry Financial Condition

The pressure caused by costs increasing faster than revenues has resulted in a profit squeeze. The current utility return on equity of 11.2 percent is four percent lower than the 1972 level. This compares with the current industrial return on equity of 14.4 percent which is 25 percent higher than the 1972 level of returns.⁷

The squeeze on profits has also had a negative effect on the utility loan and preferred covenants. The coverage ratios (income available to service debt and/or preferred dividends divided by their cost) for debt and preferred dividends has declined from 4.90 and 11.23 respectively in 1966 to a low of 2.03 and 3.22 in 1974 and is currently (fiscal 1977) 2.89 and 3.90. By comparison, the debt coverage ratio for industrial companies is 8. This decrease in coverage and position relative to other industrial companies has had a negative effect for the utility industry in the capital markets.⁷

The cash position of the utilities is significantly worse than the profit picture. The profits reported by utilities have a non-cash component which can not be employed to pay preferred or common dividends or be employed to construct new generating capacity. The most important non-cash item is the Allowance for Funds Used During Construction (AFUDC). These represent imputed and paid interest and equity charges associated with construction-in-progress, which is not in the rate base generating profits but which is nonetheless credited to income. AFUDC represented about 4 percent of net income in 1965. In 1974, however, this non-cash item peaked at 31 percent of utility earnings and jumped again in 1977 to 30 percent. When AFUDC is subtracted from reported earnings, the effective payout ratio (adjusted profits reserved divided by the dividends paid) for preferred and common dividends was between 75 percent and 110 percent. As a result, in recent years depreciation and deferred taxes have been the principal source of internally generated funds.¹⁰

In the face of rapidly inflating construction costs, the depreciation and deferred taxes, which are based on previous construction, can not be expected to generate sufficient funds to construct new capacity. It is estimated by the Edison Electric Institute that approximately 60 percent of the construction and operating needs of the electric utilities were funded internally in the early 1960's (where retained earnings were also employed). This degree of internal funding declined to a minimum of 29 percent in 1974 and was estimated to be approximately 35 percent in 1978. The utilities have to go to the capital markets for an increasing percentage of their financing, in the face of a declining profit picture relative to other industrial companies seeking funds in the same capital markets.

In summary, electric utility executives feel that the industry is going to experience problems in raising its massive needs in the capital markets. All forms of capital are going to be increasingly more expensive because of investor perceptions of increased risk. The amount of debt and equity which can prudently be raised is limited by coverage ratio covenants. The ratios are being driven lower by more expensive debt and by poor profit performance. The returns of utilities are lower than their industrial counterparts and the spread between the latter and the former is increasing.

New Capacity Decisions

The surge in general inflation, the extraordinary increase in oil, coal and natural gas costs, and the implementation of environmental standards in the 1970's caught most utilities and PUC's by surprise. Previously, the approximately level fuel costs, declining marginal costs for new capacity, and regulatory lag had aided the utilities' profits and cash position. In the 1970's, the PUC's and utilities began to take adversary positions, with the former being asked to approve substantially higher

electric costs to consumers, and the latter confronted with capital and profit squeezes. Only recently has the need for cooperation become apparent to some parties and are some steps being taken to alleviate the situation. The management of the PUC/utility interface is a significant problem.

The choice of fuels and generating facilities used by the electric utility industry was previously influenced by fuel availability and costs, ability to comply with environmental standards and the perceived profitability of each alternative. This last factor was influenced by the rate of return formula, which encourages the construction of facilities with a high capital component and a low variable or fuel cost component (to keep the price low but the profits per dollar revenue high). Basing profits on assets has encouraged larger facilities and the corresponding growth of demand. In fact, the industry tended to overcapitalize. These factors led to the surge in the use of nuclear facilities and severe overcapacity when demand dropped after 1973 (overcapacity is currently 38 percent, almost double the "prudent" reserve margin of 20 percent).⁶

Uncertainties about the future of the nuclear capacity have added an additional factor to the new "risk" associated with utilities. Overcapacity has resulted in unnecessary capital charges to the consumers (to cover the unused facilities) and a pressure on utilities to contract their construction program which had been the traditional source of increased profits. The contraction has made demand forecasting much more important than it was previously. Due to the lead times of 8 to 10 years associated with new base load capacity, a new surge in demand or a reluctance on the part of PUC's to approve new facilities could lead to spot shortages and brownouts in the near future, despite the current overcapacity.

The utility rate management process provides a barrier to the adoption of new unproven technologies. Reductions in cost of electricity are passed on to the consumer and do not increase profits, which are based on assets employed. Any increase in the risk of generating facilities leads to difficulties in raising capital due to more investor uncertainty. The rate of return allowed is not adjusted upwards for the risk of more innovative generating facilities. In the event of failure of an innovative technology, it is unclear who would absorb the loss, the ratepayers or the investors.

Much of the current utility management philosophy evolved in the 1950's and 1960's when economies of scale resulted in declining marginal costs for electricity. The current situation of rising marginal costs in relation to average revenues is only slowly being recognized by management. Conservation, and revised rate structures (to flatten out peak demand) are currently better investments than new capacity. Methods of controlling demand as opposed to simply forecasting it, lead to better facilities management and decrease the probability of costly overcapacity.

Bulk Electric Power Supply and Demand, 1977-1986¹¹

Information on bulk electric power supply and demand in the contiguous United States for the period 1977-1986 was obtained from the Federal Power Commission Bureau of Power Staff Report. Data as to projected electrical demands, energy and generating capability have been summarized from the reports filed with the Commission on April 1, 1977, by the Regional Electric Reliability Councils, in response to FPC Order 383-4. Council acronyms and geographic boundaries are shown in Figure 4.4.1.7. (This reporting system is now managed by the Energy Information Administration.)

Formation of the councils was given impetus by the Commission recommendation that the utility industry establish "strong regional organizations" to coordinate planning, construction and operation of the national bulk electric power supply. Through the standing and special committees of the councils, planning and operating personnel of the electric utilities (Federal, state and municipally owned, privately owned and cooperatively owned) endeavor to provide for rational economic development of electricity supply. The Commission, in promulgating its series of orders (383-1, -2, -3, -4) related to reliability and adequacy of bulk power supply, set up a frame of reference for the compilation of certain planning data on a long-range regional basis. The essential ingredients of satisfactory power supply are load forecasts made with reasonable confidence, timely installation of new generating plants, a properly coordinated transmission network and dependable supplies of fuel for electric generation. Since 1970, the councils in responding to the series of "383" orders have been furnishing data enabling the Commission to monitor electric system planning in the large.

The electric utility power system in the U.S. is made up of three component networks. The seven strongly interconnected council areas (ECAR, MAAC, MAIN, MARCA, NPCC, SERC, and SWPP) comprise essentially a single network covering all or part of 39 states. Interconnections among the systems in the seven councils are sufficient for the interchange of significant amounts of power in emergencies and for economic purposes. The 14 western states (all or in part) are within the area of WSCC, which, while it has numerous intraregional interconnections, has only minor interconnection capability with the other regional council areas. ERCOT is the third network. The ERCOT systems comprise an interconnected group that has no transmission interconnections with any other council region, supplying power only within a large part of the State of Texas.

The projected council summer and winter peak demands for the period 1977-1986 are listed in Table 4.4.1.11. The contiguous United States average annual summer and winter growth rates for the period are 5.7 percent and 5.8 percent, respectively (Table 4.4.1.12). Note that the data reported were developed and compiled in late 1976 and early 1977, and reflect economic expectations then current.

Figure 4.4.1.7
Regional Electric Reliability Council Areas

DEPARTMENT OF ENERGY - ENERGY INFORMATION ADMINISTRATION

Table 4.4.1.11

Peak Demand¹
As Projected April 1, 1977
By the Regional Electric Reliability Councils
Contiguous United States
Megawatts

Summer Peak Demand

Year	ECAR ⁵	ERCOT	MAAC	MAIN	MARCA ²	NPCC ²		SERC				SWPP	WSCC ²
						N.E. ³	N.Y. ⁴	FLORIDA	SOUTHERN	TVA	VACAR		
1977	59,838	27,582	32,650	33,663	17,664	13,905	21,590	15,681	19,946	20,150	26,245	37,132	70,313
1978	63,461	29,305	34,200	35,716	18,945	14,648	22,430	16,692	22,095	21,650	28,044	39,895	74,867
1979	67,156	31,077	35,780	37,932	20,278	15,455	23,340	17,796	23,977	23,350	29,995	42,586	78,971
1980	71,150	32,920	37,400	40,170	21,783	16,315	24,230	18,902	25,816	25,050	32,073	45,832	83,666
1981	75,111	34,830	39,050	42,417	23,349	17,209	25,040	20,041	27,814	26,250	34,096	48,806	88,051
1982	79,323	37,016	40,730	44,832	24,882	18,152	25,850	21,214	29,769	27,400	36,099	52,278	92,345
1983	83,655	38,996	42,450	47,402	26,376	19,125	26,850	22,347	31,848	28,650	38,044	56,053	96,839
1984	88,318	41,255	44,230	50,172	27,887	20,166	27,950	23,422	33,930	29,950	40,375	60,019	101,364
1985	93,186	43,234	46,030	53,040	29,500	21,255	28,910	24,453	36,081	31,250	42,780	64,214	106,542
1986	98,293	45,438	47,810	55,039	31,066	22,384	29,930	25,490	38,561	32,650	45,297	68,660	111,350

Winter Peak Demand

1977	58,987	19,161	27,970	27,315	15,931	15,217	19,690	15,708	16,960	23,150	25,179	26,350	68,829
1978	62,481	20,551	29,490	29,192	16,960	16,051	20,450	16,762	18,270	25,100	27,106	28,133	73,142
1979	66,370	21,746	31,010	31,108	18,166	16,918	21,340	17,802	19,611	27,200	29,234	30,278	77,371
1980	70,175	23,012	32,530	33,097	19,448	17,846	22,150	18,938	21,050	28,700	31,447	33,604	81,617
1981	74,386	24,446	34,200	35,300	20,754	18,820	22,990	20,043	22,558	30,100	33,703	34,671	85,840
1982	78,713	26,024	35,850	36,615	21,958	19,814	23,870	21,124	24,132	31,550	36,051	36,993	90,202
1983	83,255	27,395	37,560	38,942	23,221	20,851	24,850	22,165	25,840	33,050	38,551	39,841	94,731
1984	88,128	29,046	39,310	41,377	24,723	21,964	25,920	23,194	27,690	34,650	41,140	42,686	99,221
1985	93,195	30,420	41,050	43,707	26,141	23,134	26,880	24,217	29,538	36,300	43,805	46,686	104,376
1986	98,548	31,918	42,830	46,605	27,661	24,379	27,880	25,235	31,783	38,150	46,571	48,833	109,273

¹The demands listed include interruptible loads and exclude inter-regional purchases and sales.

²Includes only United States portion of Council.

³Total for the six new England states.

⁴New York Power Pool.

⁵Revised demand data for ECAR was obtained too late to be incorporated in this report. However the greatest change for any user would be less than one tenth of one percent.

Source: April 1, 1977 responses to Appendix A-1 of FPC Docket R-362 (Order 383-4), Item No. 1, as cited in Reference 11.

Table 4.4.1.12

Projected Growth of Peak Demand¹
Contiguous United States
1977-1986
Megawatts

Summer Peak Demand Periods

<u>Year</u>	<u>Total U.S. Peak Demand</u>	<u>Annual Increase</u>	
		<u>MW</u>	<u>%</u>
1977	396,359	--	-
1978	421,948	25,589	6.5
1979	447,693	25,745	6.1
1980	475,307	27,614	6.2
1981	502,064	26,767	5.6
1982	529,890	27,826	5.5
1983	558,635	28,745	5.4
1984	589,038	30,403	5.4
1985	620,475	31,437	5.3
1986	652,968	32,493	5.2
Average Growth Rate		=	5.7

Winter Peak Demand Periods

1977-78	360,447	--	-
1978-79	383,688	23,241	6.4
1979-80	408,154	24,466	6.4
1980-81	433,614	25,460	6.2
1981-82	457,811	24,197	5.6
1982-83	482,896	25,085	5.5
1983-84	510,252	27,356	5.7
1984-85	539,049	28,797	5.6
1985-86	569,449	30,400	5.6
1986-87	599,666	30,217	5.3
Average Growth Rate		=	5.8

¹Non-coincident total of demands projected by the nine Regional Electric Reliability Councils in their April 1, 1977 responses to FPC Order 383-4.

Source: Reference 11

The slower-than-historical growth rate of demand reflects the combined workings of several factors as viewed by the electric utilities: attempts at load management and conservation; higher electricity prices and new pricing schedules; a lower growth rate of the national economy. Substitution of electricity for fossil fuels, where feasible, will tend to offset the foregoing. An additional factor, which may have different weights in different areas, is increased use of electricity caused by environmental pressures. Air pollution abatement devices, for instance, may use electrostatic precipitators, thus directly requiring greater use of electricity. Or, mechanical and chemical methods of removing potential pollutants, by increasing the obstruction to flow of process gases and the gases resulting from combustion, require greater fan capacity which results in more use of electricity. In power plants, the use of scrubbers for flue gas desulfurization, precipitators that remove extremely high percentages of particulates from flue gases, and cooling towers add to the auxiliary power requirements of fossil-fuel generating units. The additional auxiliary power needed by generating units does not appear in the load forecasts, because the forecasts include only customer requirements and transmission and distribution losses. But the same type of additional power, when used by customers of a utility, does appear as a load requirement. For the Tennessee Valley Authority's (TVA) system, for instance, "it is expected that 7 percent of industrial electricity consumption will be utilized for pollution control devices among the 50 large TVA-served industries which account for 20 percent of area load."

The construction of generating units is subject to the negative pressures of financing and environmental protection, as well as delays for various causes, and therefore the actual installed capability will probably be less each year than that projected. The total installed capability of the contiguous U.S. as projected for the time of the summer and winter peak demands in the years 1977 through 1986 is listed in Table 4.4.1.13. Comparing the capacity data with the peak demands indicates that a capacity reserve margin of about 18-22 percent is planned.

As of October 1976, electric utilities intended to add 130 new coal-fired units with a total capacity of 60,325 megawatts during the years 1976 through 1980. The national average unit size planned for that 5-year period was 464 megawatts. By 1980 the projected annual coal requirements will be 2.88 tons per kilowatt of new capacity, reflecting both a higher average capacity factor for the new units and a lower average heat content of coal to be used by the new units (due to the expanded use of low-rank coals).

During the period 1981-1985, utilities plan to construct an additional 99 units with a total capacity of 51,248 megawatts, i.e., the average unit size will be 518 megawatts. The average annual coal requirement of units to be completed during this period is 3.59 tons of coal per kilowatt of new capacity, underscoring the significant shift to the low-Btu subbituminous coal from the Northern Great Plains Province (Montana and Wyoming) and to lignite from the Fort Union Region (North and South Dakota) and from Texas.

Table 4.4.1.13

Projected Growth of Generating Capability¹
At Time of Seasonal Peak Demand Periods
Contiguous United States
1977-1986
Megawatts

Capability at Time of Summer Peak

<u>Year</u>	<u>Total U.S.</u> <u>Capability</u>	<u>Annual Increase</u>	
		<u>MW</u>	<u>%</u>
1977	512,158	--	=
1978	541,592	29,434	5.7
1979	566,688	25,096	4.6
1980	591,656	24,968	4.4
1981	620,586	28,930	4.9
1982	654,274	33,688	5.4
1983	689,447	35,173	5.4
1984	729,335	39,888	5.8
1985	760,141	30,806	4.2
1986	792,909	32,768	4.3
Average Growth Rate		=	5.0

Capability at Time of Winter Peak

1977-78	529,431	--	=
1978-79	556,635	27,204	5.1
1979-80	581,351	24,716	4.4
1980-81	610,120	28,769	4.9
1981-82	641,306	31,186	5.1
1982-83	672,788	31,482	4.9
1983-84	705,259	32,471	4.8
1984-85	743,862	38,603	5.5
1985-86	773,898	30,036	4.0
1986-87	811,992	38,094	4.9
Average Growth Rate		=	4.8

¹Total of installed capabilities projected by the nine Regional Electric Reliability Councils in their April 1, 1977 responses to FPC Order 383-4. Excludes purchases and sales.

Source: Reference 11

In 1976, almost 85 percent, or 147.6 million tons, of the total 1980 projected demand of 173.9 million tons was already under long term contract. The portion of the 1985 coal demand already under contract in 1976 was 67.9 percent of the total projected demand of 357.8 million tons.

There are significant regional differences in the proportion of the total coal demand which is under contract. Generally, utilities in the western regions have a much higher proportion of their projected coal demand under contract than utilities in the eastern regions.

Origin and Destination of Coal For New Units

Of the national total of 11,573 megawatts of new coal-fired capacity scheduled for service in 1976-1985, 58.8 percent will be located in states west of the Mississippi River. Except for relatively small quantities of coal which will be shipped westward from the Eastern Coal Region of the Interior Province, the new units in the west will depend almost entirely on bituminous and subbituminous coal and lignite produced west of the Mississippi. The data supplied by the utilities project that about 94 percent of the incremental coal produced in the west will be used by new units in the west. Because of the lower average heat content of western coal, units in the west will use more than their proportionate share of the new coal, i.e., 58.8 percent of the new coal-fired capacity will require 68.7 percent of the total incremental tonnage.

The western region of the Northern Great Plains (NGP) will provide more of the incremental steam coal production in the 1976-1985 period than any other region. Of the 357.8 million tons of coal demand projected for new coal-fired units, 141 million tons or 39.4 percent will be supplied from this region. As a result, in 1985 the NGP may account for one-quarter of all the coal used by electric utilities. In 1975 this region supplied 10 percent of the total. As can be seen from Figure 4.4.1.8, most of the coal production from the western region of the NGP will be going to adjacent areas of the country. The West South Central Region will receive 62.8 million tons from the NGP while 42.9 million tons will go to the West North Central Region. In 1975 the East North Central Region was the easternmost area to receive coal from the Northern Great Plains, but by 1985 a small tonnage will be shipped as far as the South Atlantic Region.

The four states comprising the Mountain Region -- Colorado, Utah, Arizona, and New Mexico -- will supply 10.8 percent of the coal requirements for new coal-fired units. In 1975, 5.3 percent of all electric utility steam coal came from these states. Most of the coal from this four-state region going to new units will remain within the area with many of the new units being mine-mouth operations.

Figure 4.4.1.8

Flow of Coal to New Generating Units
From the Western Regions of the
Northern Great Plains (in 1000 Tons)
1980 - 1985

Bureau of Mines (BOM) District #15 which includes Kansas, Texas, Missouri and part of Oklahoma will experience a rapid rate of growth in demand for its coal production. With 15 percent of the coal demand for new units being for BOM District #15 coal, this region will supply approximately 10 percent of all electric utility coal in 1985, compared to 3.9 percent in 1975. Virtually all of this coal will stay within the region, with 96 percent of the total coal output from BOM #15 being consumed in Texas.

The Appalachian Region has traditionally been the Nation's major source of coal for electric power generation. Of the 430.5 million tons of coal delivered to electric utilities in 1975, 44.8 percent was Appalachian coal. Data for new coal-fired units coming on line from 1976 through 1985 show that the Appalachian Region will be the source for only 14.5 percent of the new units' coal requirements. Appalachia will still remain the largest source for steam coal in 1985, but its share of the total steam coal supply will drop to about 35 percent.

The Eastern Region of the Interior Province which supplied 29.4 percent of all the coal delivered to electric utilities in 1975, will supply 10.2 percent of the coal required for new units in 1985. As a result, by 1985 this region will supply only about 20 percent of the total coal used by old and new units of all utilities.

4.4.1.2.3 The Railroad Industry¹²

The transport of western subbituminous coal to remote markets is dominated by a few major railroads. For example, in 1979, 80.2 million tons of coal were shipped by Burlington Northern (BN), most of it from the Powder River Basin. Union Pacific (UP) shipped 24 million tons in the same year, much of it from southern Wyoming surface mines. 1980 shipments by UP are expected to exceed 30 million tons.¹³ BN has effectively monopolized coal shipments out of the Powder River Basin; however, if UP's proposed merger with the Missouri Pacific and Western Pacific railroads is consummated, the mine operators and their distant utility customers may be offered a broader selection of shipment options.

Rail rates for coal shipments have escalated very rapidly, to the point where they now represent the largest cost component of delivered western coal in Texas and the midwest. In addition, railroads such as BN are having difficulty moving increasing tonnages on schedule. Unit train turn-around times are getting longer, according to Coal Age magazine.⁶ BN officials have reportedly told coal producers in the Powder River Basin to buy more trains if they want to increase annual shipments by 1 million tons. However, this would increase the congestion and turn-around problem. These factors are currently working to restrain the growth of western subbituminous coal production to some extent.

The projections of substantially increased coal production in the West have given rise to questions about the capability of western railroads to expand sufficiently to manage the increase in traffic. Although some studies have suggested that certain links in the system would be overloaded, the consensus appears to be that the flexibility of rail technology is sufficient to allow for the necessary increase in traffic, but that necessary capital for upgrading the capacity will test the financial strength of even the relatively healthy western railroads.

For several decades the railroad industry has been in a state of decline. Ton-miles of rail traffic have not declined but neither have they grown nearly so fast as the economy has grown, nor so fast as the growth in ton-miles carried by trucks, barges and pipelines. Furthermore, much of the more profitable traffic, consisting of higher priced, more processed goods (generally called "merchandise freight"), has shifted to trucks. Passenger traffic has declined, from more than 75 percent of all intercity passenger-miles provided by common carrier in 1929, to three percent in recent years (reference 13, pp. 155-156). Once considered to be a blue chip investment, rail stock has become so unattractive that obtaining funds by issuing new equity shares has become impracticable for most railroads. As a result, debt financing in the form of equipment trust certificates has become an increasingly large proportion of rail capitalization. Equipment trust certificates essentially are chattel mortgages backed by specific rail cars and locomotives which can be repossessed and sold if the obligations of the certificate are not met. Equipment leasing by the railroads from financial intermediaries has also become popular, as has ownership of rail cars by shippers. Equipment trust certificates and leasing from intermediaries raise the fixed costs of railroad operations, thus making railroad even more vulnerable to severe financial pressures as a result of recessions in the economy. Also contributing to the railroads' inability to reduce expenditures when there is a downturn in traffic is the property tax liability resulting from owning their own rights-of-way, and the need to repair and maintain the rights-of-way.

There are a number of significant reasons for the long decline of railroads. One of the most significant reasons is the construction of a vast network of roads and highways accompanied by the development of automobiles, buses and trucks. Airlines have taken over the largest share of intercity passenger traffic carried by common carriers, and oil pipelines and barges have taken over a large share of bulk traffic.

As rail passenger traffic declined, the railroads' financial health was affected, since railroads were required to continue to provide unprofitable service until reduced service, and finally, total discontinuance was authorized on each specific route segment by the Interstate Commerce Commission (ICC). It was not until 1970 that the National Railroad Passenger Corporation (Amtrak) was created, relieving most railroads of the responsibility of providing rail passenger service at their own expense.

Similarly, as a large proportion of railroad trackage, usually branch lines located in rural areas, became unprofitable as a result of declining traffic and rising operating and maintenance costs, railroads could not abandon the line until each specific segment was approved for abandonment by the ICC. Rural communities strongly resist rail abandonments, feeling that such abandonments hamper their chances for economic development, and sensing, rightly or wrongly, that abandonment means increased isolation from other parts of the country.

Coupled with the problem facing rail management of passenger service discontinuance and light-traffic-density line abandonment, was an inability to adequately adjust rail rates to the changing competitive situation. For example, rate contracts with shippers cannot be for periods of more than one year. When railroads developed a significantly larger car for grain shipments, the ICC would not, for several years, allow a reduction in rail rates in proportion to the reduced costs of handling the traffic in these cars. Even now, railroads generally may not charge rates that are below the variable costs of competing modes even though the proposed rates would more than cover rail variable costs and thus make a contribution to help offset rail fixed costs. So far, the 4R Act (Railroad Revitalization and Regulatory Reform Act of 1976) has had a negligible impact on this situation.

During 1980, a bill that would substantially deregulate the railroad industry passed the U.S. Senate, but is meeting opposition in the House.¹⁴ The proposal would free the railroads from ICC intervention in setting rates as long as revenues did not exceed twice the railroads' variable costs. Alternate proposals would set the "triggering" ratio at 1.6. If passed, this bill could have substantial positive effects on the financial condition of some railroads. However, even higher freight rates for western coal would tend to encourage the use of competing fuels or transport modes such as pipelines.

Table 4.4.1.14 lists the largest 15 coal-carrying railroads along with salient financial statistics from the year 1975.

A number of studies have concluded that the necessary locomotives and hopper cars could be made available to the railroads for the greatly increased western coal traffic that is anticipated. According to a study performed for the Electric Power Research Institute by Manalytics of San Francisco, "Clearly, aside from the financial aspects, the industry can obtain the equipment necessary to meet the expanded traffic demands."¹⁵ Thus, the question of physical capacity is primarily a consideration of whether the trackage can accommodate the probable number of trains between coal producing points and coal consumers.

The Manalytics study, mentioned above, generated a substantial controversy when it was released, because it identifies numerous stretches

Table 4.4.1.14

Top 15 Coal-Carrying Railroads and Salient Coal, Hopper Car, and Financial Data

Railroad (Ranked In Order Of Amounts of Coal Carried, 1971)	Bituminous Carried Coal 1975 (millions of tons)	Coal Originated 1975 (millions of tons)	Capability to Manufacture or Assemble Cars, 1974	Open Top Coal Hopper Fleet as of 1/1/74 (# of total) (thousands of cars)	Total Operating Revenues, 1975 (millions of dollars)	Revenues from Coal Shipments 1975 (millions of dollars)	% of Total Operating Revenues	Average Dollars Revenue Per Ton Carried	Total Operating Expenses 1975 (millions of dollars)	Net Operating Income 1975 (millions of dollars)	Income As Per-Cent of Revenue, 1975 (%)
1. Norfolk and Western	77.9	67.3	Yes	55.4 (17%)	985	408	41%	5.23	870	115	11.7
2. Penn Central	74.2	41.9	Yes (inactive)	44.6 (13%)	2,175	277	13%	3.73	2,409	-236	-10.9%
3. Chesapeake and Ohio	59.1	48.1	Yes	46.3 (13%)	572	258	45%	4.36	519	53	9.3%
4. Louisville and Nashville	58.4	52.3	Yes (Assembly)	33.2 (9%)	589	173	29%	2.96	539	50	8.5%
5. Baltimore and Ohio	43.9	25.4	--	23.9 (6%)	614	169	27%	3.85	585	29	4.7%
6. Burlington Northern	38.9	36.2	No	11.1 (4%)	1320	209	16%	5.37	1266	55	4.1%
7. Southern	35.5	26.0	No	10.7 (3%)	864	103	12%	3.90	754	110	12.7%
8. Illinois Central Gulf	25.5	21.5	Yes	10.9 (3%)	547	68	12%	3.66	538	9	1.6%
9. Chicago and North Western	16.0	3.7	No	4.0 (1%)	459	40	9%	3.50	464	-5	.1%
10. Seaboard Coast Line	15.5	.1	Yes (Assembly)	--	637	33	5%	3.12	603	34	5.3%
11. Union Pacific	15.4	12.4	Yes	7.7 (2%)	992	81	8%	3.25	879	113	11.4%
12. Clinchfield	13.3	7.3	--	4.2 (1%)	45	26	58%	3.95	34	11	23.8%
13. Denver and Rio Grande Western	13.0	10.3	--	2.6 (1%)	148	36	24%	3.76	131	17	11.7%
14. Elgin, Joliet, and Eastern	12.6	.0	--	--	80	16	20%	3.27	79	1	1.2%
15. Missouri Pacific	12.4	10.4	Yes	6.3 (2%)	631	26	4%	3.10	581	50	7.9%
Total of Average of Largest 15	511.6	363.9		260.9	10658	1932	18%	3.76	10251	406	3.8%
% of All Class I, if Relevant	85%	90%		76%	65%				64%	134%	
Total All Class I	604.3	405.0		342.4	16279	2127	13%	3.52	15928	352	2.2%

Source: Reference 12

of track which were projected to be overloaded given maximized future projections. The Manalytics study did not conclude, however, that this would lead to inability of the railroads to handle the traffic, but rather to greater shipment expense and time requirements because of the necessity to employ longer routes avoiding the bottlenecks. Criticism from railroad interests was strong, alleging that the Manalytics study did not recognize sufficiently the flexibility inherent in railroad operations.

The costs of expanding rail capacity to serve the greater production of western coal will be roughly parallel to the increase in that production. Thus the wide range of uncertainty concerning the demand for western coal, which will dictate the production of western coal, puts the necessary investment into equal uncertainty. However, the construction of additional rail transportation capacity to move coal requires less time from inception to completion than either additions to production by opening a new mine or addition to demand by building a new power plant or major industrial boiler. Presumably, then, the uncertainty over the general financial requirements for upgrading rail capacity will not play a critical discouraging role, because the investment will be sought on an as-needed basis, with sufficient time to make arrangements after production and consumption commitments are made.

As the capacity of the railroad industry to provide the needed rolling stock and locomotives is more certain than is the capacity of the track to carry the necessary coal, so the railroad ability to finance the needed cars and locomotives is more certain than their ability to finance the necessary upgrading of their rights-of-way. Equipment trust certificates are generally used for railway equipment. The major coal moving railroads should be able to obtain the necessary rolling stock by this means, by leasing, or by using customer-owned equipment.

As individual railroads approach capital markets seeking money with which to expand track capacity, however, the different nature of the investment will cause a different reaction from investors. Track and right-of-way cannot be repossessed and sold; it is the condition of the company that gives them their value. The railroads will need to offer returns on investment competitive with those offered by other companies, including the coal companies and electric utilities providing the traffic, they they hope to find the financing. Although the western railroads are generally in better financial shape than most railroads, it is not clear that they have the current profitability to be able to obtain the requisite investment, much less to finance the track maintenance and improvements internally. According to the one report, their rate of return on net investment was only 3.6 percent in 1976; eastern and southern railroads fared worse.¹⁶ This report also estimated that the total capital investments required to be made by railroads to 1985 would equal about \$40 billion, of which coal-related investments would conservatively require ten percent. This would amount to twice the recent annual level of capital outlays.

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4.4.1.3 Regional Market Analysis

In this section, the development of major markets for western low-rank coal is examined on a regional basis. Lignite is utilized within a short distance of its occurrence, primarily because its high moisture content makes long-distance transport prohibitively expensive. Thus, two major regional markets for lignite currently exist, which coincide with the major strippable reserves: the Fort Union Lignite Region and the Gulf Coast Lignite Region. These areas are discussed in Sections 4.4.1.3.1 and 4.4.1.3.2, respectively.

Subbituminous coal, in contrast, is transported in large quantities to distant utilities, as well as being utilized in power plants at or near the mines. These constitute two separate "regions" from a market analysis viewpoint, although a number of distinct subregions are included in both the remote and adjacent areas using subbituminous coal. Section 4.4.1.3.3 addresses the western markets for subbituminous coal, and Section 4.4.1.3.4 discusses the midwestern (and other remote) market areas.

4.4.1.3.1 Fort Union Lignite Region

Beginning in the late 1930's, the use of lignite as boiler fuel became a common practice in North Dakota, South Dakota, and parts of Montana and Minnesota. The boilers were small (10-20 MW equivalent) and were used for utility steam and electricity production as well as industrial and institutional uses. Operating problems due to boiler tube fouling were prevalent, but the units were cleaned frequently by hand, keeping the scope of the problem manageable. Many of these units in the industrial and institutional settings continue in use today; however, the relative size of this market for lignite is very small in comparison to the electric utility market.

Table 4.4.1.15 summarizes the history of the lignite-fired electric utility boiler installations in the Fort Union Region. In 1958, 1959, and 1960, the first three pulverized-lignite boilers were installed; the size of these units was about 50 MW. In 1966, two pc-fired units of about 200 MW capacity were installed, and in 1970, the first cyclone furnace boiler (235 MW) was installed. Some of the market considerations that went into the decision to construct this plant were described in a paper at the 1967 Lignite Symposium²:

"The generating station is being built by Minnkota Power Cooperative of Grand Forks, North Dakota, to serve the power requirements of its 12-member distribution cooperatives. This capacity is in addition to the existing 45 MW of steam and diesel generation owned and operated by Minnkota, the 50 MW of contracted firm Bureau of Reclamation power, and the short-term firm capacity presently being purchased from the Upper Mississippi Valley Power Pool.

"Minnkota's service area covers about 35,000 sq.mi. of rural eastern North Dakota and northwestern Minnesota. Its 1966-67 winter capacity demand was 127 MW and is expected to be 300 MW by 1976.

Table 4.4.1.15

Lignite-Fired Power Plant Capacity
in the Fort Union Region

Period	Stokers			Cyclone Furnaces			PC-Fired Boilers		
	Number of Units Installed	Total Capacity MW	Average Capacity MW/unit	Number of Units Installed	Total Capacity MW	Average Capacity MW/unit	Number of Units Installed	Total Capacity MW	Average Capacity MW/unit
Prior to 1960 ¹	10	121	12.1	0	--	--	2	116	58
1960 - 1969	2	125	62.5	0	--	--	3	426.2	142.1
1970 - 1974	1	21	21	1	234.6	234.6	1	79	79
1975 - 1979	(5)	(55.5)	(10.7)	3	1303	434.3	1	550	550
1980 - 1983	0	0	0	1	410	410	3	1430	476.7
TOTAL	8	211.5	26.4	5	1947.6	389.5	10	2601.2	260.1

Notes: ¹Data on pre-1960 period not necessarily complete.

Source: See Table 3.5.1.27 in Volume 3, Technology Evaluation

"The plant will be located 4 miles east and 3 miles south of Center, North Dakota. This site was selected as the result of an extensive study begun in 1960 which included a search for low-cost fuel, cooling water, minimum transportation costs, low cost of delivering output into the Minnkota service area, and availability of outlets for sale of excess power.

"A field of economically minable lignite covering more than 20,000 acres was discovered. Two seams, with a parting averaging less than 1 foot, form a total average thickness of 14 feet. Continuity of the seams and the favorable overburden depth found in the initial drillings justified additional investigation. Further core drilling ultimately proved reserves of 175 million tons within 16,000 acres with overburden averaging 60 feet and not exceeding 90 feet. Minnkota has purchased leases on 16,000 acres. Baukol-Noonan, Inc., a North Dakota coal mining company, has contracted with Minnkota for the mining and delivery of mine run coal to the plant site from this field for \$1.10 per ton or less than 8 cents per million Btu. Such low fuel costs will result in some of the lowest cost thermal power in the Nation."

The evolution of electric utility lignite-burning technology that is illustrated in the table -- the phasing out of small stoker units, initial development of pulverized coal-and cyclone-fired boilers in the 100-250 MW size range, and most recently the development of very large (about 500 MW) units -- was one of the primary events associated with the very rapid growth of this industry. Whether the improvements in technology and resultant economies of scale caused the rapid penetration of this market by reducing the cost of the lignite-to-electricity cycle compared to competing fuels, or whether the rapid growth in demand for electricity pushed the technology forward, is difficult to determine. In either case, it is clear that technological progress has been closely linked to penetration of the electric utility market by Fort Union Region lignite. This linkage is expected to be strong in the future as well (a subject discussed in Section 4.4.2).

Table 4.4.1.8 in Section 4.4.1.2.2 presented historical data on all fossil-fueled (coal, oil and gas) power plants installed by privately owned utilities in the U.S. It showed the same evolution from small plants to very large plants, but indicated that this transition took place earlier than in the Fort Union Region. By 1960, there were already 47 privately-owned fossil-fueled power plants of greater than 400 MW capacity in the U.S. During the 1960's, 106 more of these plants were added (net), averaging about 984 MW each. During the same decade, 142 plants smaller than 100 MW were retired (net). During that period in the Fort Union Region, 6 small and intermediate-size stokers and pc-fired boilers (but no large units) were built. Nationally, another 98 fossil-fueled plants averaging 1284 MW each were added during the period 1970-1977. It was not until the late 1970's that a significant number of large (400-500 MW) lignite-fired power plants were built in the Fort Union Region.

Thus, the penetration of Fort Union lignite into the electricity generation market has been quite a recent and rapid occurrence. This is illustrated graphically on Figure 4.4.1.9, which shows the growth rate of

Figure 4.4.1.9

Fort Union Region Lignite-Fired Generating Capacity

Source: See Table 3.5.1.27 in Volume 3, Technology Evaluation
Reference 13

Fort Union lignite-fired capacity in comparison to the total national production of fossil-fueled electricity. The primary factor that caused this rapid growth was the one cited by Minnkota Power Cooperative in 1967: very low fuel costs, resulting in some of the lowest cost thermal power in the nation. Several factors developed in the 1960's and 1970's to make the exploitation of this low-cost resource possible on a large scale: 1) the development of technology, both for large-scale surface mining of lignite and its combustion in boilers; and 2) interconnection of the major electricity transmission systems (see section 4.4.1.22), which allowed the lignite to serve a market area much wider than the sparsely populated Fort Union Region itself.

This latter point is illustrated by the fact that in 1976, more than half the power generated in North Dakota was transmitted out-of-state through regional power pool grids. Plants built or planned since 1976 send about three-quarters of their power out of North Dakota.⁷ This issue is being raised increasingly by local interest groups concerned about the environmental and other impacts of strip mines, power plants, and transmission lines. Although North Dakotans have generally welcomed the economic boost provided by the lignite-power growth, there is an increasingly prevalent attitude that utilities should be encouraged to build their plants closer to the load centers.

4.4.1.3.2 Gulf Lignite Region

Lignite deposits in the Gulf Coast area extend through at least five states -- Texas, Louisiana, Arkansas, Mississippi, and Alabama. However, significant utilization of this resource has occurred only in Texas to date, so the following discussion is limited to that state. Several large lignite-fired power plants are planned in Louisiana for startups in the mid-to-late 1980's; utilities and industrial firms in the other Gulf Lignite Region states are actively evaluating potential lignite projects as well.

The growth of the lignite-fired power plant industry in Texas has been even more recent and dramatic than in the Fort Union Region.^a As shown in Table 4.4.1.16, only one lignite-fired unit existed in the state in 1970. This was a generating station built by Texas Utilities (TU) for Alcoa in 1954 to provide power for alumina production. During 1971-1974, TU started up three large lignite-fired units in response to the developing gas shortage and the quadrupling of intrastate gas prices.

As recently as 1975, about 90 percent of the electricity generated in the state was still made by burning natural gas.³ In 1975, the Texas

^aHowever, it should be noted that Texas Utilities Company operated a 40 MW lignite-fired plant at Trinidad (about 50 miles south of Dallas) during the 1920's and 1930's. This was the first major power plant using pulverized lignite in the world. Cheap natural gas made the plant uneconomic, and it was closed by 1940.³ During this early phase of Texas lignite's history, it was mined by more than 150 small operators in 35 different counties.⁴

Table 4.4.1.16

Low-Rank Coal-Fired Power Plant Capacity
in the Gulf Coast Region

Period	<u>Lignite-Fired Boilers</u>			<u>Subbituminous Coal-Fired Boilers</u>		
	Number of Units Installed	Total Capacity MW	Average Capacity MW/unit	Number of Units Installed	Total Capacity MW	Average Capacity MW/unit
Prior to 1970	1	360	360	0	0	--
1970 - 1974	3	1725	575	0	0	--
1975 - 1979	5	3575	715	3	1440	480
1980 - 1984	<u>7</u>	<u>4025</u>	<u>575</u>	<u>7</u>	<u>3590</u>	<u>513</u>
TOTAL	16	9685	605	10	5030	503

Sources: See Tables 3.5.1.29 and 3.5.1.31 in Volume 3, Technology Evaluation

Railroad Commission ordered major users of natural gas as a boiler fuel to restrict consumption. Sixteen new facilities burning gas were to be built and users of over 3 million scf/day of gas were ordered to cut consumption by 10 percent by 1981 and 25 percent by 1985. During the 1975-1984 decade, an additional 12 lignite-fired units are to be installed with a total capacity of 7600 MW. In the same decade, 10 subbituminous coal-fired power units are also to be installed in Texas and Louisiana with a total capacity of 5030 MW. This will amount to a seven-fold increase in the low-rank coal-fired power plant capacity in ten years. Low-rank coals (roughly 60 percent Texas lignite and 40 percent Powder River Basin subbituminous coal) will generate about 40-60 percent of Texas' electricity in 1985. The growth rate of this sector of the utility market is graphically compared to the growth of total U.S. coal-fired electricity generation in Figure 4.4.1.10.

During the same period, nuclear power plant capacity in Texas is also expected to grow dramatically. Texas' first nuclear power plant was scheduled to start up in 1980. By 1985, nuclear plants are planned to be in operation at three locations in Texas with capacity to supply 7200 MW of power.

The state and federal regulations requiring that utilities switch from oil and gas to other fuels are only partially responsible (if at all) for this major shift in Texas' power supply sources. The real driving force is economics. During the 1970's, oil and gas prices increased beyond the point of economic competitiveness with coal and nuclear power in Texas. Texas Utilities Company apparently anticipated this occurrence many years ago.

TU was considered eccentric when it began acquiring lignite leases in east Texas in the 1950's. By 1978, it owned in fee or had under lease about 750 million tons of proven recoverable reserves. By establishing its position in lignite when gas was both plentiful and cheap, TU acquired an enviable competitive position. The company decided to start using lignite in 1965, even though gas was cheaper (per Btu) than lignite at the time. TU as a company produced 31.5 percent of its electric generation from lignite in 1976, and about 50 percent in 1978.⁴ In 1976, TU considered its lignite cost to be 28.8 cents/10⁶ Btu (versus about \$2.00/10⁶ Btu for gas).³

These extremely low costs apply to the choicest lignite deposits, with very favorable stripping ratios and nearly ideal mining and reclamation conditions. The total quantity of these most economic lignite reserves in Texas is limited, and not sufficient to satisfy all potential users. Thus some utilities have initiated projects using subbituminous coal "imported" to Texas by rail from the Powder River Basin.

Under the pre-1979 New Source Performance Standards, low-sulfur subbituminous coal could be used in plants without scrubbers, whereas Texas lignite is high enough in sulfur content to require scrubbers. This is one of the primary factors allowing the Powder River Basin coals to compete with lignite in Texas despite the high costs of transportation. One cost estimate by Ebasco Services, Inc. for Phillips Coal Company showed the cost per KW of lignite generation as 30 percent higher than the cost of using

Figure 4.4.1.10

Gulf Coast Region Low-Rank Coal-Fired Generating Capacity

Source: See Tables 3.5.1.29 and 3.5.1.31 in Volume 3, Technology Evaluation Reference 13

low-sulfur coal under the old NSPS.⁵ When both fuels require scrubbing of 100 percent of the fuel gas, the difference becomes only 5 percent. With universal scrubbing requirements now in effect, and with rapid escalation of coal transportation costs, "imported" coal is less competitive with lignite in Texas today than it was in the 1970's.

The utilities are not alone in acquisition of Texas lignite reserves and commercial plans. Oil companies such as Exxon, Shell, Phillips, Sun and Texaco have accumulated large leaseholdings. Exxon (Carter Oil) had about 600 million tons of lignite reserves in east Texas in 1978 and was seeking more. The company shipped 16,500 tons of Texas lignite to SASOL (South Africa) for gasification tests in the Lurgi reactors there; a gasification project in Texas is under consideration. ICI Americas, Inc., posted a performance bond in 1978 in mining of lignite (300-400,000 tons/year) to be used in activated carbon manufacture.

The vast network of petrochemical plants and other energy-intensive industry along Texas' southeast coast has been identified for several years as a major potential market for lignite. Many companies are evaluating projects at the present time. However, the economic incentives to switch to lignite are evidently not sufficiently strong yet, since major projects have not been announced. Thus, the Gulf Coast industrial complex remains a "potential" market for the time being.

4.4.1.3.3 Western Markets for Subbituminous Coal

The relevant market for the onsite electric power generation from the western subbituminous coals is the 12-state Western Systems Coordinating Council (refer to Figure 4.4.1.7 in Section 4.4.1.2.2). This vast electric supply region is also known as the Western Loop, since the major transmission lines are interconnected and appear to circle around the state of Nevada (see Figure 4.4.1.11). There are only minor connections between the Western Loop and other power areas of the U.S., such as a 100 MW DC line between Wyoming and Nebraska.

Although generating capacity and transmission lines exist in all parts of the West region, more than 70 percent of the load requirement is along the Pacific Coast, as shown in Figure 4.4.1.12. Hydroelectric plants, situated in the Northwest, provided most of the electrical power to the Pacific Coast before 1970; thermal generation surpassed hydro in the early 1970's.

If site approvals can be obtained near adequate sources of cooling water, nuclear plants could supply increasing portions of the base loads in the Northwest. Coal-fired plants in remote areas like Wyoming, Utah and Arizona are beginning to supply considerable amounts of power to load centers along the Pacific Coast through high-capacity, long-distance transmission lines, or by power displacement along lower-capacity lines. Presently, a large coal-fired plant in Rock Springs, Wyoming, is exporting a large portion of its electricity to Idaho, which in turn exports power to Oregon. Energy is displaced in Idaho via 230 kV AC lines; from western Idaho a large 500 kV AC line is being built to transmit displaced energy to southern Oregon.

Figure 4.4.1.11

The Western Loop

Source: Reference 6

Figure 4.4.1.12

Load Centers of the West Region

Source: Reference 6

As summarized in Table 4.4.1.17, there are three distinct power generation areas in the West, which correspond to major subbituminous coal reserve areas. The states of Arizona and New Mexico currently have 15 large coal-fired units supplying both in-state and west coast markets (primarily southern California). In Wyoming and Montana, six units are currently supplying power to the transmission loop, most of which is moving to the northwestern states as mentioned previously. In the state of Colorado, there are ten small coal-fired units, primarily meeting local needs.

In comparison to the two lignite regions discussed in the preceding sections, growth of the Western region's low-rank coal-fired generating capacity has been moderate (see Figure 4.4.1.13). Some of the major constraining factors have been: 1) relatively low demand growth for coal-fired capacity, due primarily to hydroelectric power growth in the Northwest; 2) siting problems due to strict air quality standards and low water availability in the major resource areas; and 3) the long distances from the coal reserves to the major load centers. The last two factors tend to increase the cost of power delivered to the consumers, in a region where reasonably low-cost alternatives have been available.

4.4.1.3.4 Midwestern Markets for Subbituminous Coal

In 1970 and 1971, mandatory limits were imposed by the EPA on ambient SO₂ concentrations and plant emissions. This created a demand for low sulfur coals (i.e., Powder River Basin subbituminous coal) at many midwestern coal-fired power plants. Without considering utilization costs, the delivered price of western subbituminous coal exceeded the price of indigenous (but high-sulfur) midwestern coal. Approximately 60-75 percent of this delivered cost was accounted for by transportation (unit train). However, when the cost of stack gas scrubbing was added to the cost of utilizing the local coal, the western low-sulfur coal had an advantage in many market areas. A typical set of cost calculations using 1973 data is presented in Table 4.4.1.18 to illustrate this point. As shown, the low-rank coal had a substantial competitive advantage in Minnesota, and a very slight disadvantage in Indiana or Illinois in the simplified example.

It is quite likely that some utilities made decisions to go with long-term contracts for low-sulfur western coal even in cases where the cost was marginally higher, such as the illustrated Illinois-Indiana cases. Flue gas desulfurization (FGD) costs were (and remain) generally understated due to newness of the technology and inherent unreliability of the highly corrosive and fouling slurry pumparound systems. Many utilities opted to avoid these problems despite the slight cost disadvantage (on paper) of importing western coal. Also, most state utility commissions allowed an automatic pass through of fuel transportation costs (i.e., without the necessity of rate hearings), thus increasing the competitive advantage of the western low-sulfur coals.⁸

During the 1970's, the costs of all of these components - coal, transportation, and FGD systems - increased dramatically. As these shifts occurred, the incentive to switch to western low-sulfur coal rather than use local coal plus FGD increased. This is illustrated in Table 4.4.1.19. Although the delivered western coal exceeds the Illinois coal cost by about

Table 4.4.1.17

Subbituminous Coal-Fired Power Plant
Capacity in the West Region

Period	Arizona and New Mexico			Wyoming and Montana			Colorado		
	Number of Plants Installed	Total Capacity (MW)	Average Capacity (MW/plant)	Number of Plants Installed	Total Capacity (MW)	Average Capacity (MW/plant)	Number of Plants Installed	Total Capacity (MW)	Average Capacity (MW/plants)
Prior to 1970	5	1446	289	3	580	193	0	0	0
1970 - 1974	2	1505	753	1	330	330	5	169	34
1975 - 1979	6	2435	406	2	716	358	5	368	73
1980 - 1984	3	939	313	5	2441	488	0	0	0
TOTAL	16	6325	395	11	4067	370	10	537	54

Source: See Table 3.5.1.28 in Volume 3, Technology Evaluation

Figure 4.4.1.13

West Region Subbituminous Coal-Fired
Generating Capacity

Source: See Table 3.5.1.28 in Volume 3, Technology Evaluation Reference 13 .

Table 4.4.1.18

Price of Western Subbituminous Coal in Midwest Markets Compared to Prices of Midwest Coal in 1973

Origins, destinations and transport mode	Actual Cost of transportation by unit trains, cents 10 ⁶ Btu		1973 coal cost f.o.b. mine in origin state, cents/10 ⁶ Btu		Estimated average total cost of western coal delivered to state, cents/10 ⁶ Btu	November 1973 actual price of midwestern coal purchased by steam-electric plants in state destinations cents/10 ⁶ Btu	Difference in cents/10 ⁶ Btu of NGP coal delivered compared to Midwestern coal delivered	Cost of stack gas cleaning*	Price advantage of NGP coal in cents/10 ⁶ Btu, delivered compared to midwestern coal delivered with emission controls
	Range	Average							
Montana to Minnesota (approx. 815 miles) Unit train Slurry	18.6 to 31.6	24.5	16.2	=	40.7	39.6	1.1 more	15.7	14.6 less
Wyoming to Minnesota (approx. 1,100 miles) Unit train Slurry	30.5 to 32.1	31.3	21.5	=	52.8	39.6	13.2 more	15.7	2.5 less
Montana to Ill.-Ind. (approx. 1,270 miles) Unit train Slurry	45.4 to 51.7	49.2	16.2	=	55.4	46.4	19.0 more	15.7	3.3 more
Wyoming to Illinois (approx. 1,110 miles) Unit train Slurry	42.5 to 45.0	43.7	21.5	=	55.2	46.4	18.8 more	15.7	3.1 more

*Sulfur Oxide Central Technology Assessment Panel -- April 1973. Reflects costs of wet lime/limestone/CA(OH)₂ slurry scrubbing. Number cited selected average of 1.1-2.2 mills/kWhr adjusted by heat rate of 10,494 Btu/kWhr. $\frac{1.65 \text{ mills/kWhr}}{10,494 \text{ Btu/kWhr}} \times 10^6 = 157 \text{ mills/10}^6 \text{ Btu} = 15.7 \text{ cents/10}^6 \text{ Btu}$

Source: Reference 3

Table 4.4.1.19
Price Comparison Updated To 1978
(\$/10⁶Btu)

	<u>Low-Sulfur Western Coal</u>	<u>Illinois Bituminous Coal</u>
Coal Cost, f.o.b. Mine ^a	\$0.40	\$0.80
Transport Cost, Unit Train, Decker, Montana to Chicago, Illinois ^a	0.90	--
FGD Cost ^b	<u>--</u>	<u>1.33</u>
"Total" Cost for Comparison	\$1.30	\$2.13

Notes: ^aSource: Reference 9

^bSource: Reference 10; calculated from levelized 30-year cost of 14 mills/kWh on same basis as in Table 4.4.1.18.

60 percent (versus about 40 percent in 1973, indicating the relatively rapid increase in rail rates), the cost of desulfurizing the stack gas from high-sulfur coal has increased by even a greater relative amount. Thus the "total" cost for the midwestern coal plus FGD is about 60 percent greater than the western low-sulfur coal in the 1978 Illinois case, compared to an approximate breakeven condition in 1973.

It is important to recognize that the costs in Tables 4.4.1.18 and 19 are illustrative only. Each individual utility negotiates its own coal supply and transportation contracts, which can vary over a wide range. In addition, the illustrative examples do not take into account all relevant factors, even for the "new plant" cases that they represent. For example, the higher moisture content (lower heating value), lower grindability, and higher ash resistivity of the low-rank coals generally increase the boiler, pulverizer, and electrostatic precipitator costs compared to bituminous coal. When a retrofit situation is considered, the factors are different still. For example, installing an FGD unit in an existing power plant can cost 1.5 - 2.5 times as much as integrating it into a new plant.⁸ Pulverizer and fan capacity typically must be increased for the low-rank coal, and the boiler may be derated somewhat due to fouling, slagging, and heat release considerations. A new dust collection system may be required. Maintenance and sootblowing requirements generally increase also.¹¹

The net effect in many cases is an economic advantage for the low-sulfur western coal compared to adding a scrubber, despite the increased costs involved in making the fuel switch.

Tables 4.4.1.20 and 21 give a specific example of the cost comparison for fuel switching versus retrofitting an existing boiler designed for Illinois coal. The example is Commonwealth Edison Company's (Illinois) Powerton 5 and 6 units. The decision was made to switch to low-sulfur western coal "because of the unreliable performance of stack gas scrubbers, the higher cost of that option, and the lack of time to meet changed environmental restrictions".¹²

As a result of this regulation-created demand for low-sulfur coal, western subbituminous coal penetrated the midwestern electric utility market very rapidly during the 1970's. From a level of essentially zero prior to 1970, the low-rank coal-fired capacity grew to approximately 13,600 MW by 1980 in the states of Minnesota, Wisconsin, Illinois, Iowa, Arkansas, Missouri, Kansas, Oklahoma, and Nebraska. Another 7,400 MW of subbituminous coal-fired capacity is planned in these states during 1980-1985.^a (Also, as noted in Section 4.4.1.3.2, subbituminous coal has rapidly penetrated the Gulf Lignite Region utility market in the same time period.)

Year-by-year total low-rank coal capacity data in the midwest utility market are difficult to obtain due to the large number of existing plants switching to low-sulfur coal each year. However, the rapid increase between 1970 and 1975 in low-rank coal usage by Commonwealth Edison in

^aSee Table 3.5.1.30 in Volume 3, Technology Evaluation

Table 4.4.1.20

Modifications Required to Use Low-Sulfur Coal
In Commonwealth Edison's Powerton Units 5 and 6

\$(1000)

1979 Dollars

Boiler	
1. Soot blowers	\$11,381
Precipitators	
2. Flue Gas Conditioning (Boilers 51 and 52)	4,000
3. Hopper Vibrators and Poke Holes	490
4. Fly Ash Unloaders	405
Coal Handling	
5. Coal Storage Revisions	627
6. Coal Crushers	3,770
7. Coal Feeders and Conveyors	803
8. Car Dumper Replacement	2,000
Coal Dust Suppression	
9. Dust Collection and Suppression Modifications	2,803
10. Coal Silo Dust Collection	355
11. Coal Oil Facilities	837
Railroad	
12. Railroad Track Additions	1,919
13. Rebuilt Locomotive	400
14. Locomotive Maintenance Shed	275
Demineralizer	
15. Add two 300 gallon/minute Lines	3,405
Auxiliary Power	
16. Additional Auxiliary Power	330
Waste Water	
17. Collection Pond	<u>1,100</u>
Total direct costs for low sulfur coal plant	34,900
Indirect Costs	<u>4,258</u>
Total Investment Cost (1979\$)	39,158

Source: Reference 12

Table 4.4.1.21

Revenue Requirements Comparison for
Low-Sulfur Coal Versus Scrubbers at
Powerton Units 5 and 6

Case	Total Incremental Revenue Requirements	Present Value of Incremental Revenue Re- quirements to 7/1/79	Levelized Revenue Requirements Mills/KWH ^a
Burn Low Sulfur Coal	\$5,256,334,000	\$1,328,706,000	15.6 mills
Burn Low Sulfur Coal then install (40 mo.) scrubbers for Illinois Coal	6,205,640,000	1,672,072,000	19.6 mills
Burn Low Sulfur Coal then install (30 mo.) scrubbers for Illinois Coal	6,401,372,000	1,746,657,000	20.5 mills
Install (30 mo.) scrubbers for Illinois Coal	6,105,064,000	1,538,285,000	18.0 mills

^aLevelized annual revenue requirements divided by annualized net kilowatthours produced over the remaining life of Powerton Station.

Source: Reference 12

Illinois (see Figure 4.4.1.14) is probably typical of the industry-wide trend. A total of six Commonwealth Edison stations (with 16 units) currently burn low-sulfur western coal.¹²

The 1977 Clean Air Act Amendments and the 1979 New Source Performance Standards have significantly altered the situation by requiring that all new coal-fired plants reduce SO₂ emissions by at least 70 percent. While western low-sulfur coals will require substantially less sulfur removal capability than high-sulfur bituminous coals, the previous large incentive to use western coals in midwestern locations will be dramatically reduced. Technological alternatives such as coal cleaning, or conversion, dry scrubbing, fluidized bed combustion, etc., will receive increased scrutiny and development attention as utilities strive to meet the new regulations. Coal in general may become less competitive with alternatives such as nuclear power. (These considerations are addressed in Section 4.4.2.) Within the coal-fired utility market itself, coals of different rank from different regions will once again compete primarily on the basis of delivered cost (extraction plus transportation) to the consumer.

Figure 4.4.1.14

Coal Usage by Commonwealth Edison Company,
Illinois, 1969-1978

Source: Reference 12

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4.4.2 Potential Markets For Low-Rank Coal

The prospects for continued rapid growth of low-rank coal in this country are excellent. The largest existing market for low-rank coal -- electric utilities -- will continue in that role. Continued electrification of our total energy supply will cause electricity production to rise faster than total energy production. Coal is expected to maintain or increase its share of the total electric generating fuel market, with low-rank coal very likely providing the majority of the new growth. It is quite likely that half the total tonnage of coal used by electric utilities in the year 2000 will be low-rank coal.

Industrial direct use of low-rank coal is expected to grow substantially during late 1980's, as oil and gas prices continue to escalate faster than coal prices. Both direct combustion (conventional and fluidized) and low- or medium-Btu coal gasification are expected to contribute to the industrial use of coal as boiler fuel and chemical feedstock. The Gulf coast is expected to be the most active region for conversion of industry to coal as a primary fuel source.

Synthetic fuels (not counting those that may be used by electric utilities) are expected to enter the picture in a substantial way during the 1990's. The Synthetic Fuel Corporation should be able to stimulate investments in synfuels plants that would otherwise not be made, through the use of various financial incentives. Low-rank coals are expected to capture a major share of the synthetic fuels market because of their favorable physical and chemical characteristics for many of the conversion processes, and their low extraction costs per Btu.

Other markets, such as exports and residential/commercial use of low-rank coal, may develop in the future. These are not likely to account for a significant fraction of the total low-rank coal use, however.

As a summary of the potential future use of low-rank coal, Figure 4.4.2.1 illustrates a scenario prepared by the Electric Power Research Institute in a recent long-range planning study.¹ Other recent forecasts by DOE and the National Coal Association are similar. The potential shares of the three major market segments that could be penetrated by low-rank coal (based on the results of this study, not the EPRI forecast) are shown to approximate 50 percent in the 2000-2020 timeframe. This is not intended as a forecast, but rather as an indication of the potential for growth.

Under this scenario, total U.S. coal production would triple by the year 2000 to about 2 billion tons/year. This is an average annual growth rate of 4.7 percent -- much higher than the historical rate.

The low-rank coal portion of the total could grow to the order of about 50 percent, or 1 billion tons/year, by 2000. To achieve this production rate, low-rank coal use would have to continue growing much faster than total coal use, at a rate of approximately 8-10 percent per year for the next 20 years.

Figure 4.4.2.1

A Future Scenario for the U.S. Coal Industry

Source: Reference 1 (Except low-rank coal share, which was estimated in this study.)

4.4.2.1 Electric Utilities

The electric utilities will continue to be the major market for low-rank coals for many years. Long-range planning studies by the Electric Power Research Institute (EPRI) estimate that by the year 2000, electricity may constitute 45 percent of our total energy budget, in contrast to 30 percent today.¹ Thus, while total energy demand is expected to grow at an average annual rate of 1.5 - 2.8 percent during the next two decades, the average annual growth rate in electricity generation is projected to be between 3.8 and 5.6 percent. (The "base case" estimates are 2.5 percent for total energy and 4.7 percent for electricity.) Total electricity use will almost triple from 2.2 trillion kWh in 1978 to 6.1 trillion kWh in 2000. Generating capacity will need to expand from the current 560 GW to 1300 GW in the year 2000.

Coal and nuclear power represent the only proven and domestically abundant options which can be relied upon to meet growing electricity demands during the next several decades. About 75 - 80 percent of electricity used in 2000 is expected by EPRI to be generated from uranium and coal, compared with 62 percent in 1978. Even using optimistic assumptions for the growth of nuclear generating capacity, coal deliveries to electric utilities must increase to at least 1.3 billion tons/year by 2000 in order to meet this electricity demand. This compares to 476 million tons delivered in 1978. The average annual growth rate for this segment of the coal industry would thus have to be about 4.7 percent. (EPRI projects the

same annual average growth rate for total coal production, including non-utility coal, during the next two decades; this would amount to a total production rate of over 2 billion tons/year in 2000.)

Table 4.4.2.1 summarizes the EPRI "base case" projections for installed capacity and electricity generation in the year 2000. Table 4.4.2.2. summarizes the growth rates required to achieve this scenario.

Table 4.4.2.1

EPRI Projections for Installed Electric Generation
Capacity and Net Output in the Year 2000

<i>Type of Generation</i>	<i>Installed Capacity (GW)</i>	<i>Estimated Average Annual Capacity Factor (percent)</i>	<i>Net Energy Output to Lines</i>	
			<i>10⁹ kWh</i>	<i>Percent</i>
Nuclear	325	71	2020	33
Coal-direct fired (conventional and gasification)	467	62	2535	42
Coal-derived liquids and petroleum	238	26	540	9
Hydro	100	48	420	7
Geothermal ^(a)	20	75	130	2
Solar (including wind and biomass)	5	50	20	<1
Subtotal	1155		5665	93
Storage				
Pumped hydro	45			
Thermal/mechanical	15			
Batteries	10			
Energy storage losses	—		(25)	(<1)
Total	1225		5640	92
Capacity deficiency	75		460	8
Total need to meet load	1300		6100	100

(a) Steam and low salinity hydrothermal only

Source: Reference 1

Table 4.4.2.2

Forecast Growth of Coal Use by Electric Utilities
1978-2000

	<u>1978</u>	<u>2000</u>	<u>Average Annual Growth Rate 1978-2000 (percent)</u>
Total U.S. Primary Energy Consumption, Quadrillion Btu	78	130	2.4
Fraction of Total Energy Used for Electricity Generation	0.30	0.46	
Total Installed Electric Generating Capacity, GW	537	1,300	4.1
Total Coal-Fired Electric Generating Capacity, GW	212	467	3.7
Total U.S. Electricity Generation Trillion kWh	2.2	6.1	4.7
Total Coal-Fired Electricity Generation Trillion kWh	0.98	2.5	4.4
Total Coal Delivered to Electric Utilities, Million Tons	476	1,300	4.7
Low-Rank Coal Delivered to Electric Utilities, Million Tons ^a	121	650	8.0

Note: ^aEstimated in this study (not in Reference 1, 2, or 3).

Source: References 1, 2, and 3

The bottom line on Table 4.4.2.2 is this study's estimate of the potential for growth of low-rank coal use by electric utilities during the next two decades. The factors that contributed to the very rapid penetration of this market by low-rank coals during the past decade are expected to continue to apply. Thus, low-rank coals can be expected to continue providing the lion's share of the incremental coal used by electric utilities. Low-rank coals accounted for about 25 percent of the total tonnage delivered to electric utilities in 1978. In the year 2000, low-rank coals could account for about half of the total tonnage.

This rate of expansion will tax the capabilities of the coal mining and transportation industries, as well as the electric utilities. For example, if the average size of new low-rank coal surface mines during this period were 10 million tons/year, about 43 new mines would be required during the next 20 years. Along with these mines would have to come the necessary transportation, handling, and storage facilities; land and water commitments; and manpower. Although the numbers appear large, the industries involved are judged to be capable of meeting the challenge if environmental and regulatory constraints do not become excessive.

In that regard, estimates have been made of the national levels of SO₂, NO_x, and particulate emissions that would coincide with the projected growth of coal-fired electric generating capacity, if the environmental laws which have already been enacted are strictly enforced.⁵ These are shown on Table 4.4.2.3. SO₂ and particulate emissions would decline under the assumptions made. NO_x standards will tighten substantially in the future, and will pose major technical challenges to all fossil fuel combustion systems.

Table 4.4.2.3
Estimated National Air Emissions From Coal-Fired
Power Plants, 1975-2000
(million tons)

	<u>1975</u>	<u>1985</u>	<u>2000</u>
SO ₂	18.8	16.2	14.9
Particulates	3.3	1.3	1.2
NO _x	4.1	6.2	7.9

Source: DOE and EPA, as cited in Reference 5.

Two aspects of the potential electric utility market are discussed in the remainder of this section: 1) technology requirements, and 2) regional factors.

Technology Requirements

In the near term, the technology for delivery of low-rank coals to power plants and for conversion of the coal to electrical energy will remain essentially the same as at present. Large, efficient surface mines will feed coal either to minemouth power plants or to unit trains which deliver the coal to remote power plants. This aspect of the technology is

not likely to change substantially even in the longer run (with the possible exceptions of the introduction of slurry pipelines and coal cleaning facilities).

At the power plant itself, the conventional pc-fired boiler of approximately 500-1000 MW size is likely to continue as the predominant conversion device for at least 20 years (until more efficient advanced technologies become commercially dominant). Two major technical challenges must be met by the industry with regard to pc-fired generating units: 1) improved reliability and performance, and 2) cost-effective environmental control technology. Together, these challenges dictate one of the major thrusts of the recommended low-rank coal RD&D program.

Improved reliability and performance of pc-fired power plants will entail a number of evolutionary improvements in systems such as turbines, generators, boiler feed pumps, etc., that are not specific to the type of coal being burned. In addition, however, there are several major areas of boiler reliability and performance affected by the properties of the fuel. For low-rank coals, the key issue is the reduction of fouling and slagging problems. This can be attacked (depending on the specifics of the coal and boiler) by a number of means (detailed in Volume 3, Technology Evaluation) such as coal cleaning, ion exchange (sodium removal), boiler design, sootblowing systems, and use of additives. A secondary issue is improving the specification and operability of low-rank coal pulverizers.

Meeting increasingly stringent environmental standards in coal-fired power plants (while still meeting reliability and performance objectives) at reasonable cost will be a far more difficult technical challenge. Environmental control requirements, including air, water and solid waste, are becoming the dominant specification in the design and operation of new coal-fired power plants. The capital cost for a typical new coal-fired unit beginning design and engineering in 1979 is, for example, about \$1,000/kw. Approximately 40 percent of this investment is used for environmental control requirements. By 1985, potentially more stringent requirements can be expected to increase this cost to \$1,200-1,500/kw (in 1978 \$), of which 50-60 percent will be devoted to environmental control.⁴ Table 4.4.2.4 lists the major areas of concern, and indicates how the environmental standards are expected to evolve over the next few years.

Low-rank coal-specific issues exist in almost all of the environmental impact areas listed. The most urgently needed technology developments or improvements are in the area of stack gas cleaning for SO₂, NO_x, and particulate control. Solid waste disposal and water quality and quantity issues are also of critical importance. The technical options available to meet these challenges, and the issues surrounding their development or improvement, are detailed in Volume 3 of this report.

It should be noted that utilities in certain regions of the country will have to concern themselves not only with the New Source Performance Standards for new plants, but also with ambient air quality standards. Emissions from existing plants in the area may have to be reduced in order

to offset the emissions from new plants and prevent ambient pollutant concentrations from increasing. This will require the use of retrofit environmental control devices or techniques on the existing units. This, too, represents a challenging RD&D problem.

Table 4.4.2.4
Evolution of Coal-Fired Power Plant Environmental Requirements

	1969	1978	1985
Particulate	95%	99+% ESP/Baghouse	99.9% Baghouse
SO ₂	% S limit in fuel	Nonregenerable FGD	Regenerable and Nonregenerable FGD
NO _x	(California only)	Combustion Control	Combustion & Post Combustion
Water Quality	Oil Separation	Single Discharge	"Zero" Discharge (chemical treatment plants)
Cooling Water System	Open Cycle	Cooling Tower	Wet/Dry Cooling Tower
Solid Waste	Ponding	Inventory & Off-Site Disposal	Long-Term Monitoring, Byproduct, Recovery
Noise	No Special Provision	Attenuation	Equipment Standards
Auxiliary Load	1%	10%	30%
Licensing	Limited Environmental Review	EIS & Hearing	Preconstruction Review
Schedule	4 years	7 years	?

Source: Reference 4

In the longer run, utilities will begin to utilize some of the advanced coal technologies that have been developing for years and are now nearing the demonstration/commercialization phase. For baseload power plants, the most promising advanced technologies appear to be gasification/combined cycle and fluidized bed combustion. (MHD technology may eventually supplant these, but that is not expected to occur for at least 30-40

years.) For peaking units, coal liquids or gases supplied by pipeline are likely to be used. These fuels will also be needed to replace oil and gas in existing generating units (that represent about 30% of existing capacity).

An EPRI forecast of the penetration of these technologies into the utility market is shown on Figure 4.4.2.2. The expectation is that prototype advanced coal conversion plants will be built during the 1980's and 1990's, and that significant electrical energy production from these technologies will begin around the year 2000.

Figure 4.4.2.2

Projected Electricity Generation by Fuel Type and Technology
1980-2020

Source: Reference 1

Advanced technologies will eventually replace conventional combustion units for a variety of reasons, including better conversion efficiency (heat rate), easier or more effective environmental control, greater fuel flexibility, and lower water consumption. Specifically, coal gasification plants integrated with combined cycle power generation units should be able to achieve overall conversion efficiencies of about 40 percent, compared to 33-34 percent for pc-fired generators. Sulfur emission control will be better and less costly than in pc-fired plants because it will involve removal of H_2S from the syngas rather than SO_2 from flue gas. Similarly, NO_x emissions might be reduced by scrubbing NH_3 from the gas. Because of the gas turbine topping cycle, total plant water requirements will be about 40 percent lower than in a pc-fired plant with equal electric power output.

Advantages of fluidized bed combustors over pc-fired units include more efficient heat transfer (and thus lower capital costs), in-bed SO₂ removal (also reducing capital costs), lower combustion temperature (reducing NO_x emissions and fouling or slagging problems), and greater flexibility to fuel type or grade. Pressurized FBC units with hot gas cleanup and fully integrated power generation cycles offer about the same overall efficiency as gasification/combined cycle units. However atmospheric FBC technology is closer to commercial use at this time.

Tables 4.4.2.5 and 4.4.2.6 illustrate the estimated life cycle cost and environmental advantages of the atmospheric fluidized bed combustion (AFBC) and integrated coal gasifier/combined cycle (IGCC) technologies over conventional combustion with wet scrubbing flue gas desulfurization (FGD). These cases were worked out for an Illinois bituminous coal at a midwestern location, as shown along with the key design parameters in Table 4.4.2.7. As indicated, the potential advantages of the advanced technologies are significant, but not so overwhelming as to rule out the continued use of direct combustion technology many years into the future.

Table 4.4.2.5

Life Cycle Busbar Cost Comparison of Three Coal-Fired
Electric Generation Technologies
(1978 dollars)

	<u>Conv. Coal w/FGD</u>	<u>AFBC</u>	<u>IGCC</u>
Total Capital Cost (\$/kWe)	661	583	614
Levelized Cost of Electricity			
- Capital (mills/kwh)	14.8	13.1	13.8
- O&M (mills/kwh)	8.1	5.7	4.5
- Fuel (mills/kwh)	<u>22.2</u>	<u>21.9</u>	<u>19.9</u>
- TOTAL (mills/kwh)	45.1	40.7	38.2

Source: Reference 5

In both gasification and fluidized bed combustion processes, low-rank coals are generally preferred fuels to bituminous coals. In gasification, the primary reasons are the non-caking properties and high reactivity of low-rank coals. In fluidized bed combustion, the alkaline ash, low-sulfur content, and high reactivity of many low-rank coals are

advantageous. These factors plus the low extraction costs per Btu of the low-rank coals are likely to make their economics in either process favorable compared to bituminous coal, in many regions of the country. Unfortunately, detailed comparisons similar to those shown in Tables 4.4.2.5 through 4.4.2.7 have not yet been made for low-rank coals.

Table 4.4.2.6

Estimated Environmental Characteristics of Three Coal-Fired
Electric Generation Technologies

	<u>Conv. Coal w/FGD</u>	<u>AFBC</u>	<u>IGCC</u>
<u>Air Emissions</u>			
SO ₂ - % removal	90	90	95
NO _x - lb/MMBtu (max.)	0.6	0.3	0.2-0.6
Particulates - lb/MMBtu (max.)	0.03	0.03	0.03
<u>Solid Waste Production</u>			
- lb/kwh	0.26	0.29	0.24
<u>Water Use</u>			
- lb/kwh	6.4	4.8	3.4
<u>Land for Waste Disposal</u>			
Acres/200 MW	240	15	12

Source: Reference 5

Regional Factors

The four major market regions considered in Section 4.4.1 -- Fort Union Region, Gulf Region, Western subbituminous coal region, and mid-western markets for subbituminous coal -- are likely to maintain similar characteristics in the future. However, environmental constraints will play an increasingly important role, as discussed below.

Fort Union Region

The Fort Union Region should continue to be a sparsely populated area, and should continue to grow as an exporter of electric power from

Table 4.4.2.7

Key Design Parameters Used in Comparing the Three Coal-Fired
Electric Generation Technologies

	<u>Conv. Coal w/FGD</u>	<u>AFBC</u>	<u>IGCC</u>
Coal	Illinois #6	Illinois #6	Illinois #6
Net Power Output (MWe)	796	814	800
Net Efficiency (%)	34.0	34.5	37.9
Sulfur Control	Wet Scrubber (limestone/lime)	In-bed (limestone)	Selexol- Claus (cold)
Sulfur Emission	1.2 #/MMBtu	1.2 #/MMBtu	1.0 #/MMBtu
Particulate Control	ESP	ESP	Water wash
Particulate Emission	0.1 #/MMBtu	0.1 #/MMBtu	Nil
NO _x Emissions	0.65 #/MMBtu	0.6 #/MMBtu	0.6 #/MMBtu
Stack Temperature	175 °F	250 °F	250 °F
Plant Construction Time	5.5 years	5.5 years	3.33 years

lignite-fired power plants. Although there are two sides to the issue, on balance the controlled growth of mining and electric generating capacity in the area is viewed as a positive infusion of jobs and capital. Water resources appear adequate to support continued growth for both process and reclamation purposes.

One potentially significant constraint, however, is ambient SO_2 concentrations over the Theodore Roosevelt National Park (TRNP) in western North Dakota.⁶ Computer dispersion modeling by the North Dakota State Department of Health in 1977 predicted that the increment contributed by Antelope Valley Power Plant Units 1 and 2 (when added to the increments from Coal Creek and Coyote Power Plant and the ANG Coal Gasification Plant) would exceed the maximum allowable combined increment of $5 \mu\text{g}/\text{m}^3$. A permit to construct could not be granted for the Antelope Valley Units 1 and 2 unless the predicted SO_2 increase due to this plant was reduced from 4 to $1.3 \mu\text{g}/\text{m}^3$. In order to accomplish this reduction in SO_2 increment in the TRNP, the SO_2 emissions from Antelope Valley Units 1 and 2 had to be reduced by 67.5 percent below that which would have been normally permitted under the Clean Air Act Amendments of 1970. The owner of the proposed Antelope Valley Units 1 and 2 agreed to these additional restrictions.

Following the completion of the Department's review and respective 30-day public comment periods, Permits to Construct were granted for Coyote Unit 1, ANG coal gasification plant, and Antelope Valley Units 1 and 2. The sequence used in evaluating the increment available for future industrial and energy development in this area will be based upon the order in which Permit to Construct applications are received by the Department and/or Permits to Construct are issued. As in the case of the Antelope Valley Units 1 and 2, the last source considered in the allowable increment may have to provide emission reductions beyond the emission control limitations of the new source performance standards. If it is not technologically feasible to achieve these reductions at the proposed facility, a number of possible options are open to that facility. The options include: 1) finding an acceptable project site, 2) seeking a reduction of emissions from existing (pre-1975) sources, a PSD offset, 3) seeking a PSD variance, or 4) abandoning the proposed project.

Although the SO_2 24-hour increment in the South Unit of the Theodore Roosevelt National Park is filled, it is possible that future energy development could occur in western North Dakota depending upon site location.⁶ Selection of a site such that interaction with the currently approved units is minimal could allow for additional development. The site location of future developments, therefore, becomes a significant factor in the prevention of significant deterioration analysis. A case-by-case review is necessary for each Permit to Construct application, examining the combined effect of the new source and those permitted sources which preceded it.

An additional complicating factor in western North Dakota is that much of the natural gas that has recently been discovered in the area is sour gas containing from 2 to 24 percent H_2S . For safety, prior to the construction of sweetening plants, it is necessary to flare the sour gas. Flaring the gas converts the H_2S to SO_2 .

If natural gas containing H₂S continues to be found in new wells around the Theodore Roosevelt National Park, the allowable increments possibly available for future lignite development may be consumed in whole or part before lignite-fuel plants are designed and Permit to Construct applications are filed. In any event, careful attention to site selection and design of pollution control devices for major energy development projects in western North Dakota, whether coal or sour natural gas, will be required if energy development is to continue.

Gulf Lignite Region

In the Gulf Lignite region, utility and industrial growth and use of coal are closely intertwined, and are discussed together in this subsection for that reason. A comprehensive study of future prospects for Texas lignite development was recently completed, and the primary conclusions are summarized here.⁷ This analysis does not take into account the future growth of lignite use in utility plants in Louisiana (where 3,460 MW of lignite-fired capacity is scheduled to come on line between 1985 and 1989), and possibly in other Gulf lignite states as well.

A number of factors will be important in determining the future use of Texas lignite:

- overall energy growth rate
- the role of conservation and alternative, renewable fuels
- the role of nuclear power
- the availability and future use of oil and gas
- the amount of solid fossil fuel demand which can be satisfied by lignite, and
- the extent and ownership of the lignite resource.

Growth in the state's overall energy demand, in general, and electrical demand, in particular, is expected to exceed national rates. However, both national and state growth rates are expected to be below those of the pre-embargo period. The anticipated growth rate between 1980 and 1987 is 5.3 percent annually for the electric power generation industry. This rate is expected to decrease to 4.3 percent from 1987 to 2000. These rates would increase energy consumption in the electric utility sector from 2.0 Quads in 1980 to 4.8 Quads in 2000.

Industrial energy consumption is used primarily for process heat, process steam and on-site electric power generation. Projected rates of increase are based on projections of economic activity, and are estimated to be 3.8 percent per year through 1990 and 3.2 percent per year between 1990 and 2000. Such growth represents an increase from 2.6 Quads in 1980 to 5.2 Quads in 2000.

Table 4.4.2.8 lists the various sources of energy and their anticipated contribution to energy needs for Texas through the year 2000. The top two lines in the table indicate total energy use trends in the electric utility and industrial sectors, with "high" and "low" estimates bracketing the projects already mentioned.

Table 4.4.2.8
Derivation of Solid Fossil Fuels Requirements for Texas
1978-2000

	1978	1985	High	2000 Nominal	Low
(10 ¹⁵ Btu's or Quads)					
Total Conventional Energy Requirement					
Utilities	1.76	2.6	5.4	4.8	3.3
Industry	2.42	3.1	6.5	5.2	3.3
Exempted Oil and Gas Use					
Utilities	1.26	1.3	1.3	1.3	1.3
Industry	2.37	2.9	4.6	4.0	3.0
Prospective Nuclear Supply					
Utilities	0.0	0.3	0.4	0.4	0.4
Solid Fossil Fuel Requirement					
Utilities	0.50	1.0	3.7	3.1	1.6
Industry	0.05	0.2	1.9	1.2	0.3

Source: Reference 7

The "high" projection corresponds to a continuation of the current growth rate through 2000; the "low" case assumes energy consumption growth equal to the state population growth (1.7% annually) in the 1987-2000 time frame.

The almost two-fold difference in year 2000 energy consumption between these low and high cases illustrates how conservation efforts and the substitution of renewable (non-conventional) energy sources can reduce the scale of future energy development.

Aside from voluntary conservation, a major factor which could reduce overall industrial energy growth, particularly in the Gulf Coast petrochemical and refining industry, is the national policy which discourages new industrial growth in areas which do not meet air quality standards. The principal air quality nonattainment problem in Texas relates to the high levels of photochemical oxidants or ozone. The nominal case assumes that the recent relaxation of the ozone air quality standard coupled with the state's control strategies will allow continued industrial expansion to occur.

In order to determine the extent of solid fuel use to meet these needs, usage of other fuels must be considered. For oil and gas, this is shown in the second category, "Exempted Oil and Gas Use". While industrial use of these fuels will increase substantially, utility use is expected to remain at the 1985 level, consistent with the Fuel Use Act. This mandatory boiler fuel conversion program is defined as follows:

- New utility power plants will rely primarily on lignite, coal and nuclear fuels. Some use of oil and gas will be allowed in new power plants in order to maintain system reliability.
- Some existing utility power plants will receive conversion exemptions based on environmental or economic grounds; and some will continue to use gas for peaking purposes. None will convert directly to coal or lignite.
- New industrial boilers built after 1982 will use coal, lignite or gaseous fuels derived from coal or lignite.
- New industrial process heat demands will continue to be met by either oil or gas.
- Existing industrial boilers are currently exempt by law from conversion requirements and assumed to remain exempt.

The nominal case assumes a moderate approach to implementation of the Fuel Use Act. Pressure from Federal agencies to enforce the act may relax due to increases in natural gas availability (from Canadian, Mexican and domestic sources), and concern over the economic and environmental consequences of rapid conversion. Alternatively, this situation is sensitive to the prevailing price and availability of imported oil. Continued rapid change in either aspect of our foreign oil supply network could result in strict enforcement of the Act, resulting in a higher demand for Texas lignite.

Nuclear power is assumed to play a minor role in the state's energy supply picture, contributing only 8 percent of the electric generation capacity in 2000. This assumes that no new nuclear plants will be added beyond those on line or under construction by the late 1980's.

By difference, the total energy requirements which would be met by solid fuels are calculated and shown in the last category of Table 4.4.2.8. These needs can be met by either Texas lignite or "imported" western subbituminous coal. The market share captured by each fuel will depend on several economic and regulatory variables:

- The universal scrubbing requirements promulgated in 1979 to comply with Clean Air Act Amendments of 1977, which have removed the primary advantage of low-sulfur western coal--the ability to meet emissions standards without the installation of costly flue gas desulfurization units (scrubbers).
- Rising rail transportation rates, which have more than offset the relatively low minemouth costs of western coal (vis-a-vis lignite). Rate increases by rail carriers supplying coal-fired utilities have far exceeded the general rate of inflation. Transportation now accounts for almost three-quarters of the delivered price of western coal to Central Texas. By contrast, Texas lignite can be consumed at the minemouth, thus avoiding transportation costs.
- Federal coal leasing policies, which will affect the availability of western coal. More than two-thirds of the coal from the Rocky Mountain West (currently the only major source of imported coal to Texas) is owned by the federal government. A restrictive leasing policy will reduce the availability of western coal.
- Implementation of federal surface mining and reclamation legislation, which can increase the

costs of surface mining. While the regulations will apply uniformly across the nation, it is believed that the per-ton reclamation and compliance costs will be higher in arid and mountainous regions of the West than in the Texas lignite belt.

Current plans for the use of coal and lignite by utilities in Texas indicates that through 1987, approximately 60 percent of the solid fossil fuel demand will be met by lignite. The factors listed above all tend to increase the competitiveness of lignite over western coal. Thus, it appears that in the time frame of this study, lignite will continue to be the preferred fuel over imported coal. However, in the post-2000 era, lignite use may be surpassed by western coal as lignite reserves are depleted. By 2000, bituminous coal may also be imported from the Midwest.

Table 4.4.2.9 indicates the required level of lignite commitment to meet future utility and industrial demand. These figures are based on the assumption that the 60/40 split between lignite and western coal will continue to represent utility use patterns past 1985, and will also apply to industrial solid fuel use.

Table 4.4.2.9					
Potential Requirements for Texas Lignite Commitment, 1978-2000					
		1978	1985	2000	
Total Energy Required (10 ¹⁵ Btu's or Quads)	Utilities	1.8	2.6	4.8	
	Industry	2.4	3.1	5.2	
Solid Fuel Demand (10 ¹⁵ Btu's or Quads)	Utilities	0.50	1.0	3.1	
	Industry	0.05	0.1	1.2	
Lignite Demand (10 ¹⁵ Btu's or Quads)	Utilities	0.30	0.6	1.9	
	Industry	0.05	0.1	0.7	
Lignite Reserve Commitment Required (Billions of Tons @ 6500 Btu/lb)	Utilities	0.70	1.4	4.4	
	Industry	<u>0.10</u>	<u>0.2</u>	<u>1.6</u>	
	Total	0.80	1.6	6.0	

Source: Reference 7

The Texas Bureau of Economic Geology estimates that the state's economically recoverable lignite reserves are approximately 6.7 billion tons. From Table 4.4.2.9, it is clear that almost all of this reserve will be committed by the year 2000 to fuel the utility and industrial boilers being built before the turn of the century.

However, this projected ten-fold increase (from 20 million tons/year currently to 200 million tons/year in 2000) could vary depending on two major uncertainties:⁷

- The various policy and economic trends which now appear to favor lignite over western coal could easily increase the currently projected 60/40 lignite-coal ratio such that proportionately more lignite is used and the resource commitment exceeds six billion tons well before 2000.
- On the other hand, the economically-recoverable resource estimate could increase significantly as prices rise and technological advances permit recovery of lignite at greater depths and in thinner seams. Additional exploration may also increase resource estimates.

It is possible that both of these trends will develop concurrently. In this event, the state may still face the prospects of committing most of its lignite reserves by 2000. Major factors determining the sensitivity of this supply/demand relationship are listed in Table 4.4.2.10.

Factors which would extend resource availability are low overall energy growth, a higher than projected reliance on nuclear power, or both. Conversely, high energy growth, restrictions in oil and gas supplies, and strict enforcement of the Fuel Use Act would increase lignite demand. The continuing importance of oil and gas in this scenario is depicted in Figure 4.4.2.3.

Because of the concentration of industry in the Gulf Coast region, most industry use of coal and lignite is expected here. To take advantage of transportation savings, most lignite-fired power plants will site along the lignite belt. Solid fuel use in the western part of the state will most likely be by subbituminous coal imported from the Wyoming region.

Western Utility Markets for Subbituminous Coal

As described in Section 4.4.1.3.3, existing low-rank coal-fired capacity in the "Western Loop" area is concentrated in Arizona/New Mexico, and Wyoming/Montana. Growth of generating capacity in both of these locations can be expected to continue following the moderate pace it has recently. Siting problems will continue to exist due to strict air quality standards and low water availability in these areas. The long transmission distances to the major load centers are also an impediment to rapid growth of generating capacity near the western subbituminous coal deposits.

Table 4.4.2.10

Sensitivity of Lignite Commitment by the Year 2000
To Alternative Assumptions
(Billion Tons)

	Utilities	Industry	Total
Nominal Case	4.4	1.6	6.0
High Growth	5.2	2.6	7.8
Low Growth	2.2	0.4	2.6
High Nuclear; Moderate Growth	2.8	1.6	4.4
Constrained Gas and Oil; Moderate Growth	6.1	2.5	8.6
Moderately Constrained Gas and Oil; Moderate Growth	6.1	1.6	7.7
High Lignite Demand for Utilities; Moderate Growth	5.1	1.6	6.7
3% Annual Boiler Retirement Rate	5.1	2.5	7.6
Estimated Strippable Reserves (to 150 feet (currently economical))			6.7
Estimated Strippable Reserves to 200 feet			8.9

Source: Reference 7

Figure 4.4.2.3

Fuel Mixes for Texas

Figure 6-1. Fuel Mixes for Texas - Nominal Case

Source: Reference 7

Midwestern Markets for Subbituminous Coal

Continued use of low-sulfur western coal as "compliance" fuel in midwestern boilers can be expected in the future. This applies to all plants that started construction prior to September 18, 1978, the effective date of the 1979 NSPS. However, the future competitiveness of low-sulfur subbituminous coal use in new midwestern units which must comply with the universal scrubbing requirements is questionable. Increasing transportation costs may also tend to decrease the growth rate of demand for western coals in midwestern markets. As in the past, case-by-case economic analyses will determine the competitive position of western coal versus local bituminous coal. A representative set of calculations predicting the outcome of such an economic analysis for the "general case" has not been made. Therefore, it is difficult to predict what the market shares will be for future coal-fired capacity in the midwest.

4.4.2.2 Industrial Direct Use of Low-Rank Coal

The two primary uses for low-rank coal by industry would be as boiler fuel or as a chemical feedstock (via conversion to syngas). Both of these markets are now dominated by oil and gas. The outlook is quite clear that oil and gas prices will continue to escalate faster than coal prices. This means that eventually the cost of steam from coal, or chemical feedstocks from coal, will become competitive with steam or feedstocks from oil and gas. The questions are when this crossover point will occur, and in what regions of the country.

A number of coal-based technologies must be considered as competing freely with the conventional oil and gas technologies for industrial markets over the next 15-20 years. These include conventional direct combustion of coal in pc or stoker boilers; fluidized bed combustion; and gasification to produce low- or medium-Btu gas. In all of these cases, it would be feasible to consider either a small in-plant facility or a large centralized facility that markets its product (steam or gas) to a large number of nearby customers. There are some important advantages to the latter approach, but there are certain limitations as well:

1. Economies of scale are very significant in the coal extraction, delivery, utilization, and cleanup systems. Large centralized plants would be able to capture these economies, whereas the small direct coal user generally would not.
2. Centralizing the handling and use of coal in large facilities would tend to allow better overall environmental control and easier permitting than widely scattered small coal handling and utilization plants.
3. A difficulty with the use of centralized energy conversion facilities is the combination of the high capital investment required and the need for an assured, long-term market for the products from the facility.

Coal-fired boilers in the 100,000 to 1,000,000 lb/hr steam range cost roughly 2.5 - 3 times as much to install as oil- or gas-fired boilers of equal output. Operating costs (other than fuel) are relatively close. Thus, a tradeoff is established in which substantially lower fuel costs (for coal) over the life of the project must pay out the incremental capital investment in a reasonable period of time. Even if cost calculations showed a good payout (under current market conditions they generally do not), industry views coal-fired projects as overly risky for a number of reasons: uncertainties and difficulties in meeting environmental regulations (which change unpredictably), and the inconvenience and site requirements of handling a solid fuel. Under these conditions, the cost

incentive has to be quite strong before coal can penetrate the industrial market.

One recent study calculated the economics of coal utilization in industrial boilers in several regions of the country, and came to the conclusion that the cost incentive is not likely to be very strong during the early 1980's.⁸ However, coal firing to raise steam was predicted to become more economical than gas or oil for all but small installations by the late 1980's. Other key conclusions of the analysis are summarized as follows:

1. Currently, only large boilers in the industrial Midwest show better economics for coal than for oil (and the coal of choice would be local bituminous coal rather than western coal). The economic crossover points for #6 fuel oil (year in which a coal facility becomes the economical choice) for a 650,000 lb/hr boiler are:

Gulf Coast	1987
East Coast	1988
Midwest	1978
West Coast	1990+

2. Fluidized-bed combustion should become the technology choice for coal boilers in the future. However, the state-of-the-art must be improved before reliability and long-term operating costs can be established.
3. Retrofit of existing gas and oil burners not originally designed for coal is neither economical nor practical.
4. High capital costs for coal-fired boilers make the cost of steam much more sensitive to operating load factor than is the case for gas- and oil-fired boilers. Typical capital costs, including flue gas desulfurization, for a Gulf Coast location producing 650,000 lbs. of steam per hours (1978 dollars) are:

<u>Fuel</u>	<u>Capital Cost</u>
Lignite	\$35,000,000
Bituminous Coal	31,000,000
Bituminous, Fluidized Bed	24,000,000
#6 Fuel Oil	12,000,000

5. Texas lignite is the fuel of choice for generating steam on the Gulf Coast. Steam costs, in 1978 dollars per thousand pounds of steam, for a production rate of 650,000 lb/hr, are projected to be:

<u>Fuel</u>	<u>1980</u>	<u>1985</u>	<u>1990</u>
Western Subbituminous	\$5.30	\$5.65	\$5.98
Eastern Bituminous	5.16	5.36	5.49
Texas Lignite	4.91	5.18	5.36

6. Cogeneration economics are favorable now. Results for the Gulf Coast are (1985 steam cost, in 1978 dollars per thousand pounds steam):

<u>Conventional Coal</u>	<u>Cogeneration Coal</u>	<u>Conventional Oil</u>	<u>Cogeneration Oil</u>
\$4.97	\$3.93	\$4.75	\$4.00

The greatest opportunities for cogeneration occur in the pulp and paper, chemical, steel and petroleum refining industries.

7. Coal gasification cannot compete economically with direct coal-fired boilers for raising steam. In every case studied, the replacement of an existing boiler with a direct coal-fired unit results in a lower steam cost than coal gasification and burning the coal gas in an existing boiler:

<u>Steam Rate, Fuel</u>	<u>Steam Cost (1978 \$/1000 lb)</u>
100,000 lb/hr, coal	5.25
100,000 lb/hr, coal gas	5.83
1,000,000 lb/hr, coal	4.04
1,000,000 lb/hr, coal gas	5.62

8. Gasification will find some application where direct coal-firing cannot be used. Many existing facilities do not have room to put in individual coal-fired boilers. Also, some applications require controllability or flame characteristics that cannot be obtained with direct coal-firing. Smaller energy users will pay a premium for fuel to avoid the complications of direct coal-firing. Also, environmental considerations may make it impossible to use direct coal-firing.

9. Air quality considerations will become the single most important factor determining the locations of major fuel burning installations. Significant relocations of industrial facilities will occur. Economic analysis of new projects will be meaningless without a complete consideration of the air quality situation. Projects requiring growth in coal consumption, such as coal redistribution terminals, should consider whether the proposed location is in a region which can accommodate increases in coal burning. Timing is crucial for projects planned for Clean Air areas. Any new source capable of emitting 100 tons per year of a regulated pollutant is subject to Prevention of Significant Deterioration (PSD) review.
10. The Powerplant and Industrial Fuel Use Act of 1978 is a significant and far-reaching legislative act that will directly or indirectly impact almost every segment of American industry. It is designed to reduce U.S. dependence on imported oil by forcing a conversion from oil and gas to coal in powerplants and industrial boilers. Its greatest impact will be on large energy consumers, particularly those presently utilizing natural gas to raise steam. Specifically it prohibits the use of oil or natural gas in all new powerplants and major fuel burning installations with boiler heat input rates of more than 100 MMBtu/hr for a single unit and 250 MMBtu/hr for a combination of units at the same site. The prohibitions for existing facilities are more complex, and the exact implementation plans are unclear.

A recent analysis of industrial markets for low- and medium-Btu coal gasification (LBG and MBG, respectively) indicates that early adopters of this technology will be steel, chemical, and brick companies.⁹ Areas in and adjoining Pennsylvania, the Ohio and Tennessee River Valleys, East Texas, Wyoming, North Dakota, and California were identified as attractive for early penetration. The last four states mentioned would be areas using low-rank coals. The Tennessee and Ohio River Valleys were identified as areas where western subbituminous coal would be competitive with eastern bituminous coal.

Based on the overall assessment of present market trends, LBG and MBG economics, and industry's investment intentions, the study's estimate of the market by 1985 was as follows:⁹

- Ten to twenty LBG single user plants in or near operation by 1985:
 - Hot raw gas - Brick, cement, and metal forging/smelting industries
 - Clean gas - Metal treating, refractories, and possibly glass industries
- Two to three MBG single-user plants in or near operation by 1985:
 - Best potential - Steel and chemicals industries
 - Other potential - Aluminum, glass, metal fabrication, and refining industries
- No MBG multiple-user plants in or near operation by 1985, due to two key constraints:
 - Long project lead times indicate that the late 1980s is the earliest feasible target for operation.
 - Business arrangements are confused by lack of a "patron" for the technology. It is not clear whether MBG multiple-user configurations represent an opportunity for the gas industry, coal industry, user consortia, or financial ventures.

The last point, regarding MBG multiple-user plants, appears overly pessimistic in view of Carter Oil Company's (Exxon Corp.) recent announcement of a go-ahead decision on its East Texas Coal Gasification Project. Carter Oil has been planning for this project for several years.¹⁰ According to preliminary plans, the Lurgi gasification process will be used to convert 45,000 tons/day of Texas lignite to 300 billion Btu/day of medium-Btu gas for sale both as a chemical feedstock and as a clean industrial fuel on the Texas Gulf Coast. In addition, about 10,000 B/D of liquids will be produced.

This project confirms the conclusions of many studies that have indicated the high potential of the Gulf Coast for early penetration of lignite into industrial markets. The combination of the lignite reserves and the highly concentrated gas-consuming petrochemical and industrial complex in this area will make the Gulf region the nation's proving ground for large-scale industrial use of low-rank coal. One potential constraint that may limit this growth is the existence of high ambient ozone levels in likely coal plant siting areas.

4.4.2.3 Synthetic Fuels for Non-Utility Uses

Technology and cost uncertainties have confused and delayed national decisions to bring coal-based synthetic fuels into commercial reality. Overriding national security concerns regarding our overdependence on unstable OPEC oil sources have recently caused the establishment of the Synthetic Fuels Corporation (SFC). Through the SFC, various types of incentives will be made available to synfuel projects including loans, loan guarantees, fuel purchase agreements, price guarantees, and joint ventures. These types of incentives have been identified by numerous studies as the necessary stimuli to change industry's "No-Go" capital investment decisions into "Go" decisions. Assuming the SFC succeeds in implementing its charter, coal gasification and liquefaction plants should be constructed in significant numbers starting in the mid- to late-1980's.

Figure 4.4.2.4 summarizes the large number of available process configurations that can be used to produce coal-based synthetic fuels. The first two major products listed (LBG and MBG) are most likely to be utilized as industrial fuels in competition with direct oil, gas, and coal firing, and were discussed in the preceding sections. SNG projects can be expected to proliferate because of the availability of commercially proven technology and the easy marketability of the product through existing natural gas distribution networks. Low-rank coals are preferred feedstocks for first-generation gasification processes (see Volume 3), and thus, rapid growth of low-rank coal use in SNG plants can be expected.

The first commercial SNG-from-coal plant in the U.S. is the Great Plains Gasification Associates project, which will use North Dakota lignite. Almost all of the SNG projects that have been proposed during recent years (most of which have been cancelled or deferred due to the regulatory climate) intended to utilize western low-rank coals.

The prospects for commercial production of synthetic liquids from coal appear to be farther in the future than for SNG. In addition, the advantages of low-rank coals as feedstocks to direct liquefaction processes are not as obvious as the advantages in first-generation gasification processes. Preliminary economic tradeoff studies indicate that low-rank coals could be at least as attractive as bituminous coal for liquefaction, but these calculations are based on inadequate process data. The future market for low-rank coals as liquefaction feedstocks must be considered highly uncertain until more RD&D has been performed.

4.4.2.4 Other Potential Markets

In addition to the electric utility, industrial, and synthetic fuel markets described in preceding sections, other potential markets for low-rank coals exist. These include the potential export market for steam coal in the Pacific, and the possible resurgence of residential/commercial direct use of coal in some areas of the country.

Figure 4.4.2.4

Coal-Based Synthetic Fuel Technologies

Exports

Due to its high heating value and low-sulfur content, Utah coal is seen as a potential export fuel for Far East markets (Japan, Taiwan and Korea). Competitors to Utah coal in this market are Australia and South Africa, whose coal is cheaper at the mine and has shorter rail transport distances before reaching port. Despite this handicap, Utah coal may expand in this market due to supply limitations at competitors' mines. American coal (including Powder River region subbituminous coal as well as Utah coal) may ultimately be cost-competitive in the Far East if slurry pipelines are constructed to bring the coal to West Coast ports.

Residential/Commercial Markets

Businesses and homeowners in areas where free wood is available or natural gas is the primary fuel source rarely choose to burn coal. Residents of Colstrip, Montana, burn coal from the nearby Western Energy mine, while residents in the western part of the state (a heavily wooded area) burn wood exclusively. Colorado is another area which is showing residential demand for coal, both lump and stoker. Equipment specially designed for burning subbituminous coal or lignite in residential use is offered by Hardin Mfg. Co., of Longmont, Colorado.¹¹

In this market, it is clear that both fuel cost and convenience are factors which will shape future demand. The availability of reasonably priced electricity or gaseous fuel (both possibly derived from coal) are likely to prevent coal from entering the residential market in significant quantities.

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