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Final Environmental Impact Statement

FUEL USE ACT

U.S. DEPARTMENT OF ENERGY

April 1979

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Final Environmental Impact Statement

FUEL USE ACT

Responsible Official

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Assistant Secretary for Environment

U.S. DEPARTMENT OF ENERGY
Washington, D.C. 20461

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GLOSSARY

AAQS	Ambient Air Quality Standards
AFBC	Atmospheric fluidized-bed combustion
AQCR	Air Quality Control Region
ASA	Aggregated Subarea
BACT	Best available control technology
BATEA	Best available technology economically available
BOM	Bureau of Mines
BPCTA	Best practicable control technology available
CCFB	Conventional coal-fired boiler
DOE	Department of Energy
ECPA	Energy Conservation and Production Act
EPA	Environmental Protection Agency
EPCA	Environmental Policy and Conservation Act of 1975
ESECA	Energy Supply and Environmental Coordination Act of 1974
FEA	Federal Energy Administration
FUA	Powerplant and Industrial Fuel Use Act of 1978
FWPCA	Federal Water Pollution Control Act
LAER	Lowest achievable emissions rate
MFBI	Major fuel-burning installation
NEPA	National Environmental Policy Act of 1969
NPDES	National Pollutant Discharge Elimination System
NSPS	New source performance standards
PFBC	Pressurized fluidized-bed combustion
PSD	Prevention of significant deterioration
"4R" Act	Railroad Revitalization and Regulatory Reform Act of 1976
RCRA	Resource Conservation and Recovery Act of 1976
RDF	Refuse-derived fuel
SCS	Soil Conservation Service
SIP	State Implementation Plan
SNG	Synthetic natural gas
SPR	Strategic petroleum reserve
USGS	U.S. Geological Survey

1. SUMMARY

The major environmental impacts and adverse effects discussed in this environmental impact statement (EIS) are those which would result from implementation of the regulations for enacting the coal and alternate fuels use program which has been authorized by the Powerplant and Industrial Fuel Use Act of 1978 (FUA) Pub. L. 95-620. This impact statement deals with overall program and regional impacts rather than site-specific impacts and is predicated on the assumption that coal will be the primary fuel substituted for oil and natural gas in the short term (until 1990). Site-specific environmental impacts will be addressed in subsequent NEPA compliance documents, for exemption petitions and by other federal, state, and local permitting agencies.

1.1 BRIEF DESCRIPTION OF PROPOSED ACTION

The proposed action is the issuance of regulations to implement the FUA, a Congressionally mandated program prohibiting the construction of new powerplants without the capability for utilization of coal or alternate fuels and prohibiting the use of natural gas or petroleum as the primary energy source in new powerplants and MFBI boilers. The FUA also restricts, through mandatory and discretionary prohibitions, the use of natural gas and petroleum as primary energy sources in existing powerplants and Major Fuel Burning Installations (MFBIs). The Department of Energy (DOE) may grant exemptions from these prohibitions to burn oil or natural gas.

The FUA affects single units of MFBIs and powerplants with a fuel input heat rate of 100 million Btu's per hour or greater or an aggregate heat input rate for two or more units of 250 million Btu's per hour or greater.

1.2 ENERGY IMPACTS OF THE EVALUATION

The impacts of the program were assessed and modeled on the basis that a maximum number of facilities would be designed for or would convert to coal or an alternate fuel. The number of BTU's of gas or oil that will be substituted for by a fuel other than coal are not given due to the uncertainty of their usage. Coal is assumed to be the overwhelming alternate fuel choice. Other alternate fuels and their impacts are presented in Section 10.

Maximum substitution of coal was assumed in the analysis by systematic overstatement of factors that would affect the number of facilities using coal. These factors include growth rates of energy consumption, stability of oil and gas prices, substitution of coal in existing boilers (if they were once coal-capable), and exclusion of exemptions due to physical site limitations or for other reasons.

These assumptions proved necessary because site-specific locations could not be identified for boilers which would burn coal in 1985 and 1990 as a result of the program. Identification of sites requires knowledge of where new boilers will be constructed, and whether environmental laws would be violated which would preclude coal use. Because the FUA requires that coal or alternate fuel use meet all applicable environmental requirements, identification of future fuel use was modeled on a regional basis only since site-specific and local impacts would be impossible to accurately predict. The FUA excludes certain exemptions from NEPA. However, NEPA documents will be prepared on a case-by-case basis; environmental reports will be required by petitioners; and environmental agencies will review exemption petitions.

The relative magnitude of facilities that will be using a fuel other than oil or gas are illustrated at the regional level in Table 1.1. The table is only illustrative; the methodology for its development is explained in Section 3, and a discussion of the data in relation to policy options is contained in Section 10.3. The principal and only firm conclusions to be drawn from the table are as follows:

1. Maximum impacts are forecast to occur in 1990. Approximately 53 percent of coal or an alternate fuel use will occur by 1985 and the remaining 47 percent is expected to subsitute coal or an alternate fuel by 1990.
2. In the year of maximum impact (1990), about 77 percent of the facilities using coal or an alternate fuel will be new boilers rather than converted boilers.
3. Approximately 68 percent of all alternate fuel use would occur in boilers that would otherwise use natural gas; the remaining 32 percent is a shift away from the use of oil.

Table 1.1. Projected Maximum Oil and Gas Savings in 1985 and 1990 Achieved as a Result of the Proposed Action[a] (10^{15} Btu)

Demand Region[d]	1985 Increment over Base Case					1990 Increment over 1985				
	Existing		New[b]			Existing[c]		New		
	Oil	Gas	Oil	Gas	Total	Oil	Gas	Oil	Gas	Total
I	0.008	0.001	0.026	0.001	0.036	0.002	0.000	0.017	0.003	0.022
II	0.003	0.002	0.025	0.007	0.037	0.001	0.001	0.019	0.007	0.028
III	0.012	0.003	0.028	0.004	0.047	0.001	0.002	0.026	0.012	0.040
IV	0.017	0.044	0.070	0.044	0.175	0.003	0.020	0.084	0.038	0.146
V	0.069	0.035	0.009	0.003	0.116	0.000	0.003	0.022	0.004	0.029
VI	0.011	0.111	0.141	0.506	0.769	0.004	0.199	0.108	0.503	0.814
VII	0.003	0.015	0.006	0.001	0.025	0.000	0.002	0.003	0.010	0.015
VIII	0.000	0.005	0.009	0.000	0.014	0.000	0.001	0.006	0.005	0.012
IX	0.001	0.021	0.059	0.043	0.124	0.007	0.007	0.015	0.050	0.079
X	0.001	0.001	0.007	0.000	0.009	0.000	0.000	0.007	0.000	0.007
Total	0.126	0.238	0.380	0.609	1.352	0.018	0.235	0.307	0.632	1.193

[a]Assumes Best Available Control Technology (BACT) on 250 MBtu/hr, Trend-Long baseline, AQCR screen, FGD. Assumes no economic exemption unless coal is 44 percent more costly than use of imported oil. Excludes units smaller than 100 MBtu/hr and existing non-coal capable. Oil price is weighted average of distillate and residual oil plus $0.21 per million Btu's (to account for the Crude Oil Equalization Tax [COET]). Assumes utility construction with coal capability.

[b]New units are those coming on-line in 1980 and after, and include new boilers of capacity greater than 100 MBtu/hr which are economically justified in using coal or alternate fuel when the opportunity fuel cost is the imported price of oil (average of residual and distillate oil plus COET) and which are not located in nonattainment areas.

[c]Assumes existing units are those in place or scheduled to come on-line prior to 1980, and include conversions due to mixed-fuel firing (1990 only). Assumes conversions of 100 units per year.

[d]See Fig. 1.2; a detailed discussion of the coal demand regions used in this analysis is presented in Section 3.3.

For the purposes of this analysis, new facilities are defined as those which come on-line in or after 1980, and existing are those which are or will be in use prior to 1980. To the extent that the ability of facilities to substitute coal or other fuel in new and existing boilers (that is, as cost, environmental, and administrative resource constraints permit) has been consistently overstated in this EIS, then the overall impacts are overstated.

The industries expected to be affected by the program include food processing; paper and pulp; chemicals; refineries; stone, clay, and glass; primary metals; and machinery. These industries consume large quantities of natural gas and oil in large boilers which come under the purview of the program. Utilities will be affected less because new baseload facilities using fuels other than oil or natural gas are generally anticipated.

In keeping with the "worst-case" approach assumed by the overstatement of utilization, a "worst-case" approach was used in estimating environmental residuals. For example, for the calculation of air emissions of sulfur dioxide (SO_2), nitrogen oxide (NO_x), and total suspended particulates (TSP), it was assumed that New Source Performance Standards in effect prior to the Clean Air Act Amendments of 1977 are met; Best Available Control Technology (99% fly ash and 90% sulfur removal) is assumed for the calculation of waste scrubber sludge and collected fly ash. These contradictory assumptions produced the "worst-case" estimate for each factor and may have resulted in an understatement of the number of exemptions to prohibitions granted for environmental or economic reasons. These two assumptions tend to result in an overstatement of projected emissions of SO_2 and an overstatement of the amount of scrubber sludge to be disposed of. Such an approach was required due to the uncertainties about future environmental standards and the fact that individual facilities must meet those standards.

In spite of the worst-case assumptions discussed above, projected 1985 and 1990 coal use attributable to the program represents a small proportion of all coal use in the nation by that time. As noted in Table 1.2, it is projected that over one billion tons of coal will be consumed in 1985 and over 1.2 billion tons in 1990. Coal consumption attributable to the program is expected to be just 7 percent (72 million tons) of the total demand in 1985 and slightly more than 10 percent (129 million tons) in 1990. The level of coal consumption is based on the assumption that no economic exemption would be granted unless coal is 44 percent more costly than the use of imported oil. Increasing the fuel cost penalty to 100 percent increases coal use by approximately five million tons (see Table 10.5). The supply and demand regions used in the analysis are shown in Figures 1.1 and 1.2, respectively. A detailed discussion of the coal supply and demand regions is presented in Section 3.

Table 1.2. Projected Base-case Production and Production Expected to Result from the Proposed Action According to Supply Region and Method of Mining (millions of tons per year)

Supply Region	Base-case Production[a]				Production Resulting from Proposed Action[b]				Proposed Action/Base Case (%)			
	1985		1990		1985		1990		1985		1990	
	Under-ground	Surface	Under-ground	Surface	Under-ground	Surface	Under-ground	Surface	Under-ground	Surface	Under-ground	Surface
1	86	79	143	70	3	2	6	3	3	3	4	4
2	189	86	190	80	6	3	11	5	3	3	6	6
3	9	12	9	10	1	1	2	2	9	8	18	18
4	117	109	134	109	2	2	4	3	2	2	3	3
5	2	60	6	91	1	22	2	37	36	37	41	41
6	0	271	6	329	0	20	1	39	7	7	12	12
7	15	9	15	13	1	1	1	1	5	6	7	7
8	1	45	1	49	0	7	0	12	15	15	25	25
Subtotal	419	671	504	751	14	58	27	102	3[c]	9[c]	5[c]	13[c]
Total	1098		1255		72		129		7[c]		10	

[a]From Energy Information (1978).

[b]From Tables 3.7 and 3.8. Proportion of surface mining resulting from the proposed action was assumed to equal the proportion of base-case surface mining.

[c]Weighted average.

1.3 ENVIRONMENTAL IMPACTS

The FUA will have a major impact in Demand Region VI (Texas, Louisiana, Arkansas, Oklahoma, and New Mexico), which accounts for 58 percent of the projected increased coal use in 1985 and 68 percent in 1990. Coal production is projected to increase 41 percent in the Central West and Gulf Coast coal regions (Supply Region 5) to satisfy the coal needs resulting from the FUA. Three other coal supply regions--Southern Appalachia, the Northern Great Plains, and the Southwest (Supply Regions 3, 6, and 8, respectively)--are projected significantly higher than other regions in relative terms over base case. These are regional projections; local increases may be higher.

1.3.1 Air Quality

The air quality of the nation generally has been improving since 1970. Increased coal usage could reverse this improvement unless strict controls are employed on all emission sources. The potential for increased emissions was evaluated for each phase of the coal cycle.

The potential impact on air quality associated with increased transportation as a result of the proposed action through 1990 is negligible. Most of the transportation impact will result from construction activities involving new rail spurs and haul roads. The extent to which transportation will affect air quality will depend primarily on the degree to which existing transportation facilities can be used. The estimated diesel fuel combustion products associated with increased coal transportation will be less than 5 percent of the general national transportation air emissions projected for 1990. Transportation of coal by rail will be the major source of diesel exhaust air pollution since 69.2 percent of all bituminous coal is shipped by this mode.

Increased ground-level concentrations of pollutants due to the combustion of coal as a result of the proposed action were calculated using a regional dispersion model. The 1990 predicted maximum regional increase in concentrations of SO_2 due to the FUA is 2.5 $\mu g/m^3$, occurring in three AQCRs (Fig. 1.4). The predicted 1990 base-case SO_2 maximum concentration of 60-69 $\mu g/m^3$ occurs in 10 AQCRs (Fig. 5.3). Increased concentrations of SO_2 as a result of the FUA are

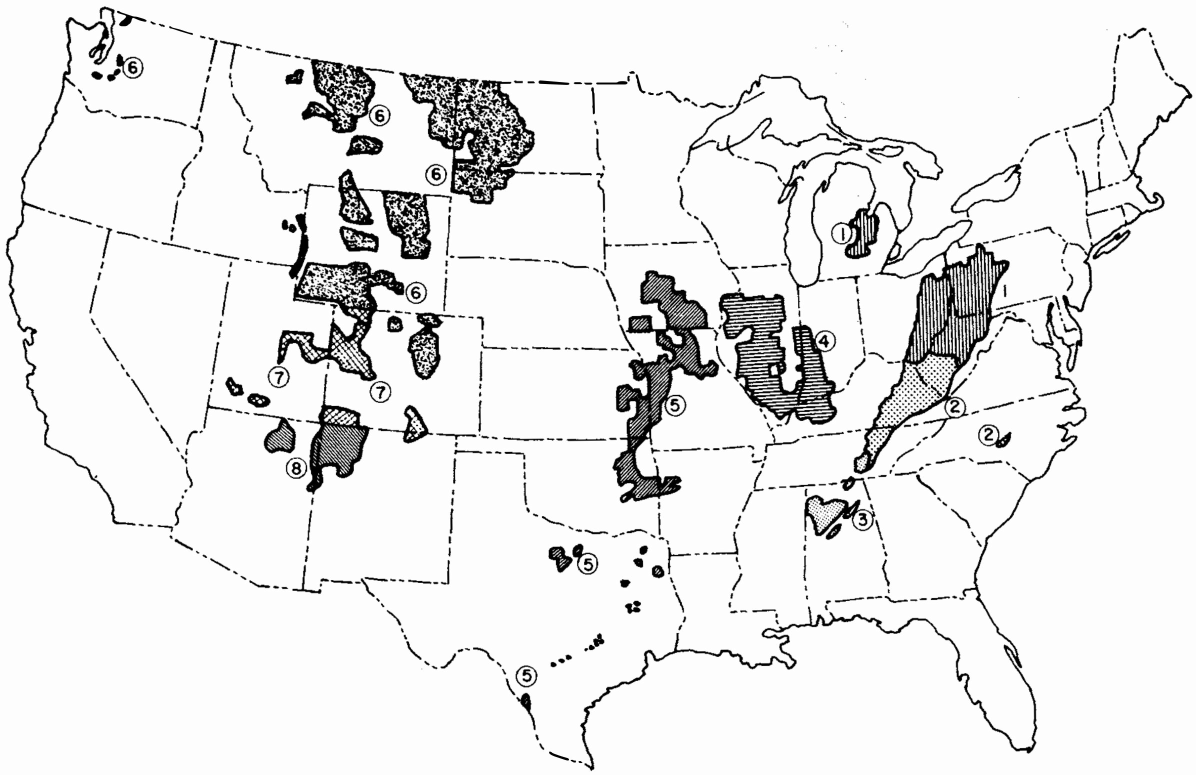

Fig. 1.1. Map of the Conterminous United States Showing Coal Supply Regions (by pattern) Used in Fuel Conversion Analysis (Supply Regions 1 through 8).

Fig. 1.2. Map of the Conterminous United States Showing Coal Demand Regions Used in Fuel Conversion Analysis (Demand Regions I through X).

predicted in 104 of the 238 Air Quality Control Regions (AQCRs) in 1985 (Fig. 1.3). It is predicted that in 1990 the number of AQCRs with increased loading of SO_2 will rise to 141 (Fig. 1.4). It is expected that little or no deterioration in air quality will occur in the Northern Great Plains states, northern New England, and Central Appalachia. Increases in concentrations of particulates and other pollutants as a result of the program are estimated to be even lower than concentrations of SO_2 expected.

The effects of local concentrations (within 10 km, or 6.2 mi, of a facility) of these air pollutants are not addressed, but will be considered by the proper regulatory agencies during the permitting process. No regional air degradation is anticipated from the storage and onsite processing of coal or from the storage and ultimate disposal of wastes from combustion and pollution abatement.

1.3.2 Weather and Climate

Implementation of the FUA is not expected to affect the climatic process of the atmosphere. The emissions produced as a result of the program (a maximum of 4 percent in 1990) are negligible when compared to total emissions. While there is a great deal of uncertainty about the effects of CO_2, because the residence time of CO_2 in the atmosphere is many years, it is unlikely that the slightly accelerated rate of coal combustion due to the proposed action will appreciably affect the weather and climate of any demand region or of the nation as a whole.

1.3.3 Water Resource Quality

It is expected that implementation of the FUA will accelerate coal mining to the greatest degree west of the Mississippi and in central (Supply Region 2) and southern Appalachia (Supply Region 3). In central and southern Appalachia, the major hazard posed to water quality and water use is sedimentation. In the west, a major concern is the disturbance and/or contamination of groundwater aquifers, which are important to regional water use. The other area of major concern in the west is the increase in levels of dissolved solids, including constituents such as sulfate. The major uncontrollable hazard to water quality from coal mining is the drainage of acid (and associated trace elements) from abandoned underground mines. Generally, the FUA will not greatly accelerate mining in areas where acid drainage is a major problem. There are exceptions, however; isolated instances of acid mine drainage have been reported in central and southern Appalachia, Colorado, and Montana, where the FUA may prompt additional mining of coal.

Implementation of the FUA will contribute incrementally to acid precipitation in the eastern United States. Water basins occurring on igneous bedrock (nonbuffering substrate) of the Appalachian and Piedmont areas of North Carolina and Virginia may be increasingly threatened by acid precipitation. The Texas-Oklahoma-Kansas-Arkansas-Missouri area (primarily Demand Region VI), where stack emissions from the Texas Gulf region may eventually be cleaned from the air as rain, and where the pH of precipitation is expected to be moderately lowered, is less sensitive to acidification of surface water because of greater water hardness. Acid precipitation is expected to be minimal in the East Texas Gulf area, where surface waters are softer.

Particulate combustion emissions and solid wastes will result in the increased mobilization of trace elements, a major environmental problem of coal use in general. Many elements are mobilized in combustion wastes in amounts greater than those mobilized at natural weathering rates. Increases due to the proposed action are minimal, but the effects from the additions combined with the general trend to increased coal use are not known.

1.3.4 Land Use

Land use impacts of the proposed action will be associated primarily with surface mining activities and disposal of combustion wastes. It is expected that by 1990, surface mining will account for approximately 80 percent of the coal produced as a result of the FUA. The greatest increase in mining activities relative to base case will occur in Supply Regions 3, 5, 6, and 8. During the period 1978-1990, an estimated 20,000 hectares (49,200 acres) of land will be disturbed directly by surface mining and an equivalent amount may be disturbed indirectly for use as roads, rail lines, storage, processing equipment, etc. Assuming a life span of 40 years for each MFBI, a total of 133,000 hectares (328,000 acres) of land may be disturbed by mining by the year 2020 as a result of the FUA. Much of the land which will be disturbed is presently used as rangeland and cropland, although forest land will be affected in Appalachia (Supply Regions 1, 2, and 3). Coal mining of prime farmlands, especially in the west and midwest, could have serious impacts on regional agriculture. However, the Surface Mine Control and Reclamation Act of 1977 (Pub. L. 95-87) and regulations for implementation of that Act (Fed. Reg. 43:41661-41940, 1978) specify strict standards for mining of prime farmlands, and requires reclamation of all surface-

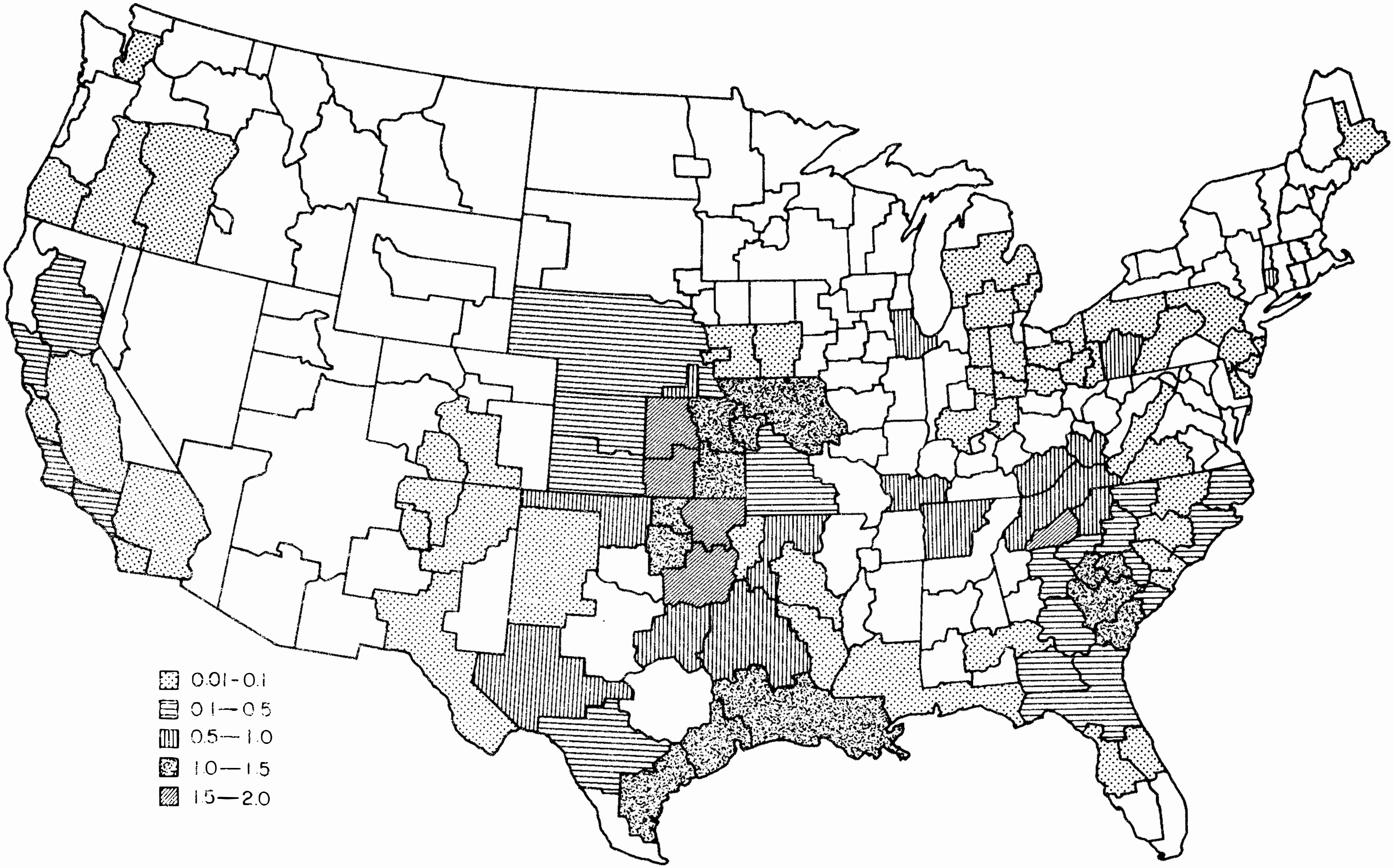

Fig. 1.3. Predicted 1985 Incremental Annual Average Ground-level SO_2 Concentrations ($\mu g/m^3$) from Major Fuel-burning Installations As a Result of the Proposed Action, by AQCR (does not include powerplants).

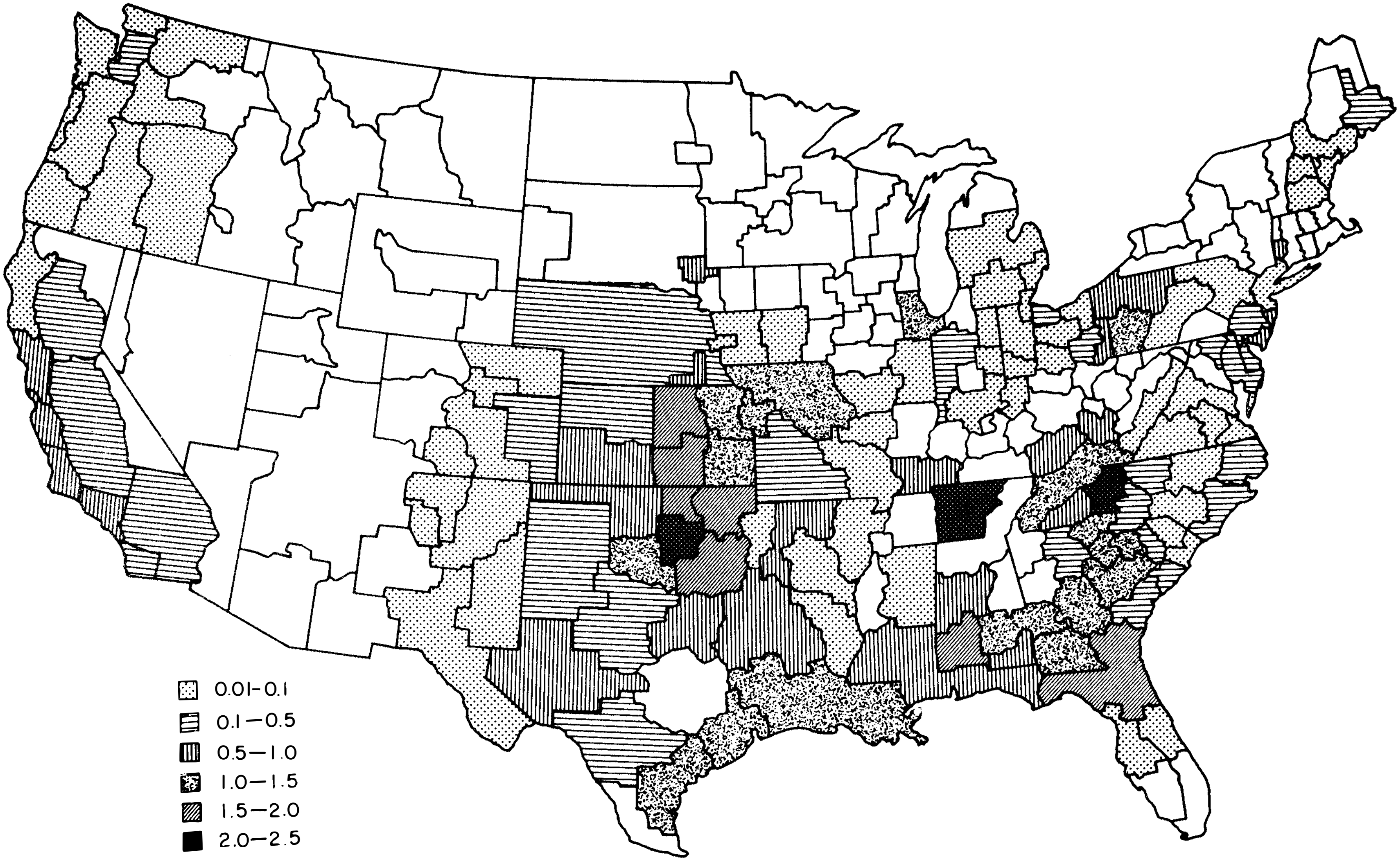

Fig. 1.4. Predicted 1990 Incremental Annual Average Ground-level SO_2 Concentrations ($\mu g/m^3$) from Major Fuel-burning Installations As a Result of the Proposed Action, by AQCR (does not include powerplants).

mined lands to a productivity equal to or greater than productivity before mining. It is not possible to estimate the amount of prime farmland which will be mined as a result of the FUA since the locations of mines which will produce the coal are not known, and the national inventory of prime farmland is not complete.

Assuming that all ash and scrubber sludge produced by the combustion of coal burned as a result of the FUA were disposed of by landfill, an estimated 10,300 hectares (25,500 acres) of land by 1990 and 69,000 hectares (170,000 acres) of land over the lifetime of the facilities would be required for waste disposal. Up to 70 percent of the wastes will be produced in Demand Region VI, mainly along the Gulf Coast of Texas. Since this area is surrounded by rice lands considered as unique farmlands by the Soil Conservation Service, wastes wil have to be transported to the west and north for disposal. Most of the land which will be used for disposal is presently used as rangeland and forestland. Reclamation of waste disposal sites may be possible if sufficient soil cover is used. Management and disposal of combustion waste materials will be regulated under provisions set forth in the Resource Conservation and Recovery Act of 1976 (Pub. L. 94-580). Land use impacts associated with transportation, onsite coal storage and processing, and coal combustion are expected to be minimal.

1.3.5 Ecology

1.3.5.1 Terrestrial

The major terrestrial ecological impact from coal mining will be in Supply Region 5 (see Fig. 1.1), where surface mining is the predominant method of extraction. By 1990, approximately 1600 hectares (4000 acres) are expected to be disturbed annually by mining in Supply Region 5 to meet coal demand due to the FUA. This is approximately one-half of the land expected to be disturbed nationally. The primary habitats that will be affected are deciduous forests and grasslands. After rehabilitation of the mined land, decades will be required for recovery of the structure and complexity of the mature forest communities. Although a much smaller amount of land will be disturbed in Supply Region 6, surface mining does pose a threat to floodplain communities, which provide a large proportion of the biotic diversity in that region. Proper mining, following the Federal Surface Mining Reclamation and Enforcement Provisions, should reduce this problem.

Wastes from cleaning of coal should not increase noticeably above baseline levels. Effects from increased transportation as a result of the FUA are expected to be minor. Storage of coal presents a problem primarily for facilities converting from use of natural gas--the predominant fuel in Demand Region VI. More than 900 hectares (2200 acres) of land may be pre-empted for storage piles in Region VI by 1990. In rural areas, creation of storage piles could eliminate wildlife habitat. Effluents from the storage piles should not pose a potential problem if the piles are properly managed.

Increased combustion emissions due to the FUA are not expected to be large enough to pose a major threat to terrestrial biota. The expected increase in long-term gaseous pollutant levels due to the FUA is well below threshold levels for injury during chronic exposure of most biota. Non-vascular plants (e.g., lichens and mosses) may be adversely affected in parts of Demand Regions IV and VII, where the baseline pollutant concentrations are already near threshold levels. Predicted increases in levels of particulate pollutants fall well below levels that can lead to deleterious trace-element loading of soils. Increases in acid precipitation due to implementations of the act are not expected to influence terrestrial biota to a noticeable degree above baseline conditions. Local impacts from combustion emissions may be more pronounced, but cannot be quantified at the programmatic level because they are highly dependent upon site-specific factors.

Storage of wastes from emissions abatement practices will require space and will pre-empt biota from that space at least temporarily. By 1990, as much as 761-1154 hectares (1901-2851 acres) of land could be utilized each year in Region VI to store wastes collected as a result of the FUA. Because lowlands, when wetlands frequently occur, have been attractive as sites for waste storage and most of the wastes will be generated near the Gulf coastal wetlands, these biotic communities may be affected by the increased coal use. It will be possible to avoid such problems if waste is disposed of appropriately, in accordance with current and proposed federal regulations.

1.3.5.2 Aquatic

On a national basis, the aquatic ecological impacts attributable to the FUA are expected to be minor in comparison to the impacts expected due to the general increase in coal use. However, the FUA may create local impacts, including biotic effects resulting from hydrological alterations, sedimentation, acid mine drainage, alkaline drainage, nutrient enrichment, acid precipitation, and trace metal precipitation. Major local biotic effects may include habitat destruction, alterations in community composition (usually to fewer species), changes in productivity, direct toxic effects on sensitive organisms, and bioaccumulation of toxicants. The specific effects produced at any given location will depend on a number of site-specific variables, including the geological nature of the substrate material; the physicochemistry of the water; the biotic communities present; the quantity of effluents added to the water and the duration and frequency at which they are added; and the other stresses impinging on the system. In general, the most severe impacts will occur in pristine soft-water environments, which include many mountain streams and bogs and lakes located in mountains or on igneous bedrock. The regions of the country expected to incur the greatest aquatic ecological impacts from coal mining and processing as a result of the FUA are central (Supply Region 2) and southern Appalachia (Supply Region 3), the Northern Great Plains (Supply Region 6), and Texas (Supply Region 5). Coal combustion effects (as they relate to changes in water quality) probably will be most severe in southern Texas.

1.3.5.3 Endangered Species

Various activities in the coal fuel cycle can lead to destruction of biotic habitat or the emission of toxic substances. Increased demand for coal under the FUA can, then, increase the potential for deleterious impact upon endangered species and their habitats. The species that may be affected will be determined in subsequent NEPA compliance documents on a site-specific basis for exemptions where applicable. Combustors not requesting an exemption still must apply for and receive permits from the appropriate regulatory agencies. The effects on endangered species will be evaluated at the site-specific level and appropriate procedures followed even if there is no NEPA document. Species in the Gulf states, northern Great Plains, and southern Appalachia would have the highest probability of being affected by the proposed action. Proper siting considerations and management of toxic emissions should ameliorate impacts upon endangered species from the increased activity in the coal fuel cycle in response to the FUA.

1.3.6 Social and Economic Impacts

The greatest social and economic impacts are expected in the Northern Great Plains area (Supply Region 6) and Texas (Supply Region 5). Texas coal production is estimated to increase the greatest amount (41 percent) due to the program. With only three mines operating in Texas, coal mining is not currently resulting in significant social impacts. It is estimated that in the Northern Great Plains, production would increase 25 percent due to the FUA. Certain counties where coal mining is now extensive would be subjected to increased strain to accommodate new migrants. By analogy, a rapid increase in coal production in Texas may produce boom town effects similar to those in the Plains states, but these impacts are associated only in part with the FUA. More information on the cost of the FUA can be obtained in this document: Analysis of Proposed U.S. Department of Energy Regulations Implementing the Powerplant and Industrial Fuel Use Act, DOE/EIA-0102/21, Energy Information Administration, November 1978.

1.3.7 Health Effects

In the evaluation of human health effects from increased industrial coal use, the occupational and general population impacts from selected components of the coal fuel cycle were defined. The fuel cycle components chosen for this analysis were extraction, cleaning, transportation, combustion and disposal. The hazards from each component, excluding combustion and disposal, were then expressed in terms of the fatal and nonfatal accidental injury and disease which would occur in exposed populations during the program years of 1985 and 1990. Potential health effects from increased combustion emissions and waste disposal were recognized and discussed in general terms, but not quantified due to the uncertainty which exists in predictive estimates.

On a national basis, increased coal use as a result of the FUA is expected to result in 41 fatal and 1300 nonfatal injuries in 1985 and 78 fatal and 2463 nonfatal injuries in 1990 from extraction, cleaning, and transportation. In this analysis, each of the ten demand regions was assessed individually for impacts expected to result from specific coal requirements.

The three supply regions in which a majority of program-related impacts would occur are Supply Regions 2, 5, and 6. The long-distance transportation requirements for Demand Regions VI and IX will result in greater accidental injury for both the occupational population (railroad workers) and general population (highway grade crossing accidents and rail right-of-way accidents).

1.4 ENVIRONMENTAL TRADE-OFFS OF THE PROPOSED ACTION

The national consequences of implementing the proposed action will be largely undiscernible to the general public. On a smaller scale, particularly local, they may be significant. The quantifiable impacts are given in Table 1.3, although the quantifiable impacts are not necessarily the more significant ones. The proposed action is designed to meet applicable environmental requirements; the identifiable specific impacts and the environmental trade-offs will be quantified and assessed in site-specific environmental analyses, where applicable. Because

Table 1.3. Summary of Environmental Impacts of the FUA

Environmental Consideration	Impact, 1990 (maximum year)
Land Use	
Mining, waste processing	3300 hectares (8151 acres)
Coal storage and onsite processing	1900 hectares (4693 acres)
Combustion waste disposal	1700 hectares (4255 acres)
Air Pollutants	
Total emissions	
SO_2	1.2×10^6 ton
NO_x	0.7×10^6 ton
Particulates	0.1×10^6 ton
Annual incremental increase in ambient air quality (maximum)	
SO_2	2.5 $\mu g/m^3$
NO_x[a]	a/
Particulates	1.5 $\mu g/m^3$
Combustion Wastes	
Scrubber sludge	23.6×10^6 ton
Fly ash	28.9×10^6 ton
Water Use	
Mining	$5\text{-}19 \times 10^8$ gal
Mining waste disposal	10×10^8 gal
Reclamation irrigation (Supply Region 6 only)	6×10^8 gal
Health Effects	
Mining and cleaning	
Fatalities	16[b]
Nonfatal injuries	1070
Transportation	
Fatalities	62
Nonfatal injuries	1394
Combustion	c/

[a]The knowledge of atmospheric chemistry of NO_x is not sufficient to permit reliable results from modeling.

[b]Includes accidents and disease.

[c]Coal-combustion-related health effects cannot be accurately quantified at this time (see Sec. 5.9.5).

Table 1.4. Definition of Positive and Negative Impact Ratings

Rating	Positive Impacts	Negative Impacts
Minimal	Benefit has some relationship to fuel use, but cannot be linked to site-specific coal use.	Impact is generally known to be linked to coal utilization, but no site-specific use will cause a noticeable or measurable impact.
Discernible	Benefit is only partially obtained by altering fuel use; benefit also depends on many other factors unrelated to the FUA. Benefit can be linked to site-specific coal use.	Impact can be linked to a site-specific reduction in environmental quality, which may not be noticed by the public but can be calculated or measured.
Significant	Benefit is obtained primarily by changing the way fuels are used in the nation's industries; benefit can be linked to site-specific coal use.	Will violate existing or future national pollutant standards (air, water, or solid waste). Impact is discernible at the local level.

quantified impacts will be assessed, the environmental considerations presented in Table 1.3 are summarized differently than the programmatic trade-offs presented in Tables 1.4 and 1.5. This separate presentation reflects the conclusion that the quantities presented in Table 1.3 are not the measure of the acceptability of the FUA. Rather, the quantities presented reflect a measure of magnitude of the program in terms of total quantifiable environmental impacts.

The trade-offs of the FUA represent disparate positive and negative impacts, with the environmental impacts being largely negative. The impacts of coal mining, combustion, and waste disposal will ultimately occur regardless of the proposed action. The primary result of the proposed action is acceleration of these impacts to the 1980s and 1990s rather than during a later period when gas and oil shortages and increased prices might force substitution to alternate fuels.

Rising prices of oil and gas would eventually encourage substitution of other fuels regardless of the FUA. With only voluntary substitutions, the nation would be more vulnerable to oil embargos, natural gas curtailment, and plant closings than it would without a mandatory program in the period from 1978 to 1990.

Through the FUA, the social and environmental costs associated with increased use of coal can be considered explicitly. If domestic natural gas and oil prices remain below world levels over the next few years, the program can force substitution without the consumer paying for increased general fuel prices that would occur as a result of immediate price increases through taxes and natural gas deregulation. Although the price of natural gas will be deregulated in 1987, it may continue to have other forms of regulation after 1987. The cost associated with fuel substitution will be much less than the cost to society of accepting a general increase in oil and gas prices.

The impact ratings in Tables 1.4 and 1.5 are based on the fact that National Ambient Air Quality Standards will not be violated as a result of the program either cumulatively, at the national or regional level, or locally at a specific site. Because both present and future applicable environmental standards will be met, the FUA will not result in "significant" impacts regionally or locally. For this reason, SO_x and particulate emissions, sludge, and wastewater effluents were not given "significant" ratings in Table 1.5.

The rating assigned to health effects resulting from implementation of the FUA represents a different kind of problem. National Ambient Air Quality Standards are based on known health effects of air pollutants, but health impacts can be assumed to occur due to increased air pollution even while standards are being met. The increased health damage may even be quantified if an adequate model of human health response can be found and if linear extrapolation is warranted. Because the increase in air pollution is only a small increment over base-case coal use, the FUA program is not expected to contribute noticeably to the overall risk to health from coal combustion.

In the FUA, the national objective of decreased dependency on imported fuel is combined with the legislative desire to achieve such self-sufficiency in a manner that minimizes the environmental and social costs. These objectives are considered sufficiently flexible in their achievement as to ensure that the environmental impacts are acceptable. The environmental considerations listed in Tables 1.3 and 1.5 and the policy options discussed in Section 10.3 illustrate the basis for making trade-offs in each site-specific conversion or exemption.

Table 1.5. National FUA Program-related Trade-offs[c]

Positive Impacts		Negative Impacts	
Impact	Rating	Impact	Rating
Increased national self-sufficiency in fuel use	Discernible	Increased particulates and SO_2[a]	Discernible
Extension of domestic oil and gas supplies	Discernible	Increased sulfate loading to water	Discernible
Increased flexibility in natural gas curtailment decisions with natural gas reserved for priority uses	Significant	Increased solid waste and scrubber sludge[b]	Discernible
Improved balance of trade	Discernible	Increased coal pile and wastewater effluents[b]	Discernible
Reduced pressure on the value of the dollar relative to other currencies	Minimal	Increased release of trace elements from coal combustion	Minimal
Foreign relations benefit resulting from demonstration of a national energy policy	Minimal	Increased use of water	Minimal
Encouragement of use of fuels which otherwise might have been discarded as waste products (pulp, bark, municipal waste, black liquor, bagasse) in certain industries	Discernible	Increased social impacts related to coal mining	Minimal
Encouragement of use of advanced coal combustion technology	Significant	Increased health risk	Minimal
Reduced frequency of oil spills of small magnitude	Minimal	Increased costs to the consumer	Minimal
Increased employment	Minimal	Increased impacts due to coal-related labor strikes when they occur including transportation of coal	Minimal
		Accelerated depreciation of capital assets and cost of generating electricity and steam from specific facilities	Discernible
		Increased stockpiling problems	Minimal
		Loss of wildlife habitat	Minimal
		Permanent disturbance or commitment of land due to mining	Minimal
		Increased emissions of hydrocarbons, NO_x, and CO	Minimal
		Increased damage from acid rain	Minimal
		Increased occupational health risk due to mining	Minimal

[a]Violation of National Ambient Air Quality Standards will not be permitted under the proposed action.

[b]Each potential fuel substitution must meet applicable environmental regulations and will be subject to future standards as they become law.

[c]The trade-offs presented in this table are general national trade-offs; there will also be site-specific impacts.

As noted in Table 1.5, one of the significant positive impacts of the FUA is increased flexibility in decisions regarding natural gas curtailment in the priority use of natural gas. A second significant positive impact is the encouragement of advanced coal-combustion technology as old units are retired, and as efforts are made to meet increasingly stringent standards for air emissions. It can be discerned on a site-specific basis that specific fuel substitutions alter fuel use, resulting in national self-sufficiency, extension of natural gas and oil supplies, decreased balance-of-trade deficit attributable to imports, and greater use of waste products such as bark, pulp, and municipal waste. These positive impacts will be traded off for the negative impacts of particulate, water, and SO_2 emissions and sulfate effluents that may be significant in that they have the potential to violate existing air and water quality standards in some localities. Existing standards could also be violated in the disposal of solid waste such as ash and scrubber sludge, and wastewater effluents attributable to acid mine drainage, coal pile runoff, and discharges of effluents at coal cleaning sites. Each of the negative impacts will be evaluated as to whether it violates existing national standards or future national standards (when they are promulgated into law). Impacts which violate national air and water quality standards ("significant" impacts) will not be permitted to occur. Moreover, state and local applicable environmental requirements will be evaluated as well. In the case of air pollution, an unmitigatable violation of state standards will be sufficient to prevent fuel substitution. Other "discernible" negative impacts traded off will be a locally noticeable increase in coal truck movement at some sites and early retirement of some existing industrial boilers. In all cases fuel substitution must be in compliance with air, water and all other applicable environmental standards.

Comments on the draft environmental impact statement were requested from the following:

Federal Agencies

Department of Agriculture
Department of Commerce
Department of Defense
Department of Health, Education and Welfare
Department of Housing and Urban Development
Department of the Interior
Department of Labor
Department of State
Department of Transportation
Department of the Treasury
Appalachian Regional Commission
Advisory Council on Historic Preservation
Environmental Protection Agency
Federal Energy Regulatory Commission
Interstate Commerce Commission
National Science Foundation
Nuclear Regulatory Commission
Office of Management and Budget
Tennessee Valley Authority
U.S. Army Corps of Engineers

State Governments

Governors of the United States
State Clearinghouses

Other Parties

Air Pollution Control Association
American Conservation Association
American Forestry Association
American Gas Association, Inc.
American Mining Congress
American Petroleum Institute
Audubon Naturalist Society
Clamshell Alliance
Conservation Foundation
Edison Electric Institute
Electric Power Research Institute
Environmental Action Foundation
Environmental Defense Fund, Inc.
Environmental Law Institute
Friends of the Earth

Institute of Gas Technology
Interstate Natural Gas Association of America
Izaak Walton League of America
League of Women Voters
National Association of Counties
National Audubon Society
National Coal Association
National League of Cities
National Parks and Conservation Association
National Wildlife Federation
Natural Resources Defense Council, Inc.
Sierra Club
Soil Conservation Society of America
U.S. Conference of Mayors
Water Pollution Control Federation

This document was made available to the U.S. Environmental Protection Agency and to the public in April 1979.

2. DESCRIPTION OF THE PROPOSED ACTION

Section 2 is a description of the proposed action--the coal and alternate fuel use program as authorized by the Powerplant and Industrial Fuel Use Act of 1978 (FUA) Publ. 95-620. Section 2.1 is a general description of the proposed action. Section 2.2 is a description of the overall national energy objectives as set forth in the FUA. The short- and long-term benefits of the proposed action are described in Section 2.3, and the proposed program is contrasted with other federal activities, particularly those relating to environmental regulatory programs and policies, in Section 2.4. Section 2.5 is a description of the scope and assumptions of this environmental impact statement.

2.1 THE PROPOSED ACTION

The proposed action is the issuance of regulations to implement the FUA, a Congressionally mandated program prohibiting the construction of new powerplants without the capability for utilization of coal or alternate fuels and prohibiting the use of natural gas or petroleum as the primary energy source in new powerplants and MFBI boilers. The Department of Energy (DOE) may grant exemptions from these prohibitions to burn oil or natural gas. The FUA excludes certain exemptions from the application of NEPA; the remaining exemptions will be subject to NEPA review. In addition, other exemption requests will receive appropriate environmental review.

An electric powerplant is any stationary electric generating unit consisting of a boiler, a gas turbine, or a combined-cycle unit which produces electric power for sale or exchange. The FUA affects single units of MFBIs and powerplants with a fuel input heat rate of 100 million Btu's per hour or greater or an aggregate heat input rate for two or more units of 250 million Btu's per hour or greater.

The term major fuel-burning installation means a stationary unit consisting of a boiler, gas turbine unit, combined-cycle unit, or internal combustion engine which has a single-unit fuel heat input rate greater than 100 million Btu's per hour or a combined-unit fuel heat input rate greater than 250 million Btu's per hour.

The proposed regulations specify eligibility criteria and application procedures for exemptions. Facilities planning to combust coal or an alternate fuel do not need to apply for exemptions under the program.

2.1.1 Description of the Proposed Action

The purposes of FUA, which shall be carried out in a manner consistent with applicable environmental requirments, are:

- To reduce the importation of petroleum and increase the nation's capability to use indigenous energy resources of the United States to the extent such reduction and use further the goal of national energy self-sufficiency and otherwise are in the best interests of the United States.

- To conserve natural gas and petroleum for uses, other than the electric utility or other industrial or commercial generation of steam or electricity, for which there are no feasible alternate fuels or raw material substitutes.

- To encourage and foster the greater use of coal and other alternate fuels, in lieu of natural gas and petroleum, as a primary energy source.

- To the extent permitted by the Act, to encourage the use of synthetic gas derived from coal or other alternate fuel.

- To encourage the rehabilitation and upgrading of railroad service and equipment necessary to transport coal to regions or states which can use coal in greater quantities.

- To prohibit or, as appropriate, minimize the use of natural gas and petroleum as a primary energy source and to conserve such gas and petroleum for the benefit of present or future generations.

- To encourage the modernization or replacement of existing and new electric powerplants and major fuel-burning installations which use natural gas or petroleum as a primary energy source and which cannot use coal or other alternate fuels, where to do so furthers the conservation of natural gas and petroleum.

- To require that existing and new electric powerplants and major fuel-burning installations which use natural gas, petroleum, or coal or other alternate fuels pursuant to the Act comply with applicable environmental requirements.

- To insure that all federal agencies utilize their authorities fully in furtherance of the purposes of the Act by carrying out programs designed to prohibit or discourage the use of natural gas and petroleum as a primary energy source, and by taking such actions as lie within their authorities to maximize the efficient use of energy and conserve natural gas and petroleum in programs funded or carried out by such agencies.

- To insure that adequate supplies of natural gas are available for essential agricultural uses (including crop drying, seed drying, irrigation, fertilizer production, and production of essential fertilizer ingredients for such uses).

- To reduce the vulnerability of the United States to energy supply interruptions.

- To regulate interstate commerce.

The exemptions which are possible under the FUA are expected to be requested primarily for new facilities rather than existing facilities since other procedures exist for rebuttal of a proposed prohibition order to existing facilities. Temporary and permanent exemptions may be granted by DOE. Temporary exemptions are effective for a period of up to five years. Some temporary exemptions may be extended for an additional five years. Permanent exemptions are effective for the lifetime of the facility. The FUA provides for numerous mandatory and discretionary exemptions. Mandatory exemptions are those which the Department of Energy must grant if the applicant proves to the Department's satisfaction that the facility meets the required eligibility criteria. Discretionary exemptions are those which the Department of Energy may grant if such an exemption is determined to be consistent with the purposes of the Act. The DOE has discretion regarding the criteria for proving eligibility for a prospective mandatory exemption. The basic exemptions included in the FUA are presented below.

1. New Facilities: Temporary, Mandatory

   a. General

      - An alternative fuel supply is not available except at a cost which "substantially" exceeds the cost of using imported petroleum.
      - One or more site limitations exist which would not permit the location or operation of a facility with coal or alternate fuel capability.
      - Prohibitions cannot be satisfied without violating applicable environmental requirements.

   b. Synthetic fuels will be used in the future.

2. New Facilities: Temporary, Discretionary

   a. The exemption is in the public interest and consistent with the purpose of the Act.

   b. For MFBIs with capacities less than 300 million Btu's per hour, if coal or alternate fuels will be used in a mixture for at least 75 percent of the time upon expiration of the exemption.

3. New Facilities: Permanent, Mandatory

   a. General

      The exemptions are those listed in 1a, and an additional exemption if the required use of coal or alternate fuel would not allow the petitioner to obtain adequate capital for financing of the facility.

b. The facility cannot totally combust coal or an alternate fuel, but can combust a mixture. In such a case, fuel mixtures are permitted.

c. Emergency use is the only purpose the facility is planned for and use of coal or alternate fuels will not satisfy the need.

d. The powerplant will be used for peakloads only and, in the case of natural gas, the use of coal or alternate fuels would cause or contribute to a violation of the National Ambient Air Quality Standards (NAAQS).

e. For MFBIs, the use of coal or alternate fuels is not technically feasible to maintain product quality or process requirements.

4. New Facilities: Permanent, Discretionary

a. State or local requirements which are not building, zoning, or nuisance ordinances preclude the use of coal or alternate fuels.

b. The benefits of cogeneration cannot be obtained using coal or alternate fuels.

c. Reliablity of service will be impaired if the exemption is not granted.

d. Intermediate-load powerplants will be constructed for replacement of units of equivalent capacity in nonattainment areas.

e. An exemption is needed to meet scheduled equipment outages.

5. Existing Facilities: Temporary, Mandatory

a. General

The exemptions are those listed in 1a.

b. Synthetic fuels will be used upon expiration of the exemption.

c. The use of innovative technologies will be feasible upon expiration of the exemption.

d. Units are being retired on or before the date of expiration of the exemption.

e. The powerplants will be used for peakload use only.

f. Reliability of powerplant service will be impaired if the exemption is not granted.

6. Existing Facilities: Temporary, Discretionary

a. The exemption is in the public interest and consistent with the purposes of the Act.

7. Existing Facilities: Permanent, Mandatory

a. General

The exemptions are those listed in 1a.

b. The facility cannot totally combust coal or an alternate fuel, but can combust a mixture. In such a case, fuel mixtures are permitted.

c. Emergency use is the only purpose the facility is planned for and coal or alternate fuels will not satisfy the need.

d. The powerplant will be used for peakloads only and reliability of service will be impaired if the exemption is not granted. Modification is technically infeasible or would result in unreasonable expense.

e. For MFBIs, use of coal or alternate fuels is not technically feasible to maintain quality or process requirements.

f. The powerplant will use liquid natural gas, and the use of coal or alternate fuels would cause or contribute to a violation of NAAQS.

g. International natural gas pipelines between the U.S. and Canada supplied gas before 1977; cancellation of the contract would cause substantial financial penalty; the pipeline serves high-priority users whose service would be jeopardized; revenues from the transportation and sale of the gas and are essential to the economic vitality of the pipeline; and the exemption is consistent with the purposes of the Act.

h. For powerplants with capacities less than 250 million Btu's per hour, if the plant was a baseload plant in 1977; and coal utilization would require substantial modification or substantial reduction in rated capacity.

8. Existing Facilities: Permanent, Discretionary

a. State or local requirements preclude the use of coal or alternate fuels and granting of the exemption is in the public interest and is consistent with the purposes of the Act.

b. The benefits of cogeneration cannot be obtained using coal or alternate fuels.

c. Intermediate-load powerplants will be constructed for replacement of units of equivalent capacity in nonattainment areas.

d. An exemption is needed to meet scheduled equipment outages.

2.1.2 Legislative History

The expiration of the Energy Supply and Environmental Coordination Act of 1974 (Pub. L. 93-319) (ESECA) necessitated the introduction of bills into the House and Senate to prohibit the construction of new powerplants without the capability for utilization of coal or alternate fuels. Although this authority was extended and expanded to include major fuel burning installations under the Energy Policy and Conservation Act of 1975 (Pub. L. 94-163) (EPCA), FUA differs from ESECA and EPCA in several respects (1) a shift of the burden of proof from the regulatory agency to industry in the case of new facilities, (2) clarification of authority to prohibit burning of certain fuels and the relation of this authority to all environmental standards including the Clean Air Act and Amendments, (3) expanded jurisdiction to include existing facilities that do not already have coal burning capability but could burn another fuel or a mixture, and (4) expansion of authority to include gas turbines and combined-cycle facilities.

The general rules by which prohibition to burn oil and natural gas in new facilities would apply were determined by Congress. Congress then empowered the Department of Energy to grant exemptions to the prohibitions based on petitions from industry and utilities. Congress expressly indicated that the FUA would not be exempted from amendments to all future environmental standards, including the Clean Air Act Amendments, enacted subsequent to the enactment of the FUA. Finally, Congress expanded the prohibitions to include categories of powerplants and MFBIs that were not previously covered.

The Conference Committee of the House and Senate agreed to amend House Bill 5146 of the 95th Congress on July 11, 1978. The short title of the Act is the Powerplant and Industrial Fuel Use Act of 1978 (FUA). The FUA was passed by the Senate on July 17, 1978, and by the House on October 15, 1978. It was signed by the President on November 9, 1978.

2.1.2.1 Previous Fuel Conversion and Utilization Program

The Department of Energy ([DOE] successor agency to the Federal Energy Administration [FEA]) currently administers a fuel conversion program under the Energy Supply and Environmental Coordination Act of 1974 ([ESECA] 15 USC 791 *et seq.*) as amended. The ESECA was enacted in response to the energy crisis precipitated by the 1973 oil embargo, and was amended in 1975 to extend FEA jurisdiction to major fuel-burning installations in the early planning process, in addition to powerplants, which were covered by the original Act. The authority to issue orders under ESECA expired on December 31, 1978; and the authority to amend, repeal, modify, rescind, or enforce such orders expires on December 31, 1984. The ESECA authority is limited both in time and scope. The FUA is enacted in anticipation of a long-term program for utilization of coal and other fuels. It is intended that the ESECA program be phased out as quickly as possible, consistent with the orderly development of the FUA. Further information on the ESECA program may be found in the revised programmatic environmental impact statement on the ESECA (FES 77-3), published by the FEA in May 1977.

2.1.3 Authority Under the FUA

The FUA prohibits the use of natural gas and oil in new boilers with a heat input rate greater than 100 million Btu's per hour and gives DOE authority to prohibit such use in existing powerplants. The FUA defines categories for which both temporary and permanent exemptions can be obtained, and contains detailed explanations of exemptions (these are discussed in Section 10.3, Policy Options). The first three titles of the law encompass exemptions and compliance with exemptions that may be issued by DOE. These titles are the essence of the FUA, and are the basis for this environmental impact statement; in these three titles, conversion to coal or other alternate fuels is required.

The law allows latitude in the use of fuels in emergency situations. This element of the FUA is contained in Title IV, along with the prohibition on the use of natural gas for outdoor lighting, and the potential restriction of increased petroleum use in existing powerplants.

In Title V, the FUA allows utilities to comply by submitting a compliance plan to DOE, under the "System Compliance Option." This option allows utilities to conform to the law without case-by-case review of individual unit operations in each utility system.

Provision for financial assistance is contained in Title VI. The FUA stipulates the availability of planning and development grants to areas in which coal and uranium mining result in impacts. The Department of Energy may also make loans to assist powerplants in the acquisition of air pollution control equipment. In the first two fiscal years, assistance to local communities is appropriated at $180 million and loans to powerplants are authorized to $800 million.

The administration and enforcement provisions of the FUA are contained in Title VII, and "Miscellaneous Provisions" regarding information and reports are contained in Title VIII.

2.2 PURPOSE IN RELATION TO NATIONAL ENERGY OBJECTIVES

The National Energy Plan prepared by the Executive Office of the President, and issued on April 29, 1977, summarized three overriding national energy objectives:

" - as an objective that will become even more important in the future, to reduce dependence on foreign oil and vulnerability to supply interruptions;
- in the medium term, to keep U.S. imports sufficiently low to weather the period when world oil production approaches its capacity limitation; and
- in the long term, to have renewable and essentially inexhaustable sources of energy for sustained economic growth."

On April 20, 1977, President Carter appeared before Congress and set forth specific energy goals to be achieved by 1985:

1. Reduction of the annual U.S. energy demand growth rate to less than 2 percent.

2. Ten percent reduction of gasoline consumption.

3. Reduction of oil imports to less than 6 million gallons per day.

4. Establishment of a 1-billion-barrel strategic petroleum reserve.

5. Increase in coal production by more than two-thirds to over 1 billion tons per year.

6. Insulation of 90 percent of existing American homes and all new buildings to meet minimum energy efficiency standards.

7. Use of solar energy in over 2.5 million American homes.

2.3 BENEFITS

2.3.1 Short-term Benefits

A major short-term benefit of the proposed action would be the redirection of petroleum products and natural gas to priority uses for which coal is not a suitable fuel source. This could result in reductions in overall use or in increased supplies of these fuels. The positive and negative impacts of that are summarized in Section 11. The environmental consequences of the proposed action are expected to be minimized by compliance with all applicable environmental standards.

2.3.2 Long-term Benefits

The major long-term positive impacts of the FUA are conservation of limited domestic petroleum and natural gas supplies and decreased reliance on imported petroleum products. In addition, development and use of coal-derived fuels and other alternate fuels would be encouraged and pollution abatement technologies would be developed and promoted. Reduction in the U.S. balance of payments deficit attributable to petroleum imports and reduction of potential for oil spills could also be expected to occur as a result of the FUA.

Supplies of domestic natural gas and oil will be conserved to ensure their availability for essential uses, such as agricultural and process use, and for use in situations where protection of the environment requires cleaner-burning fuels.

2.4 RELATIONSHIP TO OTHER FEDERAL ACTIONS

2.4.1 Relationship to Other Federal Energy Programs and Legislation

A primary goal of current energy policy is the substitution of abundant energy sources for those in short supply. This means, for the short term, reduction of U.S. dependence on foreign fuels and promotion of conservation and increased fuel efficiency, and, for the long term, development of renewable and essentially inexhaustible sources of energy. As such, the FUA is one of many federal energy programs designed to reduce the use of petroleum and natural gas or promote use of an alternate fuel wherever possible and in an environmentally acceptable manner.

Specifically, the proposed regulatory program would prohibit or restrict the use of oil and natural gas in new and existing utility and industrial boilers. Although coal would be the major substitute for oil and natural gas in the short term, other technologies for burning coal (coal gasification, fluidized-bed combustion, solvent-refined coal, coal/oil mixtures, etc.) and other alternate fuels (wood wastes, refuse-derived fuel, etc.) would be encouraged.

The FUA is directed toward fuels other than oil and gas, and therefore complements the development of non-fossil-fuel resources through federal research development and commercialization programs such as those for geothermal and solar energy. The further development of existing domestic oil resources (development of Outer Continental Shelf resources, oil shale, enhanced recovery) would serve to increase the nation's self-sufficiency in the near and middle term.

In implementing the FUA, consideration must be given to the environmental impacts of the proposed action as they may interact with or overlap environmental impacts of other federal actions. Examples of such programs are the Synthetic Natural Gas (SNG) program and the Strategic Petroleum Reserve (SPR) program. If two or more such programs were implemented in the same geographic area (for example, the same county, Air Quality Control Region, or state), the cumulative impacts could be significant, and it might be possible for the SPR or SNG program to aggravate the impacts of the FUA. Accordingly, implementation of the proposed action should be carefully pursued and, where necessary, regional or site-specific environmental analyses undertaken to assess the potential cumulative impacts of two or more federal programs.

Further information on the SNG and SPR technologies may be found in Section 10, Alternative Technologies and Regulatory Policies.

2.4.2 Relationship to Federal Railroad Transportation Programs

Transportation of coal by rail is of primary importance in the implementation of the FUA. The level of increased coal use as a result of the FUA will be affected by federal railway transportation policy. The Railroad Revitalization and Regulatory Reform Act of 1976 (45 USC 822 *et seq.*, the "4R" Act) provides major financial aid to railroad firms for the rehabilitation of railway systems. Section 284 of the FUA authorizes funds for deposit in the Railroad Rehabilitation and Improvement Fund, established under Section 502 of the 4R Act, which would be allocated for the rehabilitation of railroads used specifically for the transportation of coal.

Further information regarding coal transportation may be found in Appendix E.

2.4.3 Relationship to Environmental Programs

2.4.3.1 The National Environmental Policy Act

Section 102(2) (c) of the National Environmental Policy Act (NEPA) of 1969 (42 USC 4321 *et seq.*) requires that all agencies of the federal government prepare detailed environmental statements on proposed major federal actions which have the potential for significantly affecting the quality of the human environment. The principal objective of NEPA is to build into the agency decision-making process an appropriate and careful consideration of environmental aspects of proposed actions. In addition to complying with the procedural requirements of NEPA, agencies must review and comply with all other legislative and statutory requirements irrespective of NEPA, which may affect implementation of the proposed action. Sections 2.4.3.2 through 2.4.3.7 are brief descriptions of such requirements and legislation which may affect DOE implementation of the FUA.

2.4.3.2 The Clean Air Act

The Clean Air Act of 1970 (42 USC 7401 *et seq.*) and its subsequent amendments authorized a comprehensive regulatory program to be administered by the U.S. Environmental Protection Agency (EPA) and designed "to protect and enhance the quality of the nation's air resources so as to promote the public health and welfare and the productive capacity of its population."

To protect public health, the EPA promulgates "primary ambient air quality standards" based on criteria relating to health effects and an "adequate margin of safety." To protect public welfare, EPA promulgates "secondary ambient air quality standards." The EPA also has authority under the Clean Air Act to impose emission standards for designated "hazardous air pollutants" to which no primary ambient air quality standard is applicable, and which cause or contribute to air pollution which may result in an increase in mortality or serious irreversible or incapacitating reversible illness. New sources of air emissions are regulated by "standards of performance" and the "best technological system of continuous emission reduction that has been adequately demonstrated."

To implement these standards the Clean Air Act requires that each state designate Air Quality Control Regions (AQCRs) for the entire geographic area of the state and prepare a State Implementation Plan (SIP) which provides for the implementation, maintenance, and enforcement of the primary and secondary ambient air quality standards in those regions. The SIP must be submitted to the EPA for approval, and if the EPA determines that the plan is inadequate, the EPA may promulgate regulations applicable to the deficient portions of the state plan.

The EPA has promulgated primary and secondary ambient air quality standards for sulfur dioxide (SO_2), total suspended particulates (TSP), photochemical oxidants, and carbon monoxide (CO) and nitrogen dioxide (NO_2). Regulations have also been promulgated to set new source performance standards (NSPS) for 24 industrial categories and emission standards for 4 hazardous pollutants (mercury, beryllium, vinyl chloride, and asbestos).

The 1977 amendments to the Clean Air Act (42 USC 7401 et seq.) included new provisions designed for "prevention of significant deterioration" (PSD) of existing air quality (SO_x and TSP) in areas which are presently cleaner than would be required to meet the most stringent standards. The PSD provisions in the 1977 amendments require that each state classify clean air areas as either Class I (where air quality has to remain virtually unchanged), Class II (where moderate additional emissions will be allowed) or Class III (where more intensive industrial activity will be permitted). The air quality in each Class, will not be allowed to deteriorate in excess of increments specified in the amendments, and in no case will pollutant concentrations in the ambient air in any air quality control region be allowed to exceed the secondary National Ambient Air Quality Standards.

In order to meet the PSD requirements, new sources in certain industrial categories with potential emissions in excess of 100 tons per year, and all other new sources with potential emissions of 250 tons of pollutants per year, are required to secure preconstruction permits. Before being granted a new source preconstruction permit, a qualifying potential source must undergo a PSD review to ensure the installation of at least "best available control technology" (BACT), and to ensure that any new emissions do not cause a violation of any NAAQS in any air quality region, or violate any applicable air emission standard. PSD review will be administered by the EPA until the national requirements are incorporated in the state implementation plans submitted to EPA for approval on or before March 19, 1979. All new major sources, whether or not they are subject to PSD permit requirements, must meet the requirements established by the EPA's New Source Performance Standards.

The 1977 Amendments to the Clean Air Act (42 USC 7401 *et seq.*) also require that State Implementation Plans (SIPs) must incorporate special new provisions relating to attainment and maintenance of National Ambient Air Quality Standards in non-attainment areas* as a precondition for the construction and modification of any major stationary source on or after July 1, 1979. Upgrading of non-attainment areas must be undertaken "as expeditiously as practicable" but no later than December 31, 1982. The SIP revisions designed to achieve these objectives will

*A non-attainment area is an AQCR (or part thereof) not meeting National Ambient Air Quality Standards for a specific pollutant.

require, among other things, issuance of permits to new sources in nonattainment areas which incorporate "emissions offsets"* in order to achieve "reasonable further progress" towards attainment of minimal air quality in existing nonattainment areas. To obtain a permit, a proposed new source must meet four conditions: (1) it must achieve the lowest achievable emissions rate (LAER); (2) other sources owned by the same company must be in compliance; (3) offsets greater than 1 for 1 must be obtained; and (4) a net air quality benefit must be demonstrated. New sources in nonattainment areas may also be required to undergo PSD review if emissions from that source may result in violation of National Ambient Air Quality Standards in another AQCR.

2.4.3.3 Clean Water Act

The Federal Water Pollution Control Act (FWPCA) as amended in 1972 and 1977 (33 USC 1251 *et seq.*) authorized a comprehensive regulatory program to achieve the following goals:

1. The elimination of the discharges of pollutants to the nation's waters by 1985.

2. The attainment and maintenance of an interim goal of water quality that provides for the protection and propagation of fish, wildlife, and recreation by July 1, 1983.

3. The prohibition of the discharge of toxic pollutants.

The current regulatory program administered by the EPA and the states combines water pollution abatement programs based upon water use designations, water quality criteria, and standards with nationwide, technology-based effluent limitations on point source** discharges. These effluent limitations on the quality and concentration of pollutants applied at the point of discharge--whether derived from application of "best practicable control technology currently available" (BPCTA) or from water quality standards--are administered by means of National Pollutant Discharge Elimination System (NPDES) permits. NPDES permits may be issued either by the EPA or by states that have been delegated the authority by the EPA. In addition to the requirement that existing facilities install BPCTA on or before July 1, 1977, or meet more stringent limitations based upon water quality standards, the FWPCA as amended in 1977 requires that all point source discharges apply by July 1, 1984, "best conventional pollutant control technology" to traditional pollutant parameters (e.g. biological oxygen demand, total suspended solids, and acidity) and the more stringent "best available technology economically achievable" (BATEA) to certain identified toxic-pollutant-contaminated discharges. The FWPCA further requires application of "best available demonstrated control technology" to new point sources and provides for regulation of non-point sources** of pollution. These various technology-based standards are defined by the EPA through promulgation of nationwide effluent guidelines and standards for various industrial categories and subcategories.

In some cases, water quality standards established by the states and approved by the EPA are used as the basis for specific discharge limitations contained in NPDES permits. State water quality standards apply when the nature of the waterway is such that application of technology-based, federally established effluent limitations is insufficient to maintain the ambient water quality necessary to achieve the uses for which a particular waterway has been designated by the state. In some cases limitations based on water quality may require the development of new treatment technologies to ensure industrial compliance with water quality standards.

Facilities subject to fuel conversion or utilization requirements may be subject to one or several of these requirements if conversion or utilization results in a significant change (whether it is an increase or a decrease) in their pollutant discharges. If there is a significant change, a facility must report this to the state and the EPA pursuant to the conditions specified in the existing NPDES permit, which may then be subject to modification based upon the change in the discharge. The FWPCA allows discharges only from certain authorized outfalls designated in the facility's NPDES permit. Wherever conversion or utilization results in the creation of a potential new point source discharge, the discharge must be authorized by modification of the existing NPDES permit prior to the commencement of any new discharge.

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*The offset policy requires construction permit applicants to apply LAER or BACT and to obtain enough emission reductions of the pollutant for which the area is in non-attainment, from existing sources, to more than offset the emissions from the proposed new source. Only emissions of the same pollutant may be offset.

**A point source is an individual, identifiable emitter of pollution, such as a plant stack. A non-point source is a group of pollution emitters, such as an urban area, or an area of pollution-emitting material, such as a coal mine.

2.4.3.4 Safe Drinking Water Act

The Safe Drinking Water Act (42 USC 201 *et seq.*) requires that the Environmental Protection Agency promulgate regulations establishing primary and secondary standards for specific contaminant concentrations in public water supplies, or requiring the use of specific treatment technologies for purposes of protecting public health (primary standards) and welfare (secondary standards). The states have primary authority for enforcement of these regulations. However, should a state fail to effectively enforce the regulations, the EPA has authority to undertake such enforcement.

On June 24, 1977, the EPA promulgated final primary (health-related) drinking water regulations. These regulations require sampling programs to ensure that concentration limitations for microbiological contaminants, ten specified inorganic chemicals (metals), six organic pesticides, turbidity, and radiological effluents are not violated in approximately 250,000 community and public drinking water systems. In addition to primary drinking water standards, EPA has proposed secondary, or welfare-related, regulations to protect major underground drinking water sources, and regulations to control additional organic chemical contaminants.

Because fuel conversion or utilization in powerplants and MFBIs may result in significant additions of inorganic chemicals (metals) to navigable waters and aquifers located near these facilities (particularly through ash pond overflows, coal pile runoff, and leaching), a facility constructing for or converting to coal or an alternate fuel may be subject to requirements for safe drinking water in addition to requirements imposed by state and federal water pollution abatement programs.

2.4.3.5 Solid Waste Control (Resource Conservation and Recovery Act)

The Resource Conservation and Recovery Act of 1976 (42 USC 6901 *et seq.*), amending the Solid Waste Disposal Act, requires that the EPA publish guidelines for solid waste management, promulgate regulations applicable to hazardous wastes management, develop guidelines for state and regional solid waste management, establish criteria for sanitary landfills to generally prohibit open dumping, and provide federal assistance to the states in the development of programs in each of these areas. Proposed hazardous waste regulations were issued on December 11, 1978.

The guidelines affecting facilities burning coal are the EPA's Guidelines for Land Disposal of Solid Wastes, published August 14, 1974 (40 CFR 241), and Proposed Guidelines for State Hazardous Waste Programs, published on February 1, 1978 (43 FR 4366). The primary solid wastes attributable to coal-fired facilities are ash and scrubber sludges. The guidelines for land disposal establish recommended procedures delineating minimum levels of performance required of any solid-waste land disposal operation, including the following:

1. Routine sanitary landfill techniques of spreading, compacting, and covering consistent with the statutory injunction against open dumping.

2. Site selection consistent with public health and welfare, and air and water quality standards, and adaptable to appropriate land use planning.

The Proposed Guidelines for State Hazardous Waste Programs set forth comprehensive guidance for a management program under state supervision with federal oversight. Coal-burning facilities will be increasingly affected by solid waste disposal programs at state and federal levels.

2.4.3.6 Toxic Substance Control Act

The Toxic Substance Control Act of 1976 (15 USC 2601 *et seq.*) primarily addresses the commercial manufacture, use, and distribution of chemical substances. Sections 6 and 7 of the Act, however, grant the EPA authority to regulate the manner and method of disposal of specified hazardous chemical substances. While the regulatory program presently being developed under this legislation is unlikely to have a direct effect on facilities burning coal, the disposal authorities granted may affect resource recovery of ash and scrubber sludge.

2.4.3.7 Other Related Legislation

The Surface Mining Control and Reclamation Act of 1977 (30 USC 1201 *et seq.*, Pub. L. 95-87) is designed "to protect society and the environment from the adverse effects of surface coal mining" (Section 102(a)). This legislation is related to the FUA in that it regulates the development of new surface coal mining operations (Sections 502(a) and 596) and therefore affects the availability of coal. Implementation of reclamation procedures pursuant to this Act would serve to mitigate any potentially adverse impacts resulting from increased surface mining in response to increased coal demand due to the FUA. The Surface Mining Control and Reclamation Act is discussed further in Appendix E, Section E.2.2.1.

Under the Coastal Zone Management Act of 1972 (16 USC 1451 *et seq.*, Pub. L. 92-583), the Department of Commerce is authorized to make grants to the coastal states to assist in the development and administration of coastal zone management programs. The state program, which must be approved by the Department of Commerce with the concurrence of the Department of the Interior, defines the controlled coastal zone, permissible uses and use priorities, and a system of legal controls for enforcement. Once an approved state program is in effect, every applicant for a federal license or permit for an activity must furnish a certification from the state that the proposed activity complies with the coastal zone management program.

Pursuant to Sections 208 and 303 of the Federal Water Pollution Control Act, State Coastal Zone Management Plan requirements are coordinated with other water pollution abatement programs. In accordance with 40 CFR 130 and 131, states must establish "continuous planning processes" for regional waste treatment and water quality management. Participation in Coastal Zone Management programs is voluntary, and such programs may not interfere with or establish requirements incompatible with state water quality standards or federal effluent guidelines. Coastal Zone Management requirements could potentially apply to utility powerplants and industrial facilities which are subject to the FUA in coastal zone areas.

The purpose of the Endangered Species Act of 1973 (16 USC 1536, Pub. L. 93-205) is to provide for the conservation of endangered and threatened species and the ecosystems upon which they depend for survival. Under this Act, the Secretary of the Interior and the Secretary of Commerce determine those species which are endangered or threatened, and publish notification of such determination in the Federal Register. If an action taken by the Department of Energy under the FUA had the potential to affect an endangered or threatened species or its habitat, a review of the proposed action by the Department of the Interior would be required.

Executive Order No. 11988 issued on May 24, 1977, establishes as federal policy for administrative agencies the avoidance wherever possible of the long- and short-term adverse impacts associated with the development, occupancy, or modification of floodplains, and avoidance of direct or indirect support of floodplain development whenever there is a practical alternative. Further information on this executive order may be found in guidelines proposed by the Water Resources Council for implementation of E.O. 11988 published on February 10, 1978 (43 FR 6030).

Executive Order No. 11990, issued May 24, 1977, establishes as federal policy for administrative agencies to avoid wherever possible the long- and short-term adverse impacts associated with the destruction or modification of wetlands and to avoid direct and indirect support of new construction on wetlands whenever there is a practical alternative. This order supplements existing programs administered by the U.S. Army Corps of Engineers in cooperation with the U.S. EPA under Section 404 of the FWPCA.

Pursuant to the Energy Policy and Conservation Act (EPCA) (Pub. L. 94-163) and as amended by the Energy Conservation and Production Act (ECPA) (Pub. L. 94-385), the Department of Energy may give loans to operators of small coal mines under the Coal Mine Loan Guarantee Program. "Small" is defined as less than 100,000 tons per year production.

The objective of the legislation is the production of more low-sulfur coal from mines in which the smaller-sized coal operator can afford to invest. There are criteria regarding sales volume, production, tonnage, and links to the oil industry that restrict the kinds of companies that may participate in the program. Total loans to any one person or corporate entity is $30,000,000 and the loan is guaranteed for up to 80 percent of the loan principal or the cost of the project, whichever is less.

To the extent that those industrial facilities affected by the FUA find it desirable or necessary to use low-sulfur coal, the Coal Loan Guarantee Program will assist in ensuring the availability of low-sulfur coal from operators of small mines. Because the volume of coal used by individual industries is assumed to be low, industries rather than utilities will be affected by the Coal Loan Guarantee Program.

2.5 SCOPE AND ASSUMPTIONS OF THIS ENVIRONMENTAL IMPACT STATEMENT

Section 3 is a description of the methods by which the energy impacts of the FUA were estimated. It includes a description of the use of a "worst-case" approach, the period of time for which the impacts were analyzed, and the manner in which utilities and industries are expected to be affected.

Energy impacts are projected through two time periods, 1985 and 1990, and include a base-case scenario (impacts that would occur without implementation of the FUA) and the increment associated with implementation of the FUA. The increment is described as quads of energy produced from sources other than oil and natural gas in both existing and new facilities at the demand region level for the conterminous United States.

The regions projected to supply coal to each demand region are also delineated. In this analysis, it was assumed that most facilities would use coal as the alternate fuel; other potential fuels are described in Section 10, Alternative Technologies and Regulatory Policies. Coal was selected as the major fuel source because coal is expected to be the overwhelming choice of alternate fuel at the national level and because the assumption of coal use generally results in the worst-case environmental analysis. Other energy alternatives may be more environmentally acceptable, and various alternative technologies clearly will be stimulated by FUA. Specific industries or specific regions of the country may be able to increase the use of waste products, but such use is highly site-specific.

Section 4 is a description of the current national environment in which increased coal use will take place. Emphasis has been placed on those regions of the U.S. in which impacts will result from the proposed action. Data are presented on coal supplies, present air and water quality, land use, and biotic resources.

The environmental impact analysis is presented in Section 5. The air quality analysis was done by Air Quality Control Region (AQCR), a geographic unit smaller than any of the ten demand regions. Air quality effects were projected for 238 AQCRs. This modeling required energy use data. The energy use data were estimated at the demand-region level and were then distributed to AQCRs based on forecasts of future locations of fuel use.

Several limits were imposed on the projected oil and gas conversions of existing MFBIs expected for each AQCR (see Section 3). The data base used to establish these limits was the Major Fuel Burning Installation (MFBI) data file compiled by the Federal Energy Administration (FEA) in 1975. The data in this file included the amounts of oil, gas and coal consumed in 1974 by industrial combustors with design firing rates greater than 99×10^6 Btu/hr (10 MW).

The quantity of oil or gas conversion to coal in existing industrial plants was limited to the quantity consumed in large combustors (greater than 99×10^6 Btu/hr) in 1974. For example, if an AQCR did not contain any large combustors, it was assumed that there was no increased coal use due to the FUA.

Limits were also imposed on oil and gas utilization by MFBIs. For this case, the basic model to project energy consumption in new facilities, based on projections of employment and the assumption that the location of these facilities followed existing industrial locations. Thus, it was assumed that no new coal-capable units would be built in AQCRs which do not now contain large combustors. A second limitation on new facilities was that projected substitution which amounted to less than 400×10^9 Btu/yr were not considered. The rationale for this restriction is that 400×10^9 Btu/yr would represent a load factor of only 45 percent on the smallest combustor being considered to be regulated by the program and that such a facility would probably not be added or else a smaller unit not regulated by the proposed action would be built.

Emissions and combustion wastes were quantified based on the following assumption: (1) New Source Performance Standards (NSPS) will be met for air emissions of SO_2, NO_x and particulates; (2) Best Available Control Technology (BACT) will be implemented for calculating waste scrubber sludge and collected fly ash.

Cumulative impacts through 1985 and from 1985 to 1990 are quantified where possible. Most of these impacts will continue throughout the life of the new or converted MFBI.

This document does not contain an analysis of each site on a case-by-case basis. It does provide an overview of the full range of environmental impacts which may occur due to implementation of the proposed action.

Section 6 is a description of the effects of FUA which cannot be avoided, and of possible mitigative measures. Section 7 includes a discussion of the irreversible and irretrievable commitment of resources, and is a summary of the extent to which coal utilization would consume, destroy or transform scarce or nonrenewable resources. Section 8 contains an evaluation of how coal utilization may conflict with the objectives and specific terms of approved or proposed federal, state and local land use plans, policies, and controls for the affected area. Section 9 addresses the extent to which coal utilization would constrain the diversity and range of potential uses of the environment.

Alternatives to direct coal combustion which are possible during the time frame of this analysis and policy options available to the regulators of the proposed program are found in Section 10. A discussion of the environmental trade-offs of using coal is contained in Section 11.

3. FUEL CONVERSION ANALYSIS METHODOLOGY

The energy impact analysis methodology described in this section was designed to forecast the level of increase in the use of coal and alternate fuels in existing and new facilities as a direct result of the fuel conversion regulatory program resulting from the regulations indicated in Section 2. Cumulative energy impacts of the program were projected for 1985 and 1990. The coal production projections used in this analysis were designed to maximize impacts expected to result from the conversion regulatory program. Environmental and health impacts were assessed based on these projections.

Although the projections in this EIS are based on increased use of coal, the program encourages the development and use of technologies based on other energy sources (e.g., biomass and municipal waste). The number of Btu's of gas or oil that will be substituted for by a fuel other than coal are not given due to the uncertainty of their usage. Coal is assumed to be the overwhelming alternate fuel choice. Other alternate fuels and their impacts are presented in Section 10.

Nearly all of the impacts of the program will occur in the industrial sector, where more than 60 percent of the projected increase in oil and gas use in the U.S. between 1975 and 1985 is forecast to occur (Energy Information Administration 1978). The proposed action applies to all new and existing fuel-burning installations with a fuel heat input rate of 100 million Btu's per hour or greater or an aggregate of 250 million Btu's per hour; however, incremental coal use by utilities due to the program is assumed to be insignificant, as explained in Section 3.1, and the focus of this section is on increased coal use in the industrial sector.

Although fuel use resulting from the proposed action was not estimated beyond 1990, estimates were made of environmental impacts occurring after 1990 as a result of conversions or construction by that date. There were two principal reasons for this. First, the analysis depends heavily on the PIES (Energy Information Administration 1978) modeling framework. Energy demand projections from PIES were taken as exogenous inputs. Because of the uncertainties of the results of the PIES projections beyond 1990, PIES projections for 1985 and 1990 only were used. Second, even if PIES projections beyond 1990 were available, the uncertainty in the factors affecting program impact, such as the amount and location of industrial growth, is so great that the range of uncertainty is larger than any estimate of the program impacts. If, for example, the price of natural gas increases sharply after 1990, the impacts of the proposed action would be expected to decrease, since many facilities would convert voluntarily. Environmental control policies in the 1980s could preclude the direct use of coal in many areas, also reducing impacts.

3.1 THE ELECTRIC UTILITY INDUSTRY

3.1.1 Existing Utilities

Existing utilities will not be affected by the proposed action because they have been evaluated for conversion to coal under the Energy Supply and Environmental Coordination Act of 1974 (ESECA); many of those utilities capable of converting to coal have been ordered to do so. This provision of the FUA will be accompanied by a "Systems Compliance Option," allowing use of natural gas after 1990 for any utility which makes a commitment to restricting such use to 20 percent of its 1977 level. It appears that the large natural-gas-using utilities will be able to make and keep this commitment without increasing the amount of currently planned new coal capacity. In other words, the requirements of the Systems Compliance Option will be met even without passage of the FUA. It is assumed that no additional coal use will result from this provisicn.

3.1.2 New Utilities

The FUA will prohibit the construction of utilities which use oil or natural gas as the primary fuel unless an exemption is granted. It will not preclude the construction of plants using oil in combination with coal (mixed-fuel firing). In this case coal would have to be the primary energy source unless the facility gets a mixtures exemption.

Under certain conditions, exemptions from this prohibition may be granted to two types of facilities:

1. For peakload generation, combustion turbines fueled by distillate oil will be permitted, and exemptions for the use of natural gas may be granted.

2. For intermediate-load generation, facilities fueled by distillate oil may be granted an exemption, but the use of natural gas will not be permitted.

Categories and policy options in the granting of exemptions are discussed in Section 10.3.

The vast majority of utility construction for new baseload plants use either coal or nuclear energy. Virtually all the remaining plants under construction, or planned, use natural gas and petroleum products for peaking may obtain peaking exemptions under the FUA. Therefore, increased coal use by new utilities as a result of the FUA is unlikely to have any distinguishable effects on the analysis.

3.2 THE INDUSTRIAL SECTOR

3.2.1 Use of Worst-Case Analysis

Many factors, singly and in combination, will affect the actual number of facilities granted or denied an exemption. These factors include the location and extent of industrial growth, changes in air quality standards and federal and state environmental programs, OPEC pricing decisions, and developments in coal burning and alternate fuel technologies.

A "worst-case" approach was developed for this analysis, with the intent of establishing a likely upper bound for the range of possible increased coal use due to the proposed action. Generally, where uncertainty existed regarding a particular provision, conversion to coal due to the proposed action was systematically overstated, as described in the remainder of this section. However, several assumptions were made which would reduce the estimated increased coal use. For example, it was assumed that no facility would purchase offsets and thereby be able to locate in a nonattainment area. In fact, the U.S. Department of Energy (DOE) may be able to deny an environmental exemption on the basis that such offsets are available and that purchase of offsets would not make coal use so expensive as to qualify for an economic exemption. Likewise, the assumption that new plants will be constructed in the same areas as existing facilities probably results in an overstatement of the number of facilities exempted.

In general, however, the assumptions used in the overstatement of increased coal use are likely to be more significant. Among the more important assumptions are these:

1. Gas prices will remain controlled and world oil prices will remain constant.

2. Every existing coal-capable MFBI that has coal capability would receive an order (i.e., no constraint on administrative resources).

3. There would be no exemptions granted due to site-specific limitations (fully 20 percent of existing units are claimed not to have space for a coal pile).

4. No exemptions other than environmental and economic exemptions would be granted.

It appears that, as a result, the final estimate used represents a substantial overstatement of the likely increase in coal use as a result of the proposed action.

The industries shown in Table 3.1 are the principal industries expected to be impacted by the fuel conversion program.

3.2.2 The Model

The impact of the proposed action on fuel use in industrial combustors was assessed with the aid of a model which simulates fuel choice in projected industrial combustors. This model* was created specifically to assess the impact of the proposed incentives included in the National Energy Plan. For any of a variety of policies the model simulates industrial fuel choice decisions and projects oil, gas, and coal consumption. Starting with current policy, or "base-case" projections of industrial fossil fuel consumption, the model projects oil and gas shifts to coal

*This model was developed by Energy and Environmental Analysis, Inc., for the Energy Policy Office of the White House.

as stimulated by proposed policy options. Baseline projections of regional fuel prices and fossil fuel demand used in the model are derived from the PIES model, and are disaggregated into a hypothetical combustor population. The model then simulates the fuel choice decision process for those industrial fossil fuel processes which are technically capable of using coal. The model is described in more detail in Appendix A. The results of the modeling are presented in Section 10.3. The assumptions used in the model do not reflect the actual decision variables to be used in the regulatory process. For example, no capital costs were used to model economic penalties associated with coal use. Another assumption in the model is the substitution of coal for oil and natural gas in all cases. The regulatory process will also require or encourage the substitution of an alternate fuel for oil and natural gas. Alternatives to the use of coal are discussed in Section 10.

3.2.3 Base-case Scenarios

The major assumptions which served as the basis for the energy analysis are contained in the Series C projections of the 1977 Annual Report of the Administrator of Energy Information Administration. The major economic assumptions are derived from the Data Resources, Inc. (DRI), Trend-Long run of December, 1977. This run projects a constant-dollar compounded annual gross national product growth rate of 3.8 percent between 1975 and 1990. Table 3.1 displays the constant-dollar compounded annual industrial value added growth rates. The price of imported oil was assumed to remain at $13/bbl (in 1975 dollars) and natural gas price regulation was assumed to continue through 1990. New Source Performance Standards (NSPS) were modeled by assuming that the "Best Available Control Technology" (BACT) to be required on all combustors with firing rates greater than 25 MW through 1990 would be complied with by the use of flue gas desulfurization and particulate control.

Table 3.1. Projected Industrial Annual Growth Rates (percent)

Industry	1975-1985	1985-1990
Food processing	4.3	2.5
Paper and pulp	4.5	2.9
Chemicals	7.5	6.3
Refineries	3.0	1.9
Stone, clay, and glass	5.3	3.1
Primary metals	4.0	2.5
Machinery	5.8	4.1
Total	5.2	3.7

From Data Resources, Inc., Trend-Long run of December 13, 1977.

3.2.4 Methodology for Simulation of the Proposed Action

The proposed action was simulated with the model in the following manner. All projected oil- and gas-fired industrial combustors were considered converted to coal by regulatory authority except in cases where (a) combustors voluntarily convert to coal (baseline conversions) or (b) combustors were specifically excluded by the proposed action. Five categories of excluded combustors were:

1. Combustors other than boilers.
2. Boilers with capacities less than 100 MBtu/hr, which is approximately 10 MW of steam capacity.
3. Existing boilers not designed to use coal.
4. Boilers located in areas designated as nonattainment (see Sec. 3.2.4.4).
5. Boilers for which the costs of using coal are substantially higher than the costs of using oil.

These categories and the way they were simulated are described below in more detail. No other exclusions were accounted for in this analysis.

3.2.4.1 Nonboiler Combustors

Combustors other than boilers (nonboilers) were considered not generally subject to the conversion authority of the proposed action. Although some specific nonboiler major fuel-burning installations (MFBIs) are identified in the FUA (gas turbines, combined-cycle units, or internal combustion engines), a variety of design barriers prevent most of them from being converted to coal. Only by changing the design (e.g., replacing a gas turbine with a steam turbine) can coal be substituted for other fuels in most of these processes. The model is specifically designed to analyze boilers and nonboilers separately and includes process-specific detail for each type of combustor. Only boilers were considered in the analysis.

3.2.4.2 Boilers Less than 100 Million Btu's

The FUA applies to all oil- and gas-fired boilers which either have individual capacity greater than 100 million Btu's or, where more than one boiler is located in a facility, with combined capacity greater than 250 million Btu's. The model assigns capacity detail and modeling of the capacity exemption for individual boilers was straightforward. However, because no reliable data were available to indicate the increased coal use due to conversions by boilers 100 million Btu's or smaller but with a combined capacity exceeding 250 million Btu's, the combined capacity exemptions were not modeled. As a result, conversions resulting from the program might be somewhat understated. However, substitution of coal would be overstated to the extent that firms purchase several smaller units (less than 250 million Btu's in the aggregate), rather than a single larger unit.

3.2.4.3 Existing Boilers not Designed to Burn Coal

Two important distinctions are embodied in this exclusion. First, each projected combustor in the model is designated as "new" (combustors coming on-line in 1980 or later*) or "existing" (combustors operating today or scheduled to come on-line prior to 1980). This distinction was made for two principal reasons, one analytical and one legislative. From an analytical viewpoint, a firm's investment approach to new units is different from that for existing unit. If a unit already is in operation, the boiler capital cost has been committed. The principal costs involved in its continued operation are those for operation and maintenance. If an alternative fuel is to be considered, then both the capital costs of modifying the existing combustor plus the operating and maintenance costs of the alternative fuel are compared to the operating and maintenance costs of the original fuel. The proper comparison for the fuel choice decision for new investments, however, involves comparison of capital, and operation and maintenance of both the original fuel and the alternative fuel. Because it is a new investment, there is no sunk capital. The model includes this difference in the nature of investment decisions. From the legislative standpoint, the regulatory program treats new and existing units differently. While many existing units are covered by the regulatory program, only those receiving orders to convert will be required to convert. All new units, however, must burn coal or an alternate fuel unless the owners demonstrate to the government that they are eligible for an exemption.

The second important distinction embodied in this exclusion is that of "coal or alternate fuel capability." Of existing oil- and gas-fired boilers, only those which were designed or which acquire the capability to burn coal as the primary fuel are subject to the regulatory program. Only units designed to burn coal were identified in the model based on information received in a survey of MFBIs.

The authority to order existing combustors to use mixed-fuel firing potentially represents substantial savings of oil and gas.

For the 1985 estimate, it was assumed that the authority to order mixed-fuel firing would not be used. However, an analysis was performed to estimate the significance of this assumption. In this analysis, it was assumed that DOE would order conversion of existing units on a case-by-case basis, ordering first those units which offered the greatest savings in oil and gas,

*A two-year construction period was assumed for boilers. Any boiler beginning construction on January 1, 1978, would not be operating until January 1, 1980.

whether mixtures or solid coal. It was further assumed that administrative resources would permit only 100 orders to convert per year. Under these assumptions, the total conversion in existing units was less than the original estimate of conversion in coal-capable units alone without the administrative constraint. For this reason, it appears that the assumption that mixed fuel authority is not used until the mid-1980's does not cause impacts to be understated.

For the 1990 estimate, it was assumed that the mixed-fuel authority would be exercised in 100 orders per year, subject to economic and environmental exemptions. Since it was assumed that all eligible existing coal-capable would be converted by 1985, all conversions in existing units shown in 1990 resulted from the use of the mixed-fuel authority.

It was assumed that there would be no ordered conversions of existing units to synthetic gas or liquids from coal. For the reasons stated above, it is uncertain what effects this assumption, in conjunction with administrative resource constraints, would have on increased coal use.

3.2.4.4 Boilers Located in Areas Designated as Nonattainment

A boiler was assumed to be exempt from the regulatory program if located in a county that is designated as an air quality "nonattainment" area, i.e., an area not achieving current air quality standards for TSP, SO_2, or NO_2. The impact of this exemption was estimated for each Air Quality Control Region (AQCR). The projected combustors were allocated among AQCRs based on historical patterns of location of industrial energy use. Any oil- and gas-fired boiler located in an AQCR designated as nonattainment was considered exempt from the program, and was blocked from converting to coal. Only portions of some AQCRs are nonattainment. In such instances, a fraction of the total oil and gas conversions to coal were blocked, based on the fraction of the region designated as nonattainment.

While this represents a substantial simplification of the environmental exemption, it is uncertain whether it represents an overstatement or an understatement of the exemption's impacts. It may overstate impacts because the possibility of purchase of offsets was not simulated and because the potential use of synthetic coal gas as an alternative was assumed not to be significant. On the other hand, no provision was made to account for other programs in the Clean Air Act, such as the program for Prevention of Significant Deterioration or other measures imposed by State Implementation Plans.

3.2.4.5 Boilers for which the Costs of Using Coal Are Substantially Higher than the Costs of Using Oil

The regulatory program permits an exemption to combustors for which the costs of using coal (including conversion costs) are "substantially higher" than the costs of using imported oil. In this analysis, the costs of using coal were considered "substantially higher" than those of using imported oil if they compared unfavorably with oil when using a fuel oil price 50 percent higher than the world oil price,* which translates to an approximately 40-50 percent difference in total costs. This artificially high oil price was used as the opportunity fuel cost for all oil-fired combustors.

In the actual regulatory process capital costs and operation and maintenance costs in the substitution of coal for oil and natural gas will be considered. The cost implications of alternate fuels also will be considered.

Other exemptions from the program due to site-specific constraints on conversion include inaccessibility of coal supplies or equipment associated with coal use, and lack of storage area for a coal pile. The costs involved in overcoming these impediments would, of course, be included in the general exemption (see description of exemptions, Section 10). Because of the obvious difficulties associated with estimating the impact of such site-specific constraints, they were not taken into account in this analysis. As a result, the degree of conversion due to the regulatory program may be overstated.

3.2.5 Major Variables

As with any attempt to simulate a complex real-world situation, this analysis entailed many oversimplifying assumptions. Two key sets of assumptions necessarily subject to a great deal of

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*The world oil price was simulated by the weighted average of residual and distillate oil plus a crude oil equalization tax (COET) of $0.21 per million Btu's.

uncertainty include those regarding the projected prices of alternative fuels and the treatment of environmental exemptions.

3.2.5.1 Prices of Oil and Gas

Fuel prices are critical to this analysis in two ways: determination of baseline conversion to coal and identification of boilers subject to the legislation. The base-case levels of industrial consumption of oil, gas, and coal would be determined by fuel prices. This, in turn, will determine the amount of boiler oil and gas use subject to regulatory legislation. The higher the baseline oil and gas prices, the greater the amount of coal that would be used in the absence of a regulatory program, and the less fossil fuel demand would be subject to conversion authority. Because the baseline used in this analysis assumed continued natural gas regulation and no real rise in the imported oil price, the baseline levels of oil and gas consumption (thus, the level of oil and gas use subject to the program) may be overstated.

The economic exemption was simulated using an estimate of the imported price of oil plus a premium (coal must "substantially exceed" the cost of using oil at world prices). The world price of oil was assumed in the PIES run to remain constant except for inflation through 1990. Any change in the price of imported oil would redefine the number of boilers considered subject to the legislation.

3.2.5.2 Environmental Exemptions

A major constraint to coal use in the future will be enforced attainment of air quality standards. In this analysis, all combustors shown technically and economically capable of burning coal and located in AQCRs considered to be in violation of air quality standards ("nonattainment") were treated as automatically exempt from the program, and were considered to be precluded from coal burning.

Each projected combustor is assigned to an AQCR solely to take account of the impact of nonattainment designations. New combustor location is based on historical patterns of industrial energy use. Future locational patterns of industrial energy use may be substantially different, partially due to nonattainment designations. Because of the enormous complexity of anticipating such shifts and the uncertain influence nonattainment designations will have, no attempt was made in this analysis to project these shifts. To the extent that actual new unit siting patterns deviate from historical trends, the oil and gas use exempt on environmental grounds will probably be overstated.

It should be emphasized that a new coal-fired boiler may be permitted to site in nonattainment areas, although more stringent environmental controls and other higher costs may have to be incurred. Since this analysis assumes that no coal-fired units could be sited in nonattainment areas, the magnitude of oil and gas use exempted on environmental grounds will tend to be overstated to an unknown extent. Future amendments of the Clean Air Act and changes to other environmental standards for water and solid waste may increase the number of exemptions due to environmental considerations.

3.2.6 1985 and 1990 Coal Use Generated by the Regulatory Program

Projected 1985 and 1990 industrial conversions from oil and gas to coal stimulated by the regulatory program are shown by demand region in Table 3.2. Although the legislation is anticipated to cause 1.35 quads of conversion to coal by 1985 (a considerable increase in industrial coal use over 1975), 1.35 quads makes up only 7 percent of the total projected U.S. steam coal demand for 1985. Total industrial regulatory conversions of 2.51 quads are only 10 percent of total U.S. steam coal demand by 1990.

3.3 COAL ORIGIN AND DESTINATION

The projected coal demand in Btu's resulting from the regulatory program was translated into coal demand by demand region in terms of tonnage for assessing various environmental impacts.

The uncertainty about specific locations of future coal production to meet additional coal demand generated by the proposed action precluded a detailed coal transportation network/assignment analysis from the scope of this study. Instead, the published results of the coal origin and destination projected to 1985 by the Bureau of Mines (BOM) (1976) was adopted to demonstrate the additional coal production by supply region required to meet the projected coal requirements resulting from the proposed action. The flow patterns of the incremental coal demand as a result of the proposed action are shown in Tables 3.4 and 3.5 assuming the stability of the coal distribution pattern of the baseline projection by the Bureau of Mines (1976).

Table 3.2. Projected Maximum Oil and Gas Savings in 1985 and 1990 Achieved as a Result of the Proposed Action[a]
(10^{15} Btu)

Demand Region[d]	1985 Increment over Base Case					1990 Increment over 1985				
	Existing		New[b]			Existing[c]		New		
	Oil	Gas	Oil	Gas	Total	Oil	Gas	Oil	Gas	Total
I	0.008	0.001	0.026	0.001	0.036	0.002	0.000	0.017	0.003	0.022
II	0.003	0.002	0.025	0.007	0.037	0.001	0.001	0.019	0.007	0.028
III	0.012	0.003	0.028	0.004	0.047	0.001	0.002	0.026	0.012	0.040
IV	0.017	0.044	0.070	0.044	0.175	0.003	0.020	0.084	0.038	0.146
V	0.069	0.035	0.009	0.003	0.116	0.000	0.003	0.022	0.004	0.029
VI	0.011	0.111	0.141	0.506	0.769	0.004	0.199	0.108	0.503	0.814
VII	0.003	0.015	0.006	0.001	0.025	0.000	0.002	0.003	0.010	0.015
VIII	0.000	0.005	0.009	0.000	0.014	0.000	0.001	0.006	0.005	0.012
IX	0.001	0.021	0.059	0.043	0.124	0.007	0.007	0.015	0.050	0.079
X	0.001	0.001	0.007	0.000	0.009	0.000	0.000	0.007	0.000	0.007
Total	0.126	0.238	0.380	0.609	1.352	0.018	0.235	0.307	0.632	1.193

[a]Assumes Best Available Control Technology (BACT) on 250 MBtu/hr, Trend-Long baseline, AQCR screen, FGD. Assumes no economic exemption unless coal is 44 percent more costly than use of imported oil. Excludes units smaller than 100 MBtu/hr and existing non-coal capable. Oil price is weighted average of distillate and residual oil plus $0.21 per million Btu's (to account for the Crude Oil Equalization Tax [COET]). Assumes utility construction with coal capability.

[b]New units are those coming on-line in 1980 and after, and include new boilers of capacity greater than 100 MBtu/hr which are economically justified in using coal or alternate fuel when the opportunity fuel cost is the imported price of oil (average of residual and distillate oil plus COET) and which are not located in nonattainment areas.

[c]Assumes existing units are those in place or scheduled to come on-line prior to 1980, and include conversions due to mixed-fuel firing (1990 only). Assumes conversions of 100 units per year.

[d]A detailed discussion of the coal demand regions used in this analysis is presented in Section 3.3.

The major coal fields of the conterminous United States are shown in Figure 3.1.

The BOM coal flow table (Bureau of Mines 1976, Table 16) is designed by coal-producing districts as origins and states as destinations. The 23 BOM districts (Fig. 3.2) are those defined in the Bituminous Coal Act of 1937. The districts were originally established to aid in formulating minimum prices of bituminous coal and lignite. Because much statistical information was compiled in terms of these districts, their use for statistical purposes has continued since the abandonment of that legislation in 1943. These districts were aggregated into eight supply regions (Fig. 3.3). The correspondence between the supply regions in this document and the BOM districts is shown in Table 3.3. The ten coal demand regions used in this analysis (Fig. 3.4) are those identified by the Department of Energy as Standard Federal Regions. In this document, the coal supply regions are referred to as Supply Regions 1 through 8, and the coal demand regions as Demand Regions I through X.

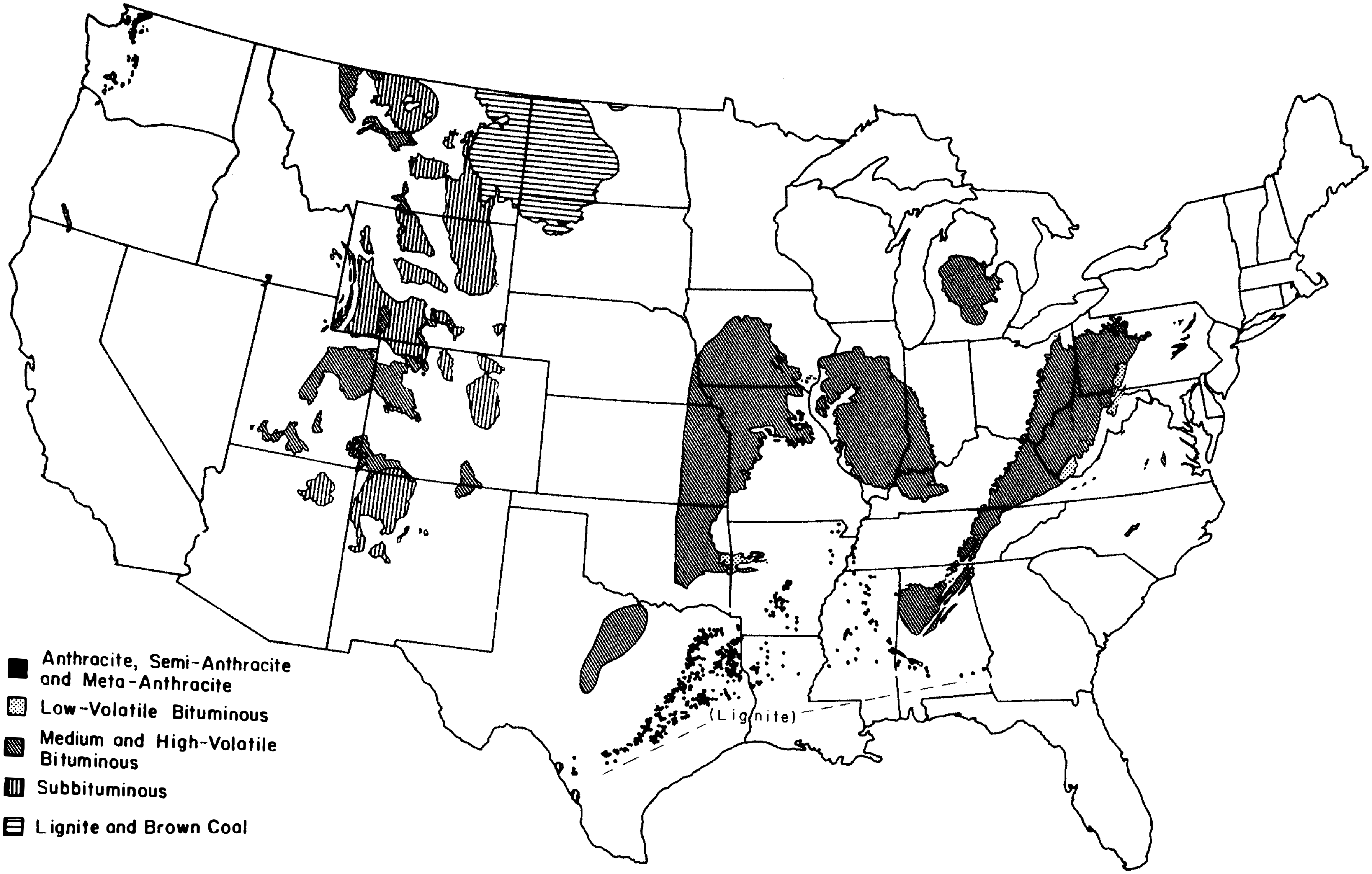

Fig. 3.1. Major Coal Fields of the Conterminous United States. Based on Keystone's Map of the Coal Fields of the United States (Keystone 1977), with permission (see credits).

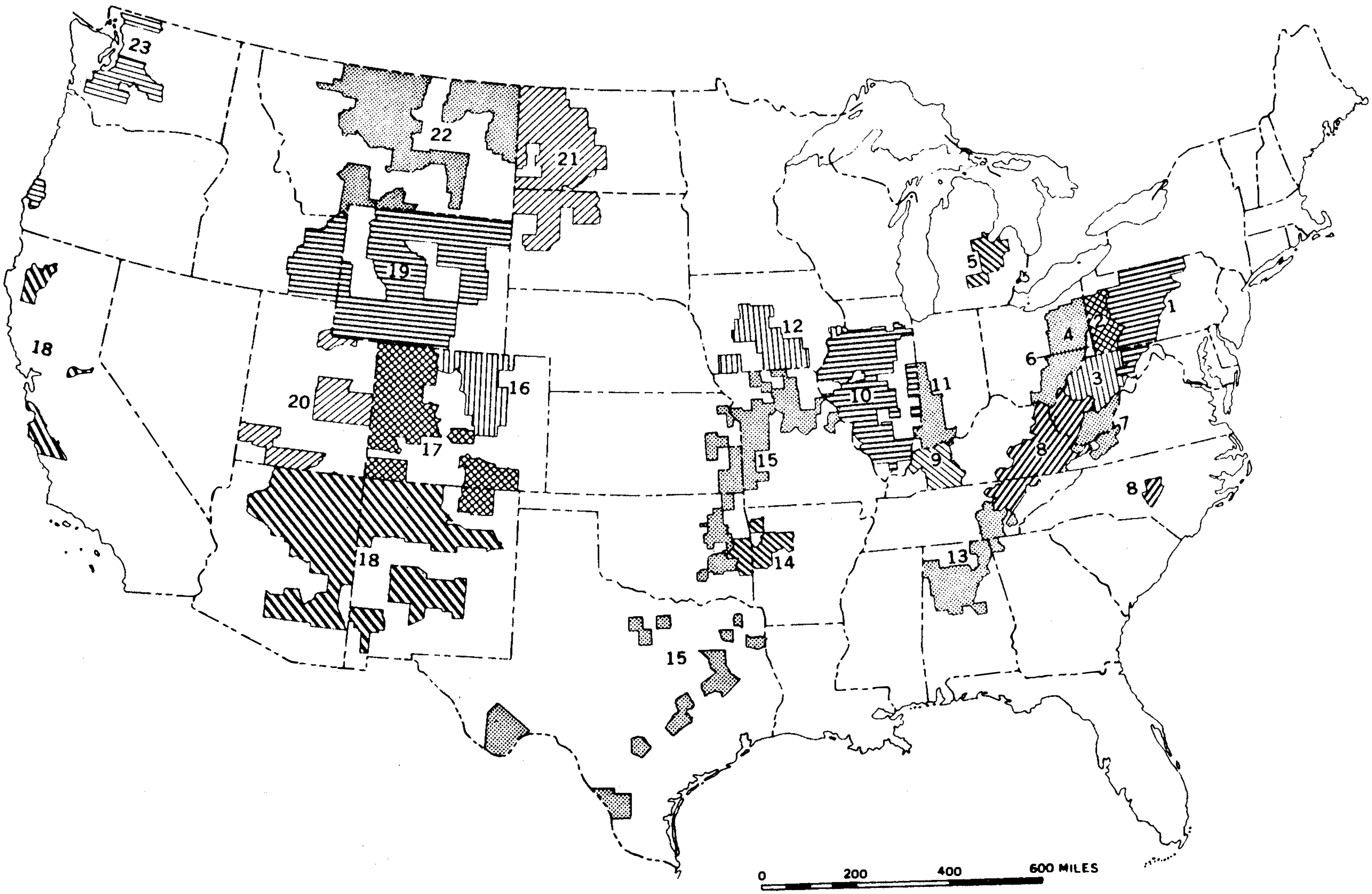

Fig. 3.2. Bureau of Mines Coal-Producing Districts. From U.S. Geological Survey (1960).

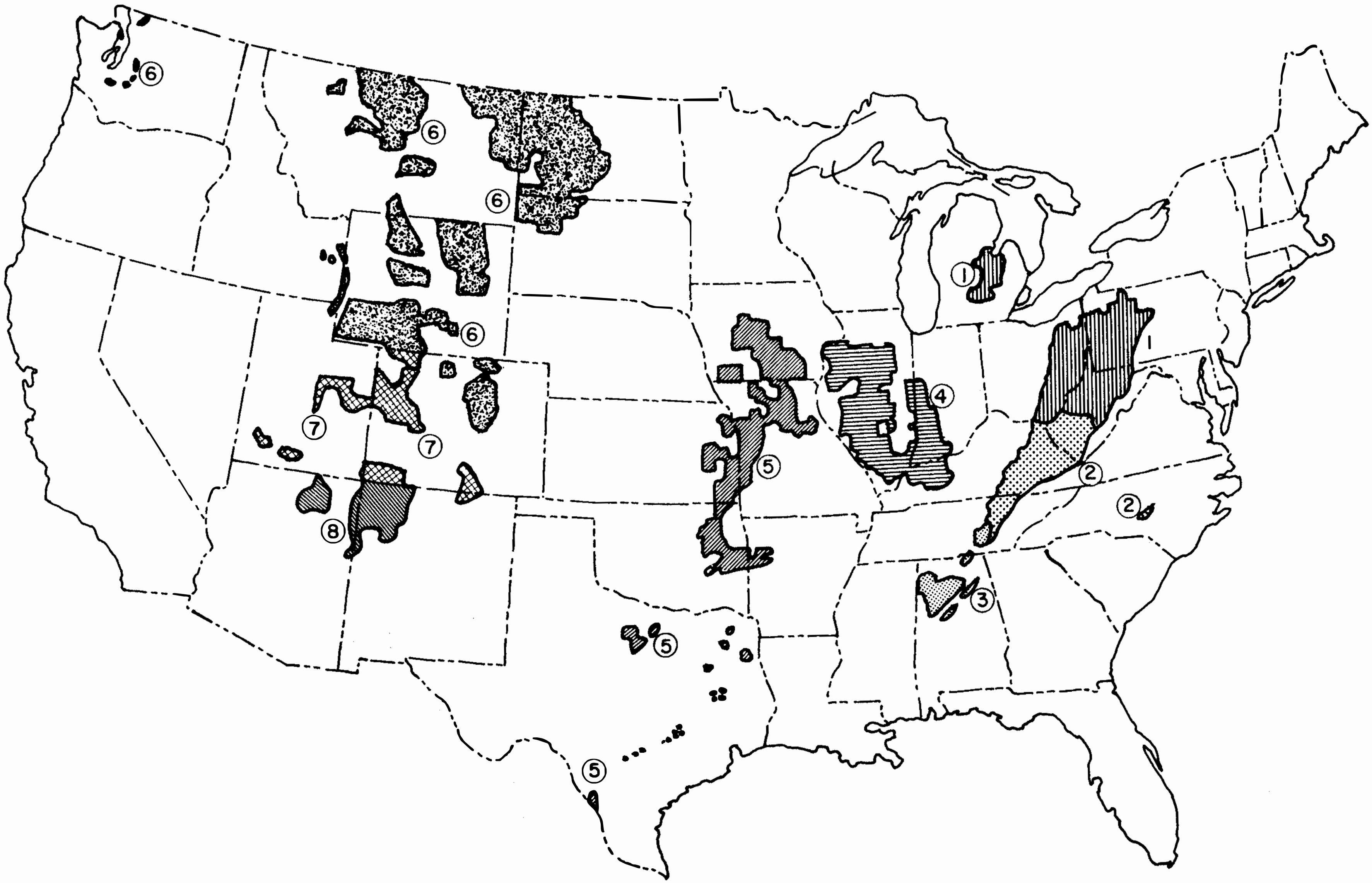

Fig. 3.3. Map of the Conterminous United States Showing Coal Supply Regions (by pattern)
Used in Fuel Conversion Analsis (Supply Regions 1 through 8)

Table 3.3. Correspondence of Bureau of Mines Districts and FUA Supply Regions

Supply Region	Geographic Area	Bureau of Mines Districts(s)	Average Btu/ton (10^6 Btu)
1	Northern Appalachia	1-6	24
2	Central Appalachia	7 & 8	24
3	Southern Appalachia	13	24
4	Midwest	9-11	22
5	Central West including Texas	12, 14, 15, and Texas	15
6	Eastern Northern Great Plains	21 & 22	18
	Western Northern Great Plains	16, 19 & 22	
	Northwest	23	
7	Rockies	17 & 20	22
8	Southwest	18	19

From Federal Energy Administration (1976).

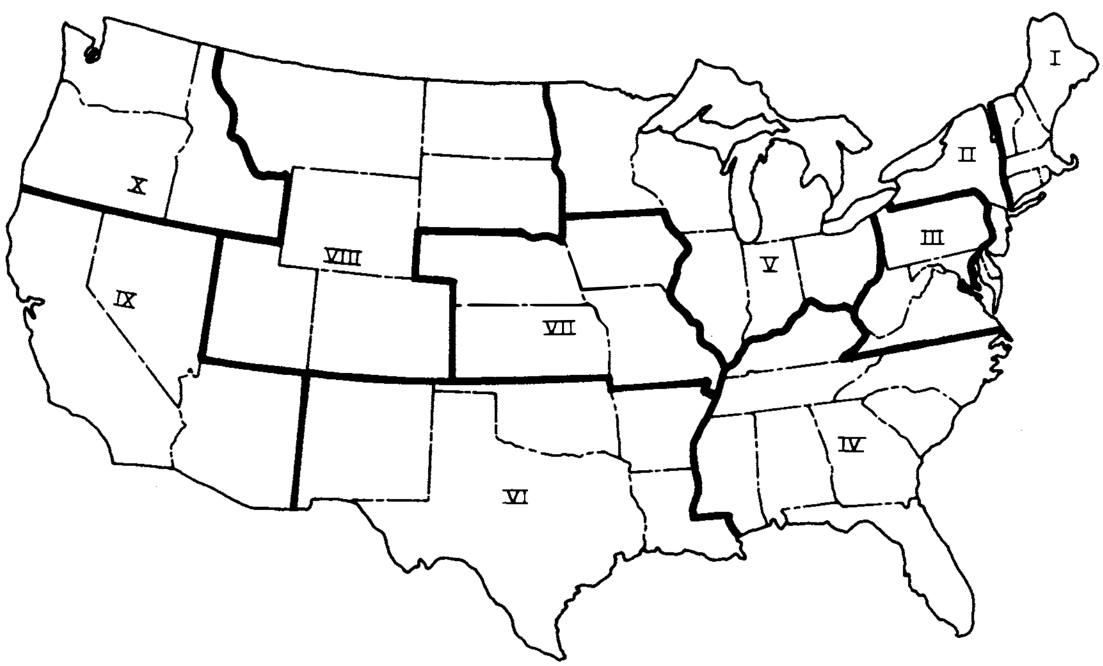

Fig. 3.4. Map of the Conterminous United States Showing Coal Demand Regions (Demand Regions I through X) Used in Fuel Conversion Analysis

The coal flows in this reconstructed matrix (Table 3.4) are defined in tonnage as in the original BOM matrix. Since the estimates of increased coal use (Table 3.2) are given in Btu's, and because the Btu content per ton of coal varies among supply regions, the tonnage values were converted to Btu's.

Table 3.4. 1985 Coal Distribution by Supply/Demand Region
(thousands of short tons)

Supply Region	Demand Region										
	I	II	III	IV	V	VI	VII	VIII	IX	X	Total
1	1,825	16,795	127,832	101	102,083	-	-	100	-	-	248,736
2	62	4,114	67,962	106,617	112,313	5,924	2,152	131	-	-	299,275
3	-	-	-	44,644	-	741	140	-	-	-	45,525
4	-	-	-	86,874	125,259	-	16,189	13	-	-	228,335
5	-	-	-	62	148	47,021	13,010	-	-	-	60,241
6	-	-	-	-	53,399	34,606	40,032	60,608	4,993	4,412	198,050
7	-	102	-	-	37	-	1,324	14,467	4,349	336	20,615
8	-	-	-	-	-	5,799	-	-	16,736	-	22,535
Total	1,887	21,011	195,794	238,298	393,239	94,091	72,847	75,319	26,078	4,748	1,123,312

From Bureau of Mines (1976), Table 16.

The coal origin/destination (O/D) coefficients were derived by dividing each entry of the Btu-based flow table (Table 3.5) by the corresponding column sum, assuming a stable coal flow pattern. Thus, the O/D coefficients (Table 3.6) represent the fractions of the additional coal shipments from coal supply region to coal demand region.

Table 3.5. Coal Distribution by Supply and Demand Region
(10^{12} Btu's)

Supply Region	Demand Region										
	I	II	III	IV	V	VI	VII	VIII	IX	X	Total
1	43.8	403.1	3,068.0	2.4	2,450.0			2.4			5,969.7
2	1.4	98.7	1,631.0	2,558.8	2,695.5	142.2	51.6	3.1			7,182.3
3				1,074.5		17.8	3.4				1,095.7
4				1,911.2	2,755.7		356.2	0.3			5,023.4
5[a]				0.9	2.2	705.3	195.2				903.6
6[a]					961.2	622.9	720.6	1,090.9	89.8	79.4	3,564.8
7		2.2			0.8		29.1	318.3	95.7	7.4	453.5
8						110.2			318.0		428.2
Total	45.2	504.0	4,699.0	5,547.8	8,865.4	1,598.4	1,356.1	1,415.0	503.5	86.8	24,621.2

[a]Weighted average (by 1985 PIES Coal Production) based on Btu's/ton of the aggregated PIES Regions.

Derived from Table 3.4 and Federal Energy Administration (1976).

Table 3.6. Coal Origin-Destination Coefficients

Supply Region	Demand Region I	II	III	IV	V	VI	VII	VIII	IX	X	Total
1	0.97	0.80	0.65	0.00	0.28			0.00			0.242
2	0.03	0.20	0.35	0.46	0.30	0.09	0.04	0.00			0.292
3				0.19		0.01	0.00				0.045
4				0.35	0.31		0.26	0.00			0.204
5				0.00	0.00	0.44	0.15				0.037
6					0.11	0.39	0.53	0.77	0.178	0.915	0.145
7		0.00			0.00		0.02	0.225	0.190	0.085	0.018
8						0.07			0.632		0.017
Total	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00

Derived from Table 3.5.

By multiplying the projected increase in coal use (as expressed in terms of Btu's; Table 3.2) by the entries of the O/D coefficient table (Table 3.6), the 1985 and 1990 coal flow patterns were derived in terms of tonnage by applying average Btu's/ton ratios (Tables 3.7 and 3.8).

Table 3.7. 1985 Origin and Destination of Coal Demanded as a Result of the Proposed Action (millions of short tons)

Supply Region	Demand Region I	II	III	IV	V	VI	VII	VIII	IX	X	Total
1	1.5	1.2	1.2		1.3			0.00			5.2
2	0.0	0.3	0.7	3.4	1.5	2.8	0.0	0.0			8.7
3				1.4		0.4	0.0				1.8
4				2.7	1.6		0.3				4.6
5						22.6	0.2				22.8
6					0.7	16.6	0.8	0.6	1.2	0.5	20.4
7		0.0					0.0	0.1	1.1	0.0	1.2
8						2.8			4.1		6.9
Total	1.5	1.5	1.9	7.5	5.1	45.2	1.3	0.7	6.4	0.5	71.6

Derived from Federal Energy Administration (1976) and Table 3.6.

Table 3.8. 1990[a] Origin and Destination of Coal Demanded as a Result of the Proposed Action (millions of short tons)

Supply Region	Federal Region I	II	III	IV	V	VI	VII	VIII	IX	X	Total
1	0.9	0.9	1.1		0.3						3.2
2		0.2	0.6	3.1	0.4	3.0					7.3
3				1.3		0.4					1.7
4				2.3	0.4		0.2				2.9
5						16.3	0.1				16.4
6					0.2	17.6	0.4	0.5	0.8	0.4	19.9
7								0.1	0.7		0.8
8						3.0			2.6		5.6
Total	0.9	1.1	1.7	6.7	1.3	40.3	0.7	0.6	4.1	0.4	57.8

From Federal Energy Administration (1976); U.S. Bureau of Mines (1976); Table 3.5-1 in Sec. 3.5.

[a]1990 data shown are the increment over 1985.

The incremental coal demand projected as a result of the proposed action is compared to 1985 base case production by supply region for both 1985 and 1990 in Table 3.9. Nationally, the increase is 7 percent over base case in 1985 and 10 percent in 1990. The total in 1990 reflects the cumulative demand for both time periods. The greatest relative increase over base case is in Supply Region 5 (41 percent) followed by Supply Region 8 (25 percent) and Supply Region 3 (18 percent).

Table 3.9. Projected Base-case Production and Production Expected to Result from the Proposed Action According to Supply Region and Method of Mining (10^6 ton/yr)

Supply Region	Base-case Production[a] 1985 Under-ground	1985 Surface	1990 Under-ground	1990 Surface	Production Resulting from Proposed Action[b] 1985 Under-ground	1985 Surface	1990 Under-ground	1990 Surface	Proposed Action/Base Case (%) 1985 Under-ground	1985 Surface	1990 Under-ground	1990 Surface
1	86	79	143	70	3	2	6	3	3	3	4	4
2	189	86	190	80	6	3	11	5	3	3	6	6
3	9	12	9	10	1	1	2	2	9	8	18	18
4	117	109	134	109	2	2	4	3	2	2	3	3
5	2	60	6	91	1	22	2	37	36	37	41	41
6	0	271	6	329	0	20	1	39	7	7	12	12
7	15	9	15	13	1	1	1	1	5	6	7	7
8	1	45	1	49	0	7	0	12	15	15	25	25
Subtotal	419	671	504	751	14	58	27	102	3[c]	9[c]	5[c]	13[c]
Total	1080		1255		72		129		7[c]		10	

[a]From Energy Information (1978).

[b]From Tables 3.7 and 3.8. Proportion of surface mining resulting from the proposed action was assumed to equal the proportion of base-case surface mining.

[c]Weighted average.

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4. DESCRIPTION OF THE EXISTING ENVIRONMENT EXPECTED TO BE AFFECTED BY THE PROPOSED ACTION

The information set forth within this section provides both past and present data on those aspects of the environment which could be affected by the proposed action. Because the proposed action involves the increased use of coal, the major environmental parameters discussed are those affected by the coal cycle--air quality, water quality, land use, and biotic resources. Data on recent coal production and available coal reserves are also presented. The discussion of these parameters is based on the most recent data available, with the intent of describing how the use of coal has and is presently affecting the environment.

4.1 TRANSPORTATION

Between 600 and 700 million tons of coal are moved each year by the U.S. transportation industry. The modes of transportation used to transport coal and the approximate percentage of coal moved by each mode are presented in Table 4.1. A more detailed description of coal transportation is presented in Appendix E.2.4.

Table 4.1 Modes of Coal Transport and Percentages of Coal Transported

Mode	% of Total
Railroad	65[a]
Barges and ships	11
Coal slurry pipeline	1
Trucks and overland belt conveyors	b/

[a]Percentage represents coal moved at least partially by rail.

[b]Trucks and overland belt conveyors are used primarily for short-distance hauls, and coal transported by these modes is usually transported by water or rail, also. Thus, any percentage given would not be meaningful.

4.2 AIR QUALITY

4.2.1 Historical and Seasonal Trends

Although some states and municipalities made quantitative measurements of air quality, there was no concerted national effort to determine the existing quality of the atmosphere until 1970. Since 1970, national emissions of total suspended particulates (TSP), oxides of sulfur (SO_x), oxides of nitrogen (NO_x), hydrocarbons (HC), and carbon monoxide (CO) have been estimated by the U.S. Environmental Protection Agency (EPA) (USEPA 1976). In addition to estimating emissions, the EPA measures ground-level concentrations of TSP, SO_2, NO_2, CO, and ozone (O_3). TSP and CO ground-level concentrations are measured as direct emission products. SO_2 and NO_2 air concentrations are measured because they are most representative of the entire family of oxides of sulfur and nitrogen, respectively. Ozone, a secondary pollutant, is an indicator of hydrocarbons;

no reliable techniques for direct measurements of ambient hydrocarbon concentrations are available (USEPA 1975). National emission estimates from 1970 to 1976 are summarized in Table 4.2. Carbon monoxide, hydrocarbons, and photochemical oxidants are all important pollutants associated primarily with vehicle emissions. Data on emissions of hydrocarbons and carbon monoxide are presented in Table 4.2. Photochemical oxidants, of which ozone is the most commonly measured, result from complicated chemical reactions involving hydrocarbons, NO_x, and sunlight (USEPA 1977). More stringent emission standards from motor vehicles have caused decreased emissions of HC and CO.

Individual states are required to submit plans to implement the Clean Air Act. For those areas presently not meeting ambient air quality standards, projected dates of compliance are required. By 1985, all areas in the nation are to meet ambient air quality standards.

Table 4.2. Summary of National Emission Estimates, 1970-1976 (10^6 short tons/yr)

Year	TSP	SO_x	NO_x	HC	CO
1970	24.9	32.1	22.5	32.7	110.0
1971	23.6	30.8	23.5	32.3	110.5
1972	22.4	31.7	24.5	32.7	112.4
1973	21.9	32.7	25.2	32.8	108.4
1974	19.3	31.1	24.9	32.6	100.9
1975	15.9	28.3	24.5	28.9	94.7
1976	14.8	29.7	25.4	30.8	96.1

From U.S. Environmental Protection Agency (1976).

4.2.1.1 Total Suspended Particulates

As shown in Table 4.2, anthropogenic (man-made) TSP emissions have decreased by 41 percent from 1970 through 1976, primarily as a result of the installation of particulate control equipment on industrial and utility facilities and a decrease in the burning of solid wastes (Federal Energy Administration 1977). The trends in TSP emissions by major source category since 1970 are shown in Figure 4.1.

National estimates of anthropogenic TSP emissions by demand region for 1975 are shown in Figure 4.2. As the anthropogenic emissions of TSP have declined, a general nationwide improvement in the measured levels of ambient concentrations of TSP has been noted, as seen in Figure 4.3, which is a presentation of national measured TSP ground-level concentrations. A map of the national maximum measured annual average concentrations of TSP due to all sources is presented as Figure 4.4. By comparing Figure 4.2 to Figure 4.4, it can be seen that those areas with high ground-level TSP concentrations in demand regions I-IV, VIII, and X are a result of the high levels of anthropogenic emissions noted in Figure 4.2. However, high concentrations in Regions VI, VII, and IX are generally due to windblown dust. Regional trends in measured TSP concentrations are presented in Figure 4.5. Because emission controls have been placed on many fuel-burning installations, decreases in measured TSP concentrations have been noted in the northeast and Great Lakes regions. Windblown dust is not amenable to man-made controls, and TSP concentrations have not decreased significantly in the west and southwest.

4.2.1.2 Sulfur Dioxide

As shown in Table 4.2, total emissions of sulfur dioxide (SO_2) from 1970 to 1976 have declined by about 8 percent, due primarily to the burning of low-sulfur coal, decreased coal use by the industrial sector, and increased sulfur removal at non-ferrous smelters, and increased sulfur removal at power plants (USEPA 1976). The trends in SO_x emissions by major source category are presented in Figure 4.6, while estimates of 1975 national emissions of SO_x are shown in Figure 4.7. Ground-level measurements of SO_2 concentrations have shown general improvement, as can be noted from Figure 4.8. National measurements of the second highest 24-hr maximum SO_2 concentrations, chosen by the EPA as a representative indicator of SO_2 levels, are presented on a county basis in Figure 4.9. Those areas in Figure 4.9 that have high measured concentrations are closely related to the areas of high SO_x emissions shown in Figure 4.7.

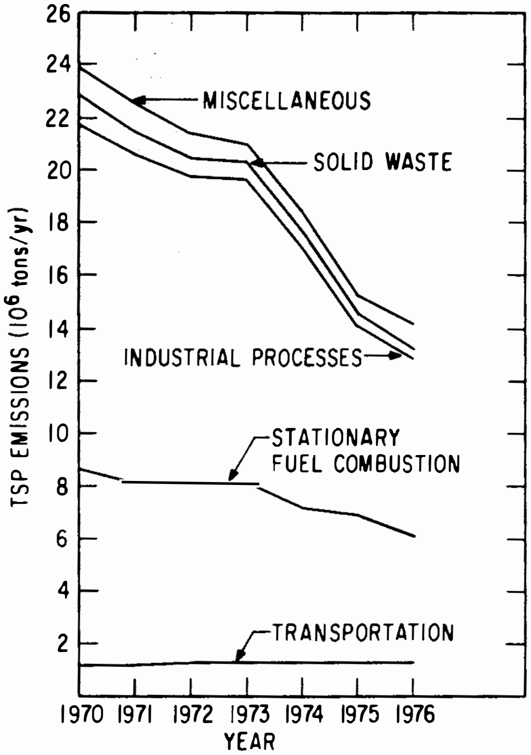

Fig. 4.1.

National Total Suspended Particulate (TSP) Emissions, 1970-1976. Data from USEPA (1976).

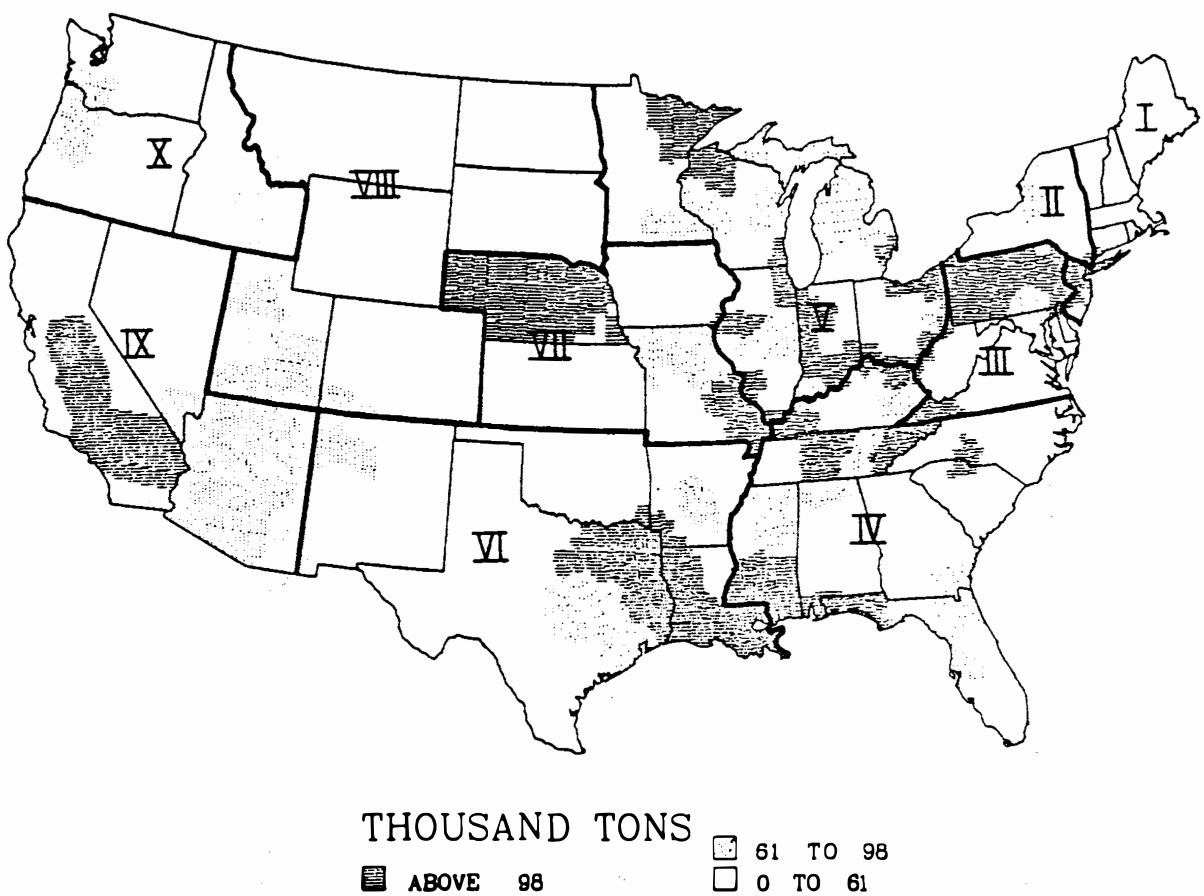

Fig. 4.2. National Anthropogenic Total Suspended Particulate (TSP) Emissions by Demand Region, 1975. Modified from Pechan (1977).

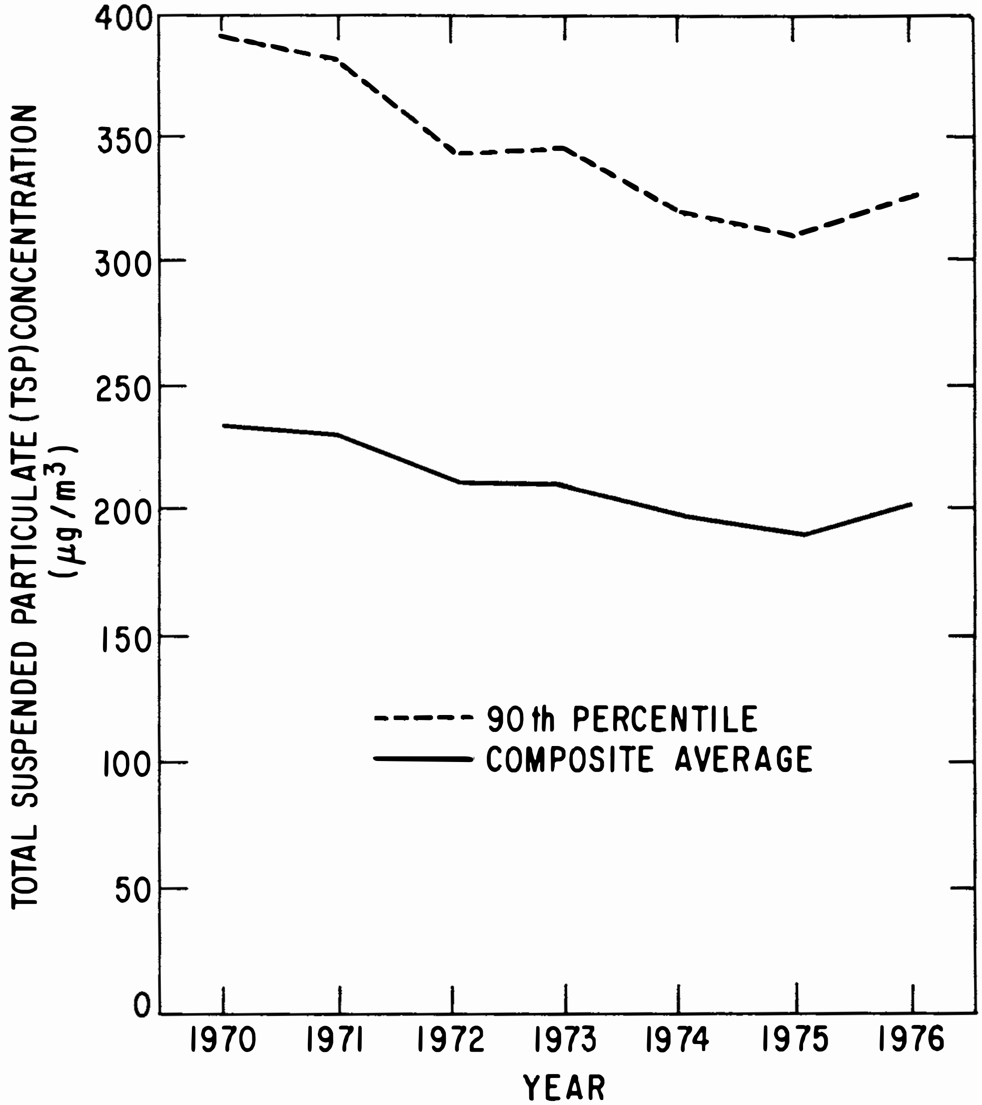

Fig. 4.3. Trends of Peak Daily Total Suspended Particulate Concentrations from 1970 to 1976 at 2350 Sampling Sites. The 90th percentile is that value at which 10 percent of the data are higher and 89 percent are lower. Data from USEPA (1976).

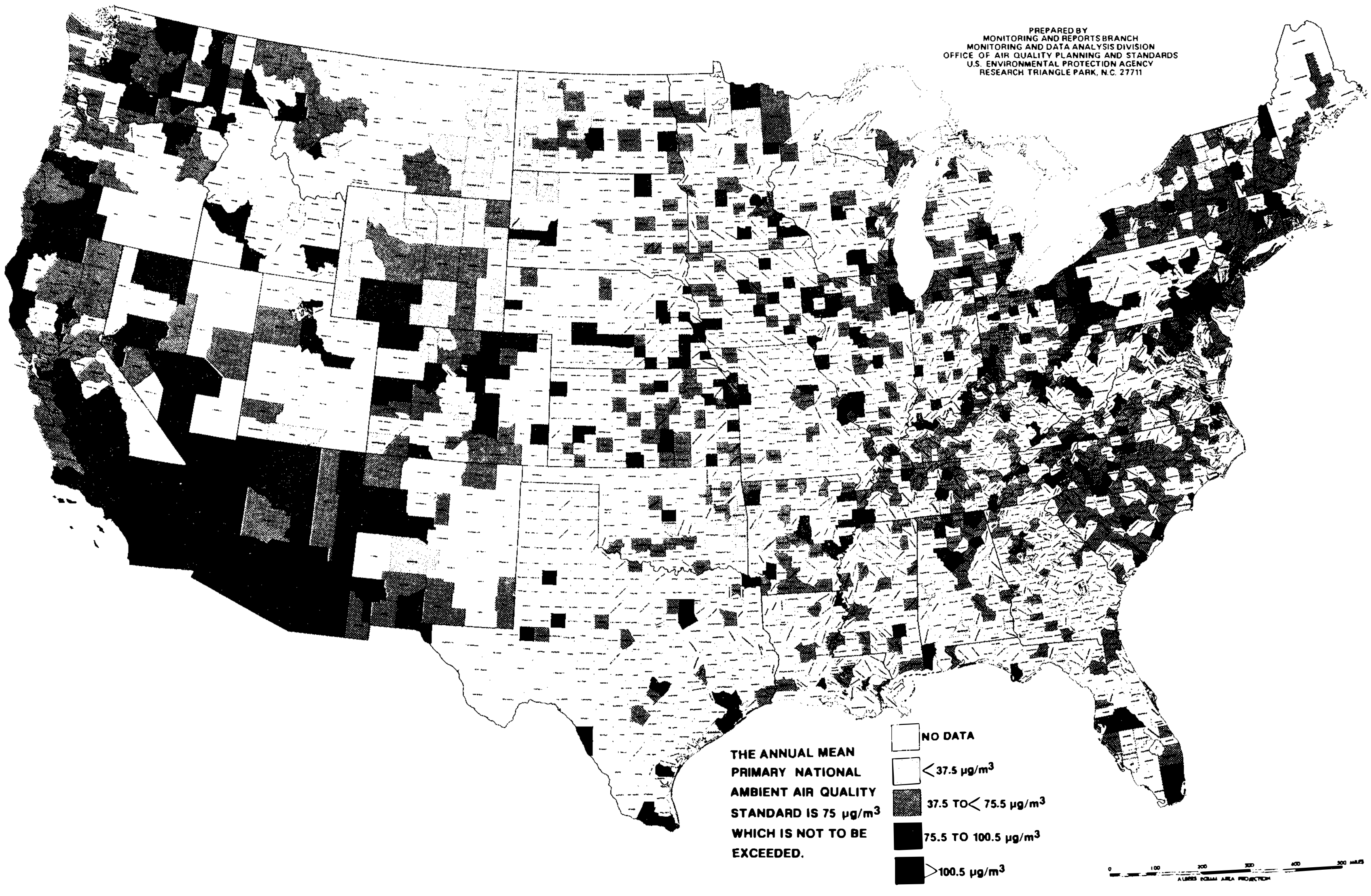

Fig. 4.4. National Total Suspended Particulate Maximum Annual Average by County, 1974-1976

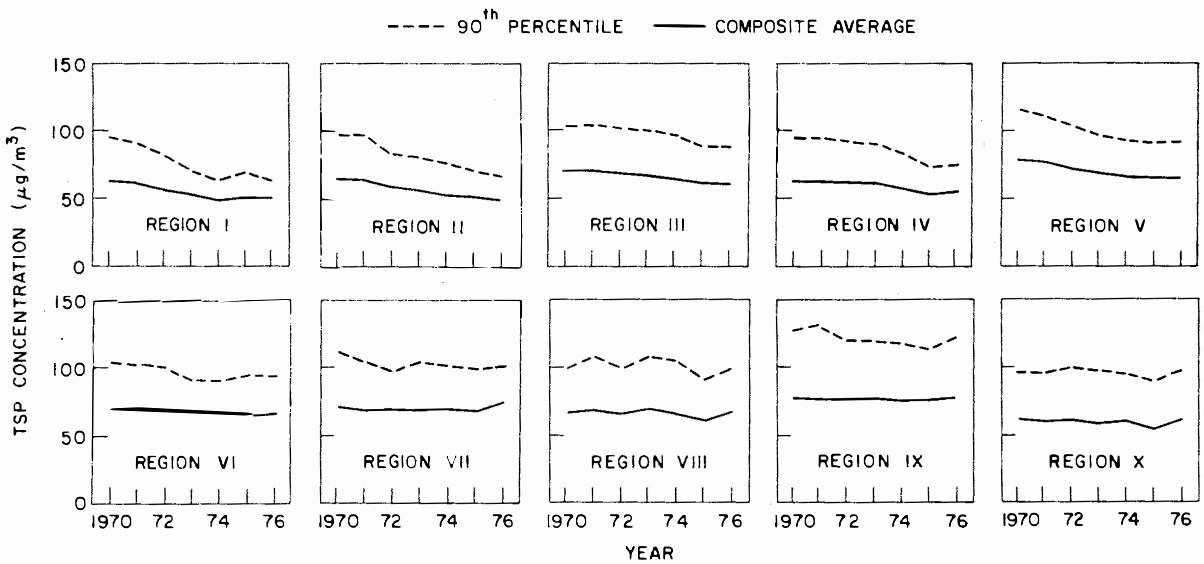

Fig. 4.5. Trends of Annual Mean Total Suspended Particulate Concentrations by Demand Region, 1970-1976. Modified from USEPA (1976).

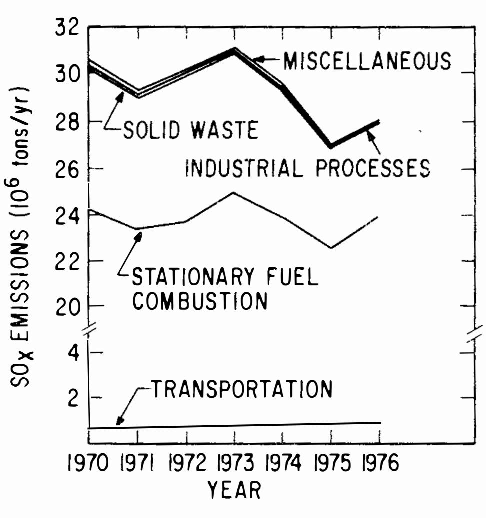

Fig. 4.6.

National Total Suspended Sulfur Oxide (SO_x) Emissions, 1970-1976. Data from USEPA (1976).

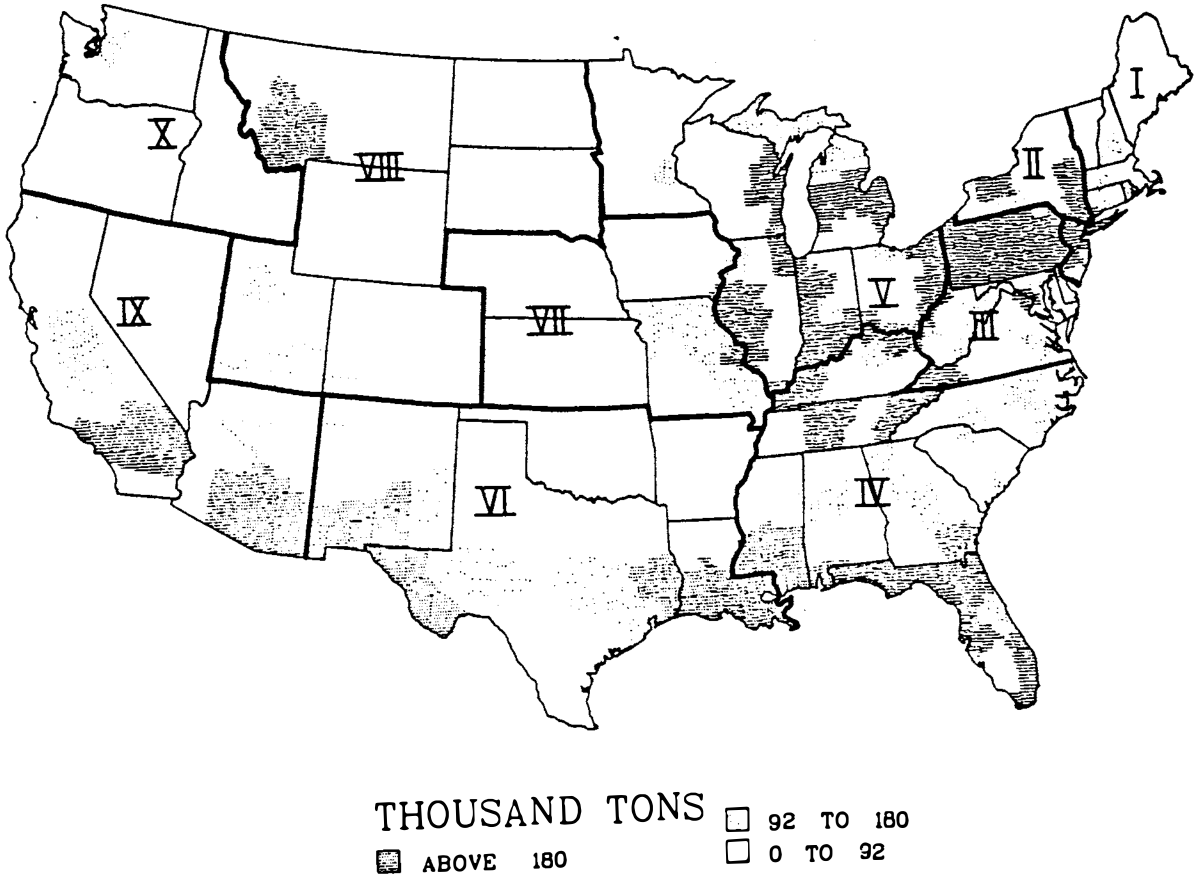

Fig. 4.7. National Sulfur Oxide (SO_x) Emissions by AQCR within Demand Region, 1975. Modified from Pechan (1977).

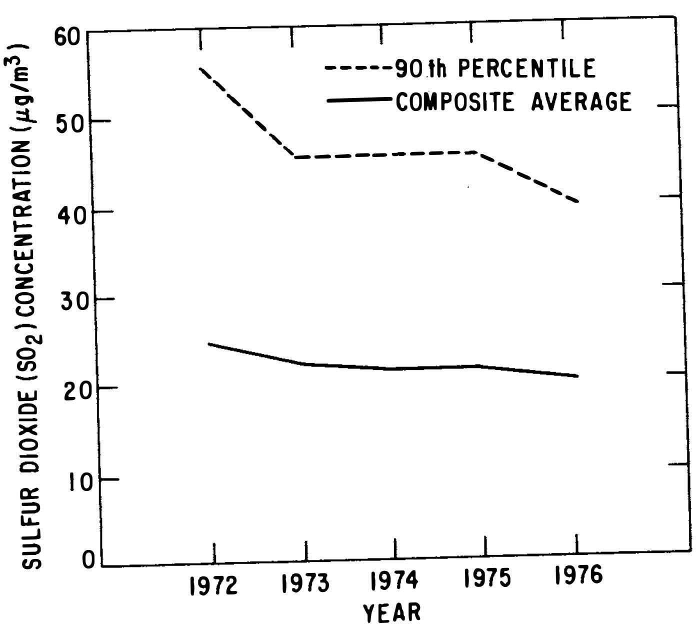

Fig. 4.8. Trends of Annual Mean Sulfur Dioxide Concentrations from 1972 to 1976 at 722 Sampling Sites. Data from USEPA (1976).

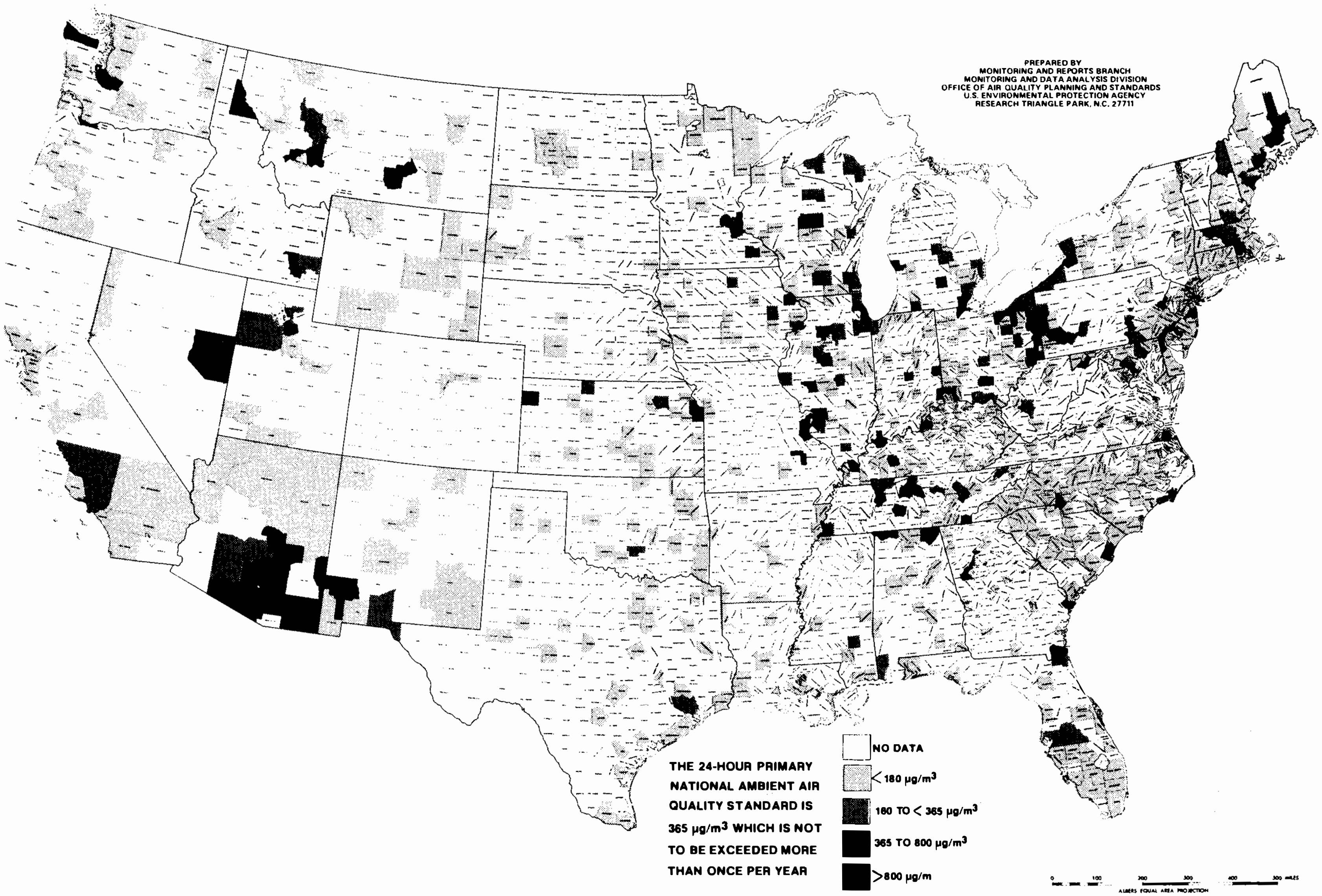

Fig. 4.9. Sulfur Dioxide Second Maximum 24-hour Average by County, 1974-1976.

High ground-level concentrations of SO_2 are generally associated with urban industrial areas or point source emitters, such as smelters and power plants, and are thus extremely local and dependent upon emission rates and emission controls. However, SO_2 emitted high into the atmosphere by tall stacks may be transported great distances and transformed into sulfates and other forms of sulfur by complicated chemical processes. These sulfur compounds are removed from the atmosphere by precipitation scavenging and dry deposition. A further discussion of this phenomenon is found in Section 4.2.1.5.

4.2.1.3 Nitrogen Oxides

Nitrogen oxides (NO_x) are formed during combustion at high temperature. Emissions of NO_x have increased by 13 percent since 1970 (Table 4.2), due primarily to increases from motor vehicles and electric power production (Federal Energy Administration 1977). The trends in NO_x emissions by major source category are presented in Figure 4.10, where it can be seen that transportation and stationary fuel combustion dominate. National estimates of 1975 NO_x emissions are shown in Figure 4.11. Unfortunately, few historical data on ambient NO_x concentrations are available. Table 4.3 is a listing of those areas with sufficient historical data to permit detection of a trend in measured concentrations from 1970 to 1976. These areas are generally associated with heavy automobile traffic, but it is likely that ambient levels of NO_x have also increased in industrialized regions due to increased stationary fuel combustion.

4.2.1.4 Meteorological Effects

Although national emissions of TSP, SO_x, HC, and CO have decreased and emissions of NO_x have increased, large daily and annual variations in the concentrations measured by local receptors have been noted. Additional problems in interpreting air quality data arise due to the nature of AQCR violations. If any receptor in an AQCR measures concentrations above a standard for a measuring period, the entire AQCR or a portion of an AQCR is reported to be in violation, when the high concentrations may exist in only a small fraction of the AQCR. Ground-level concentrations of the criteria pollutants are generally a local problem due to a single point source or a heavily industrialized sector. (A point source is an individual, identifiable emitter of pollution, such as a plant stack. A non-point source is a group of pollution emitters, such as an urban region, or an area of pollution-emitting material, such as a coal mine.) As more facilities come into compliance with emission limits, air quality over a region generally improves, even though localized effects may cause standards to be exceeded in local areas.

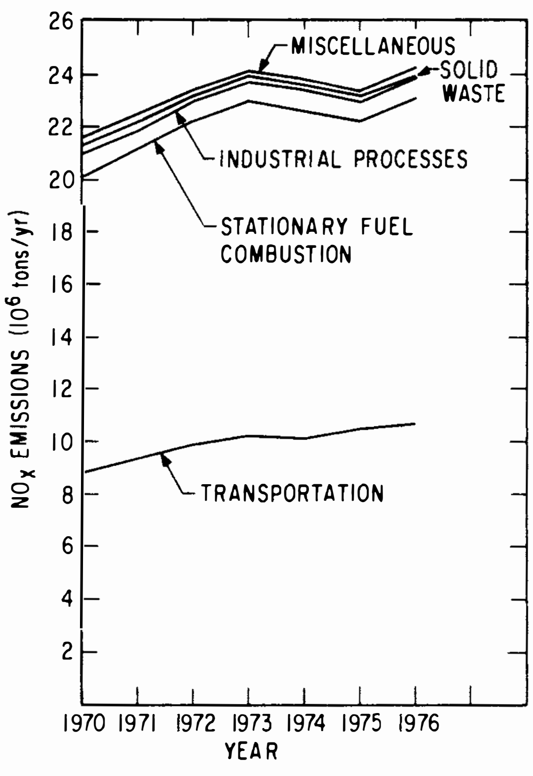

Fig. 4.10.

National Nitrogen Oxide (NO_x) Emissions, 1970-1976. Data from USEPA (1976).

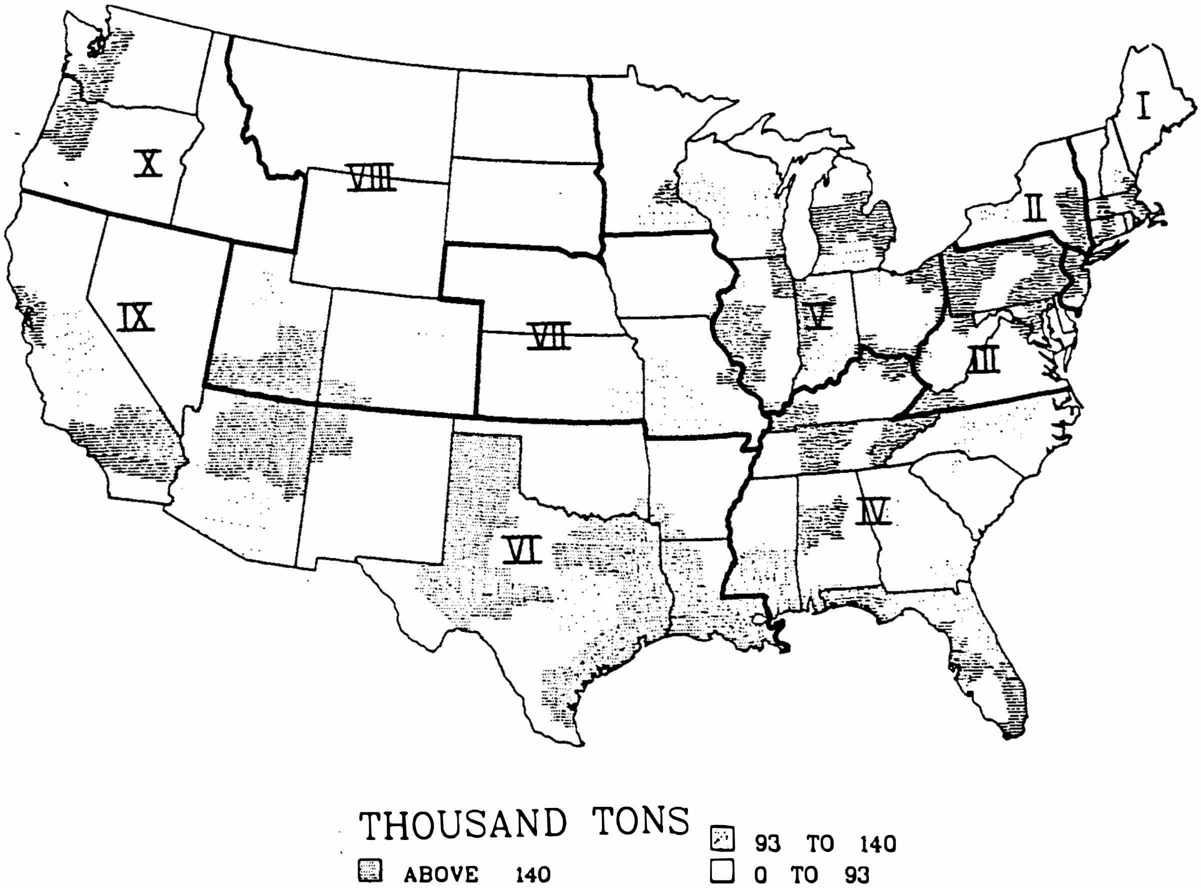

Fig. 4.11. National Nitrogen Oxide (NO_x) Emissions by AQCR within Demand Region, 1975. Modified from Pechan (1977).

Table 4.3. Nitrogen Dioxide Trends in Annual Arithmetic Mean, 1970-1976

Direction of Trend	California Sites	Non-California Sites	Total
Downward	19	77	96
No direction	4	12	16
Upward	19	145	164
Total	42	234	276

From U.S. Environmental Protection Agency (1976).

As noted in Section 4.2.1.1, there is no absolute correlation between emissions (Figure 4.2) and measured ground-level concentrations (Figure 4.4). The dispersion of pollutants and the atmospheric processes that occur during the travel from emission source to receptor are also of importance.

The ground-level concentrations of pollutants emitted by a coal-fired facility are the result of dilution of the combustion gases emitted from the stack during the time those gases travel from the stack to the ground. The variation in ground-level concentrations results from temporal and spatial variations of atmospheric conditions. The dispersion of the pollutants of interest and the ground-level concentrations that affect plants, animals, soils, and water surfaces are determined by the complex interaction of (1) the physical characteristics of the plant stack, (2) the physical and chemical properties of the emitted effluents, (3) the meteorological conditions at and near the site during the time the effluent travels from stack to ground-level receptor, and (4) the topography of the plant site and surrounding areas. By determining applicable values of each of these variables, estimates of ground-level concentrations resulting from plant operations can be made using suitable models.

Meteorological phenomena other than dispersion that affect ground-level concentrations include precipitation scavenging, dry deposition, and effluent transformations. Precipitation may remove gaseous, liquid, or solid effluents from the plume precipitation scavenging, thereby reducing the amount of pollutant and thus decreasing ground-level airborne concentrations (Johnson et al. 1977). Gases may adsorb onto particulate matter and fall from the plume to the soil or vegetative cover (dry deposition). In addition, other chemicals or particles in the plume or the atmosphere may react with the effluents and sunlight to form different products, or decay to stable gaseous or solid compounds (effluent transformations). Chemical reaction times are well known for certain effluents, but may be highly variable, depending upon temperature and availability of water vapor, other chemicals, sunlight, catalysts, or suitable particulates before reactions occur.

As a measure of the potential for high levels of air pollution, the U.S. EPA has measured mixing heights and wind speeds throughout the U.S. The mixing height is indicative of the vertical extent of dilution in the lower atmosphere, and can be forecast and measured with routine data. Those days with low mixing heights and light winds tend to lead to high measured values of pollutants. If such an episode lasts for more than one day, background concentrations are elevated, and the pollution problem is enhanced. Measured days of high pollution potential are shown in Figures 4.12 and 4.13. Figure 4.14 is a map of the total forecast days of high meteorological potential for air pollution. As seen in these figures, Regions III and IV have the greatest meteorological potential for severe pollution problems in the east, while Regions VIII, IX, and X lead in the west. In all of these regions, the primary cause of the potential is a high-pressure system remaining stationary for some length of time. These systems reduce vertical mixing and have light wind speeds, which reduce pollution dilution, and intense sunlight, which increases fuel burning due to increased demands on power production facilities. During prolonged pollution episodes in the past, mandatory reductions in emissions have been required.

4.2.1.5 Past Trends in Pollution-caused Phenomena

Visibility

Visibility is defined as the maximum horizontal distance at which prominent objects can be seen or can be recognized (Berry et al. 1945). Reduction in visibility is the result of scattering of light from the surfaces of airborne particles. The degree of light scattering is related to particle size, aerosol density, and thickness of the affected air mass, as well as the physical characteristics of the suspended particles. The particles can be natural, such as windblown dust or fog, or anthropogenic in origin such as smoke or chemical releases. In addition, secondary pollutants such as photochemical smog contribute to visibility reduction (Chambers 1976).

Visibility measurements are normally made by subjective observations, although instruments to measure the transmission of light through a portion of the atmosphere (transmissometers) are available (Hewson 1976). These measurements have been construed to represent the general pollution levels of the atmosphere, but the subjectivity of observers and the limited applicability of transmissometers make visibility measurements highly inaccurate for specifying the magnitude of pollution. No national standards for visibility are presently in effect, and visibility measurements are of limited usefulness in assessing the impacts of pollutant emissions or the trends in air quality.

Greenhouse Effect

Because the atmosphere is relatively transparent to solar radiation while being relatively opaque to long-wave terrestrial radiation (greenhouse effect), the earth's surface remains

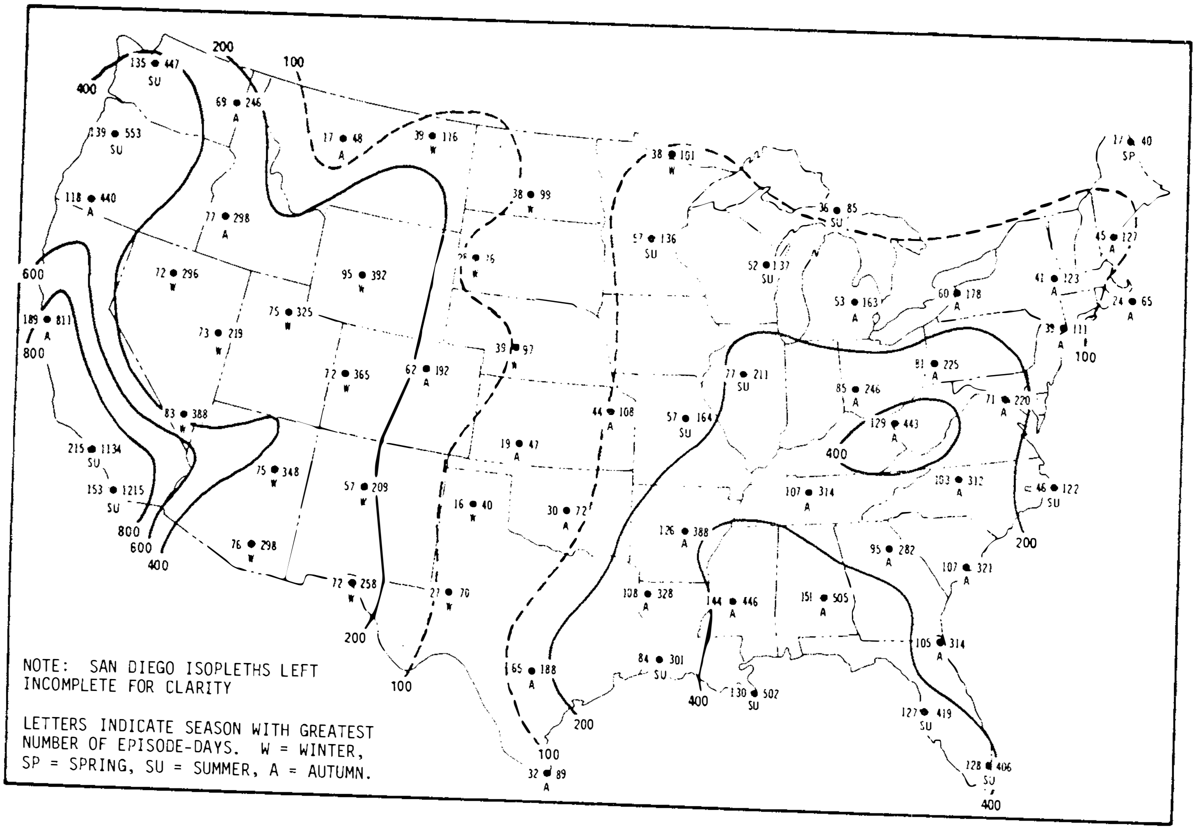

Fig. 4.12. Isopleths of Total Number of Episodes and Episode-Days in 5 Years with Mixing Heights ≤2000 m, Wind Speeds ≤6.0 m/s, and No Significant Precipitation for Episodes Lasting at Least 2 Days. From Holzworth (1972).

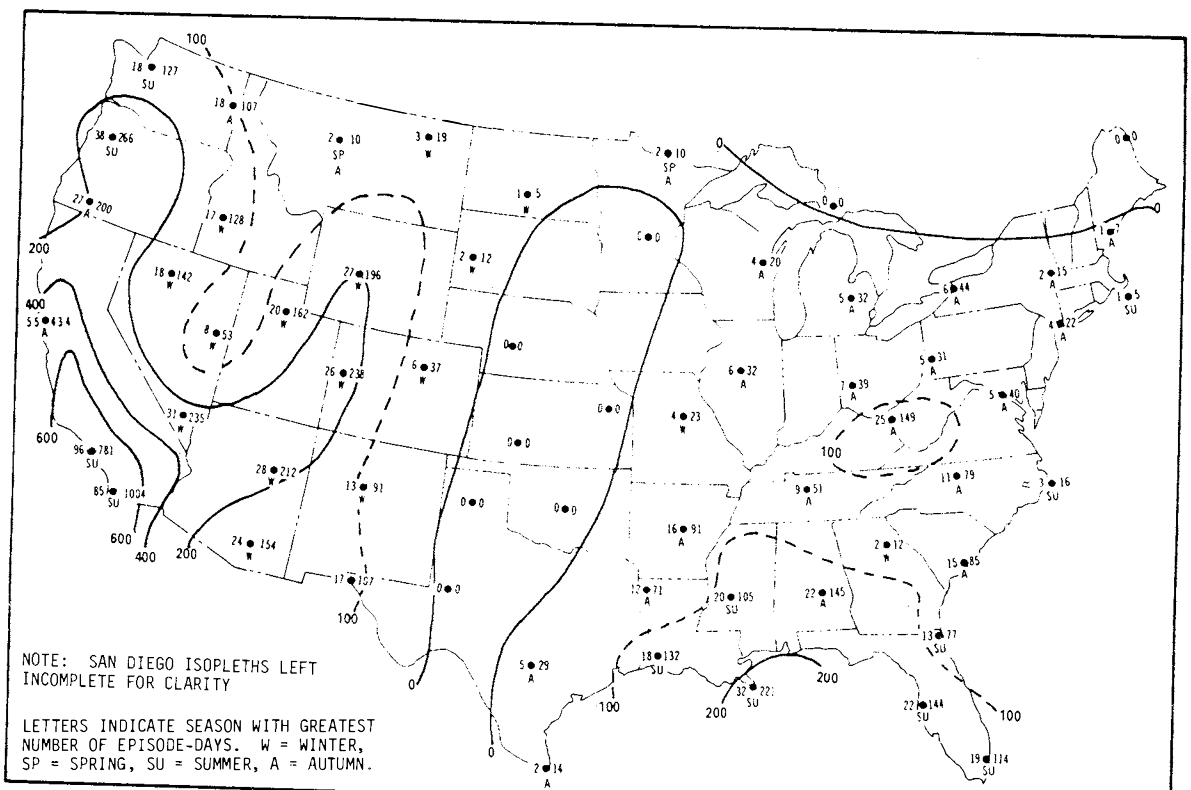

Fig. 4.13. Isopleths of Total Number of Episodes and Episode-Days in 5 Years with Mixing Heights ≤2000 m, Wind Speeds ≤6.0 m/s, and No Significant Precipitation for Episodes Lasting at Least 5 Days. From Holzworth (1972).

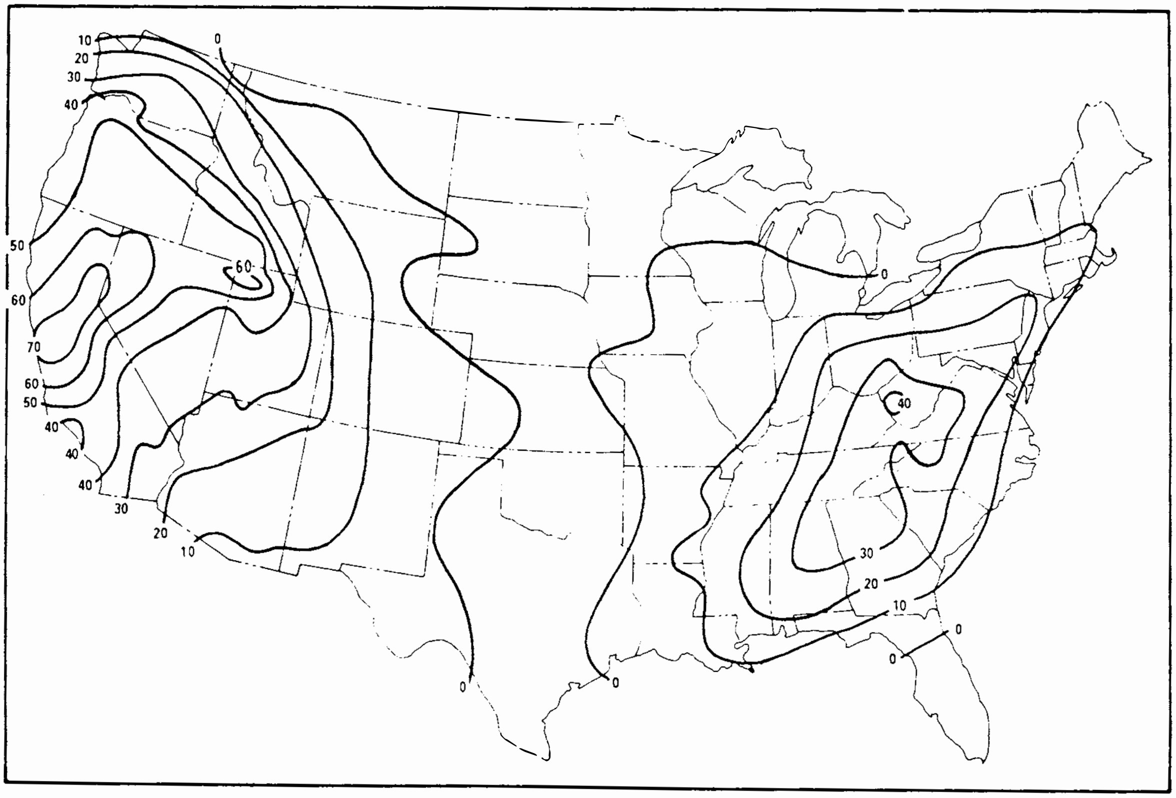

Fig. 4.14. Isopleths of Total Number of Forecast-Days of High Meteorological Potential for Air Pollution in a 5-Year Period. Data are based on forecasts issued since the program began, August 1, 1960, and October 1, 1963, for the eastern and western parts of the United States, respectively, through April 3, 1970. From Holzworth (1972).

warmer than it would if this effect did not exist. If the atmospheric concentration of CO_2 were to increase, theory predicts that the ground-level temperatures should also increase. Increased atmospheric carbon dioxide concentrations due to fossil-fuel combustion were first noted in 1940, dating from about 1860 to 1940. The trend in temperature was examined, and it was found that the average world temperature had indeed increased from 1860 to 1940. However, since 1940 CO_2 concentrations have continued to increase, while global average temperatures have decreased (Neiburger et al. 1973). Other factors must therefore be determining the earth's average temperature. Increases in the earth's temperature and the concentration of particulates could lead to increased cloudiness, increasing the amount of solar radiation reflected back to space and resulting in decreased surface temperatures. The earth's greenhouse effect is both very important and very poorly understood. The precise effects of fluctuating atmospheric CO_2 concentrations or global temperature, rainfall, and winds are unknown (McCormick and Holzworth 1976).

Acid Rain

The acidity of rain and snow falling on the United States has been rising for several decades. Evidence suggests that acid rain damages trees and other plants and is linked to sharp declines in the number of fish in streams and lakes. In addition, increased acidity accelerates weathering of buildings and corrosion of materials (Likens 1976).

Increased acidity (lowered pH) of rain is apparently due to increased contributions of strong acids (sulfuric, nitric, and hydrochloric) into the atmosphere. The major new source of these strong acids is the combustion of fossil fuels, particularly coal (see App. E and App. I).

Natural sources such as carbonic acid (from CO_2 + H_2O), salt spray, dust, and volcanic emissions, would normally be expected to produce a minimum pH of 5.6. Isopleths of the acidity of precipitation in the United States are shown in Figure 4.15. Only the eastern portions of the United States (Demand Regions I to V) are affected (1966 data). Figure 4.16 delineates this region of abnormal acidity (1973 data). There appears to be a definite trend: as burning of fossil fuels increases upwind of a region, pH of precipitation tends to decrease (Figs. 4.17 and 4.18). Coal emits greater quantities of strong acids than petroleum and far more than natural gas (App. E). Flue-gas desulfurization programs on existing facilities may slow or reverse this apparent trend.

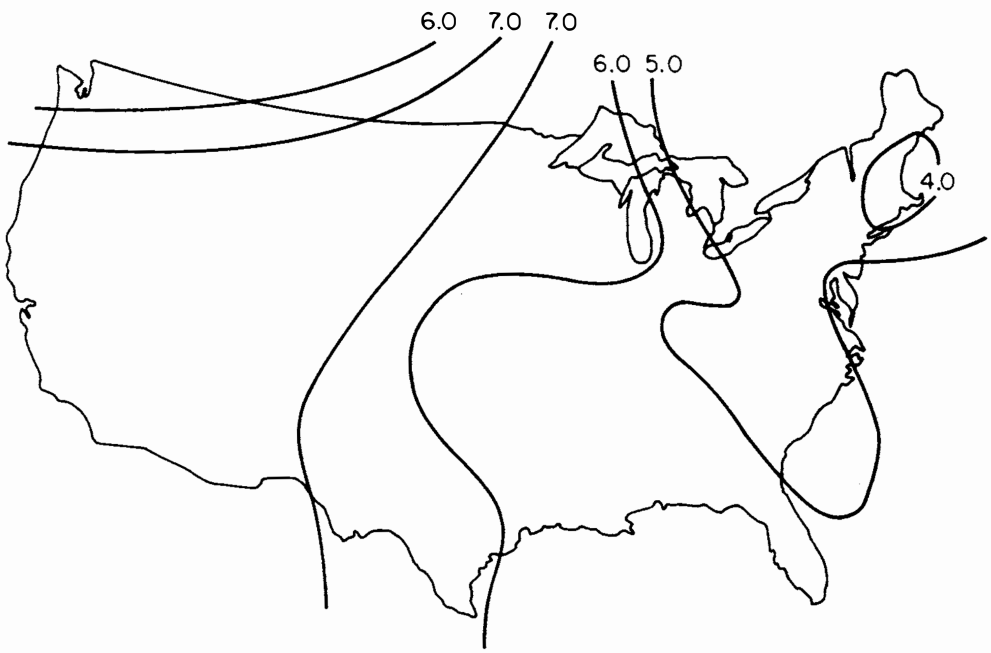

Fig. 4.15. Precipitation pH During June 1966. From Likens (1976).

Effects of acid rain on terrestrial and aquatic ecosystems are widespread, and terrestrial effects are not yet quantified. A marked decline in the pH (to less than 5.5) of thousands of lakes and rivers of southern Norway and Sweden has resulted in declines (and often elimination) of fish species, particularly trout and salmon. The number of lakes without trout has increased dramatically in the past 15 years, coinciding with a large increase in the combustion of fossil fuels. In North America, a major decline in the sport fisheries of the La Cloche Mountain Lakes of north central Ontario has also apparently resulted from acid fallout in rain and snow (Beamish and Harvey 1972). Effects of acidity on vegetation and soils are more difficult to interpret but are the subject of much concern. Acid precipitation has been implicated in increased leaching of inorganic nutrients and organic substances from foliage; accelerated cuticular erosions; leaf damage; altered response to pathogens, symbionts, and saprophytes; reduced germination of seeds and seedlings; altered availability of nutrients in the soil; decreased soil respiration; and increased leaching of ions in the soil (see review by Likens 1976).

4.3 EXISTING WATER RESOURCES, WATER QUALITY, AND WATER USE

4.3.1 Water Resource Regions

The boundaries of the Demand Regions do not necessarily reflect Water Resource Region boundaries, which are based on watersheds and stream basins (Fig. 4.19). The United States contains a diversity of water resources, both surface and underground. The characteristic surface water bodies (running waters, lakes, reservoirs, coastal bays, etc.) and groundwater aquifers found in each of the Water Resource Regions are described in Appendix F.

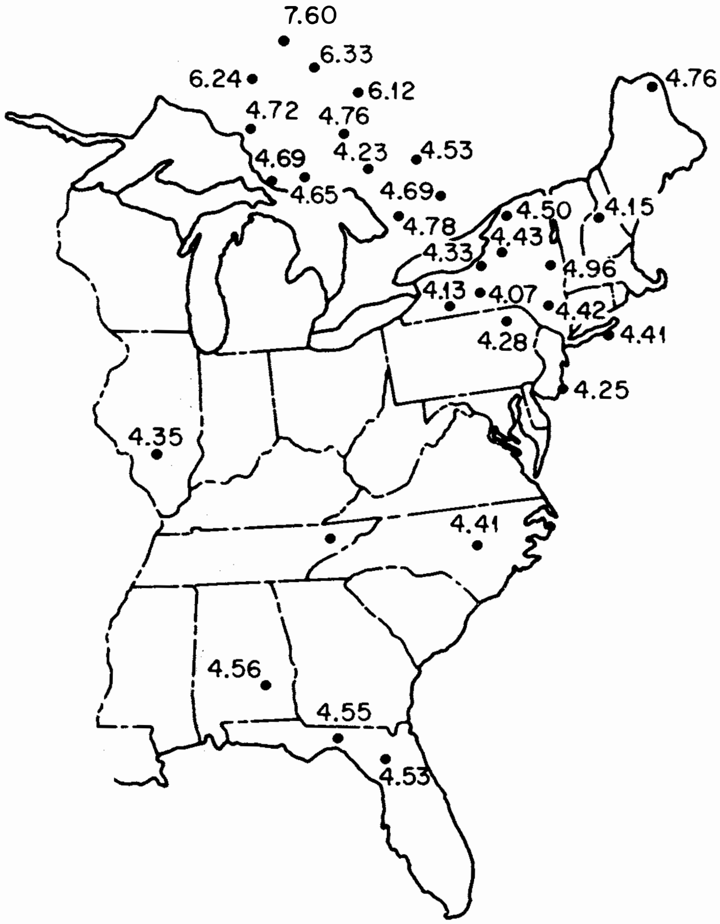

Fig. 4.16.

Precipitation pH in the Eastern United States, 1972-1973. From Likens (1976).

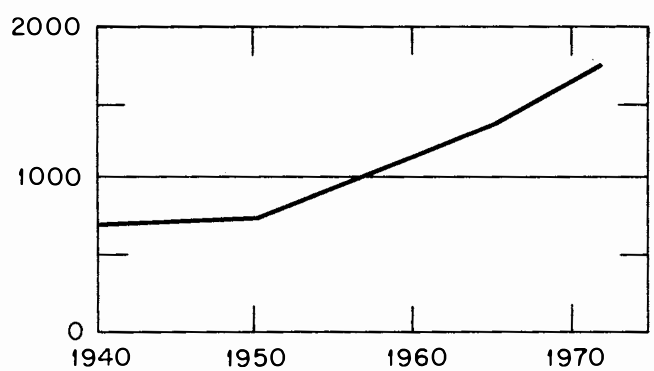

Fig. 4.17.

Coal and Oil Consumption Upwind of Norway, Millions of Tons. From Likens (1976).

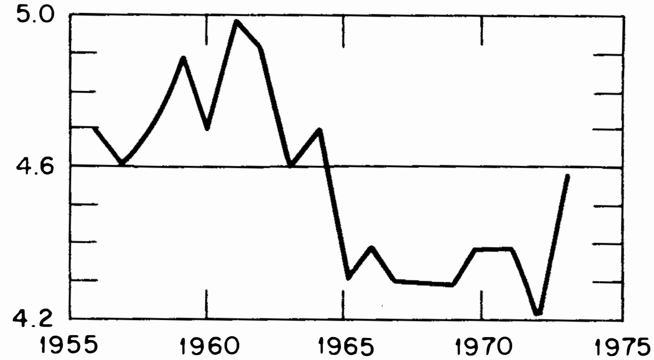

Fig. 4.18.

Annual Mean pH of Precipitation in Lista, Norway. From Likens (1976).

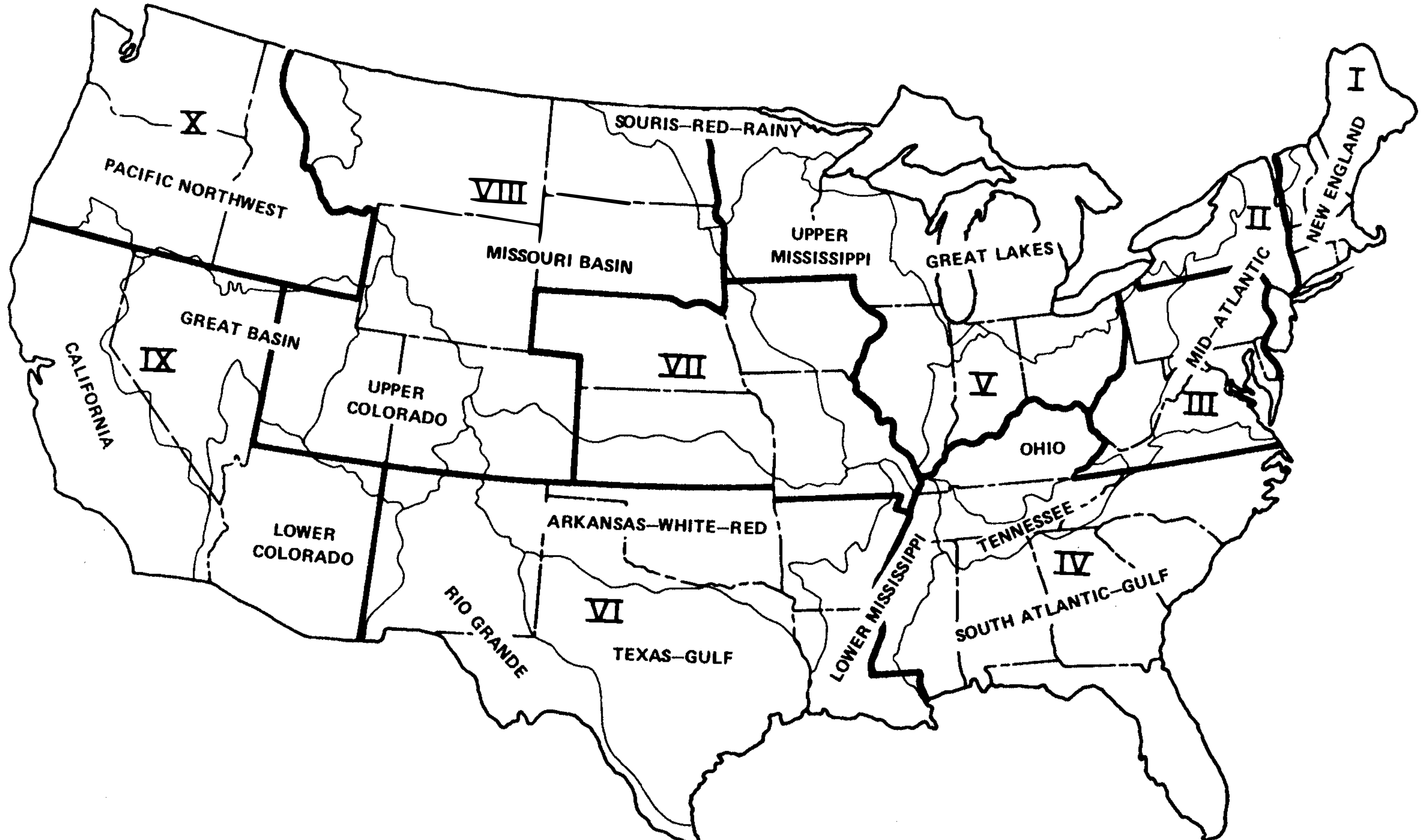

Fig. 4.19. Map of the Conterminous United States Showing Federal Regions and Water Resource Regions. Modified from U.S. Geological Survey (1977).

Generally speaking, coal resources in the eastern United States are found in areas of abundant precipitation, while the western resources are found in arid areas. The Appalachian Basin coal resources are primarily found in the Ohio, Tennessee, and South Atlantic-Gulf Water Resource Regions. Coal resources of the Illinois and Western Interior Basins are largely in the Missouri Basin, Upper Mississippi, Ohio, and Arkansas-White-Red Water Resource Regions. Further west, coal resources are primarily in the Missouri Basin, Upper Colorado, and Lower Colorado Water Resource Regions. However, coal resources are found in other Water Resource Regions, as well. Where coal mining has been cited as a contributor to regional water quality and water use problems, this has been discussed in Appendix F.

Typically, surface waters are the dominant water source in the eastern United States, whereas groundwater resources are important in the West.

Water quality problems are related to both point-source and non-point-source discharges. Point sources (e.g., industrial effluents) are amenable to control, and considerable progress has been made in their regulation. However, non-point sources (e.g., agricultural runoff) have been more difficult to control.

The discussion of environmental effects in Section 5 will be related to both Water Resource Regions and demand and supply regions, where appropriate.

4.3.2 Wild and Scenic Rivers

In accordance with the Wild and Scenic Rivers Act (Pub. L. 90-542), select river segments of the United States have been designated as wild, scenic, and/or recreational. These waters are to be preserved in a free-flowing condition, and their values (scenic, recreational, geologic, fish and wildlife, historical, or cultural) are to be protected. The categorization as wild, scenic, or recreational is a function of development and accessibility. Wild river areas are free of impoundments, and generally inaccessible except by trail, with primitive watersheds or shorelines and unpolluted waters. Scenic rivers are accessible in places by roads. Recreational river areas are readily accessible by road or railroad and may have undergone some shoreline development as well as past impoundment or diversion. In addition to the stream itself, the designated area may include a corridor up to 0.8 km (0.5 mile) in width along the bank, along the stream (U.S. Department of the Interior 1977). The river areas are to be administered so that the values causing the areas to be included in the Wild and Scenic Rivers System are protected. Primary emphasis is to be given to protecting aesthetic, scenic, historical, archaeological, and scientific features. Other uses that do not interfere with these values will not be limited.

Table 4.4 is a listing of the river segments presently included in the National Wild and Scenic Rivers System; the state, Federal Region, and Water Resources Regions (Fig. 4.19) in which they are located; and lengths of the wild, scenic, and recreational segments. In addition to these 19 segments, others are under consideration for inclusion or have been proposed for addition to the list. Many states also have wild and scenic river programs.

4.4 EXISTING LAND USE

Coal mining in the conterminous United States has had a number of important impacts on land use. Land that is mined for coal is converted from its original use to a variety of new uses, which include the excavated areas, spoil and waste disposal areas, areas for buildings and processing facilities, storage areas, and areas used for access and haul roads. The amount and type of land affected depends on the region, the type of terrain, and the type of mining operation. Indirect impacts on land use often occur on lands adjacent to those actually mined. Land slides, subsidence associated with deep mines, erosion, and acid mine drainage can often alter adjacent lands to such an extent that the use prior to mining is completely eliminated. In the past, many surface and underground mined lands have been abandoned and land use of these areas has been severely restricted. The Surface Mining Control and Reclamation Act of 1977 requires reclamation of all surface mined lands and lands disturbed at the surface by underground mining. The Act also contains a provision whereby funds will be available for reclaiming abandoned mined lands. The amount of land in need of reclamation because of coal mining is given in Table 4.5 for each of the demand regions as of 1977. These areas include both abandoned and active mine sites.

In addition to mining impacts, transportation and combustion of coal have a significant impact on land use. At the regional level, it is difficult to assess the contribution that coal transportation makes to the total transportation system. At a local level, however, the amount of land used in the construction of access roads and rail spurs for specific coal mines can be determined. Combustion of coal requires land for (1) boiler facilities, (2) storage of coal for immediate use and for reserve storage, and (3) disposal of fly ash, sludge, and other wastes produced. In heavily industrialized or urban areas where competition for land is intense, coal-burning facilities may be forced to transport wastes and reserve supplies of coal to distant locations where suitable land is available.

Table 4.4. Components of the National Wild and Scenic Rivers System

River	State	Demand Region	Water Resource Region	System (miles)[a]			
				Total	Wild	Scenic	Recreational
Clearwater, Middle Fork	ID	X	Pacific Northwest	185	54		131
Eleven Point	MO	VII	Arkansas-White-Red	44		44	
Feather	CA	IX	California	108	33	10	65
Flathead	MT	VIII	Pacific Northwest	219	98	41	80
Missouri	MT	VIII	Missouri Basin	159	72	28	59
Rapid	ID	X	Pacific Northwest	31	31		
Rio Grande	NM	VI	Rio Grande	53	52		1
Rogue	OR	X	Pacific Northwest	85	33	8	44
Salmon, Middle Fork	ID	X	Pacific Northwest	104	103		1
Snake	ID,OR	X	Pacific Northwest	67	33	34	
Allagash	ME	I	New England	95	95		
Chattooga	NC,SC,GA	IV	South Atlantic-Gulf	57	40	3	15
Little Beaver	OH	V	Ohio	33		33	
Little Miami	OH	V	Ohio	66		18	48
New	NC	IV	Ohio	27		27	
Obed	TN	IV	Tennessee	46	46		
St. Croix	MN,WI	V	Upper Mississippi	200		181	19
St. Croix, Lower	MN,WI	V	Upper Mississippi	52		12	40
Wolf	WI	V	Great Lakes	25		25	

From U.S. Department of the Interior (1977a).

[a]1 mile = 1.6 km.

Table 4.5. Lands Requiring Reclamation Because of Coal Mines[a]

Demand Regions	Land Area	
	Hectares	Acres
I		
II		
III	175,221	432,979
IV	161,109	398,108
V	216,093	533,974
VI	24,955	61,664
VII	54,984	135,869
VIII	35,409	87,498
IX	368	910
X	502	1,241
Total	668,641	1,652,243

[a]Data based on U.S. Department of Agriculture (1978).

The general pattern of land use throughout the conterminous United States is shown in Figure 4.20 by demand region. Inspection of this figure shows that land use associated with eastern coal resources is predominantly forest land. Cropland in the east ranges from 8 to 21 percent of the land use, and urban land is particularly important in the northeast. Much of the eastern coal resource is associated with hilly to mountainous terrain, which makes erosion, land slippage, and acid mine drainage important impacts on land for this area.

In the midwest, cropland is the predominant land use, although urban developments associated with the Great Lakes and the Ohio and Mississippi rivers are important features of the region. Much of the midwestern coal resource underlies agricultural land, and exploitation of coal places an additional demand on prime farmlands. The new strip-mining legislation requires that all prime farmland that is mined must be reclaimed to a level of productivity equal to or greater than that which existed prior to mining. Acid mine drainage associated with area strip-mining, contour strip-mining, and deep mining can be a severe problem in this part of the country.

The major western coal deposits are associated with rangelands in the northern plains and mountain states. The major problem associated with strip-mining in the west is the reclamation of the mined lands. The general scarcity of water and the problems associated with wind erosion place severe limitations on the success of reclamation. Where irrigation is possible or where precipitation is somewhat higher (e.g., along the eastern border of the region), successful reclamation appears to be feasible. However, in drier parts of the region, careful evaluation of reclamation potential is needed prior to permitting coal extraction. Prime farmland is a scarce commodity in the west, and exploitation of coal reserves underlying such farmland should be prohibited or very carefully controlled to avoid loss of these important lands.

A more detailed description of land use for the farm production regions of the United States is given in Appendix G.

4.5 COAL PRODUCTION AND RESOURCES

Coal deposits exist in at least 40 of the 50 states (Averitt 1975; Trumbull 1960); however, in 1975 only 26 states had producing coal mines (Mining Informational Services 1977). Coal of poor quality or such limited extent as to have questionable economic value may never be mined. The calculation of total reserves and resources excludes those deposits. Reserves are those coal deposits of sufficient quality, thickness, and extent to be economically mined at the time their quantity is estimated. Resources are all the deposits which may be economical to mine at the present or at any future time. An estimate of coal resources includes the reserves estimate. Coal reserves by state and region are quantified in the tables in this section. Estimates of known and hypothesized resources are given in the text.

Major coal fields of the conterminous United States are shown in Figure 3.1.

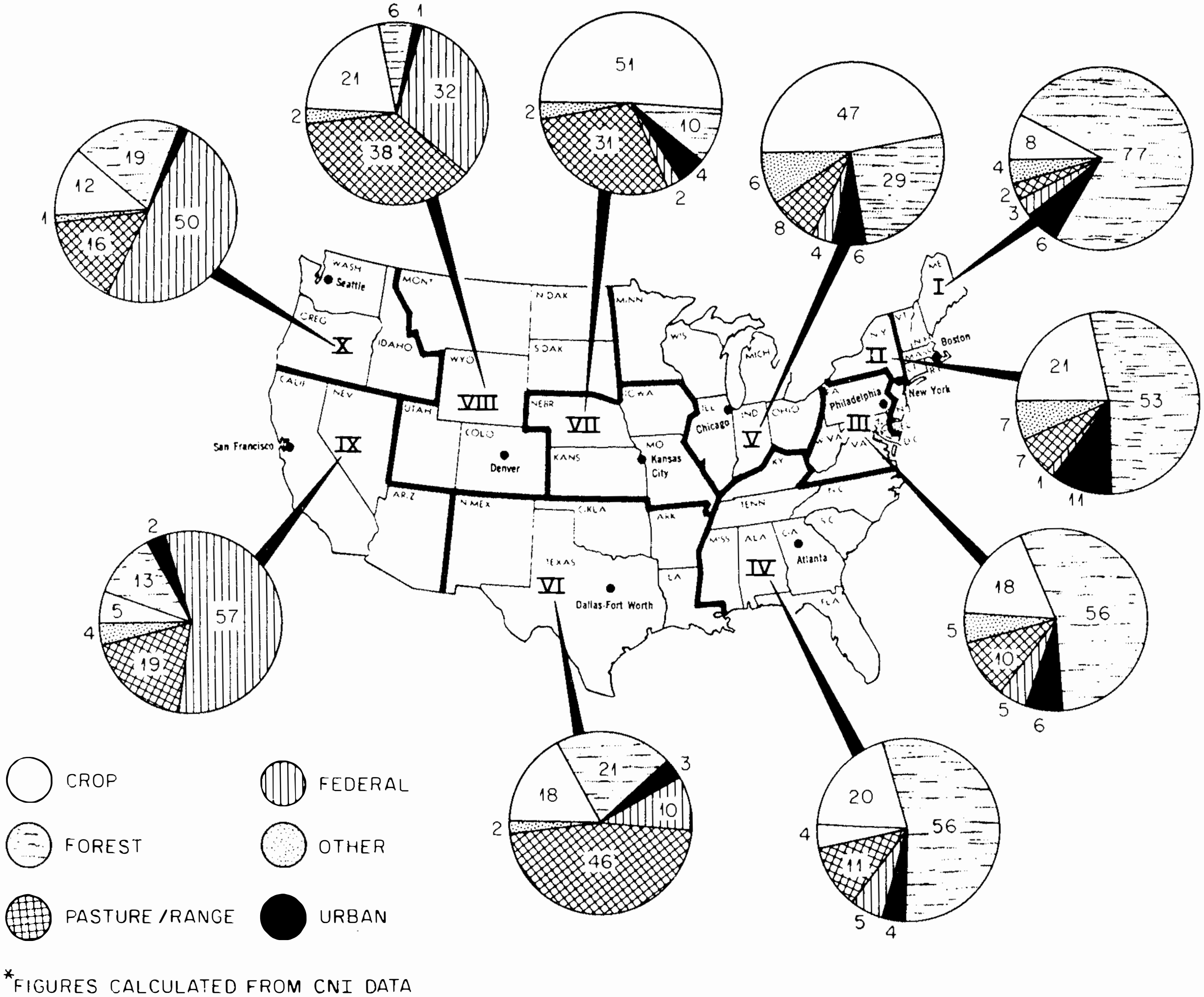

Fig. 4.20. Land Use Patterns for Demand Regions. Based on data from U.S. Department of Agriculture (1969).

4.5.1 Demand Region I (Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, Vermont)

4.5.1.1 Coal Production

At present there is no coal mining in Region I.

4.5.1.2 Coal Resources

The only coal deposits located in Region I are the anthracites in the Narragansett Basin of Massachusetts and Rhode Island. No mine development is projected between now and 1987 (Nielsen 1978).

4.5.2 Demand Region II (New York, New Jersey)

4.5.2.1 Coal Production

At present there is no coal mining in Region II.

4.5.2.2 Coal Resources

Region II coal deposits are located in the mainland portion of the region, underlying 10 square miles of the state of New York (U.S. Bureau of the Census 1973) and a small area in New Jersey. Reserves are so small as to not be included in the U.S. Bureau of Mines totals (Mining Informational Services 1977).

4.5.3 Demand Region III (Delaware, Maryland, Pennsylvania, Virginia, Washington, D. C., West Virginia)

4.5.3.1 Coal Production

The bulk of the coal located in Region III is deposited in a thick, continuous sequence of beds in the Northern Appalachian Basin (Averitt 1975). These deposits have been well preserved in a large syncline. Individual fields trend generally to the northeast. Rank ranges from high-volatile bituminous coal in the west to the anthracites of east Pennyslvania. Coal seams are excavated by contour, mountaintop removal, and auger methods of surface mining as well as by underground mining. Old culm and silt banks laid down in the early days of anthracite mining are now economical to mine again. These accounted for 45 percent of the total anthracite production in 1975 (Edmunds 1977). River dredging is also used for anthracite production, but accounts for only about 2 percent of the total (Westerstrom 1975). Region III 1975 coal production and quality are shown in Table 4.6.

Table 4.6. Demand Region III Coal Production and Quality, 1975 (millions of short tons)

State[a]	Production Total	Underground Production	Surface Production	% Ash		% Total Sulfur		% Pyritic Sulfur (avg.)	Btu/lb	
				Average	Range	Average	Range		Average	Range
Maryland	2.606	0.054	2.552	15.1	5.1-27.4	2.3	0.6-4.2	1.75	13,450	12,510-14,480
Pennsylvania	89.766	45.227	44.539	9.0	4.1-39.5	2.3	0.4-4.3	1.60	13,000	10,675-NA[b]
Virginia	35.510	23.181	12.329	9.0	1.2-26.3	0.8	0.3-3.7	0.19	13,400	11,170-15,000
West Virginia	109.283	88.357	20.926	11.2	2-34.4	2.5	0.4-9.0	1.62	13,200	10,200-15,800
Regional total	237.165	156.819	80.346	10.0	1.2-39.5	2.2	0.3-9.0	1.38	13,156	10,200-15,800

From Mining Informational Services (1977) and Cavallaro et al. (1976).

[a] No coal was mined in Delaware or Washington, D. C., in 1975.

[b] NA--not available.

4.5.3.2 Coal Resources

By January 1, 1974, estimates, Region III contains 206,705 million short tons of coal in known and hypothesized deposits less than 1829 m (6000 ft) deep (Averitt 1975). Region III demonstrated coal reserves are shown in Table 4.7.

Table 4.7. Demand Region III Demonstrated Coal Reserve Base as of January 1, 1974[a,b] (millions of short tons)

State[c]	Reserves by % Sulfur Content				Reserves by Mining Mode		Total[d] Reserves
	< 1.0	1.1-3.0	> 3.0	Unknown	Underground	Surface	
Maryland	135.1	690.5	187.4	34.6	901.9	146.3	1,048.2
Pennsylvania	7,318.3	16,913.6	3,799.6	2,954.3	29,819.2	1,181.4	30,996.6
Virginia	2,140.1	1,163.5	14.1	330.0	2,970.7	679.2	3,649.9
West Virginia	14,092.1	14,006.2	6,823.3	4,652.5	34,377.8	5,212.0	39,589.8
Regional total	23,685.6	32,773.8	10,824.4	7,971.4	68,069.6	7,218.9	75,284.5

From U. S. Bureau of Mines (1974).

[a]Bituminous coal and lignite.

[b]Demonstrated reserves are those coal deposits which have been measured or geologically projected to a high confidence level and are of a sufficient quality and volume to be economically mined at the time of the determination (Averitt 1975; U. S. Bureau of Mines 1973).

[c]There are no measurable reserves in Delaware or Washington, D. C.

[d]Data may not add to totals because of independent rounding.

4.5.4 Demand Region IV (Alabama, Florida, Georgia, Kentucky, Mississippi, North Carolina, South Carolina, Tennessee)

4.5.4.1 Coal Production

Except for the coal mined in Western Kentucky, all coal mined in Region IV (Table 4.8) comes from the southern end of the Appalachian coal basin. Western Kentucky coal comes from the Illinois basin deposits. A significant portion of the coal produced in Region IV, particularly in Eastern Kentucky and Alabama, is suitable to be used as part of a coking coal blend, and probably will continue to be reserved for that purpose. Most other coal is used for industry, utilities, and other purposes. Most of the coal is high-volatile bituminous. Notable exceptions are the lignites of southern Alabama and Mississippi.

Table 4.8. Demand Region IV Coal Production and Quality, 1975 (millions of short tons)

State[a]	Total Production	Underground Production	Surface Production	% Ash		% Total Sulfur		% Pyritic Sulfur (avg.)	Btu/lb	
				Average	Range	Average	Range		Average	Range
Alabama	22.644	7.614	15.029	9.5	1.2-21.7	1.3	0.4-4.9	0.70	13,700	11,310-15,140
Georgia	0.060	0	0.060	5.8	2.4-9.0	0.8	0.7-1.0	NA[b]	14,475	14,398-14,628
Kentucky	143.613	65.632	77.981	12.8	3.5-39.0	2.8	0.6-5.1	1.24	12,602	8,543-14,200
Tennessee	8.206	3.806	4.254	7.9	1.9-23.8	1.2	0.4-5.8	0.40	13,670	10,940-15,000
Regional total	174.523	77.052	97.874	12.1	1.2-39.0	2.5	0.4-5.8	1.13	12,802	8,543-14,200

From Mining Informational Services (1977) and Cavallaro et al. (1976).

[a]No coal was mined in Florida, Mississippi, North Carolina, or South Carolina in 1975.

[b]NA--not available.

4.5.4.2 Coal Resources

Region IV demonstrated coal reserves are shown in Table 4.9. Region IV coal deposits less than 1829 m (6000 ft) deep and hypothetical resources are estimated at 162,357 million short tons (Averitt 1975).

Table 4.9. Demand Region IV Demonstrated Coal Reserve Base as of January 1, 1974[a,b] (millions of short tons)

State[c]	Reserves by % Sulfur Content				Reserves by Mining Mode		Total[d] Reserves
	< 1.0	1.1-3.0	> 3.0	Unknown	Underground	Surface	
Alabama	624.7	1,099.9	16.4	1,239.4	1,798.1	1,183.7	2,981.8
Georgia	0.3	0	0	0.2	0.5	0	0.5
East Kentucky	6,558.4	3,321.8	299.5	2,729.3	9,466.5	3,450.2	12,916.7
West Kentucky	0.2	564.4	9,243.9	2,815.9	8,719.9	3,904.0	12,623.9
North Carolina	0	0	0	31.7	31.3	0.4	31.7
Tennessee	204.8	533.2	156.6	88.0	667.1	319.6	986.7
Regional total	7,388.4	5,519.3	9,716.4	6,904.5	20,683.4	8,857.9	29,541.3

From U. S. Bureau of Mines (1974).

[a]Bituminous coal and lignite.

[b]Demonstrated reserves are those coal deposits which have been measured or geologically projected to a high confidence level and are of a sufficient quality and volume to be economically mined at the time of the determination (Averitt 1975; U. S. Bureau of Mines 1973).

[c]There are no measurable reserves in Florida or South Carolina. Mississippi has some lignite reserves.

[d]Data may not add to totals because of independent rounding.

4.5.5 Demand Region V (Illinois, Indiana, Michigan, Minnesota, Ohio, Wisconsin)

4.5.5.1 Coal Production

About one-third of Region V coal is mined underground (Table 4.10). Surface mines are primarily area strip mines.

Table 4.10. Demand Region V Coal Production and Quality, 1975 (millions of short tons)

State[a]	Total Production	Underground Production	Surface Production	% Ash		% Total Sulfur		% Pyritic Sulfur (avg.)	Btu/lb	
				Average	Range	Average	Range		Average	Range
Illinois	59.537	31.875	27.662	11.6	3.0-24.0	3.5	0.6-6.0	2.10	11,350	9,600-15,000
Indiana	25.124	0.188	24.936	11.3	6.0-19.8	3.3	1.2-7.1	2.30	12,128	10,900-13,430
Ohio	46.770	15.455	31.315	14.7	5.0-20.0	3.9	1.0-6.0	2.50	12,250	10,000-13,000
Regional total	131.431	47.518	83.913	12.66	3.0-24.0	3.6	0.6-7.1	2.30	11,822	9,600-15,000

From Mining Informational Services (1977) and Cavallaro et al. (1976).

[a]No coal was mined in Michigan, Minnesota, or Wisconsin in 1975.

4.5.5.2 Coal Resources

Coal reserves (Table 4.11) are located in three distinct depositional basins. Eastern Ohio contains coal seams which are part of the Northern Appalachian basin deposits. These are high-volatile bituminous coals which can be mechanically cleaned to slightly reduce the sulfur levels. About 83 percent of this coal is used for steam generation.

The Michigan Basin contains deposits of bituminous coal. Much of this is not currently economical to mine. Michigan has no operating coal mines.

The coal of Illinois and Indiana (also Western Kentucky, which is located in Region IV) is deposited in the Illinois basin. The sulfur contents of Illinois and Indiana coals are generally slightly higher than those of the Appalachian coals, and the Btu's per pound are lower.

By January 1, 1974, estimates, Region V contains 348,892 million short tons of coal in known and hypothesized deposits less than 1829 m (6000 ft) deep (Averitt 1975).

Table 4.11. Demand Region V Demonstrated Coal Reserve Base as of January 1, 1974[a,b] (millions of short tons)

State[c]	Reserves by % Sulfur Content				Reserves by Mining Mode		Total[d] Reserves
	< 1.0	1.1-3.0	> 3.0	Unknown	Underground	Surface	
Illinois	1,095.1	7,341.4	42,968.9	14,256.2	53,441.9	12,222.9	65,664.8
Indiana	548.8	3,305.8	5,262.4	1,504.1	8,948.5	1,674.1	10,622.6
Michigan	4.6	85.4	20.9	7.0	117.6	0.6	118.2
Ohio	134.4	6,440.9	12,634.3	1,872.0	17,423.3	3,653.9	21,080.2
Regional total	1,782.9	17,173.5	60,885.8	17,639.3	79,931.3	17,551.3	97,485.8

From U. S. Bureau of Mines (1974).

[a]Bituminous coal and lignite.

[b]Demonstrated reserves are those coal deposits which have been measured or geologically projected to a high confidence level and are of a sufficient quality and volume to be economically mined at the time of the determination (Averitt 1975; U. S. Bureau of Mines 1973).

[c]There are no measurable reserves in Wisconsin or Minnesota.

[d]Data may not add to totals because of independent rounding.

4.5.6 Demand Region VI (Texas, Louisiana, Arkansas, New Mexico, Oklahoma)

4.5.6.1 Coal Production

The coal produced in Region VI (Table 4.12) comes from a wide variety of physiographic provinces and distinct basins. Almost all mining in this region is done by area surface methods. Arkansas coal is used primarily for coke (Howard 1977). Only 16 percent of the Oklahoma coal was used at coking and manufacturing plants in 1976; 82 percent was shipped to electric-powered generating plants (Howard 1977).

Table 4.12. Demand Region VI Coal Production and Quality, 1975 (millions of short tons)

State[a]	Total Production	Underground Production	Surface Production	% Ash		% Total Sulfur		% Pyritic Sulfur (avg.)	Btu/lb	
				Average	Range	Average	Range		Average	Range
Arkansas	0.488	0	0.488	10.1	4.1-23.2	2.5	1.1-4.0	2.30	12,126	4,660-14,324
New Mexico	8.785	0.50	8.285	14.3	3.1-22.8	0.6	0.4-3.5	0.20	11,958	9,100-15,200
Oklahoma	2.872	0	2.872	10.1	4.2-22.6	3.1	0.4-6.3	1.90	13,600	11,562-14,430
Texas	11.002	0	11.002	17.2	9.1-40.8	1.75	0.8-3.3	NA[b]	7,582	6,130-7,916
Regional total	23.147	0.500	27.647	14.62	4.1-40.8	1.28	0.4-6.3	0.67[c]	10,057	4,460-15,200

From Mining Informational Services (1977) and Cavallaro et al. (1976).

[a]No coal was mined in Louisiana in 1975.

[b]NA--not available.

[c]Excluding Texas.

4.5.6.2 Coal Resources

Region VI coal resources are listed in Table 4.13. The Oklahoma and Arkansas deposits of bituminous coal and anthracite are the southernmost portion of the western region of the Interior Coal Province (Friedman 1977). The rank increases to the east, ranging from high-volatile bituminous coals in Oklahoma (Friedman 1977) to low-volatile bituminous and semi-anthracite coals in Arkansas (Howard 1977).

The Texas bituminous and sub-bituminous resources are distributed in three areas: North-Central Texas, the Rio Grande Embayment, and Trans-Pecos, Texas. None of these regions is being actively mined (Howard 1977). According to Keystone forecasts of new coal capacity by 1987, no new mines are projected in these regions (Nielsen 1978).

Table 4.13. Demand Region VI Demonstrated Coal Reserve Base as of January 1, 1974[a,b] (millions of short tons)

State[c]	Reserves by % Sulfur Content				Reserves by Mining Mode		Total[d] Reserves
	< 1.0	1.1-3.0	> 3.0	Unknown	Underground	Surface	
Arkansas	81.2	463.1	46.3	74.3	402.4	263.3	665.7
New Mexico	3575.3	793.4	0.9	27.5	2136.5	2258.8	4394.8
Oklahoma	275.0	326.6	241.4	450.5	860.1	434.1	1294.2
Texas	659.8	1884.6	284.1	440.0	0	3271.9	3271.9
Regional total	4591.3	3467.7	572.7	992.3	3399.0	6228.1	9626.6

From U. S. Bureau of Mines (1974).

[a]Bituminous coal and lignite.

[b]Demonstrated reserves are those coal deposits which have been measured or geologically projected to a high confidence level and are of a sufficient quality and volume to be economically mined at the time of the determination (Averitt 1975; U. S. Bureau of Mines 1973).

[c]Louisiana contains a small amount of lignite reserves.

[d]Data may not add to totals because of independent rounding.

Most of the New Mexico coal is sub-bituminous to high-volatile bituminous. The San Juan basin in northwestern New Mexico contains the largest percentage of New Mexico's reserves. Except for steeply dipping eastern and northern boundaries, the coal is easily mined by area stripping (Kottlowski and Beaumont 1977). Coal in the Raton field, the second largest, is mined by underground methods. A large percentage of the coal from the Raton field is used as coking coal (Kottlowski and Beaumont 1977). Most of the smaller coal fields in the southern two-thirds of New Mexico have locally steep dips and numerous faults and are not as extensively mined. Semi-anthracite and anthracite coal exists in the Cerrillos field where the coal has been metamorphosed by heat from adjacent igneous intrusives (molten rock which subsequently cools and solidifies).

Lignite deposits are located in a broad intermittent band that extends northeasterly from south-central Texas to central Arkansas. Only in Texas are the lignites currently being mined. Considerable lignite exploration is currently in progress. All mining is done by area stripping.

By January 1, 1974, estimates, Region VI contains 362,921 short tons of coal in known and hypothesized deposits less than 1829 m (6000 ft) deep (Averitt 1975).

4.5.7 Demand Region VII (Iowa, Kansas, Nebraska, Missouri)

4.5.7.1 Coal Production

The coal deposits in Region VII all belong to the Western Interior Coal Province. Most are high-volatile bituminous and are concentrated in the center of the four-state region. In addition, some lignite deposits are scattered throughout central Kansas. Most of the mining is done by area mining techniques (Table 4.14).

Table 4.14. Demand Region VII Coal Production and Quality, 1975 (millions of short tons)

State[a]	Total Production	Underground Production	Surface Production	% Ash		% Total Sulfur		% Pyritic Sulfur (avg.)	Btu/lb	
				Average	Range	Average	Range		Average	Range
Iowa	0.622	0.400	0.222	16.2	6.8-26.8	6.7	2.5-12.8	4.60	11,592	10,242-13,259
Kansas	0.479	0	0.479	22.5	5.0-34.0	3.8	2.0-10.0	3.80	11,458	8,500-12,857
Missouri	5.638	0	5.638	15.2	8.4-29.0	4.7	3.0-7.5	3.30	11,663	10,000-12,500
Regional total	6.739	0.400	6.339	15.8	5.0-29.0	4.8	2.0-12.8	3.50	11,642	8,500-13,259

From Mining Informational Services (1977) and Cavallaro et al. (1976).

[a]No coal was mined in Nebraska in 1975.

4.5.7.2 Coal Resources

In general, coals of Region VII are characterized by relatively high sulfur contents (Table 4.15). They have coking characteristics but may be better suited for steam generation because of high sulfur contents. Some of the seams with lower sulfur contents are nearly depleted (Robertson 1977). Resources less than 1829 m (6000 ft) deep, including hypothesized resources were 91,846 million short tons as of January 1, 1974 (Averitt 1975).

Table 4.15. Demand Region VII Demonstrated Coal Reserve Base as of January 1, 1974[a,b] (millions of short tons)

State	Reserves by % Sulfur Content				Reserves by Mining Mode		Total[c] Reserves
	< 1.0	1.1-3.0	> 3.0	Unknown	Underground	Surface	
Iowa	1.5	226.7	2,105.9	549.2	2,884.9	0	2,884.9
Kansas	0	309.2	695.6	383.2	0	1,388.1	1,388.1
Missouri	0	182.0	5,226.0	4,080.5	6,073.6	3,413.6	9,487.2
Regional total	1.5	717.9	8,027.5	5,012.9	8,958.5	4,801.7	13,760.2

From U. S. Bureau of Mines (1974).

[a]Bituminous coal and lignite.

[b]Demonstrated reserves are those coal deposits which have been measured or geologically projected to a high confidence level and are of a sufficient quality and volume to be economically mined at the time of the determination (Averitt 1975; U. S. Bureau of Mines 1973).

[c]Nebraska contains small, unquantified reserves.

[d]Data may not add to totals because of independent rounding.

4.5.8 Demand Region VIII (Colorado, Montana, North Dakota, South Dakota, Utah, Wyoming)

4.5.8.1 Coal Production

Region VIII encompasses all of the Great Plains and most of the Rocky Mountain Coal Provinces. Coal production and quality for Region VIII are shown in Table 4.16.

Table 4.16. Demand Region VIII Coal Production and Quality, 1975 (millions of short tons)

State[a]	Total Production	Underground Production	Surface Production	% Ash		% Total Sulfur		% Pyritic Sulfur (avg.)	Btu/lb	
				Average	Range	Average	Range		Average	Range
Colorado	8.219	3.446	4.773	7.5	1.3-21.8	0.65	0.1-2.7	0.10	11,820	5,510-15,190
Montana	22.054	0	22.054	6.6	4.0-10.8	0.55	0.2-1.72	D.74	7,931	6,020-11,752
North Dakota	8.515	0	8.515	6.2	4.4-8.0	0.6	0.2-1.4	NA[b]	6,783	5,960-7,487
Utah	6.961	6.961	0	8.8	4.4-15.5	1.03	0.4-5.8	0.12	11,832	4,935-13,783
Wyoming	23.804	0.436	23.369	B.2	2.2-29.4	1.04	0.1-5.4	0.31	9,665	6,480-14,400
Regional total	69.553	10.843	5B.711	7.42	1.3-29.4	0.78	0.1-5.8	0.42[c]	9,240	5,510-15,190

From Mining Informational Services (1977) and Cavallaro et al. (1976).

[a]No coal was mined in South Dakota in 1975.

[b]NA--not available.

[c]Excluding North Dakota.

4.5.8.2 Coal Resources

Deposits of the Great Plains Province coals exist in the western Dakotas, eastern Wyoming, and Montana. They vary in rank from lignite to high-volatile bituminous coal. North Dakota contains the largest reserves of lignite in the nation. Deposits of North Dakota lignite, both real and hypothetical and less than 1829 m (6000 ft) deep, were estimated to consist of about 530,602 million short tons as of January 1, 1974 (Averitt 1975). The lignite is almost always mined by area stripping methods. Demonstrated coal reserves are shown in Table 4.17.

Table 4.17. Demand Region VIII Demonstrated Coal Reserve Base as of January 1, 1974[a,b] (millions of short tons)

State	Reserves by % Sulfur Content				Reserves by Mining Mode		Total[c] Reserves
	< 1.0	1.1-3.0	> 3.0	Unknown	Underground	Surface	
Colorado	7,475.5	786.2	47.3	6,547.3	13,999.2	870.0	14,869.2
Montana	101,646.6	4,115.0	502.6	2,166.7	65,834.3	42,561.9	108,396.2
North Dakota	5,389.0	10,325.4	268.7	15.0	0	16,003.0	16,003.0
South Dakota	103.1	287.9	35.9	1.0	0	428.0	428.0
Utah	1,968.5	1,546.7	49.4	478.3	3,780.5	262.0	4,042.5
Wyoming	33,912.3	14,657.4	1701.1	3,060.3	29,490.8	23,845.3	53,336.1
Regional total	150,495	31,718.6	2605.0	12,268.6	113,104.8	83,970.2	197,075.0

From U. S. Bureau of Mines (1974).

[a]Bituminous coal and lignite.

[b]Demonstrated reserves are those coal deposits which have been measured or geologically projected to a high confidence level and are of a sufficient quality and volume to be economically mined at the time of the determination (Averitt 1975; U. S. Bureau of Mines 1973).

[c]Data may not add to totals because of independent rounding.

Many of the coal deposits of the Rocky Mountain Province are situated in synclinal basins between the various mountain ranges. Coal seams are generally flat-lying near the center of these basins but may be steeply dipping and folded on the basin fringes and on the flanks of the mountains (Glass 1977; Kottlowski and Beaumont 1977). Faulting may be more common in this region than in the neighboring Great Plains Region.

The coals of the Rocky Mountain Province are located in western Montana, western Wyoming, eastern Idaho, eastern Utah, Colorado, northeastern Arizona and New Mexico. Rank varies from subbituminous to bituminous. There are a few local occurrences of anthracite resulting from a combination of structural deformations and igneous intrusions (Murray 1977). Both coking and noncoking coals are mined in this province.

By January 1, 1974, estimates, Region VIII contains 2,455,939 million short tons of coal in known and hypothesized deposits (Averitt 1975).

4.5.9 Demand Region IX (Arizona, California, Nevada)

4.5.9.1 Coal Production

Most of the coal of Region IX is scattered in small isolated deposits in California, but the only field with operating mines is the Black Mesa Field of Arizona. This coal is subbituminous (U.S. Bureau of Mines 1971) and high-volatile bituminous (Pierce and Wilt 1970), and is used to supply two electric power generating stations. Region IX coal production and quality are shown in Table 4.18.

Table 4.18. Demand Region IX Coal Production and Quality, 1975 (millions of short tons)

State[a]	Total Production	Underground Production	Surface Production	% Ash		% Total Sulfur		% Pyritic Sulfur (avg.)	Btu/lb	
				Average	Range	Average	Range		Average	Range
Arizona	6.986	0	6.986	8.0	3.4-50.8	0.5	0.4-2.3	0.11	12,350	12,187-12,856
Regional total	6.986	0	6.986	8.0	3.4-50.8	0.5	0.4-2.3	0.11	12,350	12,187-12,856

From Mining Informational Services (1977) and Cavallaro et al. (1976).

[a]No coal was mined in California or Nevada.

4.5.9.2 Coal Resources

By January 1, 1974, estimates, Region IX contains 21,234 million short tons of coal in known and hypothesized resources less than 1829 m (6000 ft) deep. Demonstrated coal reserves are shown in Table 4.19.

Table 4.19. Demand Region IX Demonstrated Coal Reserve Base as of January 1, 1974[a,b] (millions of short tons)

State[c]	Reserves by % Sulfur Content < 1.0	1.1-3.0	> 3.0	Unknown	Reserves by Mining Mode Underground	Surface	Total Reserves
Arizona	173.3	176.7	0	0	0	350.0	350.0
Regional total	173.3	176.7	0	0	0	350.0	350.0

From U. S. Bureau of Mines (1974).

[a]Bituminous coal and lignite.

[b]Demonstrated reserves are those coal deposits which have been measured or geologically projected to a high confidence level and are of a sufficient quality and volume to be economically mined at the time of the determination (Averitt 1975; U. S. Bureau of Mines 1973).

[c]California and Nevada contain small, unquantified reserves.

4.5.10 Demand Region X (Idaho, Oregon, Washington, Alaska)

4.5.10.1 Coal Production

The bulk of the coal production from Region X in 1975 (Table 4.20) consisted of lignites from the Centralia-Chehalis area of Washington (Conwell 1977; Livingston 1977).

Table 4.20. Demand Region X Coal Production and Quality, 1975 (millions of short tons)

State[a]	Total Production	Underground Production	Surface Production	% Ash Average	% Ash Range	% Total Sulfur Average	% Total Sulfur Range	% Pyritic Sulfur (avg.)	Btu/lb Average	Btu/lb Range
Alaska	0.766	0	0.766	NA[b]	NA	NA	NA	NA	NA	9,000-14,500
Washington	3.743	0.013	3.730	10.4	2.0-30.0	0.9	0.1-4.4	NA	10,612	5,510-13,787
Regional total	4.509	0.013	4.498	10.4	2.0-30.0	0.9	0.1-4.4	NA	10,612	5,500-14,500

From Mining Informational Services (1977) and Cavallaro et al. (1976).

[a]No coal was mined in Oregon or Idaho in 1975.

[b]NA--not available.

4.5.10.2 Coal Resources

In addition to the Central-Chehalis area of Washington, coal deposits are also distributed throughout the Cascade Range of the Pacific Northwest and eastern Idaho (Table 4.21). Several of the fields are not currently being mined, primarily because of their remote locations. Most of the coal is mined by stripping. Region X was estimated to contain a total of about 136,582 million short tons of coal less than 914.4 m (3000 ft) deep as of January 1, 1974 (Averitt 1975). Estimates of the combined real and hypothetical deposits less than 1829 m (6000 ft) as of January 1, 1974, are as high as 316,682 million short tons (Averitt 1975).

Table 4.21. Demand Region X Demonstrated Coal Reserve Base as of January 1, 1974[a,b] (millions of short tons)

State[c]	Reserves by % Sulfur Content < 1.0	1.1-3.0	> 3.0	Unknown	Reserves by Mining Mode Underground	Surface	Total[d] Reserves
Alaska	11,457.9	184.2	0	0	4,246.4	7,399.0	11,645.4
Oregon	1.5	0.3	0	0	1.0	0.8	1.8
Washington	603.5	1,265.5	39.0	45.1	1,445.9	508.1	1,954.0
Regional total	12,063.4	1,450.0	39.0	45.1	5,693.3	7,907.9	13,601.2

From U. S. Bureau of Mines (1974).

[a]Bituminous coal and lignite.

[b]Demonstrated reserves are those coal deposits which have been measured or geologically projected to a high confidence level and are of a sufficient quality and volume to be economically mined at the time of the determination (Averitt 1975; U. S. Bureau of Mines 1973).

[c]Idaho contains small, unquantified reserves.

[d]Data may not add to totals because of independent rounding.

4.6 BIOTIC RESOURCES

4.6.1 Terrestrial

Mining increases due to the proposed action are expected to be most marked in Demand Regions VI and VIII, while coal consumption in response to the proposed action is expected to show the greatest increase in Demand Region VI (cf. Secs. 5.2., 5.4., and 5.5). These two regions cover a large geographical area and contain a wide variety of biotic communities. Many of the communities in these regions have been disturbed by the activities of humans. However, the classification of a community by the biota of its potential climax, or most mature developmental stage, offers a convenient method of classification that will be followed here. In this discussion, those biotic communities found in Regions VI and VIII are emphasized, because these have the most potential for being affected by the proposed action. A more thorough discussion of the biotic communities of the United States may be found in Appendix H.

The temperate, deciduous forest biome, or ecological unit, extends across the eastern third of the country and enters the eastern portions of Region VI (Shelford 1963; Garrison et al. 1977). Oak-hickory and oak-pine forests are the dominant associations within this region. The multiple vegetation layers of the forests provide a variety of microhabitats for fauna. Thus, wildlife diversity is high in many of these communities.

Temperate, evergreen forests dominate the coastal plains of the southeastern United States and also enter the eastern portions of Region VI (Shelford 1963; Garrison et al. 1977). Longleaf-slash pine and loblolly-shortleaf pine are major community types within this area. Although these forests tend to be more open than deciduous forest, and thus are not as structurally complex, they do provide habitat for a number of wildlife species.

The coastal wetland communities of Region VI represent an interface of aquatic and terrestrial communities (Shelford 1963; Garrison et al. 1977). They have been disturbed by human activities and can be sensitive to disruption. The marshes of the coastal wetlands are dominated by grasses, rushes, and sedges. Woody species invade as sedimentary deposits form dry islands in the marshes. Waterfowl are abundant, and terrestrial wildlife are found in the drier areas.

The central United States is dominated by communities of the prairie and plains grasslands (Shelford 1963; Garrison et al. 1977) extending across Regions VI and VIII to the eastern foothills of the Rocky Mountains. Perennial grasses are the dominant vegetation of these communities, making up a single vegetation layer. Herbaceous plants other than grasses are subdominant in grasslands, and woody species are rare. Plant and animal diversity is moderate to low compared to the eastern forests, and productivity tends to be lower here than in forest communities.

The arid southern and southwestern margins of the grasslands are invaded by shrubs, forming shrubsteppe, savanna, and desert grassland communities (Shelford 1963; Garrison et al. 1977). These communities have a poorly to richly developed layer of shrubs or low trees, with an understory dominated by perennial shortgrasses. The fauna of these biotic communities represents a transition from the grasslands to the desert scrub communities. The additional cover of the woody vegetation results in a greater variety of fauna in these communities than in the grasslands.

Desert scrub communities occur throughout most of the lowlands of the southwestern and intermountain areas of Regions VI and VIII (Shelford 1963; Garrison et al. 1977). These communities are underlain by soils with little organic material and an accumulation of salts. The dominant community types in this biome are creosote scrub in southwestern Region VI and sagebrush and shadscale scrub in western Region VIII. Perennial shrubs are the dominant life forms in these communities, where the vegetation is open and often covers less than 10 percent of the ground surface. Annual forbs and grasses comprise the understory. The biotic diversity of these communities is relatively low, the only strata being the shrub and ground-surface levels. The reptilian fauna is highly diversified in desert communities; the mammalian fauna is dominated by small to medium-sized species.

The mountainous areas of western Regions VI and VIII contain the coniferous forests of high elevations (Shelford 1963; Garrison et al. 1977). These forests tend to be open, but provide habitat for a variety of wildlife. Productivity in these communities is variable, depending upon precipitation.

4.6.2 Aquatic

Because it contains a wide variety of physiographic features, the United States has a large diversity of aquatic environments. Major determinants of habitat types include: rainfall (amount and seasonality), terrain, chemical composition of the underlying strata, adjacent terrestrial vegetation, insolation regime, and temperature regime. Although each aquatic resource has characteristics that make it unique in comparison to any other, entities which possess similar traits (e.g., similar types of species present, similar water chemistry) can be qualitatively grouped. Thus, a few examples of major habitat types in the United States include northern bog lakes, northern oligotrophic soft water lakes, saline lakes, high altitude mountain streams, and calcareous springs.

Appendix I contains a brief description of the nonmarine aquatic ecological resources of the country by Water Resource Region, with an emphasis on the occurrence and distribution of major habitat types. To avoid excessive length of the document, the regions are not treated in great detail; therefore, the reader is referred to the cited publications for additional information. In situations where additional detail is required to adequately assess the impacts of a given event on the biota of a particular area, this information is given in Section 5.6.

For the relationship between Water Resource Regions and demand regions, see Section 4.3.1. The reader is also referred to that section for information on water quality, water use, and existing hydrological features.

4.6.3 Endangered Species

Federally designated endangered and threatened flora and fauna of the conterminous United States are listed in Volume II, Appendix J. Species are those species considered endangered if they are in danger of extinction throughout all or a significant portion of their ranges. Species are considered threatened if they are likely to become endangered within the foreseeable future. Species designated as endangered or threatened are imperiled by one or more of the following: (1) destruction, modification, or curtailment of habitat or range; (2) overutilization for commercial, sporting, scientific, or educational purposes; (3) disease or predation; (4) regulatory inadequacies (lack of effective protection and conservation measures); or (5) other natural or man-made factors. As listed in Appendix J, critical habitats have been designated for some of these species; such habitats are necessary to some or all life stages of the species and, consequently, for the survival and recovery of the species. In accordance with the Endangered Species Act of 1973, actions authorized, funded, or carried out by Federal agencies must not jeopardize the continued existence of endangered or threatened species or result in the destruction or modification of designated critical habitat. The capture, possession, transport, and sale of such species are also generally prohibited (U.S. Fish and Wildlife Service 1977, 1978).

In addition to the species listed in Appendix J, additional species are in review for possible protection under the Endangered Species Act, and other species have been officially proposed as endangered or threatened, with final action pending. Additional critical habitats and changes in status have also been proposed. State endangered species lists also exist and, in some cases, include species not on the federal list.

4.7 REGIONAL DEMOGRAPHY AND SOCIOECONOMICS

4.7.1 Introduction

From the eight coal-producing areas defined as Coal Supply Regions (Federal Energy Administration 1976), four were identified as the regions most likely to produce the additional coal required for conversion to coal. These regions are Central Appalachia, the Midwest, the Gulf Region, and the Northern Great Plains. After a determination of the relative amounts of coal that each state in the four areas is anticipated to contribute to coal conversion, ten states were selected for more intensive study of demographic and socioeconomic characteristics because they are expected to produce the largest amounts of coal for coal conversion. The states are Virginia, Kentucky, and West Virginia (Central Appalachia); Illinois and Indiana (Midwest); Texas, Louisiana, and Arkansas (Gulf Region); and Montana and Wyoming (Northern Great Plains). Mining methods are diverse, with deep mining characteristic of the Central Appalachian region while strip mining is typical in the Northern Great Plains and the Gulf Region. Both methods are used about equally in the Midwest (Nielsen 1977).

4.7.2 Regional Profiles (see Table 4.22)

4.7.2.1 Demography and Settlement Pattern

The Central Appalachian and the Northern Great Plains regions have a marked similarity in urban/rural population distribution. Population appears to be rising in all four of the regions and it can be assumed that they will continue to increase, especially in the Northern Great Plains where coal mining is to become a major revenue-producing industry (Nahel 1977; Nielsen 1977). Population stability and mobility patterns are two measures of demographic change.

Table 4.22. Demographic, Social, and Economic Profiles of the Four Major Coal-Producing Regions

	Central Appalachia	Midwest	Gulf Region	Northern Great Plains
Percent population increase, 1960-1970	8.4	10.6	14.6	2.2
Population density, 1970	35.8/km^2 (92.6/mi^2)	68.4/km^2 (177.1/mi^2)	18.0/km^2 (46.5/mi^2)	1.6/km^2 (4.2/mi^2)
Urban residents, % of population	55(65)[a]	75(96)	75(79)	55(77)
Rural residents, % of population	45(35)[a]	25(4)	25(21)	45(23)
Percent of population remaining in state of birth	75	72	74	55
Percent of population living in households	96	97	87	94
Average number of persons per household	3.16	3.11	3.15	3.08
Average number of persons per family	3.54(3.90)[b]	3.57(3.72)	3.55(4.12)	3.56(3.75)
Average age	28.1	27.9	26.8	27.2
Marital status (% of population 14 yrs or older)				
Married	65	65	65	65
Single	24	24	24	24
Male:female ratio	1:1.1	1:1.1	1:1.1	1:1.1
Percent of population with education of high school or above	42.6	52.8	43.2	61.1
Median school years completed	10.7	12.1	11	12.4
Major employment category and percentage of population employed	Ind./mfg. 23.7	Ind./mfg. 32	Ind./mfg. 20.2	Mining 4.6 Agric. 12.1 Education 9.7
Percentage of population unemployed	5.9	5.5	5.8	4.9
Approximate median annual income[c] (combined industry, mfg., mining)	$14,790	$14,280	$13,810	$16,210
Average income of poverty-level families	$1,967	$1,882	$2,007	$1,899

[a]Percentage of minority residents is given in parentheses.

[b]Average size of poverty-level family is given in parentheses.

[c]Annual income was tabulated by calculating average gross hourly wages and weekly average hours worked based on December 1977 data and then rounding to the nearest fifth.

From Cathers (1978); Hargrove (1978); U.S. Department of Commerce (1970); and U.S. Department of Labor (1978).

4.7.2.2 Social and Economic Characteristics

Family patterns of the four areas are generally similar, as shown in Table 4.23.

4.7.3 Introduction to State Profiles

The coal regions discussed in Section 4.7.1 were represented by certain states because of their probable involvement in the proposed coal conversion program. Although each state is likely to contribute coal, there will be one major coal-producing state within each region that is thought to be a primary source of coal. The states selected in each region are West Virginia (Central Appalachian region), Illinois (Midwest region), Texas (Gulf region) and Wyoming (Northern Great Plains region). Table 4.23 is a demographic and socioeconomic profile of these states.

4.8 ARCHAEOLOGICAL, CULTURAL, AND HISTORICAL RESOURCES

National resources of archaeological, historical, or natural landmark importance are protected and preserved by the National Park Service of the U.S. Department of the Interior (undated). Over 10,000 historical sites in the contiguous United States are listed in the "National Register of Historic Places" (U.S. Department of the Interior 1977b). Many of these are stone or masonry structures that can be affected negatively by coal-derived air pollution. Erosion of surfaces of these structures is caused by acid rain and particulate emissions. Noise, dust, visual degradation due to nearby coal mining and onsite coal transportation and processing also may negatively affect historic places. Any proposed activity which may interfere with archaeological sites having potential for inclusion in the National Register is determined on a site-by-site basis.

Over 200 natural landmarks are listed in the "National Registry of Natural Landmarks" (U.S. Department of the Interior, update).

4.9 HEALTH EFFECTS

Each of the five components of the coal fuel cycle (extraction, cleaning, transportation, combustion, and disposal) has its own set of associated injuries and disease in the form of morbidity and mortality in the occupational and general populations. Occupational morbidities and mortalities occur as the result of respiratory diseases and job-related accidents. Public health impacts can result from transportation accidents and from effluents which find their way to air and water. Increased public mortality and morbidity can result from respiratory diseases caused by increased air pollution, and decreased quality of water supplies is known to influence the incidence of infectious diseases and possible non-infectious diseases. A more detailed description of the health effects of the coal fuel cycle is presented in Appendix E.2.6.

Table 4.23. Demographic, Social, and Economic Profiles of a Representative State in Each of the Four Major Coal-Producing Regions

	West Virginia	Illinois	Texas	Wyoming
Percent population increase, 1970-1975	3.4	0.9	28.0	7.4
Population density, 1975	28.9/km^2 (74.9/mi^2)	77.5/km^2 (200.6/mi^2)	18.0/km^2 (46.5/mi^2)	4.8/km^2 (12.4/mi^2)
Urban residents, % of population	36(55)[a]	83(97)	80(83)	60(87)
Rural residents, % of population	64(64)[a]	17(3)	20(17)	40(13)
Percentage of population remaining in state of birth	81.4	71.6	72.9	44.9
Percent increase in workers age 25-44, relocated from elsewhere, 1965-1970	9.8	9.1	11.2	23.0
Percent increase in workers age 45-64, relocated from elsewhere, 1965-1970	3.1	2.7	4.0	8.0
Percentage of population living in households	93.9	97.5	85.2	97.3
Average number of persons per household	3.11	3.09	3.13	3.09
Average number of persons per family	3.50(3.84)[b]	3.57(3.79)	3.54(4.17)	3.55(3.68)
Average age	30	28.6	26.4	27.2
Marital status (% of population 14 yrs or older)				
Married	23.9	60.9	66.1	23.6
Single	63.2	25.7	27.1	65.4
Male:female ratio	1:1.1	1:1.1	1:1.1	1:1.1
Percentage of population with education of high school or above	41.6	52.6	47.4	62.9
Median school years completed	10.6	12.1	11.6	12.4
Major employment category and percentage of population employed	Ind./mfg. 23.2 Mining 8.8 Agric./ed. 10.0	Ind./mfg. 30.3 Agric./ed. 10.0	Ind./mfg. 18.5 Mining 2.5 Agric./ed. 12.0	Education 10.1 Agric. 10.0 Mining 9.0 Ind./mfg. 6.0
Percentage of population unemployed	7.8	5.6	4.7	3.8
Approximate median annual income[c]	Ind./mfg. $13,020 Mining $23,505	Ind./mfg. $14,090 Mining $14,805	Ind./mfg. $12,370 Mining $15,055	Ind./mfg. $11,985 Mining $17,765
Families below poverty level, % of population	18.0	7.7	14.6	9.3
Mean annual income of families below poverty level	$1,965	$1,868	$2,086	$1,924

[a]Percentage of minority residents is given in parentheses.

[b]Average size of poverty-level family is given in parentheses.

[c]Annual income was tabulated by calculating average gross hourly wages and weekly average hours worked based on December 1977 data and then rounding to the nearest fifth.

From Appalachian Regional Commission (1977); Cathers (1978); Hargrove (1978); U.S. Department of Commerce (1970, 1976, 1976-77); and U.S. Department of Labor (1978).

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5. ENVIRONMENTAL CONSEQUENCES OF THE PROPOSED ACTION

Prohibiting the use of oil or natural gas in power plants and major industrial fuel-burning installation will result in increased coal use in both existing and new facilities. The coal supply regions, the amount of coal and the increased coal demand because of the FUA are presented in Section 3. In this section, the potential environmental impacts which could result from increased coal use as a result of the FUA are assessed. The impacts for each phase of the coal cycle (extraction → cleaning → transportation → combustion → waste disposal) are assessed for the following series: air quality; hydrology, water quality, and water use; land use; biotic resources, historical and archaeological sites; socioeconomics; and health. Each assessment includes a discussion of impacts for the years 1985 and 1990, both with the proposed action and without it (base case).

The uncertainties of the regional impacts discussed are highlighted. Many of the impacts associated with the FUA will be site-specific and will be addressed in subsequent NEPA compliance documents, as appropriate.

5.1 TRANSPORTATION OF COAL

In this section, the major impacts of increased coal movement on transportation systems are identified first for base case and then for increased coal use resulting from the proposed action. The extent of the future increase in coal traffic and the corresponding capacity requirements differ widely by region and also by transportation mode.

To meet the projected demand, the nation's transportation system will probably move larger loads of coal longer distances. The railroad is likely to continue to be the major mode of coal transportation in 1985 and beyond. The use of unit trains will continue to increase, partly due to the increasing importance of western coal. Short-distance hauling by truck would be complementary to railroad transport in some areas. In other areas, truck shipments could be competitive with railroads, particularly to MFBIs in the east.

Waterborne transportation is competitive with railroads for long-distance hauls; however, the intrinsic rigidity of the mode and the constraints on capacity, particularly before 1985, would be limiting factors to the growth of coal movement by this mode. On the other hand, the coal slurry pipelines may be developed as an economically competitive alternative to railroads for certain routes. The extent of coal transportation by pipeline in the near future will be very much limited, due in part to institutional and regulatory constraints (U.S. Department of Transportation 1976a). Perhaps more important are the capital investment and water needs for coal slurry pipelines.

To meet the projected demand for coal, the expansion and upgrading of railroads, highways, and lock systems will be required. More comprehensive system-wide transportation planning and judicious institutional arrangements will be needed to augment private interests and to assure that no mode of transportation is penalized.

5.1.1 Impact on Transportation (Base Case)

5.1.1.1 Railroad

Currently, the railroad is the principal mover of U.S. coal. In 1975, railroads transported approximately two-thirds (418 million tons) of the nation's coal and will remain as the major coal transportation mode in the future (U.S. Comptroller General 1977; National Coal Association 1977; U.S. Bureau of Mines 1976). Nationwide, coal accounted for 29 percent of the total traffic originated and 13.4 percent of the freight revenue received by Class I railroads in 1975 (U.S. Department of Transportation 1978, p. II-8). To meet the expansion of coal supply and demand, coal transport by rail, a projected increase of two-thirds over current levels would have to occur by 1985 in coal transport by rail (U.S. Department of Transportation 1978, p. II-16). Coal production in the west would have to increase from 16 percent of the 1975 total production to 34 percent and 41 percent in 1985 and 1990, respectively (Energy Information

Administration 1978). The ability of the railroads to handle this increase in western coal traffic will be crucial in meeting the goals of the National Energy Plan.

There has been a growing trend in coal movement by rail toward longer distances with heavier car loads; the average coal load per car was 76.6 tons in 1970 and 85.8 tons in 1976; the average hauling distance per car of coal was 290 miles in 1973 and 318 miles in 1976 (U.S. Department of Transportation 1975, 1977). The increase in the importance of western coal and the economics of the unit train have caused the share of nationwide coal transportation by unit train to increase from 32 percent of the total in 1971 to 46 percent in 1976 (U.S. Department of Transportation 1978, p. II-16). Because of the economic advantages of unit trains (rapid turnaround, dependable schedule, and a more economic use of fuel) (U.S. Department of Transportation 1978), the share of coal transportation by unit train is likely to increase in the future.

In several transportation studies (Electric Power Research Institute 1976; Federal Energy Administration 1976; U.S. Department of Transportation 1976b, 1978) it has been concluded that a majority of coal-carrying railroads appear to be capable of handling the expected growth of coal traffic and many of them have already installed heavy-duty welded rail (Federal Energy Administration 1976). In some areas, railroad capacity should be expanded and upgraded, and existing capacity should be more fully utilized (Electric Power Research Institute 1976). A survey of the major coal-carrying railroads (U.S. Department of Transportation 1976b) indicates that these railroads anticipate a rather optimistic 95 percent increase in coal traffic, from 341 million tons in 1974 to over 700 million tons in 1980 (Table 5.1), and the majority of railroads have adopted planning processes to project future coal and other traffic demand and have identified their capacity requirements. Estimates (U.S. Comptroller General 1977, pp. 5-10) of investment requirements based on the survey are presented in Table 5.2.

Table 5.1. Projected Coal Traffic By Rail District

	Total Rail Traffic				% Increase in Each District (1980 Compared with 1974)
	1974		1980		
Rail District[a]	Million Tons	%	Million Tons	%	
Eastern	195	52.6	288	39.8	48
Western	66	17.8	279	38.5	323
Southern	110	29.6	157	21.7	43
Total	371	100.0	724	100.0	95

From U. S. Department of Transportation (1976c). (As cited in U. S. Comptroller General [1977], p. 5.6.)

[a]The eastern rail district consists of all states north of Kentucky and North Carolina and east of the Mississippi River. The southern district consists of all other states east of the Mississippi River. The western district consists of all states west of the Mississippi River.

In a more recent survey of the railroads (Federal Energy Administration 1976), it was determined that all solvent railroads plan to acquire the equipment that will be needed to meet increased coal traffic. Physical limitations, in most cases, are not viewed as a problem for expansion of track or operating trains. In addition, the lead time for manufacturing railroad equipment is generally regarded as being shorter than the time required to open new mines (Federal Energy Administration 1976).

It is expected that some relatively short segments of right-of-way costing $300 million will be constructed between now and 1985 to improve access to coal resources. The investment required to meet the projected increase of coal rail traffic between 1977 and 1985 will be $5-7 billion for rail cars and $4-5 billion for track, primarily in the west and midwest* (U.S. Department of Transportation 1978, p. 11-21). The major uncertainty concerning the ability of the railroads

*The Federal Railroad Administration released, in October 1978, the results of a preliminary report on the capital needs of the railroad industry pursuant to Section 504 of the Railroad Revitalization and Regulatory Reform Act of 1976. The report is in the process of being finalized.

Table 5.2. Planned Railroad Investment to Meet 1980 Coal Needs

Investment	Expenditure (millions of dollars)			
	Rail District			
	Southern	Western	Eastern	Total
Hopper cars[a]	$667[b]	$1,044[b]	$1,189[b]	$2,900
Locomotives	60[b]	539[b]	66[b]	665
Physical plant	242	1,135	182	1,559
Maintenance facilities	1	102	--	103
Total	$970	$2,820	$1,437	$5,227

[a]Includes replacement of retired equipment.

[b]Estimate based on TSC survey breakdown of regional or hopper car/locomotive requirements.

From U.S. Comptroller General (1977), p. 5.10.

to carry the increased coal traffic projected for the future is whether the railroad will be able to finance the improvement required for the existing rights-of-way particularly for those financially weak railroads in the midwest. The Railroad Revitalization and Regulatory Reform Act of 1976 (4R Act) provides major financial aid to some of those financially weak railroads in the midwest and west. The public financial assistance under Sections 505 and 411 of the 4R Act has been heavily directed to the marginal midwestern railroads. Virtually all the approved financial assistance projects to date are related to upgrading coal hauling facilities (U.S. Department of Transportation 1978, p. 11-24). The continuation of this trend would be favorable in handling the projected increased railroad coal traffic.

If the predicted coal supply grows at a reasonably even rate throughout the period, most of the solvent railroads, particularly in the west, can handle future coal traffic without government aid (Federal Energy Administration 1976). Capital availability is not viewed as a critical constraint to most of those railroads (e.g. Union Pacific, Burlington Northern) (Federal Energy Administration 1976; U.S. Department of Transportation 1978).

The midwestern and western rail lines would require an extensive upgrading of the tracks. These tracks were originally constructed for hauling grain, and much of this lightweight rail is still in use for coal traffic. The financially weak midwestern railroads are having serious problems attracting private investors for expansion of coal-carrying capacity. Public financial assistance under a program created by the Railroad Revitalization and Regulatory Reform Act may be necessary to meet needs. Section 803 of FUA authorizes up to 100 million dollars for deposit in the Railroad Rehabilitation and Improvement Fund established under Section 502 of the 4R Act.

Some bankrupt eastern railroads, amalgamated as Conrail (a major coal-hauling railroad operating through much of the northeast and midwest), have more serious problems in meeting the increased demand for coal. Until recently, funds were not available to Conrail to maintain track and upgrade cars and locomotives (Federal Energy Administration 1976; U.S. Department of Transportation 1978). Penn Central alone anticipates the need for more than 10,000 new hopper cars by 1985, assuming a doubling of the coal traffic in its service area during the interim period (Federal Energy Administration 1976). Conrail, which projects that one-third of all its traffic will be for coal carriage, is currently receiving public funds which will total approximately $2.1 billion, and is engaged in a $6 billion overall rehabilitation and modernization program, largely to accommodate the projected coal traffic (U.S. Department of Transportation 1978). Some of the smaller insolvent railroads have key functions in coal delivery because of their locations and their essential roles in connecting shipments between roads or between other railroads and water terminals or final destinations (e.g., the Reading, Erie Lackawana, Lehigh Valley, Annator, and Lehigh and Hudson railroads) (Federal Energy Administration 1976; U.S. Railway Association 1975).

5.1.1.2 Truck

Truck transportation is the major mode of short-haul coal movement, and is the most versatile. Average hauling distance has been estimated at 55 miles for mine-to-market hauls (11 percent of total production) and 5 to 10 miles for mine-to-tipple hauls (30 percent of total production) (U.S. Department of Transportation 1978, p. II-14). A coal truck typically carries 20 tons of coal and may carry as much as 100 tons in off-highway service. Nationally, about 10 percent of total production is estimated to be hauled from mine to mine-mouth generating plant (U.S. Department of Transportation 1978, p. II-8). The percentage will vary on a regional basis. For example, from January to September of 1978, one-third of all coal was shipped by truck in Demand Regions II and VIII, including Pennsylvania, Ohio, Colorado, and North Dakota (U.S. Department of Energy 1978).

Through 1985, mine-to-tipple distances are likely to increase if many of the new mines are not located near bulk loading facilities (U.S. Department of Transportation 1978, p. II-8). The increases in coal production and the short production life of surface mines, particularly in the Appalachian region (Table 5.3), will make the heavy capital investment by other transportation modes uneconomical (U.S. Department of Transportation 1978, p. II-9). As indicated by the study under Section 153 of the Federal-Aid Highway Act of 1976 (U.S. Department of Transportation 1978), highway needs from energy-related activities were identified by 27 states. It is expected that approximately $7.3 billion will be needed between now and 1985 for building or rebuilding roads for hauling coal (U.S. Department of Transportation 1978). The Appalachian states account for $6.4 billion, 88 percent of this amount.

On a regional basis, the energy related highway needs, identified by the study under Section 153 of the Federal Aid Highway Act of 1976, are greatest in the Appalachian states (Department of Transportation, 1978, Table II-4). The increase of coal haulage by truck anticipated east of the Mississippi, especially in Appalachia could well become so significant as to cause a bottleneck in coal production (U.S. Department of Transportation 1978). The truck tonnage could increase even more rapidly than expected if coal reserves are developed in areas not served by the bulk hauling modes.

Table 5.3. Coal Movements in Appalachia by State of Origin, 1974
(thousands of short tons)

	Truck Only	Truck and Rail	Truck and Water	Rail Only	Water Only	Other[a]	Total
Alabama	2,598 (13.3)[b]	5,681 (29.0)	2,995 (15.3)	5,014 (25.6)	1,446 (7.4)	1,843 (9.4)	19,577
Eastern Kentucky	4,597 (5.4)	68,530 (80.5)	968 (1.1)	11,050 (13.0)	- -	- -	85,145
Maryland	835 (37.3)	1,403 (62.7)	- -	- -	- -	- -	2,238
Ohio	11,478 (27.8)	3,666 (8.9)	2,738 (6.6)	14,734 (35.6)	3,195 (7.7)	5,538 (13.4)	41,349
Pennsylvania	18,711 (21.3)	25,536 (29.1)	2,116 (2.4)	20,793 (23.7)	13,312 (15.2)	7,173 (8.2)	87,641
Tennessee	2,343 (25.4)	2,460 (26.6)	754 (8.2)	3,683 (39.9)	- -	- -	9,240
Virginia	8 (<0.1)	29,420 (80.4)	- -	7,196 (19.6)	- -	- -	36,624
West Virginia	3,122 (3.2)	25,587 (26.0)	5,588 (5.7)	56,424 (57.3)	2,218 (2.3)	5,572 (5.7)	98,511
Appalachian Region	43,692 (11.5)	162,305 (42.6)	15,137 (4.0)	118,893 (31.3)	20,172 (5.3)	20,126 (5.3)	380,325

From Committee on Energy and Natural Resources (1977, 1978).

[a]Conveyor movement and mine-mouth consumption.

[b]Numbers in parentheses are percents of row totals.

In the areas where the railroads do not plan to build additional spur lines or have abandoned a portion of the track during reorganization of the railroads, coal transport is likely to be primarily by highway. In addition, if the mandated pollution control technology for coal-fired boilers makes it uneconomical to use western coal in the midwest and east, the utilization of eastern coal and, consequently, truck hauling in the east probably will increase.

The Coal Transportation Task Force (U.S. Department of Transportation 1978) concluded that "the coal-producing states of Appalachia are heavily dependent on highway transportation for getting their coal to the market. Because Federal aid programs do not take into account the special needs created by heavy coal traffic and state revenues are inadequate, these states are likely to have an increasingly difficult time providing a highway system capable of meeting the growing coal hauling demands. Because the Appalachian states are of such major importance in meeting national coal production goals, and because highways play such an important role in Appalachian coal transportation, the improvement of coal haul highways in Appalachia is essential to ensure that the goals of the National Energy Plan will be met."

The Task Force predicts that approximately $7.3 billion or 76 percent of the coal-related highway improvements needed between now and 1985 would be incurred by building or rebuilding roads used for hauling coal, and that $6.4 billion or 88 percent of the estimated capital requirement for coal-haul roads would be required in Appalachia.

In the case of coal truck fleets, the heavy truck and trailer manufacturers have suggested that sufficient excess capacity already exists to produce the additional trucks required in the near future (U.S. Department of Transportation 1978, p. II-3).

The increase in coal truck traffic is expected to result in damage to roads used for coal hauling. The damage to a road from a 55,000-pound truck is reported equal to that of roughly 2,500 automobiles (Committee on Energy and Natural Resource 1977, p. 82). The short haul required for the shipments of coal connecting long-haul modes to small industrial boilers owners, particularly in Demand Regions I and VI, is likely to raise safety and transportation problems. In particular, the passing of coal trucks through relatively congested residential areas will exacerbate the need for grade crossings, rerouting, and maintenance of existing roads and highways.

Automobile trips generated by coal development and the consequent population shift in all states during 1977 to 1985 would reach 4 million trips--about 47 percent of the total trips generated by all energy-related activities (Watson et al. 1977, p. 3-22).

5.1.1.3 Movement of Coal by Water

The transportation of coal by water accounted for approximately one-tenth of all bituminous coal shipments loaded and one-quarter of all shipments unloaded in 1974 (U.S. Department of Transportation 1978, p. II-29).

Waterways constitute a major means of transportation in much of the eastern U.S., particularly the area surrounding the Great Lakes and the inland rivers, including the Ohio and Kanawha rivers, the Ohio-Tennessee river, and the Mississippi-Gulf Coast System (U.S. Department of Transportation 1978, p. II-29). The hardware for the shipment of coal by barge or other water carrier includes tugboats or other self-propelled vessels which push the tows, composed of as many as thirty-six barges, usually of 1500 tons capacity (Committee on Energy and Natural Resources 1977, p. 59).

Between now and 1985, coal traffic on the waterways is expected to grow significantly. Barge traffic is expected to increase by 8.8 to 16.4 percent (U.S. Bureau of Mines 1976, p. 1). The Federal Power Commission and the Federal Energy Administration have identified that an additional 38.5 million tons of coal will be transported by water by 1985 for coal-consuming power plants (U.S. Department of Transportation 1978) (Table 5.4). Water transportation was found to be a feasible alternative mode for industry, where some 800,000 tons of coal will be transported annually (U.S. Department of Transportation 1978, p. II-34).

Increased coal traffic for new and converted power plants and industries will occur primarily along large portions of the Atlantic Coast and the Ohio River. The upper Mississippi River will be little affected by western coal shipments by barge (U.S. Department of Transportation 1978, p. II-43).

Some of the facilities and equipment planned to accommodate this growth is already underway, as indicated in Appendix E.2.4.2. The number of additional barges required by 1985 is estimated to be in the range of 1,750 to 5,940 (U.S. Bureau of Mines 1976; U.S. Department of Transportation 1978). Incremented domestic coal traffic on the Great Lakes is estimated at 5.6

Table 5.4. Estimated Additional Demand For Waterborne Transportation of Coal by 1985[a]

Source of Demand	Waterway	Additional Coal (10^6 tons)
Power plant conversion	Atlantic Coast	14.2
	Illinois River	1.7
	Total	15.9
New power plants	Illinois River	0.3
	Mississippi River	3.2
	Ohio River	18.1
	Other	1.0
	Total	22.6
Total		38.5

From U.S. Department of Transportation (1978).

[a]Based on power plants scheduled for completion or conversion by 1985.

million tons by 1985, requiring additional vessels having a total capacity of 136,000 tons; such vessels cost $100 million in 1976 dollars (U.S. Department of Transportation 1978, p. II-38).

Coal movement in the area of the Mississippi, Ohio, Tennessee, Kanawha, and Green/Barren rivers would require 48 new tugboats at a cost of $140 to $200 million, and 1120 additional barges at a cost of $168 million by 1985 (U.S. Department of Transportation 1978, p. II-36).

In the short run, most of the constraints on lock capacity should be amenable to solutions not requiring structural modification (improved scheduling, helper boats, etc.) (U.S. Department of Transportation 1978, p. II-35). However, constraints could be significant after 1985 (Desai 1976; U.S. Department of Transportation 1978, p. II-35).

The transportation rates of common carriers operating on inland waterways are typically lower than the rail rate by about 20 percent (Committee on Energy and Natural Resources 1977, p. 93). However, there are several areas of constraints (U.S. Department of Transportation 1978). These include Lock and Dam 26 at Alton, Illinois, on the Mississippi River, and points on the Gulf Intra-Coastal Waterway, Ohio River-Gallipolis Lock, Illinois Waterway, Kanawha River (Winfield Lock), and Monongahela River (Lock 3) (Electric Power Research Institute 1976; U.S. Department of Transportation 1978). The industry has identified the Industrial Lock at New Orleans as a potential bottleneck (U.S. Department of Transportation 1978).

There is concern in transportation industries about the user's charge (House Bill 8309) that requires the users of the Inland Waterway System to pay fees. A bill passed both the Senate (May 4, 1978) and the House of Representatives (October 13, 1977) and was referred to a House/Senate conference but did not become law. The bill may be re-introduced in forthcoming congressional sessions. The user's charge could bring an impact to the competitive positions of alternative transportation modes, particularly waterways and railroads.

5.1.2 Impacts of the Proposed Action on Transportation

From January to September of 1977, about 44.4 million tons of coal were shipped to various industrial users--an increase of 14 percent over 1976 for similar shipments (U.S. Department of Energy 1978). Shipments to electric utilities also were increased 9 percent from 340 to 376 million tons. An annual national growth rate of 5.4 percent is anticipated from 1975 to 1985, and 5.0 percent from 1975 to 1990 (Energy Information Administration 1978).

The additional coal demand resulting from the regulatory program is estimated based on data provided by PIES Midrange Trendlong Scenario and on other published data (see Sec. 3). The additional increases in domestic coal demand are presented in Table 3.7 and 3.8. In 1985, the additional demand increase from the proposed regulatory program would constitute about 7 percent of the nationwide baseline coal demand.

In the southwest (Demand Region VI), the west (Demand Region IX), and New England (Demand Region I), the additional demands due to the regulatory program (regulatory demand) are 44, 38, and 16 percent of the 1985 trend-long coal demand, respectively. The percentage increases in regional coal demand, both from the trend-long baseline projection and regulatory demand, are particularly large in the southwest and west regions.

Large portions of coal required in the southwest and west would be likely to originate from the western mines, including the central west and the Gulf regions (Supply Region 5), and the Northern Great Plains region (Supply Region 6), as indicated in Tables 3.7 and 3.8.

5.1.2.1 Transportation Modes

As shown in Tables 3.7 and 3.8, the additional coal demand due to the proposed action is projected to be particularly high in Demand Regions IV, VI and IX in that order. About 90 percent of the coal required in 1985 in the southwest and 80 percent of coal required in the central region will originate in Supply Regions 5 and 6. The unit train will likely play a major role in transporting western coal to Demand Regions V, VI, and VII. Transportation of western coal by barge will be limited; however, small amounts of eastern coal (less than 10 percent of the regulatory demand in the southwest and central regions in 1985 and 1990) will be shipped by water. The alternative to shipment of western coal by unit train in those regions would be slurry pipelines. Coal slurry pipelines could prove to be an economic mode of coal transportation in the areas where excess capacity of high-quality pipelines and inexpensive water are available; and the competitions from the railroads and barges are limited due to economic and geographic constraints. In spite of the advantage of the pipeline transport of coal in terms of variable cost, the installed system will be inflexible. Thus, the most favorable situation for pipeline transport will be connecting large closely spaced mines and large consuming capacities. The extent to which slurry pipelines will be used is uncertain.

The largest increases in coal supply generated by the regulatory program would be in Supply Region 5 (the central-west Gulf Region), Supply Region 6 (the Northern Great Plains), and Supply Region 2 (Central Appalachia), as shown in Tables 3.7 and 3.8.

While the additional traffic from the western coal supply region will be largely on the railroads, this is not likely to create financial problems for most of the solvent western railroads.

The impacts of abandoned rail lines on the transportation availability to individual boilers have not been analyzed. Site-specific analyses will indicate whether individual boilers will be isolated from rail access through abandonment of specific secondary lines. This concern is greatest in the northeast (Meier et al. 1977). When Conrail was established, some of 5700 miles of track was not accepted in the system; of this, some 3000 miles of track is to be abandoned, and the other 2700 miles of track is expected to be continued under federal and state subsidies. A portion of the abandoned track will be protected under the Railbank Provisions of the 4R Act and can physically be utilized in the future for coal hauling if upgrading is warranted (Federal Energy Administration 1976). However, in some cases, failure to exercise the right over a certain period of time results in automatic reversion of the title to the original title holder. In addition, the rail bank as presently conceived does not address the question of rail access to the coal-fired plant site (Watson et al. 1977, p. 42). This may result in some of the industries located in scattered areas having to increase their reliance on coal hauling by truck. The conversion to coal by industrial boiler owners is not likely to be large enough to generate sufficient revenue on abandoned railroads to revive the portion of the track serving these boilers.

In the mid-Atlantic region (Demand Region III) and midwest (Demand Region V), the coal delivered by river constitutes approximately one-fifth of the total regional shipment during January-September 1977 (U.S. Department of Energy 1978). Some of the additional coal originating from areas surrounding the Ohio, Monongahela, and Green Barren rivers and shipped to Demand Regions III and V is anticipated to be transported by water.*

The additional coal traffic could contribute to the congestion and delay in the upper Mississippi and Ohio rivers and part of the Tennessee River; these areas are identified as critical links to limit the increasing water traffic in 1985 (Electric Power Research Institute 1976).

Despite the low ton-mile cost of the barge, western coal shipments by water will likely be limited to eastern, midwest, and southwestern destinations. The transloading expense and greater distance of the barge traffic in those flows is not likely to be competitive with alternative

*For the industrial conversions, water transportation was found to be a feasible alternative mode in the case of some 800,000 tons annually (U.S. Department of Transportation 1978, p. II-34).

transportation modes, principally unit trains. However, the waterborne transportation of Appalachian coal to some coal users in the south-central and midwest regions would have significant transportation cost advantages to alternative modes. Although the coal-fired boiler owner would realize transportation cost from Appalachian coal, these deep mines would require higher prices than strip-mined western coal (Desai 1976).

Meeting the projected increase of the regulatory demand will require an increase in coal truck traffic. Truck traffic will play an important role in transporting coal from the small and the short-lived mines and small and dispersed industrial coal users, particularly in the Appalachian region. The possibility of the increasing use of unit trains, in addition to the railroad abandonment through reorganization of eastern and midwestern railroads, could increase the share of coal hauled by truck significantly.

5.1.2.2 Local Impacts

The annual coal requirement for 24 major fuel-burning installations among the 24 surveyed by FEA ranges from 11,000 to 200,000 tons per year in the period from 1979 to 1983 (Federal Energy Administration 1977a, 1977b). Assuming 20 deliveries per year by train and 85 tons per car, the annual demand of coal would require an additional 7 cars (for 11,000 tons of coal) to 118 cars (for 200,000 tons of coal). Using 40-ton trucks, the 11,000 and 200,000 tons of coal demand would generate 275 and 5000 trucks per year, respectively.

The increase in coal traffic will additionally generate significant impacts on the local communities, including (1) road damage by heavy coal trucks, (2) disruption of local traffic flow, and (3) secondary growth at the transportation centers (e.g., developments at shorelines due to barge serving activities).

5.2 AIR QUALITY

5.2.1 Mining and Mine Site Processing

Air pollutants from surface coal-mining operations originate from diesel-powered equipment and from wind erosion of the disturbed land. Estimates of particulates caused by wind erosion and total emissions from diesel-fueled equipment are presented in Table 5.5. These emission estimates should be considered accurate only within one order of magnitude. Particulates from wind erosion as a result of increased surface mining due to the proposed action are presented in Table 5.6.

Table 5.5. Surface Mining Emissions Factors

Demand Region[a]	Emissions (tons/10^{12} Btu)	
	Particulates	Diesel[b]
III	0.05-0.07	2.3-3.6
IV	0.04-0.07	2.1-3.5
V	0.05	2.55
VI	0.05	2.55
VII	0.05	2.55
VIII	2.27	1.85
IX	6.60	1.90
X	2.27	1.85

From University of Oklahoma (1975).

[a]Regions I and II contain no measurable coal resources and thus there will be no surface mining emissions.

[b]Includes SO_x, NO_x, CO, and hydrocarbons.

Table 5.6. Estimated Particulates from Wind Erosion Resulting from Increased Surface Mining

Particulates (ton/yr)	Demand Region							
	III	IV	V	VI	VII	VIII	IX	X
1985	4 (3)[a]	5 (3)	1 (8)	2 (2)	16 (37)	100 (8)	300 (15)	70 (6)
1990	5 (4)	8 (6)	2 (20)	4 (3)	30 (40)	200 (12)	500 (25)	150 (8)

[a]Numbers in parentheses are percents of base-case emissions.

These emissions were calculated by applying the emission factors in Table 5.1 to the estimated coal mining increases from each demand region, using the average Btu content of the coals in each region. The percentages are assumed equal to the percentage of coal production to base case production in Table 3.9.

These increased particulate emissions are negligible when compared with the national emissions of particulates in Table 4.2. Wind erosion is most severe in Demand Regions VIII, IX, and X, where surface mining predominates, and where high winds and dry soil result in severe wind erosion. Fugitive dust from mining operations is generally of such a large size that it settles to the ground quickly. The increased dust may present a problem on a local basis, but will have no impact on the air quality of any demand region.

The variation in total diesel emissions shown in Table 5.5 is due to the amounts of overburden that must be moved, as well as the percentage of diesel rather than electric power. In Demand Regions III, IV, and V, approximately 33 tons of overburden are removed per ton of coal recovered, while in Regions VI, VII, VIII, and IX, the ratio is 13 to 1. Also, in Regions VIII and IX, much of the equipment is electrically powered, reducing mine-site emissions; however, emissions do occur at the electric generating station. The highest diesel emissions occur in Demand Regions III and IV (University of Oklahoma 1975).

Because electrically powered equipment is generally used in underground mines, mine-site emissions are not a problem in areas of underground mining. Some emissions from above-ground coal processing at underground mines may occur, but will be negligible.

5.2.2 Transportation

The extent to which transportation will affect air quality will depend primarily on the degree to which existing transportation facilities can be used (Hittman Associates 1975). Transportation impacts will also be affected by the efficiency of equipment and the number of trips made. Since the eastern regions already have a dense transportation pattern, the impacts from construction of new lines and roads can be expected to be less than that for the western regions, where the much-less-developed transportation system will be required to accommodate not only an increase in the quantity of coal produced for western consumption, but also an increase in coal production for the east, with the attendant longer hauls required.

Air emissions from all modes of coal transportation will consist of wind-borne dust from the coal during transport, and the rail or truck diesel fuel combustion products associated with this transport. Windblown dust from open car tops is substantially reduced when the coal is sprayed with oil prior to shipment. Haul distances govern the magnitude of the total amounts of diesel fuel combustion products emitted. The amount of diesel fuel consumed (about 4000 gallons to transport 1000 tons of coal 1000 miles) and therefore the quantity of emission products produced could be increased detectably over baseline emissions if coal is delivered from western coal fields to industries in the east or midwest presently dependent on other fuel sources (Federal Energy Administration 1977c, p. iv-196).

Each transportation mode has its own characteristic contribution to air quality degradation. Trucks produce the greatest air pollution per ton mile within a given distance, whereas closed pipeline systems produce almost none. Trucks, however, account for only a small portion (10.7 percent) of the total ton-mile coal shipments and therefore contribute little to the overall increase in air pollution (University of Oklahoma 1975, pp. 1-122). Transportation of coal by rail is by far the major source of air pollution, since 69.2 percent of all bituminous coal is shipped by this mode. Unit trains provide more efficient coal transportation and therefore contribute fewer air pollutants than do conventional trains. Mixed or conventional trains have greater (by a factor of almost two) wind loss and particulate emissions than unit trains because it usually takes them longer than unit trains to travel a given distance, due to delays for loading and unloading other freight (Federal Energy Administration 1977c, p. iv-196).

The estimated air pollutants resulted from transporting increased coal required by the proposed action through 1985 and 1990 are presented in Tables 5.7 and 5.8, respectively. The data base from which these calculations are derived is presented in Table 5.9. Total coal tonnages used in the calculations are taken from Tables 3.7 and 3.8. The percentages of coal expected to be moved from the supply regions to the demand regions by rail, barge, and truck are presented in Table 5.10. These percentages are based on the Department of Energy's Data Report for Bituminous Coal and Lignite Distribution for 1977. Although it is possible to generalize about future coal transportation patterns, it is difficult to provide the specific percentages needed to calculate transportation air emissions because limiting factors such as economics, equipment availability, and social and political constraints are not predictable. For this reason, the DOE data were adapted to provide the data presented in Table 5.10. The DOE report did not, however, distinguish between unit train and conventional or mixed train transportation. Although unit train transportation is expected to increase in most areas by 1985, conventional car service will still be used by an indeterminable number of smaller mines and industrial consumers whose supply and demand tonnages are too small to justify utilization of the unit train. Therefore, in determining air emissions for the total percentage of rail transportation in each region, both the unit and mixed train values are presented (with the exception of the Southwest and Northern Great Plains coal supply region), each based on the hypothetical assumption that 100 percent of the total percentage of rail movement in each region would be from either the unit or mixed mode. Actual emissions would be somewhere between these two extreme values.

Air pollutants resulting from coal transportation are not limited to the region in which the coal is mined (the supply region), but are emitted in all the states along the transportation route to the final destination (the demand region). There is considerable overlap between supply and demand region boundaries and functions. For example, portions of Supply Region 6 are located in both Demand Region X and Demand Region VIII. Therefore, Demand Region VIII may be receiving coal from a supply region within its own boundaries. In another case, Demand Region VIII may act as a supply region (Supply Region 7) for some other demand region. Realistically, therefore, one region of the country may be receiving more air pollutants from coal transportation than another because it may transport coal both intra- and interregionally. Further examples of this are Supply Region 8 which is a part of Demand Region VI, and Supply Region 4, which is a part of Demand Region V. These distinctions are not made in Table 5.7; however, supply and demand region boundaries are defined in Figures 3.3 and 3.4.

Transportation distances for rail were assumed to be from the city centers of each of the coal supply regions to the demand centers of each of the demand regions. These distances were determined from the National Atlas (see Table 5.11). The average haul distance assumed for all truck transport was 55 miles; trucking economics would probably prohibit longer hauls. The average haul distances assumed for barge transport were 800 miles for Supply Region 1 and 300 miles for Supply Regions 2 through 8.

The emissions presented in Tables 5.7 and 5.8 should not be considered absolute, but rather an estimate of the potential impact that increased transportation requirements could have on air quality. A two percent wind loss is assumed for conventional trains as opposed to one percent for unit trains, river barges, and trucks. Other air emissions presented are due to diesel exhaust emissions. The additional annual contributions (through 1990) of particulates (256,934 tons, NO_x (25,408 tons), SO_x (19,387 tons), hydrocarbons (15,027 tons), CO (23,110 tons), and aldehydes (3,250 tons) are negligible (less than five percent) compared with general national transportation air emission projections for 1990. A comparison of the air emissions from coal transportation for the regulatory program as opposed to the baseline scenario is presented in Table 5.9. Through 1985 and 1990, coal transportation air emissions resulting from the regulatory program would be less than 9 and 8 percent, respectively, of the emissions which would result from the requirements for coal transportation for the 1985 and 1990 baseline cases.

5.2.3 Storage and Onsite Processing

Storage of coal and the onsite processing of coal before combustion can produce particulate matter that enters the atmosphere. Dust from the coal storage piles is a function of wind speed, coal size, coal moisture content, and other factor, including mitigative measures taken to reduce fugitive dusting. Coal processing, particularly coal handling and crushing operations, can also produce fugitive dusting if proper mitigative measures are not taken. Because the coal-dust particles produced are large, they will quickly settle to the earth's surface. While some increases in TSP may be noted on a local scale, there will be no measurable regional effects.

5.2.4 Combustion

The predicted changes in annual average ambient air quality due to the proposed program were calculated by the statistical trajectory model developed at Argonne National Laboratory (Sheih

Table 5.7. 1985 Projected Air Pollutant Emissions from Transportation of Coal from Supply Regions to Demand Regions (short tons)

Demand Region	Particulates				NO_x				SO_x				Hydrocarbons				CO				Aldehydes			
	M[a]	U[a]	B[a]	T[a,b]	M	U	B	T	M	U	B	T	M	U	B	T	M	U	B	T	M	U	B	T
From Supply Region 1 to Demand Regions I, II, III and V																								
I	2,097	1,106			204	258			117	223			136	171			191	240			30	38		
II	875	461	86	272	85	108	9	20	74	93	9	2	57	72	4	2	79	100	7	12	13	16	N[c]	N
III	634	334	78	564	62	78	8	42	53	67	8	3	41	52	6	4	58	73	6	26	9	11	N	N
V	1,023	540	179	147	99	126	18	11	86	109	19	N	67	84	5	4	93	117	7	27	15	18	N	N
Total[d]	4,629	2,441	343	983	450	570	35	73	330	492	36	5	301	379	15	10	421	530	20	65	67	83	N	N
From Supply Region 2 to Demand Regions I, II, III, IV, V, VI and VII																								
I	128	48			11	13			10	12			7	9			10	13			2	2		
II	473	176	34		40	49	1		35	43	1		27	33	N		38	46	1		6	7	N	
III	740	276	116	15	63	77	4	1	55	67	5	N	42	52	3	N	59	72	4	2	9	11	N	N
IV	1,518	565	242	370	130	158	9	29	113	137	11	2	87	106	6	3	121	148	8	40	19	23	5	N
V	1,231	458	287	32	105	128	11	3	91	111	12	N	70	86	7	N	98	120	10	3	15	19	N	N
VI	716	267	1,089		61	74	43		53	65	46		41	50	27		57	70	37		9	11	2	
VII	58	22	5		5	6	N		4	5	N		3	4	N		5	6	N		N	N	N	
Total[d]	4,864	1,812	1,773	417	415	505	68	33	361	440	75	2	227	340	43	3	388	475	60	45	60	73	7	N
From Supply Region 3 to Demand Regions IV and VI																								
IV	707	263	29		60	73	1		52	64	1		40	49	N		56	69	1		9	11	N	
VI	377	140	30	1,525	32	39	1	120	28	34	1	8	22	26	3	12	30	37	1	163	5	6	N	2
Total[d]	1,084	403	59	1,525	92	112	2	120	80	98	2	8	62	75	3	12	86	106	2	163	14	17	N	2
From Supply Region 4 to Demand Regions IV, V and VII																								
IV	1,351	706	637	485	119	145	25	36	103	129	27	N	80	99	18	4	111	139	21	22	17	22	1	N
V	792	414	339	253	70	85	13	19	60	76	15	N	47	58	9	2	65	82	12	12	10	13	N	N
VII	234	122	31	26	21	25	2	2	18	22	2	N	14	17	N	N	19	24	N	1	3	4	N	N
Total[d]	2,377	1,242	1,007	764	210	255	40	57	181	227	44	N	141	174	27	6	195	245	33	35	30	39	1	N
From Supply Region 5[e] to Demand Regions VI and VII																								
VI	3,529	1,804		24,978	161	203		1,843	139	177		135	107	136		184	150	190		1,123	24	30		29
VII	361	185		273	17	21		20	14	18		1	11	14		2	15	19		12	2	3		N
Total[d]	3,890	1,989		25,251	178	224		1,863	153	195		136	118	150		186	165	209		1,135	26	33		29
From Supply Region 6 to Demand Regions V, VI, VII, VIII, IX and X																								
V		1,362	42			153	3			134	4			103	2			144	3			22	2	
VI		55,423				6,244				5,437				4,174				5,847				912		
VII		2,056	1			232	N			202	N			155	N			217	N			34	N	
VIII		427		438		48		32		42		2		32		3		45		20		7		N
IX		4,486				505				440				338				473				74		
X		1,204				136				118				91				127				20		
Total[d]		64,958	43	438		7,318	3	32		6,373	4	2		4,893	2	3		6,853	3	20		1,069	2	N
From Supply Regions 7 and 8 to Demand Regions VI, VII, VIII, IX and X																								
VI		8,218				625				543				417				586				92		
VII		85				6				6				4				6				N		
VIII		289		53		22		4		19		N		15		N		21		2		3		N
IX		25,261		513		1,922		38		1,668		2		1,281		4		1,800		23		283		N
X		232		6		18		N		15		N		12		N		17		N		3		N
Total[d]		34,085		572		2,593		42		2,251		2		1,729		4		2,430		25		381		N
National Totals	16,844	106,930	3,225	29,950	1,345	11,577	148	2,220	1,105	10,076	161	155	899	7,740	90	224	1,255	10,848	118	1,488	197	1,695	10	31

[a]M - mixed train; U - unit train; B - barge.

[b]Projections include only those regions where truck is a major mode of transportation.

[c]N indicates a negligible value (< 1).

[d]Includes negligible values listed in table.

[e]Texas lignite characteristics are not available; threfore, Northern Great Plains lignite characteristics are assumed in the calculations.

Table 5.8. 1990 Projected Air Pollutant Emissions from Transportation of Coal from Supply Regions to Demand Regions (short tons)

Demand Region	Particulates				NOx				SOx				Hydrocarbons				CO				Aldehydes			
	M[a]	U[a]	B[a]	T[a,b]	M	U	B	T	M	U	B	T	M	U	B	T	M	U	B	T	M	U	B	T
From Supply Region 1 to Demand Regions I, II, III and V																								
I	3,360	1,772			327	413			187	357			218	274			306	385			48	61		
II	1,544	814	152	480	150	191	16	35	131	164	16	4	100	127	7	4	139	176	12	21	23	28	N[c]	N
III	1,175	619	145	1,045	115	145	15	78	98	124	15	6	76	96	11	7	108	135	11	48	17	20	N	1
V	1,277	674	223	183	124	157	22	14	107	136	24	N	84	105	6	5	116	146	9	34	19	22	N	N
Total[d]	6,079	3,879	520	1,708	716	906	53	127	523	781	55	10	478	602	24	16	669	842	32	103	107	131	N	1
From Supply Region 2 to Demand Regions I through V																								
I	204	76			18	21			16	19			11	14			16	21			3	3		
II	835	311	60		71	86	2		62	76	2		48	58	N		67	81	2		11	12	N	
III	1,371	511	215	28	117	143	7	2	102	124	10		78	96	6	N	109	133	7	4	17	20	N	N
IV	2,900	1,079	462	707	248	302	17	55	216	262	21	4	166	202	11	6	231	283	15	76	36	44	10	N
V	1,537	572	358	40	131	160	14	4	114	139	15	N	87	107	9	N	122	150	12	4	19	24	N	N
Total[d]	6,847	2,549	1,095	775	585	712	40	61	510	620	48	4	390	477	26	6	545	668	36	84	86	103	10	N
From Supply Region 3 to Demand Regions IV and VI																								
IV	1,350	502	55		115	139	2		99	122	2		76	94	N		107	132	2		17	21	N	
VI	776	288	62	3,141	66	80	2	247	58	70	2	16	45	54	6	25	62	77	2	336	10	12	N	4
Total[d]	2,126	790	117	3,141	181	219	4	247	157	192	4	16	121	148	6	25	169	209	4	336	27	33	N	4
From Supply Region 4 to Demand Regions IV, V and VII																								
IV	2,478	1,295	1,169	890	218	266	46	66	189	237	50	N	147	182	33	7	204	255	39	40	31	40	2	1
V	989	517	423	316	87	106	16	24	75	95	19	N	59	72	11	2	81	102	15	15	12	16	N	N
VII	373	194	49	41	33	40	3	3	29	35	3	N	22	27	N	N	30	38	N	2	5	6	N	N
Total[d]	3,840	2,006	1,641	1,247	338	372	65	93	293	367	72	N	228	281	44	9	315	395	54	57	48	62	2	1
From Supply Region 5[e] to Demand Regions VI and VII																								
VI	6,077	3,107		43,014	277	349		3,174	239	305		232	184	234		317	258	327		1,934	41	52		50
VII	574	294		434	27	33		32	22	29		2	18	22		3	24	30		19	3	5		N
Total[d]	6,651	3,401		43,448	304	382		3,206	261	334		234	202	256		320	282	357		1,953	44	57		50
From Supply Region 6 to Demand Regions V through X																								
V		1,700	52			191	4			167	5			129	2			180	4			27	2	
VI		114,116				12,488				11,195				8,594				12,039				1,878		
VII		3,273	2			369	N			322	N			247	N			345	N			54	N	
VIII		793		813		89		59		78		4		59		6		84		37		13		N
IX		7,366				829				722				555				777				122		
X		2,206				249				216				167				233				36		
Total[d]		129,454	54	813		14,216	4	59		12,700	5	4		9,751	2	6		13,658	4	37		2,130	2	N
From Supply Regions 7 and 8 to Demand Regions VI through X																								
VI		16,921				1,287				1,118				859				1,207				189		
VII		135				10				10				6				10				N		
VIII		536				98				41		7		35		N		39		4		6		N
IX		41,428		841		3,152		62		2,735		3		2,100		6		2,952		38		464		N
X		424		11		33		N		27		N		22		N		31		N		5		N
Total[d]		59,444		852		4,580		62		3,931		10		3,022		6		4,239		42		664		N
National Total	25,543	201,523	3,427	51,984	2,124	21,387	166	3,855	1,744	18,925	184	278	1,419	14,537	102	388	1,980	20,368	130	2,612	312	3,180	14	56

[a]M - mixed train; U - unit train; B - barge.

[b]Projections include only those regions where truck is a major mode of transportation.

[c]N indicates a negligible value (< 1).

[d]Includes negligible values listed in table.

[e]Texas lignite characteristics are not available; threfore, Northern Great Plains lignite characteristics are assumed in the calculations.

Table 5.9. Data Base for Air Emissions[a] Resulting from Increased Transportation of Coal Due to the Proposed Action (ton/10^{12} Btu/mile)

	Particulates	NO_x	SO_x	Hydrocarbons	CO	Aldehydes
Unit trains						
Northern Great Plains	0.158	0.0178	0.0155	0.0119	0.01667	0.0026
Central region	0.07	0.0144	0.0128	0.00983	0.0138	0.00216
Northern Appalachia	0.0575	0.0134	0.0116	0.00891	0.0125	0.00196
Central Appalachia	0.0458	0.0128	0.0111	0.00856	0.01197	0.00188
Southwest	0.209	0.0159	0.0138	0.0106	0.0149	0.00234
Texas[b]	0.158	0.0178	0.0155	0.0119	0.01667	0.0026
Mixed trains						
Central region	0.134	0.0118	0.0102	0.0079	0.0110	0.00173
Northern Appalachia	0.109	0.0106	0.00919	0.00709	0.00991	0.00156
Central Appalachia	0.123	0.0105	0.00913	0.00702	0.00982	0.00154
River barge						
Central region	0.0667	0.00265	0.00283	0.00189	0.00223	0.00015
Northern Appalachia	0.0246	0.00238	0.00255	0.00153	0.00204	0.000119
Central Appalachia	0.058	0.00230	0.00246	0.00143	0.00197	0.000113
Truck						
Central region	19	1.4	0.104	0.14	0.866	0.023
Northwest	22.9	1.69	0.124	0.169	1.03	0.027
Northern Appalachia	17	1.28	0.093	0.128	0.776	0.021
Central Appalachia	16.4	1.29	0.09	0.124	1.754	0.02

Adapted from University of Oklahoma (1975), Tables 1-55 and 1-56.

[a]Based on an average haul distance of 16 km (10 mi). Particulates represent those associated with wind losses along the route and at the end points. The NO_x, SO_x, hydrocarbons, CO, and aldehyde emissions are those due to diesel fuel combustion.

[b]Data on Texas lignite characteristics are not available; therefore, Northern Great Plains lignite characteristics are assumed in the calculations.

1977). The energy consumed within each demand region, by fuel type for 1985 and 1990, with and without the proposed action, originated from the PIES model (see Sec. 3), and were disaggregated to the AQCR level within each demand region by the method described in Appendix D. The emissions of SO_2, NO_x and particulates were then assumed to meet New Source Performance Standards (NSPS) of 1.2 lb SO_2 per 10^6 Btu, 0.7 lb $NO_x/10^6$ Btu and 0.1 lb particulates/10^6 Btu, respectively. These standards are presently under revision by the Clean Air Act Amendments of 1977. Any new regulations will be at least as restrictive, so these assumptions provide a worst-case analysis of emissions and ground-level concentrations. The emission sources within each AQCR were located at one or two points, depending on present industrial locations. The effective stack height of the utilities was assumed to be 500 m, the industries 135 m, and residential and commercial 50 m. Isopleths of concentrations were computer generated. These isopleth values were overlain

Table 5.10. Percentages of Coal Expected to be Moved from Supply Regions to Demand Regions by Rail, Barge, and Truck by 1990

Supply Region	Demand Region I	II	III	IV	V	VI	VII	VIII	IX	X
1	R-100 - -	R-75 B-15 T-10	R-67 B-13 T-20	R-33 B-67 -	R-66 B-29 T-5	- - -	R-100 - -	- - -	- - -	- - -
2	R-100 - -	R-73 B-27 -	R-59 B-40 T-1	R-78 B-17 T-5	R-53 B-46 T-1	R-10 B-90 -	R-68 B-32 -	- - -	- - -	- - -
3	- - -	- - -	- - -	R-46 B-5 T-49	R-27 B-73 -	- - -	- - -	- - -	- - -	R-100 - -
4	- - -	- - -	- - -	R-37 B-55 T-8	R-44 B-49 T-7	- - -	R-69 B-27 T-4	- - -	- - -	- - -
5	- - -	- - -	- - -	R-12 B-38 T-50	R-49 B-50 T-1	R-49 B-1 T-50	R-49 B-<1 T-51	R-100 - -	- - -	R-100 - -
6	- - - -	- - - -	- - - -	- B-100 - -	R-62 B-38 - -	R-100 - - -	R-99 B-1 - -	R-60 - T-33 C-7	R-100 - - -	R-67 - - C-33
7	- - -	- - -	- - -	- - -	R-99 B-1 -	- - T-100	R-100 - -	R-85 - T-15	R-91 - T-9	R-93 - T-7
8	- -	- -	- -	- -	- -	- T-100	- -	- -	R-100 -	- -

From U.S. Department of Energy (1977).

R = rail; B = barge; T = truck; C = conveyor, tramway, private rail.

Table 5.11. Mileage Estimated for Transportation of Coal from the Supply Regions to Demand Regions

Supply Region	Demand Region									
	I Boston	II New York	III Philadelphia	IV Atlanta	V Chicago	VI Dallas	VII Kansas City	VIII Denver	IX San Francisco	X Seattle
Northern Appalachia Pittsburgh, Penn.	561	368	288		452					
Central Appalachia Knoxville, Tenn.	911	715	615	193	527	837	728			
Central Region Shawneetown, Ill.				470	388		400			
Texas Dallas						574[a]	562			
Northern Great Plains Sheridan, Wyo.					1139	1200	1015	428	1320	948
Southwest Grants, N. Mex.		2144				718	860	580	1236	1736

[a]This is the mileage between Dallas and El Paso, representing one of the longer hauls that could take place in the state.

Table 5.12. 1985 and 1990 Projected Annual Air Pollutant Emissions from Transportation of Coal by Supply Region
(short tons of emissions/10^{12} Btu)

Supply Region	Particulates		NO_x		SO_x		Hydrocarbon		CO		Aldehydes	
	BC	PA	BC	PA	BC	PA	BC	PA	BC	PA	BC	PA
						1985						
1	117,719	3,767	21,188	678	16,656	533	12,625	404	19,219	615	2,594	83
2	125,063	4,002	18,938	606	16,156	517	12,063	386	18,125	580	2,500	80
3	23,654	1,987	2,786	234	1,286	108	1,310	110	3,226	271	226	19
4	143,476	3,013	16,762	352	12,905	271	9,857	207	14,905	313	1,905	40
5	75,041	27,240	5,749	2,087	912	313	926	336	3,702	1,344	171	62
6	711,293	65,439	79,924	7,353	69,337	6,379	53,239	4,898	74,739	6,876	11,641	1,071
7 & 8	406,563	34,657	30,911	2,635	26,430	2,253	20,330	1,733	28,800	2,455	4,470	381
Total	1,602,809	140,105	176,258	13,945	143,682	10,392	110,350	8,074	162,716	12,454	23,507	1,736
						1990						
1	271,654	6,107	48,308	1,086	37,632	846	28,558	642	43,459	977	5,872	132
2	148,654	4,419	27,349	813	22,606	672	17,123	509	26,508	788	3,801	113
3	46,147	4,048	5,358	470	2,417	212	2,041	179	6,259	549	422	37
4	299,371	4,894	32,421	530	26,854	439	20,431	334	30,953	506	3,976	65
5	189,655	46,849	14,525	3,588	2,299	568	2,332	576	9,351	2,310	433	107
6	1,807,032	130,321	197,993	14,279	176,223	12,709	135,318	9,759	189,950	13,699	29,562	2,132
7 & 8	609,113	60,296	46,894	4,642	39,812	3,941	30,589	3,028	43,247	4,281	6,708	664
Total	3,371,626	256,934	372,848	25,408	307,843	19,387	236,392	15,027	349,727	23,110	50,774	3,250

BC - base case.
PA - proposed action.

with an AQCR map (see Fig. 5.1), and appropriate resultant concentrations within each AQCR were then determined. Particulate concentrations were assumed to be a constant 25 percent of SO_2 concentrations.

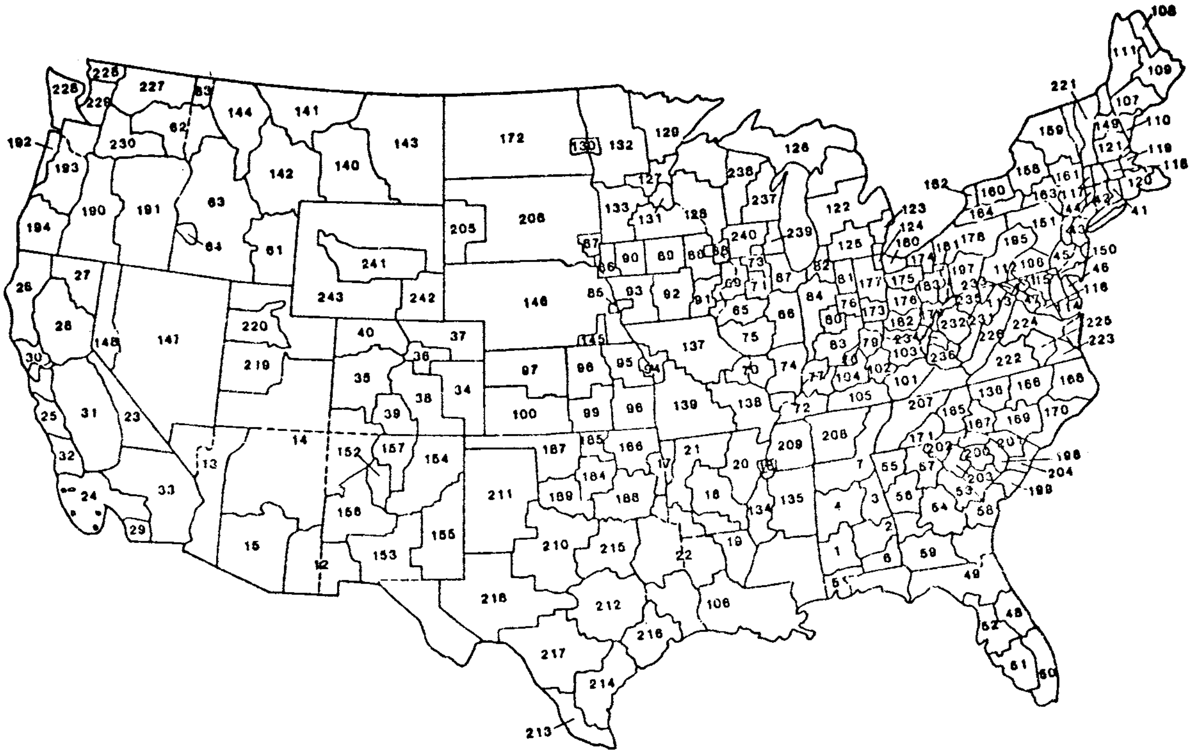

Fig. 5.1. Boundaries of Air Quality Control Regions. From Pechan (1977).

These ground-level concentrations are calculated by an analytical method which by design ignores local effects. Local ground-level concentrations dominate in industrialized regions, but these predicted values represent the contributions to background concentrations due to facilities upwind of the region.

Base-case emissions for 1985 and 1990 were calculated in a similar fashion, with representative emission factors (USEPA 1973) and emission heights for the industrial, utility, residential, and commercial sectors used to determine SO_2, NO_x, and particulate emissions. The 1985 and 1990 base-case concentrations of SO_2 are presented in Figures 5.2 and 5.3, respectively.

Maps of the national annual average concentrations of SO_2 resulting from the increased coal combustion for 1985 and 1990 are presented as Figures 5.4 and 5.5, respectively. The maximum predicted concentration is less than 2.5 $\mu g/m^3$. This compares with a predicted maximum concentration of 48 $\mu g/m^3$ in 1985 and 69 $\mu g/m^3$ in 1990 resulting from all emissions (Figs. 5.2 and 5.3). The 1976 measured background values (Fig. 4.8) average more than 20 $\mu g/m^3$, with reported maximum exceeding 80 $\mu g/m^3$.

Ground-level TSP concentrations follow the same patterns as SO_2, due to the constant percentage assumed between SO_2 and TSP concentrations. The maximum predicted regional TSP concentration resulting from the shift to coal is less than 1. 5 $\mu g/m^3$. This compares with the maximum predicted 1985 and 1990 TSP concentrations due to combustion of fossil fuels of 13 $\mu g/m^3$ and 18 $\mu g/m^3$. The 1976 measured national annual average background including natural sources was in excess of 35 $\mu g/m^3$, as presented in Figure 4.4.

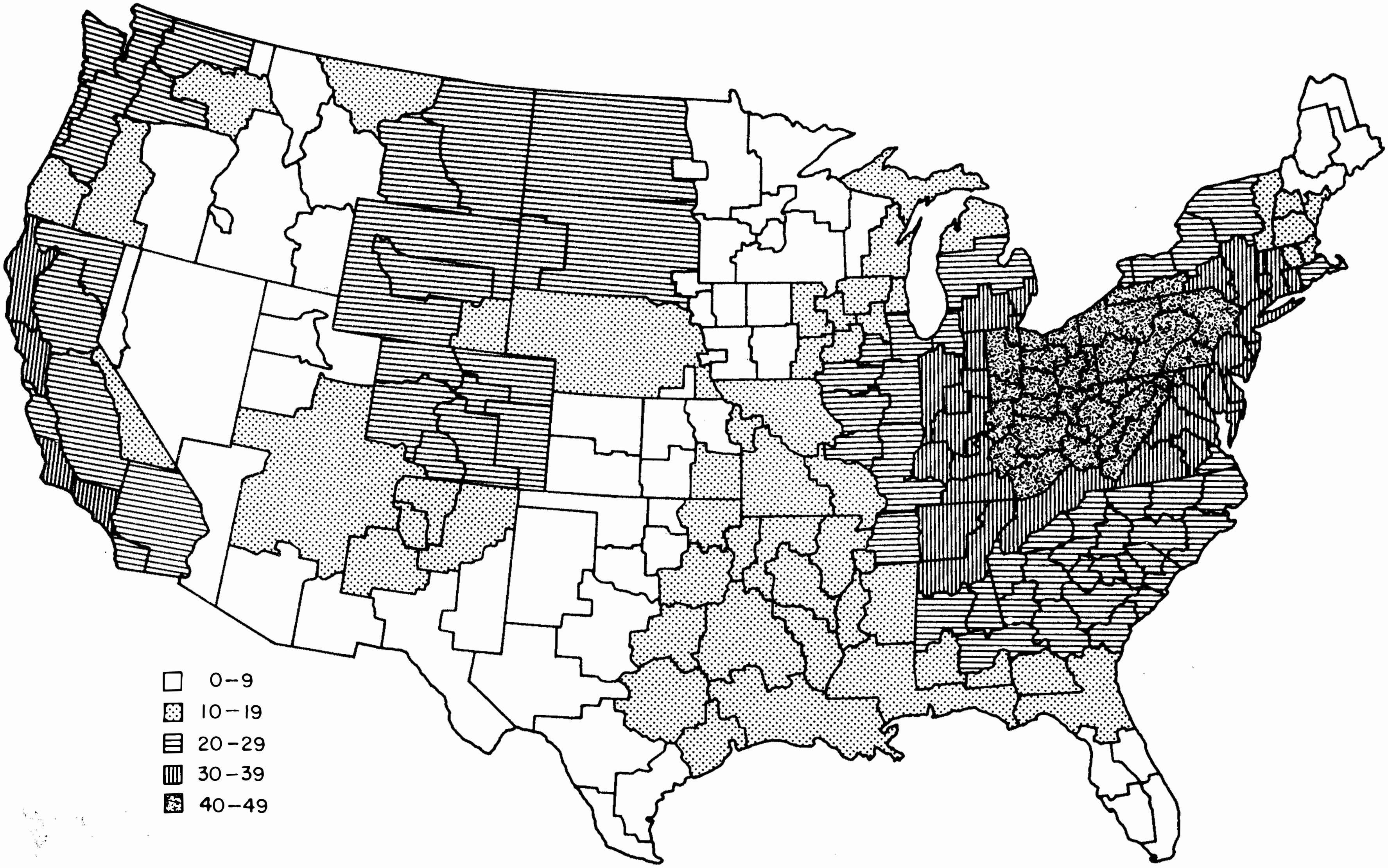

Fig. 5.2. Predicted 1985 Base-case Annual Average Ground-level SO_2 Concentrations ($\mu g/m^3$) from All Combustion Sources by AQCR

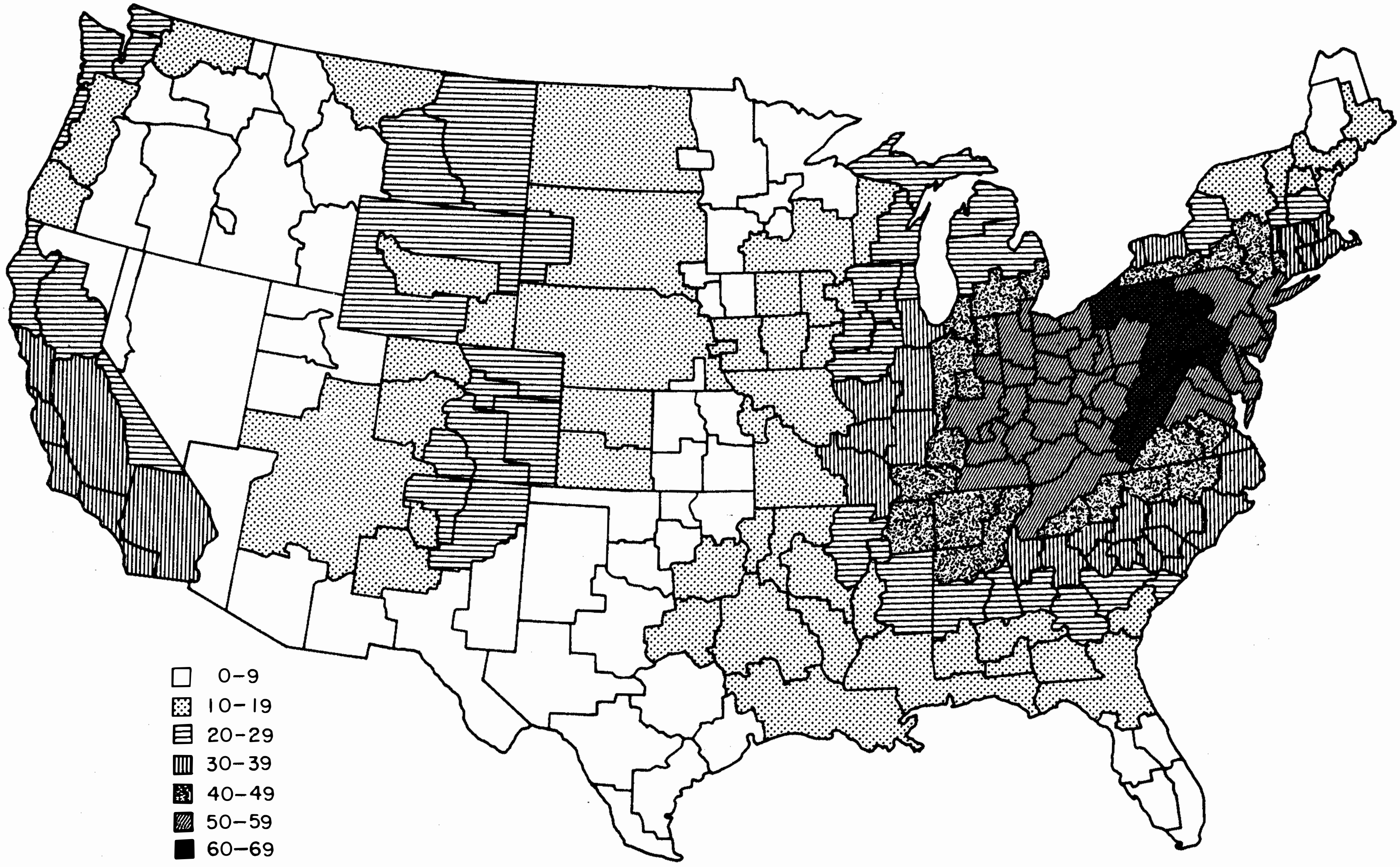

Fig. 5.3. Predicted 1990 Base-case Annual Average Ground-level SO_2 Concentrations ($\mu g/m^3$) from All Combustion Sources by AQCR

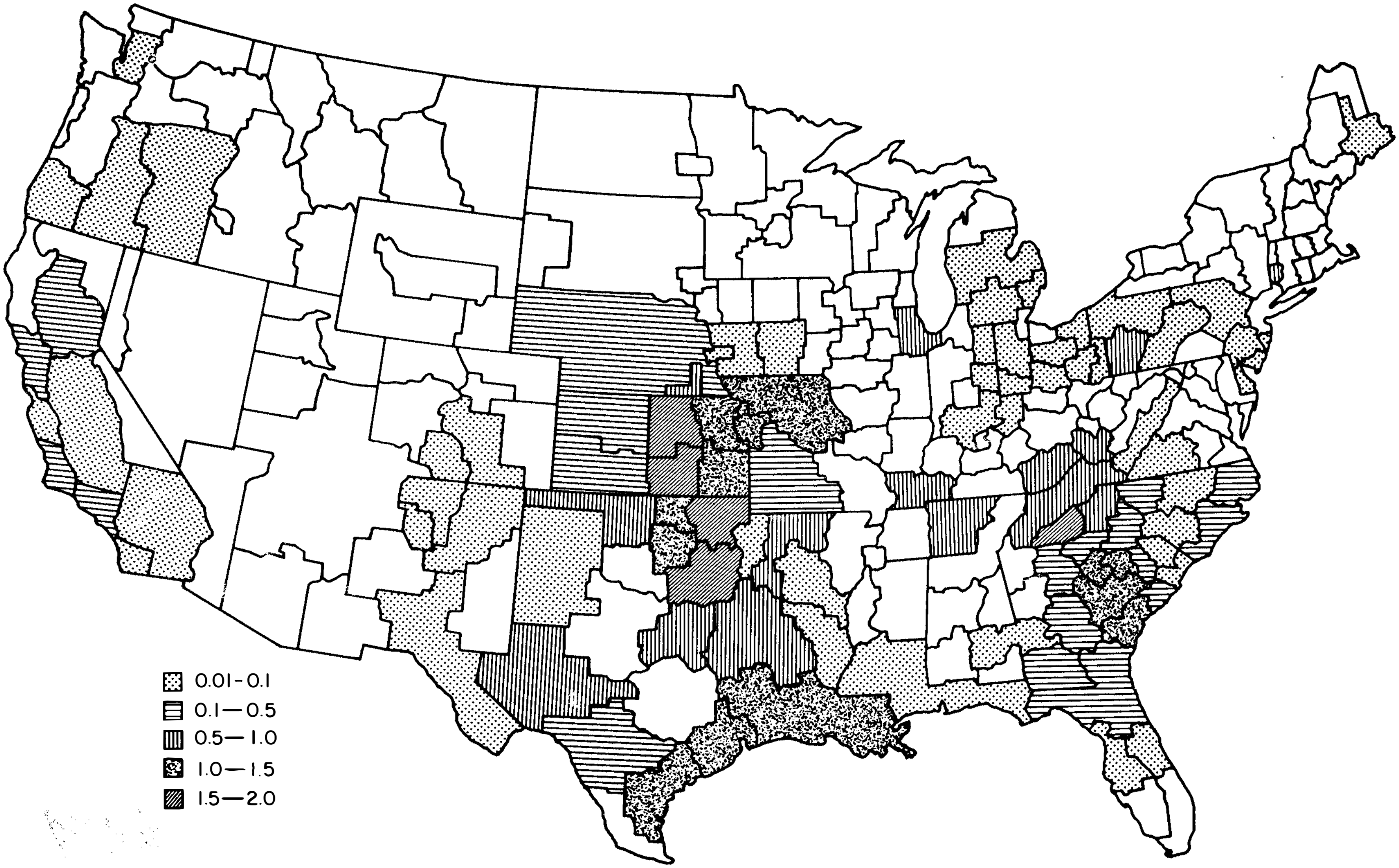

Fig. 5.4. Predicted 1985 Incremental Annual Average Ground-Level SO_2 Concentrations ($\mu g/m^3$) from MFBI Sources As a Result of the Proposed Action, by AQCR

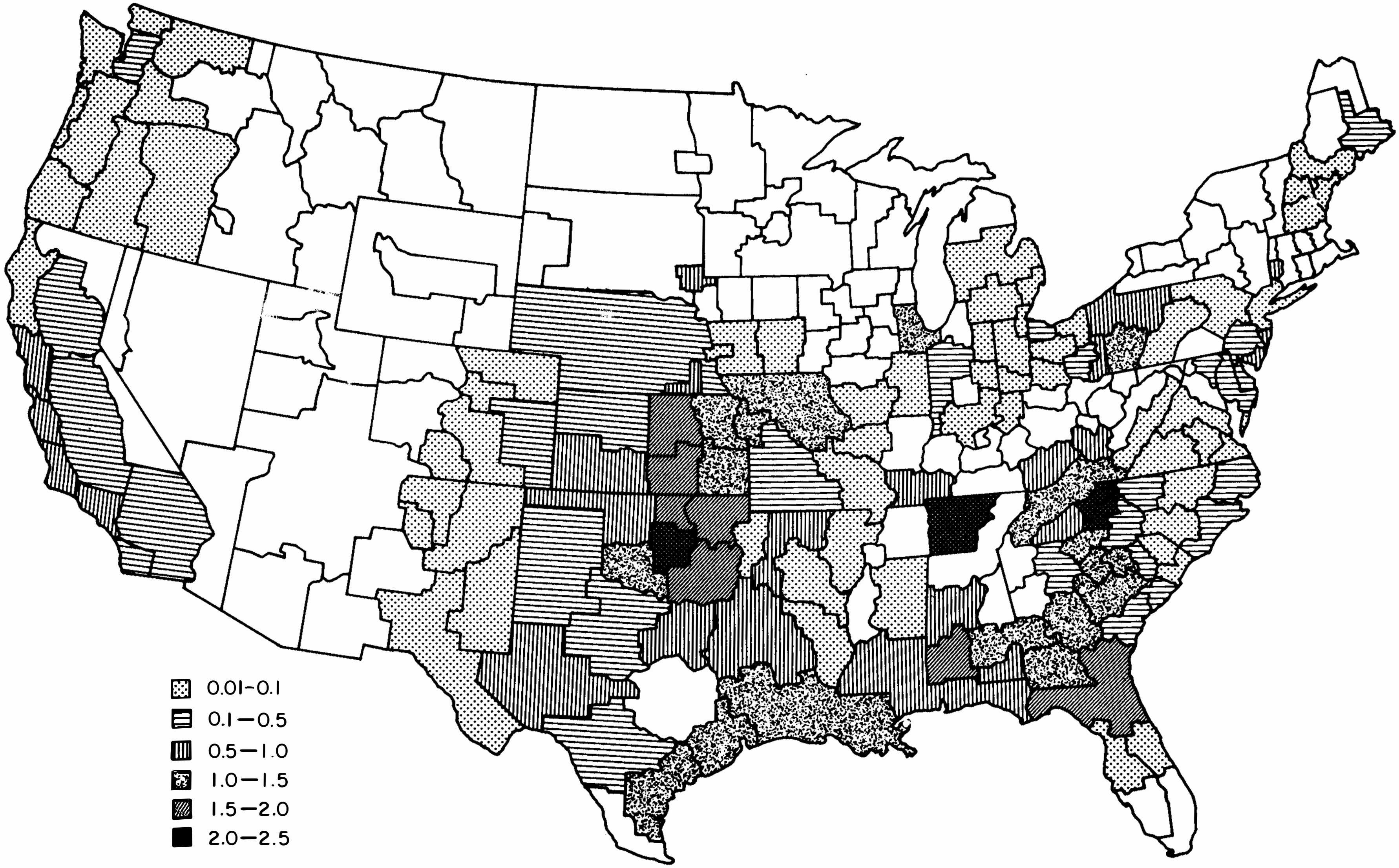

Fig. 5.5. Predicted 1990 Incremental Annual Average Ground-level SO_2 Concentrations ($\mu g/m^3$) from MFBI Sources As a Result of the Proposed Action, by AQCR

The primary 1985 regional increases will occur north of Texas, in Southern Appalachia, and in the vicinity of Pittsburgh. The same general trends are noted in the 1990 shift with the coastal region of Texas more heavily affected. Those regions predicted to have high background concentrations in both 1985 and 1990 are Southern Appalachia and the heavily industrialized Great Lakes. The predicted increases due to coal conversion will have little effect on those AQCRs predicted to have high background concentrations, considering that the maximum predicted 1990 background is 69 $\mu g/m^3$, while the maximum shift is 2.5 $\mu g/m^3$, and in no AQCR predicted to have the highest background does the maximum shift increase occur.

Gaseous oxides of nitrogen are formed by the reaction of oxygen with nitrogen, both from the combustion air and from nitrogen bound in the fuel, during combustion at high temperatures and are emitted from the plant stack. NO_2, a brown toxic oxide, is a criteria pollutant for which both ambient and emission standards have been set by the USEPA.

Oxides of nitrogen react with other compounds in the atmosphere, forming nitric acid, nitrates, nitrites, nitro-compounds, aldehydes, ketones, peroxides, acyl-nitrates, and particles. These compounds, collectively called photochemical smog, all absorb solar radiation and produce free radicals which result in the formation of other new compounds (Varney and McCormac 1971). Various oxides of nitrogen react with water and serve to acidify precipitation (Council on Environmental Quality 1979). Gaseous and particulate nitrogen oxides both discolor and attenuate light transmission through the atmosphere, reducing visibility.

Formation and regulation of ozone and hydrocarbon concentrations are related to NO_x concentrations. It is estimated that more than 150 elementary reactions, with varying reaction rates, determine NO_x transformations (Muthukrishnam and Peters 1977). These reactions depend on sunlight, temperature, and the presence or absence of other chemicals in the atmosphere. Experiments in carefully controlled smog chambers are being made to determine the parameters of interest, but no accurate NO_x model presently exists. Because NO_x chemistry is so poorly understood, no projections of ground-level concentrations of NO_2 were made.

Emissions of nitrogen oxides will increase as a result of the implementation of the Act. These increases were estimated, as discussed earlier in the section, based on emissions meeting New Source Performance Standards for coal, gas, and oil facilities of 0.7, 0.2, and 0.3 lb/10^6 Btu, respectively. The maximum increase is less than 4% of total 1990 base-case projections. The percentage increase in NO_2 emissions will be slightly less than the percentage increases of the other pollutants, as NO_2 is also formed from atmospheric nitrogen during the combustion of all fuels and is not strictly a function of the nitrogen content of the fuel. However, the increases in the emission of oxides of nitrogen may result in the production of additional amounts of photochemical smog and may exacerbate respiratory ailments on a local basis. Visibility may be impaired and precipitation may be acidified on both local and regional scales.

These SO_2 and TSP regional concentrations are below the annual fluctuations in concentrations. However, due to the low effective emission heights and location of the industrial facilities, the local concentrations (within 10 km [6.2 mi] of a facility) may be important. These impacts will be addressed by the proper regulatory agencies during the permitting process.

Gaseous SO_2 is converted to particulate sulfate in the atmosphere (Dvorak et al. 1977). The sulfate concentrations resulting from increased SO_2 emissions as a result of the implementation on the Act were calculated and used to estimate precipitation acidification in Section 5.3.2. Additionally, these sulfate particles contribute to regional TSP loadings. Because sulfate particles are small and reactive, they may represent a greater health hazard than larger particles, as discussed in Section 5.9.5.

Increases in sulfate concentrations as a result of the implementation of the Act are projected to be small. Less than 4% of the nation is subjected to projected ground-level concentrations in excess of 1 $\mu g/m^3$, and 86% of the nation is projected to experience concentrations less than 0.25 $\mu g/m^3$ at the time of maximum impact. These calculations are conservative, for no removal of particles by precipitation is assumed. Actual sulfate concentrations will be less, for precipitation will remove many of the particles before they disperse to ground level (see Sec. 5.3.2, Acid Rain).

In addition to presenting a health hazard, sulfates and other particles and gasses reduce visibility (Robinson 1958). Because SO_2 to sulfate and NO_x to nitrate transformations occur long after the time of emission at varying distances downwind, increased sulfate, nitrate, and other gaseous and particulate concentrations at mid- and upper-levels in the atmosphere can reduce visibility on a regional scale. Although sulfate concentrations can be predicted with some confidence, no means are presently available to determine the impact of increased emissions on regional visibility (Leaderer et al. 1979; Wolff 1979). However, it can be inferred that the problem is most likely to be a problem in the West, where pollutant removal by precipitation is slow, visibility is presently good, and distances to objects of interest is great. However, as shown in Figures 5.20 and 5.21, increases in SO_2, and thus sulfates, are small in the West.

Increasing precipitation removal decreases atmospheric concentrations, while increasing the distance to viewed objects allows for more atmospheric filtering and thus more potential modification due to atmospheric constituents.

The operator of any new or modified facility classified as a major source by the USEPA must demonstrate to the satisfaction of the proper regulatory authority that no significant impact on the visibility of any Class 1 PSD area will result from the operation of that facility. Increased coal use resulting from the implementation of the Act will be examined on a case-by-case basis, and the final determination will rest with the proper regulatory authority. Increases in SO_2, sulfates, fly ash, and NO_x emissions as a result of the implementation of the Act are projected to be small. Correlation of these small emission increases with visibility impairments is beyond the present state-of-the-art.

Because coal use in existing and new facilities is assumed to occur in presently industrialized regions where air quality may presently be poor, conflicts between increased coal use and air quality regulations may occur. A total of 421 of the 3033 counties in the conterminous United States are presently in non-attainment for TSP, and 101 counties for SO_2 concentrations (USEPA 1978). TSP emissions are expected to decrease as control devices are installed in more stationery emission sources. However, SO_2 emissions will be even more difficult to decrease, and therefore may represent a greater obstacle to increased coal use. Increased coal use in some AQCRs may be constrained in order to comply with air quality standards, unless emission offsets are purchased.

For 1985, 17 percent of the total fuel usage due to the proposed action is allocated to AQCRs presently in non-attainment for SO_2 concentrations. Eleven percent of the 1985 new facilities and 31 percent of the existing plant conversions are in non-attainment AQCRs. In 1990, 11 percent of the total fuel usage is allocated to AQCRs presently in non-attainment, with 11 percent of both new and existing facilities so sited. It is impossible to project the number or locations of AQCRs that will be in violation of the National Ambient Air Quality Standards (NAAQSs) in 1985 or 1990. The predicted increases in SO_2 and TSP concentrations are due not only to emissions within an AQCR, but also include contributions of AQCRs that are located upwind.

Coal-burning facilities can be sited in non-attainment areas. The facility must demonstrate that the Lowest Achievable Emission Rate (LAER) will occur by meeting either the most stringent emission limit for such a source found in any State Implementation Plan or the lowest rate achieved in practice or reasonably expected to be achieved in practice for such sources. Any other source owned or operated by the same company in the same AQCR must also be in compliance with all applicable air quality regulations or on an approved compliance schedule. Before operating, the facility must achieve, through emission offsets, a greater reduction in the emission of the pollutant(s) for which the area is in non-attainment than the facility will produce. The operator must also demonstrate a net air quality benefit. If a facility is sited in a non-attainment area, a net improvement in air quality must be predicted using acceptable techniques before the facility can operate.

As an area can be in non-attainment for one or more pollutants and meet ambient standards for other pollutants, both PSD and non-attainment regulations may simultaneously apply to a facility. In such a situation, a net air quality benefit must be shown for those pollutants in excess of ambient standards while ambient levels can increase up to the alloted PSD increment for those pollutants below ambient standards.

Non-attainment status is constantly changing due to variations in pollution emissions and monitoring networks. Future projections of non-attainment areas are impossible, but all AQCRs are to be in compliance with the National Ambient Air Quality Standards (NAAQS) by 1982. However, it is likely that those industrialized regions of the country that presently have poor air quality have the potential to continue to have air quality problems. Implementation of the FUA has the potential to affect the air quality of portions of the nation. In those areas predicted to have ground-level concentrations approaching standards, any incremental increases reduce the air resource available to other polluters. This reduction in the availability of pollutable air may preclude industrial development, or force certain emitters to seek offsets before development can occur. Also, incremental increases in ground-level concentrations may be high enough in certain areas to degrade presently pristine airsheds. These increments may change the character of a region, and result in a significant impact even if NAAQSs are not approached.

Table 5.12a is a listing of those AQCRs that are predicted to have the highest ground-level concentrations under base-case use, their present attainment status with respect to both TSP and SO_2, and the increased ground-level SO_2 concentrations that would result from implementation of the FUA. The maximum projected increase due to the program (AQCR 178, Northwest Pennsylvania-Youngstown, Ohio) is 0.75 $\mu g/m^3$, or about 1 percent of the predicted 1990 base-case concentration (65 $\mu g/m^3$). All other AQCRs with predicted high base-case concentrations have smaller increases. It is unlikely that implementing the FUA will have significant impact on other industrial development on a regional scale in any part of the nation.

Table 5.12a. Present Attainment Status and Predicted Ground-level Concentration of SO_2 in Those AQCRs with Highest Projected Base-case Concentrations

AQCR	Demand Region	1978 Attainment Status[a]		1985		1990	
		TSP	SO_2	Base Case ($\mu g/m^3$)	Increment ($\mu g/m^3$)	Base Case ($\mu g/m^3$)	Increment ($\mu g/m^3$)
112	III	Part	Yes	45	0.01	65	0.01
113	III	Part	Yes	45	0.01	65	0.01
115	III	No	Yes	35	0.01	65	0.30
178	III	Part	Part	45	0.05	65	0.75
195	III	Part	Part	45	0.05	65	0.05
196	III	No	Yes	45	0.01	65	0.01
226	III	Yes	Yes	45	0.05	65	0.05
231	III	Yes	Yes	45	0.01	65	0.01
233	III	Yes	Yes	45	0.01	65	0.01

[a]From Federal Register, Friday, March 3, 1978. Part II, Environmental Protection Agency, National Ambient Air Quality Standards, States Attainment Status.

All - in attainment.
No - not in attainment.
Part - partially in attainment.

Table 5.12b is a listing of those AQCRs that are predicted to have the highest increases in ground-level concentrations due to the implementation of the FUA, their present attainment status with respect to both TSP and SO_2, and the predicted 1985 and 1990 base-case ground-level concentrations. None of these AQCRs are predicted to have high base-case concentrations. Only maximum increase (2.0-2.5 $\mu g/m^3$ SO_2) exceeds the allowable PSD Class 1 increment. However, no Class 1 areas are affected by the AQCRs receiving the maximum increase, and even the maximum increases are allowable under Class 2 and Class 3 regulations if they do not cause a violation of the standards. Thus, no pristine airsheds would be strongly affected by the program.

Air quality projections were all performed on a regional basis. In those AQCRs not in attainment as conversions begin, operators must obtain permits from the EPA before increasing emissions. In those AQCRs near pristine (Class 1) airsheds, it must be demonstrated that no degradation will occur before conversions may begin. However, some of the increased coal use assumed at the programmatic level may not be enacted due to potential violation of the PSD classification/nonattainment status of a given region, unless offsets are purchased for the latter. Compliance with all applicable federal, state, and local air quality regulations is required before coal combustion can occur. Industrial facilities will consume some of the incremental increases allowed under PSD regulations, and may purchase some of the less expensive emission offsets. These actions may preclude additional development in certain areas, or force other polluters to install more extensive pollution abatement devices on proposed facilities before siting in certain locations. These additional costs, for abatement equipment, increased maintenance and energy requirements, and solid waste disposal may have a social and economic impact on a region.

5.2.5 Waste Collection and Disposal

As fly ash and bottom ash are stored before ultimate disposal, some slight increases in suspended particulates may be noted in the immediate vicinity of the storage areas. However, these increases will be only slightly discernible and will not affect air quality in any demand region.

Table 5.12b. Present Attainment Status and Predicted Ground-level Concentration of SO_2 in Those AQCRs Most Affected by the Implementation of the FUA

AQCR	Demand Region	1978 Attainment Status[a] TSP	1978 Attainment Status[a] SO_2	1985 Base Case ($\mu g/m^3$)	1985 Increment ($\mu g/m^3$)	1990 Base Case ($\mu g/m^3$)	1990 Increment ($\mu g/m^3$)
165	IV	Part	All	25	0.30	45	2.25
184	VI	Part	All	5	0.75	5	2.25
208	IV	Part	Part	35	0.30	45	2.25
1	IV	All	All	15	0.01	15	1.75
49	IV	Part	All	15	0.30	15	1.75
96	VII	All	All	5	1.25	5	1.75
99	VII	All	All	5	1.75	5	1.75
171	IV	All	All	25	1.75	45	1.75
185	VI	All	All	5	1.25	5	1.75
186	VI	Part	No	15	0.75	5	1.75
188	VI	All	All	15	1.25	15	1.75
2	IV	All	All	25	0.05	15	1.25
53	IV	All	All	25	0.75	25	1.25
54	IV	Part	All	25	0.05	25	1.25
59	IV	All	All	15	0.05	15	1.25
67	V	No	No	25	0.30	35	1.25
94	VII	No	All	15	0.75	15	1.25
95	VII	Part	All	5	0.75	5	1.25
98	VII	All	All	15	0.75	5	1.25
106	VI	All	All	15	0.75	15	1.25
137	VII	Part	All	15	0.75	15	1.25
189	VI	All	All	5	0.01	5	1.25
197	III	Part	Part	45	0.30	55	1.25
200	IV	All	All	25	0.75	45	1.25
202	IV	All	All	25	0.05	45	1.25
203	IV	All	All	25	0.75	45	1.25
207	III, IV	Part	Part	35	0.30	55	1.25
214	VI	Part	All	5	0.75	5	1.25
216	VI	Part	All	15	0.75	5	1.25

[a]From Federal Register, Friday, March 3, 1978. Part II, Environmental Protection Agency, National Ambient Air Quality Standards, States Attainment Status.

All - in attainment.
No - not in attainment.
Part - partially in attainment.

5.3 EFFECTS ON WEATHER AND CLIMATIC PROCESSES

5.3.1 Greenhouse Effect (Global CO_2)

The combustion of coal results in an increase of atmospheric CO_2 and particulate loadings. Additional CO_2 and/or particulates are emitted into the atmosphere during other phases of the coal cycle: mining, processing, transportation, storage, and waste disposal. Combustion of fossil fuels, however, is not the sole source of atmospheric CO_2. Biologic processes strongly affect CO_2 concentrations, as do other atmospheric constituents and the oceans. The predicted atmospheric CO_2 concentrations often disagree with actual measured values, for as yet unknown reasons. It has been observed that fluctuations in the concentrations of naturally occurring CO_2 vary with CO_2 from fossil fuel burning (Cheremisinoff 1977). However, reasonably good agreement on a gross scale exists between observed atmospheric CO_2 measurements and calculated CO_2 emissions.

Increases in CO_2 and particulate emissions could affect the climate of the entire earth, thereby affecting the human and biotic resources of the world (Broecken 1976). However, the range of uncertainty of the effects is so large that no definitive conclusions can be drawn about the type or size of impact that increased coal combustion will have. An increase in atmospheric CO_2 concentrations could serve to increase the global temperature or result in increased global cloudiness or both, or could have some other effect (Robinson 1968). No technique to accurately predict the ramifications of increased CO_2 emissions is presently available. However, due to the long residence time of many years of CO_2 in the atmosphere, it is unlikely that the slightly accelerated rate of coal combustion due to the proposed action will affect the weather and climate of any demand region or of the nation as a whole.

5.3.2 Acid Rain

In light of the history of acid rainfall in the eastern United States during the past two to three decades (Sec. 4.2.1.5), it is probable that the acidity of precipitation and the area of the United States affected will increase as a result of increased coal use even without the proposed action. A major effect of the proposed action may be to cause a large increase (greater than 50 percent) in combustion of coal in Demand Region VI (primarily south coastal Texas). To the present, this area has had precipitation of normal (even neutral) acidity (Fig. 4.15); acid precipitation has been considered an eastern or northeastern United States environmental problem. The impacts of acid precipitation are discussed in Sections 4.1.1.3, 5.4.4.1, 5.5.4, and 5.6.4.2.

The conversion of large numbers of natural gas and petroleum burning facilities to coal under the proposed action can be expected to impose additional burdens of atmospheric sulfates in as yet unaffected regions and in the already heavily impacted northeast. Estimation of the environmental changes associated with these trends is a multistep process necessitating reliance on both theoretical and empirical relationships between emissions and air quality, air quality and precipitation chemistry and environmental response.

To make these estimations an air transport model (Sheih 1977) was used to calculate the pattern and magnitude of additional sulfate burdens associated with the spatial distribution and source strengths of emissions resulting from the proposed action. The SO_4 additions (mean annual concentration in $\mu g/m^3$) relative to base-case scenarios for both 1985 and 1990 were described. The results shown in Table 5.13 are a description of the areal extent of changes in SO_4 concentrations. These tables, formulated from maps produced by the model simulations, emphasize two conclusions which may be made regarding the distribution of the added sulfate: (1) In most of the area impacted (90 percent) by 1985, rather small annual SO_4 increments ($\leq 0.50\ \mu g/m^3$) will occur. Only 1 percent of the total area (712,250 sq km [275,000 sq mi]) impacted (additions $\geq 0.25\ \mu g/m^3$) will have additions $\geq 0.75\ \mu g/m^3$. (2) Most of the area affected by 1985 (80 percent) will be in those regions which currently have rather low projected base-case concentrations of SO_4 ($\leq 3\ \mu g/m^3$). Less than 1 percent of the area impacted will fall in the base-case area with the highest annual SO_4 concentrations (5-6 $\mu g/m^3$).

By 1990 the areal impact of SO_4 due to the proposed action will have increased to 1,253,560 sq km (484,000 sq mi), an increment of 75 percent; however, the same approximate distribution trends noted previously would occur. In 1985 most of the impact would occur in Demand Regions VI and VII. By 1990, significant areas within Region IV would also be impacted.

Translation of these increased sulfate levels to changes in the acidity of precipitation requires that well-defined relationships between sulfate levels in the atmosphere and in rainwater be developed and that a known relationship between rainfall sulfate and rainfall pH exist. Although some generalized data of this type are now available, the reduced pH of rainfall is related to a complex array of anionic and cationic species from a variety of sources which interact to affect precipitation chemistry.

Table 5.13. 1985 and 1990 Projected Incremental Sulfate Concentrations ($\mu g/m^3/yr$)

Projected Base-case Sulfate Concentrations ($\mu g/m^3$)	% of Land Area Affected	Increment (sq mi of area affected) 0.25 μg	0.50 μg	0.75 μg	1.0 μg	Total
		1985				
5-6	<1	1,246				1,246
4-5	3	8,570				8,570
3-4	5	13,950	749			14,699
2-3	12	26,906	5,630			32,535
1-2	44	72,249	40,609	9,615		122,473
<0.9	35	53,935	29,312	11,021	1,876	96,144
		176,856	76,300	20,636	1,876	275,667
		64%	28%	7%	1%	
		1990				
7-8	<1	697	597	199		1,493
6-7	3	11,454	996			12,450
5-6	3	11,205	1,494	498		13,197
4-5	23	101,941	4,482	4,631	1,245	112,299
3-4	5	16,434	7,470	1,494		25,398
2-3	13	35,358	12,201	15,189	1,494	64,242
1-2	41	95,616	38,595	47,310	14,940	196,461
<0.9	12	32,370	19,920	4,980	1,245	58,515
		305,075	84,858	74,302	18,294	484,055
		63%	18%	15%	4%	

The staff has developed the relationship shown in Table 5.14 to calculate the impact of an addition of 1.0 $\mu g/m^3$ on areas having a range of base-case pH levels.*

These calculations based on the effects of aqueous SO_4 on solution acidity actually overestimate the extent of pH changes which can be derived from existing relationships between average annual sulfate and precipitation over the eastern U.S. (U.S. Department of Energy, USEPA 1978). Calculations based on these relationships indicate a maximum pH change of 0.5 pH units in areas with a current pH range of 5.0-5.6 (the most sensitive areas to pH change).

The environmental impacts of these changes would be expected to be small. With terrestrial systems, there have been no documented cases of either short- or long-term yield reductions at rainfall pH levels above 4.0. While in most of the areas being impacted precipitation currently is relatively low in sulfate and is nearly neutral in acidity and would be relatively sensitive to pH changes, these changes (a maximum of 1.1 pH unit occurring over only 4 percent of the area affected) would not be expected to cause short-term negative impacts. In fact, many areas of the country (including much of the region receiving the greatest sulfate as a result of the proposed action) are deficient in sulfur and some beneficial effect may occur (Coleman 1966). Long-term impacts via soils as well as adverse impacts on aquatic systems would appear unlikely due to the relatively high buffering capacity of the indigenous soils and the relatively low ultimate acidity attributable to the proposed action.

*Data collected from Oak Ridge National Laboratory's Walker Branch Watershed relating atmospheric SO_4 to SO_4 in rainfall [correlation coefficient = 0.77 ($\leq$ .05)].

Table 5.14. Impact of an Annual Increment of 1 $\mu g/m^3$ of SO_4 on the pH of Precipitation

Base-case pH	pH Resulting from an Increment of 1 $\mu g/m^3$ of SO_4
5.6	4.5
5.0	4.4
4.6	4.3
4.0	3.9

In summary, although slightly elevated levels of atmospheric sulfate would occur in rather large areas as a result of the proposed action, the impact of these additions on environmental quality would be expected to be slight. Most of the areas impacted have rather low levels of atmospheric sulfate at present and the further increments anticipated would not be sufficiently large to cause measurable adverse impacts. Little impact would occur in other areas particularly the northeast, where acidity levels may be approaching the level necessary for undesirable environmental consequences.

5.4 HYDROLOGY, WATER QUALITY, AND WATER USE

On a regional (demand region or water resource region) basis, many of the environmental effects of the proposed action are expected to be felt as small increments to the effects of coal utilization in general and to other environmental disturbances (other land disturbances, water pollution sources, water development projects, etc.). The Committee on Health and Environmental Effects of Increased Coal Utilization (appointed by the Secretary of Health, Education, and Welfare at the request of the Department of Energy) reported that even on as large a scale as the National Energy Plan (of which the proposed action is a part), it is difficult to predict differences between the environmental effects of the NEP and the effects of a non-NEP future; limitations are imposed by available data and by the state of the art in environmental forecasting (U.S. Department of Health, Education, and Welfare 1978).

The nature and magnitude of environmental impacts associated with coal extraction, beneficiation transportation, storage, combustion, and waste disposal have been addressed previously for the most part (U.S. Army Corps of Engineers 1974; Kash et al. 1977; Federal Energy Administration 1977d; Habegger et al. 1977; Dvorak et al. 1977). Because it is not possible to project on a small geographic scale where the activities necessitated by the proposed action will occur, impacts will be generically treated, with an indication of where a particular effect (e.g., acid drainage) would be expected to be most serious. Reference will be made to more exhaustive studies of such effects.

5.4.1 Mining and Mine Site Processing

Projections of the proposed action indicate that coal mining will be accelerated to some degree in all major regions currently mined. The proposed action is not expected to necessitate the mining of regions that would otherwise be unexploited. On a national basis, the effect will be seen as an increase of 7 percent by 1985 and 10 percent by 1990 over the base case (Table 3.9). Bearing in mind the difficulty of accurately predicting the environmental effects of small increments in mining, and without a knowledge of site-specific locations (particular mine openings caused by the proposed action, watersheds affected, tonnages of coal mined, and acres of land disturbed within each watershed), it is expected that those environmental impacts which have been experienced in the past as a result of coal mining, and which would be experienced in the future even without the proposed action, will be incrementally exacerbated on a regional scale. The most serious potential effects, but the least possible to predict, are expected to be felt on a local scale. These would be more amenable to site-specific analysis and quantification.

On the basis of information received to date, it has been possible to determine the distribution of increased mining required by the proposed action only on a supply region basis. There are eight of these regions, each consisting of one to six Bureau of Mines mining districts (Appendix B). As presented in Table 3.9, a comparison of the coal-shift production for each supply region for 1985 and 1990 to the base case production from the same regions shows a percent increase caused by the proposed action. This increase is expected to range from 2 percent in Supply Region 4 to 36 percent in Supply Region 5 in 1985, and from 3 percent in Supply Region 4 to 41 percent in Supply Region 5 in 1990. The distribution of production tonnage for the various mining districts within each supply region or the percent increase in production for these districts is presently unknown.

To facilitate the distinction between those regions where the proposed action would cause a relatively large increase in coal production and those regions where it would cause only a slight increase, a 5 percent increase over the base case is operationally chosen as a cutoff. Additionally, the absolute magnitude of coal production, in terms of tonnage, is considered. The percent increase in production over the base case is taken as an indicator of potential regional impacts, while the absolute magnitude of the increased production is taken as an indicator of potential site-specific impacts.

The regional incremental effects of mining associated with the proposed action are expected to be insignificant when the increase in production is less than 5 percent. Nevertheless, localized effects may be expected, particularly when the absolute tonnage is large; the role of regulation by Federal and state agencies will be significant in this regard. Thus, the production increase for Supply Regions 1 and 4 ranges from 2 to 3 percent in 1985 and from 3 to 4 percent in 1990. For Supply Region 2 only a 3 percent increase is expected in 1985. In these areas, the impacts from mining necessitated by the proposed action would be expected to be insignificant on a regional scale (when superimposed over coal mining in general and other disturbances). However, this production represents about 26 and 12 percent of the total increase in tonnage necessitated by the proposed action, or about 19×10^6 tons and 16×10^6 tons of coal mined, in 1985 and 1990, respectively. Therefore, the potential for impacts of local significance exists; these potential impacts are discussed in Sections 5.4.1.1, 5.4.1.2, and 5.4.1.3.

For the other supply regions, the mining necessitated by the proposed action is expected to exceed a 5 percent increase over base-case production. In these situations, the impacts of the mining are expected to achieve potential regional significance, even though particular impacts or specific exacerbations of impacts might not be directly attributable to the proposed action. For Supply Regions 3, 5, 6, 7, and 8, the production increase ranges from 5 to 36 percent in 1985. For Supply Regions 2, 3, 5, 6, 7, and 8, the increase ranges from 6 to 41 percent in 1990. Furthermore, the increased production for Supply Regions 5 and 6 represents about 60 and 61 percent of total mining, required by the proposed action, or about 43×10^6 tons and 80×10^6 tons of coal mined, in 1985 and 1990 respectively. Thus, throughout the coal resource regions of central and southern Appalachia and the United States west of the Mississippi River, the potential exists for mining impacts of regional significance, with particular emphasis on Supply Regions 5 and 6. Without a more detailed knowledge of the location of mining necessitated by the proposed action, it is not possible to project with any confidence the relative magnitude of mining impacts throughout central and southern Appalachia and the western United States. The kinds of impacts experienced in the past (the extent largely to be determined by Federal and state agency regulation) and those potentially expected as a result of the proposed action are described in Sections 5.4.1.1, 5,4.1.2, and 5.4.1.3. Those impacts of greatest potential consequence in central and southern Appalachia and the West are expected to be the impacts of greatest potential consequence as a result of the proposed action.

5.4.1.1 Hydrology

Mining and mine site processing have historically affected both surface-water and groundwater hydrology. The National Strip Mine Study provides an overview of hydrologic effects of surface and underground mining of coal and other minerals (U.S. Army Corps of Engineers 1974).

Coal mining has been observed to alter the volume and rate of surface-water runoff, which is of course interrelated with groundwater hydrology (U.S. Army Corps of Engineers 1974). Depending on the particular site-specific conditions, dry-weather flow in small streams may be decreased or increased (U.S. Army Corps of Engineers 1974; Minear and Tschantz 1976). Increased dry-weather flow in western Kentucky has been attributed to storage in last-cut impoundments and overburden piles (U.S. Army Corps of Engineers 1974), while the same effect, noted in small watersheds of the New River basin (Ohio Water Resource Region), resulted from the gradual release of stored spoil-bank seepage and bench impoundment (Minear and Tschantz 1976).

The existing subsurface hydrologic environment can be affected by mining and mine site processing in numerous ways. Depending on the geographic location, the topography, the nature of the overburden, and the underlying geology, the flow regime can be adversely or beneficially altered.

In areas of last-cut impoundments, overburden piles, spoil banks, and benches, groundwater storage can occur. The gradual release of this stored water to a stream would alter the stream's low-flow characteristics in several ways. First of all, the discharge at low-flow frequencies would increase in amount; secondly, a given low flow (groundwater contribution) of a stream could be expected to be sustained for a longer period of time. Springflows would also be increased and sustained. Water stored in the pile-and-bank material would create local high-pressure mounds in the groundwater body's potentiometric surface (the actual or potential water level within a well). Depths to water would be correspondingly decreased, even causing the water table to intersect the land surface, forming swamps. Flow directions would be altered from those existing prior to mining and mine site processing, with possible downgradient movement of groundwater in directions opposite to previous ones. Groundwater could, under these conditions, move locally away from a nearby stream, contributing to the flow at another reach of the stream, entering a different stream, or exiting the basin by underflow entirely. These storage effects would be more pronounced in areas of gradual slope underlain by unconsolidated rock material or bedrock that is low in clay content (i.e., more permeable), such as the Texas—Gulf Coast region where the mounded overburden itself would be more permeable.

In steep-sloped coal areas of eastern Kentucky, storm runoff was noticeably affected in watersheds where at least 10 percent of the land was disturbed by contour stripping. Because storm runoff is accelerated when vegetation is lacking, reclamation is obviously an important determining factor. The reduced runoff-carrying capacity of streams with higher sediment loads (Sec. 5.4.1.2) has increased flood damages (U.S. Army Corps of Engineers 1974). Increased flood peaks as a result of coal mining have been seen as particularly hazardous in southern Appalachia (Kash et al. 1977). Eastern Kentucky has experienced a flooding hazard because of waste embankments and overburden slopes. On the other hand, western Kentucky has experienced reductions in flooding that have been attributed to storage in last-cut impoundments and overburden piles (U.S. Army Corps of Engineers 1974).

Steeply sloped areas with large amounts of rainfall (>1000 millimeters per year [>39 inches per year]) and consolidated bedrock, such as Appalachia, are characterized by flashy streams (streams which exhibit rapid and extreme flow responses to precipitation events, as distinguished from streams where flow response to precipitation events is moderated by interaction with groundwater storage). Mining and mine site processing in this more rugged topographic area could reduce recharge to the groundwater systems. The residuum in such areas is thinner and typically less permeable, being weathered from clayey sandstones and carbonaceous shales. The permeability of the spoil banks and overburden piles would be similarly less than that of areas underlain by more permeable bedrock (such as unconsolidated sands and silts). Rainfall would run off the locally steeper, relatively impermeable slopes. The infiltration component of precipitation would be decreased. Consequently, flood peak stages of smaller tributaries could increase. Additionally, depths to groundwater would be depressed below normal levels. The depressions in the potentiometric surface (the actual or potential water level within a well) would alter groundwater flow, decreasing the sustained low flows of nearby streams. Spring discharges would also decrease and could cease flowing at times when flow would ordinarily be expected.

Groundwater flow regimes could also be altered by mine pumpage and/or subsidence. Pumpage would depress the potentiometric surface, creating locally higher heads and inducing or pirating flow from adjacent areas, which could possibly deplete nearby well fields and streams. Subsidence in underground mining areas could occur, inducing interior drainage. Groundwater recharge would increase locally, with resultant pressure mounds and, again, downgradient flow in places where it may not have existed previously. Mining in the western United States has also exposed groundwater aquifers to the surface (Kash et al. 1977).

Surface waters may be lost if their flow is intercepted by induced fractures or subsidence (particularly from underground mining), with resulting flow into the mines (Hill and Bates 1977). Surface waters may also be created in the mining process, not only by last-cut impoundments (Doyle 1976) but also by swamping. Swampy conditions may be created by large, area-strip mines and sediment-blocked channels in flat, poorly drained landscape (U.S. Army Corps of Engineers 1974). Changes in natural drainage patterns caused by subsidence may also form swamps (Hill and Bates 1977). The potential formation of extensive closed drainage basins in the Gillette, Wyoming, area has been described as a result of surface mining for coal (Keefer and Hadley 1976).

In accordance with the Surface Mining Control and Reclamation Act of 1977, hydrologic effects of surface and underground mining are to be controlled. Features of the hydrologic system to be protected include depth to groundwater, location of surface-water drainage channels, flow regimes, and groundwater recharge capacity (Office of Surface Mining Reclamation and Enforcement 1977). The extent to which appropriate Federal and state regulations are applied and enforced will determine the extent to which the potential hydrologic effects described in this section are realized or prevented.

5.4.1.2 Water Quality Effects

Water quality effects from coal mining and mine site processing may be grouped broadly into acid drainage, other dissolved constituents (alkaline drainage, trace substances), and increased suspended solids loads. Several works contain a more thorough discussion of coal mining and processing effects on water quality (U.S. Army Corps of Engineers 1974; Hill and Bates 1977; Dvorak et al. 1977; Martin, undated; Minear and Tschantz 1976). Van Hook (1978) addresses the state of the art with respect to mobilization of trace substances from coal mining and processing.

Acid drainage is a consequence of sulfur-bearing materials within coal or disturbed overburden. In areas of high-sulfur coal, such as in part of Appalachia, pyrite and marcasite are the main sulfide minerals. During the leaching process, these iron disulfides undergo oxidation to a series of hydrous iron sulfates. Acid mine drainage results when the iron sulfates come in contact with water, generating large amounts of iron and sulfate. Determining factors (as with other water chemistry aspects) include contact time of water with the sulfide minerals; hydrologic, geologic, and topographic features of the mine and surrounding terrain; type of mine operation; and active or inactive status of the mining (U.S. Army of Corps of Engineers 1974). The amount of pyrite and marcasite present in the coals and associated rock formations is not necessarily proportional to the potential acid generated. Several modes of iron disulfide are commonly present in coal strata: marcasite, primary framboidal reactive pyrite, primary euhedral pyrite, and secondary inert pyrite. Associated with acid drainage are elevated levels of trace substances, including heavy metals (Hill and Bates 1977; Cairns et al. 1971). In general, abandoned underground mines have been the primary source of acid drainage, although surface mining and refuse (gob and slurry) contribute appreciable quantities in certain areas (U.S. Army Corps of Engineers 1974; Martin, undated, 1974b; Hill and Bates 1977; Minear and Tschantz 1976; Tomkiewicz and Dunson 1977; Dvorak et al. 1977).

The effects of coal processing are similar to those of mining, although of lesser magnitude. Air and water can easily enter refuse piles, with resulting acidity. Processing and refuse effluents have been estimated to contribute 7.5 percent of the acid drainage in Appalachia (Dvorak et al. 1977). The acid drainage from coal refuse has been described for Eastern Interior and Appalachian areas (Martin, undated, 1974a, 1974b).

Acid mine drainage has been characterized (Cairns et al. 1971) as exhibiting the following characteristics:

pH	<6.0
Acidity	>3 mg/L
Alkalinity	0 mg/L, normally
Alkalinity/acidity	<1.0
Fe	>0.5 mg/L
SO_4	>250 mg/L
Total suspended solids (TSS)	>250 mg/L
Total dissolved solids (TDS)	>500 mg/L
Total hardness	>250 mg/L

Water quality measurements for acid mine and refuse effluents for a variety of coal mining areas are given in Table 5.15. Streams in Indiana and Illinois have had pH levels reduced by 4 to 5 units, with a change from net alkalinity to net acidity (Martin 1974b).

For comparison, selected water quality criteria for drinking water, irrigation, livestock watering, and protection of aquatic biota are presented in Table 5.16. This table, however, is incomplete: standards and criteria exist for other parameters and other uses. Additionally, state standards and criteria, in accordance with the Federal Water Pollution Control Act, may be more stringent than those that have been federally promulgated. Nevertheless, the tabulated criteria provide a useful basis for comparison. Characteristically, acid drainage exceeds many of the standards and criteria for drinking water, protection of aquatic biota, and other uses.

The full impact of acid drainage from new mines is not felt until after their closure (Hill and Bates 1977). The acidity problem with self-draining underground mines, as well as with auger mines and refuse banks with high pyritic concentrations, continues for an indefinite time (U.S. Army Corps of Engineers 1974). Area and contour strip mines typically produce more early acidity than deep mines. However, total acidity is less, acidity is more controllable, and some neutralization occurs during the mixing of strata (U.S. Army Corps of Engineers 1974). The presence of calcareous soils and formations limits the acid problem in some areas (U.S. Army Corps of Engineers 1974). Neutralization of acidity by alkaline earth compounds in mine spoils, soils, and water bodies; by absorption to clays; and by reaction with alkaline surface waters and groundwaters is a factor (Dvorak et al. 1977). However, when neutralization occurs from overburden alkalinity, high sulfate concentrations may still be a problem. For example, northwestern Pennsylvania coal fields capped by calcareous glacial drift generate neutral, although high-sulfate, mine drainage. Even after treatment of acidity, high dissolved solids and hardness may limit domestic and industrial uses (Hill and Bates 1977). Also, after neutralization, concentrations of iron, aluminum, manganese, and zinc may still range from 1 to 10 ppm, in

Table 5.15. Representative Water Quality Measurements for Coal Mine and Refuse Effluents (all values except pH expressed as mg/L [ppm])

Parameter	Effluent											
	a	b	c	d	e	f	g	h	i	j	k	l
Al	15–31	52	1.0	0.10	87	1.8	440	340		0.9–1,014	3.6–220	1–20
As	0.01											
B	0.5	0.3										
Ba		<0.006										
Cd	<0.001	0.02										
Co		0.06										
Cr	0.05	<0.004										
Cu	0.02	0.09	0.01	0.02	0.14			0.16		0.04–0.18		
Fe	93–300	156.7	3.0	0.50	30	6.2	3,400	2,600	50–13,500	0.1–6,168	260–2,940	45–120
Hg	0.0003											
Mn	4–6	11.1	2.0	0.10	50	3.5	72	120		0.1–545	9–70	3.4–25
Ni	0.20	0.15			1.7		3.0	1.6		0.3–1.7		1.0
Pb		<0.02					0.12	0.30				
Se	<0.001											
V		<0.02										
Zn	0.25	3.5	0.05	0.03	2.8	0.1	8	7.2		0.1–2.8	0.2	0.1–1.5
SO_4	610–3,040		3,000	1,400	3,000	690	7,800	9,500	1,200–28,600	75–40,500	3,800–10,054	310–3,300
Acidity (as $CaCO_3$)	470–640				690	7	7,020	6,500	640–25,700	0–34,300	150–6,940	11–300
Alkalinity (as $CaCO_3$)	0–17					135				0–170	0	0
Hardness (as $CaCO_3$)	303–480											
Total dissolved solids (TDS)	1,050–4,320		4,000	2,700								
pH	2.8–5.0				3.0	6.9	2.5	2.4	2.1–3.6	2.1–7.5	2.9–4.9	3.1–5.2
Total suspended solids (TSS)			20	20								

[a]Typical acid mine drainage. From Hill and Bates (1977).

[b]Acid mine drainage water. From Barnthouse et al. (1977).

[c]Composite Appalachian mine effluent; lime-neutralized; TSS, Fe, and Mn assumed adjusted to meet effluent limitations. From Dvorak et al. (1977).

[d]Composite northern Great Plains mine effluent; untreated, except TSS assumed adjusted to meet effluent limitations. From Dvorak et al. (1977).

[e]Refuse effluent, northeastern Pennsylvania. From Martin (1974a).

[f]Refuse effluent, eastern Kentucky. From Martin (1974a).

[g]Refuse effluent, western Kentucky. From Martin (1974a).

[h]Refuse effluent, southwestern Indiana. From Martin (1974a).

[i]Refuse effluent, southern Illinois. From Martin (1974b).

[j]Refuse effluent, western Pennsylvania. From Martin (1974b).

[k]Refuse effluent, northern West Virginia. From Martin (1974b).

[l]Refuse effluent, southern West Virginia. From Martin (1974b).

Table 5.16. Selected Federal Water Quality Criteria for Drinking Water, Irrigation, Livestock Watering, and Protection of Aquatic Biota (all values except pH expressed as mg/L [ppm])

Parameter	Drinking Water Standard	Recommended Irrigation Water Limit[a]	Recommended Livestock Water Limit[b]	Aquatic Biota Protection Limit
Al		5.0	5	0.1[c]
As	0.05[d]	0.10	0.2	0.3[c]
B		0.75	5	392[c]
Ba	1[d]			104[c]
Cd	0.010[d]	0.010	0.050	0.0004–0.004 (soft)[e] 0.0012–0.0120 (hard)[e]
Co		0.050	1.0	6.25[c]
Cr	0.05[d]	0.10	1.0	0.100[e]
Cu	1[f]	0.20	0.5	0.0009[g]
Fe	0.3[f]	5.0		1.0[e]
Hg	0.002[d]		0.010	0.00005[e]
Mn	0.05[f]	0.20		0.35[c]
Ni		0.20		0.015[g]
Pb	0.05[d]	5.0	0.1	0.003[g]
Se	0.01[d]	0.020	0.05	0.02[g]
V		0.10	0.1	4.8[c]
Zn	5[f]	2.0	25	0.0004[g]
SO_4	250[f]			
Alkalinity				≥20[e]
Total dissolved solids (TDS)	500[f]		3000	
pH	6.5–8.5[f]			6.5–9.0[e]

[a]For waters used continuously on all soil. From U.S. Environmental Protection Agency (1973).

[b]U.S. Environmental Protection Agency (1973).

[c]Lowest concentration lethal to fish. From Cushman et al. (1977).

[d]From U.S. Environmental Protection Agency (1975).

[e]From U.S. Environmental Protection Agency (1976).

[f]From U.S. Environmental Protection Agency (1977b).

[g]Application factor recommended in reference e multiplied by the lowest concentration reported as the 96-hr LC_{50}, the concentration lethal to 50 percent of the test organisms in 96 hours, in Cushman et al. (1977).

dissolved or colloidal form, and iron and aluminum, when neutralized, form flocculant precipitates (Dvorak et al. 1977). The covering of waste piles with nontoxic soil materials has been effective in mitigating acidity problems (Martin 1974b).

Groundwater quality problems associated with mining and mine site processing result primarily from the leaching of spoils in stripped areas and of material in underground mines.

Ultimately, the local degradation or contamination of groundwater can be areally extensive. Groundwater movement can be quite rapid, up to hundreds of meters per year. This rapid groundwater movement, associated with interaquifer flow, can spread groundwater degradation over a large volume of aquifer material. Areas of calcareous material in, or constituting, bedrock, (glacial drift, limestone) are important. Groundwaters in these strata, which have a pH (before mining) greater than 6.4, can neutralize minor amounts of acidity by their alkalinity. Additionally, iron bacteria are not supported in this environment, and the acid reaction is not catalized.

The alkalinity and pH of infiltrating groundwater can be controlled, at least partially, during reclamation. Alkaline chemical compounds or calcareous rock material could be spread over spoil banks or backfilled into mine areas. An alkaline front could thus be formed that would move with infiltrating water, displacing iron bacteria before any groundwater acid problems could occur.

The effect of stream flow on dilution and assimilation is important. Reduction in the dry-weather flow of small streams (Sec. 5.4.1.1) may exacerbate acid drainage effects (U.S. Army Corps of Engineers 1974). In the New River basin (Ohio Water Resource Region), it was found that when flow was lowest, pH in affected streams also fell, with resulting destruction of stream alkalinity and severe pH oscillations (Minear and Tschantz 1976). Conversely, in some Appalachian areas, the major production of mine acidity is in winter and spring, when higher flows (and lower temperatures) limit effects (U.S. Army Corps of Engineers 1974).

Acid mine drainage and its effects have been described for the Mid-Atlantic Water Resource Region (abandoned deep mines and, secondarily, surface mines in the Delaware, Potomac, and Susquehanna river basins) and for the South Atlantic—Gulf Water Resource Region (abandoned strip mines in the Tombigbee-Black Warrior basin). The Ohio Water Resource Region is the most affected region, with acid drainage being a serious problem in the Allegheny, Monongahela, and Ohio river watersheds of the upper basin; in the Green, Tradewater, Saline, and Wabash watersheds of the lower basin; and in certain small tributary systems of the middle basin. The Tennessee Water Resource Region, the Upper Mississippi Water Resource Region (area stripping in the Big Muddy and Kaskaskia river basins in Illinois and in the Des Moines river basin in Iowa), and the Missouri Water Resource Region (area stripping in tributaries to the Chariton, Osage, and Missouri rivers in Missouri) have also experienced acid mine drainage (U.S. Army Corps of Engineers 1974). In the Appalachian area, where many stream reaches are almost constantly acidic, the acid drainage problem (primarily from abandoned deep mines) is the most serious in the northern part, because of the absence of calcareous soils (U.S. Army Corps of Engineers 1974; Kash et al. 1977). In southern Appalachia, calcareous formations are widespread, and acid mine problems are more localized (U.S. Army Corps of Engineers 1974).

Area stripping in Montana, Wyoming, North Dakota, and South Dakota is not a major problem yet, because of low precipitation rates, low sulfur content of coal, remoteness of streams, and state regulations (U.S. Army Corps of Engineers 1974). However, there are exceptions to these regional generalizations. The northern Great Plains are a potential problem area, if high-pyrite coal is mined (Kash et al. 1977); isolated cases of acid mine drainage have been reported from Colorado and Montana.

In accordance with the Surface Mining Control and Reclamation Act of 1977, discharges from surface and underground mining operations must have a pH of between 6.0 and 9.0 (Office of Surface Mining Reclamation and Enforcement 1977).

Alkaline drainage is a problem in the western coal fields (Habegger et al. 1977). There, overburden and deposits between coal seams are characterized by high concentrations of sodium, calcium, magnesium, CO_3, HCO_3, SO_4 (from overburden sulfate rather than from pyrite oxidation as in acid drainage), and chlorine. The dilution potential of many western streams is marginal, because of ephemeral or reduced summer and winter flows (Dvorak et al. 1977).

Reduction of pH from acid drainage has been associated with increased concentrations of zinc, copper, manganese, calcium, magnesium, and arsenic (Cairns et al. 1971). Not only is the solubility of many trace elements increased at a lower pH, but also the minerals of copper, zinc, aluminum, and manganese are often associated with pyrite (Hill and Bates 1977). Elevated levels of boron, in addition to many of the previously mentioned elements, have been found in coal refuse effluents (Martin, undated). Metals and sulfate concentrations in refuse seeps are generally proportional to acidity levels (Martin 1974b).

In addition to these elements, cadmium, chromium, cobalt, iron, nickel, lead, and selenium are considered to be of major concern from coal mining (Dvorak et al. 1977). Coal mining also typically causes TDS increases (Dvorak et al. 1977; Minear and Tschantz 1976). Total dissolved solids concentrations in groundwater would increase as leachate from spoils and mines infiltrates area aquifers. Substances such as iron, manganese, aluminum, zinc, and SO_4 may be locally quite increased in concentration (Table 5.15). In the western coal fields, where groundwaters are characteristically alkaline and saline, leaching of salts from spoils could appreciably degrade the groundwater quality of the aquifers. When high TDS levels are encountered, sulfate, which is toxic in sufficient concentration, is often a constituent. However, calcium, magnesium, and HCO_3 provide much of the total salinity, and toxicity to aquatic biota is considered to result more from osmotic stress than from particular toxic constituents (Dvorak et al. 1977).

Water quality measurements for mine and refuse effluents for a variety of coal mining areas are presented in Table 5.15. By comparison with Table 5.16, many of the concentrations in Table 5.15 (aluminum, cadmium, cobalt, chromium, copper, iron, mercury, manganese, nickel, lead, zinc, TDS, SO_4, alkalinity, and pH) do not meet various water quality criteria.

The reported adverse effects of coal mining and mine site processing can be attributed mostly to untreated or inadequately treated effluents or discharges. But even the effluent limitations for coal mining and associated activities established by the Office of Surface Mining Reclamation and Enforcement (1977) would allow iron and manganese concentrations exceeding the criteria or standards for drinking water, irrigation water, and aquatic biota protection. Thus, dilution by receiving waters is assumed. The aforementioned effluent limitations allow maximum total iron and manganese concentrations of 7.0 and 4.0 mg/L, respectively; averages of daily values for 30 consecutive discharge days shall not exceed 3.5 and 2.0 mg/L, respectively. Assuming a typical mine effluent flow of 160 L (2500 gpm) (Dvorak et al. 1977), the following flows (cfs; 1 cfs = 450 gpm = 28 L) of distilled water are required to dilute the maximum iron and manganese concentrations to the water quality criteria for drinking water, irrigation water, and protection of aquatic biota.

Constituent	Drinking Water	Irrigation Water	Protection of Aquatic Biota
Iron	125	2.2	33
Manganese	440	106	58

Where more than one mine discharge was entering a receiving water, or where there were nonzero background levels of iron or manganese, the dilution requirement would be increased.

The National Strip Mine Study (U.S. Army Corps of Engineers 1974) contains an overview of the effects of sedimentation on aquatic resources. The magnitude of sedimentation is related to the land area disturbed, but sedimentation also results from coal processing runoff and spills (U.S. Army Corps of Engineers 1974; Dvorak et al. 1977). Sedimentation from coal mining and mine site processing is most serious where steep terrain is prevalent and where precipitation is abundant and intense (U.S. Army Corps of Engineers 1974; Kash et al. 1977). Mountainous areas with little space for adequate retention ponds pose a major problem (Dvorak et al. 1977). In areas of level and rolling topography, area stripping and open-pit mining present lesser sedimentation hazards, but problems nevertheless result from stream-edge mining (U.S. Army Corps of Engineers 1974).

Southern Appalachia is considered the area of most severe actual and potential sedimentation problems, with steep slopes and abundant and intense precipitation (U.S. Army Corps of Engineers 1974; Kash et al. 1977). Summer rainstorms in the Appalachian area cause intense, rapid runoff with erosion (U.S. Army Corps of Engineers 1974). In eastern Kentucky, thousand-fold increases in sediment yields have been measured for contour strip areas compared with undisturbed forests (U.S. Army Corps of Engineers 1974). Indicative of the diffuse nature of the sedimentation problem, access and haul roads in that area account for 10 percent of the total land disturbed by contour and auger mining (U.S. Army Corps of Engineers 1974). Runoff from slurry pond overflow and refuse pile erosion after storms are a particular problem in the mountainous regions of southern West Virginia and eastern Kentucky (Martin 1974b). Abandoned strip mines in the Tombigbee-Black Warrior basin (South Atlantic-Gulf Water Resource Region) are the primary source of sediment there (U.S. Army Corps of Engineers 1974).

In the middle basin of the Ohio Water Resource Region, contour and auger mines, roads, and processing plants contribute sediment to the Kanawha, Guyandotte, and Big Sandy river subbasins, and contour and area stripping are important sources in the Muskingum subbasin. In the lower basin of the Ohio Water Resource Region, sediment from coal mining is a problem in the upper Kentucky and Cumberland, Green, Tradewater, Saline, and Wabash river subbasins (U.S. Army Corps of Engineers 1974). While not considered as severe a regional problem in the Tennessee Water Resource Region (U.S. Army Corps of Engineers 1974), sedimentation from coal washing has caused major problems in the Guest River and Dump's Creek, tributaries to the Clinch River (Cairns et al. 1971).

In the Mid-Atlantic Water Resource Region, sedimentation is most severe as a result of surface mining in the anthracite region (U.S. Army Corps of Engineers 1974). Sedimentation can also be significant in the midwest because of abundant rainfall and the density of mining in some areas (Kash et al. 1977). Sedimentation in the Upper Mississippi Water Resource Region is a problem in the Big Muddy and Kaskaskia river basins in Illinois and the Des Moines River basin in Iowa, a result of area stripping (U.S. Army Corps of Engineers 1974). Similarly, high suspended solids levels have been identified as a problem in some western coal fields (Habegger et al. 1977). Sedimentation in the northern Great Plains and Rocky Mountains results from short, high-intensity, local precipitation events (Kash et al. 1977).

In accordance with the Surface Mining Control and Reclamation Act of 1977, sediment discharges from surface and underground mining are to be controlled (Office of Surface Mining Reclamation and Enforcement 1977). For most states, TSS levels in discharges are not to exceed 70.0 mg/L at any time, or 35.0 mg/L as an average for 30 consecutive discharge days. The corresponding values for Arizona, Colorado, Montana, New Mexico, North Dakota, South Dakota, Utah, and Wyoming are 45 and 30 mg/L, respectively. With respect to the southeastern United States, where the sedimentation potential is most severe, one analysis indicates that these regulations should keep TSS levels in mined areas within the expected range for nonmined areas (Davis et al. 1978). Even the large-storm exemptions of the regulations would result in TSS levels comparable to levels in basins with other land uses.

To summarize, acid mine drainage is considered a potential problem primarily in northern Appalachia (Supply Region 1) and in the Eastern Interior (Supply Region 4). The severity of trace metal impacts on water quality is largely related to the acid mine drainage problem. Sedimentation is considered of greatest hazard potential in southern Appalachia (Supply Region 3), one of the areas where coal production will be significantly increased as a result of the proposed action. Alkaline mine drainage, with elevated levels of dissolved solids and such constituents as sulfate, is considered of greatest hazard potential in the western United States (Demand Regions VI, VII, VIII, and IX), where coal production will also be significantly increased by the proposed action. These are generalizations, and the occurrence of exceptions is stressed.

As in the case with hydrologic effects, the extent to which the regulations promulgated pursuant to the Surface Mining Control and Reclamation Act of 1977 are applied and enforced will determine the extent to which effects on water quality (pH, sediment, trace substances) are controlled.

5.4.1.3 Water Use Effects

Effects of coal mining and mine site processing on water use fall into two major categories: effects on water availability (mining withdrawals and consumption, reduced stream flow, dewatered groundwater aquifers, etc.) especially in the semi-arid West, where there are conflicts over water use, and effects on water quality sufficient to constrain use (excessive acidity, trace substance contamination, suspended sediments, hardness, etc.). The effects of coal mining on use of water resources are discussed in the National Strip Mine Study (U.S. Army Corps of Engineers 1974).

Various estimates exist for the water needs of coal mining, processing, and reclamation. It has been estimated that mining requires 15 to 57 L/metric ton (4 to 15 gal/ton), that coal mining waste disposal requires an additional 30 L/metric ton (8 gal/ton), and that reclamation irrigation in the semiarid West requires another 61 L/metric ton (16 gal/ton) (Kilpatrick and Davis 1976). Water demand for reclamation irrigation in the Powder River Basin in eastern Wyoming, where about 8 hectares (ha) (20 acres) of land are affected per million tons of surface-mined coal, has been estimated to be about 3×10^3 m^3/ha (1 acre-ft/acre) reclaimed land, assuming irrigation for one year [equivalent to about 25 L (6.5 gal) per ton of coal (Trelease and Burman 1975). The water demand by mining (including irrigation) has been described as nominal, even in arid land (Kilpatrick and Davis 1976). However, the 46×10^6 m^3/year total demand in the mid-1970s (Kilpatrick and Davis 1976) could increase significantly if more reclamation irrigation is required. If water development projects are necessitated by the increased water demand for irrigation, the replacement of flowing waters by static ones would also potentially affect some uses (such as aquatic habitat and recreation).

Complicating the estimation of the impact of coal mining water demand is the fact that in the western United States the coal beds themselves may be important groundwater aquifers (Dvorak et al. 1977).

The importance of the loss of surface waters, dewatering of groundwater aquifers, lowering of hydraulic heads, disappearance of springs, etc. (Sec. 5.4.1.1) will depend on the uses made of them (for water supplies, wildlife habitat, etc.). In northern Appalachia, mining has disturbed important limestone aquifers, and in southern Appalachia, perched aquifers have been dewatered; in both areas, wells have been damaged by blasting (Kash et al. 1977). The loss of shallow groundwater supplies as a result of deep mine subsidence (primarily in Demand Regions III, IV, and V) also affects their beneficial use (Hill and Bates 1977). Texas lignite deposits are associated with important groundwater aquifers (Kash et al. 1977). In the western United States, coal-bed groundwater, even if not of drinking-water quality, is used for livestock watering (Dvorak et al. 1977). In the northern Great Plains, groundwater is used heavily for domestic and livestock water supplies (Kash et al. 1977). However, subirrigation of alluvial valley floors is vital to agriculture in some western states (Kash et al. 1977; Carter et al. 1977), and the disturbance of their groundwater systems is of particular concern (Carter et al. 1977). Although springs are important to livestock and wildlife, these populations may benefit if some groundwater aquifers are exposed (Kash et al. 1977). Groundwater quality can at least be reduced locally by influent leachates.

Factors such as elevated levels of suspended sediment, dissolved solids, acidity, trace substances, etc., may constrain water uses that are dependent on water quality. These uses include habitat for biota, drinking water, livestock watering, irrigation, public water supplies, industrial uses, pollutant dilution and assimilation, recreation and aesthetics, and navigation. Increased water treatment costs may be incurred to meet quality criteria.

Water uses for aquatic life habitat and for recreation have been considered the most constrained by coal mining (U.S. Army Corps of Engineers 1974). Effects on fishing and other aspects of aquatic ecology are considered more fully in Section 5.6.1.2. In addition to effects on fishing, impacts on recreational water use have been of an aesthetic nature (views of mines, waste piles, and haul roads; water coloration from iron), related to accelerated corrosion of piers and other instream structures as a result of acid drainage and to navigability and anchorage limitations because of sedimentation (see Sec. 5.4.1.2) (U.S. Army Corps of Engineers 1974). Commercial navigation has also been affected - by acidity in the upper Ohio basin (Monongahela River), where boats, barges, dams, and locks have been corroded; and by sedimentation, with dredging necessitated in the Schuylkill (Mid-Atlantic Water Resource Region) and Big Sandy (Ohio Water Resource Region) rivers (U.S. Army Corps of Engineers 1974).

Acidity affects the self-purification and sewage-assimilation capacity of streams, with major implications for downstream domestic withdrawals (U.S. Army Corps of Engineers 1974). Water supplies are imperiled, particularly in areas such as southeastern Ohio, Pennsylvania, and northeastern West Virginia (Ohio Water Resource Region), where alternative supplies are not available. Significant costs may be incurred due to corrosion as well as for water neutralization and softening. Where small streams are used, sediments and turbidity, especially, clog intake pipes and increase treatment costs - a major problem in southern West Virginia, eastern Kentucky, Tennessee, and western Virginia (Ohio and Tennessee Water Resource Regions) (U.S. Army Corps of Engineers 1974). Where alkaline drainage is a hazard, water uses may also be affected by changes in quality: increased dissolved solids are considered a problem in Colorado, where wells and springs are used by livestock and wildlife (Kash et al. 1977).

For those supply regions where production will be significantly increased by the proposed action (2, 3, 5, 6, 7, and 8), the greatest potential effects on water use are expected. For the western United States (Supply Regions 5, 6, 7, and 8), these potential effects are related to alkaline mine drainage (with high dissolved solids levels and elevated levels of such constituents as sulfate) and to disturbance of groundwater hydrology and quality. For the central and southern Appalachian area, sedimentation is of prime concern, although localized occurrences of acid mine drainage may affect water use.

In accordance with the Surface Mining Control and Reclamation Act of 1977, effects on water use resulting from effects on hydrology (Sec. 5.4.1.1) and water quality (Sec. 5.4.1.2) are to be controlled. Additionally, where a legitimate use of groundwater or surface water is affected by contamination, diminution, or interruption because of the mining operation, the affected supply is to be replaced by the mining permittee (Office of Surface Mining Reclamation and Enforcement 1977). The extent to which regulations in accordance with the act are applied and enforced will determine the extent to which water uses are protected from the adverse potential effects of coal mining.

5.4.2 Transportation

The exact mix of transportation modes and routes associated with the proposed action is not known; uncertainty arises from the location of production, the location of demand, and the transportation mode used to move coal to the point of demand. New transportation systems are developing to handle increased coal traffic, some of them controversial (such as the slurry pipeline), and it is not possible to define the transportation mix associated with the proposed action, although estimates are made in Section 5.2. Therefore, what follows is a generic discussion of the water quality and water use effects of the various coal transportation modes.

5.4.2.1 Water Quality Effects

Many of the effects of coal transportation on water quality are common to all the transportation modes - railroads, barges and ships, slurry pipelines, conveyor belts, and trucks. The environmental effects of the various modes have been discussed (Dvorak et al. 1977). Erosion and resulting siltation, turbidity, and sedimentation are expected to be associated with railroads, especially in the Appalachian region, due to high precipitation, and in the northeastern mountains, where railroads are close to streams, and valleys are narrow. Lesser problems are expected in the West, because of aridity and because railroad lines can be planned to avoid paralleling streams, although sedimentation at stream crossings will still be a problem. Sedimentation problems are also experienced with barges (the effects of dredging to maintain channels; construction; bank erosion if barge traffic is heavy in a narrow channel), with slurry pipelines (construction impacts are likely, although the aridity and generally flat terrain in the western and midwestern states would limit these impacts), and with trucks (the effects of road construction and maintenance, with erosion and sedimentation being especially troublesome in mountainous terrain such as Appalachia) (Dvorak et al. 1977). Similarly, sedimentation is a hazard with conveyor belts, which are seen as particularly useful in rough terrain (App. E.2.4.4).

Spills, leaching, and leakages of coal and/or fuels are also seen as a problem common to all transportation modes. The derailment of a unit coal train could result in the spilling of about 10,000 tons of coal; seepage from loading and unloading stockpiles is also seen as a problem (Dvorak et al. 1977). Slurry spills are a potential problem with pipelines, while spills of coal and fuels are possible from barges and trucks (Dvorak et al. 1977). Spills from barges and ships (with loads of up to 62,500 tons) would of course be most likely to affect water quality directly because of proximity, whereas effects from the other modes would be more dependent on exact location, topography, soil mobility, etc.

The infiltration of fluids (including leachate) from coal and/or liquid fuel spills is a potential problem where groundwater quality is concerned. Depending on the type and amount of liquid spilled or leachate generated, as well as the nature of the soil and bedrock present in an area, aquifer contamination may or may not occur. The groundwater quality effects are, therefore, site specific, although generalizations can be made. In areas typified by a thick, clay-rich soil, the infiltration of contaminants should be, at most, minimal. Besides adsorption onto individual clay particles, the permeability for transmission of fluids would be low. Where overburden is thin, consisting of particles larger than 125 microns (fine sand), or where jointed bedrock is exposed, percolation of contaminants would occur rapidly. Areas underlain by carbonate bedrock would be especially prone to aquifer degradation from spills, because of rapid groundwater movement in the solution openings and joints prevalent in these rocks.

Effects on water quality from spills, leakages, and leachates may be expected to increase roughly proportionately with the increased demand and use of coal. On the other hand, increases in construction-related effects will be determined by the extent to which additional lines, roads, slurry pipelines, etc., are required; this extent is undetermined presently. Similarly, the impoundment of streams and the construction of locks required for barge traffic alter aquatic habitats and interfere with fish migration, but the proposed action would aggravate this problem only to the extent that new impoundments and locks would be required (Sec. 5.6.2.2) (Dvorak et al. 1977; Minckley and Deacon 1968).

5.4.2.2 Water Use Effects

Although presumably smaller in magnitude, water use effects as a result of sedimentation and water quality deterioration will be similar qualitatively to corresponding effects of mining and mine site processing (Sec. 5.4.1.3), and storage and onsite processing (Sec. 5.4.3.2).

A major problem, unique to the slurry pipeline, is the consumptive water requirement for the slurry. The point of water demand would frequently be in regions already short of water (Sec. 4.3.1), and difficult legal and institutional problems must be overcome if this technology is to be implemented (Kilpatrick and Davis 1976). Typical water requirements are expected to be about 1 cubic meter of water per metric ton of coal (30 ft^3/ton) (Kilpatrick and Davis 1976). Although it cannot be stated how the water will be provided, conflicts over water rights may be anticipated. If regional consumption is increased, drawdown of groundwater aquifers and lake levels may result (Dvorak et al. 1977).

Groundwater would be diverted from some areas because of local depression of the potentiometric surface by increased pumpage. In water-short areas, groundwater mining could occur (discharge is greater than recharge to the system). Areas in which groundwater is already being mined (such as the High Plains of Texas) would be most affected by an increased demand for slurry water. If water development projects are necessitated by the slurry pipeline water demand, or by barge or ship transportation, replacement of flowing waters by static ones would also potentially affect some uses (aquatic habitat, recreation, etc.).

5.4.3 Storage and Onsite Processing

For storage and onsite processing, as well as for combustion and waste collection and disposal (Secs. 5.4.4 and 5.4.5), the potential severity of impacts on aquatic resources may be related to both the percent increase in regional coal consumption from the proposed action and the absolute magnitude of increased coal use. The values for the percent increase in coal consumption and for the absolute magnitude of the increased coal use required by the proposed action are given in Table 5.17. When the percent increase in coal consumption over the base case within a demand region is less than 5 percent, the regional effects of the proposed action are expected to be insignificant (Sec. 5.4.1), as is the case for Demand Regions III, V, VII, and VIII in both 1985 and 1990 and for Demand Region IV in 1985. Together, the consumption required by the coal shift in these Federal regions will account for 23 and 10 percent of the total national shift tonnage in 1985 and 1990, respectively. Particularly for Demand Region IV (10 percent of the national shift tonnage in 1985) and Demand Region V (7 percent of the 1985 national shift tonnage), the percent increase in consumption might be slight, but the absolute tonnage is large enough so that localized effects might be significant. As discussed in Section 5.4.1, the role of federal and state regulation in the prevention of localized impacts will be critical.

For Demand Regions I, II, VI, IX, and X in 1985 and 1990, and for Demand Region IV in 1990, the percent increase in coal consumption necessitated by the proposed action will be at least 5 percent. For Demand Region VI, the percent increase and the absolute magnitude are both large, with this region having 63 and 66 percent of the national shift tonnage in 1985 and 1990, respectively. While the percent increase in Demand Region I is large, the absolute tonnage is small - 2 percent of both the 1985 and 1990 national shift tonnage. For Demand Region II (8 and 12 percent increase in 1985 and 1990, respectively) and Demand Region X (11 and 17 percent increase in 1985 and 1990, respectively), the absolute tonnage magintude is also small - 2 percent for Demand Region II and 1 percent for Region X for both the 1985 and 1990 national shift tonnage. For Demand Region IX, both the percent increase (27 and 36 percent in 1985 and 1990, respectively) and the absolute tonnage (9 and 7 percent of the national shift tonnage in 1985 and 1990, respectively) are significant.

The potential for regionally significant impacts is expected to be related to both the percent increase in consumption and to the absolute magnitude of consumption. Where the percent increase is at least 5 percent, the regional impacts are considered potentially significant, especially when the absolute magnitude is large (Sec. 5.4.1), as is true for Demand Regions IV, VI, and IX. When the percent increase is large but the absolute magnitude is small (Demand Regions I, II, and X), and when the percent increase is small but the absolute magnitude is large (Regions IV and V), the potential impacts may be expected to be more localized in nature. The potential impacts of storage and onsite processing (Secs. 5.4.3.1 and 5.4.3.2), as well as of combustion (Sec. 5.4.4) and waste collection and disposal (Sec. 5.4.5), are addressed generically.

5.4.3.1 Water Quality Effects

The effects of coal storage are similar to those of mine site processing and refuse (gob and slurry) disposal, although smaller in magnitude (Dvorak et al. 1977). Water contact is controlled by storage practices, and the coal piles generally contain lower levels of contaminants than do processing wastes (Dvorak et al. 1977). Contamination of surface water and groundwater may result from runoff and infiltration from coal pile leachates; parameters of concern include coal fines, humic acids, low pH, acidity, sulfate, and iron and other trace elements. These impacts are more pronounced in areas of heavy runoff. Additionally, coal storage piles may be sprayed (for dust suppression) with alkyls, phenol, ether, and ethylene (Dvorak et al. 1977), which may be toxic to aquatic biota and may contaminate groundwater reservoirs.

Water quality measurements for a variety of coal leachates and coal pile drainages are given in Table 5.18. Characteristically, these potential effluents exceed many of the standards and criteria for drinking water, livestock water, irrigation water, and protection of aquatic biota (Table 5.16). Consequently, dilution by receiving waters would be required so that the final concentrations in the environment would not be in violation of these criteria. Point source discharges from industrial sites are subject to NPDES permit procedures, which require that effluents meet standards prior to discharge. Point source effluent standards for coal storage piles at industrial sites may be promulgated in accordance with the Federal Water Pollution Control Act and Amendments (see Sec. 8).

5.4.3.2 Water Use Effects

The primary potential water use effect of storage and onsite processing is constraints on water use as a result of contamination of surface waters and groundwaters. Characteristically, coal pile drainage exceeds promulgated criteria and standards for water-quality-dependent uses (Sec. 5.4.3.1). Although of lesser magnitude, the coal pile runoff and infiltration problems

Table 5.17. Calculated Base-Case Coal Consumption, Consumption Required by Proposed Action, and Percent Increase in Consumption Caused by Proposed Action by Demand Region, 1985 and 1990

Demand Region	Estimated Percentage of Total National Consumption, Base Case (%)	1985 Base Case (10^6 tons)	1985 Increased Coal Use, (10^6 tons)	1985 Shift, Δ(%)	1990 Base Case (10^6 tons)	1990 Increased Coal Use, (10^6 tons)	1990 Shift, Δ(%)
I	0.18	1.84	1.501	82	2.24	2.405	107
II	1.87	19.34	1.542	8	23.52	2.721	12
III	17.43	180.23	1.958	1	219.15	3.629	2
IV	21.21	219.35	7.512	3	266.72	14.141	5
V	35.01	361.97	5.133	1	440.14	6.409	1
VI	8.38	86.61	45.266	52	105.31	85.587	81
VII	6.49	67.06	1.345	2	81.54	2.141	3
VIII	6.71	69.33	0.745	1	84.30	1.383	2
IX	2.32	24.00	6.421	27	29.19	10.543	36
X	0.42	4.37	0.493	11	5.31	0.903	17
		1034.[a]	71.916[a]	7[b]	1257.[a]	129.862[a]	10[b]

[a]Total.

[b]Percent national shift.

Table 5.18. Representative Water Quality Measurements for Coal Pile Leachate and Coal Pile Drainage (all values except pH expressed as mg/L [ppm])

Parameter	Effluent			
	a	b	c	d
Al	825-1,200	48-1,200	22.0-440	
As		0.02-0.1	0.005-0.6	
Ba			0.1	
Cd		0.002	<0.001-0.006	<0.05
Co		0.09-0.4		
Cr	0-15.7	0.02-15.7	<0.005-0.011	<0.05
Cu	1.6-3.9	<0.2-6.1	0.01-1.4	0.1-0.15
Fe	0.4-2.0	0.06-93,000	62-1,800	0.65-12
Hg			<0.0002-0.027	
Mn	90-180	3.4-72.0	0.88-110	<0.05-0.08
Ni		0.2-2.8	0.24-4.5	
Pb		0.2	<0.01-0.023	<0.1
Se		<0.005-0.02	<0.001-0.03	
V		<1		<2
Zn	0.006-12.5	0.006-26.0	1.0-16	0.15-0.23
SO_4	130-20,000	525-21,920	870-9,600	
Acidity (as $CaCO_3$)	10-27,800	8.84-21,700	270-7,100	
Alkalinity (as $CaCO_3$)	15-80	0-36.41		37.5-124
Hardness (as $CaCO_3$)	130-1,850	130-1,851	600-980	
Total dissolved solids (TDS)	700-44,000	720-44,050	1,200-16,000	490-1,720
pH	2.8-7.8	2.1-6.6	2.3-3.1	7.2-8.0
Total suspended solids (TSS)	20-3,300	22-610	8-2,500	

[a] Coal pile drainage, unspecified coal. From Federal Energy Administration (1977d), Table IV-9.

[b] Coal pile drainage, unspecified coal. From Davis and Boegly (1978), Tables 4, 5, 12, 13, and 14.

[c] TVA plant coal pile drainage, unspecified coal. From Davis and Boegly (1978), Tables 9, 10, and 11.

[d] Western coal leachate; wet aerobic (pH 7.4), intermediate aerobic (pH 7.2), and anaerobic (pH 8.0) conditions. From Davis and Boegly (1978), Table 6.

are seen as similar to the water quality and use effects from mine site processing discussed in Sections 5.4.1.2 and 5.4.1.3 (Dvorak et al. 1977). The geographic distribution of storage and onsite processing will also reflect the distribution of demand and utilization, rather than the distribution of mining activities to meet the coal demand.

5.4.4 Combustion

Effects on aquatic resources as a result of the combustion of increased coal use necessitated by the proposed action will be limited in this discussion to those stack emissions peculiar to coal. Effects common to the use of fossil fuels (thermal discharges, water consumption for cooling, entrainment and impingement of aquatic biota) will not be addressed.

The impacts of trace elements deposition from combustion (Sec. 5.4.4.1) are expected to be of greatest potential regional significance in Demand Regions VI and IX and of greatest potential localized significance in Demand Regions I, II, IV, V, and X (Sec. 5.4.3). However, the overall significance of trace element enrichment from combustion may not be great (Sec. 5.4.4.1).

The large-scale atmospheric transport phenomenon of acid rain (Secs. 5.3.4.2 and 5.4.4.1) precludes the application of the percent-increase and the absolute-tonnage approach, discussed in Section 5.4.3, to determine the potential regional significance of impacts. On the basis of expected atmospheric transport from stack emissions of the increased coal combustion, the acid rain phenomenon is projected to be increased more towards the southwest because of inputs from the Texas Gulf Coast area (Sec. 5.3.4.2). Consequently, in addition to the overall contribution to acid rain, the proposed action could especially aggravate the potential freshwarer acidification problem highlighted for igneous regions of North Carolina and Virginia (Sec. 5.4.4.1).

5.4.4.1 Water Quality Effects

Effects on water quality from the combustion of coal necessitated by the proposed action will fall into two major categories: the effects of acid rain (Sec. 5.3.1) and the effects of trace substances in stack emissions. Dvorak et al. (1977) contains a discussion of these effects on water quality.

The most direct effects of acid rain on water quality include lowered pH and reduced buffering capacity (Dvorak et al. 1977; Glass 1977). Lake acidification is most serious in the Adirondack Mountains (where the igneous and metamorphic geology results in low TDS and low buffering capacity, with dominance by calcium, magnesium, SO_4, and chlorine ions) and in New England (particularly the White Mountains of northern New Hampshire and western Maine [granitic geology]) (Dvorak et al. 1977). Typical pH levels of Adirondack lakes range from 4.5 to 5.5, with 51 percent of 217 investigated lakes at altitudes above 600 m (1969 ft) having pH below 5.0. (Dvorak et al. 1977; Glass 1977). New England lakes have had measured pH of 3.0 to 4.0 (Federal Energy Administration 1977d). Similar effects have been noted in the La Cloche Mountains of southeastern Ontario (many with pH below 4.5) (Dvorak et al. 1977) and in Scandinavia. Other potential problem areas are pre-Cambrian igneous regions in the Piedmont and Appalachia of North Carolina and Virginia, as well as dilute headwater streams and alpine lakes of the Cascade Mountains of Oregon and Washington (Dvorak et al. 1977). Aquifer degradation by acid rain recharge would probably not be appreciably detectable for hundreds of years.

Indirect effects of acid rain on water quality include increased trace element solubilization and availability because lowered pH strips trace elements from bonding sites on organic and inorganic complexing agents (Dvorak et al. 1977). Acidified lakes frequently have elevated concentrations of aluminum, manganese, zinc, cadmium, lead, copper, and nickel both from increased deposition and from resolubilization from sediments (Glass 1977). The buffering capacity of lakes is destroyed by acid rain inputs, so that new inputs cause pH to drop sharply (Glass 1977).

Dispersion calculations (Sec. 5.2) indicate that a major area of sulfur dioxide and sulfate deposition resulting from the proposed action is the North Texas, Oklahoma, Missouri, and Arkansas area. Lakes in this area tend to be high in total hardness with a large buffering capacity, thus mediating the impact of acid precipitation. The proposed action will have the effect of incrementally adding to an acid precipitation problem in the northeast and southern United States.

In addition to mobilization from terrestrial and sediment sources, and increased availability due to acid rain, trace element inputs from effluent emissions and deposition may potentially affect water quality. Several trace elements have been identified as of concern in aquatic environments: arsenic, cadmium, cobalt, mercury, copper, lead, selenium, manganese, chromium, and tin (Dvorak et al. 1977; Van Hook 1978). In a conservative study of trace element deposition in a hypothetical closed lake, with 30 years of operation of a 1000-MW power plant, only mercury and zinc would exceed criteria for the protection of aquatic biota (Dvorak et al. 1977). Van Hook (1978) concludes that trace element enrichment from coal combustion atmospheric effluents is not a significant hazard in surface aquatic systems. In addition, the amounts of trace metals leaching into a groundwater reservoir from combustion would be insignificant. Clay minerals in the overburden and bedrock would probably adsorb nearly all trace metals (ion substitution would also take place).

5.4.4.2 Water Use Effects

Any effects on water use from coal combustion effluents as a result of the proposed action would be expected to occur from deterioration of water quality, most probably from acidification and increased trace element levels. Although similar qualitatively to corresponding effects from other parts of the coal fuel cycle (Secs. 5.4.1.3, 5.4.2.2, 5.4.3.2, and 5.4.5.2), these effects, being related to atmospheric deposition, would be more diffuse and hence less identifiable as resulting from particular sources.

5.4.5 Waste Collection and Disposal

The impacts of waste collection and disposal on water quality and use are expected to be of greatest potential regional significance in Demand Regions VI and IX and of greatest potential localized significance in Demand Regions I, II, IV, V and X (Sec. 5.4.3).

5.4.5.1 Water Quality Effects

Potential effects on water quality from the waste collection and disposal associated with the proposed action are related to trace contaminants, high pH levels, chemical oxygen demand, and dissolved and suspended solids. A more thorough discussion of the environmental effects of waste disposal from coal utilization is contained in Environmental Protection Agency (1977a) while Van Hook (1978) discusses the state of the art with respect to mobilization of trace elements from coal combustion wastes.

Ash pond overflow, dike failure, ash-slurry pipeline rupture, and site erosion may result in the release of high dissolved and suspended solids loads to receiving waters (Dvorak et al. 1977; Barnthouse et al. 1977). For example, the collapse of a fly ash holding pond in 1967 released about 500 x 10^3 m^3 (130 x 10^6 gal) of highly alkaline effluent to the Clinch River in less than one hour; this release represented about 40 percent of the river flow at the time and adversely affected about 145 km (90 mi) of river (Cairns et al. 1971). Table 5.19 contains water quality measurements for scrubber sludge and pond overflows.

Leachates from ash or scrubber sludge (Table 5.19) may also have adverse effects on water quality. Experimental ash leachate had excessive levels of boron, barium, chromium, mercury, and selenium, while experimental scrubber sludge leachate had excessive boron, barium, and selenium levels (Dvorak et al. 1977). The extent to which concentrations of these and other elements will be attenuated depends on such factors as soil type, depth of water table, pond sealing, dilution, and element mobility (Dvorak et al. 1977; Barnthouse et al. 1977). Leachate from a highly contaminated anaerobic landfill was not renovated after passage through 12 m (40 ft) or more of sandy loam-sandy clay soil (Barnthouse et al. 1977). Because overburden thicknesses are often less than 12 m (40 ft), and because overburden is often of larger particle size (generally more permeable), toxic elements can be expected to reach the water table easily. The soil type, bedrock, topography, and rainfall are site specific; therefore, groundwater impacts will have to be generalized. Depending primarily on the soil composition and percolation rates and on bedrock composition and transmissivity, fly ash and scrubber sludge leachates may remain localized after introduction to the groundwater system. Slow percolation downward through, for instance, a clay-rich, partially confining bed would considerably reduce the amount of contaminants in an underlying aquifer. On the other hand, contaminated groundwater in carbonate rocks may move over long distances through fractures, joints, fault planes, and other permeable zones (Barnthouse et al. 1977). Groundwater discharge points such as wells, streambeds at gaining reaches, and springs may be tens of kilometers away from the point at which the leachate entered the system (Quinlan 1976). Thus, the time of transit through the system could be in terms of hours, or several days.

The Committee on Health and Environmental Effects of Increased Coal Utilization singled out the issue of mobilization of trace elements from combustion wastes and resulting entrance into food chains as being of particular environmental importance (U.S. Department of Health, Education, and Welfare 1978). The committee stressed the need for better data on the mobilization potential of the trace elements. A similar need was found for better understanding of the toxicity and mobility of vanadium and thallium, so that the hazard potential of these two elements could be assessed (Barnthouse et al. 1977). For some of the trace elements (arsenic, cadmium, cobalt, copper, iron, molybdenum, nickel, lead, scandium, selenium, uranium, and zinc), discharge into ash settling ponds exceeds 10 percent of the natural weathering rate, with the rate for

Table 5.19. Representative Water Quality Measurements for Coal Pile Waste Disposal Effluents (all values except pH expressed as mg/L [ppm])

Parameter	Effluent a	b	c	d
Al	0.02–513	1.4–9.8		
As		0.01–0.05		
Cd		0.01–0.03		
Cr	negligible–0.14	0.02		
Cu	0.005–0.06	0.1		
Fe	0.02–2.9	0.02		
Hg	0.0002–0.002	0.0015–0.0055		
Mn	0.0002–0.10	0.05		
Ni	0.008–0.015	0.015		
Zn	0.001–0.12	0.01–0.02		
SO_4	100–300	0–344	520	377
Acidity (as $CaCO_3$)			5	5
Alkalinity (as $CaCO_3$)	30–400		80	32
Hardness (as $CaCO_3$)	200–750	285–602	696	484
Total Dissolved solids (TDS)	250–3,300	68–296	1,095	750
pH		10.5–11.8	6.7	7.2
Total suspended solids (TSS)	25–100	4–8	70,780	5

[a]Ash pond overflow. From Federal Energy Administration (1977d), Table IV-9.

[b]Simulated leachate from sludge fixated with Dravo "Calcilox." From Federal Energy Administration (1977d), Table IV-13.

[c]Fixed scrubber sludge, as discharged to pond. From Federal Energy Administration (1977d), Table IV-12.

[d]Fixed scrubber sludge pond overflow, discharge to water source. From Federal Energy Administration (1977d), Table IV-12.

molybdenum, selenium, and uranium approximating the natural weathering rate (Van Hook 1978). Mercury, cadmium, and lead are also of concern because their present levels of intake approach human health limits (Van Hook 1978). Because of their immobility in soil, zirconium and titanium (the latter abundant in some western coals) were judged of concern only from pond leaks or failure (Barnthouse et al. 1977).

In addition to their trace element concentrations, combustion waste effluents are hazardous because of their elevated pH levels (Table 5.19). The hydrolysis of alkali and alkaline earth metals in ash settling basins may raise the pH to greater than 11 (Van Hook 1978). The reaction of lime in ash with water to produce calcium hydroxide raised the pH in the fly ash holding pond lagoon at the steam plant mentioned previously to 12.0–12.7 (Cairns et al. 1971); the slurry's alkalinity was 90 percent hydroxide and 10 percent carbonate. The dissolved oxygen in the receiving water of the spill from that pond (the Clinch River) dropped as a result of decaying organic matter (Cairns et al. 1971); calcium sulfite in scrubber sludge, with its high oxygen demand, may have the same effect (Dvorak et al. 1977; U.S. Environmental Protection Agency 1977a).

Ash disposal impacts have been judged of greatest potential for Demand Regions VI, VIII, IX and X — the warmwater ecosystems of Region VI and the small-stream, cold-water fisheries of Regions VIII and IX were emphasized. Scrubber sludge impacts were seen as potentially hazardous in the coastal estuaries and warmwater systems of Region VI and in the high-quality, cold-water fisheries in the northern part of Region III. Coal waste storage may be affected by federal regulations in accordance with the Resource Conservation and Recovery Act of 1976 (see Sec. 8), if coal wastes are classified as hazardous.

5.4.5.2 Water Use Effects

Ash disposal typically requires from 4 to 150 m^3 (1000 to 40,000 gal) of water per ton of ash (Federal Energy Administration 1977d). However, the greatest potential effects on water use are expected as a result of contamination of receiving waters (surface and ground). The dissolved and suspended constituents of effluents from coal ash and scrubber sludge may cause surface waters and groundwaters to be in violation of water standards and criteria for drinking water, livestock watering, irrigation, protection of aquatic biota, and other uses (Sec. 5.4.5.1).

5.5 LAND USE

Land use impacts resulting from the proposed legislation are primarily related to the preemption of land for mining activities and for disposal of fly ash and scrubber sludge. Lands affected by mining are primarily in Supply Regions 3, 5, 6, and 8 and are predominantly used as rangeland and cropland. Prime farmland may be affected by mining in localized parts of the western states and, more generally, in the midwest. A maximum of 20,000 hectares (49,200 acres) of land will be disturbed by mining under the proposed action between 1978 and 1990. Reclamation of much of this area is required by law, but problems associated with water availability will be an environmental constraint in successful reclamation.

In the case of waste disposal, 63 to 70 percent of the waste will be produced in Demand Region VI, mostly along the Texas Gulf Coast. On a nationwide basis, a maximum of 10,300 hectares (25,500 acres) of land will be needed for waste disposal between 1978 and 1990, with 4330 hectares (10,700 acres) being in Demand Region VI. Because much of the industrial area on the Texas Coast is surrounded by unique farmlands, land availability for waste disposal will be limited to areas to the west and north at some distance from the combustion source.

Land use impacts associated with transportation, coal storage and onsite processing, and coal combustion are believed to be minimal.

5.5.1 Mining and Mine Site Processing

The impact of mining and mine site processing resulting from implementation of the FUA will vary regionally. In 1985 and 1990, Supply Regions 2, 5, and 6 will provide 72 and 75 percent of the coal produced under the proposed action, respectively. Approximately one-half of the land area that will be disturbed by surface mining will occur in Supply Region 5 (Table 5.20). Those regions that have the most significant shift in production in relation to the base case are Regions 3, 5, 6, and 8, which account for about 72 percent of the total land area disturbed. Although Region 2 will provide a significant amount of the required coal, the production resulting from the FUA is only a small proportion (3-6 percent) of the base-case production in that region. Thus, the impact is relatively minor on a regional basis.

Approximately 80 percent of the coal produced as a result of the proposed action will come from surface mines. The land areas given in Table 5.20 represent only those lands that would be directly disturbed by surface mining and do not reflect the land that would be required for buildings, haul roads, access roads, storage, coal cleaning, spoil piles, etc. These additional land uses would be considerable and could in some cases amount to as much as twice the areas given in Table 5.20. Estimates of surface disturbance associated with underground mines are not given because land areas subject to subsidence are difficult, if not impossible, to estimate on a regional basis.

If the plants that use coal under the proposed action have an assumed average lifespan of 40 years, mining disturbances will take place from implementation of the legislation in 1978 until 2030. Using the annual figures shown in Table 5.20, and assuming that the plants convert to coal gradually over the period 1978-2030, it is estimated that the total land area that will be disturbed by surface mining during this period is estimated to be approximately 133,000 hectares (328,000 acres). For the period up to 1990, about 20,000 hectares (49,200 acres) will be disturbed. Land disturbed by mining and mine site processing would be subject to reclamation under provisions of the Surface Mining Control and Reclamation Act of 1977 (Pub. L. 95-87). Thus, it is assumed that the majority of the land would be returned to a potential use that would be equal to or better than the original and that mining would be restricted on lands where reclamation potential is low. The Act also contains provisions (see Sec. 5.2.2) to designate areas unsuitable for all or certain types of coal mining and thus permits state and federal governments to deal with conflicts which may arise between coal mining and other land uses.

Current and historical land use impacts resulting from coal mining have been discussed in Section 4.4 and Appendix G. In 1977, a total of 672,148 hectares (1,660,908 acres) was disturbed by coal mining operations to the extent that reclamation was needed (U.S. Department of Agriculture 1977a). Mining and mine site processing impacts caused by the proposed action will occur primarily in the western states (Coal Supply Regions 5 through 8), although significant impacts are also predicted for the southern Appalachians Supply Region 3).

Table 5.20. Land Area Disturbed Annually by Surface Mining as a Result of the Proposed Action[a]

Supply Region	1985, hectares (acres)	Percentage of Base Case[b]	1990, hectares (acres)	Percentage of Base Case
1	130 (322)	3.2	210 (518)	5.8
2	238 (589)	3.2	437 (1081)	6.4
3	51 (126)	8.4	99 (244)	19.4
4	148 (366)	2.1	239 (591)	3.4
5	944 (2333)	36.3	1625 (4015)	41.7
6	209 (517)	9.2	414 (1022)	12.2
7	20 (49)	5.3	33 (82)	5.8
8	145 (358)	15.1	262 (648)	25.2
Total	1885 (4660)	7.5	3319 (8201)	12.4

[a]Areas estimated in this table represent that amount of land actually mined and therefore do not include fixed land requirements.

[b]Percentage of base case = $\frac{\text{Area disturbed by the proposed action}}{\text{Area disturbed by base case}} \times 100$.

In the western regions, most of the land disturbed by mining activities is presently used as rangeland or for supporting wildlife. However, in Supply Region 5 and in localized parts of the other western regions, prime farmlands occur that may be disturbed by mining. Serious impacts could occur by disrupting prime farmlands, especially in areas where they are not abundant, which is the case for much of the western region. Mining that affects alluvial valleys, which are often important for raising hay for winter livestock feed, can destroy shallow water tables and thus remove an important agricultural resource in local areas of the west (Schuman et al. 1976). Although legislation (Pub. L. 95-87) and provisional surface mining regulations (U.S. Department of the Interior 1977b) require reclamation of such areas, the feasibility and energy cost of accomplishing this goal are yet to be demonstrated.

In the southern Appalachian Mountains of Tennessee, Alabama, and Georgia, contour mining of the hilly to mountainous terrain will predominate. Forest lands will be most affected by such operations.

5.5.2 Transportation

Land use impacts associated with transportation of the coal produced under this legislation are expected to be localized and minimal. Existing transportation systems will have to be upgraded to handle increased traffic associated with coal movement; however, in most cases, such upgrading will require little, if any, acquisition of additional land. Local impacts are expected to be associated with construction of access roads and spur rail lines to new or expanded mine operations and should be evaluated on a site-specific basis. The possibility of construction of slurry pipelines would require an unknown quantity of land for rights-of-way. Spills from such pipelines could have a serious impact on lands adjacent to the rights-of-way.

5.5.3 Storage and Onsite Processing

Estimates of the land requirements for onsite coal storage and waste handling associated with the implementation of the proposed action are given in Table 5.21. If the majority of plants assumed to be affected by the proposed action are using coal by 1990, a maximum fixed land requirement for onsite coal storage and waste handling of 1934 hectares (4778 acres) is predicted. By 1985, approximately 56 percent of this land area will be required. Approximately 82 percent of the land needed will be in Demand Regions IV and VI.

Table 5.21. Land Area Required Annually for Onsite Coal Storage and Waste Handling As a Result of the Proposed Action[a]

Demand Region	1985, hectares (acres)	1990, hectares (acres)
I	23-29 (57-72)[b]	37-47 (92-116)
II	23-30 (58-74)	42-53 (104-130)
III	30-38 (74-94)	56-70 (138-174)
IV	112-141 (276-348)	211-266 (521-657)
V	74-93 (183-231)	93-117 (229-288)
VI	492-620 (1215-1532)	931-1174 (2300-2900)
VII	16-20 (40-50)	26-32 (64-79)
VIII	9-11 (22-28)	17-21 (41-52)
IX	79-100 (196-247)	112-141 (276-348)
X	6-8 (15-20)	11-14 (27-34)
Total	864-1091 (2136-2696)	1535-1934 (3792-4778)

[a]Areas calculated using land requirements given in Dvorak et al. (1978), Table 4.

[b]Lower limit of range assumes converted major fuel-burning installation (MFBI) is equivalent to a 50-MWe coal burning power plant, and the upper limit assumes MFBI is equivalent to a 100-MWe power plant.

Coal storage includes land for rail sidings, reserve storage, live storage, crushers, and surge bins, while waste handling includes areas for ash ponds and sludge ponds. Land areas estimated here will likely already exist for industries that have previously used coal. The major land use impact resulting from the proposed action will be on those industries that do not have sufficient land available for these uses and will thus be forced to acquire land near their operations. The availability of land in such areas is apt to be very limited, and expansions by industries are apt to place increasing demands on agricultural lands surrounding urban areas if use of oil or natural gas is prohibited (see Sec. 10.4). Potential impacts of drainage from coal storage and waste facilities could occur on lands adjacent to these operations if proper control measures are not exercised.

5.5.4 Combustion

Combustion of coal under the proposed legislation will be greatest in Demand Region VI, particularly along the Texas Gulf Coast. No major changes in land use pattern are expected as a result of this action, assuming that air quality standards are maintained. The effects of combustion of coal on terrestrial ecosystems is discussed in Section 5.6.4.1. The additional increment of atmospheric emissions added as a result of the proposed action will contribute to a slight, but general, deterioration of productivity of lands surrounding industrial centers that convert to coal. Such deterioration is impossible to measure on the short term, but it may take the form of long-term reduction in soil fertility as a result of increased acidity in waters percolating through the soils. The significance of this potential reduction of soil fertility is unknown, but is assumed to be mitigative with cultural management practices.

5.5.5 Waste Collection and Disposal

Sludge and ash wastes resulting from combustion of coal produced under the FUA will require considerable land area for short-term storage and long-term disposal. Approximately 65 and 67 percent of the coal waste produced under the legislation will be generated in Demand Region VI in 1985 and 1990, respectively (Table 5.22). The greatest impacts of this program will probably occur along the Texas Gulf Coast because this area is the most heavily industrialized portion of Region VI. Elsewhere in the nation, the increases in coal combustion and coal waste production associated with the proposed action will add relatively small increments to the amounts of coal and waste anticipated under base-case conditions. Impacts other than those in Region VI are expected to be localized and minimal.

The land areas needed for disposal of fly ash and scrubber sludge produced as a result of the FUA are given in Table 5.22. In 1990, it is estimated that a maximum of 1722 hectares (4255 acres) of land will be needed for waste disposal. Over the period 1978 to 1990, the cumulative land requirement would be approximately 10,300 hectares (25,500 acres). Assuming a 40-year life span for each MFBI that converts to coal, a maximum of 69,000 hectares (170,000 acres) of land will be required for waste disposal between 1978 and 2030. Cooper (1975) notes that land area for waste disposal of fly ash and scrubber sludge can be significantly reduced by recycling these materials. Lightweight concrete for construction, roadway pavements, airport runways, and a variety of other uses can be made from these wastes.

Table 5.22. Solid Waste Produced and Land Required for Disposal[a]

Demand Region	Tons of Waste Produced ($\times 10^6$)		Land Required for Disposal,[b,c] hectares (acres)			
	1985	1990	1985		1990	
I	0.70	1.12	15-23	(38-57)	25-37	(61-91)
II	0.71	1.26	16-23	(39-58)	28-41	(68-102)
III	0.90	1.67	20-30	(49-73)	36-55	(90-136)
IV	3.47	6.51	76-114	(187-281)	142-214	(352-528)
V	2.34	2.92	51-77	(127-190)	64-96	(158-237)
VI	19.28	35.17	422-633	(1042-1563)	769-1154	(1901-2851)
VII	0.50	0.80	11-17	(27-41)	17-26	(43-65)
VIII	0.17	0.32	4-6	(9-14)	7-11	(17-26)
IX	1.53	2.52	34-50	(83-124)	55-83	(136-204)
X	0.11	0.21	2-4	(6-9)	4-7	(11-17)
Total	29.72	52.49	650-975	(1606-2410)	1148-1722	(2837-4255)

[a]See Appendix M for assumptions made in calculating solid waste.

[b]Assumes depth of waste disposal area is 10 ft.

[c]Low limit of range assumes waste density of 2000 lb/m^3; upper limit of range assumes waste density of 3000 lb/m^3.

The principal land use impact associated with disposal of coal waste in the Texas Gulf Coast Region will be the preemption of land. Much of the industrialized portion of the region is surrounded by agricultural land that is intensively managed for rice production. Rice lands in Texas are considered to be prime or unique farmlands under the definition of the Soil Conservation Service (U.S. Department of Agriculture 1978). Using a large area of such lands for waste disposal would create a serious impact on the region's agriculture. In addition, reclamation of landfills in these areas to return them to rice production would be highly unlikely because surface modifications would restrict the ability of these lands to be flooded periodically. Flooding of former landfills would also pose the danger of possible contamination from the toxic coal wastes.

Alternatives to disposing of coal wastes in close proximity to the industries creating them would be to transport them further to the west or north, where land use is predominantly rangeland or forest. Although transportation costs would be higher, the potential impacts on agriculture would be somewhat less. In the drier areas adjacent to the Texas Gulf Coast, competition for water supplies is extremely intense. Special care would have to be used in containing landfills in this region to avoid contaminating underground aquifers and damaging regional water supplies. Reclamation of areas used for disposal of coal wastes may be successful if sufficient soil cover is placed over the wastes to isolate toxic materials from the cover vegetation. Such areas when reclaimed might be used for a wide variety of purposes including rangelands, forestlands, recreation developments, housing, industrial purposes, etc. Such areas probably could not be returned to agricultural cropland use because the potential for contamination of crops by coal waste products is high.

Disposal of coal combustion wastes will be regulated under provisions of the Resource Conservation and Recovery Act of 1976. Recent proposed guidelines and regulations for handling of hazardous wastes (USEPA 1978a) cover the management and control of such wastes from their generation to final disposal. Identification of wastes as being hazardous is based on four characteristics: (1) ignitability, (2) corrosiveness, (3) reactivity, and (4) toxicity. The proposed rules list methods of determining these characteristics. Standards included in the guidelines and regulations cover site location, design, operating methods, contingency plans, personnel training, and environmental protection. A manifest system would be established to track hazardous wastes from generation to final disposal.

In selecting sites for waste disposal, facilities are prohibited from locating in the following types of areas unless a demonstration can be made that no impact will occur: (1) active fault zones, (2) coastal high hazard areas, (3) 500 year floodplains, (4) wetlands, (5) areas where the presence of the facility would jeopardize the continued existence of endangered or threatened species or result in the loss of critical habitat, and (6) areas in the recharge zone of a sole source aquifer. Active portions of a facility are to be separated from the property boundary by a 60 m buffer zone. Landfills are to be designed, constructed, and operated to prevent or minimize discharges from the site. Sites must utilize some combination of soil liners, leachate collection, leachate removal, and leachate detection dependent upon climatic conditions and specific site conditions. Monitoring of groundwater hydraulically down-gradient from a facility is required. Any discharges from the site must meet standards set by the Clean Air Act, the Federal Water Pollution Control Act, and the Safe Drinking Water Act. Transportation of hazardous wastes will be governed by Department of Transportation shipping regulations.

The proposed guidelines and regulations on hazardous wastes state that a decision on the applicability of most treatment, storage, and disposal standards for selected high volume, relatively low risk wastes (including mining and utility wastes) will be deferred until more information is gathered on how best to handle these materials. This provision is likely to apply to most of the coal wastes generated during the first years of the FUA. Designation of coal wastes as hazardous materials will place stringent requirements on MFBIs combusting coal. However, this problem is not unique to the FUA-affected facilities, but is an issue.

5.6 IMPACTS UPON BIOTIC SYSTEMS

5.6.1 Mining and Mine Site Processing

5.6.1.1 Terrestrial

Underground Mining

An estimated 20 percent of the coal required as a result of the proposed action will come from underground mines (Table 3.9), and an increase of only about 3 to 5 percent above national baseline underground production is expected to occur. In Supply Regions 3, 5, and 8, where underground mine production is low, increases due to the proposed action form a larger percentage of the base-case production. However, even in Supply Region 5 the absolute production from underground mines will be low. Thus, effects from increased underground mining due to conversion are expected to be small relative to base-case expectations.

Because of the comparatively small amount of underground mining that is expected as a result of the proposed action, few, if any, new underground mines are expected to open due to that action. Thus, the construction of new surface facilities to support underground mining will not be widespread, and therefore surface disturbance should be minimal.

Surface disturbance due to the construction of roads, shafts, and support facilities disrupts the soils and vegetation over a small area (U.S. Bureau of Land Management 1975; Dvorak et al. 1977). These areas are removed from use by wildlife. Most of the larger game mammals tend to avoid such sites due to the presence of humans and the noise generated by operation of the mine. Disruption of surface hydrology by construction of the mining facilities can lead to degradation of riparian habitat below the mine. Waste piles not only require storage space that removes natural habitat from the area, but they also allow for the leaching of materials into surrounding soils. In many areas of underground mining, surface disturbance can accelerate erosion by both wind and water. This leads to loss of soil in the area, making revegetation difficult. Erosion is particularly a problem in Supply Regions 1-3, where mining occurs in areas of high topographic relief. The long-term effects of the mining can be partially mitigated upon abandonment of the mine. Proper removal of facilities and revegetation helps to stabilize the soils and accelerates the recovery of habitat suitable for supporting the native fauna.

A major problem associated with the mines of Supply Regions 1-4 is acid mine drainage (U.S. Bureau of Land Management 1975; Dvorak et al. 1977; Hill and Bates 1977). Some terrestrial impacts from acid runoff might be expected. Leachates from acid mines or waste piles can acidify the soils of adjacent habitats. In acid soils the availability of some nutrients may be decreased while some heavy metals become more available for uptake by the vegetation (Brady 1974; Hill and Bates 1977). Disruption of soil chemistry may lead to reduced plant production or a reduction in the activity of soil microorganisms. Most soils in the areas of acid mine drainage do not have a great buffering capacity and are thus susceptible to acidification.

The primary problem associated with underground mines is subsidence (U.S. Bureau of Land Management 1975; Dvorak et al. 1977; Hill and Bates 1977). Large trees can be adversely affected by the collapse of the soil surface, particularly if the velocity of earth movement is high. Herbaceous plants suffer little direct damage from collapse of the ground because of their resilience. A subsidence crater can form a catchment basin for runoff and could develop into a swampy area, drowning the original vegetation. Surface hydrology can also be disrupted, affecting riparian habitats. Large animals, including man, located immediately over the subsidence could be seriously injured at the time of collapse. Small animals in the soil probably are killed by the pressures exerted during movement of the soil.

Impacts from subsidence are expected to be most extensive in the deciduous forests, remnant prairie, and agricultural land of Supply Regions 1-4, where most of the underground mining occurs (Table 3.9). Measures for control of the effects of subsidence include backfilling of the mine to provide support for the overburden and inducing subsidence under controlled conditions. It is difficult to estimate the amount of land that will be affected by subsidence because of the variables involved. Scenarios depicting the effects of the National Energy Plan (NEP) upon subsidence have assumed that rates of subsidence are directly proportional to rates of underground mining (Hill and Bates 1977). If this is true, subsidence due to increased mining as a result of the proposed action would be 3 to 5 percent of the national baseline expectations (Table 3.9). Thus, the proposed action would contribute little to the overall problems of subsidence.

Occasional fires in mines and waste piles pose a threat to surrounding biotic communities. Because some of these fires can persist for many years, they are a source of long-term emissions of airborne pollutants. Precipitation of these particulate and gaseous pollutants could adversely affect the biota in a manner similar to emissions from coal-fired plants, as discussed in Section 5.6.4.1. Proper burial of the wastes should reduce the potential for fires in waste piles. Proper safety measures in mines will reduce the probability of mine fires.

Surface Mining

Surface mines will provide about 80 percent of the coal needed as a result of the proposed action (Table 3.9). By 1990, Supply Region 5 is expected to increase its surface mine production to over 40 percent of the base-case production. Approximately 1900 hectares (4700 acres) of land by 1985 and 3300 hectares (8200 acres) by 1990 (Table 5.20) will have to be disturbed in the United States to support the coal consumption in those years. About one-half of that land disturbance will occur in Supply Region 5, with about 40 percent of the disturbance occurring in Supply Regions 2, 4, 6, and 8. These areas could be removed from the natural habitat for up to several decades.

The general increase in surface mining will require that new mines will have to be opened. This is particularly true in Supply Region 5, where current mining operations are limited. Development of a new mine will have a greater impact per unit of coal produced than would increased production in an existing mine. The reason for this difference is that a new mine requires new support facilities. Thus, the impact of a new surface mine results from more than just increased stripping of the overburden.

Surface mining has a dramatic effect upon the communities within which it occurs (U.S. Bureau of Land Management 1975; Dvorak et al. 1977). The soils and biota overlying the mineable coal are destroyed. Although the soils may be returned to the site for reclamation, the processes of removal and storage have modified their chemical and physical properties. The original strata of the surface soils are destroyed in the process of stripping the overburden. The organic litter and humus of the upper layers is diluted by mixture with lower soil strata. Microfloral and microfaunal composition of the soil communities will be reduced and changed as soil conditions change. Many elements and organic compounds will be leached from the stored overburden. After the cessation of mining, reclamation of the land will be required. However, it may take several decades for the soils to approach their original condition.

Most of the coal-bearing deposits of Supply Region 5 underlie oak-hickory and oak-pine communities (U.S. Bureau of Land Management 1975). The primary impacts are going to result from preemption of the land by stripping operations. The smaller, less mobile wildlife will be killed by stripping operations. Removal of these communities will force more mobile wildlife into adjacent areas, increasing competitive pressures among the biota. In many instances this will result in increased mortality of wildlife. Because these forests are on the western margin of the deciduous forests biome forming an ecotone with the grassland biome, wildlife diversity should be higher here than in more eastern forests. Strip mining could result in a marked decline in wildlife diversity as forest edge is lost.

As a result of the proposed action, surface mining also is expected to increase in Supply Regions 6 and 8, where there will be impacts on semi-arid and arid lands. Reclamation of these lands to their original communities is difficult. Thus, several hundred acres of some habitats dominated by long-lived woody species may be lost for several decades or even permanently. In the Northern Great Plains area, most coal deposits underlie grasslands and sagebrush vegetation (Northern Great Plains Resources Program 1975). Loss of these habitats adversely affects such wildlife as pronghorn, sage grouse, and lesser prairie chickens, which are dependent upon these vegetation types for forage and cover (Northern Great Plains Resources Program 1975; Rickard 1977). Displacement of wildlife from mined areas increases the competition for use of the undisturbed land and could increase grazing pressure on adjacent rangelands. Many of the small vertebrates of these communities are ground-dwelling and undoubtedly are killed by stripping activities. Packer (1974) estimates that reclamation of stripped land in the Northern Great Plains may take from one to fifteen years, depending upon locality and whether the land is being reclaimed to cropland or to natural vegetation.

Of particular concern in the Northern Great Plains are effects upon surface hydrology by disruption of floodplains (Northern Great Plains Resources Program 1975). Riparian communities are adversely affected if stream flow is reduced or diverted, or if water quality is decreased. These riparian communities provide habitats for a variety of wildlife that cannot readily exploit the simply structured grasslands (Shelford 1963). Bird diversity is considerably higher in these floodplains than in grasslands, and most of the birds are adapted for nesting and foraging in the tree and shrub strata of the floodplain forests. The distribution of white-tailed deer extends westward with the floodplain forests. These forests provide browse and cover for deer and for the few wapiti still remaining in this area. Reclamation of the floodplains is difficult, involving return to the former channel of water flow, and regrowth of the woody vegetation that makes these communities unique within the Northern Great Plains.

Under the Surface Mining Control and Reclamation Act of 1977 (30 USC 1201, Pub. L. 95-87), the Department of Interior has issued proposed, permanent regulations that should reduce, if not eliminate, mining effects upon floodplain habitats (U.S. Department of the Interior 1978). These regulations require that the mining be carried out in such a manner as to not disrupt the essential hydrological features of western floodplains. Thus, mining carried out in response to the proposed action should pose little threat to the floodplain communities of Supply Region 6 if these regulations are followed.

Stripping of land in Supply Regions 2 and 4 will impact primarily oak-hickory and remnant prairie communities (Dvorak and Pentecost et al. 1977). Because of the difficulties in reforestation, grassland communities will be established during reclamation, and it will be several decades if ever before mature forest could become reestablished.

It is not expected that surface mining activities will markedly affect major wetlands because few mineable coal deposits are associated with these habitats. Where mining may have impacts on wetlands, regulations promulgated in accordance with Executive Order 11990 and under the Resource Conservation and Recovery Act of 1976 (Pub. L. 94-580) may mitigate such impacts. In addition, provisions in the regulations promulgated under the Surface Mining Control Act of 1977 (Pub. L. 95-87) for the protection of fish and wildlife will reduce impacts from mining.

It is not expected that surface mining due to the proposed action will constitute a large proportion of the base-case production in most regions (Table 3.9). In Supply Region 5, however, surface mining to meet expected demands may be over 40 percent of the baseline production in 1985. This is due to the low coal production in the region and the disproportionately increased demand for coal here as a result of the proposed action, compared to other regions.

Coal Cleaning and Processing

Supply Regions 1-4 will have the greatest potential for problems from coal cleaning (Dvorak et al. 1977). Coals from Supply Regions 5 and 6 are generally not cleaned. Because of the relatively small increase in production from supply regions where coal cleaning is practiced (Table 3.9), it is unlikely that increased coal use as a result of the proposed action will markedly increase the amounts of refuse from coal mining and processing above levels due to base-case increases. Proper burial and stabilization of processing refuse as called for under federal surface mining regulations (U.S. Department of the Interior 1978) should reduce the potential for impact as a result of the proposed action.

Noise will tend to disturb wildlife and may induce them to avoid the vicinity of the mine operations, which extends the impact beyond the mine site (USEPA 1971). Many wildlife species use auditory stimuli as a means of communicating alarm or locating mates. Noise emissions from coal processing may inhibit the effectiveness of these stimuli in the immediate vicinity of the mine. These effects can be mitigated by locating the processing activities as far as possible from the boundary of the mining or plant area and constructing facilities in a manner that will reduce the emission of noise to the ambient environment.

Marsh vegetation may become established around refuse slurry ponds, providing a habitat for some wildlife. This could provide pathways for the transfer of trace elements into the surrounding biota via the food chain. In addition, seepage from the ponds may transport trace elements into the soils of adjacent communities. This could lead to the buildup of elements to toxic levels within some of the biotic components of the ecosystem. However, the gradual filling of the ponds may make them unstable enough to reduce the amount of marsh development. In addition, the noxious quality of the slurry liquor should discourage wildlife from ingesting great quantities. Proper lining and construction of the ponds will reduce seepage to a minimum.

Coal refuse (gob) piles pose two primary threats to the environment (U.S. Bureau of Land Management 1975; Dvorak et al. 1977). First, coal fragments in the piles may occasionally catch fire, releasing gaseous and particulate pollutants into the air. These fires often burn for an extended period before they are brought under control, resulting in prolonged exposure of the nearby biota to these pollutants. Second, trace elements and acids are leached from the piles into surrounding soils. The soils of the regions in which this might occur tend to have low buffering capacities and are more susceptible to increased acidification.

After cessation of the mining operation the potential for impacts from gob and slurry refuse remains. Many states require that the refuse be stabilized and revegetated. Such rehabilitation reduces erosion, acid drainage, and the likelihood of combustion, and beautifies the landscape. The land may be returned to a condition suitable for wildlife use in a relatively brief period; however, return of forest habitat may require an extended period of time.

5.6.1.2 Aquatic

As mentioned in Section 5.4, the environmental effects of the proposed action are not expected to be significantly different from the types of effects caused by the overall increase in coal utilization. Thus, it is not possible to determine what ecological impacts will occur on a site-specific basis. This discussion is therefore largely confined to a general description of the aquatic ecological impacts of the coal fuel cycle. However, where possible, predicted impacts are given for those regions projected to receive the greatest increases in coal mining and utilization as a result of the proposed action. The reader is referred to Section 5.4 for information on hydrology, water quality, and water use effects. Because of the obvious close relationship between these topics and aquatic ecology, the sections dealing with aquatic biological effects will complement the material in Section 5.4.

Hydrological Effects on Biota

Hydrological effects that can occur as a result of coal mining are listed in Section 5.4. Among these are altered flow rates and flow volumes, disappearance of surface waters, and the creation of more surface waters. Altered flow regimes can be highly disruptive to stream communities (Hynes 1971). Drawdown can result in the loss of habitat, and greater flows can produce bottom and edge scouring, thus resulting in fewer benthic organisms, less autochthonous food for higher organisms, and higher turbidities from the suspended substrate material (see the following section on water quality effects for turbidity and sedimentation impacts). The loss of surface waters obviously constitutes a loss of habitat for the biota, and the creation of surface water (e.g., impoundments from last-cuts in strip mining) provides new areas for biotic colonization. Newly created habitats may only offer highly stressed conditions, however, because the water may have high concentrations of heavy metals, acids, and sulfates.

Water Quality Effects on Biota

The major water quality effects from mining and mine processing are from (1) sedimentation, (2) acid drainage, (3) alkaline drainage, and (4) nutrient enrichment. Details on the derivation of the constituents and on their concentrations are found in Section 5.4.

Sedimentation occurs as a result of erosion and from spillage from coal washing areas. Erosion is particularly acute in the mountainous coal mining regions of the eastern United States, but it is also a considerable problem in western mining areas where highly erodible soils exist, vegetation is generally sparse, and rainfall events, though sporadic, are intense (Dvorak et al. 1977). In addition to the scouring impacts discussed previously, sedimentation has several other effects on the biota of a stream. The shading it produces decreases photosynthesis, which can result in the elimination of benthic plants and the virtual elimination of phytoplankton (Fogg 1975). Such a decrease in the autotrophic communities usually has concomitant ramifications for higher trophic levels, including decreased standing crops and species composition changes (Russell-Hunter 1970). Sedimentation tends to smother benthic animals as well and creates an unstable substrate on which few organisms can recolonize (Hart and Fuller 1974). The loss of a significant portion of the benthic fauna usually has a detrimental influence on invertebrate predators; this effect alone has been cited as eliminating various fish species from affected streams (Hynes 1971). Direct effects of sedimentation on fish include the clogging of gills, the loss of spawning habitat, reduced resistance to disease, and disruption of migrations (Dvorak et al. 1977). The sediment may also carry high levels of organic compounds that can cause local deoxygenation upon decomposition, thereby stressing organisms directly or producing indirect effects through an influence on the toxicity of other compounds.

Acid drainage contains high levels of TDS (much of which is contributed by sulfates), has a low pH, sometimes has high hardness, and contains numerous trace contaminants, including heavy metals. Because of the complexity of this type of effluent, biotic effects are variable and are often highly site-specific (Roback and Richardson 1969). Thus, for example, acid drainage that enters a highly calcareous stream may be rapidly neutralized and rendered relatively innocuous within a short distance downstream. Conversely, the same effluent added to a water body that has little buffering capacity may exert effects for a considerable distance.

The lowering of the pH of a water body can have a profound effect on numerous aspects of an organism's existence, and the responses of different organisms are highly variable. Some species thrive in very low pH environments, including sulfur and iron bacteria (e.g., *Thiobacillus* and *Ferrobacillus*), which help oxidize the sulfide minerals associated with some coals to produce the acidity in the effluent (Dugan 1972). However, some organisms do not tolerate pH values much below neutral. For example, most blue-green algae display optimum growth between pH 7.5 and 9.0 and will not survive for long periods below pH 6.0 (Fogg et al. 1973). Most fish are able to live within a fairly wide pH range (e.g., pH 5 to 10); sensitivity to bacterial diseases increases tremendously below about pH 5 and is a major factor preventing long-term survival at lower pH values (Bennett 1970). The mechanisms that govern pH tolerance are poorly known for most organisms because of the multiplicity of effects, both direct and indirect, which the hydrogen ion concentration can have on biota. A significant indirect effect of pH is its influence on the ionization of compounds and the solubility of certain ions. Thus, most heavy metals are more soluble at lower pH values; therefore, heavy metal effects are usually more pronounced at lower pH levels (Van Hook 1978).

The physiological bases for the effects of altered TDS levels caused by the addition of acid drainage are usually related to osmotic influences rather than toxic reactions (King et al. 1974). The sulfate ion, for example, is not highly toxic to most organisms, even at high concentrations, but many species cannot survive in ionic strengths as high as those associated with acid drainage. However, there is some evidence that the effects of altered hardness are more complex than this for at least some species. For example, calcium and other divalent cations (ions with a double positive charge) may alter the efficiency of ion uptake systems in some plants (either negatively or positively) (Fogg 1975). Of particular pertinence is the fact that hardness can greatly modify the toxic effect of a given concentration of heavy metals. In general, heavy metals exert greater toxicities in soft water than in hard water (National Academy of Sciences, National Academy of Engineering 1973).

Metals commonly found in coal mining and processing effluents are listed in Section 5.4, along with typical concentrations encountered. Levels of certain metals can reach such high values that changes in pH (to more alkaline) or Eh (to less reducing) can produce large blanket-like deposits of the metal hydroxides in the bottom of the water body (Dvorak et al. 1977). Iron and aluminum hydroxides, in particular, are commonly found in streams located a short distance from waste outfalls as a result of partial neutralization of the acidity in the effluent by the receiving stream or its substrate. Although these compounds are not highly toxic in the precipitated form, they produce effects that are quite similar to the effects of other extraneous sediments (see previous discussion) (Hynes 1971).

Because of the number of toxic trace metal contaminants commonly contained in acid mine drainage, a variety of toxic effects may be produced. Aside from the toxicities produced by each ion individually, several synergistic (the coexistence of two or more toxic metals produces effects that are greater than the additive effects of the individual ions) and antagonistic effects can be produced by the coexisting metals (Lind and Campbell 1970; Van Hook 1978). The toxicities of trace elements from coal to several aquatic organisms are listed in Dvorak et al. (1977).

As indicated in Section 5.4, mine and processing waste effluents commonly contain concentrations of elements in excess of criteria designated for the protection of aquatic life. The extent to which any given effluent will exert effects on a receiving stream will depend, not only on the concentration of the toxic constituents in the effluent, but on the dilution capacity of the stream. The ecological effects from toxic metal additions are similar to those produced by many toxicants, that is, the communities become more simplified (have less diversity because only resistant organisms survive), and overall production drops (Roback and Richardson 1969; Lind and Campbell 1970; Hynes 1971).

In addition to direct toxic effects, many of the trace metals are bioaccumulated. Thus, even low environmental levels may indirectly result in toxic effects at higher trophic levels, while organisms lower on the food chain are unaffected (Van Hook 1978).

Several studies have been conducted on the ecological effects of adding acid mine drainage to streams and lakes (e.g., King et al. 1974; Smith and Frey 1971). Although specific details vary from site to site, certain common conclusions have emerged. In general, diversity of the major communities decreases in proportion to the amount of pollutants added. Those organisms that do survive can obtain large standing crops, however, because much of the competition which they formerly experienced is removed. Sport fish, particularly the salmonids, are among the first organisms to disappear. In some cases, this results from direct toxic effects, but in others it is caused by an influence on their food supply (e.g., the benthic invertebrates). Total biomass of autotrophs, primary consumers, and secondary consumers may either increase or decrease (Smith and Frey 1971; Hynes 1971, 1972; Sculthorpe 1967).

Alkaline drainage occurs primarily in the western United States, where pyritic minerals are generally sparse in the coal and where the overburden contains large quantities of sodium, calcium, magnesium, carbonate, bicarbonate, sulfate, and chloride. Thus, leaching from the overburden produces adverse effects rather than runoff from the coal and associated minerals. In general, the constituents of alkaline drainage (Na^+, Ca^{2+}, Mg^{2+}, $CO_3{}^{2-}$, $HCO_3{}^-$, $SO_4{}^{2-}$, Cl^-) are not highly toxic, but they frequently occur at high enough concentrations in the receiving waters to induce osmotic effects and ionic imbalances (Dvorak et al. 1977). The specific effects are highly site specific, however, because the relative quantities of the ions in the effluent depend on the particular overburden being leached. The sporadic nature of the precipitation in much of the western United States makes many of the alkaline drainage inputs episodic rather than continual. In extremely arid areas, leachates from the overburden may only reach ephemeral streams, which have no true aquatic biota; impacts to these would thus be minimal (Dvorak et al. 1977).

If alkaline drainage inputs to a particular water body are not excessive, no changes in community structures or population densities may be noted. However, large additions of the previously listed ions may result in a flora and fauna that are more euryhaline (Hynes 1972; Lind and Campbell 1970). Such biotic assemblages can be very diverse and productive, although extreme salinities or hardness generally create low diversity (but high population densities of the components) (Hynes 1971). Additions of carbonate and/or bicarbonate to highly eutrophic systems can stimulate production if the major autotrophs are carbon limited (Hutchinson 1967). These ions also tend to reduce pH fluctuations. In general, the addition of even large amounts of bicarbonate/carbonate produce little damage to ecosystems (National Academy of Sciences, National Academy of Engineering 1973).

Small quantities of substances other than water are occasionally used in washing coal (Sec. 5.3). Although some alcohol and kerosene may escape into the environment, for example, the quantities are expected to be so small that only very localized effects will be felt. Dilute alcohol can actually stimulate the growth of certain heterotrophs because it can be used by them as an energy source (Brock 1966).

As stated in Section 5.4.1, it is not possible to pinpoint where mining will occur as a result of the proposed action. However, a prediction has been made of the increase in coal production to be sustained by each of the eight coal supply regions. As indicated in Section 5.4.1, those in which production will increase by a small percentage only (e.g., 5 percent or less) are not expected to demonstrate significant regional impacts. However, local impacts may occur. Those areas expected to receive impacts of potential regional significance include the central and southern Appalachian area and the western United States (primarily the northern Great Plains and Texas). Sedimentation and acid mine drainage have been particularly severe problems in some of the mining districts of the Appalachians (Sec. 5.4.1), and the proposed action will probably contribute to these problems. Likewise, sedimentation and alkaline drainage problems in the western United States will likely become more severe. However, without site-specific information of where mining will take place as a consequence of this policy, it is impossible to carry the analysis any further.

5.6.2 Transportation

5.6.2.1 Terrestrial

The major effect of the increased coal transportation will be along pathways leading into Demand Region VI. Coal from Supply Regions 5 and 6 will most likely be transported by rail. The greatest impacts from transportation probably will occur near the receiving end of the transport linkage because here coal transport is being concentrated as shipments come in from several dispersed sources. However, transport increase due to the proposed action are only a small proportion of the expected base-case increases (cf. Sec. 5.2.2), and impacts from the proposed action are then expected to be small relative to base case.

Damage to forest ecosystems and crops in southern California have been attributed to emissions of photochemical oxidants from urbanized areas (Miller and McBride 1975). These pollutants also have been shown to cause pulmonary pathologies in terrestrial animals (National Academy of Sciences 1977). Emissions from coal transport in response to conversion to coal will not be large enough to pose a serious threat to biota. These emissions would form only a small percentage of the total emissions from base-case pollutant sources (cf. Sec. 5.2.2). The small incremental decrease in air quality due to transport of coal to converted industries would be of importance only in those areas with marginal air quality, where even a small increase in emissions may degrade the air quality to the threshold levels for damage to biota.

Shipment of coal in open railroad cars, barges, or trucks can lead to increased coal dusting of vegetation lining the main routes of transport (Dvorak et al. 1977). Such dusting can decrease production in plants by blockage of stomata and decreased light penetration to the sites of phytosyntheses (Lerman and Darley 1975). Dusting can also reduce the quality of the vegetation as forage or human food. The severity of the problem is dependent upon the moisture content of the coal, the amount of coal shipped along a given route, whether coal is washed at the mine, whether hoppers with tight doors are used, and whether the coal shipment is covered. The impact from increased coal use will be important only when dusting levels are near the threshold for damage to nearby biotic systems.

Accidental spillage of coal during transport can threaten specific sites along transport routes (Dvorak et al. 1977). However, the amount of additional coal required as a result of the proposed action probably will not noticeably increase the likelihood of spillage. Increased barge traffic along narrow waterways could increase bank erosion, disturbing riparian communities, but, again, the contribution to erosion from transportation of coal under the proposed action will be small compared to baseline transportation. Increased traffic and noise may disturb the larger animals inhabiting communities adjacent to roadways and railroad beds.

5.6.2.2 Aquatic

Transportation effects resulting from the proposed action are difficult to evaluate because the proportional quantity of coal to be hauled by each mode is unknown, the new transportation routes are unknown, and the accident rates and specific operational characteristics for the newer conveying methods (such as the slurry pipeline) are not known. Water quality effects from each major mode of transportation (truck, railroad, barge, and slurry pipeline) are generically treated in Section 5.4.2.1. In general, construction for the terrestrial transport methods will increase sedimentation problems, particularly in the mountainous east and the arid west (Dvorak et al. 1977). These areas are likewise those from which the majority of the coal for the proposed action is expected to be derived (Sec. 5.4.1). The impacts of sedimentation on the aquatic biota are described in Section 5.6.1.2. Coal spills and slurry spills near or in a water body will provide the potential for several of the types of effects discussed in Section 5.6.1.2, primarily, acid or alkaline drainage and sedimentation effects. The overall severity of such impacts is expected to be considerably less than those produced by mining and mine site processing. However, the potential does exist for severe local effects (e.g., in the case of a large spill near a small, pristine, poorly buffered lake).

5.6.3 Storage and Onsite Processing

5.6.3.1 Terrestrial

MFBIs and power plants burning coal require land area for coal storage. The increased coal consumption in Region VI due to the proposed action may require that up to 600 and 1200 hectares (1500 and 2900 acres) be occupied by coal storage and waste handling facilities by 1985 and 1990, respectively (Table 5.21). In rural areas this may mean that plant facilities must expand into wildlife habitat, displacing the resident biota. As noted above, displacement can result in a decrease in wildlife populations due to the intensified competition for limited resources.

Storage and handling of coal will increase fugitive dust levels around the facility. Soot (particulate remnants of coal combustion) has been shown to plug stomata, reduce photosynthesis, and cause leaf necrosis (Lerman and Darley 1975). Although soot has somewhat different chemical properties than coal dust, the physical effects may be similar. Fugitive dust settling onto soils may change the elemental concentrations on the soil surface. Increased ambient dust due to conversion to coal will probably not have a marked regional effect, but may noticeably affect the air quality in the immediate vicinity of the plant. It is unlikely that dusting will become a major problem if the piles are properly maintained.

Leaching of materials from the storage piles leads to an increase in trace element concentrations in nearby soils (Dvorak et al. 1978). In Region VI, where most of the increased coal use is likely to take place, the relatively high rainfall along the Gulf coast may result in a considerable amount of leaching of materials from storage piles. Effects of the leachate would probably not extend very far from the piles.

Another potential problem with coal storage piles is the danger of spontaneous combustion. Not only is coal lost, but the uncontrolled emissions degrade local air quality. Proper monitoring of pile conditions should reduce the likelihood of such fires.

Most processing will be carried out at the mine sites because of the ease with which waste products can be managed at the mines rather than at converted industries. Crushing of coal may be required at the site of coal use. Noise production from these crushers could disturb the biota of adjacent habitats. It is unlikely that noise levels will interfere with sound communication such as courtship display, or alarm calls among wildlife (USEPA 1971). Noise levels may induce wildlife to leave the vicinity of crushing activities, forcing them to compete with residents of other communities for resources. These effects will be small on a regional scale because of the relatively small increase in coal processing required by conversion of industries. On a local scale in industrial plants located in large urban, industrialized centers, conversion to coal may not result in sufficient increase in noise production to be noticeable above ambient noise levels. In plants located in rural areas, coal and limestone crushing could be sufficient to disturb surrounding wildlife and livestock. It appears, however, that most of the effects will occur in urbanized areas such as the Gulf Coast of Texas.

5.6.3.2 Aquatic

Effects from storage and onsite processing result mainly from runoff from the coal (Sec. 5.4.3). The constituents in the effluent are virtually the same as those emanating from coal mining and mine site processing, but the absolute amounts are generally much less (see Sec. 5.4.3.1). The contaminant quantities are usually lower because (1) the coal has usually been washed already and (2) water contact is usually kept to a minimum in coal storage piles because wet coal has a lower Btu value per unit of weight. Regions with the greatest coal consumption will also obviously have the largest quantity of effluents from coal storage, onsite processing, waste collection, and waste disposal. Few data are available on where coal consumption will specifically occur as a result of the proposed action. For a discussion of the effects of the constituents on aquatic biota, see Section 5.6.1.2.

Coal storage piles are occasionally sprayed by miscellaneous chemicals (see Sec. 5.4.3.1) for dust control. Most of these are toxic organics (e.g., phenol, ether, or ethylene glycol), but the amounts used are small enough that little of the material is added to surface waters. Toxic effects to aquatic biota of these compounds in situ have not been distinguished from the effects of the other contaminants (Dvorak et al. 1977).

5.6.4 Combustion

5.6.4.1 Terrestrial

Gaseous Emissions

Levels of emissions of SO_2 will increase under the proposed action, but the maximum increase by 1990 is expected to be less than 2.5 $\mu g/m^3$ in most areas (Fig. 5.5). The largest effects are expected in parts of Demand Regions IV, VI, and VII. Even in these regions the changes in air quality due to the program are very small relative to the effects of base-case increases in coal combustion (cf. Sec. 5.2.4).

Threshold levels of SO_2 as low as 470 $\mu g/m^3$ have been reported to injure plants during chronic exposure (Mukammal 1976). Animals are less sensitive to SO_2; they exhibit chronic exposure responses at levels above 13,000 $\mu g/m^3$ (U.S. Department of Health, Education and Welfare 1969; Dvorak et al. 1978).

It seems probable that, in natural ecosystems exposed to SO_2 from a coal-fired plant, vegetation will be the first major biotic component to exhibit pollution injury symptoms, if they occur. The animal component may be impacted indirectly by effects on vegetation. Herbivores are likely to be the first trophic level affected since they are dependent on vegetation for both food and habitat. Depending on the severity of the impacts to vegetation, gaseous pollutant effects could elicit changes in higher trophic levels as well.

Increased coal utilization due to conversion to coal should not have major effects upon vegetation, even in Region VI. By 1990, increased coal use due to the proposed action in these regions will result in increased ambient average concentrations of SO_2 by an increment of less than 2.5 $\mu g/m^3$, well below levels that are detrimental to biota.

Lichens and other lower plants have been shown to be particularly susceptible to gaseous pollutants (LeBlanc and Rao 1975; Hawksworth and Rose 1976). Some species are intolerant to ambient levels of SO_2 of 13 $\mu g/m^3$ on an annual average. Disruption of this flora can interfere with the nutrient recycling pathways, resulting in the retention of nutrients in unavailable, organic forms. In semi-arid and arid sections of the west, lichens and fungi are important factors in binding soils and reducing wind and water erosion. Increased utilization of coal due to the program will probably not be sufficient to reduce the size of sensitive populations of lower plants in most areas (Sec. 5.2). In parts of Regions IV, VI, and VII, increases in ambient concentrations of SO_2 related to the proposed action may be as high as 2.0 $\mu g/m^3$ by 1990. This could have impacts on some lower plants if ambient concentrations are already near the 13 $\mu g/m^3$ threshold.

The photochemical oxidants, including ozone (O_3) and nitrogen dioxide (NO_2), are secondary pollutants derived from combustion emissions. Nitric oxide is the major coal combustion emission contribution to these photochemical oxidants. As with other pollutants, the sensitivity of biota to the oxidants varies greatly among species. Some sensitive plants have been shown to exhibit pathological responses during chronic exposure to levels as low as about 100 $\mu g\ O_3/m^3$ and about 60 $\mu g\ NO_2/m^3$ (National Research Council 1977; Heck and Brandt 1977). Laboratory animals are less sensitive and have shown pathological responses during chronic exposure to levels as low as about 500 $\mu g\ O_3/m^3$ and 1000 $\mu g\ NO_2/m^3$ (National Research Council 1977; Coffin and Stockinger 1977).

On a regional basis, it is impossible to assess the degree to which increased coal combustion under FUA will affect ambient concentrations of photochemical oxidants. The concentration of these secondary pollutants are highly dependent upon site and time specific factors which regulate the rate of their production. The factors include: local meteorological conditions, incident solar radiation, and local air quality. Therefore, although there may be site-specific impacts in biota from photochemical oxidants produced in response to implementation of FUA, the extent to which this will occur cannot be assessed at the programmatic level.

Acid Precipitation

Acid precipitation affects terrestrial ecosystems through modification of soil pH and direct impacts upon the vegetation. Lowering the soil pH decreases the cation exchange capacity of the soil allowing some cations to be readily leached from the soil (Brady 1974). Low pH increases the availability of some metallic ions to plants, possibly exacerbating toxicity problems, and lowers the availability of phosphorous, which is frequently a limiting element for plant growth. Acid precipitation can also inhibit the activity of soil microorganisms, accelerate leaching of nutrients from foliage, inhibit germination, injure foliage, and depress plant growth (Dvorak et al. 1978).

The proposed action is expected on a national and regional basis to add only a small amount of sulfur oxides to the base-case concentrations except in highly localized situations (cf. Sec. 5.2), and would, therefore, be a minor contributor to regional problems of acid precipitation. Thus, the impacts to terrestrial biota are expected to be small.

Particulate Emissions

Direct dusting of organisms by particulate emissions can produce adverse effects (Lerman and Darley 1975). On vegetation, stomata can be occluded by particulates, disrupting the gaseous exchange patterns. In addition, dusting can modify leaf absorption of incident solar radiation, reducing photosynthesis and inhibiting heat exchange. Particulates inhaled by animals adsorb to the gaseous exchange surfaces and irritate or damage the tissues. This can reduce the effectiveness of gaseous exchange between the air and the body fluids of the organism.

Most studies of impacts from dust have been concerned with cement kiln and limestone dust. Effects on vegetation have been reported for dustfall rates as low as 365 $g/m^2/day$ (Lerman and Darley 1975). Equating the effects of cement kiln dust with those of fly ash is tenuous because of the differences in chemical composition. However, a comparison does suggest that the fallout due to implementation of the proposed action (Sec. 5.2.4) should not reach threshold levels for which physical disruption of vegetative function has been noted. Nor do the predicted concentrations at ground level approach levels known to induce pulmonary dysfunction after chronic exposure. Even in Region VI, industrial plants should be sufficiently dispersed to reduce dustfall to nonharmful levels.

Many of the constituents of fly ash can be toxic if assimilated in sufficient amounts (Berry and Wallace 1974; Heit 1977). Dvorak et al. (1978) provide an extensive discussion of the potential effects of the toxic elements in fly ash. They also discuss several models of trace element deposition around model power generating stations. Trace elements began to pose a threat to biota only if the models assumed maximum rates of accumulation in the soil and maximum uptake by vegetation. A major role in the impacts from trace elements was played by the endogeneous concentrations of the elements in the soil; greatest impacts were expected when soil levels of trace elements already approach toxic concentrations.

Increased emissions of trace elements due to the program probably will not be a serious problem on the whole. Effects of the conversion probably will increase ambient particulate levels by no more than 1.0 $\mu g/m^3$ (Sec. 5.2.4), much less than expected for the model plants discussed above. Deposition rates should be well below those expected to create problems of trace element toxicity.

5.6.4.2 Aquatic

Only the effects of combustion on aquatic habitats peculiar to coal as an energy source will be considered in this section. Effects common to all fuel-driven generating stations and MFBIs (e.g., entrainment and impingement) will not be discussed. The major sources of impact that occur to aquatic environments as a result of coal combustion are acid precipitation and trace metal deposition (Dvorak et al. 1977).

The biotic consequences of lowering the pH in surface waters due to acid precipitation are highly site-specific and depend on (1) how much the pH is lowered, (2) the existence, if any, of other stresses on the system, (3) the biotic assemblages already present in the affected area, (4) the persistence of the acid precipitation (seasonality, frequency) and the potential for the communities to recover between pH "insults," and (5) the regional geochemistry. In general, the greatest damage to community composition, population sizes, and other ecological parameters occurs when the pH shifts from neutral or alkaline to a permanent acid condition (Hynes 1971). Shifts of this nature are generally accompanied by sharp drops in productivity, the magnitude of which is proportional to the shift magnitude. Although certain communities may actually experience increases in diversity with a lowered pH (e.g., the phytoplankton) (Brock 1966), most experience reductions in the number of taxa (Beamish and Harvey 1972). Fish are particularly sensitive to pH shifts below about 5.5, and man-induced values below this have been associated with sharp drops in fish production or virtual fish extinction (e.g., in the Adirondacks) (Cogbill and Likens 1974). Other effects of lowered pH on aquatic biota are discussed in Sections 5.4.4.1 and 5.6.1.2.

If the pH shifts occur relatively infrequently, there may be few discernible effects on ecological parameters because short-term exposure may not affect the organisms or the damage may be compensated for by recruitment or reproduction (Hynes 1971).

Areas in the United States which are projected to receive the greatest impact from increases in acid rain are discussed in Section 5.4.4.1. Section 5.3.4.2 indicates that one area in particular, the southern Texas coast, may experience acid rain as a result of the proposed action (this area does not receive an appreciable amount at this time). Quantification of the potential problem is not possible. However, the eastern one-third of this area contains relatively soft surface waters (less than 60 mg/L total hardness, as $CaCO_3$) (Sec. 4.6.2) and, therefore, would be potentially vulnerable to acid rain impacts.

Although the addition of trace metals to aquatic environments from the deposition of airborne combustion effluents represents a potential problem, it is not generally considered to be of major concern (Dvorak et al. 1977; Van Hook 1978). The quantities deposited are usually several orders of magnitude less than the amounts added from other sources. Therefore aquatic impacts from trace element deposition due to the proposed action will be negligible. However, any incremental additions in areas already near problem levels can result in detrimental effects.

5.6.5 Waste Collection and Disposal

5.6.5.1 Terrestrial

A certain amount of land may be withdrawn from use by native biota at least temporarily, in order to dispose of the solid wastes from coal combustion (cf. Sec. 5.5.5). In Region VI, by

1985, approximately 422 to 633 hectares (1042 to 1563 acres) of additional land per year will be required to dispose of combustion wastes; by 1990, 769 to 1154 hectares (1901 to 2851 acres) will be required annually (Sec. 5.5). Many converted plants will have little space for waste disposal, particularly in urban sites. Solid wastes will then most likely be transported offsite for disposal in landfills. New plants may be able to acquire sufficient land for waste disposal onsite, particularly if they are to be located in rural areas. Preemption of land for waste disposal will remove that area from available habitat for use by wildlife. Most of the disposal will occur along the Gulf coast, where coastal prairie, oak-hickory forests, pine forests, broadleaf evergreen forests, and wetlands are the major biotic communities present. Disturbance of the forests for landfill could remove these areas from use by forest wildlife for several decades. Burial of the waste under sufficient soil should permit revegetation and eventual reestablishment of some wildlife habitat.

In the past, wetlands areas would have been particularly attractive sites for disposal of combustion wastes (Dvorak et al. 1978). There is a tendency for low wetlands to be used for waste disposal because little excavation is required prior to deposition of the waste, and drainage from deposition sites is less than in highlands. The accelerated urbanization along the Gulf coast has removed much of the wetlands habitat in Demand Regions IV and VI. Because they are an interface between terrestrial and aquatic systems, wetlands contain a diversity of species. Many species are uniquely adapted to life in this ecotone, e.g. mangroves and several halophytes. These communities provide habitat for a number of waterfowl and species of tropical origin. The President's Executive Order No. 11990 requires that wetlands be protected from further degradation. Because implementation of the proposed action will have to comply with this Order and appropriate requirements of the Federal Water Pollution Control Act (33 USC 1251, Pub. L. 92-500), increased waste disposal due to the proposed action should have negligible impact upon wetland communities. Regulation promulgated under the Resource Conservation and Recovery Act of 1976 (Pub. L. 94-580) and other laws in accordance with this order may mitigate impacts of waste disposal upon wetlands. The EPA's proposed guidelines for hazardous waste disposal call for the protection of wetlands (USEPA 1978).

Bottom ash and fly ash contain a number of trace-elements (App. E, Tables E.13 and E.14). All are toxic to biota if they are encountered in high enough concentrations (Berry and Wallace 1974). Many of these elements are dissolved or suspended in the liquor of the storage pond. Runoff from these ponds could introduce these trace elements into the surrounding soil (USEPA 1977). Runoff occurs if the impoundment is unable to contain excessive rainfall and runoff or its dikes are poorly constructed. Overflow or washout of the dikes could result in extreme erosion of neighboring soils, and the destruction of herbaceous vegetation and the less mobile animals in the pathway of flooding. In addition, washout would result in the deposition of trace elements found in the pond liquors. The deposition of large quantities of potentially toxic elements in the soil poses a threat to the biota occupying the area. The occurrence of rains sufficient to overflow storage ponds is less likely in Region IX than in the eastern and southeastern regions in which most of the conversion is expected to take place.

Another pathway by which toxic elements may be released from the impoundment is the invasion of marsh vegetation or use of the pond as a watering source by wildlife. In the semi-arid sections of Regions VI and IX, an open body of water would be particularly attractive to wildlife. Ingestion of the water or of the vegetation could introduce toxic elements into the local food web. The probability is low that such a pathway would channel large quantities of toxic elements into the food web. As with slurry ponds for coal mining waste, the noxious quality of the liquor and precipitate should discourage establishment of marsh vegetation and repeated use of the water by wildlife. Proper control measures can be taken during the lifetime of the pond to prevent the influx of vegetation or wildlife. After the pond is full, proper dewatering, burial, and revegetation should reduce the movement of elements from the waste.

Even in the best-designed impoundments, some seepage can occur through the sides and bottom of storage ponds (USEPA 1977; Dvorak et al. 1978). This will transport toxic elements into the soils surrounding the impoundment. The rates at which seepage will transport elements from the sludge- or ash-disposal sites is dependent upon a number of factors, including permeability of the impoundment materials, concentration and chemical form of the elements in the leachate, pH of the leachate, and the physical and chemical properties of the soil.

5.6.5.2 Aquatic

Section 5.4.5.1 contains a discussion of the effluent composition resulting from waste collection and disposal and of the water quality effects resulting from the release of this material. In general, the material is characterized by high concentrations of trace contaminants (metals), high pH levels, a high chemical oxygen demand, and high dissolved and suspended solids levels. Although small routine releases are common from waste treatment ponds, the major impacts that occur from this material result from accidents (pond failure or overflow and spillage during transport) (Sec. 5.4.5). Such events can create enormous stresses on receiving waters; the impact can be severe enough to extirpate virtually all organisms for some distance from the facility (Dvorak et al. 1977).

The severity of the effects induced by trace metal releases is dependent on the concentrations produced in the receiving waters, the pH, the presence of other ions (e.g., calcium and magnesium), and the organisms exposed. The elements are essentially the same as those encountered in mine drainage and mine processing, but the relative quantities may be different (Sec. 5.4.5.1). Section 5.6.1.2 contains a discussion of trace metal effects on biota.

Levels of pH of 11 or greater can be induced in receiving waters from waste effluents (Sec. 5.4.5). In some cases, the effects produced may be minimal (especially if the change is episodic); many highly productive surface waters naturally obtain pH values of 10 or greater during active photosynthesis (Fogg 1975). Prolonged high pH levels or extremely high levels result in drastic drops in species diversity and productivity (Hynes 1971). Although a few organisms (chiefly a few algae and insect larvae) can survive at values as high as 13 (Hart and Fuller 1974; Brock 1966), fish seldom exist in waters continually above pH 10 (Bennett 1970). The physiological bases for intolerance of high pH levels are not well understood for many organisms. However, some of the factors include toxicity of OH^- (by enzymatic inactivation or ion transport alteration) and the inability of some autotrophs to use HCO_3^- or CO_3^{2-} in lieu of free CO_2 in photosynthesis (little free CO_2 is available in surface waters at high pH levels) (Soeder and Stengel 1974).

A few constituents in the waste material (notably calcium sulfite) can create a high chemical oxygen demand in receiving waters (Sec. 5.4.5). The resulting lowered oxygen levels can produce massive mortality of sensitive species (e.g., most sport fish) even if the discharge event is short-lived (National Academy of Sciences, National Academy of Engineering 1973). Low oxygen levels can also result in greater trace element availability (and, therefore, toxicity) and can favor the production, by reductive chemical processes, of other toxic compounds such as ammonia and hydrogen sulfide (National Academy of Sciences, National Academy of Engineering 1973).

The effects produced by high dissolved solids and high suspended solids are essentially the same as those discussed in Section 5.6.1.2.

Because the effects from waste effluents are highly site specific, it is not possible at this time to be more specific about the impacts that will result from the proposed action.

5.6.6 Endangered Species

Increases in coal utilization as a result of the proposed action have the potential to further threaten several of the species listed in Appendix J. Habitat destruction and toxic emissions stand out as primary reasons for decline of species threatened with extinction. Both of these factors can result from various activities in the coal fuel cycle and could contribute to the decline of a species.

5.6.6.1 Terrestrial

Terrestrial endangered species, with the exception of a few species of raptors, are threatened because of habitat destruction. Coal mining, especially in remote areas, may affect a few of these species. Habitat of the Indiana bat and eastern cougar could be affected by strip mining in the eastern United States. Potentially affected western species include the gray wolf, Utah prairie dog, red-cockaded woodpecker, and bald eagle. With proper site consideration, no impacts should result.

Effects of airborne pollutants will be felt to some extent on plant species. Although no existing listed plant species could be affected by this action, some of the over 2000 proposed endangered plants could be affected. It is unlikely that air pollution will have a serious effect on habitats of endangered terrestrial animal species.

5.6.6.2 Aquatic

Endangered and threatened aquatic species are often principally imperiled by habitat destruction, such as occurs from sedimentation from strip mining (see Sec. 5.6.1.2). As with all biota, however, they may be affected by toxins or pH changes, and each species has different tolerance levels for each parameter. Mining induced by the proposed action is projected to be largely concentrated in central and southern Appalachia and in the western United States (Sec. 5.4.1). Because these are areas that also have the greatest sedimentation problems associated with mining (Sec. 5.6.1.2), the potential exists for the destruction of some endangered species.

This is particularly true of the southern Appalachian area where numerous endangered and threatened fish and mollusks have been identified (App. J). Coal utilization might also contribute to the decline of some species, particularly from waste disposal effluents. However, the possibility of affecting any endangered species would be more predictable, and, thus, proper management might prevent any impacts.

5.6.7 Wild and Scenic Rivers

The intent of the Wild and Scenic Rivers Act is described in Section 4.3.2, and those river segments currently designated under this act are listed in Table 4.4. The Act stipulates that each designated river segment maintain the same quality which prompted it to be designated initially. The diffuse nature of mining impacts and of some of the coal combustion effects is such that protection of these rivers from coal fuel cycle impacts may be difficult. It is not possible to predict which rivers will potentially be impacted because of the proposed action. However, those located near or in the areas expected to experience the greatest coal mining shift (central and southern Appalachia, the western United States) and coal combustion shift (southern Texas) would likely require the most effort to avoid alteration. This would include segments of the Missouri River; the Rio Grande River; the Little Beaver, Little Miami, and New rivers in Ohio; and the Obed River in Tennessee.

5.7 HISTORICAL AND ARCHAEOLOGICAL SITES AND NATURAL LANDMARKS

5.7.1 Mining and Mine Site Processing

Many of the historical sites listed in the National Register are associated with coal mining towns or are near recoverable seams and could be affected. However, mine operators seeking a Federal permit are required to locate and avoid all listed and potential historic or archaeological sites (36 CFR Part 800). Although a few gravesites, mine shafts, or other potential sites for inclusion in the National Register may be destroyed by mining that results from increased coal use caused by this action, little (if any) significant loss of historical resources is expected. Also, natural landmarks will be located and avoided on mining projects seeking federal permit. Little impact is expected.

5.7.2 Transportation

New transportation routes will avoid historic sites and natural landmarks (see Sec. 5.7.1).

5.7.3 Storage and Onsite Processing

No effects on historic or archaeologic sites and natural landmarks are expected from storage and onsite processing. If during excavation of storage areas the discovery of historic or archaeologic artifacts is potential, a mitigation plan and the protection of any uncovered artifacts is required (36 CFR 100).

5.7.4 Combustion

Emissions of coal combustion, especially acidic and particulate emissions, are known to mar and damage old masonry or stone structures; acid precipitation is known to increase the erosion rate of such structures. An effect of this act may be to degrade such structures, particularly clay or adobe structures, in Demand Region VI.

5.7.5 Waste Collection and Disposal

Properly sited disposal areas will have no effect on historic sites or natural landmarks (see above).

5.8 SOCIOECONOMIC IMPACTS

Overall economic impacts of the FUA were not evaluated in this environmental analysis; however, information on the cost of the FUA can be found in this document: Analysis of the Proposed U.S. Department of Energy Regulations Implementing the Powerplant and Industrial Fuel Use Act, DOE/EIA-0102/21, Energy Information Administration, November 1978.

5.8.1 Mining and Mine Site Processing

A "worst-case" assessment was performed to indicate the nature and extent of socioeconomic impacts that would occur if mines were opened in representative coal mining counties. This assessment is presented in Appendix K.

The counties chosen for study were selected because they represented disparate regions of the country (Midwest, Appalachia, and Northern Great Plains), because these counties had been studied before and data were available, and because they are expected to be affected by the proposed action.

No boom town impacts are expected due to the proposed action. The worst-case analysis presented in Appendix K is based on individual mines producing all the coal needed to meet the increased demand due to the proposed action. Although the analysis in Appendix K reflects real impacts that do occur in coal towns, the coal required due to the proposed action is extremely dispersed geographically. Predicted impacts (Appendix K) would not be caused by the proposed action even in Texas (35 percent increase in production) or Wyoming (15 percent increase) because the coal needed is likely to come from many individual mines even within the same supply region. Coal to meet the demand due to the proposed action will consist of coal with disparate characteristics from many seams for boilers whose individual coal demand would not justify new mines opening. It is more likely that coal will be produced from existing mines or mine expansion and with the work forces that either already live in an area or come to an area to satisfy utility demand for coal. The impacts presented in Appendix K do illustrate, however, the social and economic impacts of mining as the demand for coal production increases. This analysis attempted to specify the nature of impacts, since these impacts could not be predicted at either the site-specific or programmatic level.

The principal impacts of coal production on local government developed in the worst-case example would be in education expenditures. Other impacts affect social service delivery primarily. The general observation on the detrimental aspects of such increased public service impacts is that the revenues from coal production are usually available after the boom effects have already occurred.

5.8.2 Socioeconomic Impacts of Sludge and Ash Disposal

This section is a discussion on alternatives to throwaway flue gas desulfurization systems and the socioeconomic problems of combustion waste disposal. Because disposal problems for boilers used for generating electricity differ from those for boilers used for process and space heat, the two types of problems will be discussed separately, with the former being presented first.

5.8.2.1 Sludge Disposal Impacts

More than 90 percent of boilers now planned for operation in 1980 will use lime/limestone scrubbers (nonregenerable or throwaway systems) in those cases where flue gas desulfurization (FGD) is required. Disposal of these sludges represents major disposal problems (Argonne National Laboratory 1976). About four tons of coal burned produces one ton of ash and sludge (dry basis), most of which is SO_2 sludge (Stites et al. 1977). Alternatives to lime/limestone FGD exist but either are not in use or are in the demonstration stage (PEDCO Environmental 1977a). Regenerable processes could substantially reduce waste disposal problems; however, commercially competitive regenerable systems are unlikely to play a role in the U.S. before 1985 (Argonne National Laboratory 1976) or 1995 (Meier et al. 1977). There are only eight operable regenerable scrubbers in the U.S. used on a commercial basis (PEDCO 1977a). For this reason the proposed action is likely to impact the need for suitable disposal sites for scrubber sludge.

A 115-MW coal-fired boiler using the Wellman-Lord FGD method and a sulfur-dioxide-reduction process of Allied Chemical has operated as a demonstration plant, partially funded by the U.S. EPA, producing about 25 tons of pure elemental sulfur per day. The sulfur is shipped as a liquid and used to make sulfuric acid. The 3-4 tons/day of sodium salt produced will also be sold industrially (Friedlander 1978). The process was designed to use about 14,000 standard cubic feet of natural gas per long ton of sulfur produced (Link and Ponder 1977). Also, production of elemental sulfur and/or sulfuric acid through FGD is not now economically viable. But, it is possible there will be an increased demand for sulfur developing over the next two decades (USEPA 1976).

Most sulfur consumed in the U.S. is used to produce sulfuric acid, 58 percent of which is consumed in the fertilizer industry. Consumption for non-acid purposes is about 12 percent. One model predicting demand showed that about 40 U.S. boilers producing 3.3 million tons of sulfur would satisfy demand and sulfur prices, which might have risen, would not (USEPA 1976). Although a demand of this sort, if it occurs at all, may not soon affect conversion of existing facilities some new boilers are being installed with the Wellman-Lord FGD (Boyer and Pedroso 1977).

Despite these trends, scrubber sludge is likely to be a waste product and the FUA will increase the problem of disposal. At present there is no market for FGD sludge in the United States.

Some markets presently being investigated are: landfill (after fixation); fertilizer (after extracting the sulfur as described above); a calcium source for peanuts (through gypsum); as an ingredient in road-base and paving materials, artificial aggregates, and lightweight concrete; and in portland cement. These all either are experimental or have no proven market potential. Further, the variable chemical and physical properties of FGD sludge, the high transportation cost, dewatering requirements for many applications, and inability to compete economically with other materials are major deterrents to the use of flue-gas desulfurization sludge. Even if use became possible, sludge production will soon be so high only a small portion could be marketed (Argonne National Laboratory 1976).

For the near term, FGD sludge disposal will continue to be ponded or, after fixation, put in a permitted landfill (Argonne National Laboratory 1976). Environmental impacts from sludge disposal include the noise and spillage from trucks, the cost of the land for processing and dumping the sludge and ash, the cost of reclaiming the land, the total tonnages generated, and total acres needed for disposal (see Table 5.22). The amounts of sludge generated by three large coal units are estimated in Table 5.23.

Table 5.23. Commonwealth Edison Company Calculated Wet Scrubber Waste Disposal,[a] 1972

	Sludge[b] Cubic Yards	Treated Sludge Cubic Yards	Boiler		% Increase[c]	Treated Sludge Trucks/hr[d]
			Slag Cubic Yards	Fly Ash Cubic Yards		
Will County[e]	792,000	946,000	78,018	107,350	452	9
Waukegan[f]	721,000	827,000	44,124	148,092	379	8
Joliet[g]	1,404,000	1,677,000	126.527	362,843	304	16
	2,917,000	3,450,000	258,669	618,825		

From Commonwealth Edison (1973).

[a]Assumes scrubber in operation whenever unit is operating.

[b]Based on 4% sulfur coal, 82% SO_2 removal efficiency, 50% solid/50% water sludge.

[c]$\frac{\text{Treated sludge - fly ash in treated sludge}}{\text{Boiler slag + fly ash}} \times 100$

[d]12-cu-yd trucks, 24 hours per day.

[e]Based on 1,083 MW; capacity factor 48.74%; SO_2 removal only.

[f]Based on 946 MW; capacity factor 50.78%; SO_2 removal only.

[g]Based on 1,695 MW; capacity factor 55.2%; SO_2 removal only.

Disposal of fly ash in slurry ponds (as opposed to sanitary or valley landfill) is common. This is due to transport and handling cost savings. The following factors have increased cost and made the slurry option more difficult to implement (American Society of Civil Engineers 1977): increasing institutional requirements for undisturbed buffer zones and fill height requirements to control visual impact, less volume per acre, impermeable liners, and movement and stabilization of finer ashes caused by higher-efficiency removal and improved coal preparation; more widespread requirements for recirculating water; and reduction by slurry method of the value of ash for use as pozzolan.

The amount of ash used in 1975 (9.8 million tons; see Table 5.24) was three times the amount in 1966, an increase from 12.1 to 16.4 percent of the total ash produced, so that as production increases, usage may also increase, although more slowly. A rough breakdown of the end uses of ash is given in Table 5.24. The exact end use of about one-half the fly and bottom ash is unidentified, but it was sold.

Some of the advantages of using fly ash for cement in concrete construction are (1) a decrease in cement cost from $30/ton to $6-$7/ton, (2) shorter pouring and finishing time than for standard concrete, (3) an energy saving (1300 kWh/ton) required to produce standard cement vs.

Table 5.24. Commercial Utilization of Ash in the U.S. in 1975[a] (thousands of tons)

Use	Fly Ash	Bottom Ash	Boiler Slag
Type 1-P cement	225	70	36
Partial substitute for cement	945	-	-
Lightweight aggregate	90	35	-
Stabilization and roads	450	525	72
Filler in asphalt mix	135	-	-
Ice control	-	280	54
Blast grit and roof granules	-	420	864
Misc.	180	350	414
Ash removal at no cost to utility[b]	1,080	875	270
Ash utilized[b] from disposal sites	1,395	945	90
1975 total utilized	4,500	3,500	1,800

From Argonne National Laboratory (1976).

[a]Compiled by the National Ash Association and Edison Electric Institute.

[b]Specific end use not known.

nominal kWh/ton for cement made with waste fly ash, and (4) expansion of plant capacity with practically no investment in new facilities.

Other actual or potential uses of fly ash, bottom ash, and/or boiler slag are (1) as an agricultural soil amendment, (2) as a component of grout, (3) in the production of mineral wool, (4) in the extinguishing of burning spoil piles, (5) as a source of chemical (sulfur alumina, etc.), (6) as a trench backfill, (7) the deodorization of animal waste, (8) the manufacture of kitty litter, and (9) blending with sewage.

The basic disadvantages of disposal of most ash and all FGD sludge are (Stites et al. 1977):

1. Generates no income.
2. Utilizes power (to operate scrubbers) that could otherwise be sold.
3. Utilizes land for disposal and chemicals for fixation and environmental protection that are removed from other use.
4. Requires additional maintenance, manpower, and machines which add to operating cost.
5. Produces dusting problems (from ash and to a small extent from SO_2 sludge).
6. Leaves the holder of the disposal permit with uncertainties about the long-term stability of fixed sludge or diked ponds for ash or sludge.
7. Generates truck noise, road spills from trucks, and visual impact.

It may affect property values where new dumps are created. At best, a small amount of increased coal use does not threaten available land for dumping (Meier et al. 1977) and it does provide employment.

5.8.2.2 Special Considerations for Small Industrial Boilers

Although there is wide overlap between large industrial boilers and small utility boilers, consideration of capacity is important as regards impact. Here, small means less than 100 MW and usually less than 50 MW.

In December 1977, there were 39 operational FGD systems at 22 plants, and 9 more at 3 Caterpillar Tractor installations due to become operational before 1978 (PEDCO Environmental Inc. 1977b). These boilers generate process steam, space heat, and electricity, and generally use >1% sulfur coal. A number use >3% sulfur coal. From Table 5.25 it can be seen that 71 percent of these plants have been retrofitted and that a variety of disposal options and control systems are in use.

Table 5.25. Industrial Boiler FGD Characteristics

	Number
SO_2 Control System	
Caustic Waste Stream	2
Caustic Scrubbing	3
Sodium Scrubbing	8
Air Pol Caustic Scrubbing	1
Double Alkali	8
Citrate Process	1
Sodium Addition	1
GM Sodium Scrubbing	2
Weliman-Lord	1
Alkali Addition	1
Proprietary	7
Lime Scrubbing	1
Sodium Hydroxide Addition	1
Water Scrubbing	2
Ammonia Scrubbing	1
Percent Plants Retrofitted	71%
Waste and Byproduct Disposal Practice	
Alkaline Sulfate/Bisulfate Recycled to Pulp	2
Dewatered Slurry to Landfill	10
Holding Pond for Evaporation	4
Non-Fixated Slurry to Lined Pond	2
Regenerable - elemental sulfur	1
Regenerable - liquid sulfur dioxide	1
Wastewater Treatment and Discharge to City Sewer	6
Wastewater Treatment and Discharge to River	2

Derived from PEDCO Environmental (1977b).

The dewatered slurry-to-landfill option is used at Caterpillar Tractor in Illinois. Boilers of 10- to 20-MW capacity are used for 150-pound steam for heat. Sodium products of the FGD system are vacuum filtered. The resultant material can be handled as a solid, picked up by a contract hauler, mixed with municipal garbage, and dumped in a municipal landfill. The only problems are those already discussed for larger plants. The amount of landfill-permitting rights and degree to which a municipality will permit mixing of thixotropic sludge--sludge which could become fluid when disturbed--with garbage is limited. Operations could also be hampered where the sludge could not be mixed with garbage. Those plants discharging to public water have onsite water treatment and thickener facilities. In view of tightening water pollution control standards, however, this method may become harder to operate. One of these plants is now shut down.

The aspects of FGD sludge disposal and ash disposal are rapidly changing, but for small boilers all the environmental problems of large boilers persist. They are:

1. Uncertainty of the final disposal characteristics of ash and sludge, which makes the disposal permit holder or dump owner liable to financial claims for some time into the future.
2. Larger space than necessary for dumping may be needed to reduce visual impact.
3. Dusting, particularly of fine ash and some sludge, will require long-term control, although this problem is not great.
4. Property values near dump areas may be reduced.
5. Noise and spillage from trucks transporting sludge and ash disturb people who live near the travel route or who use it.

In addition, for small boilers, the following problems are added:

1. If the boiler is in a high-density area, there may not be enough room to dewater sludge sufficiently for shipment to a dump; it may be difficult to retrofit tubing, pumps, etc., for ash and sludge removal to a boiler in a small confined area, particularly if the boiler is part of the production stream; or sludge and ash may have to be trucked long distances to a disposal site, raising product prices even more.
2. If many small boilers in a small geographic area must convert, it may be difficult to find adequate disposal sites.
3. Some companies may not convert if so ordered, but may simply purchase new coal boilers.

Because more scrubbers will be required, all of the above problems are expected to be exacerbated by New Source Performance Standards and the proposed action.

Some of these problems represent costs that may be passed onto the consumer. Other social costs reflect the difficulty of finding suitable disposal sites. Sites near converted boilers may be pre-empted by space limitations requiring industry to transport the waste some distance. As discussed previously, the outlook for regenerable scrubbers or a marketed use for scrubber sludge appear to be quite limited in the near term.

5.9 HEALTH EFFECTS

The potential for detrimental influences on human health necessitates a thorough evaluation of the use of coal as a fuel. Although some of the effects of occupational exposure (lost wages and medical costs) are shared indirectly by all members of society, on the whole the burden is shouldered by the selected groups whose occupations carry increased health risks. Not so with the effects of air and water pollution from coal cycle effluents. The toxic substances contained therein spread indiscriminantly and to the detriment of all those in the area. Therefore, evaluation of the health impacts expected from a program of industrial coal conversion will include both occupational and public health impacts.

Each step of the coal fuel cycle--extraction, cleaning, transportation, combustion and waste disposal--will be discussed individually. The incremental health impacts for both occupational and public sectors will be assessed for their contribution to the overall impact on human health.

5.9.1 Mining and Mine Site Processing

Of all the components in the coal fuel cycle, the extraction process has the greatest rate of fatal occupational injury. This is not surprising when one considers the physical hazards of daily activities in coal mining. In the future, as greater dependence is placed upon surface mining, underground mining is further automated, and stricter safety regulations are enforced, these factors may combine to reduce the absolute number of injuries. However, the economic incentives of greater coal demand may offset these positive forces by allowing the reopening of many small, marginal mining operations which would employ relatively small numbers of people and be difficult to adequately monitor for safety violations. The presence of these small units as well as a large, inexperienced work force would result in an increased rate of occupational injury.

The 1973 injury and production figures (National Coal Association 1976) were used to derive fatal and nonfatal injury rates per million short tons for underground and surface mining. The result is two injury rates (fatal and nonfatal) weighted by the surface and underground components of the total regional coal production for each coal supply region:

$$I_w = \frac{(I_s)(P_s) + (I_u)(P_u)}{P_s + P_u},$$

where I_s = surface mining injury rate per million tons of mined coal (0.06 fatality rate, 3.37 nonfatality rate),

I_u = underground mining injury rate per million tons of mined coal (0.35 fatality rate, 30.93 nonfatality rate),

P_s = surface mine production,

P_u = underground mine production, and

I_w = weighted injury rate per million tons of mined coal.

The injury rate of each coal supply region is applied to the projected increment supplied by that supply region to each coal demand region (see Table 3.8) to produce the number of injuries resulting from the proposed action. From Table 5.26 it is clear that in 1985 and 1990 about 40 to 50 percent of the nation's fatal occupation injuries from coal extraction due to the program will occur in the course of supplying coal to Demand Region VI (Arkansas, Louisiana, New Mexico, Oklahoma and Texas). This is about two-fold greater than the expected fatal injury rate resulting from the coal-use needs of Demand Region IV. About 45 percent of the nonfatal occupational injuries from coal extraction for the proposed action will occur in meeting the consumption needs of Demand Regions VI and IV. The smaller impact in 1990 compared to 1985 results from the increasing proportion of surface mined coal, which has a lower injury rate than underground mining.

Table 5.26. Estimated 1985 and 1990 Annual Extraction-related Occupational Injuries[a] Resulting from Increased Coal Use in Demand Regions as a Result of the Proposed Action

	1985		1990	
Demand Region	Fatal Injuries	Nonfatal Injuries	Fatal Injuries	Nonfatal Injuries
I	0.32	26.8	0.55	46.6
II	0.34	28.8	0.62	54.9
III	0.45	37.8	0.88	75.~~5~~0
IV	1.71	103.8	3.27	237.0
V	1.04	63.9	1.32	87.7
VI	3.59	233.3	7.08	470.4
VII	0.15	5.9	0.24	12.4
VIII	0.09	5.0	0.15	9.2
IX	0.60	42.9	0.97	68.8
X	0.04	2.2	0.08	3.39
Total	8.3	550.3	15.2	1065.4

[a]The rates used to derive these numbers are per million tons of mined coal.

It should be stressed that comparisons made on the basis of coal demand region do not mean that all of the extraction-related (or cleaning-related) occupational injuries will occur in that region. Obviously such injuries will occur in the coal supply regions where extraction takes place. The program-related mining injuries by supply regions is shown in Table 5.27. On this basis, Supply Region 2 will receive the greatest impact, with about 30 percent of the fatal injuries and 30 to 35 percent of the nonfatal injuries occurring there. Supply Region 5 will incur the second greatest impact.

On the basis of man-hours in 1975, an average of 145 disability days were incurred for each underground coal mining injury (National Safety Council 1976, p. 26), the second highest severity rate of all reporting industries. Although the incidence rate is much lower in surface mining, the severity of the injuries is similar, with an average 140 disability days per injury. In 1974, the average financial loss (in 1974 dollars) due to an underground mine fatality was $125,000. For each nonfatal accident the loss averaged $4,000 (Cole 1977).

5.9.2 Occupational Disease

In addition to safety hazards encountered in underground coal mining, the miner is also exposed to disease-inducing conditions. It has previously been recognized that underground miner respiratory disease rates are much higher than those of any other occupational group, including surface miners.

Pneumoconiosis is the general term applied to occupational lung diseases resulting from inhalation of dust. Coal Worker's Pneumoconiosis (CWP) results from tissue reaction to the accumulation of coal dust in the lungs. Progressive Massive Fibrosis (PMF), the complicated form of CWP, occurs in a small number of CWP cases. Once a certain degree of simple CWP is present, the

Table 5.27. Estimated 1985 and 1990 Annual Extraction-related Occupational Injuries[a] in Supply Regions as a Result of the Proposed Action

Supply Region	1985 Fatal Injuries	1985 Nonfatal Injuries	1990 Fatal Injuries	1990 Nonfatal Injuries
1	1.12	94.1	1.95	165.1
2	2.26	194.1	4.19	360.5
3	0.33	25.2	0.66	52.5
4	0.97	15.1	1.60	68.3
5	1.60	98.9	2.87	181.6
6	1.24	68.4	2.56	146.0
7	0.31	26.7	0.50	42.3
8	0.46	27.4	0.83	49.4
Total	8.3	550.3	15.2	1065.7

[a]The rates used to derive these numbers are per million tons of mined coal; see text for calculation of the weighted injury rate.

development of PMF does not require further exposure to dust. PMF is generally associated with decreased lung function and permanent lung damage. The presence of simple CWP can lead to minor respiratory impairment, but PMF is considered to represent a life-threatening situation.

From 1969 to 1973 U.S. Public Health Service sponsored surveys that studied the prevalence of CWP in the U.S. miner population. The results of two such studies are reported in Table 5.28. The data in this table clearly demonstrate a greater prevalence of CWP in underground miners compared to surface miners. The difference between the disease rates of the two groups becomes even greater when work histories of the surface miners are considered. Five of the seven surface miners diagnosed with more than simple CWP were found to have extensive underground experience.

Table 5.28. The Prevalence of Coal Worker's Pneumoconiosis (CWP) in U.S. Coal Miners

CWP Category	1969-71[a] Underground No.	1969-71[a] Underground % Total	1972-73[b] Surface No.	1972-73[b] Surface % Total
0	5985	70.0	1378	95.8
1	1905	22.3	52	3.6
2	452	5.3	2	0.1
3	38	0.4	0	0.0
PMF[c]	173	2.0	5	0.4
Total	8553		1438	

[a]From Morgan, W. K. C., et al. 1973. Arch. Environ. Health 27:221-226.

[b]Fairman, R. P., et al. 1977. Arch. Environ. Health 33:211-215.

[c]Progressive massive fibrosis - complicated CWP.

The purpose of the Federal Coal Mine Health and Safety Act of 1969 (MHSA) and the amendments which followed was to compensate men who are totally disabled due to pneumoconiosis. At the present time, the term "black lung" is applied to respiratory disease in a miner whether or not it is related to coal mining.

It is assumed in the Coal Mine Health and Safety Act that any respiratory impairment that develops in a miner with more than 15 years of underground exposure is related to his occupation. Under the legal definition of disability, it was estimated that 0.2 percent of the underground labor force became disabled by CWP in 1970. Regulatory provisions of the Act are intended to insure a future mine work force which is free from the debilitating effects of complicated CWP. As a result of this provision, a respirable dust level of 2 milligrams per cubic meter (mg/m^3) has been in effect in underground U.S. mines since 1975. A similar approach initiated in 1943 by the British is responsible for restricting the prevalence of CWP to its mildest form in only 3 percent of the workers and no PMF after 35 years of exposure. The U.S. standard is believed to be more strict than the British standard. As a result of this assumption it is anticipated that future U.S. miner populations will exhibit a rate of simple CWP which is lower than that presently found in the United Kingdom. However, the U.S. miner will continue to pay the price, in terms of lung disease, for the 25-year delay between implementation of a dust standard in the U.S. and the U.K.

Although miners who start their work experience after 1975 are expected to be protected by the U.S. dust standard, those men who began prior to 1975, especially those with more than 10 years pre-standard experience, can anticipate a continued prevalence of disability from CWP among their cohorts. This disability rate will be reflected in the overall worker population rate which will decline as a result of the attrition of pre-1975 workers from the miner work force over the next 25 years and as mine safety regulations take effect.

Without strict adherence to the provisions of the 1975 Coal Mine Health and Safety Act and its amendments the assumption of improved coal worker health status for future miner populations is not valid. If the regulations are relaxed to allow pre-1975 mine conditions to exist, a return to retired-miner disability from CWP would be inevitable.

CWP is a major component of coal miner respiratory disease but not the only component. Coal miners also have an elevated prevalence of bronchitis and emphysema. Industrial bronchitis is an identifiable disease entity and can be accounted for by coal dust deposition in bronchi and bronchioles; however, the effects on the lungs are expected to be slight. Evidence indicates that cigarette smoking has between five and ten times the effect of coal dust on ventilatory capacity. Since a large portion of the miner population contains smokers, cigarette-related lung disease is expected to be a primary factor in determining the health status of the future miner work force.

For the reasons outlined above (i.e., work force exposure prior to the establishment of permissible dust levels and miner smoking habits), lung disease is expected to continue plaguing active and retired miners at rates above those for the rest of the population, irrespective of future increases in mine production.

5.9.3 Cleaning

Compared to the occupational injury rates for extraction, the rates associated with coal cleaning are low. The occupational impact of coal cleaning is relevant to the present analysis because the quantity of coal requiring such preparation is expected to increase in the future. With greater underground production and stricter environmental regulations, mechanical cleaning and washing of coal will continue to be an identifiable part of the coal fuel cycle.

As with coal extraction, an injury rate per million tons of cleaned coal was derived from the 1973 injury and production figures (National Coal Association 1976) and made specific for each coal production region. The amount subjected to cleaning was assumed equal to that mined underground, producing a weighted injury rate for each coal production region:

$$I_w = \frac{(I_c)(P_u)}{P_s + P_u} ,$$

where I_c = 1973 cleaning occupational injury rate per million tons (0.03 fatality rate, 0.13 nonfatality rate),

P_u = 1973 underground mined production in millions of tons, and

P_s = 1973 surface mined production in millions of tons.

This weighted rate was then applied to the anticipated increments in coal production resulting from industrial conversion (see Table 3.8). Summation of these incremental injuries by coal demand region is seen in Table 5.29 and by coal production region in Table 5.30.

Table 5.29. Estimated 1985 and 1990 Cleaning-related Occupational Injuries[a] Resulting from Increased Coal Use in Demand Regions as a Result of the Proposed Action

Demand Region	1985 Fatal Injuries	1985 Nonfatal Injuries	1990 Fatal Injuries	1990 Nonfatal Injuries
I	0.02	0.10	0.04	0.18
II	0.03	0.11	0.05	0.21
III	0.03	0.15	0.06	0.30
IV	0.13	0.56	0.27	1.08
V	0.07	0.33	0.10	0.42
VI	0.08	1.77	0.19	2.25
VII	0.01	0.04	<0.02	0.05
VIII	<0.01	<0.01	<0.02	0.02
IX	0.02	0.10	0.03	0.15
X	<0.01	<0.01	<0.02	0.02
Total	0.4	3.2	0.8	4.7

[a]The rates used to derive these numbers are per million tons of cleaned coal.

Table 5.30. Estimated 1985 and 1990 Cleaning-related Occupational Injuries[a] in Supply Regions as a Result of the Proposed Action

Supply Region	1985 Fatal Injuries	1985 Nonfatal Injuries	1990 Fatal Injuries	1990 Nonfatal Injuries
1	0.08	0.36	0.15	0.64
2	0.18	0.78	0.33	1.45
3	0.02	0.10	0.04	0.20
4	0.07	0.31	0.11	0.52
5	0.02	1.50	0.05	1.63
6	0.001	0.001	0.01	0.04
7	0.02	0.11	0.03	0.17
8	0.004	0.02	<0.01	0.04
Total	0.4	3.2	<0.7	4.7

[a]The rates used to determine these numbers are per million tons of cleaned coal.

The low occupational injury rate for coal cleaning is reflected in Tables 5.29 and 5.30. Overall, the greatest impact will occur as a result of meeting the increased coal demands of Demand Region VI. This is attributable primarily to the 1985 nonfatal injuries, which are about 50 percent of the total for that year. Coal cleaned to meet the consumption needs of Region IV will also have a relatively strong impact. This region is expected to have about 36 percent of the projected fatal and 18 to 35 percent of the nonfatal cleaning-related occupational injuries in 1985 and 1990 as a result of the proposed action.

5.9.4 Transportation

Coal transportation in this country utilizes a mixed mode system: railroad, truck, barge, and other minor modes such as pipeline and tramway. Rail is the principal mode of choice (see Sec. 5.2.2), with nearly 70 percent of the total national production shipped by rail. However, specific regional requirements influence transportation mode such that the percentage by rail will range from 21 to 100 percent in any particular region.

The physical constraints of the nation's inland waterway system, primarily a north-south transportation route, as well as the economic constraints of truck and other short-haul modes imply a limited future growth for coal transportation modes other than rail. Since rail transport of coal is presently the largest single mode and future prospects for its growth are better than any other mode, rail transport has been selected for estimation of regional impacts of coal transportation on accidental injuries. This analysis takes into account the variation observed in mode mix by region.

The health consequences of coal transportation are assumed for this analysis to take the form of accidental injury in the occupational and general public populations. Three injury measures are used to define the transportation impact; injury to the railroad work force, trespassers on railroad property, and injuries occurring as a result of highway grade crossing accidents. The sum of these three measures is believed to be representative of the magnitude of impact which will occur as a direct result of increased usage of coal related to the program.

Occupational injury rates related to transportation of coal were derived from fourteen years of data (1961-1974) on railroad employee accidents (National Safety Council 1976; U.S. Bureau of the Census 1961-1974). These rates (1.52 fatal and 158 nonfatal per 100,000 loaded railcars) were then applied to the appropriate amount of coal shipped by rail in each consumption region. The proportions shipped by rail were assumed to be the same in 1985 and 1990 as in 1977.

The estimate of nonfatal injury includes all reported cases of on the job injury to railroad employees. Since the majority of such injuries are minor in nature, nonfatal occupational injuries are assumed to represent a less intense individual impact than general public nonfatal injury resulting from rail transportation or occupational injury occurring in other phases of the fuel cycle. In 1974, 15,448 such injuries occurred to on-duty employees of the total national railroad system. An additional 156 fatal accidents occurred during the same time period.

The total railroad-employee injuries in both 1985 and 1990 (Table 5.31) is an estimated 13 fatal and 1330 nonfatal injuries. Coal shipments to meet the needs of Demand Region VI will be responsible for about 67 percent of these injuries. The near total dependence upon rail transportation in this region coupled with the program-related coal demand will result in occupational injuries for transportation that exceed the number anticipated for extraction. Demand Regions IV and IX will also be affected, but at a rate of about 1/7 that in Region VI.

Transportation-related injury rates in the public sector will be greatest in Demand Regions IV, VI and IX. Fatal and nonfatal trespasser injury rates per 100,000 loaded railcars (2.96 and 1.49, respectively) were derived from fourteen years of data (National Safety Council 1976; U.S. Bureau of the Census 1961-1974). The injuries referred to in Table 5.32 are the result of applying these injury rates to the appropriate amount of coal in each demand region. Since this measure uses the same base loaded rail cars, the percentage of total accidents in each region will be the same as rail employee injury. About 67 percent of the trespasser injuries will occur during transportation of coal for Region VI program-related increases in coal consumption. Coal transportation to meet conversion requirements in Region IV and IX will be responsible for another 20 percent of the fatal and nonfatal trespasser injuries. The low number of nonfatal injuries relative to fatal injuries is probably the result of unreported injuries; 13 fatalities, 6 to 7 nonfatalities.

The second component of public injuries considered in this report is the portion of the accidental injuries occurring at highway railroad grade crossings. Fatal and nonfatal injury rate coefficients were calculated on the basis of train-miles traveled per year using data from the Federal Railroad Administration (National Safety Council 1976; U.S. Bureau of the Census 1961-1974). For the interval of 1964 to 1974, the coefficients were determined to be 3.48 fatal and

Table 5.31. Estimated 1985 and 1990 Transportation-related Occupational Injuries[a] to Railroad Employees in Demand Regions as a result of the Proposed Action

Demand Region	1985 Fatal Injuries	1985 Nonfatal Injuries	1990 Fatal Injuries	1990 Nonfatal Injuries
I	0.23	23.9	0.37	38.4
II	0.17	17.7	0.29	30.1
III	0.18	18.7	0.34	35.3
IV	0.65	67.6	1.24	128.9
V	0.11	11.4	0.22	22.9
VI	4.63	481.3	8.56	889.8
VII	0.17	17.7	0.33	34.3
VIII	0.06	6.2	0.11	11.4
IX	0.62	64.4	1.24	128.9
X	0.05	5.2	0.09	9.4
Total	6.87	714.1	12.79	1329.5

[a]The rates from which these numbers are derived are per 100,000 loaded railcars.

Table 5.32. Estimated 1985 and 1990 Trespasser Injuries[a] Incurred During Transportation of Coal in Demand Regions as a Result of the Proposed Action

Demand Region	1985 Fatal Injuries	1985 Nonfatal Injuries	1990 Fatal Injuries	1990 Nonfatal Injuries
I	0.4	0.2	0.7	0.3
II	0.3	0.2	0.5	0.3
III	0.4	0.2	0.7	0.4
IV	1.3	0.6	2.5	1.2
V	0.2	0.1	0.4	0.2
VI	9.0	4.5	16.7	8.4
VII	0.3	0.2	0.6	0.4
VIII	0.1	0.1	0.2	0.2
IX	1.2	0.6	2.4	1.2
X	0.1	0.1	0.2	<0.2
Total	13.4	6.8	24.9	12.8

[a]The rates used to derive these numbers are per 100,000 loaded railcars.

7.08 nonfatal injuries per million train-miles traveled. These rates include motor vehicle passengers and pedestrians injured as a result of railroad crossing accidents.

Applying the calculated rate coefficients to regional demand assumptions for coal use in 1985 and 1990, estimates of the public injury at highway grade crossings were made. These estimates are presented in Table 5.33. From the assumptions of this analysis, Demand Region VI is shown to have 73 percent of the fatal and nonfatal injuries expected to occur as a result of facility conversion in 1985, and 75 percent of those expected in 1990.

Table 5.33. Estimated 1985 and 1990 Highway Grade Crossing Injuries[a] Incurred During Transportation of Coal to Demand Regions as a Result of the Proposed Action

	1985		1990	
Demand Region	Fatal Injuries	Nonfatal Injuries	Fatal Injuries	Nonfatal Injuries
I	0.3	0.6	0.5	1.0
II	0.2	0.3	0.3	0.6
III	0.2	0.4	0.3	0.7
IV	0.4	0.8	0.7	1.5
V	0.1	0.3	0.2	0.6
VI	9.0	18.8	17.8	37.2
VII	0.3	0.7	0.5	1.1
VIII	0.1	0.2	0.2	0.3
IX	1.7	3.6	3.4	7.2
X	0.1	0.2	0.2	0.2
Total	12.3	25.7	24.1	50.6

[a]The rates used to derive these numbers are per million train-miles, two-way distance between point of production and center of consumption.

5.9.5 Combustion

In contrast to the previous three cycle components, health impacts on the work force will be secondary to those affecting the public. The occupational injuries associated with an operating combustion facility are not expected to be significantly altered by fuel choice. Occupational health and safety guidelines clearly define procedures and work practices that must be followed to insure a safe and healthful work environment in a combustion facility irregardless of the fuel used.

Due to its physical nature, however, coal is a less convenient form of fuel for industrial purposes. The fuel and ash handling requirements of a coal-fired unit necessitate the employment of a larger work force compared to oil or gas-fired units of equivalent energy output. This larger work force size has the consequence of increasing the man-work hours per unit of power. Values taken from electrical power plant operation give the following rates for man-hours per MW_e; 0.113 for coal, 0.089 for gas, and 0.09 for oil (Olmstead 1971). Industrial fuel burning facilities are believed to have manpower requirements similar to those of the electrical industry. Thus occupational injury rates, on the basis of power output, would be expected to reflect the increased work force size in a similar electric power facility converted to coal use. No attempt was made to calculate the occupational injury rate per unit energy output for the present analysis.

The stack emissions from coal-burning facilities can have direct impacts on the public and evaluation of the long-term effects of additional air pollution on public health is necessary in the assessment of increased power plant and industrial coal use.

Investigators generally accept a causal relationship between air pollution and resultant adverse health effects. The classic air pollution episodes in the Muese Valley, Donora, and London have clearly demonstrated the adverse nature of population exposure to high levels of airborne combustion products. However, there is less firm agreement on the actual quantitative form of such relationships and many problems arise during attempts to estimate them. One approach used is that of the damage function, which is a quantitative expression of a relationship between exposure to specific pollutants and the type and extent of the associated damage (Hershaft 1976). In this formulation exposure is measured in terms of ambient concentration levels and exposure time, expressed as dose. The resulting physical or biological damage--health effect--is the response.

The data base for health damage functions involves both epidemiological and toxicological investigations. In epidemiological studies, the observed effects in selected portions of the general population are compared on the basis of ambient exposure levels. Toxicological studies involve deliberate administration of toxic agents to test animals. Ethical as well as legal constraints limit the use of human subjects in such experimentation; therefore, human health effects functions are developed principally on the basis of epidemiological studies. As a result, health effects damage functions tend to reflect the natural variation and measurement errors inherant in the epidemiological approach. Quantitative health effect projections should be carefully interpreted.

The Report of the Committee on Health and Environmental Effects of Increased Coal Utilization (the Rall Report) identifies three possible health issues resulting from increased coal use. They are (1) increased respiratory disease from acid sulfate production, (2) the possible link between urban air concentrations of polycyclic organic matter (POM) and the incidence of lung cancer, and (3) the potential health impacts from trace substances in ash. The Committee recommends the establishment of an improved national system of environmental data collection, modeling, and monitoring. Such a recommendation would go far in alleviating the recognized deficiencies in the present health impact data base.

The principal components of the emission stream have known effects on human health which include physiological irritation and direct toxicity. A carcinogenic potential has also been postulated for these emissions. Some of the more important emission stream components are discussed below.

5.9.5.1 Sulfur Dioxide

Sulfur dioxide (SO_2) was one of the earliest suspected toxic agents in air pollution episodes, and has therefore been studied extensively. In high concentrations, it is generally absorbed in the upper respiratory tract and never reaches the pulmonary region; but at low concentrations, most of the inhaled amount reaches the terminal bronchioles and alveoli. Thus, the effective dose received by the most sensitive parts of the respiratory system does not decrease linearly with decreasing atmospheric concentration. Subjects exposed to SO_2 in the pure state, under experimental conditions, exhibit no serious effects at exposure levels less than 5 ppm. However, in epidemiological studies as cited by Amdur (1975), SO_2 concentration greater than 0.25 ppm have been identified with "excess mortality" in the exposed general population. This apparent contradiction in the toxicity of SO_2 is resolved by the observation that in the natural environment, SO_2 rarely exists in the pure state. It is generally shown in association with particulate aerosols. These aerosols are thought to adsorb SO_2 and thus increase the effective concentration at the site of physiological action in an exposed subject.

Initial low-level exposure produces a slight temporary vasoconstriction which lasts about 10 to 20 minutes in a previously unexposed human subject, with measurable reduction in the elasticity of the lung lasting for somewhat longer periods of time. Subjects exposed over several days show slight changes in lung capacity and pulmonary resistance, and in blood chemistry. Long-term, low-level doses result in thickening of the mucus layer over the cilia, producing an effect similar to that seen following acute exposure (Amdur 1975).

In some studies SO_2 has been found to interact with other irritants, both enhancing and ameliorating their effects. An experimental subject habituated to SO_2, for example, will not react as strongly to a subsequent dose of nitrogen dioxide as one without prior exposure. Indications of a synergism have been found in studies involving ozone (O_3) and histamine; previous exposure to SO_2 will result in more severe reactions to those irritants.

5.9.5.2 Nitrogen Oxides

Nitrogen oxides (NO_X) are produced by the oxidation of organically bound nitrogen in coal and by the secondary oxidation of atmospheric nitrogen during the combustion of coal and most other hydrocarbons, especially at high temperatures and/or pressures. The two most important species are nitric oxide (NO) and nitrogen dioxide (NO_2, also known as nitrogen peroxide). Nitrogen oxides are important in the generation and regulation of ozone (O_3) levels and in producing the organic components of photochemical smog. The species most commonly found in the atmosphere is NO_2.

NO_2 is a strong irritant (National Academy of Sciences 1977). Human experiments at moderate levels have shown evidence of inflammation as measured by diminished lung compliance, but, unlike the effects of SO_2, this reaction seems to be delayed several hours after the onset of exposure. As with SO_2 and O_3, there is a protective habituation effect to the consequences of acute inflammation. The protection does not necessarily apply to effects other than acute inflammation. In fact, in the opinion of many researchers the reverse is true: the mechanism of habituation to the acute inflammatory response may be part of the effect of chronic toxicity. NO_2 seems to reduce ciliary action in the same fashion as SO_2.

5.9.5.3 Carbon Dioxide, Carbon Monoxide

In the Rall report, increased production of carbon dioxide is identified as a potentially significant result of increased coal use. Very large increases in atmospheric carbon dioxide (CO_2) could produce climatic changes by means of a "greenhouse effect" (see Sections 4.2.1.5 and 5.3.1), which could adversely influence population health from heat stress. The impacts of increased CO_2 emissions resulting from the FUA program are not expected to be significant compared to the global production of CO_2 emissions.

Carbon monoxide (CO) may be produced during incomplete combustion of coal, and is therefore most likely to appear when a concerted effort is being made to control NO_X emissions. CO is best known for its affinity to hemaglobin, combining to form carboxyhemaglobin (COHb), which has a very long residence time in the blood (USEPA 1970). At COHb blood levels greater than 1.3 percent over eight hours, persons with stable coronary artery disease (angina pectoris) may begin to note increased frequency and duration of symptoms; at blood levels of 1.9 percent, excess deaths may occur among people with pre-existing cardiovascular disease (Hackney 1976).

5.9.5.4 Hydrocarbons

The network of aromatic carbon compounds interspersed with various heterocyclic compounds which composes coal provides the potential for the formation of a wide variety of organic effluents, especially during transient operating conditions which permit incomplete combustion.

The consequences of hydrocarbon inhalation are complex because the inhaled substances are always in mixtures. This intermingling of compounds makes it virtually impossible in field studies to incriminate any single material as the causative agent of pathologic changes. However, in experimental situations several organic compounds arising from the combustion or processing of coal have been identified as either known or "suspect" carcinogens; others have been identified as strong eye and lung irritants.

The intensity of acute and chronic inflammatory reactions depend on the specific toxicological properties of the pollutant. Olefins or unsaturated aldehydes, for example, produce more noticeable irritation than do saturated aldehydes. Their toxicity increases with the addition of a double bond and decreases with increasing molecular weight (National Research Council 1976a). Polycyclic compounds have the most serious potential for carcinogenic effects. Polycyclic aromatics and aza-arenes derived from the benzanthracene skeleton have been shown to contain a number of strong carcinogenic agents (Freudenthal et al. 1975). The most widely studied is benzopyrene (National Research Council 1976b) which has been clearly established as a causative factor in skin and lung cancers among experimental animals.

According to the Rall Report, it is possible that increased POM emissions from coal utilization may result from the location of many small, inefficient industrial combustors within urban areas. The potential therefore exists for greater incidence of pulmonary neoplasm if an association of this disease state and the emission characteristics is proven.

5.9.5.5 Photochemical Oxidants

Photochemical reaction products can be considered as secondary products of combustion processes. These compounds result from the interaction with ultraviolet radiation and the oxidation of emitted hydrocarbons. Ozone and the PAN series are examples of this group. Photo-oxidation is also a pathway for aldehyde formation.

The production of photochemical oxidants is usually tied closely to combustion processes which release large amounts of unburned hydrocarbons, such as these in internal combustion engine exhaust. The combustion environment of industrial energy processes burning coal is not conducive to the formation and release of substantial quantities of the precursors of photochemical oxidants. Therefore, photochemical oxidant formation is not believed to be a significant issue for the proposed program.

5.9.5.6 Particulates and Trace Elements

A significant portion of coal combustion products are the microscopic solid particles and liquid droplets, termed particulates, formed during and after combustion. The size range for the particulate matter from coal combustion (0.01 to 10 μ range of equivalent aerodynamic diameters) neatly brackets the size defined for respirable particles. Thus, these particulates pose a significant potential for adverse human health effects. Direct combustion processes give rise to primary particulates while secondary particulates can be formed from the post-combustion interactions of gaseous products and sunlight. The sulfates, nitrates, and hydrocarbons usually result from photochemical reactions. The size range associated with these particles is 0.01 to 1 μ (Fennelly 1976).

The effects of particulate or particulate-borne emissions on human health are determined by three factors: the composition of the particulates, their size, and the amount of time they spend in contact with sensitive tissues. For example, particle size has a strong influence on the probability of particle deposition and the anatomical site in which deposition occurs in the lung. Particles less than about 0.01 μ in diameter tend to behave as gases and may not be deposited at all. Particles with diameters 0.1 to 1 μ are deposited predominently in the alveolar or pulmonary regions, while large particles show a greater tendency to deposit in the nasopharyngeal and tracheobronchial regions (Natusch and Wallace 1974a).

A cytotoxic material can influence its own rate of clearance. Such a substance can damage or destroy the phagocyte, thereby directly reducing macrophage action. Over time tissue reaction to a sequestered particle can result in the progressive segregation of the foreign body behind a mass of fibrous material, making removal more difficult. The formation of the silicotic nodule is an example of the latter type of reaction (Casarett and Doull 1975).

The toxic effect produced by respirable particles can also depend on the chemical species contained therein. Small particles are generally more toxic than large ones (Natusch and Wallace 1974b). A submicron fly-ash particle presents a double threat to human health. Not only does it reach the pulmonary region of the lung and remain there for extended periods, it also delivers relatively high concentrations of combustion effluents. Because they can absorb SO_2 and other irritant gases and vapors, respirable particulates have the ability to magnify their initial effects by holding high concentrations of these irritants in close proximity to sensitive tissues for protracted periods.

According to the findings of the Rall Committee, toxic effects from acid sulfates in combination with other particulates may far outweigh any effects from SO_2 or particulates alone.

The sulfate ion, for example, is often associated with small particles and aerosols and appears to be a potent irritant. This is probably due in part to the fact that the ion forms a very strong and reactive acid and also to the fact that it is so strongly associated with the particulates (Amdur 1975). Cations associated with sulfates are important mediators of irritant potency (Amdur 1971). Pure sulfuric acid (H_2SO_4) and ferric ammonium sulfate ($FeNH_4[SO_4]_2$) are the most potent forms.

Finally, particulates act as carriers of many trace elements and hydrocarbons in the effluent stream. Many organic particulates contain the known carcinogen benzopyrene and related compounds (National Research Council 1976b). Trace elements are capable of interfering with and disrupting the function of the central nervous system and other organ systems of the body unrelated to the respiratory system (Dulka and Risby 1976).

Contrary to other phases of the coal cycle, a quantitative assessment has not been included in this report for public health impacts of the increased air pollution from the proposed action. Considerable uncertainty exists in the estimation of health effects from the combustion phase of the coal cycle, where estimates range over several orders of magnitude (Comar and Sagan 1976). This is largely due to the lack of a reliable data base for predicting health effects from the various pollutants emitted from coal combustion and the effect of the EPA New Source Performance Standards and Best Available Control Technology for coal combustors regarding particulate and sulfur emissions in future years on a long-term basis. As pointed out by the Rall Committee, it is not possible to predict with confidence the ambient air levels of toxic components even when the locations of the sources and the quantities of emissions are known. This has introduced an unsatisfactory degree of uncertainty to all such estimations.

5.9.6 Waste Disposal

The potential health effects of ash and sludge disposal are sufficiently site specific to be unquantifiable at this time. They will depend on the amount of ash, mode of disposal and distance to disposal site. It is anticipated that the primary occupational health effects will result from exposure to fugitive dusts. If waste disposal takes place away from the site of combustion, the risk of vehicle accidents is increased.

The public health impacts of waste disposal will also take two directions. Persons close to the waste disposal site may suffer increased respiratory disease incidence related to the fugitive dusts. More important is the possibility of a contaminated water supply from the waste leachate or direct spillage into surface waters. Water quality has a significant influence on population health. Alkalinity is important because it influences the amounts of chemicals necessary to treat municipal water supplies. Insufficient alkalinity requires that additional chemicals be added to the water before distribution. The pH of the water affects its corrosive ability as well as the treatment processes of coagulation and chlorination. The solubility of metal compounds is also affected. Dissolved solids are undesirable because of their laxative effect on humans (primarily from magnesium sulfate and sodium sulfate) and the deleterious effect of sodium on certain cardiac patients. Suspended solids are important for their influence on effective chlorination of water supplies. Many of the dissolved metals found in water can be deleterious to human health. Barium, for example, is readily absorbed through the gastrointestinal tract and has a toxic effect on the cardiovascular system. Cadmium in drinking water can affect the bones, while lead can impair neurological and motor development and can damage the kidney in children (USEPA 1976). These kinds of public health impacts are all possible if the combustion wastes are not properly disposed. Leaching of trace substances from coal ash and flue-gas desulfurization sludge is identified in the Rall Report as a potentially significant source of public health impact. This possibility must be mitigated through careful monitoring of disposal sites. There is, however, little experience to indicate the leaching and migration rates of toxic substances from large-scale disposal as would be required by the proposed action.

5.9.7 Recommendations for Mitigation of Potential Health Effects

It is concluded in the report of the Committee on Health and Environmental Effects of Increased Coal Utilization associated with the National Energy Plan (NEP) that the elevation of gases and aerosols near or above current ambient level may be associated with increased respiratory disease, acute and chronic, including lung cancer. Two urgent considerations need answers: (1) identification of the chemical species in the acid particulate complex chiefly responsible for the health effects, and (2) quantification of the actual health impacts of defined amount levels of air pollution. It also is concluded in the Report that potential health impacts from increased coal use could be reduced by adherence to five policies. These policies are:

1. Compliance with federal and state air, water, and solid waste regulations.
2. Universal adoption and successful operation of best available control technologies on new facilities.
3. Compliance with reclamation standards.
4. Compliance with mine health and safety standards.
5. Judicious siting of coal-fired facilities.

The Committee's basic finding is that it is safe to proceed with the NEP through 1985 if strong environmental and safety policies are followed. Since the Rall Report analysis was based on an incremental coal use two and one-half times that of the FUA projections, it is therefore concluded that the FUA impacts will be minimal given these same considerations.

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6. UNAVOIDABLE ADVERSE ENVIRONMENTAL EFFECTS

Increased consumption of domestic coal as primary fuel instead of oil or gas at both existing and new major fuel-burning installations will cause unavoidable environmental impacts, even after appropriate pollution control measures are taken. In fact, the pollution control measures themselves present problems in the area of solid waste disposal. This section delineates the adverse effects which may occur for each impact area (air, water, land, etc.) and the potential to mitigate such effects.

6.1 AIR QUALITY

The proposed action is projected to result in increased ground-level concentrations of SO_2, particulates, and nitrogen oxides in 104 of the 238 Air Quality Control Regions (AQCRs) through 1985 and in 141 AQCRs through 1990. The predicted maximum SO_2 concentration increase is less than 2.5 $\mu g/m^3$. The maximum predicted regional total suspended particulates (TSP) concentration is less than 1.5 $\mu g/m^3$. The maximum base-case SO_2 and TSP concentrations during this same time period are 69 $\mu g/m^3$ and 75 $\mu g/m^3$, respectively. In this worst-case regional analysis it has been assumed that New Source Performance Standards (NSPS) will be the only restrictions on air emissions from combustion through the time periods analyzed. This places the limit at 1.2 lb $SO_2/10^6$ Btu, 0.1 lb TSP/10^6 Btu, and 0.7 lb $NO_x/10^6$ Btu.

In addition to these standards, the NSPS provisions of the 1977 Clean Air Act Amendments will require "the achievement of a percentage reduction in the emissions from such category of sources from the emissions which would have resulted from the use of fuels which are not subject to treatment prior to combustion." This requires that new facilities subject to Section III of the Clean Air Act install the "best technological system of continuous emission reduction ... which the Administrator (of EPA) determines has been adequately demonstrated." The use of naturally low-sulfur coals, while contributing to State Implementation Plan attainment, does not constitute a "technological system"; consequently, new emission sources may not rely on fuel characteristics in order to comply with emission limitations established under Section 111 of the Clean Air Act. It is probable that sulfur reductions of at least 85 percent and particulate reductions of 99.5 percent will be mandated. A state governor, the EPA administrator, or the President may prohibit major fuel-burning sources from using any fuels "other than locally or regionally available coal or coal derivatives." The operator of the fuel-burning source may be required to enter into long-term contracts for local coal and also to contract for additional emission abatement devices required to comply with emission standards.

If an area is not in compliance with one or more ambient air quality standards, a preconstruction permit required pursuant to Section 172 of the Clean Air Act (42 USC, Section 7502) may not be issued unless additional emissions from the proposed new source will be offset by reduced emissions from existing sources in the same AQCR such that total emissions after the new source begins operations are less than the total emissions prior to its permit application.

6.2 WATER RESOURCES

Many of the potential impacts on water resources are avoidable on a site-specific level: hydrologic and water quality protection is specified for surface and groundwaters in accordance with the Surface Mining Control and Reclamation Act of 1977 and other legislation. However, drainage from underground mines (with acidity, trace element, and dissolved solids loads) has proven difficult to control, even with the application of such technology as mine sealing. In addition to the obvious insults to water quality represented by unregulated effluent releases, even the discharge of effluents in accordance with environmental regulations assumes dilution by receiving waters in order to meet quality criteria for the protection of aquatic biota, drinking water, and other uses. Thus, the assimilative capacity of water resources is stressed. Some acidification of aquatic systems via acid precipitation is expected as a result of stack emissions. The long-term loading of aquatic systems with low-level inputs of trace contaminants from all parts of the coal cycle has poorly understood implications, but represents an unavoidable impact.

Strictly in terms of water consumption, the major unavoidable impact of the conversion policy is expected to be the water requirement of reclamation irrigation in arid coal resource areas.

6.3 LAND USE

The principal unavoidable, adverse impact on land use resulting from the proposed action will be the preemption of land for mining and disposal of combustion wastes. Although these lands will eventually be reclaimed, the land will be severely disrupted for relatively long periods of time during the mining and waste disposal processes. An estimated 20,000 hectares (49,200 acres) of land will be disrupted directly by surface mining during the period 1978 to 1990 and an equivalent amount may be indirectly disturbed for use as roads, rail lines, buildings, processing facilities, etc. Assuming a 40-year lifespan for each plant affected by the program, 133,000 hectares (328,000 acres) of land may be disturbed by the year 2030. Lands disrupted for waste disposal will amount to an estimated 10,300 hectares (25,500 acres) by 1990 and 69,000 hectares (170,000 acres) over the lifetime of the facilities.

6.4 ECOLOGY

6.4.1 Terrestrial

The major adverse impact due to the program will be losses of deciduous forests and grassland communities due to increased surface mining. After reclamation, decades will be required to recover the structure and complexity of forest communities. Although combustion emissions due to the program are not expected to achieve concentrations at a regional level to cause damage to terrestrial biota, non-vascular plants (e.g., lichens and masses) may be adversely affected.

6.4.2 Aquatic

The major potential impacts on aquatic biota resulting from this policy are expected to be controllable on a site-specific level. Nevertheless, residual impacts of an unavoidable nature to be expected include long-term ecosystem responses to water quality shifts; namely, effects on body burdens of contaminants, and effects on community structure and productivity. In general, community composition will tend to become simpler (less diverse) and productivity will decrease as a result of the impacts (water quality shifts and hydrologic alterations) produced by the policy.

6.5 HEALTH EFFECTS (ACCIDENTS)

On a national basis, increased coal use as a result of the proposed action is expected to result in the health impacts shown in Table 6.1.

Table 6.1. Summary of Health Impacts Expected to Result from Increased Coal Use due to the Proposed Action

Cycle Component and Exposed Population	1985 Fatalities (accident and disease)	1985 Nonfatal Accidental Injuries	1990 Fatalities (accident and disease)	1990 Nonfatal Accidental Injuries
Extraction and cleaning				
Occupational	9	551	16	1070
Transportation				
Occupational (railroad worker)	7	714	13	1330
General public				
Highway grade crossing	12	26	24	51
Trespassers on right-of-way	13	7	25	13
Disposal		Potential Source of impacts.		

Nearly half of all the national health impacts from the proposed action are expected to occur as a result of increased coal use in Demand Region VI. The remaining impacts are projected to occur as a result of increased coal use in Demand Regions IV, V, and IX. Increased production from underground mining will be reflected in coal extraction and cleaning occupational injury in Supply Regions 2, 5, and 6. The distance required to transport coal into Demand Regions VI and IX is projected to result in greater accidental injury for both the occupational population (railroad workers) and general population (highway grade crossing accidents and rights-of-way trespassers).

These impacts could be reduced by a policy of rigorous adherence to federal and state air, water and solid waste regulations, operation of best available control technology, and compliance with coal-mine health and safety standards.

7. IRREVERSIBLE AND IRRETRIEVABLE COMMITMENTS OF RESOURCES

Irreversible commitments generally concern changes initiated by the proposed action which, at some later time, could not be altered so as to restore the present order of environmental resources. Generally, these irretrievable commitments are the use or consumption of resources that are neither renewable nor recoverable for subsequent use.

7.1 MINERAL RESOURCES

The maximum coal demand that could be generated by this program is approximately 130 million tons of coal per year in 1990. The projected coal demand in 1990 is approximately 1257 million tons, so the maximum impact of this program would result in a 10.3 percent increase in demand. Current demonstrated coal reserve for the U. S. are 436,735 million tons. This program will only utilize 0.03 percent per year of these reserves. This does not result in a rapid depletion of current reserves, particularly when viewed against the alternative of using additional scarce oil and gas.

7.2 WATER RESOURCES

Water consumption because of this program will be minimal and is expected to be the water required for reclamation irrigation in arid coal resource areas. Aquifers which either exist above the coal or as part of the coal will be permanently disrupted by surface mining.

Low-level inputs of trace contaminants from all parts of the coal cycle has poorly understood implications, but represents an irreversible impact. In addition some acidification of aquatic systems via acid precipitation is expected as a result of stack emissions.

7.3 BIOTIC RESOURCES

Although land disturbance because of mining and waste disposal is considered to be short-term, some of the more complex habitats and some biota will be eliminated. The increased pollutant loading to aquatic ecosystems may have long-term or cumulative effects on regional aquatic productivity.

The increased combustion emissions due to the program are not expected to cause visible damage to terrestrial ecosystems. However, effects on ecosystems subjected to persistent long-term pollution levels are poorly known. These chronic and long-term effects take on added significance in natural ecosystems because of the relative permanence of the vegetation and other components, coupled with the delicate balances that exist between all components.

7.4 LAND-USE COMMITMENTS

Commitment of land resources for increased coal production and combustion in general is short-term and is neither irreversible nor irretrievable. Original productivity of the land can be restored after mining in most cases. Such reclamation is required by the Surface Mining Reclamation and Control Act of 1977. Landfill areas used for disposal of combustion wastes will be managed to promote the protection of health and the environment under provisions set out in the Resource Conservation and Recovery Act of 1976.

7.5 HUMAN RESOURCES

Two social impacts from the coal conversion program are considered irretrievable, but these can be attributed directly to the overall national program to shift to coal. First, there will be social impact on some western communities which may undergo a permanent lifestyle change as they change from a rural range and ranching economy to a more urban-oriented mixed economy partially based on coal resources.

A decrease in air quality is considered to be one indicator of the quality of life. On that basis, the second social cost will be a decrease in the quality of life. The slowing of improving air quality is not considered irreversible. Nevertheless, whatever additional gain in air quality in the next ten years that would have been made by the continued combustion of oil and natural gas will be irretrievably lost. These gains foregone will be irretrievable for that period of time that coal combustion clean-up equipment cannot compete with burning of natural gas and coal.

Concomitant with the increased use of coal are occupational and public nonfatal and fatal accidents. These accidents are projected to occur from extraction, cleaning, and transportation of coal.

8. RELATIONSHIP OF LAND USE PLANS, POLICIES, AND CONTROLS

The conversion of existing and construction of new natural gas- and petroleum-burning facilities to other fuels may impinge on local and regional plans and policies. With the greater land requirements for coal and waste storage of similarly sized coal plants, conflicts with local plans are likely to develop. Planned plant expansions may be preempted for space by land needed for coal handling facilities, or, because of land or pollution constraints, coal plants may be sited in less industrialized areas. Transportation access to the plant may be somewhat altered to ensure coal supplies to the plants. Conformance with local plans and policies will have to be evaluated on a site-by-site basis.

Several federal policies and laws have the potential to be in conflict with individual conversion sites. Many of these policies and laws are briefly described in Section 2; all are highlighted below. Conflicts may arise related to specific individual sites, mines, or waste disposal areas. Such conflicts will be resolved prior to Department of Energy (DOE) action.

1. Act: Prime and Unique Farmlands Policy
   Agency: U.S. Department of Agriculture, Soil Conservation Service
   Source: Secretary of Agriculture, Memorandum No. 1827, 7 CFR 762, and Fed. Regist. 43(1): 40304033

   This policy requires identification of prime and unique farmland associated with federal actions and requires that such lands be preserved whenever possible. Mining, waste disposal, and combustion effluents have the potential to conflict with this policy. However, the program is no different than any other siting decision in this regard.

2. Act: Surface Mining Reclamation and Control Act of 1977.
   Agency: U.S. Department of the Interior, Office of Surface Mining Reclamation and Enforcement
   Source: Fed. Regist. 42(239): 6263962716 (December 13, 1977); 30 CFR 700

   This law is designed to protect health and minimize damage to the environment from surface mining, to balance environmental protection standards with coal production goals, and to coordinate state and Federal regulatory programs. Because the program requires more produc tion of coal, this law may affect (in theory) the availability of certain coals.

3. Act: Federal Water Pollution Control Act of 1972 and Amendments
   Agency: Environmental Protection Agency
   Source: State-implemented standards

   The purpose of this act is to maintain and enhance water quality in the United States. Coal conversion will increase the number of coal piles and may add to runoff. Discharges to water bodies from coal conversion are controlled by NPDES permits. The U.S. EPA has delegated enforcement of the program to some states.

4. Act: Safe Drinking Water Act
   Agency: Environmental Protection Agency
   Source: State implemented standards

   The purpose of this law is to assure safe drinking water for the public. No violations of this law are expected because of the proposed action.

5. Act: Endangered Species Act of 1973
   Agency: U.S. Department of the Interior, Fish and Wildlife Service
   Source: Fed. Regist. 41: 4333943358 and periodic republications; 50 CFR 17

   This act not only calls for preservation of listed species, but it calls for preservation of their habitats and the identification and enhancement of critical habitats. Added space around specific sites converting to coal may be in areas where this law can be a consideration.

6. Act: Wild and Scenic Rivers Act of 1976
   Agency: U.S. Department of the Interior

The purpose of this law is to preserve certain selected rivers of the nation which, with their immediate environments, possess remarkable scenic, recreational, geologic, fish and wildlife, historic, cultural, or other similar values. No mines would be allowed to be opened as a result of the program which may impinge on this land.

7. Act: National Historic Preservation Act of 1966
   Agency: National Park Service, Advisory Council on Historic Preservation
   Source: Fed. Regist. 42(21): 6198-6362 (1977) and updates

   This law provides for protection, rehabilitation, restoration, and reconstruction of sites, structures, and districts; the law also encourages preservation. Conversions at specific sites would have to consider both any land use charges and air pollution impacts.

8. Act: Executive Order 11593, "Protection and Enhancement of the Cultural Environment" (May 13, 1971)
   Source: 36 CFR 800

   This Executive Order provides for furtherance of the purpose of the National Environmental Policy Act (NEPA), National Historic Preservation Act, The Historic Sites Act, and The Antiquities Act. It asserts that, "The Federal Government shall provide leadership in preserving, restoring, and maintaining the historic and cultural resources ... to assure that Federal plans and programs contribute to the enhancement of non-federally owned sites ... of historical, cultural, or archaeological significance." The conversions at specific sites would have to consider incremental pollution damage that may occur.

9. Act: Clean Air Act 1970 Amendments (1977 Amendments)
   Agency: Environmental Protection Agency

   The purpose of this law is to maintain and enhance air quality of the United States. This law controls decisions with respect to specific conversions and requires the concurrence of the Environmental Protection Agency. The U.S. EPA has delegated to the states the responsibility for enforcement plans and programs.

10. Act: U.S. Railroad Reorganization Act

    The purpose of this act is to consolidate, upgrade, and, in the case of less-used lines and ties, eliminate these lines from the nation's railway system. Specific sites may be located on lines that are destined to be abandoned. The impact of increased cost of conversion and disruption attendant truck movement, would have to be considered.

11. Act: Protection of Wetlands Executive Order
    Agency: U.S. Department of the Interior
    Source: Executive Order 11990 (May 24, 1977)

    The purpose of this order is to ensure wetlands are preserved and management of such areas is coordinated among local and Federal agencies. Sites converting near wetlands would have to consider water quality affects from coal piles or siting effects of sludge wastes.

12. Act: Coastal Zone Management Act of 1972
    Agency: U.S. Department of Commerce

    The purpose of this law is to manage and/or preserve coastal zone resources for optimal public use. The location of sludge ponds, coal piles and the transportation of coal or sludge would be regulated by coastal zone plans.

13. Act: Resource Conservation and Recovery Act of 1976
    Agency: Environmental Protection Agency

    This act provides for Federal regulation of disposal of solid wastes that represent a danger to the public. Coal wastes may be classified as hazardous. Guidelines on treatment and disposal are forthcoming. Type and size of disposal area may be significantly affected.

14. Act: Executive Order 11988, Floodplain Management
    Agency: Water Resources Council

    This Order is intended to protect lives in floodplains, and restore and preserve natural and beneficial floodplain values. Activities (mining, transportation, combustion, and disposal) in or affecting floodplains may be affected.

9. RELATIONSHIP BETWEEN SHORT-TERM USES OF THE ENVIRONMENT AND THE MAINTENANCE AND ENHANCEMENT OF LONG-TERM PRODUCTIVITY

The conversion of existing and construction of new utilities and major fuel-burning installations (100 million Btu's or greater) from oil or gas to coal and other fuels involves primarily an expansion of current levels of coal mining and a corresponding increase in coal combustion impacts. These uses of the environment are balanced by increased utilization of the nation's most available energy resource, coal. The maximum estimated increased coal demand due to the FUA is 130 million tons of coal annually by 1990. From the date when the FUA is implemented to the year 1990, combustion of approximately 143 million barrels of petroleum and 1.7 trillion cubic feet of natual gas will have been replaced by coal and other fuels.

Through increasing the use of coal, the proposed program will, in the short term, cause a redirection of petroleum products and natural gas to priority uses for which coal presently is not a suitable fuel. In addition, the program will use more energy to remove air pollutants due to the combustion of dirtier fuels, and NO_x, SO_x, and particulate emissions will increase. The program will also increase the quantities of solid wastes to be disposed of and the amount of land disturbed by coal extraction and processing.

The long-term benefits are conservation of increasingly scarce domestic petroleum and natural gas supplies and decreased reliance on imported petroleum products. The environment will be no different than without the program because the nation is likely to rely more heavily on coal. Because technology will improve coal combustion to a point where its emissions will compare reasonably well to current oil and natural gas emissions, air pollution in the long term will not become worse.

Because of the future increased reliance on coal irrespective of the program, long-term productivity over base case will not be affected. The long-term productivity of the environment will be impacted by the program only if vast quantities of domestic oil and natural gas are discovered which could justify continued use in powerplants and MFBIs. Productivity, as measured by economic activity and personal convenience and which depends on adequate energy supplies, will be maintained by the FUA. The increased productivity in the energy sector will cause some decline in productivity in terrestrial and aquatic ecosystems as a result of combustion effluents and expanded mining. Depending upon the land use before mining, production from land formerly used for agriculture and grazing would be temporarily diminished. In addition, wildlife habitat could be eliminated or limited. Land disturbance from mining and waste disposal is expected to be returned to a level of productivity equal to or greater than predisturbance. Compliance with air, water, and solid waste regulations will ensure environmentally acceptable increased coal use in both the short term and long term.

10. ALTERNATIVE ENERGY TECHNOLOGIES AND REGULATORY POLICIES

One of the main objectives (see Section 2 for others) of the proposed action is to allow the U.S. to be less dependent on natural gas and oil. The development and use of technologies based on U.S. coal or other energy sources (e.g., biomass, municipal waste) are encouraged by national energy policy through government-sponsored research and development programs and tax incentives.

The major part of this document deals with the impacts associated with burning of coal in conventional coal-fired boilers (CCFB). In this section, the impacts associated with candidate alternative programs and alternative energy technologies within the proposed program (FUA) are discussed. Candidate alternative programs must be able to reduce U.S. dependence on imported energy sources within the 1990 time frame with little or no economic or social penalties. Candidate alternative coal and non-coal technologies within FUA must be able to commercially generate, as either process steam or direct heat, at least 10^8 Btu/hr (10 MW), which is the minimum boiler size regulated by the FUA within the 1990 time frame.

Since the proposed program has been mandated by Congress, it is unlikely that an alternative program would be selected; however, each candidate alternative program is summarized in Section 10.1. Case-by-case considerations of environmental and technological parameters for existing and proposed facilities, on the other hand, may indicate that a particular candidate alternative energy technology within FUA may be more suitable than another or that no action is preferred. Information on impacts associated with each alternative will be summarized in Section 10.2. Finally, there are several alternative interpretations or policy options pertaining to the enforcement of FUA. These are presented in Section 10.3. Detailed information on environmental impacts will not be presented in the report since this was done in the environmental impact statements for the ESECA program (Federal Energy Administration 1977) and the Market Oriented Program Planning Study (Energy Research and Development Administration 1977c). Most of the conclusions regarding the relative impacts of the various alternative technologies in the following sections are from these two documents.

10.1 ALTERNATIVES TO THE PROPOSED ACTION

The available alternatives which could meet the objectives of the proposed action must decrease the domestic consumption of oil and natural gas in general and imported fuels, especially. The alternatives which may partially satisfy these objectives are the Oil and Gas User Tax, Crude Oil Equalization Tax, energy conservation programs, and petroleum from the Outer Continental Shelf (OCS). Because each of these alternatives has its own environmental and economic consequences, and because each differs in some important way from the FUA, none appears to be a perfect substitute. Each of these alternatives and the no-action alternative are discussed below.

10.1.1 No-action Alternative

The "no-action" (no regulatory program) alternative--continued and increased importation of oil and natural gas--is feasible. Many users of gas and oil would continue to use these fuels despite higher prices, if they considered the use of gas and oil as the best way to meet corporate operating needs. The no-action alternative would mean fewer conversions, less gas availability to priority gas users, and more imported oil in both the short and long terms. In addition, it would mean that foreign imports would continue to the extent that price is a less important consideration than using oil to meet environmental regulations. Even in cases where environmental considerations are not a factor, there will be industries for which the no-action alternative means continued reliance on imported oil, because such a decision does not significantly affect the cost of production. In these industries, continued use of oil would be less difficult than conversion to coal.

This alternative would be affected by other proposed measures in the National Energy Plan. If natural gas deregulation were assumed to occur by 1985, there would be a trend toward conversion even without the FUA because of increased natural gas prices, assuming static supplies. This "no-action" alternative would mean that increased coal use would take place over a longer time interval and that there would be fewer conversions in cases where price alone is not a primary reason for the use of natural gas. The short-term impact of "no action" would be to increase the susceptibility of MFBIs and power plants to natural gas curtailments. This susceptibility would be greatest between the enactment of the FUA and 1985.

The no-action alternative would reduce administration and paperwork. The FUA is complicated and will require a high level of administrative understanding in order to make the cost of compliance as easy as possible for industry.

Should significantly increased natural gas supplies become available from both conventional and unconventional sources, then its use may be an alternative to FUA and consideration could be made by Congress to alter the Fuel Use Act.

10.1.2 Oil and Gas User Tax

An alternative to the proposed action is an oil and gas user tax imposed on large users of oil and gas. As originally proposed, this tax was designed to apply to gas and oil consumption at new and existing facilities designed to burn coal as well as gas and oil. For powerplants, it was estimated that the proposed legislation would effectively tax oil to powerplants at 25 cents per billion Btu's and that the natural gas tax would be variable. Gas taxes would be aligned to the price of distillate oil and by 1985 the tax would make natural gas 50 cents less than distillate and by 1990 the tax on natural gas would make the two fuels equivalent in price.

Any taxes directed to industrial and utility users that raise the cost of energy generation by oil and gas significantly above the price of coal will increase the rate of substitution of coal. At some level of tax, this alternative will have the same effect as the FUA with exceptions noted below:

1. A tax will have a greater differential impact on geographic regions than the more even impact now anticipated to result from the FUA. Some users will shift to coal at low levels of taxation and others would require higher taxes. The south and south-central regions would probably require higher tax levels than the rest of the country in order to shift an equivalent amount of energy production to coal because of the present low cost and availability of natural gas.

2. At the level of tax originally assumed in the National Energy Plan, the impact on "voluntary" substitution of coal is not expected to be as great relative to the FUA, if the tax were substituted for the program. About 1.1 million barrels of oil per day were estimated to be saved in 1985 and 1990 due to the tax. There are several limitations on the effectiveness of these taxes.

Many non-fuel cost considerations enter into the fuel-use decision including environmental and regulatory costs. These other kinds of costs could cause any oil and gas users to delay conversion, if the incentive to convert is merely a tax rather than the FUA.

Under the proposed tax, many facilities would be converted based on the useful lives of existing boilers. Under the FUA, because of forced conversion there are some incentives to retire boilers early rather than convert and operate boilers to the end of their useful lives.

3. A final consideration is that the cost of passing the tax on to the consumer may be judged by the installation management to be an acceptable alternative to conversion. Substitution of coal requires the use of managerial talent and energy which may be directed to other areas of concern rather than energy use and consumption. This possibility always exists where taxes are considered rather than a regulatory requirement such as the FUA.

In summary, the oil and gas user tax is complementary to the FUA rather than a complete substitute to it, particularly as the tax level imposed is restricted to large installations and use of fuel in new boilers. A user tax would provide, however, an added incentive to convert, but is not likely to force an equivalent number of conversions as the FUA would at the tax level originally proposed to Congress.

10.1.3 Crude Oil Equalization Tax

The crude oil tax would allow newly discovered domestic oil to rise to the world oil price. This equalization tax has several important differential impacts than the FUA. First, the economic impact of allowing domestically produced crude oil to rise to world prices is far greater than the economic impact of the FUA. Second, the facilities using natural gas would not be directly affected by such a tax.

More than half of existing MFBIs are fired by gas rather than oil. In a regulated gas market, the crude oil equalization tax would increase the demand for natural gas. In an unregulated natural gas market, the price of this scarce commodity (natural gas) would rise to reflect its higher value. Consequently, the crude oil tax would not directly impact conversions of natural gas installations, but in an unregulated gas market, it would have an indirect positive impact on conversions to coal.

Compared to the FUA, the crude oil equalization tax would have a much different economic impact on society. Unlike the FUA, which is directly oriented to industrial and utility users, the crude oil tax would affect all users. The FUA will not affect the transportation sector, but the crude oil tax will have a significant impact on gasoline and other transportation fuel prices.

The complementary aspect of the FUA and the crude oil tax is that the acceptable cost of converting to coal in the FUA is linked to the price of oil. With a crude oil tax, it will be much easier to prove that coal conversion ordered by the FUA is justified on economic grounds, i.e., in regulatory findings to determine if an economic exemption is valid.

The primary difficulty in relying on these proposals rather than the FUA is that they have a much broader economic impact on society. As a result, the two measures (gas deregulation and oil tax) would be far blunter instruments to achieve the level of conversion estimated by the FUA.

10.1.4 Energy Conservation Programs

In the past, there were no concerted efforts to conserve energy because there was little concern over environmental quality and uncertainty of immediate and long-term energy supplies. More recently, however, air and water quality deterioration and shortages of energy resources, such as liquid and natural gas, have resulted in governmental action (i.e., the Energy Policy and Conservation Act of 1975) aimed at developing energy conservation programs. While these programs are alternatives to the proposed program, in that they reduce the demand for energy, they are not direct substitutes for the FUA because they cannot satisfy the expected energy needs in 1985 and 1990. According to estimates in the environmental impact statement for the ESECA (Federal Energy Administration 1977), 46 additional quads of energy will be needed by 1985 and energy conservation programs will eliminate only about 33 quads. Approximately 13 quads of energy will still have to come from energy sources such as coal.

From an environmental point of view, energy conservation programs would be a highly attractive alternative. Reducing the need for energy production and consumption would reduce environmental residuals and land and water requirements. A lower energy demand also provides the opportunity to generate needed energy from "cleaner" energy technologies and phase out "dirtier" energy technologies.

While energy conservation programs cannot prevent an increase in energy production and consumption, they can be utilized in conjunction with the proposed program to reduce the potential for environmental insults without the extensive development of mitigative technologies. In concert with these energy conservation programs, there would also be greater options with the FUA as to choice of energy technology to be employed.

10.1.5 Petroleum from the Outer Continental Shelf (OCS)

Offshore natural gas and oil reserves remain largely untapped and given (1) current high natural gas and oil prices, (2) an accelerated offshore lease program, and (3) technological breakthroughs in offshore drilling, they could replace the natural gas and oil used by facilities considered under the FUA by 1985. The USGS has estimated that there is a 95 percent chance of at least 20 billion barrels of oil reserves. Oil production could reach 42 million barrels per day by 1985. The FEA has estimated that there is a 95 percent chance of at least 153 billion cubic feet of offshore natural gas reserves. By 1995 offshore natural gas production could reach 6.1 billion cubic feet per year. Total energy production from these offshore reserves would be comparable to that from coal reserves estimated in the ESECA document.

Environmentally, utilization of offshore natural gas and oil reserves is less acceptable from an aquatic ecosystem viewpoint and more acceptable from a terrestrial ecosystem viewpoint. Aquatic ecosystem (including coastal habitat) impacts would be higher than for the proposed program because of the offshore drilling and laying of pipeline to onshore facilities. Oil spills and discharged brine would lead to increased concentrations of toxic chemicals. Turbidity due to drilling and laying of pipeline could decrease primary productivity, cause mechanical damage to respiratory structures and affect feeding behavior in aquatic biota. Benthic habitat will be altered or destroyed at the drilling site and along the pipeline corridor. However, once the well is fully operational, the major impacts would result from oil spills and transportation of oil or natural gas.

Terrestrial ecosystem impacts associated with OCS production, transportation, and utilization would be less than for those associated with greater utiliztion of coal reserves. Air pollutants are lower (by a factor of 20 for SO_x, 1 for NO_x and 8 for particulates) for OCS. Land requirements (and concomitant habitat loss) are also less for OCS since existing onshore facilities can be used for processing.

10.2 ALTERNATIVES WITHIN THE PROPOSED PROGRAM

10.2.1 Alternative Coal Technologies

The National Energy Plan (NEP) requires a greater utilization of domestic coal resources and suitable alternative fuels. Because of the tendency to use coal, alternative coal technologies will receive greater consideration in the research and development programs of the Department of Energy. While more funds are to be spent in this area, the 1990 time frame for the FUA limits the number of alternative coal technologies available for industrial use between now and 1990. While coal liquefaction, high-Btu gasification, and pressurized fluidized-bed combustion (PFBC) may be attractive alternatives in the near future, they do not appear to be commercially viable to provide a significant energy contribution by 1990 (U.S. Energy Research and Development Administration 1976, 1977; U.S. Department of Energy, 1978). The alternative coal technologies most likely to be available for significant industrial application before 1990 are coal gasification (low- and medium-Btu) (U.S. Department of Energy 1977) and atmospheric fluidized-bed combustion (AFBC) (U.S. Department of Energy 1978).

10.2.1.1 Low- and Medium-Btu Gasification

Low- and medium-Btu gasification technologies have been in commercial use for several years (Considine 1977). The two processes most commonly used, and thus likely to be used within the 1990 time frame, are Lurgi and Koppers-Totzek (U.S. Department of Energy 1978; see University of Oklahoma 1975 for process descriptions). It has been estimated by the U.S. Department of Energy (1978) that maximum industrial use of low- and medium-Btu gas will be 154,000 barrels per day (0.31 quads/year) by 1990. Low-Btu gasification plants are suitable to meet the minimal MW requirement of facilities; however, they must be located within a few miles of the industrial user because of inefficiencies in piping low-Btu gas (U.S. Department of Energy 1977a). Medium-Btu gasification facilities can supply sufficient fuel to fulfill the needs of several facilities; however, the industrial users must be within 50 miles of the gasification plant since medium-Btu gas can only be piped efficiently over short distances.

Environmental impacts associated with the extraction, processing and transportation of coal for the gasification plant would be identical to those associated with CCFBs. It is expected that impacts of construction of CCFBs and gasification facilities would be of a similar magnitude. Since the end product is a gaseous fuel, end-use impacts would be lower for gasification technologies than for direct combustion of coal. Airborne residuals from both gasification processes will be able to meet the New Source Performance Standards (NSPS) of 1.2 pounds per million Btu's ($lb/10^6$ Btu's) for airborne SO_x, 0.7 $lb/10^6$ Btu's for airborne NO_x, and 0.1 $lb/10^6$ Btu's for airborne particulates. As shown in Table 10.1, the airborne residuals from low- and medium-Btu gas production will be well below the acceptable levels of 600 tons per 10^{12} Btu's for SO_x, 350 tons per 10^{12} Btu's for NO_x, and 50 tons per 10^{12} Btu's for particulates. Higher airborne residuals from medium-Btu gas derived from Central Interior coal may limit the application of this technology in geographical areas that are at or near permissible air-quality standard levels for these air pollutants.

Land and water requirements would be similar for gas production as well as extraction, processing, transportation and end-use. Land requirements will be somewhat higher for low-Btu gasification processes since a separate facility must be located in close proximity of the industrial user in order to supply the fuel for the industrial boilers. Medium-Btu gasification facilities will require less land for storage of coal and associated ash than direct coal combustion processes since a single facility can supply the fuel for several industrial users. Alternately, however, medium-Btu gasification facilities may be required in the form of right-of-ways for delivering gas to the end users. If recycling of water is required at gasification facilities, water requirements and effluent discharges would be minimal, reducing the potential for impacts to aquatic ecosystems. A summary of the technological capabilities, land and water requirements, and environmental residuals can be found in Table 10.1.

10.2.1.2 Atmospheric Fluidized-bed Combustion

Atmospheric Fluidized-bed Combustion (AFBC) systems are presently at the pilot or demonstration plant stage and are expected to be commercially available in the near term. The technological and environmental advantages associated with this technology will make it a particularly attractive alternative for larger conventional pulverized-coal-fired boilers (100×10^6 Btu/hr). By 1990 it is estimated that industrial application of AFBCs will provide 0.99×10^{15} Btu's per year, or 15 percent of industrial needs (Farmer et al. 1977).

Environmental impacts associated with the extraction, processing, and transportation of coal for the AFBC boiler are identical to those for coal for CCFBs. End-use impacts are generally lower than for CCFBs with flue-gas scrubbers or low- and medium-Btu gas, particularly those associated with air pollutants. AFBC boilers can burn "dirty" coal in an environmentally acceptable fashion

Table 10.1. Alternative Industrial Energy Technology Characterizations[a]

	Low-Btu Gasification, Lurgi (675 MWt)	Medium-Btu Gasification, Koppers-Totzek (675 MWt)			Atmospheric Fluidized-bed Combustion (35 MWt)	Geothermal Hydrothermal (12.5 MWt)
End product	Low-Btu gas	Medium-Btu gas			Steam, heat	Steam, heat
1990 production estimates (quads/year)	0.08-0.26[b]	0.04-0.05[b]			0.99[c]	0.10[d]
Overall thermal efficiency (Btu's out/Btu's in)	77%	73-81%			70%[e]	100%[e]
Land requirements[e]						
Facilities (acres)	235	235			3.87	44-72
Storage (acres/10^{12} Btu)	0.01	0.01			0.40	0.07
Water requirements[e] (gallons/10^{12} Btu's)	4×10^6	4×10^6			NA	18.4×10^6
Residual environmental effluents (tons/10^{12} Btu)		NWC[f]	NAC[f]	CC[f]		
Air						
SO_x	3.32	17.6	8.2	41.2	175.7	0
NO_x	0	5.2	0	270.0	96.4	0
Particulates	0	5.4	0	5.0	24.3	0
Hydrocarbons	0	5.5	0	290.0	NA	0
CO	0	3.7	0	195.0	NA	NA
CO_2	NA[g]	NA	NA	NA	NA	515.5
CH_4	NA	NA	NA	NA	NA	38.3
NH_3	NA	NA	NA	NA	NA	46.7
H_2S	NA	NA	NA	NA	NA	12.6
Land						
Solid wastes	3500	3500	5400	8400	7350	1226
Water						
No discharge	0	0	0	0	0	0

[a]All data from University of Oklahoma (1975) unless otherwise noted.

[b]Data from U.S. Department of Energy (1977a).

[c]Data from Farmer et al. (1977).

[d]Data from Federal Energy Administration (1977).

[e]Data from Energy Research and Development Administration.

[f]NWC = Northwestern coal; NAC = Northern Appalachian coal; OC = Central coal.

[g]NA = not available.

(meets NSPS requirements) using only electrostatic precipitators to remove the higher particulates created by the turbulence of the coal bed (see Energy Research and Development Administration [1977b] for process description).

Land (and concomitant habitat loss) and water requirements are similar for AFBCs, CCFBs, and gasification technologies. AFBCs will require some additional land for storing spent sorbent from the boilers. If the technology to recycle spent sorbent is developed, land requirements for CCFBs and AFBCs would be very similar. Zero discharge and recycling of water from AFBCs would minimize impacts to aquatic ecosystems.

The technological, land and water requirements, and environmental residuals of the AFBC Program are summarized in Table 10.1.

10.2.2 Alternative Non-Coal Technologies

The alternative non-coal technologies likely to be feasible for industrial use by 1990 are geothermal (hydrothermal reservoirs), nuclear, biomass conversion, and municipal wastes utilization. Ocean Thermal Energy Conversion (OTEC) and solar are either economically and/or technologically precluded for industrial use in the 1990 time frame (Energy Research and Development Administration 1976, 1977; U. S. Department of Energy 1976).

10.2.2.1 Oil Shale

Estimates of total oil shale resources vary from 2 to 27 billion barrels of oil; however, only a small fraction of this may be recovered economically. Projected maximum production estimates are 300,000 barrels per day in 1990. This would not be sufficient energy to replace the oil used by facilities considered under the FUA.

Environmental impacts associated with extraction, processing, and transportation of the oil from shale would be of the same magnitude as those associated with coal extraction, processing and transportation. Land requirements (and concomitant loss of habitat) would be high due to mining, processing and waste storage. Water requirements would be high during processing and discharged process waters would contain toxic levels of chemicals and trace metals. End use air quality impacts would be lower for oil from shale than from coal, but there will be air quality impacts associated with processing operations. Aquatic and terrestrial ecosystem impacts would be comparable to those from coal use.

10.2.2.2 Geothermal

This technology is already in commercial use in California (e.g., Geysers and Imperial valley) and is expected to assume a more important role in supplying regional energy needs. Nationwide application of this technology will be limited because of geographical and piping constraints. The great majority of geothermal reserves are located in the western states, particularly California and Nevada, with limited reserves present in the Appalachian Mountains, Arkansas, Louisiana, and Texas. This will limit utilization of these reserves to a regional basis. Also, industries would have to be located within the geothermal field because of the inefficiency of transporting steam over distances longer than one mile. While there are three types of geothermal reservoirs (hydrothermal, geopressurized and dry hot rock), hydrothermal will receive the most emphasis because of the demonstrated technological feasibility for using these reserves. As a result of all these factors, only a small fraction of the potential 3400 quads of energy available from geothermal resources are expected to be available within the next 25 years. Current production rates vary from 40,000 pounds of steam per hour (shallow wells-Geyser) to 440,000 pounds of steam per hour (Imperial Valley).

Environmental impacts associated with exploration, extraction, and transmission differ from those for coal technologies in several ways. The dominant air pollutant associated with extraction and transmission is hydrogen sulfide, which may reach levels of 500 ppm. The detection level for hydrogen sulfide by humans is approximately 30 ppm. State standards for hydrogen sulfide vary. Additionally, steam must be vented periodically at the well and during transmission. This creates high noise levels (100 decibels at 50 feet and 90 at 250 feet) which displaces wildlife from the immediate area and can be irritating to humans in the immediate area. Mufflers can be installed on the relief valves to minimize these noise impacts. The vented steam can also contribute to local fogging in cooler climate areas.

During extraction at hot-water-dominated systems, brine is separated along with water and its disposal contributes to water pollution. Dissolved solids in the brine can reach levels of

250,000 ppm and must be treated before discharge or rejection. Land subsicence may also occur during extraction of geothermal resources and fluid must be maintained within the strata to minimize this substance. Reinjection of brine is one means of minimizing this. Extraction can also cause changes in pore pressure, either through withdrawal or reinjection, that may lead to instability and earthquakes along faulted or fractured zones.

Other air pollutants associated with exploration, extraction, and transmission tend to be lower than for coal technologies. Habitat losses as a result of support facilities, wells, transmission pipelines and access roads are much lower than for coal technologies. Aquatic impacts should also be lower for geothermal since it is likely that brines and water extracted from steam will be reinjected.

A summary of the geothermal technological capabilities, land and water requirements and environmental residuals can be found in Table 10.1. More specific information on geothermal impacts can also be found in Armstead (1977).

10.2.2.3 Nuclear

This technology is already in commercial use, primarily to produce electricity. Process steam can be produced; however, the cost would be quite high for smaller industrial users who may not benefit from economies of scale; and there are problems related to meeting NRC criteria on siting. Also, MFBIs are too small to effectively utilize nuclear power. Unlike the other alternatives discussed thus far, there are public apprehensions concerning the transport and storage of radioactive wastes from nuclear facilities. As a result of these factors and some of the environmental considerations stated in the next paragraph, it is unlikely that this will be a viable alternative for widespread industrial use in the 1990 time frame.

Environmental impacts associated with extraction, processing, and transportation of nuclear fuel are similar to those for coal, and so are probably greater than for geothermal. End-use impacts differ from both geothermal and coal in several ways. There are unique impacts associated with the transport and storage of radioactive wastes. Most of the radiation impacts of nuclear fuel are associated with the extraction and processing of uranium ores. Water requirements (approximately 50 percent higher) and thermal loading to aquatic ecosystems are also higher for nuclear facilities. On the other hand, SO_x, NO_x, and particulate airborne effluents and chemical effluents to surface waters are much lower at nuclear facilities.

10.2.2.4 Biomass

The term biomass refers chiefly to terrestrial and marine plant life, including short-rotation tree species, giant California kelp, and various agricultural, silvicultural, and animal residues. There are various processes which convert biomass to energy or secondary fuels. These processes include thermochemical conversion (liquefaction and gasification), bioconversion (anaerobic digestion and fermentation), direct combustion, and biophotolysis (production of hydrogen by photosynthesis). The present state of development of biomass technologies and anticipated production in commercially usable quantities indicates that there is little likelihood of major contribution to the industrial sector of process steam by the utilization of biomass as a direct or indirect fuel by 1990 (U.S. Department of Energy 1977, Electric Power Research Institute 1978) except for wood.

As a result of a U.S. Department of Energy Commercialization Task Force effort, the DOE, in late 1978, identified wood combustion as one of eight technologies ready for rapid commercialization, and appointed a resource manager to facilitate the rapid commercialization of this technology. In addition, the FUA may stimulate utility interest in the co-combustion of coal and wood (or possibly other biomass sources) as a result of the planning and design necessary under the requirements for conversion from oil and natural gas.

The forest industry and several electric utilities have been generating steam in large boilers for many years, utilizing forestry waste products. Although there are large quantities* of forestry wastes as residues from logging operations and from the manufacture of timber products, the economics of collecting and transporting such waste as well as the reliability of supply have limited the use of residues to localized situations. Wood, primarily from silviculture energy farms (i.e. tree plantations), is being seriously studied by some larger utilities and is considered to be the most feasible biomass feedstock for direct combustion in steam boilers.

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*Some estimates indicate that one third of the volume of wood harvested in the United States is unused.

The combustion properties of wood wastes are compared to three types of coal in Table 10.2. Due to the very low sulfur content of wood, sulfur oxide emissions from wood combustion are low. Although there will be other air and water pollution impacts from the combustion, harvesting, storage, and transportation of wood in tree crop plantations, these impacts should be significantly less than those encountered in coal utilization. Additional information on a comparison of fossil and wood fuels can be found in Battelle-Columbus Laboratories (1976).

10.2.2.5 Municipal Wastes

Municipal waste is a complex mixture of refuse consisting of residential and commercial solid wastes (trash, etc.) and sewage sludge. As collected, it contains an average of 30 percent moisture, 30 percent metals, glass and other inert materials, and 40 percent combustible materials (Gage and Chapman 1977). Typically, municipal solid waste, after shredding and air classification, has about 20 percent moisture, 15 percent ash and inert materials, and about 60 percent combustible materials (Table 10.2) (Bechtel Corp. 1975). Estimates of current quantities of municipal wastes produced in the United States vary, as do estimates of theoretically recoverable energy from these wastes. Table 10.3 presents such estimates for 1974. These rough estimates indicate that there are large concentrations of wastes available as fuel. If all the combustible waste discarded in 1974 were made available as fuel, wastes would provide about 7.38 quadrillion Btu (quads), or about 10 percent of the energy consumption of the United States (Gage and Chapman 1977). Municipal wastes would provide roughly 1.5 percent of the energy consumed.

Table 10.2. Combustion Properties of Municipal Solid Waste, Wood Waste, and Coal

Proximate Analysis (as fired)	Degree of Preparation of Municipal Solid Waste: Nominal	Degree of Preparation of Municipal Solid Waste: Maximum	Wood Waste	North Dakota Lignite	Western Subbituminous Coal (Wyoming)	Midwestern Bituminous Coal (Illinois #6)
Moisture (%)	25	5	35	36	29.0	12.9
Ash (%)	15	5	2	5.5	5.2	10.9
Volatile Matter (%)	48	72	48	28.01	33.4	35.5
Fixed Carbon (%)	12	18	15	30.4	32.4	40.7
Sulfur (%)	0.2	0.3	0.05	0.5	0.6	4.0
Higher Heating Value (Btu/lb)	5220	7830	5750	6870	8250	10740
Pounds Sulfur per Million Btu	0.35	0.35	0.09	0.73	0.73	3.72

From Gage and Chapman (1977).

Of the various processes that convert solid waste to energy (in particular, those for production of steam), two processes will be technologically feasible and economically viable by 1990. They are (1) direct combustion of raw or processed municipal solid waste and (2) co-firing of raw or processed municipal solid waste with coal. Direct combustion of raw or processed municipal solid waste for energy recovery is presently employed at 250 facilities in Europe and Japan and 12 facilities in the U.S. Traditionally, steam was produced by burning of raw refuse by connecting waste heat boilers to refractory-lined stoker-fired incinerators. Due to increasingly stringent air pollution standards, this technology has been superseded by the waterwall combustion furnace. Waterwall furnaces are generally easier and cheaper to maintain, smaller and less costly to build, and more efficient in recovering energy. The concept of utilizing mixed municipal solid waste as a supplementary fuel with coal in utility and industrial boilers has been adopted in a number of cities (in particular Union Electric Co. in St. Louis, Missouri) in this country. In this process, municipal solid waste is shredded to reduce particle size, and is then injected into an air classifier where a vertical column of turbulent air separates the waste fuel or refuse-derived fuel (RDF) from inorganic and heavy, dense organic materials. Recoverable materials also are often separated during this phase. Shredded waste is then passed over a screen or trommel to remove glass fines and the RDF is passed to a secondary shredder to further reduce particle size, generally to 1/4 inch to 2 inches. The RDF is then fired or stored. Storage of shredded or unshredded waste is required to accommodate daily and seasonal supply variations.

Table 10.3. Composition of Typical Municipal Solid Waste

Waste	Refuse (% by weight)	Moisture (% by weight)	Btu/lb (moisture/ ash-free)
Food Waste (12% of total)			
Garbage	10	72	6,484
Fats	2	0	16,700
Rubbish (64% of total)			
Paper	42	10.2	7,572
Leaves	5	50	7,096
Grass	4	65	7,693
Street sweepings	3	20	6,000
Wood	2.4	20	8,613
Brush	1.5	40	7,900
Greens	1.5	62	7,077
Dirt	1	3.2	3,790
Oil, paints	0.8	0	13,400
Plastics	0.7	2	14,368
Rubber	0.6	1.2	11,330
Rags	0.6	10	7,652
Leather	0.3	10	8,850
Unclassified	0.6	4	3,000
Noncombustible Wastes (24% of total)			
Ashes	10	10	
Metals	8	3	
Glass and ceramics	6	2	

From Bechtel Corp. (1975).

The proximate analysis of municipal solid waste in relation to coal indicates that the sulfur content in municipal waste (about 0.35 pounds per million Btu's) is low compared to the sulfur content of coal (Table 10.2). Municipal solid waste also has a low carbon content relative to coal. However, in general, RDF is inferior to coal in terms of heating value, handling, bulk density, and (generally) cost (Table 10.4). The advantages of using RDF are primarily environmental and/or solid waste management considerations. Most utilities, however, are not in the solid waste management business unless there is sufficient incentive for them to do so.

Table 10.4. Quantity and Fuel Value of Dry Combustible Solid Waste Discarded in 1974

Waste Source	Combustible Material Discarded (10^6 dry tons)	Fuel Value (10^{15} Btu)	Amount Available (10^6 dry tons)	Fuel Value Available (10^{15} Btu)	Currently Collected (% of available)
Municipal waste	101	1.64	60	0.97	100
Industrial waste	39	0.58	23	0.34	100
Agricultural waste					
Crops	322	5.16	278	4.45	2
Manures	36	0.48	26	0.35	100
Forestry	82	1.30	80	1.27	53
Total	580	9.16	467	7.38	

From Gage and Chapman (1977).

The Bureau of Mines (Haynes et al. 1977) conducted an analytical study to compare the concentrations of major, minor, and trace elements in the combustible fraction of waste collected in six geographic areas with the element concentration found in typical coal samples. The conclusions of the study were that the concentration of several trace and minor elements--silver, cadmium, copper, mercury, lead, and zinc--were one or two orders of magnitude higher in the combustible fraction of municipal waste than that found in coals. Titanium was found to be higher in the waste by a factor of four. The chlorine content was also an order of magnitude higher than in coal.

The land required for municipal-waste-to-energy systems is primarily for the plant site and landfill. The plant site area will vary with a number of factors, including the specific resource recovery process employed and geographical location relative to major population areas. In general, however, smaller processing plants (in the range of 200 to 500 tons per day) will require about 2 hectares (5 acres), and larger plants (in the range of 1000 tons per day) will require up to 4 hectares (10 acres) of land (Levy and Rigo 1976).

In a study by the Bechtel Corp. (1975), the landfill requirements for the solid waste effluents of a co-fired plant (10 percent RDF with 90 percent coal, on a heat input basis and 1000 tons per day of solid waste processing) were compared with a comparable (82.6×10^9 Btu/day heat input) 100 percent coal-fired utility boiler. The results indicate that the landfill volume required for the co-fired system is 687 cubic yards per day as compared to 229 cubic yards of ash from the coal-fired unit. However, if the landfill requirements for disposition of the 1000 tons/day of solid waste not fired in the coal-fired unit are considered, an additional 2960 cubic yards per day are required (assuming 25 lb/cu ft bulk density of raw waste). The co-fired system then results in an approximately 78 percent reduction in landfill volume requirements. A reduction in landfill disposal may minimize potential adverse impacts, such as leachate and groundwater contamination due to landfilling of municipal mixed solid wastes.

In addition to conserving natural resources through recovery of materials and energy, a primary purpose of resource recovery from municipal wastes is the reduction of adverse environmental impacts associated with other solid waste management options. Consequently, the use of solid waste in direct-combustion and co-fired system provides a major environmental benefit by reducing the volume requirements for sanitary landfills. In addition, municipal waste is routinely collected as part of municipal waste management and, except for possible additional transportation to the site for resource recovery, there are few undesirable environmental impacts of the collection of waste as compared to mining of coal. There are, however, undesirable impacts associated with the processing and combustion of solid wastes. The major air pollution sources are dust from the size reduction and classification operations at the processing plant, gaseous emissions at the boiler site, and transportation of the prepared waste. Other environmental impacts which may be greater for direct combustion and co-fired plants as compared to coal-fired plants include noise levels and adverse occupational health and safety effects. Noise levels due to resource recovery operations and municipal waste delivery vehicles may be an adverse environmental factor, particularly if such operations are near residential areas or other sensitive areas. Municipal solid waste contains human excrement and other potentially hazardous materials, including explosive materials. Additional provisions to protect employees will be required.

The ERA recognizes that a concerted effort among various federal agencies and industry is required to provide a greater catalyst for increasing the technological feasibility and commercial viability of systems utilizing municipal refuse as a source of direct or indirect energy. The FUA provides an opportunity for the evaluation of the feasibility of using municipal waste as an alternative to gas and oil.

10.2.2.6 Petroleum Coke

Petroleum coke is made from petroleum residues during the petroleum refining process. Coking is a form of thermal cracking of residual bottoms from the distilation of crude oil. These residuals ordinarily resist cracking by other means. The value of the coke produced and its subsequent use depends upon the crude oil source. Low sulfur and low ash crude oil results in a finished coke with similar properties.

The two primary methods of producing petroleum coke are delayed coking and fluid coking. Delayed coking is a semi-continuous, long-residence-time process often employed for low-sulfur crude oil sources. The product is a coke with sufficiently low sulfur and metal contents to be suitable for the manufacture of carbon electrodes and aerospace components. In fluid coking, thermal cracking of the residues occurs by a continuous-feed, fluidized-solids technique. The product is often not pure enough for use in the manufacture of electrodes. The majority of fluid coke produced is burned as pulverized fuel or briquettes in boilers at the producing refinery (Noel 1975).

The quantity of coke produced is a function of the intended use of the crude oil. A high demand for distillate fuel such as gasoline favors greater production of coke whereas high demand for residual fuel oil (i.e., by heavy industry) results in less production of coke. Since, under the FUA, utilities and MFBIs are directed to convert from burning oil and gas to coal, the effect will be to lessen the demand for residual fuel and potentially make coking more attractive.

Coke with intermediate sulfur content makes a reasonably good, low ash fuel for generating electricity. The majority of fluid coke produced is burned as a boiler fuel by the producing refiner. The petroleum coke consumption by the industrial sector for fuel uses in 1975 was 368 trillion Btu (U.S. Department of the Interior 1976). Utilities, principally in the midwestern U.S., will substitute petroleum coke up to approximately 10% for coal to enhance the Btu value of low-sulfur coal from the western states. The Btu value of petroleum coke is 14,000 Btu/lb as compared to 9500-10,000 Btu/lb for western coal. Use of coke also facilitates the removal of coal slag (Foulkes & Harper 1978).

Since petroleum coke contains the impurities from the original crude oil, the surfur content is often high, and appreciable vanadium salts may be present. Ranges of composition and properties (Perry and Chilton 1973) are as follows:

Composition and Properties	Delayed Coke	Fluid Coke
Volatile matter, wt %	8-18	3.7-7.0
Ash, wt %	0.05-1.6	0.1-2.8
Sulfur, wt %	-	1.5-10.0
Grindability index	40-60	20-30
True density, g/ml	1.28-1.42	1.5-1.6

Petroleum coke has exhibited increased concentrations of impurities, such as sulfur and metallics, over the past several years. This is due to increasing foreign crude importation which tend to contain higher impurity levels than domestic crudes.

Cracking operations may be a significant source of atmospheric emissions within the refinery (Jones 1973). Coke fines, which result from the movement and handling of coke, are a potentially hazardous material in the petroleum coking process since most of the non-volatile metals contained in the petroleum are concentrated in the coke and coke fines. Coke fines are generally trucked to landfills for offsite disposal. This wastewater from the thermal cracking generally contains high BOD levels, various oil fractions, COD, ammonia, phenol, and sulfides (Jones 1973). Such wastewaters, however, are generally treated as part of an overall wastewater treatment operation for the refinery. There is relatively little published information characterizing air emissions and water effluents resulting from the use of petroleum coke as a fuel. Consequently a more detailed environmental impact analysis is difficult at this time since additional characterization, monitoring, and measurements are required. Overall, however, based upon preliminary information, greater negative environmental impacts can be anticipated in the combustion of petroleum coke as compared to coal on a weight-per-weight basis.

10.3 POLICY OPTIONS

The environmental and economic implications of administration of the FUA are described in this section. Throughout the analysis a "worst-case" environmental assessment has been presented. In this worst-case approach, a maximum number of new coal facilities has been assumed. Generally speaking, the Secretary of Energy can exercise policy discretion to reduce environmental impacts by granting exemptions to the prohibition of the use of oil and gas. With respect to the worst-case approach, there is virtually no latitude for the Secretary to increase the use of coal and alternate fuel beyond the level assumed in this analysis. Program impacts on air quality as they relate to off-setting existing polluting sources (offsets) are discussed on page 5-23 of this EIS.

10.3.1 Applicable Environmental Requirements

One of the major purposes of the FUA is to require that all facilities meet applicable environmental requirements. These requirements include air, water, and solid waste emissions. Facilities are to meet both federal and state standards, regulations, and limitations. For further clarity, the Committee of Conference issued the following explanation:

> In agreeing to use the term "applicable environmental requirements" the conferees do not intend to refer only to those requirements which are applicable or in effect on

> the date of enactment of this Act. Rather, the conferees intend to include within the scope of that term any limitation, standard, or prohibition, or other requirement which subsequently becomes applicable under any environmental law. For example, the conferees are aware that several regulatory changes are anticipated under the Clean Air Act. Among these expected changes are the revision of state implementation plans, the regulation of previously unregulated pollutants and sources of pollution, and revision of certain national standards. The conferees expect and intend such new and revised regulations be counted as "applicable environmental requirements" for the purpose of this Act.*

The major purpose of the Act is to prohibit or, as appropriate, minimize the use of natural gas and petroleum as primary energy sources. Congress has issued a general prohibition against the burning of oil and natural gas in new powerplants and new MFBIs consisting of boilers. The authority to grant or deny exemptions is based on eligibility and evidence supplied to the satisfaction of the Secretary. The federal/state environmental requirements exemption will be granted if the Secretary is satisfied that compliance with applicable environmental requirements is a physical impossibility.

10.3.2 Discretion Over Types of Facilities Regulated

Because new powerplants and new MFBIs are generally prohibited from burning oil and natural gas, facilities eligible for an exemption must be reviewed by the Department of Energy when completed petitions are received. Facilities which meet eligibility requirements for an exemption and supply good-faith evidence supporting their contentions must be reviewed. The Secretary can, however, issue general prohibitions to MFBIs which are non-boilers. The Secretary may prohibit the use of oil and natural gas by category in such facilities. In this way, the Secretary's authority may be extended to facilities that may be built either as boilers or non-boilers, thereby ensuring equitable treatment by facility type in conformance with the purposes of the FUA.

In the programmatic EIS, a maximum use of coal and subsequently a maximum prohibition program for MFBIs has been assumed. Any prohibition order issued under the program must meet applicable environmental standards and requires a site-specific review pursuant to NEPA.

10.3.2.1 Powerplants

For existing powerplants, the Secretary has more discretion with respect to the prohibitions and exemption process. Congress issued general prohibitions to the use of natural gas in existing powerplants by limiting such use by 1990. Prior to 1990, only plants that used natural gas during 1977 would continue to be eligible to use natural gas, and only in prescribed proportions. Congress allowed an option to facilitate compliance on a utility system-wide basis rather than on a plant-by-plant basis.

The greater latitude of the Secretary over regulation of existing powerplants is subject to certain findings that DOE must make. These findings by DOE and their case-by-case application are subject to the discretion of the Secretary in distinction to the more mandatory nature of review of petitions to exempt new facilities.

10.3.2.2 Major Fuelburning Installations (MFBIs)

The Secretary's discretion to extend prohibition also applies to existing MFBIs. An important factor in the issuance of the prohibition order is whether the Secretary makes the finding that the facility has coal or alternative fuel capability and that such use is financially feasible.

The extent to which the Secretary prohibits use of oil and natural gas in an existing facility is a major discretionary area. With respect to the purposes of the law, oil and gas fuel saving is a benefit wherever it occurs, but the environmental implications are site-specific.

The subject areas about which the Secretary must make a finding if an existing facility did not have or did not acquire coal or alternative fuel-burning capability include: (1) substantial physical modification and (2) substantial reduction of rated capacity.

Several factors militate against the importance of existing facilities in the overall magnitude of use of coal or alternative fuels. First and foremost is the expectation that reasonable growth in energy consumption and natural retirement of older facilities will place emphasis on

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*Joint Explanatory Statement of the Committee of Conference, July 11, 1978, Section 103, Definitions.

new facilities (see Section 3). Another reason for emphasis on new facilities is that more options are available in the fuel use decision, primarily because there are far fewer cost constraints for the facility owner. New facilities can be designed to meet environmental requirements, burn lower-quality fuels, and overcome physical site limitations at a lower cost than retrofitting existing facilities. For new facilities, there is the option of building a plant at a different site. Many exemptions require that utilities must consider alternative sites prior to eligibility. There are also more options in improving on technology with new facilities compared to existing facilities, such as using fluidized-bed combustion.

In exercising discretion in authority to grant or deny exemptions, the Secretary could employ a lenient approach that would, in the granting of many exemptions, subsequently reduce environmental impacts. Limited use of exemptions, on the other hand, would mean closer adherence to the "worst-case" analysis assumed in this programmatic EIS. However, utilization of alternative fuels other than coal would be consistent with the strict approach and might also result in less environmental impact than that estimated in the worst case.

10.3.3 Principal Exemption Categories: New Powerplants and MFBIs

General Requirements

Although the exemption categories are numerous, the findings and demonstration of the petitioner of good-faith efforts to comply may be crucial in the number of exemptions granted. The Secretary has the discretion to define what constitutes an adequate showing of good-faith efforts and the regulations contain criteria and tests to be used. There are several general requirements, in addition, that must be satisfied prior to eligibility for the exemptions. These requirements include a demonstration by the petitioner that a fuel mixture cannot be used before the petitioner can be eligible for an exemption which allows a 100 percent use of petroleum or natural gas. A second requirement precludes DOE from granting a permanent exemption if DOE has found that use of fluidized-bed combustion is economically and technically feasible. Once DOE has made a finding that the use of fludidized-bed combustion is feasible, the petitioner will not be eligible for a permanent exemption unless it is demonstrated that, for the petitioner, fluidized-bed combustion is not feasible. For powerplants, an additional requirement is the necessity for the petitioner to show that there is no alternative supply of electric power available within reasonable distance and at a reasonable cost subject to the condition that use of such alternative power source does not impair reliability of service. All of these general requirements must be met before the petitioner can demonstrate eligibility for any permanent exemption except the peakload exemption. In addition, petitioners requesting a permanent fuel-mixtures exemption do not have to meet the general requirements for mixtures or fluidized-bed. Utility petitioners requesting a permenant cogeneration exemption do not have to meet the alternative supply of power requirement.

10.3.4 Policy Options in the Exemption Process

Although the exemption categories have been briefly described, they are not fully indicative of how the exemption process will proceed with respect to areas where discretion will be used.

Lack of Alternative Fuel Supply

The cost test under this exemption permits an exemption only where the cost of using coal or alternative fuel substantially exceeds the cost of using imported oil. In making this determination the Secretary will exercise policy discretion in applying the level of economic penalty that is appropriate to the use of coal.

For the analysis of worst-case impacts, the amount of coal burned in the various regions of the nation was modeled based on the relative cost of coal use versus the cost of residual oil. When a lenient cost penalty associated with coal was used, there was less coal use and when greater penalties were assumed there was more coal use. Greater penalties mean that the cost ratio of coal to imported oil use will be high, and a lenient cost penalty implies the reverse.

The results of this modeling effort are illustrated in Table 10.5. For example, at a "substantially exceeds" fuel cost penalty of 10 percent, in 1985 about 54 million tons of coal-burning in MFBIs captured in the economic cost test and at 50 percent fuel cost penalty, 72 million tons of coal burning in MFBIs are captured. The table is merely illustrative that most coal burning may take place in a rather narrow cost range. More important may be the obvious regional disparity in impacts, whereby at the 10 percent fuel cost penalty Demand Region VI accounts for over three-fourths of the program impacts. At higher penalties, Demand Region VI (mostly in Texas and Louisiana) remains dominant, but to a lesser extent. The heavily urbanized east and west coasts are not projected to be greatly impacted by the program.

The impacts in Table 10.5 are merely illustrative, because the actual definition of "substantially exceeds" will depend on a number of factors which are site-specific. For example, the illustrative example merely compared fuel costs of coal and oil but actual regulation of the program will assess the trade-off of capital cost and operation and maintenance costs of coal (or alternative fuel) with the cost of using imported oil. In other words, regulation will compare total costs where important elements in the fuel use decision would include the capital cost of meeting environmental requirements as part of the total cost. The setting of the "substantially exceeds" criterion is an important area of discretion. The impacts in Table 10.5 merely illustrate the importance of the test and do not define the "substantially exceeds" criterion.

Other Areas

Another general exemption is site limitation. The site limitation definition is restricted to physical factors in conformance with Congressional intent. Important in regulation is the DOE definition of what constitutes good-faith efforts to overcome site limitations. Again, this is an area where no precise requirement can be set, but discretion is necessary.

Table 10.5. Increased Coal Consumption in 1985 as a Result of the FUA: Illustration[a] of Relative Impacts
(millions of tons)

Demand Region	10^6 Btu/ton[c]	Fuel Cost Penalty (%)[b]					
		0	10	20	30	50	100
I	24	0.04	0.08	0.50	0.87	1.50	1.90
II	24	0.08	0.63	0.92	1.17	1.54	1.75
III	24	0.83	1.17	1.50	1.67	1.96	2.13
IV	23	3.22	5.39	5.65	6.13	7.70	8.86
V	23	0.70	1.21	3.22	3.83	5.04	5.43
VI	17	22.47	41.64	42.35	44.41	45.18	46.53
VII	19	0.26	0.26	0.52	0.95	1.32	1.42
VIII	19	0.11	0.47	0.53	0.53	0.74	0.89
IX	19	1.46	3.15	3.73	5.89	6.53	7.00
X	18	0.33	0.33	0.44	0.44	0.50	0.61
		29.51	54.33	59.36	65.89	72.01	76.52

[a]Illustrative only and does not purport to identify "substantially exceeds" cost test.

[b]Fuel cost only reflects price increases over imported petroleum and does not reflect increases in operating, maintenance or capital cost. However, some of the impacts of these latter costs may be implied from the fuel cost analysis.

[c]Based on Tables 3.4 and 3.5.

The Systems Compliance Option permits utilities to make the most efficient use of generating capacity without a plant-by-plant review of how natural gas is used. Under the option, utilities submit to DOE a plan of compliance, whereby by 1990 natural gas is reduced by 80 percent over current usage. Among other things the plan includes a commitment not to build baseload oil and gas facilities and requires a realistic timetable for the plan submitted. The System Compliance Option will particularly affect utilities in the southwest that currently have baseload natural gas units.

Other areas of discretion include the means by which reliability is evaluated for the purpose of demonstrating eligibility for the reliability exemption. Fuel mixtures will also require discretion in that no specific mixture of coal or an alternate fuel and oil and gas can be determined in advance of the particular operating conditions of the facility. For alternate sites for powerplants, there is discretion as to what represents an adequate showing for intermediate exemption and the general exemption. On the one hand, a select number of sites can be evaluated as fairly and reasonably as possible by the utility, or the utility may also have to develop an elaborate and supportive site-selection methodology as to ensure that "straw men" site candidates are eliminated. Sites can be selected to minimize environmental impacts or in some cases to prevent coal or alternate fuel burning instead of oil and natural gas. Thus the environmental impacts of this exemption must be determined on a site-specific basis.

The discussion of discretionary areas and exemption categories is not exhaustive. The focus of the EIS discussion is on permanent exemptions to new MFBIs and powerplants, as these facilities are expected to account for greater amount of shift to coal. In the modeling effort, it was assumed that all baseload coal use was already planned in the utility sector. Because of the nature of the regulatory process, many areas subject to policy will become explicit when petitions for exemption are received. The areas reviewed in this section are those that are believed to be important at this time.

10.3.5 DOE Authority Relative to Environmental Requirements

The Department of Energy has authority to grant or deny exemptions on the prohibition of oil and gas use. Exemptions to use oil and gas will be granted if applicable environmental requirements will be violated. Efforts to meet environmental requirements and use coal or alternate fuel will be demonstrated to DOE by the petitioner for an exemption. DOE has authority to judge the adequacy of the demonstration.

With respect to exemptions for peakload plants to use natural gas and intermediate plants to use oil, the Administrator of EPA or the appropriate state air pollution control agency must assess whether the use of coal or alternate fuel would result in or contribute to a violation of National Ambient Air Quality Standards.

With the exceptions noted above, the Secretary's authority in environmental matters is not modified, but the requirement for facilities to meet environmental standards is unequivocal.

10.3.6 Prohibition and Exemption Procedures

The regulatory process is designed to be largely an exemption process rather than a prohibition process. The number and importance of existing facilities over which the Secretary can issue prohibition orders may be small compared to the number of new facilities which may desire to burn oil or gas.

Owing to the nature of the exemption process, the Secretary will be petitioned for an exemption based on the petitioner's view that eligibility requirements have been met, and that the required evidence has been submitted. DOE will review submissions to determine whether they are complete. General requirements will be satisfied by the petitioner before review of eligibility for a particular exemption will be assessed by DOE. Efforts to overcome obstacles to the use of coal or alternative fuel will be assessed by DOE and adequacy of that effort may be considered insufficient. In such cases, no exemption will be considered unless the petitioner improves the level of showing of eligibility so as to satisfy good-faith efforts. For some exemption areas an adequate showing will automatically result in an exemption, while in other exemption areas the use of that exemption category is at the discretion of the Secretary. The distinction is not meant to define ease or stringency in application of the law, but to indicate that in some circumstances it is the weight of the petitioner's demonstration of eligibility and supporting evidence which is important, while in other areas the use of a particular exemption category would also involve discretionary latitude on the part of DOE. For example, reliability is generally conceded to be an important reason to use a particular fuel, but what constitutes a demonstration of reduced reliability (because of coal or alternate fuel use) may require extensive documentation. Public interest, however, is generally conceded to be a vague phrase, which may not in and of itself constitute a category for which many exemptions may be granted. The above examples illustrate two kinds of discretionary powers by the Secretary, and are not intended to characterize future findings.

10.3.7 Environmental Impacts of Policy Options to Exempt

For every exemption granted in the program, less coal or alternate fuel will be used instead of oil or gas. On balance, the environmental impacts of exemptions may be beneficial. Coal, municipal waste, bagasse, and pulp wastes may release residuals to air and water that exceed the amount due to the use of oil or gas. From a resource management viewpoint, the use of municipal waste, bagasse, and wood pulp waste all have the benefit of consuming materials that would otherwise be discarded. From the strict viewpoint of particulate emissions, however, the use of waste materials has no intrinsic advantage.

10.3.7.1 Environmental Exemptions - Applicable Environmental Regulations

Until the regulations are promulgated and the regulatory process has been implemented for some time, it is not possible to make precise statements about environmental impacts of granting or denying exemptions at the programmatic level, and certainly not for specific locations. The presumption is, however, that the air quality impacts will be the single most important factor in granting environmental exemptions. For new boilers, a determination of whether units qualify for an exemption depends on the future locations of industrial facilities relative to dirty AQCRs, fuel type, pollution control equipment and the ability to obtain offsets. In general, however, an air shed is inclusive of a metropolitan area, i.e., the boundaries of the air shed incorporate the metropolitan area. Although urban areas have become increasingly suburban in the last 30 years, it is unlikely that many industrial facilities will be located outside a metropolitan area. Most new MFBIs will probably be located in the same location as at present.

For power plants, their locational decisions are increasingly becoming independent of load centers, because of environmental reasons and for other reasons. Nuclear plants, by dint of NRC licensing procedure, must be located in low population areas. Coal plants require considerable land area and the trend is toward multiple plant sitings in remote areas wherever acceptable sites are found.

The environmental impact of granting an exemption will be beneficial in most cases with respect to air quality wherever the plant is sited. The environmental impact of exempting an existing facility will probably be more beneficial than an exemption of a new facility. New facilities can be planned so as to minimize environmental impact by meeting stringent new source performance standards, and by using best available control technology. Granting exemption to existing facilities would allow more growth for new facilities relative to cumulative air quality concentrations.

10.3.7.2 Site Limitations

Several environmental advantages may accrue to exemptions due to site limitations with respect to sludge disposal for existing facilities. There would probably be few environmental advantages to exemptions for new facilities if options on sludge disposal increased. Where facilities are located in built-up areas, an exemption for reason of site limitation will also benefit air quality.

10.3.7.3 Systems Compliance Option

Choice of the System Compliance Option may have several environmental advantages. Although the environmental impacts of fuel choice are site-specific, the energy objective regarding fuel choice is not a site-specific consideration, i.e., a barrel of oil or 1,000 cubic feet of gas saved is the same saving regardless of the manner in which it is saved. Consequently, this option allows greater flexibility to meet air quality objectives.

10.3.7.4 Other Exemptions

The above specific exemptions have a direct or indirect relationship to meeting environmental objectives. The indirect relationship is due to the location of an existing MFBI or powerplant in a highly urbanized area.

Other possible exemptions, including state and local exemptions, have a coincidental relationship to the environment. Each exemption under the other categories will result in fewer residuals, because oil and gas is burned rather than coal or other fuels. Indirectly, efforts to improve environmental cleanup control equipment may be encouraged by the FUA.

On a site-specific basis, exemptions due to innovative technology, fuel mixtures, fluidized-bed, and cogeneration may have a positive environmental advantage.

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11. ENVIRONMENTAL TRADE-OFFS OF THE PROPOSED ACTION

The national consequences of the proposed action will be largely undiscernible to the general public. However, on a smaller scale, particularly local, they may be significant. Some of the impacts are quantified in Table 11.1, although the quantifiable impacts are not necessarily the more significant ones. Because the proposed action is designed to meet air and water quality standards, the identifiable specific impacts can only be determined on a site-specific basis. Environmental trade-offs will be quantified and assessed in a site-specific evaluation for those facilities applying for exemption from FUA. Because quantified impacts will be assessed by DOE or other regulatory agencies during the permitting process, which falls outside DOE's purview, the summary of environmental considerations presented in Table 11.1 are summarized differently than the programmatic trade-off summary presented in Table 11.2 and 11.3. This separate presentation reflects the conclusion that the quantities presented in Table 11.1 are not the measure of the acceptability of the program. Rather, the quantities presented reflect a measure of magnitude of the program in terms of total pollutants produced.

11.1 ENVIRONMENTAL TRADE-OFFS: NEGATIVE IMPACTS

The environmental trade-offs presented in Table 11.3 have been described as having (1) minimal, (2) discernible but not significant, or (3) significant impacts. The categorization reflects a relative and qualitative assessment, as shown in Table 11.2. A discernible impact is defined as one that could be specifically linked at a particular site to the FUA. A discernible impact is one that is recognized as a separate and distinct impact of the proposed action. A minimal impact would not be discernible, and may be a near-zero impact. A significant impact is discernible and would result in the violation of existing or future national standards. The FUA does not allow such violation to occur; each construction or conversion must meet applicable environmental requirements, including new ones that may be enacted in the future. Accordingly, site-specific "significant" impacts will not be permitted by the proposed action. No known impacts were identified in the EIS which were considered equal in consequence to impacts already regulated (or impacts for which regulation is already being considered); i.e., the proposed action does not induce an activity for which new legislation should be considered.

11.2 ENVIRONMENTAL TRADE-OFFS: POSITIVE IMPACTS

Positive impacts in Table 11.2 were also treated as having minimal, discernible but not significant, and significant impacts. Because these benefits are so different than the environmental impacts, the benefits cannot be compared directly with the impacts. "Significant impacts" reflect those which depend directly on how fuel is used in utilities and major fuel-burning installations. "Discernible" is defined as a benefit which could be specifically linked to the action of converting a boiler under FUA, but the benefit does not necessarily depend on fuel use; it may depend on many factors unrelated to FUA. Some benefits may be important but they may not be discernible under this definition, because the definition requires a specific conversion to be linked to the identified benefit. For example, the foreign-relations benefits depend on the perception of how the U.S. is solving its energy problems, and the FUA is neither the total energy program nor is it the most visible aspect of the nation's energy program. This categorization of benefits require that in order to be "significant" or "discernible" an impact must have a direct rather than indirect effect on fuel use. FUA is directed to reduction of natural gas and oil use by 1990. Even with temporary exemptions of up to 10 years, nearly all conversions will probably have taken place by 1990. Priority use of natural gas and oil will be the most significant benefit.

11.3 DISCUSSION

The trade-offs of the FUA represent disparate benefits and impacts, with the environmental impacts being largely negative. The impacts of coal mining, combustion, and waste disposal will occur regardless of the proposed action. The main thrust of the proposed action is to accelerate these impacts to the 1980s and 1990s rather than during a later period when gas and oil shortages may force increased coal use through shortages and prices.

Table 11.1. Summary of Environmental Impacts of the FUA

Environmental Consideration	Impact, 1990 (maximum year)
Land Use	
Mining, waste processing	3300 hectares (8151 acres)
Coal storage and onsite processing	1900 hectares (4693 acres)
Combustion waste disposal	1700 hectares (4255 acres)
Air Pollutants	
Total emissions	
SO_2	1.2×10^6 ton
NO_x	0.7×10^6 ton
Particulates	0.1×10^6 ton
Annual incremental increase in ambient air quality (maximum)	
SO_2	2.5 μg/m^3
NO_x[a]	a/
Particulates	1.5 μg/m^3
Combustion Wastes	
Scrubber sludge	23.6×10^6 ton
Fly ash	28.9×10^6 ton
Water Use	
Mining	$5\text{-}19 \times 10^8$ gal
Mining waste disposal	10×10^8 gal
Reclamation irrigation (Supply Region 6 only)	6×10^8 gal
Health Effects	
Mining and cleaning	
Fatalities	16[b]
Nonfatal injuries	1070
Transportation	
Fatalities	62
Nonfatal injuries	1394
Combustion	c/

[a]The knowledge of atmospheric chemistry of NO_x is not sufficient to permit reliable results from modeling.

[b]Includes accidents and disease.

[c]Coal-combustion-related health effects cannot be accurately quantified at this time (see Sec. 5.9.5).

Table 11.2. Definition of Positive and Negative Impact Ratings

Rating	Positive Impacts	Negative Impacts
Minimal	Benefit has some relationship to fuel use, but cannot be linked to site-specific coal use.	Impact is generally known to be linked to coal utilization, but no site-specific use will cause a noticeable or measurable impact.
Discernible	Benefit is only partially obtained by altering fuel use; benefit also depends on many other factors unrelated to the FUA. Benefit can be linked to site-specific coal use.	Impact can be linked to a site-specific reduction in environmental quality, which may not be noticed by the public but can be calculated or measured.
Significant	Benefit is obtained primarily by changing the way fuels are used in the nation's industries; benefit can be linked to site-specific coal use.	Will violate existing or future national pollutant standards (air, water, or solid waste). Impact is discernable at the local level.

Table 11.3. National FUA Program-related Trade-offs[c]

Positive Impacts		Negative Impacts	
Impact	Rating	Impact	Rating
Increased national self-sufficiency in fuel use	Discernible	Increased particulates and SO_2[a]	Discernible
Extension of domestic oil and gas supplies	Discernible	Increased sulfate loading to water	Discernible
Increased flexibility in natural gas curtailment decisions with natural gas reserved for priority uses	Significant	Increased solid waste and scrubber sludge[b]	Discernible
		Increased coal pile and wastewater effluents[b]	Discernible
Improved balance of trade	Discernible	Increased release of trace elements from coal combustion	Minimal
Reduced pressure on the value of the dollar relative to other currencies	Minimal	Increased use of water	Minimal
Foreign relations benefit resulting from demonstration of a national energy policy	Minimal	Increased social impacts related to coal mining	Minimal
		Increased health risk	Minimal
Encouragement of use of fuels which otherwise might have been discarded as waste products (pulp, bark, municipal waste, black liquor, bagasse) in certain industries	Discernible	Increased costs to the consumer	Minimal
		Increased impacts due to coal-related labor strikes when they occur including transportation of coal	Minimal
Encouragement of use of advanced coal combustion technology	Significant	Accelerated depreciation of capital assets and cost of generating electricity and steam from specific facilities	Discernible
Reduced frequency of oil spills of small magnitude	Minimal	Increased stockpiling problems	Minimal
Increased employment	Minimal	Loss of wildlife habitat	Minimal
		Permanent disturbance or commitment of land due to mining	Minimal
		Increased emissions of hydrocarbons, NO_x, and CO	Minimal
		Increased damage from acid rain	Minimal
		Increased occupational health risk due to mining	Minimal

[a]Violation of National Ambient Air Quality Standards will not be permitted under the proposed action.

[b]Each potential fuel substitution must meet applicable environmental regulations and will be subject to future standards as they become law.

[c]The trade-offs presented in this table are general national trade-offs; there will also be site-specific impacts.

Rising prices of oil and gas would in time encourage increased coal use regardless of the proposed action. With only voluntary conversions the nation would be more vulnerable to oil embargoes, natural gas curtailment, and plant closings, than without such a mandatory program in the period from the present to 1990.

Through the FUA, the public, social, and environmental costs associated with increased use of coal can be considered explicitly. Insofar as domestic natural gas and oil prices remain below world levels over the next few years, the program can force increased coal use without the consumers' assumption of increased general fuel prices that would occur as a result of immediate price increases through taxes and national gas deregulation. Increased coal use will cost some money, but nowhere the amount it would cost society to accept a general increase in oil and gas prices to all users.

The irreversible nature of the proposed action lies in the requirement to make increased coal use in the next few years as financial and technological feasibility permit, rather than delaying those actions until gas curtailments or fuel prices force conversion. The proposed action is designed to allow for the appropriate timing of conversion so that specific circumstances are considered, as outlined in Section 10.4.

The environmental impacts of the proposed action will represent an incremental maximum increase of about 7 percent in mining- and transportation-related activities in 1985 and 10 percent in 1990. Acceptability of impacts will be considered on a site-specific basis as governed by applicable regulations. All environmental impacts may be valid grounds for not taking on specific increased coal use. Other factors will also be considered in making a determination about specific increased coal use action, as discussed in Section 10.4; however, environmental impacts are always a valid basis for a determination that increased coas use is not acceptable.

Many of the benefits and negative impacts of the proposed action are disputed. They cannot be expressed and weighed in dollars and a consensus achieved regarding how such a trade-off analysis arrived at some of the underlying weighing factors.

The national objective of increased fuel self-sufficiency is combined with the legislative desire to achieve such self-sufficiency in a manner that minimizes the environmental and social costs. These objectives are considered over-riding and sufficiently flexible in their achievement as to ensure that the environmental impacts are acceptable. The environmental considerations listed in Tables 11.1 and 11.3 and the policy options described in Section 10.4 illustrate the basis for making trade-offs in each site-specific fuel substitution.

As noted in Table 11.2, one of the significant benefits identified by the proposed action is the increased flexibility in natural gas curtailment decisions in the priority use of natural gas. A second significant impact is the encouraged use of advanced coal combustion technology as old units are retired, and as efforts are made to meet increasingly stringent new source performance standards for air emissions. On a site-by-site basis it can be discerned that specific fuel substitutions alter fuel use, adding to national self-sufficiency, extension of natural gas and oil supplies, decreased balance of trade deficit attributable to imports, and greater use of waste products such as bark, pulp, and municipal waste. These benefits will be traded off for impacts on particulate, sulfate, and SO_x emissions that may be significant in that they have the potential to violate existing air quality standards in some localities. This same potential to violate existing standards extends to solid waste as ash and scrubber sludge, and to wastewater effluents that are attributable to acid mine drainage, coal pile runoff and discharges of wastewater effluents at coal plant sites. Each of the impacts will be evaluated as to whether it violates existing national standards or future national standards (when they are promulgated into law). No "significant" impacts will be permitted (i.e., violation of national standards). Moreover, state and local standards will be evaluated as well. In the case of air pollution, a violation of state standards will be sufficient to prevent increased coal use. Other "discernible" negative impacts traded off will be a locally noticeable increase in coal truck movement at some sites and early retirement of some existing industrial boilers.

12. COMMENTS AND RESPONSES

Comments requiring response are reproduced in this Section, with responses presented adjacent to the comments, in the following order: federal agencies, state agencies and state-related organizations, and others (private industries, utilities, organizations, and individuals). Letters of comment not requiring a response are reproduced as Section 13.

Tennessee Valley Authority

TENNESSEE VALLEY AUTHORITY
CHATTANOOGA, TENNESSEE 37401
268 401 Building

FEBRUARY 02 1979

Mr. Steven A. Frank, Chief
Environmental Evaluations Branch
Department of Energy
Room 7202
2000 M Street, NW.
Washington, D.C. 20461

Dear Mr. Frank:

As you requested in your November 13, 1978, letter, TVA has reviewed your draft programmatic environmental impact statement (EIS) entitled, "Fuel Use Act." Within the 1978-1990 timeframe specified by the EIS, TVA will not be directly affected by this Act. This is because we have no definite plans for new coal-fired power plants to operate by 1990 and because peaking gas turbines are exempted from the Act. However, we expect to experience such indirect effects as higher prices for coal and for limestone, which is used with scrubbers in controlling sulfur dioxide emissions, as demand for these products increases.

We are enclosing some minor editorial comments noted in our review. We appreciate the opportunity to review this statement.

Sincerely,

Harry G. Moore, Jr., Ph.D.
Acting Director of Environmental
Planning

Enclosure

Tennessee Valley Authority (continued)

MINOR COMMENTS ON FUEL USE ACT ENVIRONMENTAL IMPACT STATEMENT

The criteria concerning miners in line 3 of Appendix C should list an average production of 9.15 tons per man per day, rather than 915 tons. Also, in Appendix E-13 a typical longwall face should be listed as 85 m to 100 m (260 to 305 feet), rather than 260 m to 305 m (85 to 100 feet).

On page 4-33 under West Virginia, the percentages for urban and rural residents do not total 100; and page 5-58 under section 5.8.1, first paragraph, appendix "L" should be appendix "K."

U.S. Department of Commerce

UNITED STATES DEPARTMENT OF COMMERCE
The Assistant Secretary for Science and Technology
Washington, D.C. 20230
(202) 377-4335

January 11, 1979

Mr. Steven A. Frank, Chief,
Environmental Evaluations Branch
Department of Energy, Room 7202
2000 M Street, N.W.
Washington, D.C. 20461

Dear Mr. Frank:

This is in reference to your draft environmental impact statement entitled "Fuel Use Act." The enclosed comments from the National Oceanic and Atmospheric Administration's Environmental Research Laboratories are forwarded for your consideration.

U.S. Department of Commerce (continued)

Thank you for giving us an opportunity to provide these comments, which we hope will be of assistance to you. We would appreciate receiving ten (10) copies of the final statement.

Sincerely,

Sidney R. Galler
Deputy Assistant Secretary
for Environmental Affairs

Enclosure Memo From: Dr. Eugene J. Aubert
Director, GLERL, RF24
NOAA

DEC 28 1978

U.S. DEPARTMENT OF COMMERCE
National Oceanic and Atmospheric Administration
ENVIRONMENTAL RESEARCH LABORATORIES
Great Lakes Environmental Research Laboratory
2300 Washtenaw Avenue
Ann Arbor, Michigan 48104

December 22, 1978

TO : Dr. William Aron
Director, Office of Ecology and Conservation, EC

FROM : Dr. Eugene J. Aubert
Director, GLERL, RF24

SUBJECT: DEIS 7811.18 - Fuel Use Act

The subject DEIS, prepared by the Office of Fuels Regulation, on environmental effects of the Fuel Use Act, has been reviewed and comments herewith submitted.

The Draft Environmental Impact Statement is reasonably well done and identifies that adverse effects on air, land, and water are to be expected from the use of coal instead of oil or gas in existing power utilities and industry. The degradation of the environment is the price to be paid to become less dependent on natural gas and oil. The program of conversion to coal will use only seven to ten percent of the total coal used in the nation.

There is insufficient mention in the DEIS of the potential effects of the Fuel Use Act on the Great Lakes. While this may be viewed as a regional or site specific problem, this is not the case. The present loads to the Great Lakes from atmospheric fallout and rainout are significant for many classes of contaminants. It is generally agreed that this present contaminant loading comes from atmospheric sources, some of which are within the Great Lakes basin but many sources are at great distance.

The scope of the assessment did not allow for detailed treatment of the effects of the act on specific areas. The statement does mention the types of effects which will likely occur, and these include those mentioned in your comment (see Secs. 5.4 and 5.6). Without additional site-specific information it would be impossible to quantify the impact of the FUA on the Great Lakes. DOE fully concurs that additional research into the effects of coal utilization on ecosystems is needed and should be pursued.

U.S. Department of Commerce (continued)

The DEIS recognizes that the additional use of coal will cause additional sourcea and contaminant loads of SO_2, acid precipitation (and resulting change in pH of land and water), toxic metals (in fly ash) and toxic organics (in incomplete combustion). While the DEIS is forthright in stating that the effects of these additional pollutants is the price we have to pay to become less dependent upon oil and gas, it is not clear that we know the full economic and environmental impact of this decision.

We are concerned about the effects on the Great Lakes from increased use of coal. Of particular concern are the increased pollution of toxic metals, toxic organics, changes in pH and changes in CO_2 which will come to the Great Lakes by both the atmospheric and land drainage/tributary pathways. These potential changes could have a major effect on the Great Lakes ecosystem and beneficial uses of this major international resource. GLERL has made a preliminary analysis of the potential effects of increased atmospheric CO_2 on the Great Lakes ecosystem and find that at some increase in CO_2, the annual carbonate cycle in Lakes Michigan, Erie and Ontario would be significantly changed with likely significant ecosystem effects. Our knowledge of the dynamics of the Great Lakes ecosystem is incomplete, however, and our assessment therefore an educated guess. Our knowledge is likewise incomplete on the long-term effects on the Great Lakes of the other increased contaminant loads associated with increased coal consumption (e.g., toxic metals, toxic organics, and changed pH).

It is recommended, therefore, that in parallel with increased use of coal, increased marine ecosystem research be undertaken to improve understanding of the complex processes and ecosystem dynamics so that more precise assessments can be made in the future and corrective actions can be taken as needed to protect the Great Lakes.

U.S. Department of Energy

Department of Energy
Region I
150 Causeway Street
Boston, Mass. 02114

MEMORANDUM FOR STEVE FRANK
DIVISION OF COAL UTILIZATION
ECONOMIC REGULATORY ADMINISTRATION

FROM: HAROLD J. KEOHANE
REGIONAL REPRESENTATIVE

SUBJECT: DRAFT PROGRAMMATIC ENVIRONMENTAL IMPACT STATEMENT - FUEL USE ACT

Any effects on the Great Lakes which do occur as the result of the FUA should be largely restricted to those induced by the atmospheric transport of contaminants and by the runoff of leachates from waste disposal operation. No significant mining impacts should result since little mining is expected in those watersheds which drain into the Great Lakes. The effects which do occur from the FUA will be incremental to and indistinguishable from, those resulting from the overall increase in coal use by utilities and industries.

U.S. Department of Energy (continued)

We have reviewed the above referenced document and have the following specific comments which relate to this Region.

On Page 4-21, Section 4.5.1.2 - Coal Resources - reference is made to the "small meta-anthracite deposits in Rhode Island". The conclusion that these geographic finds are too badly crushed and graphitic is completely wrong.

The text (Sec. 4.5.1.2, p. 4-21) has been changed in response to this comment.

Current studies by the Weston Observatory of Boston College under grants by the National Science Foundation (NFS) and the Bureau of Mines (BOM) have laid to rest the old theories that the deposits in the Narragansett Basin are of little value.

We suggest that:

1) the conclusions in the EIS be corrected;
2) the referenced material be updated to include Weston's recent publications; and,
3) the Narragansett Basin deposits are in Massachusetts as well as Rhode Island, and it should be so noted.

U.S. Department of Health, Education, and Welfare

DEPARTMENT OF HEALTH, EDUCATION, AND WELFARE
PUBLIC HEALTH SERVICE
CENTER FOR DISEASE CONTROL
ATLANTA, GEORGIA 30333
TELEPHONE (404) 633-3311

January 5, 1979

Mr. Steven A. Frank
Chief, Environmental Evaluations Branch
Division of Coal Utilization
Economic Regulatory Administration
Department of Energy
Room 7202, 2000 M Street, NW
Washington, D. C. 20461

Dear Mr. Frank:

We have reviewed the draft programmatic environmental impact statement on the Fuel Use Act. We are responding on behalf of the Public Health Service.

This statement deals with what are termed "overall program impacts" rather than site-specific impacts. These program impacts deal with greater use of coal and the construction of power plants that use coal. The exclusion of site-specific considerations for the time period between 1985 to 1990 is based on the reasoning that specific locations for these facilities are unknown. This is non-tenable since power companies are making construction decisions for these facilities at this time for 1985 to 1990. Since most of these facilities will be near large metropolitan

It is true that locations of coal-fired electric generating stations between now and approximately 1985 have been ascertained. However, the EIS analysis was predicated on the regulatory program primarily (almost solely) impacting industry and not utilities. New construction of utility coal plants ready for operation in 1985 would have been decided upon prior to the Fuel Use Act. New baseload powerplants are constructing for coal, as the primary fuel, with or without the Fuel Use Act.

areas, site considerations make a significant difference on localized impact of SO_2, NO_x, and particulate matter emissions and public health.

Another disturbing omission from this impact statement is the impact of conservation in consumptive energy use in the residential/commerical and the industrial sectors. Such measures that would reduce energy demand would reduce primary fuel use, thus achieving the same decrease by dependency on foreign and domestic fuel supplies. Such reductions in measures to conserve energy would also reduce emissions of regulated air pollutants and reduce consumer costs for energy. We believe these important socio-economic aspects should be taken into consideration.

We appreciate the problems associated with the current energy crisis and the need to shift from the use of natural gas and petroleum to coal. In our review of this statement, we were distressed to note that the section on health effects was very brief and addressed only occupationally associated accidents. No consideration was given to other occupationally related disorders which might be attributed to the working environment or to possible health effects associated with the accelerated use or combustion of coal products. It was equally disappointing to note that the material devoted to impacts on water quality was convincingly shallow.

The EIS recognizes that there will be contamination of aquifers, but it does not present a comprehensive strategy for minimizing this contamination.

The review of this EIS emphasizes the need for consultation by the DOE with agencies that have competency in human health considerations. These consultations should take place prior to the development of the draft document so that potential health problems are given at least equal consideration to other aspects of the proposed action.

Thank you for the opportunity of reviewing this document. We would appreciate receiving a copy of the final statement when it is issued.

Sincerely yours,

Frank S. Lisella

Frank S. Lisella, Ph.D.
Chief, Environmental Affairs Group
Environmental Health Services Division
Bureau of State Services

It is true that slower growth in energy consumption will reduce the rate of coal consumption. Energy conservation was treated in substantial detail in the ESECA Final EIS (Volume I, pp. VIII-13, -15, and -48 through -73) as well as the FUA Draft EIS. Conservation as outlined in the National Energy Plan also was a parameter in the base case modelling effort for the FUA Draft EIS as an alternative within the FUA program.

Occupational disease was addressed in Section 5.9.2. The health effects of coal combustion were discussed in Section 5.9.5. The Committee on Health and Environmental Effects of Increased Coal Utilization, whose basic conclusions on health effects impacts have been supported by the EIS analysis and which is cited in the EIS, was comprised of representatives of numerous agencies dealing with human health.

Water quality impacts, like the impacts on other environmental components, were treated generically since the overall effect of the act on the country was considered. Thus, it was beyond the scope of this document to treat site-specific impacts.

Aquifer contamination should be kept minimal due to the need, on a given site, to comply with local, state and federal requirements for the protection of such resources. Measures used to prevent aquifer contamination would vary from site to site and could include the lining of earthen disposal pits with an impervious material such as clay or plastic, the construction of concrete disposal basins, or the burial of waste in sealed landfills from which leaching has been demonstrated to be minimal.

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
WASHINGTON, D.C. 20460

21 FEB 1979

OFFICE OF THE ADMINISTRATOR

Office of Public Hearing Management
Department of Energy, Box WA
Room 2313
2000 M Street, NW
Washington, D.C. 20461

Dear Sir or Madame:

This letter is in reference to the Environmental Protection Agency's comment letter dated February 9, 1979, in which we classified the November 1978 Draft Programmatic Environmental Impact Statement on the Fuel Use Act as Category "ER-3". We would like to inform you that we have reclassified that Draft EIS as Category "ER-2" (Environmental Reservations -- Insufficient Information).

Thank you for your attention to this matter.

Sincerely yours,

William N. Hedeman, Jr.
Director
Office of Federal Activities (A-104)

cc: Steven A. Frank
Robert Stern

12-6a

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
WASHINGTON, D.C. 20460

9 FEB 1979

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OFFICE OF THE ADMINISTRATOR

Office of Public Hearing Management
U.S. Department of Energy
Box WA, Room 2313
2000 M Street, NW
Washington, D.C. 20461

Dear Sir or Madame:

The Environmental Protection Agency's comments on the Draft Programmatic Environmental Impact Statement on the Fuel Use Act dated November 1978, has been classified as Category "ER-3". Our procedure is to categorize our comments on both the environmental consequences of the proposed action and the adequacy of the impact analysis at the draft stage. "ER" means that we had environmental reservations concerning the impacts of the proposed action and "3" means that we felt there was inadequate information provided in the Draft.

Our comments are listed in the enclosure. The major issues which need to be addressed in the Final EIS are as follows:

- The analysis in the Final must be more closely aligned with the regulations as they are currently drafted (see comment I-A).
- Projected NO_x emissions must be analyzed (see comment II-A).
- The effect of FUA on both new and existing utilities must be analyzed (see comment II-B).
- More attention should be given to regional acid rain impacts (see comment II-C).
- The impact of FUA on PSD Class I areas should be given more attention (see comment II-D).
- The CO_2 Green House Effect should be given more attention (see comment II-F).
- The solid waste analysis in the Final should take into account the new criteria for disposal proposed under Section 3004 and 4004 of the Resource Conservation and Recovery Act (see comment III-B).
- The new NSPS standards should be used when analyzing the worst case for waste generation (see comment III-C).
- The Final should devote more attention to the alternative of using municipal refuse as a supplemental fuel (see comment III-F).

Comments are addressed in the detailed section following this summary of major issues.

U.S. Environmental Protection Agency (continued)

- Further analysis should be performed on the regional water quality impacts of FUA induced mining activities (see comments on Water Quality).

- A strategy for wetland impact mitigation must be developed and an approach for addressing this issue on a site specific basis must be devised (see comments on Wetlands).

- The financial estimates for railroad transportation should be brought into line with estimates used by DOI in the DEIS on the Federal Coal Management Program (see comment VI-A).

- Further attention should be given to the analysis of projected oil and gas savings (see comment VII).

- We request that the Final include regional estimates on the numbers of permit applications and site-specific EIS's which will be required under FUA to allow EPA regions to anticipate future workloads (see comment VIII-C).

We would welcome the opportunity to meet with you to discuss the enclosed comments. The person at EPA for follow-up on these comments is Thomas Pierce (755-0770).

Sincerely yours,

William N. Hedeman Jr.
Director
Office of Federal Activities (A-104)

Enclosure

February 9, 1979

ENVIRONMENTAL PROTECTION AGENCY
COMMENTS ON THE
DRAFT PROGRAMMATIC ENVIRONMENTAL IMPACT STATEMENT
ON THE FUEL USE ACT

The following comments have been organized by subject categories and represent agency-wide participation from both EPA headquarters and Regional Offices. They are intended to provide a constructive response to the environmental analysis provided in the Draft EIS.

I. Comments Comparing the Current FUA Regulations with the FUA DEIS

On page 3-2, the DEIS states that it was assumed for purposes of the analysis that no facility would be able to purchase offsets to locate in a non-attainment area. On page 3-5, the DEIS again states that no boilers in non-attainment areas for TSP, SO_2 or NO_2 would be forced to use coal. The regulations, as they are presently drawn, will tend to force coal conversion in non-attainment areas due to the severity of the cost test.

The cost of pollution abatement equipment was included in the modelling efforts and analysis to ascertain the number of boilers which could meet the cost test assumed by the worst case analysis. A high removal technology also was assumed so that this assumption did not understate the flyash and sulfur sludge volumes. The EIS does not state that there will be no coal use in non-attainment areas, but uses this as a representation for the total environmental exemption which would include problems of compliance with all applicable Federal, State and local standards.

The cost test was set at 1.5 times the cost of imported oil, or ($4.50-5.10/$10^6$BTU depending on whether #2 oil or residual oil is used). Many plants should be able to install considerable control technology and purchase offsets for less than this. In addition, DOE's proposed regulations require that a person seeking an environmental exemption apply to EPA for permits to burn all available alternate fuels and be turned down in formal proceedings on all of them, before DOE will consider granting an exemption. Figures 5.4 and 5.3 show predicted changes in SO_2 by AQCR in 1985 and 1990. We note that the predicted changes are minor in the industrial Northeast and Northcentral, and greater elsewhere, particularly in the Southwest. Are the low figures in the Northeast and Northcentral region derived from the assumption that no coal will be added in non-attainment areas?

The EIS states, in both cited references on pages 3-2 and 3-5, that while offsets may be purchaseable in non-attainment areas, it is uncertain whether the assumption "represents an overstatement or an understatement of the exemption's impacts." and that "...the assumptions used in the overstatement of increased coal use are likely to be more significant." Since most offsets, to date, have been within companies and there is very little available information on the costs of purchasing offsets, DOE believes its analysis to be justified and reasonable.

The analysis should be redone to take into account the regulations DOE has issued, and its intentions to enforce them in non-attainment areas.

Original estimates of increased coal use assumed no use in non-attainment areas. However, regional impacts were predicted without consideration of present attainment status.

II. Comments on Air Quality Analysis

A. The absence of any NO_x analysis is evident throughout the DEIS and yet, as stated correctly in the draft, "Emissions of NO_x have increased by 13% since 1970 due primarily to increases from motor vehicles and electric power production" (page 4-9). On page 1-12, table 1.5, increased emissions of NO_x are rated as having a "minimal" negative impact. How can the NO_x impact be rated if it wasn't analyzed? Merely stating that NO_x chemistry is too uncertain to permit modeling is not sufficient reason to eliminate all detailed discussion of nitrogen oxide emissions. We are not asking that a new model be developed, but that a comparison be made between total projected NO_x emissions and the base case. In keeping with your worst case scenario, you could assume that all NO_x was converted to NO_2 in order to obtain an estimate for total emissions.

The text has been modified to further discuss the potential impacts of the Act on NO_x concentrations (see Sec. 5.2.4).

A 4% increase over base case is projects for the maximum coal use year, 1990. This assumption has not reduced the NO_x emissions that would have been emitted by the fuel (natural gas and petroleum) being substituted.

B. Tied to the nitrogen oxides issue is the concern that although increased electric power production was one of the major contributors to increased NO_x emissions (Section 4.2.1.3), very little discussion was provided in the DEIS (Section 3.1) on the effects of FUA on the electric utility industry. Figures 1.3 and 1.4 seem to ignore any effect from the act on utility emissions. These figures should be corrected to account for this. On page 1-9 the summary of environmental trade-offs again only discusses non-utility use.

The vast majority of the utility sector construction for new base load plants utilize either coal or nuclear energy. Virtually all the remaining plants under construction, or planned, utilize natural gas and petroleum products for peaking and may be eligible to apply for peaking exemptions under the FUA. *The 8th Annual Review of Overall Reliability and Adequacy of the North American Bulk Power System*, published by the National Electric Reliability Council, shows increases in steam-coal generation capacity through the period covered (1987) but decreases in steam generation by oil and gas combustion capacity after 1982 and 1987, respectively. Projections through 1987 indicate that facilities used for peaking and intermediate load are less than 10% of total capacity and a much lower percent of total generation. Oil capacity increases only in combustion

No analysis of existing utilities was performed due to the assumption that they are all covered by ESECA (Section 3.1). This assumption can be challenged for the following reasons:

Under ESECA, the burden of proof was on FEA, and few if any, conversions resulted. Under FUA, the burdens of proof are reversed, which would tend to increase existing utility conversions. Indeed, one of the reasons cited for including existing facilities under FUA was the failure of ESECA. Because of the strong cost tests in FUA, and the restricted range of exemptions, plants that may not have converted under ESECA may well do so under FUA. In addition FUA prohibits the use of gas in utilities hy 1990 with very limited exemptions. This will force the conversion or replacement of additional plants. We therefore recommend that the analysis in the final EIS take into account utility emissions.

turbines and combined cycle units, which can apply for peaking and intermediate load exemptions. Gas generating capacity is constant. The oil increases are minimal compared to the annual increase in coal generating capacity. The extremely few units not included in the general utility exclusion, therefore, are not expected to have any distinguishable effects on the analysis.

The "burden of proof" shift noted in the comment is not nearly as pronounced for existing facilities as for new facilities. The use of gas in utilities is not expected to cause additional coal combustion and will be reflected in a switch to petroleum use in dual-fired units. The indications about the tendency of the utility industry, as noted above, show that the industry is voluntarily moving away from natural gas combustion except for peaking and the FUA provision will have very little effect on the utility industry's natural gas use.

C. The EIS states on page 5-22c, Section 5.3.2, that one major air quality impact resulting from implementation of FUA will be rain acidification. Referring to the last paragraph on page 5-23, DOE notes that although the Northeast is approaching undersirable levels of acid rainfall, the implementation of FUA will do little to aggravate the situation. Low ph rainfalls are a major problem in the Eastern and Northeastern United States. The Monongahela National Forest has been especially affected by rainfalls with a ph range of 3.4-5.0. Contaminated rainfall has affected photosynthetic rates in all floral types and although we cannot attribute a decrease in faunal species diversity and richness in the affected area, there is evidence that this may be the case.

The U.S. Forest Service is conducting an extensive analysis of the effects of acid rainfall on the Monongahela National Forest Ecosystem. We suggest that DOE contact the forest supervisor in order to review data compiled on the problem thusfar.

References to effects observed and attributed to acid rainfall in the Monongahela National Forest are as yet unsubstantiated by Forest Service staff contacted, although the rainfall pH data is regarded as basically accurate. Controlled laboratory experiments on effects of acid precipitation on photosynthetic rates of vegetation do not support the pH ranges cited (Ferenbaugh 1976) as being associated with direct effects on photosynthetic rates.

Reference

Ferenbaugh, R. W. 1976. Effects of simulated acid rain on *Phaseolus vulgaris* Fabaceae. Am. J. Bot. 63(3):283-288.

Table 5.14 on page 5-24, is extremely misleading. Conditions along the Ohio River Basin, a major coal-burning powerplant region, are already below the increment ph levels.

Table 5.14 is based on best available data - see comment of State of New York.

We believe that DOE's summary concerning increased levels of atmospheric sulfates and their relationship to rain acidification should be properly presented in light of the severe acid rainfall conditions that exist in parts of the Eastern and Northeastern United States.

If an effect were to occur, it would be in those areas where high base levels are combined with the highest incremental increase (a relatively small percent of the total area affected). Such areas would be included in some land areas within the most acidic (pH 4.22) isopleth of Likens (1976). The text has been revised to include further discussions of the effects of sulfates (see Sec. 5.2.4, p. 5-22).

U.S. Environmental Protection Agency (continued)

D. The EIS does not address the impact that increased coal-burning activity could have on a Class II/III area adjacent to a Class I area. Page 5-22 provides a brief discussion of the Class I issue, however, the necessity for pollution buffer zones around Class I areas was not discussed and should be.

The text has been revised to further discuss the potential impacts of the Act on PSD areas (see Sec. 5.2.4).

E. The EIS, on page 5-22, Section 5.2.4., notes that predicted SO_2 increases resulting from FUA coal-burning activities will have no impact on the high background concentrations of SO_2. In some AQCR's, (especially Appalachia) local ambient air quality levels will be affected considering the unusual topographic conditions in this area.

All applicable federal, state, and local air quality regulations must be met. Local effects will be considered by the proper authorities in a new-source review on a site-specific basis. Local effects were not considered in this document because site-specific locations are not known, but will be considered on a case-by-case basis by local regulatory agencies as incremental coal use begins.

F. Section 5.3.1 entitled Greenhouse Effect (Global CO_2) states that increases in CO_2 and particulate emissions could affect the climate of the entire earth, but then discounts the "greenhouse effect" by arguing that the uncertainty of the effect is so large that no definitive conclusions can be drawn. Although this is an area of much speculation and uncertainty, a more detailed discussion of the greenhouse effect in general, and the related impacts of the Fuel Use Act in particular, is needed. This effect will be more pronounced as a consequence of switching from oil and gas to coal combustion as coal liberates approximately 1.3 times as much CO_2 per BTU compared to oil, and 1.8 times as much as gas. We realize that the CO_2 greenhouse effect is of a global nature and that the incremental contribution to global CO_2 levels due to FUA will be minimal, however, it is important that each incremental contribution be analyzed.

The text has been modified to further discuss the potential impact of the Act on the global CO_2 budget (see Sec. 5.3.1). Because it is true that there is much speculation and uncertainty regarding the effects of CO_2 and particulate emissions on the climate, the discussion is not detailed.

III. Comments on Solid Waste Analysis

A. It is very difficult to evaluate whether the Act's impact on solid waste generation has been estimated correctly since the document failed to provide an estimate of the megawatt capacity of the industrial boilers in the non-utility sector which will be affected by the regulations. We request that this information be provided on an industry-specific basis to insure that the waste generation estimates are accurately determined.

Assumptions and sample calculations used for estimating solid waste generation are given in Appendix L.

B. The section of the EIS (page 2-9) addressing the Resource Conservation and Recovery Act (RCRA) does not address the criteria for disposal proposed under either section 3004 or 4004 (of RCRA). The 4004 criteria were proposed in February 1978 and the 3004 criteria, while only published this month, have been available in draft since March 1978. An estimate of the impact of these regulations should be provided in the final EIS.

See text revision (Sec. 5.5.5).

U.S. Environmental Protection Agency (continued)

C. The EIS states that it is assuming the worst case for waste generation. However, it also indicates on page 1-2 that the New Source Performance Standards in effect prior to the Clean Air Act amendments of 1977 are the basis for the estimates. The regulations which have been proposed since those amendments were passed will result in a significant increase in the amount of solid waste generated. The worst case analysis should be modified to reflect the rulemaking proposed this past September. (See proposed NSPS for SO_2, NO_x and TSP for Electric Utility Steam Generated Units, 43 FR page 42154, September 19, 1978).

In the worst-case analysis for waste generation, it was assumed that 90% of the sulfur and 99% of fly ash are removed as waste. This is based on the application of Best Available Control Technology (BACT).

D. The table on page 1-10 provides a chart of combustion wastes and land use. It is not clear whether the amount of fly ash and sludge estimated to be generated are national totals or only those which are the result of this Act. If the figures represent the latter, then the impact of this Act on solid waste generation is extremely significant and could represent a doubling of the amount of fly ash and sludge already estimated to be generated.

See revised Tables 1-10 and Section 5.22.

E. Discussions on page 5-54 and 6-2 both indicate the land required for waste disposal. On one page the estimate is given as 33,000 hectares and on the other it is listed as 44,000. These numbers appear to be contradictory and require further explanation.

The figures on pages 5-45 and 6-2 have been revised and are now consistent.

F. Another issue which was not discussed in the DEIS relates to the implementation of RCRA disposal regulations. Tighter controls over land disposal of solid waste will reduce the amount of land available for waste disposal. Facilities converting to coal will find themselves in fierce competition with cities and counties for a limited amount of landfill space. An alternative which we feel should be analized in the final EIS would be to require facilities converting to coal to explore the feasibility of either using municipal refuse as a supplemental fuel to coal or purchasing energy from municipal resource recovery facilities. (This policy is mandatory for Federal agencies that generate heat, mechanical or electrical energy from fossil fuel in systems that have the technical capability for using recovered material and recovered-material-derived fuel under section 6002 of RCRA.) Many cities have rejected resource recovery because they lack a market for materials or energy. Implementation of the Fuel Use Act would create new energy markets where they previously did not exist. Another benefit of this approach is the reduction in landfill volume needed to dispose of municipal and utility type refuse, as pointed out in Section 10.2.2.4. The overall impact of the Fuel Use Act with respect to solid waste disposal could change from negative to positive. We request that the above option be discussed in detail in the FEIS and that its projected impacts be analyzed.

See revised Section 5.5.5 for discussion of RCRA disposal regulations.

IV. Comments on Water Quality

A. Referring to page 1-5, Section 1.3.3, we note that major water quality impacts will occur in coal supply regions West of the Mississippi and in Central and Southern Appalachia. Although the Document states that sedimentation resulting from mining activities will be greatest in the above Regions, it discounts program-related acid mine drainage impacts in Regions II and III. The Central and Southern Appalachia region is notorious for having entire watersheds with ph values less than 5 and in some cases, streams in that region rarely exhibit pH values greater than 3. The climatology of the

For an expanded discussion of the water quality impacts to be expected in the Appalachian region, see the main text (e.g., Secs. 5.4 and 5.6).

area (precipitation greater than 40" annually plus extremely humid conditions) is conducive to high runoff due to saturated soils and steeply sloping topography. Furthermore, the disruption of natural drainage patterns from surface mining combined with haul road and railroad rights-of-way preparation will further contribute to acid mine drainage conditions. A discussion of these impacts should be included in the final EIS.

B. Increased erosion activity resulting from related mining activity will cause increased turbidity in stream systems in the mining regions. Turbidity values can approach readings as high as 200-500 Jackson Turbidity Units (JTU's) with a subsequent adverse impact to species diversity and richness. Aquatic life impacts will be extremely high in the Appalachian region, (page 1-9, Section 1.3.5.2), yet the EIS does nothing to mitigate these impacts. The site-specific EIS will detail impacts particular to each coal supply region. However, DOE should be aware of our past and present gains in the control of sedimentation, and increased aquatic life enrichment in the Appalachian streams. FUA related impacts to those areas should be adequately anticipated and mitigated.

See response to Comment IV.A. DOE is aware of the progress being made in the control of sedimentation derived from mining in mountainous regions. However, mitigation of potential impacts will have to occur on a site-specific basis as directed by local, state, and federal laws and enforced by regulatory agencies. The DOE has no authority to impose mitigation or force compliance with laws governing the characteristics of the effluents.

C. Referring to page 5-26, Section 5.4.1.1, we note that surface and groundwater hydrology will be severely affected by FUA mining activities. The EIS admits that denuded landscapes combined with large amounts of precipitation will contribute to increased flood stages in stream networks in the vicinity of the mining activity. This is especially true in the Appalachian physiographic region. Substantial increases in storm water runoff will generate higher flow values causing stream bank erosion and subsequent flooding of floodplain communities. This issue and mitigation measures should be addressed in the FEIS.

See response to Comment IV.B. An increased hazard of flooding for floodplain communities will result from increased coal use in general, but that increment associated with the program, however, cannot be quantified. This issue and appropriate mitigation will be controlled by compliance with the Surface Mining Control and Reclamation Act of 1977.

D. Referring to page 5-35, section 5.4.2.2, we note that mining activities could disrupt groundwater resources considerably, and could induce the construction of environmentally undesirable impoundment projects, which will alter watersheds, aquatic and terrestrial bio-systems. The benefits of mining should be weighed against the costs of water supply disruption before any earth and bedrock is disturbed.

Such an evaluation would be highly site-specific and is therefore beyond the scope of this document. Furthermore, the DOE has no authority to alter the mine permitting process to require such a comparative analysis before mining can commence. Such actions would have to be taken by the appropriate local, state, and federal permit agencies.

E. The utilization of coal slurry pipelines (page 5-34, Section 5.4.2) will rob valuable water supplies from the water short Western portions of the United States. Recycling of slurry water should be a mandatory provision should this transportation medium be utilized.

The FUA program will not create the need for coal slurry pipelines. However, the recycling of scarce water supplies is an essential consideration in the environmental impact of these projects.

F. On page 5-37, Section 5.4.3.1, we note that coal piles will be periodically sprayed with toxic dust suppressants. This procedure could adversely affect surface and groundwater hydrology and ultimately all forms of biological life. Any FUA related mining activity should seriously consider other less environmentally damaging techniques such as the use of tarpaulin covers in favor of chemical dust suppressants.

Apart from spraying toxic dust suppressants, other mitigating measures such as tarpaulins can be considered on a site-specific basis.

V. Comments on Wetland Impacts

On page 1-8, the DEIS states, "because wetlands have been attactive as sites for waste storage and most of the water will be generated near Gulf coast wetlands, these biotic communities may be particularly threatened by the increased coal use." Coal waste disposal and combustion ash disposal must be restricted from using coastal estuaries and adjacent wetlands. Any leachates from the disposal practice would produce unacceptable impacts on these delicately balanced ecosystems.

The text has been modified to indicate that implementation of various federal regulations will prohibit or mitigate the impacts of waste disposal upon wetlands (p. 1-8 and p. 5-55).

The DEIS states that it should be possible to avoid damaging wetlands because of Executive Order 11990. This issue was further discussed in Section 5.6.5.1 Waste Collection and Disposal - Terrestrial and Executive Order 11990 was sited again on page 8-2 in the list of federal policies and laws. Similarily, it is unclear in the discussion how the Executive Order 11988 on Floodplain Management will serve to assure the adequate management of floodplains. Both executive orders govern federal actions only, and it is open to interpretation as to whether the E.O.'s govern only the primary impacts of these actions or cover both primary and secondary impacts of Federal actions. Furthermore, it was stated on page 3-1 that, "nearly all the impacts of the program will occur in the industrial sector." It is unclear how the authority provided in the executive orders will be applied and how that authority will carry over from the public to private sector. Under both orders, DOE along with other federal agencies is required to promulgate regulations to carry out their intent. Some discussion as to how DOE's regulations will be applied to this issue would be appropriate. It would also be appropriate to discuss how 404 (Section 404 of the P.L. 92-500) dredge and fill permits can be applied to protect wetlands. The discussion should also address the issue of surface mining activities adjacent to wetlands and how projected adverse impacts are to be mitigated.

DOE proposed regulations for compliance with Executive Order 11990, Protection of Wetlands, and Executive Order 11988, Floodplain Management, which appeared in the Federal Register on July 19, 1978. (43 F.R. 31108). Final regulations were promulgated on March 7, 1979. These regulations will be applied to site-specific actions under FUA as DOE processes prohibition orders and acts on exemption petitions submitted by powerplants and MFBIs. The regulations will require DOE to make a finding that there is "no practicable alternative" before taking or supporting certain actions which would occur in floodplains and wetlands. If no practicable alternative to such actions exists, DOE must adopt mitigation measures to be determined on a case-by-case basis, in order to minimize the impact on the floodplains or wetlands.

Other agencies have additional authorities for protection of floodplains and wetlands. For example, the U.S. Army Corps of Engineers must issue permits, pursuant to Section 404 of the Clean Water Act, before dredging or filling of navigable waterways may take place. Moreover, each agency has the responsibility to promulgate its own regulations on compliance with Executive Order 11988.

VI. Comments on Coal Transportation

A. The discussion of railroad transportation of coal appears to be considerably more optimistic than the discussion of the same subject in the DEIS on the Federal Coal Management Program on pages 5-105 to 5-116 of that document published by the Department of the Interior in December of 1978. In DOI's EIS, the railroad industry's current financial posture was characterized as being "anemic." The potential total investment in new trackage and upgrading existing tracks was estimated at between $17 to $155 billion, with the lower bound of the estimate ($17 billion) "associated with increased coal traffic in the west through 1990" (page 5-113, DOI EIS). These and other estimates do not conform with the more optimistic assumptions in the FUA DEIS which states that "the investment required to meet the projected increase in coal rail traffic between 1977 and 1985 will be ... $4-5 billion for tracks, primarily in the west and midwest" (page 5-2). Why is there such a large discrepancy in the estimate being used in these two documents?

Capital investment required for the western rails in the future depends on various financial and institutional factors, which are currently uncertain. These uncertainties are partly caused by (1) the estimates of future coal consumption due to environmental regulations (2) the uncertainty of the degree of movement by slurry pipelines for the base case, and (3) the uncertainty of the share of coal traffic increases by coal unit train. The difference in DOI estimates (DOI, Draft EIS, Federal Coal Management Program, December 1978) and DOT estimates, adopted in the FUA Draft EIS, are partly due to the uncertainties on which the assumptions of those estimations are based. In addition, the DOT estimates on the investment requirement are projected up to the year 1985, while the DOI estimates extend to the year 1990. The difference in the two estimates could be much smaller if the two estimates were made for the same projection period.

B. On page 3-6, why are the U.S. Bureau of Mines production/distribution estimates (1976) used when DOE produced a more recent set of 1985 projections for DOI (see page 2-52 of the Federal Coal Management Program DEIS) based on a sophisticated linear programming model? Also, were these numbers coordinated with National Energy Plan (NEP) estimates?

As indicated in Section 3.2, the FUA Draft EIS adopted the trend-long baseline scenario, which reflects the National Energy Plan (p. 3-3). The BOM coal distribution pattern was applied only for the incremental coal demand as a result of the proposed action. The BOM's coal flow projection is based on the historical coal flow matrix (by coal districts and by state) modified by minimum cost algorithm. In addition, the model incorporates river capacity as a constraint to the multi-mode solution. Given the relatively small magnitudes of coal demand increases as a result of the proposed action compared to the baseline coal demand, the distributional patterns of the incremental coal demand is assumed to take the patterns in the BOM baseline projection.

VII. Comments on Projected Oil and Gas Savings

The projected maximum oil and gas savings in 1990 over the base case is approximately 2.5 quads. Since the current projections of excess gas production, over previous estimates, due to the Natural Gas Policy Act, is about 2-3 quads, it would seem that the same energy savings and reductions in oil imports could be achieved by using this gas, instead of curtailing demand for it. This would dramatically reduce emissions of all particulates, as well as alleviate the environmental impact of increased mining. This alternative should be considered in the final EIS section on analysis of alternatives, in light of the Natural Gas Policy Act and DOE's own analysis of the act showing the increased gas production.

The purposes of the Fuel Use Act, "which shall be carried out in a manner consistent with applicable environmental requirements" include:

> "To conserve natural gas and petroleum for uses, other than electric utility or other industrial or commercial generation of steam or electricity, for which there are no feasible alternative fuels or raw materials substitutes;
>
> to encourage and foster the greater use of coal and other alternate fuels, in lieu of natural gas and petroleum, as a primary energy source;
>
> to prohibit or, as appropriate, minimize the use of natural gas and petroleum as a primary energy source and to conserve such gas and petroleum for the benefit of present and future generations;
>
> to insure that adequate supplies of natural gas are available for essential agricultural uses (including crop drying, seed drying, irrigation, fertilizer production, and production of essential fertilizer ingredients for such uses)."

While the same energy volume may be available through the Natural Gas Policy Act, that Act and FUA are not inconsistent, having complementary objectives. The objective of the Natural Gas Policy Act is to encourage suppliers to produce more natural gas through orderly price increases at the wellhead. The objective of the Fuel Use Act is to reserve such fuel for uses other than raising steam and producing electricity. Both acts, to the extent they are successful, will increase flexibility in decisions regarding natural gas use. Only hindsight will reveal which act is more successful at making a premium fuel more available for priority uses. Natural gas is not expected to be deregulated in all markets until after 1985; discovery and production in new fields requires some lead time. Natural gas is a cleaner burning fuel and results in fewer environmental impacts than coal combustion. Should much larger quantities of natural gas become available, then its use may be an alternative to the Fuel Use Act and consideration could be made to alter the congressionally mandated FUA.

As published in the Federal Register, Jan. 5, 1979, Proposed Special Rule for Temporary Public Interest, "DOE continues to prefer that industrial facilities and electric utilities use coal or other alternate fuels rather than either oil or natural gas. Such increased use of coal, uranium, renewables and other alternate fuels will make more natural gas available for existing facilities and thereby further decrease petroleum consumption."

U.S. Environmental Protection Agency (continued)

High estimates have been provided for the amount of unconventional gas and tight sands formation, devonion shale, etc., that would be commercially producable for between $\$4\text{-}5/10^{b}$ BTU. Since the cost test to gain exemption from burning coal is $\$4.50\text{-}\$5.10/10^{b}$ BTU, this gas would seem to be no more expensive then the coal many people must purchase, yet much more environmentally acceptable. The regulations could be drafted to allow this gas to be considered as "alternative fuel" and thus possibly lower the environmental impact of the FUA program, while still displacing imported oil. This alternative was not considered in either the EIS or the proposed regulations but should be addressed in the final.

DOE has designated certain gaseous or petroleum-related fuels as alternate fuels based on considerations of commercial marketability and other factors. Wider use of these fuels would lessen the environmental impacts of the FUA program. In keeping with a worst-case analysis, conventional coal burning has been assumed for this assessment.

VIII. Comments on Other Significant Issues

A. Endangered Species

We are particularly concerned that DOE has under-estimated the program related to endangered species. In particular, the impacts of increased sedimentation combined with increased acid rainfalls will affect floral and faunal species. The degree of the affects should be qualified in the final document.

Without site-specific information on the magnitude of the effects, it is not possible to refine the analysis of the impact on endangered species. Furthermore, the effects of some phenomena are difficult to determine, even at a local level (e.g., acid rain) due to currently poor predictive capabilities. The U.S. Department of Interior regulates the use of, or effect on, critical habitat of endangered species, and if critical habitats are likely to be affected, then DOI procedures would have to be adhered to.

B. Wild and Scenic Rivers

We note on page 5-57, Section 5.6.7, that proposed Wild and Scenic Rivers could be affected in Central and Southern Appalachia. The impacted rivers should be identified in the document and mitigation measures described.

The rivers most likely to be impacted are listed on page 5-57. DOE cannot stipulate that measures be taken to mitigate any impact to these rivers. The Department of the Interior has the authority, under the Wild and Scenic Rivers Act, to protect these water bodies from degradation, where possible. As such, they might require that mitigative measures be taken at particular sites (e.g., increased sedimentation control, neutralization of the effluent, heavy metals removal, etc.). DOE would consult with DOI on specific sites and evaluate impacts in the exemption process.

C. Since, as is stated in page 3-1 of the subject report, "nearly all of the impacts of the program will occur in the industrial sector..." and since low and medium BTU coal gasification is expected to make an impact in this area prior to 1990, it is difficult to understand the statement on page 3-5 that "it was assumed that there would be no ordered conversion of existing units to synthetic gas."

The outlook for low- and medium-Btu gasification is discussed in Section 10. This outlook refers to new facilities constructed until 1990. The statement on pages 3-5 refers to existing facilities. As old facilities are retired, the outlook for synthetic gas improves for use in new units.

U.S. Environmental Protection Agency (continued)

D. The potential impacts of both low and medium BTU coal gasification and atmospheric fluidized bed combustion (AFBC) should be included in this study since it is fair to conclude that they will impact the industrial boiler sector by 1990. It may be inappropriate to assume that the impacts of operating of conventional combustion units and gasification facilities are similar in magnitude. It is fair to assume that AFBC solid wastes differ from those of conventional combustion in nature and quantities. It should be noted that the lower operating temperature of AFBC should affect the type of organic compounds present, possibly affecting carcinogenicity.

The text has been changed in response to this comment (see Sec. 10.2.1.1, p. 10-4).

This comment may be particularly valid for AFBC systems during startup and shutdown. Molecular weight of released organic compounds is related to boiler efficiency; molecular weight increases as boiler efficiency decreases. However, the results to date, based primarily upon bench-scale tests, indicate that even though there may be greater concentrations of organic compounds emitted during AFBC as compared to conventional coal-fired systems, the concentrations of organic compounds in both AFBC and conventional systems is so low that quantitatively their impact on health is overshadowed by the potential impacts of sulfur oxides and other components (ANL Special Task Force, 1977, Preliminary Assessment of the Health and Environmental Impacts of Fluidized-Bed Combustion of Coal as Applied to Electrical Utility Systems).

E. A benefits vs. costs analysis for the national program was not included in the EIS. We feel that it is appropriate that such an analysis be prepared. On the surface, the reader is led to believe that FUA will aid in the reduction of imports of foreign oil and gas supplies through the use of domestic coal reserves. However, the hidden costs associated with mining, processing and burning coal reserves could be costly. For instance, the increased mining activity resulting from FUA related coal activities will cause increases in erosion and result in stream sedimentation, fugitive dust emissions, acid mine drainage, and reductions in prime agricultural and forest areas. Further, the subtle impacts to the overall quality of life resulting from increased coal combustion is a hidden cost to the health and welfare of the populations segment in energy demand regions that cannot be overlooked.

Under NEPA regulations, the Department of Energy conducts an environmental trade-off analysis and this analysis is analogous to a benefit-cost analysis. In the impact statement, all known "subtle" impacts have been addressed and have been quantified to the extent reasonable. Many of the "hidden" impacts alluded to (resulting from mining, transportation, and burning) are regulated activities. Both the Surface Mining Act of 1977 and the Resource Conservation and Recovery Act of 1976 increase the cost of using coal. These costs will be reflected in the "substantially exceeds" test in the administration of the program. For this reason, many of the "hidden" costs of using coal are not hidden, but will be explicitly included in the program because they will be reflected in the price of coal. For more information on the cost of the program, a regulatory analysis has been performed (Energy Information Administration, 1978, Analysis of Proposed U.S. Department of Energy Regulations Implementing the Powerplant and Industrial Fuel Use Act, DOE/EIA-0102/21, U.S. Department of Energy, Washington, D.C.).

F. To further coordination and cooperation between our two agencies, EPA would like to request that estimates be developed by geographic region for the numbers of powerplants and MFBI biolers which, due to FUA regulations, will require EPA or state permit review. EPA regional EIS offices will also need to obtain these estimates as early as possible to facilitate the review of FUA related site-specific EIS's in concert with air quality and water quality permit review. Inclusion of such a listing by region in the final EIS will lead to improved coordination between programs and will allow our regional offices to anticipate the time requirements and resources for proper review in developing their respective management plans.

Construction of all major (new and modified) MFBIs and powerplants requires EPA or state review. FUA regulations will not change the number of boilers and powerplants subject to EPA review. The staffs of the two agencies have been discussing and coordinating their plans for the implementation of FUA for over six months. DOE is confident that this cooperative working relationship will continue in the future as more specific information becomes available to both agencies. EPA will receive a copy of each exemption petition.

National Science Foundation

NATIONAL SCIENCE FOUNDATION
WASHINGTON, D.C. 20550

nsf

OFFICE OF THE
ASSISTANT DIRECTOR
FOR ASTRONOMICAL
ATMOSPHERIC EARTH
AND OCEAN SCIENCES

January 30, 1979

Mr. Steven A. Frank
Chief, Environmental Evaluations
Branch
Economic Regulatory Administration
Department of Energy, Room 7202
2000 "M" Street, N.W.
Washington, D.C. 20461

Dear Mr. Frank:

Several individuals in the Foundation have reviewed the Draft EIS (DOE/EIS-0038-D) and their comments are attached. If you wish to discuss our input, your contact point is John Giacomini who can be reached on 632-7360.

Sincerely yours,

Daniel Hunt
Deputy Assistant Director

12-17a

National Science Foundation (continued)

Comments on DOE/EIS-0038-D

1. Air quality effects will bring a potential major increase in air pollution. Requlations will be needed and will have to be enforced, otherwise the consequences will be a potentially serious degradation of air quality with a consequential increase in health effects over large areas of the U.S. The air quality consequences may take the form of increased ozone (due to particulates), acid rain and crop damage (due to sulfur dioxide), and respiratory irritations (due to nitrogen oxides). For example the net increase in emmisions, expected under the Act because of industrial coal conversion, is about 10% in the next 10 years.

2. The DEIS dismisses any attempt to perform an environmental or social impact analysis of the proposed action in the context of alternatives. It seems that the main argument is that there is a larger goal, i.e., executive objectives and stated desires in legislation to achieve energy self-sufficiency, and that that goal overrides any impacts which might be discovered pro and con.

It is by no means clear and proven that the proposed action is the only, or best, way to achieve executive and legislative goals. Without such proof, the conclusion does not follow that no further discussion is necessary. Also, the intent of other executive and legislative objectives seems to be that a clear and intelligent analysis be applied to proposals in addition to any conclusion drawn from the political process.

The emissions of SO_2, NO_x, and particulates associated with the proposed action were calculated based on the New Source Performance Standards (NSPS) of 1.2 lb SO_2, 0.7 lb NO_x, and 0.1 lb particulates/10^6 Btu. Actual emissions will be regulated by the Clean Air Act Amendments of 1977, which will be more stringent than NSPS for SO_2 and particulate emissions. Oxides of nitrogen are produced irregardless of the fuel combusted including natural gas and petroleum, but to lesser degrees. Therefore, the air quality projections associated with both the FUA and the base case represent a worst-case analysis.

The maximum SO_2 increase of 2.5 $\mu g/m^3$ projected for 1990 occurs in only three AQCRs (Fig. 5.5). For this same time frame, 97 of the 238 AQCRs have no projected regional increase. The predicted maximum SO_2 concentration for 1990 is 69 $\mu g/m^3$ from all emissions.

The choice of coal as the alternate fuel represents a worst-case environmental analysis. Other alternate fuels and policy options are discussed in Section 10. The purpose of the FUA is discussed in a response to a comment by the USEPA (p. 12-15). Socioeconomic impacts are discussed in Section 5.8, Appendices E and K and the regulatory analysis.

STATE AGENCIES

ALABAMA

Alabama Energy Management Board

STATE OF ALABAMA

ALABAMA DEVELOPMENT OFFICE

FOB JAMES
GOVERNOR

BOBBY A. DAVIS
ACTING DIRECTOR

January 24, 1979

TO: Ms. Ruth C. Clusen, Assistant
Secretary for Environment
Department of Energy
Washington, D. C. 20461

FROM: Michael R. Amos, Administrator
State Clearinghouse
State Planning Division

SUBJECT: DRAFT ENVIRONMENTAL IMPACT STATEMENT

Applicant: Department of Energy

Project: Draft Environmental Impact Statement for the Coal and Alternate Fuels Program for the Department of Energy.

State Clearinghouse Control Number: ADO-040-78

The Draft Environmental Impact Statement for the above project has been reviewed by the appropriate State agencies in accordance with Office of Management and Budget Circular A-95, Revised.

The comments received from the reviewing agencies are attached.

Please contact us if we may be of further assistance. Correspondence regarding this proposal should refer to the assigned Clearinghouse Number.

A-95/05
Attachments
Agencies contacted for comment.
Alabama Energy Management Board - Hudspeth
Alabama Coastal Area Board - Trickey
ADO - Sternenberg

3734 ATLANTA HIGHWAY • MONTGOMERY ALABAMA
MAILING ADDRESS: STATE CAPITOL • MONTGOMERY, ALABAMA • 36130
(205) 832-6810

ALABAMA ENERGY MANAGEMENT BOARD

[illegible]

3734 Atlanta Highway
Montgomery, AL 36130
Phone: 205-832-5010

December 12, 1978

[illegible]

TO: State Clearinghouse

FROM: Edwin G. Hudspeth

SUBJECT: Comments on Draft Programmatic Environmental Impact Statement on Fuel Use Act

This EIS underestimates the coal production forecast for Alabama and the coal reserve base for Alabama. Table 1.2 and Table 3.9 show base case production for 1990 to be approximately 19 million tons. Based on current production and anticipated new mine openings, Alabama's projected coal production for 1990 should be approximately 29 million tons, of which approximately 19 million would be surface mined and 10 million underground mined. Table 4.9 lists total reserves for Alabama of just under 3 billion tons. A soon to be completed study by the Geological Survey of Alabama will prove Alabama's reserves. Partially completed results indicate Alabama's total reserves will be between 10 and 60 billion tons with the most probable figure around 15 billion tons.

Since both the reserve base and anticipated production of coal in Alabama are underestimated, we question the oil and gas savings and the transportation requirements as a result of the Fuel Use Act.

I recommend this EIS be reviewed by the Alabama Air Pollution Control Commission, the Water Improvement Commission and the Geological Survey of Alabama.

Table 4.9 lists coal reserves as of January 1, 1974, as given by the U.S. Bureau of Mines. The Alabama figures are based upon coal reserve estimates made by W. C. Culbertson in 1964. Culbertson estimated Alabama's resources to be 13,754 billion short tons. The Geological Survey of Alabama recently recalculated the strip-mineable reserves to be about 2 billion short tons. The deep-mineable reserves are being recalculated by the U.S. Geological Survey in Reston, Virginia. These results are not expected until May or June of 1979. The Geological Survey of Alabama notes that the estimate of stripable reserves is up substantially over earlier estimates. They anticipate that higher estimates may be true for the deep-mineable reserves. No total figure is yet available. Culbertson's 13.8 billion ton estimate for resources may also be low. Reserves must not be confused with resources (see Sec. 4.5, p. 4-19).

ALASKA

Department of Natural Resources, Division of Parks

STATE OF ALASKA

JAY S. HAMMOND, Governor

OFFICE OF THE GOVERNOR

DIVISION OF POLICY DEVELOPMENT AND PLANNING

Phone 465-3512
Pouch AD - Juneau 99811

December 27, 1978

Mr. Steve Frank
U.S. Department of Energy
Economic Regulatory Administration
Office of Fuels Regulation
Washington, D.C. 20461

Subject: Fuel Use Act DPEIS
State I.D. No. 78122702

Dear Dear Mr. Frank:

The State Clearinghouse has received the subject project which you submitted for review.

Materials concerning the project have been distributed to the appropriate governmental agencies for review and comment. The review is scheduled to close on January 26, 1979, and you should be receiving review results soon after that date.

The Clearinghouse has assigned State I.D. No. 78122702 to the project. Please use this number in all future correspondence concerning the project, both with this agency and with the federal agency.

Thank you for your cooperation in this matter.

Sincerely,

Jerry L. Madden
Jerry L. Madden
State-Federal Coordinator

JM/cz

12-20

STATE OF ALASKA

OFFICE OF THE GOVERNOR
DIVISION OF POLICY DEVELOPMENT AND PLANNING

JAY S. HAMMOND, Governor

POUCH AD
JUNEAU, ALASKA 99811
PHONE: 465-3512

February 13, 1979

Mr. Steve Frank
U.S. Department of Energy
Economic Regulatory Administration
Office of Fuels Regulation
Washington, D.C. 20461

Subject: State Clearinghouse Close-out of Fuel Use Act DPEIS
State I.D. No. 78122702

Dear Mr. Frank:

The Alaska State Clearinghouse has completed review of the subject draft programmatic environmental impact statement.

The following agencies commented:

The Department of Natural Resources, Division of Parks, said:

"This agency has reviewed the FUA DPEIS and supports the project so long as future coal mining, transportation, storage and use in Alaska considers and avoids areas of existing or potential recreational or historic values considered important to the public welfare.

"The State Historic Preservation Officer has the following comments: with regard to Part 5.7.1, there seems to be some incongruity. On the one hand it's pointed out that:

'. . .mine operators seeking a Federal permit are required to locate and avoid all listed and potential historic or archaeological sites (36 CFR Part 800).'

"This is the way it should be, and follows the guidelines of preservation law. But immediately following this it's stated that:

'Although a few gravesites, mine shafts, or other potential sites for inclusion in the National Register may be destroyed by mining that results from increased coal use caused by this action, little (if any) significant loss of historical resources is expected.'

"Two comments automatically come to mind after considering this last quote: (1) the destruction/adverse impact of any site eligible for the National Register of Historic Places is illegal when done by Federal agencies without proper mitigating measures.

The misinterpretation of Section 5.7.1 concerning historic sites is regretted. The intent was to make it clear that: "all mine operators seeking a federal permit are required to locate and avoid all listed and potential historic or archaeologic sites." It is clear in the rest of the statement that not all mine

Alaska Department of Natural Resources, Division of Parks (continued)

Moreover, it is the responsibility of the lead Federal agency to initiate the determination of which sites are eligible for the NRHP before they are destroyed by actions which they are sponsoring, licensing, etc., (2) the destruction of just one site which is eligible for the NRHP is — by and of itself — a 'significant loss', since any site which is eligible for the Register is automatically considered a significant cultural resource.

operators who are opening new mines or expanding operations as a result of the proposed action will seek federal permits on all occasions. The result may be the inadequate search for potential sites for inclusion in the National Register at a very few but unquantifiable number of mine sites. Therefore in order to present the potential impacts of this federal action and the relative magnitude of the impacts, it should be stated that there is a likelihood that "a few gravesites, mine shafts, or other potential sites for inclusion in the National Register may be destroyed by mining that results from increased coal use caused by this action." Because this would be an extremely rare event and nearly always mitigated, it is stated that "little (if any) significant loss of historical resources is expected."

Municipality of Anchorage

The Municipality of Anchorage commented:

"The Fuel Use Act prohibits the use of natural gas or petroleum as the primary energy source in new power plants and MFBI boilers, thereby forcing the use of other energy sources, primarily coal. Therefore, the basic questions which should be answered by the EIS are 'what are the environmental impacts and adverse effects of the coal utilization mandated by the FUA? Is the balance of trade-offs positive or negative?' These are vitally important questions which should be answered before the FUA is implemented.

"We believe that the EIS simply does not address and answer these critical questions satisfactorily.

"The following specifics are not intended to be an exhaustive analysis of the EIS, but only serve to illustrate its deficiencies:

"The EIS contends that electric utilities will not be affected by the FUA because they are already subject to ESECA which requires conversion to coal. Yet it is intended that the ESECA program be phased out quickly as FUA takes over. By thus eliminating electric utilities - because they will be forced by ESECA to burn coal - the remaining future use of coal by industrials becomes only a relatively small part of all coal consumption, and the EIS is able to treat the incremental effects as insignificant!

"Where EIS cannot evaluate an adverse effect it is labelled 'unknown' and disregarded. An example of this technique - coupled with that described in the previous paragraph - is found in section 5.3.1 Greenhouse Effect (Global CO_2).

Several unknown environmental effects are listed within the EIS. There are two major reasons for this. One is the necessity for site-specific information which is outside the scope of a programmatic EIS. The other is the state-of-the-art for assessing a given issue, e.g., the greenhouse effect, has not developed to the point where a predictive assessment can be made. Even though predictions are not made, the discussion of greenhouse effects is contained in Section 5.3.1.

"Finally, EIS concerns itself with the Coterminous United States, ignoring Alaska and Hawaii except for brief mention of the characteristic and reserves of coal in Alaska. Forced accelerated use of coal in Alaska would have serious impact on the State."

Based upon the comments quoted above, it appears that the subject document is deficient in important areas which must be more sufficiently and sensitively addressed.

Alaska - Office of the Governor, Division of Policy Development and Planning

The State Clearinghouse would hope that the U.S. Department of Energy Regulatory Administration becomes more aware of the laws and regulations governing listed and potential historic or archaeological sites and will take a less cavalier attitude towards the fate "...of a few gravesites, mine shafts or other potential sites for inclusion in the Federal Register..."

The use of words such as "insignificant" and "unknown" in environmental statements are not conducive to furthering public trust in regulatory agencies. There are strategic areas of impact which cannot be relegated (out-of-hand) to that type of verbal dismissal.

Finally, the people of Alaska believe that national impact studies should give due consideration to use of Alaskan resources and what the impact of that use will be. The subject document, in virtually ignoring Alaska and Hawaii, cannot be considered a national statement of programmatic environmental impact.

Sincerely,

Jerry L. Madden
State-Federal Coordinator

cc: State Department of Natural Resources
The Municipality of Anchorage

JM:cl

CALIFORNIA

Air Resources Board

OFFICE OF THE SECRETARY
RESOURCES BUILDING
1416 NINTH STREET
95814

(916) 445 5656

Department of Conservation
Department of Fish and Game
Department of Forestry
Department of Navigation and Ocean Development
Department of Parks and Recreation
Department of Water Resources

EDMUND G. BROWN JR
GOVERNOR OF
CALIFORNIA

Air Resources Board
California Coastal Commission
California Conservation Corps
Colorado River Board
Energy Resources Conservation and Development Commission
Regional Water Quality Control Boards
San Francisco Bay Conservation and Development Commission
Solid Waste Management Board
State Coastal Conservancy
State Lands Commission
State Reclamation Board
State Water Resources Control Board

THE RESOURCES AGENCY OF CALIFORNIA
SACRAMENTO, CALIFORNIA

FEB 13 1979

Ms. Ruth Clusen
U. S. Department of Energy
2000 M Street, N. W.
Washington, D. C. 20461

Dear Ms. Clusen:

The State of California has reviewed the Draft Programmatic Environmental Impact Statement, Fuel Use Act, submitted through the Office of Planning and Research in the Governor's Office. The only comments received, those of the Air Resources Board, are attached and constitute the State's official response on this document.

This review fulfills the requirements of Part II of Office of Management and Budget, Circular A-95 and the National Environmental Policy Act of 1969. It was coordinated with the Departments of Conservation, Fish and Game, Parks and Recreation, Water Resources, Food and Agriculture, Health Services, and Transportation; the Air Resources, Solid Waste Management, and State Water Resources Control Boards; and the Energy and State Lands Commission.

We appreciate having been given an opportunity to review this report.

Sincerely,

L. FRANK GOODSON
Assistant Secretary for Resources

Attachment

cc: Director of Systems Management
Office of Planning and Research
1400 Tenth Street
Sacramento, CA 95814
(SCH 78122526)

12-23a

State of California

Memorandum

To : L. Frank Goodson
Project Coordinator
Resources Agency

Date : February 9, 1979

Subject : Comments on Draft Programmatic Environmental Impact Statement Fuel Use Act SCH #78122526

From : Air Resources Board
Harmon Wong-Woo, Chief
Stationary Source Control Division

Our comments will be limited to the air quality sections of the Draft Environmental Impact Statement (DEIS). The Fuel Use Act (FUA) prohibits the use of natural gas or petroleum in new and/or existing power plants and major fuel burring installations (MFBI). The Act defines power plants and MFBI as stationary sources with a minimum heat input rate of 100 million Btu/hour for one unit or 250 million Btu/hour for two or more units. The primary purposes of the FUA is to reduce the nation's dependence on foreign oil, to encourage the use of sources of energy that are indigenous to the United States, and to conserve petroleum and natural gases for future uses. The Department of Energy (DOE) is authorized to promulgate regulations establishing criteria for granting exemptions from the prohibitions of the FUA.

General Comment

The DEIS did not discuss the impact of this act relative to California. California's unique air pollution problem is caused primarily by products of combustion. Although local burning facilities can be controlled so the emissions would be very low, it is not practical to apply such control technology to a large number of facilities within a short period. If a substantial number of existing facilities are required to convert to coal, California may not be able to attain the national ambient air quality standard, as required by the Clean Air Act. Mandatory conversions to coal would also be catastrophic to California's economy because virtually all available emissions offsets would be required for use by these converted facilities, leaving little room for future economic growth. We believe the DEIS should specifically address the problems of these states with existing significant air pollution problems. The DEIS seems to blithely dismiss this problem by stating that nonattainment areas will automatically be granted an exemption. Neither the FUA nor the regulations proposed by DOE include such automatic exemptions.

California Air Resources Board (continued)

Specific Comments

(1) The DEIS appears to believe that nonattainment areas would be exempt from the prohibitions of the FUA. The FUA does not specifically exempt combustion facilities that are located in nonattainment areas. In fact, the proposed DOE regulations implementing the FUA would make it extremely difficult to obtain any exemptions, even in nonattainment areas.

The regulations concerning siting in non-attainment areas are explained in Section 2.4.3.2. The impact of siting coal combustion facilities in non-attainment areas is discussed in Section 5.2.4.

(2) The DEIS discounts the air quality impact of converting existing power plants. This is based on DOE's belief that conversions of existing power plants are covered by the Energy Supply and Environmental Coordination Act (ESECA) of 1974. We believe that an air quality impact analysis should be performed to assess the cumulative impact of the proposed regulations and ESECA.

See responses to comments by U.S. Environmental Protection Agency (p. 12-10) and California Energy Commission (p. 12-33).

(3) On page 3-4, the DEIS states that fuel burning facilities built before 1980 will be excluded from the FUA. However, DOE recently proposed regulations that will include all fuel burning facilities built after November 9, 1978, and may even include some facilities built after April 20, 1977.

See response to comment by California Energy Commission, p. 12-28.

(4) In determining the air quality impact of the Fuel Use Act, DOE seems to place a great deal of reliance on 1974 information specifying the location of fuel burning facilities. Since 1974, the number of fuel burning facilities may have substantially increased which would result in underestimating the air quality impact of the proposed regulations. DOE should investigate whether the use of 1974 information is appropriate for determining air quality impacts.

DOE used the latest available comprehensive data. Based on the distribution of facilities in that data base, projections were made to account for growth before air quality impact assessments were made.

(5) Tables 5-12a and 5-12b make no mention of increases in SO_2 or TSP concentrations in Region IX.

Tables 5-12a and 5-12b present data on those AQCRs which have the highest projected base case emissions and those AQCRs which have the highest projected emissions associated with the proposed action. None of these occur in Demand Region IX. Maximum levels (1990) of SO_2 projected for Demand Region IX are 0.5 to 1.0 $\mu g/m^3$ (see Fig. 5.5).

(6) The DEIS presents emissions increases based on air quality control regions. Since these regions are large, it is very difficult to assess any localized impacts. We suggest that DOE perform a worst case analysis for a nonattainment area assuming that all major facilities within that area will be required to use coal. This would identify the maximum localized impact of the proposed regulations.

DOE believes that such an analysis would serve no valid purpose. The document assesses the regional and national impacts of the Act. Local effects will be determined on a case-by-case basis by the proper regulatory authorities before conversions begin.

(7) The estimated increases in transportation emissions are presented for the entire Region IX, which comprise of several states. The areas in which transportation emissions would have the greatest impact should be identified.

Data on specific locations of origin and destinations of coal are insufficient to delinate the specific areas within a Demand Region that would have the greatest impact from transportation emissions.

(8) Fugitive dust emissions from storage and on-site processing were assumed to be insignificant. Our experience with proposed coal-fired power plants suggest that this may not be true. The basis for this assumption should be stated in the DEIS.

Particulate emissions from storage and processing facilities will degrade air quality around those facilities. However, because the particles are generally large, most should settle out within the area adjacent to the facility. Therefore, no regional air quality impacts are expected from these facilities.

California Air Resources Board (continued)

(9) The modeling analysis used to assess the air quality impact is wholly inadequate because the results are based on using nonrepresentive stack heights of 500 meters for utilities and 135 meters for industries and ignoring the localized effects. These effective stack heights usually occurred during non-stable atmospheric conditions which are rather infrequent in California during the summer months. As we mentioned in item 6, DOE should select a nonattainment localized area to perform the modeling analysis.

Effective stack heights were chosen to be representative of average utility and industrial locations on a national basis. Consideration of local effects such as basin inversions is beyond the scope of the document. As noted in Section 5.2.4, compliance with all applicable federal, state, and local air quality regulations must be demonstrated before coal combustion can begin.

(10) The comparison between a regional SO_2 increase and the national SO_2 background concentration is inappropriate because localized effects are again not considered.

Regional pollution increases were calculated to determine the national impact of the Act. Local effects will be considered by the appropriate local regulatory authorities before coal combustion begins.

California Energy Commission

STATE OF CALIFORNIA—THE RESOURCES AGENCY

EDMUND G. BROWN JR., Governor

ENERGY RESOURCES CONSERVATION
AND DEVELOPMENT COMMISSION
1111 HOWE AVENUE
SACRAMENTO, CALIFORNIA 95825

(916) 920-6105

February 9, 1979

Mr. David J. Bardin, Administrator
Economic Regulatory Administration
2000 "M" Street, N.W.
Washington, D.C. 20461

COMMENTS ON DRAFT ENVIRONMENTAL IMPACT STATEMENT FOR THE FUEL USE ACT

Dear Mr. Bardin:

The California Energy Commission (CEC) has reviewed the Draft Programmatic Environmental Impact Statement (EIS) on the Power Plant and Industrial Fuel Use Act of 1978 (FUA). Our detailed comments on the EIS are attached to this letter. The CEC's comments on the FUA regulations will be forwarded separately and in accordance with the timetable outlined in the Federal Register.

As you can readily see from the comments following and those attached, we are not satisfied that the EIS adequately describes the environmental impacts associated with the issuance and utilization of the regulations required to implement FUA. Although the issuance of regulations is the stated purpose of the document (see page 1-1), there are numerous major deficiencies in the EIS, the most serious of which are described in detail in the attached comments and may be summarized as follows:

1. The major assumptions regarding the regulations utilized as the basis for the EIS analysis, e.g., number of plants affected, air quality emissions, substantially exceeds index, etc. (see infra), differ significantly from the parameters actually proposed in the draft regulations.

2. Assuming that the EIS begins to describe that which it is evaluating, the FUA regulations, there are numerous erroneous conclusions regarding the environmental impacts from the regulatory scheme described in the EIS. These include identification of worst case scenarios and other scientific and technical evaluations and conclusions.

3. The EIS fails to adequately address the environmental impacts of the utilization of alternative energy sources encouraged by the proposed FUA regulations.

Detailed comments have been addressed in the pages following these summary comments.

California Energy Commission (continued)

4. The purpose of the EIS is to aid in agency decision making and not to serve as an after-the-fact justification for the decision reached. In order to fulfill this purpose, the EIS must describe the environmental impacts associated with the various options that can be implemented within the framework of the statutory mandates. While mentioned in the EIS, their impacts are not discussed or evaluated. As written, it is difficult to imagine how this EIS contributes to or aids in agency decision making, the preeminent purpose of the entire EIS process.

As we have noted before (see CEC comments on Transitional Facilities Regulations dated January 17, 1979), ERA's proposed definition of "new facilities" transcends the letter and intent of the Act itself. We believe that this injects uncertainty as to the validity of the regulations, above and beyond the questions which we have raised with respect to the EIS.

Lastly, we would note with some concern that ERA has excluded California from its hearing schedule. Inasmuch as California is one of the most populous states, with its concomitant need for energy for industry and its citizens, and has many unique environmental and energy planning problems, it seems appropriate that hearings should be conducted in California. We trust that hearings on the other portions of the FUA regulations will be held in California.

Sincerely,

ROBERT L. SOLOMON
Deputy Executive Director

Attachment

Mr. Robert L. Solomon
Deputy Executive Director
State of California
Energy Resources Conservation
and Development Commission
1111 Howe Avenue
Sacramento, California 95825

MAR 19 1979

Dear Mr. Solomon:

I am responding to your letter of February 9, 1979, to David J. Bardin, Administrator of the Economic Regulatory Administration (ERA), regarding the State of California's comments on the draft Programmatic Environmental Impact Statement (EIS) on the Fuel Use Act.

ERA does not concur with your assertions that the EIS has failed to address the environmental impacts or that the EIS has not contributed nor aided this Administration's decision-making. Evaluation of the environmental impacts of the Fuel Use Act began at an early stage and much of the information appropriately predated the regulations development. The information developed in the environmental analysis has and continues to assist in the development of the regulations.

Your specific comments on the draft EIS are being addressed in the final EIS, which will be changed to reflect those areas where the comments correctly noted that changes would improve the analysis and usefulness in the decision making process. Thank you for the time and effort spent on helping us to improve the final EIS.

Sincerely,

/S/

Barton R. House
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California Energy Commission (continued)

ATTACHMENT

DETAILED COMMENTS OF THE

CALIFORNIA ENERGY COMMISSION

ON THE

DRAFT PROGRAMMATIC ENVIRONMENTAL IMPACT STATEMENT

ON THE FUEL USE ACT

(DOE/EIS-0038-D)

California Energy Commission (continued)

1. Page 1-1

The proposed action that is the subject of the Draft EIS is "the issuance of regulations to implement FUA." On January 5, 1979, ERA issued and made effective the Special Rule for Temporary Public Interest Exemption (44 FR 1694). Under CEQ's National Environmental Policy Act NEPA regulations, this Federal action should not have been taken until a Final EIS describing the proposed actions had been circulated for at least 30 days.

The Federal Register cited only proposes and does not make effective the exemption. It is not envisioned that any further action regarding this rule will be taken prior to the issuance of the Final EIS. Viable alternate fuels are considered in the EIS, and discussion of some of the alternate fuel impacts are being expanded from the Draft EIS.

2. Page 1-1 fourth paragraph

ERA states that "Predicted impacts of alternate fuels are not given due to the uncertainty of their usage." Under NEPA full disclosure requirements, all reasonable impacts of the program must be described.

The text has been revised (pp. 1-1 and 3-1) to indicate how alternate fuels are presented.

Several alternate fuels proposed in the FUA regulations may indeed have greater and more severe environmental impacts than coal. For example, petroleum coke in many cases contains high concentrations of heavy metals. Similarly, shale oil production can be much more environmentally damaging than coal mining since large quantities of water are required and the spent shale creates a massive solid waste disposal problem.

Petroleum coke is discussed in Section 10.1.7.

The environmental impacts of the use of oil shale are presented in the FUA Draft EIS as well as in the ESECA Final EIS (Volume I, pp. VIII-119 through -137). In addition to the references presented in these documents, the following reference is also recommended: Oil Shale and the Environment, EPA-600/9-77-033.

The Draft EIS should therefore analyze at least programmatically the impacts of use each alternate fuel proposed by ERA.

See response to Comment 1 (page 1-1).

3. Page 1-1 fifth paragraph

ERA intends the Draft EIS as a systematic overstatement of factors that would affect the number of facilities that would use coal.

The assumption of constant oil and gas prices reflects the worst-case analysis. Should oil and gas prices rise as indicated in the comment, it is likely that there will be greater voluntary construction of coal-fired units and fewer changes due to the FUA.

In several respects, the Draft EIS is not a worst case analysis:

- Oil and gas prices were assumed to be stable in real terms. Several recent events (e.g., Iran, the Natural Gas Policy

Act and other world oil market aspects) have shown this assumption to be wrong. In fact, oil and gas prices will likely exceed real prices and therefore the rationale for excessively stringent and inflationary provisions in the regulations implementing FUA is exaggerated.

- The group of facilities affected by the proposed FUA regulations (10 FR 500.2(a)(51) and (52)) includes many small (e.g., less than 100 million Btu/hr) combustors omitted from the Draft EIS, since a reasonable reading of the Act would lead one to exclude them. Therefore, the EIS has underestimated the likely amount of coal conversion and subsequent emissions due to the FUA regulations.

The FUA restricts DOE to only reviewing smaller combustors which are co-located at a site for which the total heat input rate is more than 250 million Btu per hour. Existing facilities of this size probably will not have coal-burning capability. To the extent that these units could use synthetic fuels as alternate fuels, the impacts would be small. Small new units will have a greater probability of qualifying for the cost-test exemption. Due to the general attempt to overstate coal combustion related to the program, and the small number of units which may fall within the noted size, fuel, and exemption categories, any changes due to a revision in this assumption are expected to have an extremely small impact on the results.

- The "substantially exceeds index" proposed in the FUA regulations greatly exceeds the economic test used in the Draft EIS. Due to this difference, many more facilities will fail to qualify for exemptions, would therefore be required to use alternate fuels (coal) and generally produce more emissions.

As indicated in Table 10.5, the amount of coal combustion impacted by the "substantially exceeds" index is asymptotic, and the coal volume captured by the index used in the EIS captures virtually the entire possible universe. Any higher "substantially exceeds" index would be expected to involve such a small additional increment of boilers that the incremental impacts could be due to the limited uncertainty involved in the projections.

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4. Page 1-2, Table 1.1, Footnote a.

The footnote presumes that "New units are those coming on line in 1980 and after...." However, the transitional facility regulation's definition of "new units" reaches further back to sweep within the purview of the prohibition other units that would be scheduled to go on line before this date.

This difference between the Draft EIS and the proposed FUA regulations can be substantial: numerous facilities that were treated as "existing" (and therefore less likely to be forced to coal) by the Draft EIS may be indeed "new" according to ERA's proposed definitions. Impacts due to the FUA program are therefore underestimated.

Facilities are defined in the EIS as being new if the date of operation is in or after 1980, and existing if the date of operation was prior to that date. Since it takes several years to complete a facility, the above definition results in most "transitional" facilities being considered existing rather than new. The revised interim rule on transitional facilities states that a facility will be considered existing if it is operational May 8, 1979. If it is not operational on that date, it will still be considered existing if 25% or more of nonrecoverable outlays of the total expected project cost has been expended. The latter is anticipated to account for those facilities becoming operational between May 8 and December of 1979.

5. Page 1-2, Table 1.1, Footnote c.

Similar comment applies to Footnote c. (assumption regarding existing units) as the preceding comment No. 4.

6. Page 1-2, second paragraph.

The Draft EIS assumes that "Utilities will be affected less because new baseload facilities using fuels other than oil or natural gas are generally anticipated."

In California, this presumption is wrong. Repowering, combined cycle combustion and cogeneration are efficient modes of oil use that are indeed proposed by utilities for new baseload facilities. For example, Pacific Gas and Electric Company's Pittsburg 8 and 9 units will probably be "new" facilities under FUA and would provide 1600 MW of combined cycle, oil fired baseload capacity.

As indicated in the response to U.S. EPA (p. 12-10, Item B), the DOE methodology and analysis required projections based on national trends. Indications are that the electric utility industry is not constructing oil- or gas-fired baseload facilities during the period covered by the EIS. Any aberrations from this national trend cannot be accounted for except on a site-specific basis, which will be afforded other examinations under NEPA and FUA. DOE information, furnished by the Western Systems Coordinating Council in April, 1978, indicates that Pittsburg 8 and 9 are expected to be operational in 1985. A determination of their status without formal submission to DOE for a determination is premature.

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Here again impacts due to the proposed FUA regulations are therefore under-estimated.

7. Page 1-3, fifth paragraph.

The Draft EIS concludes that maximum regional increases of SO_2 due to FUA will be 2.5 ug/m^3 and even less Total Suspended Particulates.

These conclusions are not "worst case", notwithstanding the declaration in the EIS. In addition, it should be noted that MFBI's do not locate in a regionally dispersed manner, as was used for the air quality modeling.

The air quality impacts of this program were considered on an Air Quality Control Region basis. The analysis technique used is discussed in Section 5.2.4. If siting takes place in areas which are now industrialized, the emission factors used in the analysis are likely to be too high, resulting in a conservative analysis. A further discussion of siting in non-attainment areas is contained in Section 5.2.4.

In fact MFBI's tend to be urban (e.g., factories usually are in cities or suburbs) and the true concentrations of SO_2 and TSP will in fact be higher on a regional basis than projected by the Draft EIS.

For example, in certain portions of California, oil production is enhanced by steam injection; the steam for which is produced from oil fired boilers. If these boilers were forced to use coal, the regional SO_2 and TSP concentrations would exceed ERA's projections. (Assuming that EPA and the State Air Resources Board allowed them to use coal.) Moreover, many of these combustors are in the 50 million Btu/hr range, omitted from the Draft EIS, but not from the proposed FUA regulations.

Units which cannot meet air quality standards will be eligible to apply for an environmental exemption. Portable package units, such as those generally used in oil production are likely to apply for exemption under FUA because of economic and environmental constraints. The subject of units in the 50-100 million Btu per hour range was further addressed in Comment 25 on p. 12-27. Many of the units described in the comment are existing units and subject to different exemptions and processing under FUA than new units would be.

8. Page 1-11, third paragraph.

The Draft EIS justifies the FUA program by stating that "...the program can force substitution without the consumer paying for increased general fuel prices that would occur as a result of...taxes or natural gas deregulation."

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This statement is fallacious in several respects:

- It totally ignores the massive costs of Fuels Decision Reports required by ERA in the proposed regulations (but not in the Act). One California company has cited 1,000,000 as the cost for one FDR under the proposed FUA regulations.
- The costs of the taxpayer for ERA's large, new bureaucracy are ignored.
- Natural gas is being deregulated, under legislation ignored by the Draft EIS. (Natural Gas Policy Act)

DOE believes this comment is misleading. DOE anticipates that the cost estimates for preparation of the Fuels Decision Reports will vary substantially. However, DOE does not intend for companies to spend $1,000,000 in preparation of the FDR. It should be further noted that if companies owning the affected powerplants and industrial boilers comply with the intent of the Congress and do not apply for exemptions to combust oil or natural gas, they will not have to file the Fuels Decision Report.

In regard to ERA's "large new bureaucracy," the Fuel Use Act will be primarily implemented by use of existing government personnel and a small additional staff. This will minimize any additional costs to the taxpayers.

The Natural Gas Policy Act has the potential to deregulate gas by 1985. The economic and environmental impacts of such deregulation will be addressed in Environmental Impact Statements by the Department of Energy and the Federal Energy Regulatory Commission. These EISs will be published in the near future. The impacts of the Natural Gas Policy Act are not expected to alter the impacts of the Fuel Use Act as projected in the worst-case analysis.

9. Table 1.3 (pages 1-10 and 1-11)

As discussed in previous comments, the Draft EIS is not a worst case analysis. All "environmental residuals" in Table 1.3 are therefore too small and are misleading since they attempt to convince the reader that the proposed regulations will have only minor environmental impacts.

Based on the responses to previous comments, it is felt that a worst-case analysis has been performed.

No health effects from coal combustion are predicted, an obvious omission of the most probable concern of people who will be affected by coal conversions.

The effects on human health from coal combustion air emissions (i.e. SO_2, NO_x, CO, CO_2, hydrocarbons, photochemical oxidants and particulates, including sulfates) and trace elements are presented in Section 5.9.5 and briefly in Appendix E, Section E.2.6. Human morbidity and mortality attributed to coal combustion emissions are presented qualitatively for coal use in general, not specifically for the proposed action. Health impacts due to the program are recognized but due to the uncertainty in the estimates of health effects from coal combustion a quantitative assessment has not been included. Recommendations for mitigating potential health effects from coal use including the proposed action are presented in Section 5.9.9.

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10. Page 1-13

The Draft EIS states that "one of the significant positive impacts of the FUA is increased flexibility in decisions regarding natural gas curtailment...."

In fact, the natural gas savings attributed by the Draft EIS to FUA will probably occur due to the changes in the energy source market brought about by the Natural Gas Policy Act rather than from FUA. Therefore, one of the "significant positive impacts" of FUA is no longer valid. Furthermore, recent DOE policy encourages the use of natural gas in power plants which is contrary to the assumptions in the EIS. (See Special Rule for Temporary Public Interest, 44 FR 1694, January 5, 1978).

The Natural Gas Policy Act (NGPA) and the Fuel Use Act (FUA) have complementary objectives (see response to comment by U.S. Environmental Protection Agency, p. 12-15). For these reasons, there is no firm basis on which to demonstrate that gas curtailments on the order of 1976-1977 cannot recur and that the flexibility needed will be solely due to the FUA or the NGPA. DOE continues to prefer that industrial facilities and electric utilities use coal or other alternate fuels rather than either oil or natural gas.

11. Table 1.5, page 1-12

This table is also erroneous, for the same reasons discussed in comment 10 above.

The table has been revised but the alternatives do not reflect a change in the basic conclusions that the benefits of FUA outweigh the negative impacts.

12. Page 2-5, last paragraph

The Draft EIS asserts that negative impacts associated with coal use will be minimized by compliance with environmental regulations.

ERA proposed regulations, however, actually request and encourage a combustor to obtain a relaxation of the applicable rules. (10 CFR 504.23(b)(2) and (4)). If the EIS assumes in its analysis that facilities will comply with applicable environmental requirements, the impacts will be understated from those occurring from the implementation of the proposed regulations.

Emission estimates used in modeling environmental impacts were based on environmental regulations in effect at the time the EIS was written. All future regulations will be at least as stringent as the assumed regulations. If complete relaxation of all future environmental regulations is obtained, no emissions greater than those assumed in the environmental models will occur. The environmental impacts of the Act are thus not understated.

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13. Page 2-6, Section 2.4

The relationship of FUA to other Federal actions is inadequately described. As noted previously, major provisions of the National Energy Act such as the Natural Gas Policy Act were ignored by the Draft EIS. CEQ regulations for preparation of EIS documents require that an EIS carefully consider these other closely related Federal actions.

DOE agrees that the synergistic effects of overlapping Federal actions should be taken into account and these were included in the modeling effort. However, it does not agree that the implementation of the Natural Gas Policy Act represents such an overlap. Additional comments on gas supplies and the Natural Gas Policy Act are addressed in comments to the USEPA and the California Energy Commission (comment regarding page 1-3).

14. Page 2-11, sixth paragraph

The Draft EIS states that no increased coal use was attributed to an AQCR if there were no large (greater than 100 million Btu) combustors. As noted previously, this assumption is erroneous since ERA's regulations propose to include small combustors.

See response to comment by California Energy Commission comment regarding page 1-1 (p. 12-27).

Similarly, paragraph seven erroneously excludes small combustors with low load factors from the Draft EIS. In reality, the proposed FUA regulations will impact small combustors such as canneries that have very low annual load factors. The EIS therefore understates the impacts of the proposed FUA regulations.

The FUA provides flexibility for combustors with respect to low annual load factors. The assumption of a 60 percent capacity factor mentioned in the regulations can be rebutted. This would affect the application for any exemptions.

15. Page 3-1, fifth paragraph

The Draft EIS assumes that "Existing utilities will not be affected by the proposed action..." since they were already analyzed under the old coal conversion program.

This assumption is contrary to the proposed regulations. 10 CFR 504 subparts D and E require stringent tests to be passed before a temporary or permanent exemption will be granted to existing power plants. For example, 10 CFR 504.21(a)(2) requires that the substantially exceeds index (apparently 1.5 initially) be used to justify lack of alternative fuel supply. Since purchased power, or for that matter a number of alternate fuels, may be considered available if the index is set at this level, it seems probable that some existing facilities will be forced to use coal or alternate fuels. This assumption is contrary to the assumption in the EIS which means the impacts from the proposed regulations are again underestimated.

Most utilities meeting economic, environmental, and reliability criteria received orders under ESECA. Some utilities were not issued prohibition orders due to perceived economic, environmental, and other problems similar to those exemptions included in the FUA. The remaining utilities with a potential to be affected by the FUA between now and 1990 are negligible, based on pages 57 and 58 of the Regulatory Analysis (see next response).

16. Page 3-1, fifth paragraph

The Draft EIS assumes that large natural gas-using utilities will elect the "Systems Compliance Option."

In reality, due in part to recent DOE policies (see 44 FR 1694) large natural gas-using utilities will be using more natural gas than projected in the EIS. In addition, ERA's system compliance regulations are so burdensome that most utilities will probably not elect to file for the option.

DOE's regulatory analysis of the proposed regulations (*Analysis of Proposed U.S. Department of Energy Regulations Implementing the Powerplant and Industrial Fuel Use Act*, DOE/EIA-0102/21, November 1978) notes that total utility fuel use and utility coal use in 1990 will be virtually identical with or without the Systems Compliance Option. The main impact of the Option will be to allow continued use of some gas rather than requiring a full shift.

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17. Page 3-2, Section 3.2.1

This entire Section, which lists the assumptions upon which the Draft EIS is based, is erroneous and out of date. Emissions and impacts from FUA are therefore not correctly predicted:

- Natural gas prices will not remain controlled, nor will world oil prices remain constant.

- Environmental and economic exemptions will not really be available if ERA's proposed FUA regulations become effective. Since ERA's proposed regulations require a Final Determination by EPA or the State on an environmental permit, most applicants will not elect to invest two years and substantial funds into obtaining an EPA turn-down, only to be possibly rejected by ERA. Furthermore, if ERA's substantially exceeds index remains high (e.g., 1.5-1.8 or more, as proposed) it is unlikely that anyone will receive an economic exemption. The Draft EIS assumes an approximate 1.4 ratio (Footnote a., pages 3-7).

See response to comments by California Energy Commission regarding page 1-1 (p. 12-26).

Environmental and economic exemptions will be available under DOE's FUA regulations. The "substantially exceeds" criterion used in the EIS to reflect a worst-case analysis was selected to bring virtually all new industrial facilities within the scope of the program. The index was designed to include almost all exemptions applicants, and therefore reflects the potential difficulty in receiving an economic exemption. The potential applicants can elect not to be processed through the FUA system by combusting an alternate fuel. Should the applicant decide to combust oil or natural gas, an FUA exemption will be needed if the facility falls within the limitations of FUA coverage.

18. Page 3-5, third paragraph

The Draft EIS assumes that boilers in nonattainment areas are exempt from the program. However, the proposed regulations choose an opposite approach which would make environmental exemptions almost impossible to obtain.

Again the impacts of the proposed regulations are understated in the EIS.

The assumptions concerning siting in non-attainment areas are explained in response to EPA, page 12-9. The impact of siting coal combustion facilities in non-attainment areas is discussed in Section 5.2.4.

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19. Page 3-6, Section 3.2.5.2

The Draft EIS assumes all combustors in nonattainment areas are "automatically exempt" from the program. As noted previously, this assumption is false.

See response to Comment 18 above.

20. Table 3-2, page 3-7

This table is in error, due to the false assumptions discussed above.

For the reasons cited above, DOE believes the table is correct.

21. Environmental Consequences of the Proposed Act - Section 5

For ease of evaluation our comments on the sections will be discussed by technical area rather than by progressive placement in the document.

A. Air Quality

As we have pointed our earlier, the EIS does not describe the impacts of the proposed regulations. Moreover, baseline conditions and basic assumptions were incomplete and inaccurate, particularly from California's perspective. The three critical air pollutants in this state are oxidants (ozone), TSP and sulfates. We believe that conversion to coal could aggravate the existing widespread violations for these three pollutants. This is because coal combustion generally produces more NO_x, SO_2, and particulate emissions than does oil or gas combustion, assuming BACT in all cases.

The text has been modified to include a discussion of the potential impacts of the Act on NO_x concentrations. In this revision (Sec. 5.2.4), increased NO_x production and potential impacts are discussed.

The EIS stresses hydrocarbons as a key factor in ozone formation (p. 4-1,4-2). While this is true, NO_x is also a key factor in the formation of ozone, and no estimates were made of ozone concentration increases due to increased NO_x emissions.

TSP is a problem throughout much of California, with many areas exceeding concentrations of 100 ug/m^3 (the national ambient TSP standard) for 24-hour averaging periods, several times each year.

All base-case projections assume only anthropogenic sources. Fugitive dust levels from soil cover were not considered. The worst-case baseline assumed that the national ambient TSP standards were just being met. Assumptions pertaining to non-anthropogenic sources would require estimates that are beyond the present state-of-the-art.

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The EIS uses a "worst case" baseline TSP concentration of 75 ug/m^3, which is unrealistically low. We suspect that this is true for other places within the U.S.

The numerous problems derived from sulfates were completely overlooked in the EIS. SO_2 produced by coal combustion could contribute to these problems significantly. While there are no national ambient air quality standards for sulfates, the detrimental health effects of this pollutant are widely recognized. None of these were discussed.

A discussion of the effects of sulfates is contained in a text revision in Section 5.2.4. Also, see response to Comment 9, p. 12-30.

The modeling approach used in the EIS was to determine changes in annual average ambient air quality in entire air quality control regions as a result of the implementation of the proposed regulations. This approach is defended by stating that localized impacts will be addressed on a case by case basis. This is an unacceptable method of analysis simply because the major air quality problems will mostly be for short-term periods under adverse meteorological conditions. This means that ambient standards for short averaging times (e.g. one-hour, twenty-four hour) are completely overlooked. Violations of such short averaging time standards will most certainly be the primary obstacle to either conversion to coal or construction of new coal facilities. To dismiss this problem as a case-by-case issue is overly simplistic and fails to get to the heart of the matter. Relative to this issue is the statement on page 3-6 that for purposes of the EIS, combustors located in nonattainment areas were "treated as automatically exempt from the program." No similar exemption is "automatically" granted under the regulations

Violations of short-term pollutant standards are generally a local phenomenon. The prediction of such violations is site-specific, and will be addressed by appropriate regulatory agencies before coal combustion is allowed.

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for facilities located in nonattainment areas. If coal conversion resulted in preventing the attainment or maintenance of ambient air quality standards, the source would have to either shutdown to obtain expensive, hard-to-obtain emissions tradeoffs.

The text has been modified to further assess the potential impacts of the Act on non-attainment areas (see Sec. 5.2.4). Increased coal use in non-attainment areas was not included in the energy modeling (see Sec. 3.2.1), but was included in the analysis of environmental impacts.

Finally, the EIS did an inadequate assessment of impacts on PSD areas of all classes. Only increases in annual average pollutant concentrations were predicted, and it is quite likely that short averaging time impacts will be much more significant and more likely to cause violations of allowable PSD increments.

All applicable federal, state, and local air quality regulations must be met before coal combustion is allowed. See response on previous page (12-36).

We believe that the EIS waives the most important air quality issues affecting the nation's air quality. The EIS should examine typical case-by-case examples in critical air quality control regions. These examples should be in a variety of different areas throughout the United States where several types and sizes of facilities are examined under worst case meteorological conditions.

DOE believes that such an analysis would serve no valid purpose. The document assesses the regional and national impacts of the Act. Local effects will be determined on a case-by-case basis by the proper regulatory authorities before coal combustion begins.

B. Public Health

With regard to public health, the EIS uses difficulties in explicitly quantifying dose-response relationships between air pollutants and human health as an excuse to virtually ignore this area of concern. In addition, the unique nature of coal fly ash, (in terms of size and therefore ability to penetrate to the deep lung) and the toxic and carcinogenic substances associated with it, are not adequately treated. The implications to public health from air emissions resulting from the interpretation of the regulations vs. the status quo is absent.

See response to Comment 9, p. 12-30.

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Further, the conclusions and discussions pertaining to air pollution health effects, including but not limited to, acid fall-out, trace elements, radionuclides and health implications of increased coal combustion throughout the nation are insufficient.

Specific Comments

Health effects are listed as a "minimal" impact on page 1-12, Table 1.5. This requires a judgement that the fatal and non-fatal injuries related to extraction, cleaning and transportation of coal (estimated in the report), and those related to combustion and waste disposal <u>which are specifically not estimated</u> in the report are "minimal." Based on the state of knowledge, the EIS should classify these effects "discernible" or as significant." This is appropriate given the definitions listed in Table 1.4.

The discussion of Total Suspended Particulate (TSP) in the existing environment fails to differentiate between the size, chemical composition and hence health effects potential of coal fly ash and other particulates such as dust. This is particularly significant in areas such as California which currently does not have a significant fly ash component in their ariborne TSP.

The conbustion air quality impact analysis in Section 5.2.4 fails to address SO_2 transport and transformation to sulfates which may have significant health impacts.

Section 5.2.4, on page 5-17, indicates that ground level SO_2 values were used in health effects models. The results of such modeling have not been presented. If such modeling was done, the results should be presented, or an explanation of why the results of such efforts are not relevant or reliable.

Health effects impacts are only discussed in the most extremely generic fashion in Section 5.9.5. No real attempt has been made to relate the air impacts quantified earlier in the EIS to health impacts.

Discussions of radionuclides are contained in the responses to comments by the Colorado Office of Energy Conservation (p. 12-45), the State of New York (p. 12-60), and the State of Oregon, Division of State Lands (P. 12-72).

The "minimal" determination of health effects stems primarily from the overall increase in coal production due to the program. Moreover, most coal demand due to the FUA is for sufficiently small quantities that the opening of new mines is not justified. Consequently, the accidents expected would result primarily from greater production levels at existing mines. Cause and effect would be difficult to establish.

Increased occupational health effects at combustion sites would result from the handling and combustion of coal rather than oil or natural gas. The relative hazards were not judged to be discernible. The analysis of public health impacts reflects DOE's best estimate of such impacts. The small volume of total coal use which is due to the program and the mandatory compliance with applicable environmental standards indicate the program will have "minimal" public health impacts on a national and regional basis.

A discussion of the potential impact of the Act on national sulfate levels and the potential implications is contained in Section 5.2.4.

See response to Comment 9, p. 12-30.

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C. Water Supply

Sections 5.4, 6.2 and 7.2, which address water resources impacts, overlook a significant potential impact of the implementation of the regulations in California. Demands for power plant cooling water supplies in the state promise to be considerably higher if new nuclear and/or coal-fired power plants comprise most of the new generating capacity. Such plants would most likely be sited inland using wet cooling towers and requiring two to three times as much cooling water as oil-fired combined cycle plants. Furthermore, repowering of existing coastal facilities and development of co-generation projects can provide new generating capacity with little or no increase in cooling water requirements. The difference in cooling water requirements between a high nuclear case and a case relying more heavily on repowering and cogeneration is estimated to be as much as 400,000 acre-feet per year by the year 2000. This difference is most significant, given the increasing competition for California's as well as the West's limited water supplies which has already resulted in major opposition to new use of inland waters for power plant cooling.

The FUA has no stipulations regarding the cooling cycles which will be employed on a given site. Because the use of cooling water by conventional oil-, gas- or coal-fired plants is roughly equal (per unit of energy produced), the Act will not appreciably affect water consumption by powerplants. Furthermore, the Act is not expected to have any appreciable impact on fuel choice decision by power-plants since these plants generally are constructing for coal combustion with or without the Fuel Use Act.

22. Page 6-1, Discussion of Unavoidable Adverse Impacts

The inavoidable adverse impacts of the proposed FUA regulations are not described adequately in Section 6.1 and 6.2 of the Draft EIS.

As discussed previously, environmental residuals resulting from the proposed regulations will be greater than projected in the EIS due to:

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- The draft EIS omission of small combustors from analysis
- The draft EIS's failure to analyze alternate fuels such as petroleum coke
- The draft EIS's failure to attribute any emissions from existing utilities to the program
- The draft EIS's failure to consider the shortages of water in the Western United States.
- The draft EIS's faulty assumptions regarding automatic environmental exemptions in non-attainment areas.

These issues were addressed above.

- The draft EIS's failure to analyze a high substantially exceeds index.

See response to California Energy Commission comment regarding page 1-1.

23. Page 7-1, Discussion of the Irreversible and Irretreviable Commitments of Resources

- The coal projected to be used is underestimated

The comment that coal projections are underestimated is based on several earlier comments that a worst-case analysis was not performed. As indicated in previous responses, a maximum annual production of 129 million tons projected for FUA beginning in 1990 is a worst-case projection.

- Water resources required are underestimated and not specified. The EIS should make a realistic projection of Western water requirements that would result if the stringent proposed regulations are adopted.

In a generic assessment of this nature it is not possible to provide detailed assessments of local or site-specific impact. The DOE stands behind its analysis as an overview of projected impacts to major regions and to the country as a whole. Although the overall effects of the act have been judged to be minimal, it is acknowledged that severe local problems may occur. Many of these will be addressed in subsequent NEPA compliance documents.

- The EIS fails to consider the consumption of air emission offsets that are required by the proposed regulations. Since the proposed regulations do not exempt non-attainment areas, offsets will be needed for facilities to be located in these areas.

A discussion of the potential impact of the Act on the consumption of offsets is discussed in Section 7.6.

24. Page 9-1

The Draft EIS inadequately predicts the relationshop between short term uses of the environment and the maintenance and enhancement of productivity.

Prime examples of inadequacy are:

- The second paragraph incorrectly assumes natural gas "savings" due to the program. DOE's own recent policy statements refute this argument.
- The second and third argument incorrectly assume displacement of imported oil. Domestic heavy crudes will also be affected by the proposed regulations.

DOE believes that the subject is adequately addressed in Section 9.

See response to USEPA comments about Projected Oil and Gas Savings (p. 12-15).

The second and third items listed in Paragraph 2 are not "arguments" but indications of the environmental impacts of increased coal combustion.

25. No Action Alternative

The no action (no regulatory program) is falsely premised upon a natural gas shortage that by DOE's own recent projections is not occuring and is not likely to occur through the mid-1980's. (Page 10-1) Since the Natural Gas Policy Act was passed, the "base case" used in the draft EIS is unvalid and moot: indeed, much of the "savings" claimed for the program will occur die to the National Gas Policy Act, the market place and not FUA.

From the perspective of conservation, the Natural Gas Policy Act does not "save" gas, but it encourages suppliers to produce more natural gas. Only the Fuel Use Act actually "saves" natural gas. Only when all prices are completely deregulated (an alternative far from "no action") will the real scarcity of natural gas and likelihood of shortages be known.

26. Alternate Fuels

The Draft fails to predict the impacts of the use of alternate fuels, such as petroleum coke and shale oil, which are proposed by ERA in its FUA regulations. (10 CFR 500.2(a)(7)). The environmental impacts of these fuels, particularly petroleum coke, may in fact exceed those of coal in many cases.

A discussion of petroleum coke has been added to the text (Section 10.2.2.5). Shale oil is discussed in the ESECA Final EIS, which is referred to in Section 10.

27. Conservation

The Draft gives only cursory attention to a conservation alternative (Page 10-3). The Energy Information Administration's economic analysis of FUA indicated that an "80% economic exemption level" (Page 87, DOE/EIA-0102/21 Analysis Memorandum) corresponds to a cost of approximately $15 dollars per barrel of oil saved under FUA. A number of conservation measures are viable alternatives to the proposed program at this cost level but were not discussed.

See response to comment of U.S. Department of Health, Education, and Welfare, p. 12-6.

28. Page 10-13

Table 10.5 purports to compare the Fuel Cost Penalty to Coal Consumption but disavows any relationship to the "substantially exceeds index".

The substantially exceeds index is indeed a critical parameter in qualifying for an exemption, yet it is not analyzed nor are the effects quantified. Since the question of what is meant by "substnatially exceeds" represents a discretionary decision making opportunity for ERA, the EIS should discuss the options available to ERA and the impacts associated with each option.

Moreover, if the ERA process is to aid in agency decision making, all policy options which the ERA has with regard to the Act and in drafting and implementing regulations, should be explored and evaluated in the EIS if the document is to fulfill its stated purpose.

The Fuel Cost Penalty described in Table 10.5 reflects a variable cost parameter which is a substitute for the "substantially exceeds" index. Actually, capital and operating costs were evaluated as part of the modeling, and the 50 percent fuel cost penalty reflects a 44 percent total cost penalty when capital and operating costs are included. As can be seen from Table 10.5, the coal use variable is asymptotic and this index level captures virtually the entire feasible universe that would be subject to the Fuel Use Act, in accordance with the worst-case analysis taken by the EIS.

COLORADO

Office of Energy Conservation

Department of Local Affairs
Colorado Division of Planning
Philip H. Schmuck, Director

STATE OF COLORADO 1876
Richard D. Lamm, Governor

January 23, 1979

Mr. Steven A. Frank, Chief
Environmental Evaluations Branch
Division of Coal Utilization
Office of Fuels Regulation
Department of Energy
2000 M Street N.W.
Washington, D.C. 20461

SUBJECT: Draft Programmatic Environmental Impact Statement
Fuel Use Act

12-43

Dear Mr. Frank:

The Colorado Clearinghouse recently received the above-referenced Environmental Impact Statement and circulated it for review by interested state agencies. The enclosed comments of the Office of Energy Conservation resulted from that review.

Thank you for the opportunity to participate in your decision-making.

Very truly yours,

S O Ellis

Stephen O. Ellis
Principal Planner

SE/CGJ/vt
Enclosure

cc: Office of the Governor
Office of Energy Conservation

520 State Centennial Building, 1313 Sherman Street, Denver, Colorado 80203 (303) 892-2351

State of Colorado

OFFICE OF ENERGY CONSERVATION

DENVER

RICHARD D. LAMM
Governor

BUIE SEAWELL
Director

To: Clearing House

JAN 19 1979

DIV. OF H...

From: O E C

Date: January 15, 1979

Re: THE FUEL USE ACT, DRAFT PROGRAMMATIC ENVIRONMENTAL IMPACT STATEMENT

This EIS appears to cover less than 34 percent of the proposed new facilities affected by the Fuel Use Act if the initial definitions and premises (Sec. 1. 2; p. 1-1) are taken literally. There is a contradiction that needs clarifying if this EIS is intended to meet all new facilities.

Specifically, the EIS maintains that "a maximum number of facilities would be designed for or would convert to coal or an alternate fuel." The alternate fuels are defined to include waste products from certain industries and the EIS then states that the "predicted impacts of alternate fuels are not given due to uncertainty of their usage". Then, the enumerated conclusions state that "approximately 34 percent of facilities will be using coal or an alternate fuel by 1985 and the remaining 66 percent are expected to substitute an alternate fuel by 1990." Hence, on a coal versus alternate fuel comparison, only 34 percent maximum of the proposed new facilities will use coal by 1990- the remainder are alternate fuel fired. If this is the intended conclusion, this EIS fails to consider at least two-thirds of the new facilities, but on p2-11, it is stated that " most facilities would use coal as the alternate fuel and that coal is expected to be the overwhelming choice of alternative fuel......" There is an obvious contradiction in coal versus alternate fuels in several parts of this EIS.

The text has been revised to indicate that the choice of fuels for both the 1985 and 1990 time periods will be coal or an alternate fuel. This revision does not alter the assumption that coal is expected to be the overwhelming choice of alternate fuel. Recalculation of the data in Table 1.1 has resulted in a corrected estimation of the facilities which will be using coal or an alternate fuel due to the proposed action between implementation and 1985, and between 1985 and 1990.

Biomass (sec 10.2.2.3) is one alternative fuel that is dismissed by the DOE as having little likelihood of major contribution by 1990. While this may be so, there are certain specific sites that have considerable biomass potential. The combined use of biogas with existing or possibly new national gas facilities may prove to be more economical, both fiscally and on a net energy basis, than coal-fired units. Variances allowing this full mixture should be part of the exemptions possible under the FUA. It is not obvious which of the categorized exemptions listed on p. 2-2 and 2-3 such variances might be permitted.

The text (Sec. 10.2.2.3) has been changed in response to this comment.

Energy conservation programs are included as an alternative energy technology (10.1.4) and are dismissed in 3 short paragraphs. Yet energy conservation via a net energy analysis for each proposed action in the FUA need not be considered as an alternative but rather as an integral part of this program. This FUA EIS completely ignores net energy considerations; it would appear that an essential chapter is missing.

See response to comment by U.S. Department of Health, Education, and Welfare, p. 12-6.

Only in the air quality section (P5-9) are such concepts alluded to stating that 4,000 gallons of diesel fuel are required to transport 1,000 tons of

1600 Downing Street, Denver, Colorado 80218 (303) 839-2507

coal 1,000 miles. Such a statement, even though incomplete, is unique to this EIS and there is virtually no other inference to energy costs to meet the FUA programs and more importantly to maximize its effectiveness.

Upgraded rail and road facilities, new railroad cars, new boiler facilities, etc all require energy to be implemented. Yet energy costs are ignored. Population shifts and increase auto-traffic were likewise mentioned but again with no energy analysis. While these may be dismissed as one-time costs, the continual aspects of the FUA deserve serious study to maximize net energy content of the transported fuels. Transportation of western low sulfur, low BTU coal to eastern regions primarily to meet air quality standards is expected by this EIS. Yet since the EIS concludes that the FUA won't add significantly to existing air pollution or won't be implemented in non-attainment areas, the additional transportation costs-on a net energy basis-versus the perceived benefits aren't obvious. The intent of the FUA is to minimize oil and gas use. One means to achieve this is via a careful analysis based upon net energy evaluations for each proposed action. Possibly an energy degradation figure should be considered. That is, if the transportation costs evaluated on an energy basis exceed a predetermined fraction of the total energy transported, the movement would be disallowed.

Again, energy conservation is not an alternative to be dismissed but rather must be considered as part of each proposed action. Only then can the true intent of the FUA be met with maximum effectiveness.

Furthermore, an energy accountability would help define the exemptions permitted by this act. It appears that an additional chapter addressing net energy concepts relating to FUA programs should be included in the final EIS.

The news media has related certain fears this past year that increased coal combustion will lead to dangerously high radioactive concentrations in some areas. Curiously, the EIS (sec 5.2) on air quality confines its discussion to SO_x, NO_x and particulate emission parameters and doesn't mention radioactive particles. Yet the appendix (sec E. 2.5.4) includes several tables listing thorium and uranium content in various coal categories. The significance of these tables is missing in the discussion. Does omission of a radioactive-health hazard discussion imply no hazard? The EIS might be a good place to refute the news media changes, hazards are not. Regardless, since radionuclides are considered in the appendix, a brief discussion appears warranted.

An energy balance sheet could be prepared for the program comparing it to continued use of oil and gas. Such an approach ignores both the economic basis for fuel choice and the strategic objectives of the program. Such an energy balance also does not provide information on environmental effects. The regulations require calculation of the economic costs or conversion, including the costs associated with transporting coal, etc. Use of the net energy basis cannot be the basis for determination of the acceptability of the FUA.

Energy conservation, as depicted in the National Energy Plan, was included in the EIS analysis. Energy conservation and the FUA are consistent with each other; therefore, energy conservation is not considered an alternative to the FUA program but is expected to complement the program. At this time, quantifiable net energy concepts--coal combustion, coal mining, coal transportation, alternate fuels--have been addressed as reasonably as possible given the undeterminable site-specific economic, energy and environmental impacts resulting from the FUA program.

Although the concentrations of natural uranium and thorium may be high in specific coal samples (Table E.11, p. E-26), the mean concentrations both by region and by coal rank (Table E.12, p. E-27) are within the background ranges for various types of rock as reported in NCRP Report No. 45 (National Council on Radiation Protection and Measurement 1975). Fly ash is expected to have radionuclide concentrations of approximately ten times that in the coal ore (Klein et al. 1975). The staff has calculated regional mean dose commitments due to 1985 and 1990 baseline coal use on the basis of the above activities of natural uranium and thorium in coal and in fly ash, and the air concentrations of particulates as indicated on page 5-17 and in Figures 5-2 and 5-3. The regional mean dose commitments from baseline concentrations are small with respect to the regional natural background radiation doses (National Council on Radiation Protection and Measurement 1975; U.S. Nuclear Regulatory Commission). The incremental increase in dose commitments due to increased fuel use (based on Figs. 5.4 and 5.5) are very small in comparison to the base-case dose commitments.

References

National Council on Radiation Protection and Measurement (eds). 1975. Natural Background Radiation in the United States - Recommendations of the National Council on Radiation Protection and Measurement. NCRP Report No. 45.

Klein et al. 1975. Pathways of Thirty-seven Trace Elements Through Coal-Fired Power Plants. Environ. Sci. Technol. 9(10):973.

U.S. Nuclear Regulatory Commission. Generic Environmental Impact Statement on Uranium Milling, USNRC, NUREG-0511, in preparation.

ILLINOIS

Department of Conservation

STATE OF ILLINOIS
EXECUTIVE OFFICE OF THE GOVERNOR
BUREAU OF THE BUDGET
SPRINGFIELD 62706

February 13, 1979

Mr. Steven A. Frank, Chief
Environmental Evaluations Branch
Division of Coal Utilization
Office of Fuels Regulation
Department of Energy
2000 M Street, N.W. - Rm. 7202
Washington, D.C. 20461

Dear Mr. Frank:

RE: Draft Programmatic Environmental Impact Statement: Fuel Use Act
DOE/EIS-0038-D
SAI #78 11 28 61

The Illinois State Clearinghouse wishes to revise its January 8, 1979 letter concerning the above referenced subject. Attached are comments from the Illinois Department of Conservation which should be included in the final EIS.

Thank you for your cooperation.

Respectfully yours,

T E Hornbacker/SED

T. E. Hornbacker, Director
Illinois State Clearinghouse

TEH/li

Attachment

12-46

Illinois Department of Conservation (continued)

Illinois Department of Conservation
life and land together

605 WM. G. STRATTON BUILDING •400 SOUTH SPRING STREET •SPRINGFIELD 62706
CHICAGO OFFICE – ROOM 100, 160 NO. LASALLE 60601
David Kenney, Director • James C. Helfrich, Assistant Director

February 5, 1979

Ms. Linda Impson
Illinois State Clearinghouse
Bureau of the Budget
Springfield, IL 62706

Re: Fuel Use Act Draft Programmatic
Environmental Impact Statement
#78 11 28 61.

Dear Ms. Impson:

The Department has received summary information on the above referenced subject. According to our review of these materials, we feel that one important case may not have been fully examined in the assessment of environmental impacts by coal supply region.

In describing the methodology used to evaluate energy impacts of the program, certain simplifying assumptions were reportedly made in order to arrive at a maximum figure for total coal substitution. No provision has been explicitly made for the regional effects on local demand of a US EPA policy decision to revise the Federal New Source Performance Standards to reflect the Best Available Control Technology (BACT) for reducing sulfur emissions. Although BACT was assumed for calculations of projected maximum oil and gas savings, and for the calculation of amounts of waste scrubber sludge and fly ash, the results of this assumption do not seem to have been accounted for in the projected production expected to result in various supply regions.

Coal Supply Region 4, which includes Illinois, has large reserves of high sulfur coal that are projected to become relatively more economically attractive than lower sulfur Western coals as a result of this environmental policy decision. This is a conclusion reached in an analysis conducted at Argonne National Laboratory's Energy and Environmental Systems Division (Argonne report ANL/AA-16). If the base and proposed action cases have not accounted for the interactive effect of a stringent BACT policy, the magnitude of coal production impacts in Region 4 will have been underestimated, and we recommend that this case be examined in the Final EIS.

Given the simplifying assumption of New Source Performance Standard stated in Section 3.2.3, the distributional pattern of the incremental coal demand by major fuel-burning industries as a result of the proposed action is estimated based on the data from the BOM coal flow matrix (see Comment 2). It would be expected that the incremental coal demands generated by the major fuel-burning installations are radically different from the total coal demand projected by the report cited (ANL/AA-16). The regional basis in the ANL report is also different from the FUA EIS. Comparison of the projected energy supply of FUA Supply Region 4 and the Midwest Region in the ANL report demonstrates the differences of regional bases and the variations in the assumptions associated with emission standards (see Table 3.9 in FUA and p. 2 in the ANL report). Because of the disparate assumptions in the cited reports, differences in coal demand projections would be expected.

Illinois Department of Conservation (continued)

Ms. Linda Impson
February 5, 1979
Page Two

With the exception of the above, we find this Draft EIS adequate in its treatment of issues and examination of alternatives. Thank you for your attention.

Sincerely,

Steven W. Harrison
Division of Planning & Design

SWH:ju

KANSAS

Forestry, Fish and Game Commission

STATE OF KANSAS

Department of Administration

OK

OPERATIONS RP

17 JAN 79 3:45

DIVISION OF STATE PLANNING AND RESEARCH
5th Floor—Mills Building
109 W. 9th
Topeka, Kansas 66612

January 10, 1979

Director
U. S. Dept. of Energy
Economic Regulatory Admn.
Office of Fuels Regulation
Washington, D.C. 20461

Re: Fuels Use Act - Draft
Environmental Statement
SAI#: 6385 - DES
Reviewed by: Fish & Game, Park & Resources

Kansas Forestry, Fish and Game (continued)

The referenced project has been processed by the Division of State Planning and Research under its clearinghouse responsibilities described in Circular A-95.

After review by interested state agencies it has been found that the proposed project does not adversely affect state plans. There has been concern expressed by the Kansas Fish & Game Commission, and Park & Resources Authority regarding final plans and specifications for construction. Should this project be funded by U. S. Dept. of Energy we request that the applicant work with the above listed state agencies in assuring that all expressed concerns are incorporated in the final plans and specifications.

Should you have qny questions please contact this office. Please refer to the State Application Identifier (SAI) Number above in all future correspondence.

Sincerely,

Paul V. DeGaeta
A-95 Coordinator

PVD:jc

Attachment

cc: Robert D. Wood, Kans. Fish & Game Comm.
Wayne Herndon, Planning Dept., Kans. Park & Resources Authority

STATE AGENCY A-95 TRANSMITTAL FORM

Return to:
Division of State Planning & Research, Department of Administration, Suite 501
Mills Building, Topeka, Kansas 66612

PROJECT TITLE: Office of Fuels Regulation, U.S. Dept. of Energy
Draft Programmatic Environ. Stmt. Fuels Use Act

[ ] Notification of Intent
[ ] Preapplication
[ ] Final Application

DATE REVIEW PROCESS STARTED	DATE REVIEW PROCESS ENDED	SAI NUMBER
11-27-78	12-18-78	6385 - DEIS

PART I Initial Project Notification Review (To be completed by Clearinghouse):

The attached project has been submitted to the State Clearinghouse under the provisions of the Federal OMB Circular A-95 revised. This form provides notification and opportunity for review of this project to the agencies checked below. Please fill in Part II and Part III below and return to the State Clearinghouse.

[X] Return by 12/15/78
[ ] Expedite
[ ] Add. Info. Avail.

REVIEW AGENCIES

[ ] Aging
[X] Agriculture - DWR
[ ] Civil Rights Commission
[X] Economic Development
[ ] Education
[X] Forestry, Fish & Game Commission
[X] Health and Environment
[X] Historical Society
[ ] Human Resources
[X] Kansas Corporation Commission
[X] Park and Resources Authority
[ ] Social and Rehabilitation Services
[X] State Conservation Commission
[ ] Transportation
[ ] Water Resources Board
[X] Planning & Research

PART II Nature of Agency review comments (To be completed by review agency and returned to CH):

Check one or more appropriate boxes. Indicate comments below. Attach additional sheet if necessary or use reverse side.

[ ] Request clarification or additional info. [X] Suggestions for improving project proposal

COMMENTS:

SEE COMMENTS ON REVERSE

PART III Recommended State Clearinghouse Action (To be completed by review agency and returned to Clearinghouse):

Check one box only:

[ ] Clearance of the project should be granted

[ ] Clearance of the project should be delayed until the issues or questions have been clarified by the Applicant

[X] Clearance of the project should not be delayed but the Applicant should (in the final application) address or clarify the questions or concerns indicated above

[ ] Request the opportunity to review the final application prior to submission to the federal funding agency

Reviewer's Name	Div./Agency	Date
Robert D. Wood	Kans. Fish & Game Comm.	12-6-78

Because Kansas is an intensively farmed state, areas still vegetated with naturally occurring species are critical to maintenance of the state's wildlife resource base. Any loss of naturally vegetated areas through land-use conversion results in loss of wildlife. Only by including measures for habitat replacement and enhancement can we hope to even maintain what we have now.

Table 1.5: We realize the project sponsors may consider loss of wildlife habitat to be minimal on a national basis, but on a state basis, this is not accurate. Using the definitions cited herein, we suggest the rating for wildlife habitat be changed to "Discernible".

The impacts on the State of Kansas are not considered to be discernible because it is not expected that coal will be mined there. The Surface Mining Control and Reclamation Act of 1977 and good reclamation practices can return lands to their original habitat function.

Pg. 5-47: Cited here is the common misconception that when wildlife habitat is destroyed, the animals dependent on it merely move to another parcel of habitat. Once wildlife habitat is destroyed, those animals dependent on it are also lost. Surrounding habitat parcels will already be at their carrying capacity for indigenous species. Those animals displaced will perish unless additional carrying capacity is provided through habitat replacement or enhancement of remaining habitat. If all things remain static, habitat loss results in wildlife loss.

Pg. 7-1: Irreversible commitments of biotic resources. Losses of native woodlands and rangelands border permanency as it is impossible for man to duplicate the species diversity of plants of those habitat types. Since the natural process of plant succession will have to be relied upon, "replacement" will require centuries not decades.

It has been the Kansas experience that when reclaiming mined land, man tends to replace natural habitats with domestic crops of grass or grain. The monocultures which result are not conducive to the diverse wildlife resource present in naturally vegetated areas.

Even during the natural successional process, duplicating of the former biotic composition and diversity is unlikely. The randomness of biotic dynamics overlies the directional process of succession; this results in post-disturbance communities with similar qualitative features but lacking quantitative equality with pre-disturbance communities. In many cases (e.g., climax forest), it will require centuries to develop similar habitat. However, earlier successional stages may provide suitable habitat for some wildlife species found in the climax stages. In other cases (e.g., grasslands), recovery of wildlife or livestock supporting capacity can be obtained in decades or shorter. Wildlife species found in the early stages of typical old field communities of early successional stages would be expected to become reestablished in the mined area more quickly than species requiring communities climax.

Pg. 11-1: Environmental trade-offs. The opening sentence of this chapter could be said of every resource exploitative activity devised by man, especially when adverse impacts affect renewable natural resources such as wildlife. The "general public" generally only notices something that directly impacts their pocketbooks. This "public" attitude does not, however, provide measure to the significance of adverse impacts of exploitative activities.

The statement did not refer to current and projected impacts of coal mining, but to the impacts attributed to the program itself. The acres of land disturbed are quantified in Table 11.1.

Table 11.3: As stated earlier, wildlife habitat losses will be discernible by the project sponsor's definition. Additional acres of land to be stripped are documented, therefore, acres of wildlife habitat lost as a result of FUA can be documented.

There is no way to accurately determine which customers are using coal due to the Fuel Use Act and how much additional coal that is based on the FUA compared to total coal use by that customer. Additional documentation would be speculation.

Kansas Park and Resources Authority

FACSIMILE

It would appear that an important alternate not mentioned within this document is elimination of wasted energy. Many city lighting systems could be cut overnight by 50% to 75% with no serious problems to residents. Also state highway lighting systems could be eliminated - substituting reflectorized signs, color-coded to direct traffic.

See response to comment of U.S. Department of Health, Education, and Welfare, p. 12-6.

ORIGINAL

STATE AGENCY A-95 TRANSMITTAL FORM

Return to:
Division of State Planning & Research, Department of Administration, Suite 501
Mills Building, Topeka, Kansas 66612

PROJECT TITLE: Office of Fuels Regulation, U.S. Dept. of Energy
Draft Programmatic Environ. Stmt. Fuels Use Act

☐ Notification of Intent
☐ Preapplication
☐ Final Application

DATE REVIEW PROCESS STARTED	DATE REVIEW PROCESS ENDED	SAI NUMBER
11-27-78	12-18-78	6385 - DEIS

PART I Initial Project Notification Review (To be completed by Clearinghouse):

The attached project has been submitted to the State Clearinghouse under the provisions of the Federal OMB Circular A-95 revised. This form provides notification and opportunity for review of this project to the agencies checked below. Please fill in Part II and Part III below and return to the State Clearinghouse.

☒ Return by 12/15/78
☐ Expedite
☐ Add. Info. Avail.

REVIEW AGENCIES

☐ Aging	☐ Human Resources
☒ Agriculture - DWR	☒ Kansas Corporation Commission
☐ Civil Rights Commission	☒ Park and Resources Authority
☐ Economic Development	☐ Social and Rehabilitation Services
☐ Education	☒ State Conservation Commission
☒ Forestry, Fish & Game Commission	☐ Transportation
☒ Health and Environment	☐ Water Resources Board
☒ Historical Society	☒ Planning & Research

PART II Nature of Agency review comments (To be completed by review agency and returned to CH)

Check one or more appropriate boxes. Indicate comments below. Attach additional sheet if necessary or use reverse side.

☐ Request clarification or additional info. ☐ Suggestions for improving project proposa

Kansas Park and Resources Authority (continued)

COMMENTS: It would appear that an important alternate not mentioned within this document is elimination of wasted energy. Many City lighting systems could be cut overnight by 50% to 75% with no serious problems to residents. Also State Highway lighting systems could be eliminated-substituting reflectorized signs, color coded to direct traffic.

PART III Recommended State Clearinghouse Action (To be completed by review agency and returned to Clearinghouse):

Check one box only:

- [ ] Clearance of the project should be granted
- [ ] Clearance of the project should be delayed until the issues or questions have been clarified by the Applicant
- [ ] Clearance of the project should not be delayed but the Applicant should (in the final application) address or clarify the questions or concerns indicated above
- [ ] Request the opportunity to review the final application prior to submission to the federal funding agency

Reviewer's Name	Div./Agency	Date
Wayne Hendon	Planning	12-26-78

MARYLAND
DEPARTMENT OF STATE PLANNING
301 WEST PRESTON STREET
BALTIMORE, MARYLAND 21201
TELEPHONE: 301-383-2451

MARVIN MANDEL
GOVERNOR

VLADIMIR A. WAHBE
SECRETARY OF STATE PLANNING

January 11, 1979

Ms. Ruth C. Clusen
Assistatn Secretary for Environment
Department of Energy
Washington, D.C. 20461

SUBJECT: ENVIRONMENTAL IMPACT STATEMENT (EIS) REVIEW

Sponsor: U.S. Department of Energy

Project: Draft EIS - Proposed Regulations to Implement the Fuel Use Act, DOE - EIS-0038-D

Dear Ms. Clusen:

The State Clearinghouse has reviewed the above statement. In accordance with the procedures established by the Office of Management and Budget Circular A-95, the State Clearinghouse received comments from the following:

Department of Economic and Community Development, Environmental Health Administration and our staff: noted that the Statement appears to adequately cover those areas of interest to their agencies.

Department of Natural Resources: forwarded comments (copy attached) from their Energy Policy Office which noted that more attention should be given to the probable impacts in the Northeast, particularly where prevailing air mass movement lowers air quality, and to the negative impact in terms of cost and actual environmental benefit derived from enforcement of the Surface Mine Act.

Tri-County Council for Western Maryland and the Baltimore Gas and Electric Company: were afforded an opportunity to review and comment but have not responded as of this date.

Thank you for your attention to the A-95 review process and we look forward to continued cooperation with your agency.

Sincerely,

J. W. McConnaughhay

James W. McConnaughhay

cc: Steven Frank
Henry Silberma
Donald Milsten
Lowell Frederick
Donald Noren
Balto. Gas & Electric Co.
Stephen Kocsis

Maryland Department of State Planning (continued)

Maryland Department of State Planning
State Office Building
301 West Preston Street
Baltimore, Maryland 21201 Date:

SUBJECT: ENVIRONMENTAL IMPACT STATEMENT REVIEW

Applicant: U.S. Department of Energy

Project: Draft EIS Fuel Use Act

State Clearinghouse Control Number: 79-11-591

We have reviewed the above draft environmental impact statement and our comments as to the adequacy of treatment of physical, ecological, and sociological effects of concern are shown below:

	Check (X) for each item: None	Comment enclosed
1. Additional specific effects which should be assessed:		The negative impact in terms of cost and actual environmental benefit derived from enforcement of the Surface Mine Act of '77 as it affects expectations in this EIS.
2. Additional alternatives which should be considered:		
3. Better or more appropriate measures and standards which should be used to evaluate environmental effects:		
4. Additional control measures which should be applied to reduce adverse environmental effects or to avoid or minimize the irreversible or irretrievable commitment of resources:		Conclusions focusing on i pacts in VI do not appear to adquately emphasize impacts in Northeast particularly where prevailing air mass movement lowers air quality in Maryland.
5. Our assessment of how serious the environmental damage from this project might be, using the best alternative and control measures:		

6. We identify issues which require further discussion of resolution as shown:

Signature [signature]

Title Director

Agency EPO, of DNR, FC2A

These costs will be reflected in the price of coal, and provide an economic basis for applying for an exemption.

The major impact of the FUA will occur in Demand Region VI, which accounts for 58 percent and 68 percent of the increased coal use for 1985 and 1990, respectively. However, the air quality projections associated with the proposed action were based on a regional dispersion model which takes into account long-range transport. The impacts on air quality in Maryland does take into account prevailing air mass movement.

NEW YORK

State of New York

M. Peter Lanahan, Jr.
First Deputy Commissioner

STATE OF NEW YORK
DEPARTMENT OF
ENVIRONMENTAL CONSERVATION
ALBANY, NEW YORK 12233

'79 FEB 16 PM 1:29

Office of Public Hearing, Management
U. S. Department of Energy
Box WA, Room 2313
2000 M Street, NW
Washington, DC 20461

FEB 15 1979

Attention: Steven A. Frank

Gentlemen:

The State of New York has completed its review of the Draft Programmatic Environmental Impact Statement "Fuel Use Act", issued by DOE in November 1978. In preparing the attached comments, we have taken into consideration the views of all appropriate state agencies.

The major premise of the Fuel Use Act is that oil and natural gas use must be replaced with the use of coal or alternate fuels wherever possible. However, indigenous natural gas supplies have recently been estimated to be plentiful, even without new technology. Combining natural gas with other presently available technologies (i.e., energy conservation, hydroelectric, nuclear, solar, wind energy, biomass, refuse-derived fuel, cogeneration, etc.) can reduce our dependence on imported oil in an environmentally compatible manner. In other words, we should not place all our emphasis into one fuel cycle.

We in New York State are particularly concerned with the ongoing measurable destruction of our prime recreational areas in the Adirondacks and with the immeasurable health effects attributable to long range transport of SO_2 and NO_x and ultimate conversion to sulfates, nitrates, and acid precipitation. The only way to reverse this trend is to reduce the presently unacceptable emissions. The Fuel Use Act will be counterproductive with respect to this goal. Mandating conversion from oil to clean burning natural gas (and other environmentally compatible technologies) rather than solely to coal should be an alternative to be seriously investigated in the FES.

We appreciate the opportunity to review this environmental statement and we request that you give our comments your foremost consideration.

Sincerely,

M. Peter Lanahan, Jr.
First Deputy Commissioner

Attachment
cc: H. Peyrebrune

See responses to following detailed comments.

State of New York (continued)

NEW YORK STATE COMMENTS

ON THE DRAFT PROGRAMMATIC

ENVIRONMENTAL IMPACT STATEMENT

"FUEL USE ACT"

ISSUED BY THE U. S. DEPARTMENT OF ENERGY
NOVEMBER 1978
#DOE/EIS - 0038-D

February 1979

1. General Comment

The intent of the Fuel Use Act is to wean industry and utilities away from existing and prospective scarce gas and oil use, thereby reserving supply for fuel-critical uses. Current industry outlook regarding gas supply and price advantages appears to contradict the FUA assumption of scarcity and necessity for conversion to coal (ref. U. S. News & World Report, January 29, 1979). According to the estimate in this report, there is a total potential reserve of 4335 trillion cubic feet (TCF) of natural gas within the U. S. At the present consumption rate of 20 TCF per year, this would equal a 217 year supply. Even if gas use were increased to substitute for oil consumption, there would still be sufficient reserve until non-depletable energy sources are developed (by the 21st century).

The natural gas reserves referred to in U.S. News and World Report include those that will not be economically recoverable or, if recoverable, at prices that the consumer cannot now afford. The American Gas Association recognizes that even to maintain current consumption, more gas has to be found and higher prices must be available to produce this higher-cost gas. Even with the Natural Gas Policy Act and the increase in wellhead prices, there is no evidence that sufficient increased production will result to allow for growth in the natural gas industry. Those users who have an economically substitutable source such as coal or alternate fuel are being encouraged to switch. Such fuel switching will still conserve existing low-cost natural gas reserves and make these available to higher-priority users. (See response to USEPA, p. 12-15.)

State of New York (continued)

Current pronouncements by Secretary of Energy Schlesinger regarding use of gas by industrial users indicate a shift in policy from that enunciated by ERA in the Fuel Use Act. On January 3, 1979, Secretary Schlesinger stated that industries would be encouraged to switch from oil to natural gas or coal, if they could, evidently in preference to the continuing dollar drain imposed by oil imports (ref. NY Times, January 4, 1979).

See response to U.S. EPA comment, p. 12-15.

2. General Comment

The UPEIS states that the coal substitution program for electric power generation will not be permitted to cause violations of National or State air quality standards, even though use of local coal will be required regardless of its quality. This will be achieved by gas cleaning equipment and processes and, if necessary, by requiring existing sources in the AQCR to reduce their emissions adequately before a preconstruction permit will be issued. The draft EIS, however, should discuss the technological or economic feasibility of accomplishing the necessary degree of air pollution control.

It is obvious that greater degrees of control will be necessary with coal as a fuel. There is a potential for numerous conflicts between the economic health of this state and air quality. Inflated prices for electrical power and manufactured goods are one consequence our society can ill afford. In addition, the rules may prove to be an obstacle to the normal and essential growth of industry. These considerations are an integral part of the problem and cannot be overlooked. It is therefore incumbent upon DOE to provide evidence that appropriate air standards can be achieved without serious economic penalty. This critical consideration must not be left as a problem for those agencies responsible for the continuing administration of air quality programs.

We already have two large non-attainment areas in New York State, where we have thus far been unable to reduce emissions sufficiently to meet air quality standards. Except for possible trade-offs, the situation

The technological feasibility of achieving air pollution control is well documented by EPA rules and regulations. The economic cost of installing and using this equipment can be one of the factors considered as a basis for obtaining an exemption under the FUA regulations. At the programmatic level, the mix of existing technology, local air pollution laws, and other factors is sufficiently diverse to preclude identification of how an individual facility can comply.

in these areas precludes introducing the air pollutants which would be emitted from new coal burning power plants in them. One alternative course would be to select sites outside of such AQCR's. Yet here we have possible destruction of agriculture -- for example, the grape industry. These impacts must be addressed in any site-specific analysis for coal conversion. However, it should be recognized in the DPEIS that this problem exists.

The maximum expected annual average concentrations of SO_2 per AQCR are expected to approach 71 $\mu g/m^3$ (baseline plus increment due to the FUA, Figs. 5-3 and -5). This is still well below the threshold levels (470 $\mu g/m^2$) that have been reported to injure sensitive plants during chronic exposure to SO_2. Most of the data available on responses of plants to gaseous pollutants are derived from studies using crops or other economically important plants. Thus, it is unlikely that agricultural yields will be affected on a regional basis in response to the implementation of the FUA. Local impacts may occur but we cannot judge the magnitude of the local impacts at the programmatic level.

3. General Comment

Landfill disposal of fly ash, rich in iron and containing more aluminum that we produce annually from bauxite, represents a frightening waste of resources.

4. General Comment

The impact statement evaluates "...annual average ambient air quality..." (p. 5-10); which "...by design ignores local effects..."; yet acknowledges that "...the local concentrations may be important..." (p. 5-17). However, on p. 5-22 this issue is left to "...be addressed on an individual basis as conversions begin". Yet it is concluded that "The increase in gaseous pollutant levels due to the Fuel Use Act is well below threshold levels for injury to most biota". (p. 1-8).

This conclusion is unsupported by the background discussion. Generic short-term concentrations need to be developed in the statement because annual averages are of limited value in predicting impacts to vegetation from air pollutants.

The text has been modified to reflect the fact that the threshold levels under consideration are for chronic exposure to SO_2 (p. 1-8). Acute exposures to higher concentration can only be evaluated on a site-specific basis because short-term concentrations are highly dependent upon factors influencing local meteorological variability. It is indeed possible that local meteorological events may result in concentrations of pollutants that are toxic to biota during short-term exposure. However, the extent to which this will occur cannot be evaluated at a programmatic level.

5. General Comment

One area of geologically related concern is the potential for ground-water degradation from runoff and leachate from fly ash disposal areas.

State of New York (continued)

The fly ash generated by coal burning contains heavy metals in soluble forms which can, via percolation through disposal piles and surface runoff, enter and degrade groundwater.

Fly ash contains varying concentrations of thorium and uranium which originally had been associated with coal. The radioactivity of fly ash disposal areas is currently the subject of investigation within US DOE and elsewhere. It is not presently clear whether this aspect of fly ash poses any threat to public health and safety. A rigorous reading of criterion Number 1 of the Environmental Protection Agency's recommended "Criteria for Radioactive Wastes" can lead to the conclusion that fly ash should be considered a radioactive waste meriting complete isolation over its hazardous lifetime.

Guidelines and regulations proposed under RCRA will require protection of groundwater supplies. These regulations are discussed in the revised text in Section 5.5.5.

Conclusions concerning the increased regional dose commitments due to incremental increases in coal use are discussed in the comments from the Colorado Office of Energy Conservation, State of Colorado (p. 12-45).

Fly ash may be considered a radioactive waste under Criterion No. 1 of the Environmental Protection Agency's (EPA) proposed "Criteria for Radioactive Wastes" (U.S. EPA 1978a). Unacceptability of risk is discussed in Issue No. 4 of this document. On a regional basis, the risks due to radiation from incremental increases in coal use are negligible. The EPA has also proposed guidelines for identification of hazardous wastes on an individual basis (U.S. EPA 1978b). Fly ash is exempted from the definition, and classified as a "special waste". The EPA states that a proposed rulemaking will be published at a later date regarding treatment, storage, and disposal of special waste (anonymous 1978). At this time there are no guidelines which require special handling of fly ash because of its radioactivity.

References

Environmental Protection Agency. 1978a. Criteria for Radioactive Wastes - Recommendations for Federal Radiation Guidance. Fed. Reg., Nov. 15, 1978, Part IX.

Environmental Protection Agency. 1978b. Hazardous Waste-Proposed Guidelines and Regulations and Proposal on Identification and Listing. Fed. Reg. (40 CFR Part 250), December 18, 1978, Part IV.

Anonymous. 1978. ERA Proposed Hazardous Waste Regulations under the Resource Conservation and Recovery Act 43 FR 58946, Dec. 18, 1978. Environmental Protection Agency 40 CFR Part 250. Environmental Reporter, Vol. 9, Number 34, Part II.

State of New York (continued)

In any case there are excellent prospects that EPA may, because of the heavy metals associated with the fly ash, declare it a toxic waste product requiring special disposal techniques. Regardless of whether or not fly ash is considered to be toxic, storage in specially designed disposal areas is necessary. These aspects should be thoroughly discussed in the FEIS.

See response to similar comment, p. 12-59.

6. General Comment

Approximately 80 percent of the coal produced as a result of the proposed action will come from surface mines. Aesthetic impacts will result from mining and restoration activities, transportation, processing, spoil piles, user stockpiling and ultimate ash disposal. No mention is made of the potential aesthetic impacts of increased coal utilization. This is an unfortunate oversight which should be remedied in the final impact statement.

The coal demand of individual users is sufficiently small as to result in increased production in existing mines rather than opening of new mines. Aesthetic impacts resulting from increased production at existing mines will be largely restricted to the combustion site where the coal pile and coal handling equipment will be the primary new features of the site. Because of the nature of most manufacturing sites, it is largely questionnable whether these features will be viewed by the general public as different from the general overall aspect of the site. A number of mitigating measures, primarily screening, would be available in a case where existing industrial activity was perceived to be substantially less obtrusive than addition of coal-burning facilities. Aesthetic impacts are predominantly a site-specific problem.

7. General Comment

In general the impact of the proposed Fuel Use Act on transportation policies and systems appears to have been adequately addressed. However, we feel that a section concerning transportation should have been added to Chapter 5.8, Socio-Economic Impacts. Other sections of the EIS identify the need for significant public investment in transportation facilities (highways, railroads, canals, and port facilities) in order to successfully implement this proposal. The funding source for these improvements is not specified. They conceivably might come from:

-- additional federal, state, and local appropriations

-- a shift of current funding to transportation away from other programs

-- a shift from within existing transportation programs to meet the needs of this proposal.

The impacts from coal hauling were addressed in Section 5, and cover the items mentioned in the comment. In all states, the shift to coal for specific users would have to consider the adequacy of transportation modes. Until individual sites are assessed, there is no *apriori* basis for establishing the relative adequacy of the New York State transportation network to handle coal movement.

State of New York (continued)

The importance and difficulty of these decisions, with their inherent social, economic, environmental, and political consequences merit discussion in this Chapter.

While New York State will not be directly impacted by coal mine operation, neither shall we be benefited by an expanded job market in that area. However, we shall be faced with the indirect effects of higher fuel costs, conversion costs, and increased demands for improved transportation facilities. The New York State Department of Transportation has already received numerous complaints in western New York concerning the effects of increased highway coal hauling.

These heavily laden vehicles generally have increased the rate of normal wear-and-tear on the highways. On portions of roadway having extended steep grades, the movement of vehicles has been considerably slowed, necessitating the construction of climbing lanes. The cost of these improvements would necessitate altering priorities and programs if no source of additional new funds is created to fulfill this new demand. Consequently we feel that the Environmental Impact Statement should address this problem.

8. General Comment

The discussion of the issues of Wild and Scenic Rivers (section 5.6.7) and Archaeological, Cultural and Historical Resources (section 5.7) needs to be expanded. The report defers discussion of these subjects to the case-by-case analyses. While this approach may be valid with respect to specific impacts, there should at least be a clear commitment to mitigating the impacts. An impact statement of this type could provide guidance in the form of a mitigation strategy to be followed later when case-by-case impacts are evaluated.

The operators of mines, disposal areas, and other facilities which may, through their activities related to the Fuel Use Act, affect these important natural resources, should take all measures to avoid or mitigate potential impacts on Wild and Scenic Rivers and Historical and Archaeological Sites and Natural Landmarks. Operators should contact the appropriate administering agency responsible for each potentially affected Wild and Scenic River (U.S. Department of Agriculture, through the Forest Service; U.S. Department of the Interior, through the Bureau of Land Management, Fish and Wildlife Service, or National Park Service; or individual state governments) for guidance in protecting Wild and Scenic Rivers. Operators should contact state Historic Preservation Officers to determine individual state procedures for investigation, identification, and preservation of Archaeological, Cultural, and Historical Resources. Operators should also contact the U.S. Department of the Interior, Heritage Conservation and Recreation Service for current listings of the National Register of Historic Places. This consultation is required by state law, but is otherwise not explicitly guaranteed by the U.S. Department of Energy in its administration of the Fuel Use Act.

State of New York (continued)

9. General Comment

There is no discussion of terrestrial impacts from ozone generated within a coal-fired power plant plume (Science, December 1978, V. 202:1186-1188). New York and other areas are currently experiencing vegetative injury and damage from ozone. Any incremental increase is likely to increase damage, particularly if it were to occur when ambient ozone is at or above levels causing damage. This oversight should be remedied in the final impact statement.

The text has been modified to discuss the generic terrestrial impacts from photochemical oxidants (p. 5-57). The dynamics of photochemical oxidants such as NO_x and ozone are highly dependent upon local meteorological conditions. Therefore, programmatic analysis of the effects from photochemical oxidant production from increased coal combustion under the FUA cannot be made with any precision.

10. pp. 1-8, 9, section 1.3.5 Ecology

Acid rain is treated as an aquatic problem on page 1-8 but is not similarly identified on that same page under terrestrial ecology. A more balanced discussion is needed.

The text has been modified to indicate that noticeable terrestrial impacts from acid precipitation are not expected from the implementation of the FUA (p. 1-8).

11. p. 1-11, section 1.4 Environmental Trade-Offs
p. 10-1, section 10.1.1 No-action Alternative (+pp. 11-1,5)

The DPEIS (p. 1-11) states "If domestic natural gas and oil prices remain below world levels in the next few years, the program can force (fuel) substitution without the consumer paying for increased general fuel prices that would occur as the result of immediate price increases through taxes and natural gas deregulation. The cost associated with fuel substitution will be much less than the cost to society of accepting a general increase in oil and gas prices".

The comment that implementation of the FUA would not be cheaper than a general increase in oil and gas prices is based on some debatable assumptions. One is that after phased decontrol of natural gas in 1985, further increases in natural gas prices would not occur. Second, that the availability of natural gas would allow stable prices after 1985. The FUA reduces the demand price pressure on natural gas later by encouraging fuel substitutions now.

State of New York (continued)

This assumption is no longer valid. Phased decontrol of natural gas prices has been legislated through 1985, and the will of OPEC has prevailed to implement further world oil price increases. Removal of domestic crude oil price control is a current possibility. Therefore, it appears that with FUA, State industries and utilities will incur (1) costs associated with fuel substitution and/or Fuels Decision Report procedures (ultimately passed on to the consumer via the price mechanism), (2) the general increase in oil and gas prices proposed as an alternative to FUA and (3) externalized environmental clean-up costs and costs associated with rising morbidity and mortality, as well as losses to the recreational and tourist areas of the Adirondack Mountains due to increased acid precipitation and loss of this once prolific fisheries.

The assumption that natural gas price deregulation by 1985 would increase the trend toward coal conversion (p. 10-1) is not realistic. Because of the enormous amount of pollution control and waste handling needed for a coal facility compared to a natural gas facility, the cost of natural gas would need to be significantly greater than that of coal before coal conversion from natural gas would be considered economically attractive.

In addition, the statement erroneously assumes static supplies of natural gas. The mere passage of the Energy Act has created a present-day significant surplus of natural gas. The purpose of gas price deregulation was to create an incentive for increased gas exploration. Present projections of indigenous natural gas supplies using both existing and proposed feasibile technologies is very large.

A further assumption stated in the comment is that removal of domestic crude oil price controls is a current possibility. Crude oil decontrol would be felt by every consumer and would not be restricted to large facilities using oil or natural gas to raise steam and generate electricity.

State of New York (continued)

A third argument which was made against natural gas (pp. 10-2 and 11-5) is that this alternative would increase the susceptibility of facilities to natural gas curtailments. The recent prolonged coal strike shows that no source of fuel is completely immune from this contingency.

Natural gas use is, in fact, an eminently feasible alternative, both in terms of environmental and economic considerations. The FES should update and expand the analysis of this fuel as an alternative to coal conversion.

The use of natural gas would be an alternative to the Fuel Use Act as a "no-action" alternative. However ERA is implementing regulations for a law which prohibits natural gas use. (See U.S. EPA comment, p. 12-15.) It is well documented that the recovery, transport, and use of natural gas has had fewer negative environmental impacts than the use of coal.

12. pp. 5-10 to 5-22c, section 5.2.4 Combustion

The impacts of NO_x and hydrocarbons should have been addressed in this section as well as those of SO_2 and particulates.

The text has been modified to include further discussion of NO_x (and hydrocarbons).

13. pp. 5-22c, 5-23 Acid Rain

Although sulfate is the predominant pollutant associated with acid precipitation, the impact of nitrates is not insignificant. This should be addressed in the FES, in descriptive, tabular, and graphical form.

The accurate prediction of atmospheric nitrate concentrations, as discussed in Section 5.2.4, is beyond the present state of the art. Potential effects of increased NO_x emissions on precipitation are discussed in Section 5.2.4.

State of New York (continued)

14. p. 5-22c, section 5.3.2 Acid Rain

It appears as if this section was not completed, since the last sentence on this page reads "A major effect of the proposed action may be to cause a large increase(."

The text has been corrected.

15. p. 5-23, section 5.3.2 Acid Rain

"Long-term impacts via soils as well as adverse impacts on aquatic systems would appear unlikely due to the relatively high buffering capacity of the indigenous soils and the relatively low ultimate acidity attributable to the proposed action".

This may be true for certain parts of the country, but definitely not for the Adirondack Park in New York State. This 6,000,000 acre park (both privately and publicly owned) is presently in danger of losing its prime recreational (and economic) assets to acid precipitation, the source of which has been traced (by trajectory analysis) to the Ohio Valley industrial/power plant complex. The Adirondack Park does not contain the buffering soils referred to in the DPEIS. Its bedrock and soils cannot neutralize the acid precipitation which has, to date, caused about 200 lakes in the Park to become devoid of fish.

Although the DPEIS claims that this action will not cause a significant impact, the argument is not convincing for vulnerable areas such as the Adirondack Park.

Although sensitive areas such as the Adirondack Lakes Area may be significantly impacted by acid rains, based on the projections in Figures 5.4 and 5.5, the proposed action is not expected to impact the Adirondack Lakes Area, or other areas containing lakes that are sensitive to acidification by acid precipitation (Galloway and Cowling 1978).

16. p. 5-23, section 5.3.2 Acid Rain

It is stated "...there have been no documented cases of short-term yield reductions at rainfall pH levels above 4.0". This is misleading because the concern is for long-term impacts, not short-term impacts. Further, the entire northeast currently experiences annual precipitation at 4.0 with some areas below that and with individual rainfalls as low as 2.1 (Science, June 1974, V. 184:1176-1179)--almost two orders of magnitude more acidic.

The judgments from which these projections were made were based on the best available data at the time--those of Likens (1976). Those data do not support the statement that "the "the entire northeast currently experiences annual precipitation [averages] at 4.0 with some areas below that." The single lowest data point on Likens' survey is pH 4.07; the lowest pH isopleth, confined to areas of Pennsylvania and New York, is pH 4.22. It is also misleading to imply that the lowest recorded rainfall pH value (pH 2.1) which appears to have validity is characteristic, as suggested by the wording "and with individual rainfalls as low as 2.1."

State of New York (continued)

As far as vegetation effects are concerned, the sentence might better be reworded: . . .there have been no documented cases of either short-term or long-term yield reductions at rainfall pH levels above pH 4.0. The text has been revised to more accurately represent the situation. It should be noted, however, that an adequate data base does not currently exist from which either effect or null effect judgments of a broad scale can be made. Since those areas most heavily impacted by acid rains are also characterized by elevated levels of SO_2, NO_x, and photochemical oxidants, those gaseous pollutants must also be recognized for their potential impact in this type of an assessment.

17. **p. 5-24, Table 5.13 Projected Sulfate Concentrations**

This table is of little value for decisionmaking, since it gives impacts only in terms of square miles and per cent of land area affected. In conjunction with this table, maps similar to Figures 5.2-5.5 (SO_2 concentration increments) should be presented for sulfates. This is the only way that the projected impact on vulnerable areas (such as the Adirondacks) can be visualized.

This is also of vital importance for health impact analysis, as stated on p. 5-73 of the DPEIS: "According to the findings of the Rall Committee, toxic effects from acid sulfates in combination with other particulates may far outweigh any effects from SO_2 or particulates alone". U. S. maps depicting isopleths of present and predicted sulfate concentrations in conjunction with the maps of high air pollution potential, could be of immense aid in decisionmaking.

A computer-based map was used for the analysis of areas affected by increased acid precipitation, but it was felt that a tabular presentation would be more useful in indicating the magnitude of the problem. Particulate sulfate distribution patterns will generally follow SO_2 concentration patterns. Maps were not presented because existing data on the relationship between sulfate levels in the atmosphere and in rainwater are only generalized data and reduced pH of rainfall is related to a complex array of anionic and cationic species from a variety of sources which interact to affect precipitation chemistry.

18. **p. 5-71, section 5.9.5 Combustion Health Effects**

The second paragraph refers to a "...casual relationship between air pollution and resultant adverse health effects". This must be a misprint, since the writer probably meant to use the word "causal" instead of "casual".

The text has been corrected.

19. **p. 6-1, section 6.1 Air Quality Unavoidable Impacts**

This section should state that the given predicted concentrations for SO_2 and particulates are annual values and that shorter term concentrations (3 hours and 24 hours for SO_2 and 24 hours for particulates) will be higher and site specific.

State of New York (continued)

In addition, NO_x, sulfates, nitrates and hydrocarbons emissions should be addressed as unavoidable adverse impacts.

20. p. 10-7, section 10.2.2.3 Nuclear Energy Alternative

The statement "On the other hand, SO_x, NO_x and particulate airborne effluents do not exist at nuclear facilities..." is not accurate. Auxiliary boilers and cooling towers at nuclear facilities can emit significant air pollution under site specific conditions although their air pollution problems for non-radioactive effluents are usually much less than that of similar sized coal plants.

The text has been revised in response to this comment.

21. p. 10-9, section 10.2.2.4 Municipal Wastes

The statement is made "Most utilities, however, are not in the solid waste management business unless there is sufficient incentive for them to do so". This is as irrelevant to the use of solid waste as declaring that utilities are not in the coal management business. If proper arrangements are made with local municipalities, the utilities could receive the solid waste from the municipality in its processed state (or refuse-derived fuel), leaving "solid waste management" to local government.

In addition, the DFEIS should state how the emission of trace elements can be controlled from both the use of coal and refuse derived fuel.

It is generally accepted that utilities are not directed towards solving a community's solid waste management problems if that is the only incentive for their utilization of the solid waste. Consequently, the potential environmental benefits in the utilizations of refuse-derived fuel (RDF) in itself will not be a sufficient incentive for utilities to use RDF. The utility, because of responsibility to the rate-payers and stockholders, will not enter into arrangements which will result in a loss of money for the utility. A further discussion of this topic is to be found in the EPA publication entitled *Use of Solid Waste as a Fuel by Investor-Owned Electric Utility Companies*. (Proceedings: EPA/Edison Electric Institute Meetings. EPA/530/SW-6p, 1975). In particular, see the "Economics and Financing Session" report.

The assumption that "if proper arrangements are made with the local municipality, the utilities could receive the solid waste from the municipality in its processed state, leaving the solid waste management to local government" underestimates the impact of the term "proper arrangements." The commenting organization is referred to the problems encountered in two of the more prominent such solid waste-to-energy ventures in establishing proper arrangements. (See *Solid Waste Management*, March, 1978, p. 16 for information related to the Union Electric experiences in St. Louis, and the Wall Street Journal article of Thursday, November 16, 1978, p. 14 for information on Wheelabrator Frye, Inc. experiences at the Saugus, Mass., plant.)

A discussion of the potential air pollution control required for the control of trace elements from the use of coal and refuse-derived fuel (RDF) was beyond the scope of the EIS. However, results from coal and RDF demonstration facilities indicates that electrostatic precipitator performance efficiency may be reduced

State of New York (continued)

when coal and RDF are fired. At a facility in St. Louis, particulate standards were not achieved above 100 MW (regardless of the coal and RDF mix ratio). Consequently, increased efficiency of ESP systems will most likely be required for coal and RDF systems. With the use of improved ESP systems, control of those elements, particularly those in the submicrometer size range, is also anticipated. Trace elements which are emitted in vapor form is more difficult to contain for coal and RDF systems but improved SO_2 scrubbing systems may be effective in controlling some of these emissions. The amounts of trace elements emitted will be a function of the trace element content in the coal and the RFD. Further research in this area will most likely be required. A more detailed discussion of emissions and their potential control for municipal solid waste/control systems can be found in the following reference:

Gorman, P. G., et al. 1977. St. Louis Demonstration Final Report, Power Plant Equipment, Facilities and Environmental Evaluation. Environmental Protection Agency. NTIS PB-279 828.

22. p. 11-1 Environmental Trade-Offs

It is stated "The national consequences of implementing the proposed action will be largely undiscernible to the general public". Although a large portion of the population will not notice the consequences of this act, those in the immediate vicinity of various impacts will be aware of them. It is most unlikely that the strip mining of 4000 acres annually will be undiscernible to those who live or travel through Demand Region 5, for example.

Although it is recognized that these impacts will be evaluated in separate impact statements on the various individual activities, many extreme impacts have been smoothed over in averaging the impacts over a large area.

The reason for stating that the proposed action would be largely undiscernable to the general public is that the majority of the populace of the U. S. will not notice the consequences of the Act. The EIS does identify those aspects of coal use associated with the proposed action which may cause regional problems, such as increasing coal mining 42 percent over base case in Supply Region 5 (Sec. 5.5.1). This mining activity will be discernable to those persons living within the general vicinity of the mine. The mine output, however, may not be substantially dedicated to FUA facilities, but will produce for expected utility demand. Impacts of the FUA are expected to be dispersed and not clustered in a particular area.

Extreme impacts due to the program are not anticipated either at the programmatic or site-specific level. The word extreme is interpreted to mean unacceptable. This will not be allowed because of mining, water, and air quality standards which must be met before increased coal use can be initiated at a given site.

23. p. 11-1 Environmental Trade-Offs

It is stated, "The main thrust of the proposed action is to accelerate those impacts to the 1980's and 1990's rather than during a later period when gas and oil shortages may force conversions through shortages and prices". This seems to minimize the actual damage done, by implying that it will happen eventually anyway, regardless of the program.

State of New York (continued)

This is not necessarily true. Forced to use alternate fuels at this time, industries may very well turn to coal, with its undesirable impacts. In 10 or 20 years, however, other, more benign, alternatives may be more feasible than they are today, as well as more advanced pollution control technologies.

The implied inevitability of conversion to coal should not be used to justify the program.

The use of alternate fuels may be more benign in 10 or 20 years, as the comment suggests. The use of coal may also be more benign in the future.

Fuel substitution now, however, mitigates many of the potential problems associated with immediate de-control of oil prices and reduces somewhat the reliance on foreign sources. Consequently, the program is less inflationary than the alternatives in the short term.

It is questionable whether in 10 or 20 years the direct combustion of coal will look any less desirable than alternate fuels. To incur the environmental impacts of fuel substitution now in order to reduce the economic costs and strategic risks is considered an acceptable trade-off.

24. p. 11-4, Table 11.3 Trade-Offs

The footnote to this table states that the trade-offs are generally national and that site specific impacts may be more pronounced. However, site-specific impact would be addressed at a later date. At that time, it would likely be too late to expect effective control of widely separated multiple actions with cause and effect relationships such as the Adirondack acid precipitation problem.

The purpose of the programmatic EIS is to evaluate the environmental impacts of the FUA to the general populace. However, the potential for FUA to cause significant local or regional impacts has been identified. Little impact is projected for the northeast USA, where acidity levels may be approaching the level at which undesirable environmental consequences can occur.

OREGON

Division of State Lands

Executive Department
INTERGOVERNMENTAL RELATIONS DIVISION
ROOM 306, STATE LIBRARY BLDG., SALEM, OREGON 97310

January 16, 1979

Ruth C. Clusen.
Assistant Secretary for Environment
Department of Energy
Washington, D.C. 20461

Dear Ms. Clusen:

RE: Fuel Use Act
PNRS 7812 4 230

12-70

Thank you for submitting your draft Environmental Impact Statement for State of Oregon review and comment.

Your draft was referred to the appropriate state agencies. The Departments of Fish and Wildlife, Lands and General Services offered the enclosed comments which should be addressed in preparation of your final Environmental Impact Statement.

We will expect to receive copies of the final statements as required by Council of Environmental Quality Guidelines.

Sincerely,

Kay F. Wilcox

Kay Wilcox
A-95 Coordinator

KW:cb

Enclosures

OREGON PROJECT NOTIFICATION AND REVIEW SYSTEM

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Ph: 378-3732

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PNRS STATE REVIEW

Project #: 7[illegible]   Return Date: ~~DEC 20~~ 1-12-79

ENVIRONMENTAL IMPACT REVIEW PROCEDURES

1. A response is required to all notices requesting environmental review.
2. OMB A-95 (Revised) provides for a 30-day extension of time, if necessary. If you cannot respond by the above return date, please call the State Clearinghouse to arrange for an extension.

ENVIRONMENTAL IMPACT REVIEW
DRAFT STATEMENT

( ) This project does not have significant environmental impact.

( ) The environmental impact is adequately described.

(X) We suggest that the following points be considered in the preparation of a Final Environmental Impact Statement regarding this project.

( ) No comment.

REMARKS

See attached

Agency Lands   By [signature]

12-71

Oregon Division of State Lands (continued)

Division of State Lands Dec. 14, 1978

PNRS State Review
Project 7812 4 230
Return Date: 1/12/79

The regulations to be issued as the proposed action are not provided. **The statement of** broad purposes of the Fuel Use Act is a self-serving, **"God, flag and motherhood"** ruse to commit the reader to stand and salute. **Let's see draft** regulations.

Similarly, broad statements that effects of acid rain "are not yet quantified," **but have been "implicated" are** unacceptable in view of increases in SO_2 **in over half of the nation's** air quality regions. The purpose of a **programmatic statement may be** broad coverage, but when serious problems **are identified at the national and** programmatic scale, these must be examined.

The fact that fly ash may contain radioactive contaminants in quantities sufficient to create a long-term health hazard is not even mentioned.

The entirety of Chapter 6 is mere summation and does not provide enough detail to assess **whether an unacceptable loss will** take place or not. Effects **of 81,000 acres of landfill, while** differing on a site-specific basis, **are not minor because this is** cumulative and in addition to future sanitary **and solid waste landfill requirements.** Perhaps the Department of Energy **feels that rangeland is** unproductive and therefore available to use for **waste disposal, but the cattlemen don't.**

The proposed regulations for implementing the FUA were published in the Federal Register on November 17, 1978, (New Facilities); November 22, 1978 (Transitional Facilities); January 5, 1979 (Special Rule For Temporary Public Interest) and January 29, 1979 (Existing Facilities).

Since increases in AQCRs are very small and cannot be quantified, only a qualitative analysis was done. Prediction of changes in acid rain would be premature because all factors determining rainfall acidity are not well enough understood at this time.

Individual fly-ash samples may contain U-238, U-235, Th-232 and progeny in sufficient quantities to warrent concern. The half life of U-238 is 4.8×10^9 years, of U-235 is 7.1×10^8 years, and of Th-232 is 1.4×10^{10} years. The hazard from these radionuclides on a regional level are discussed in the response to the response to the statement of the State of Colorado O.E.C., and the present proposed EPA guidelines for defining and handling the radioactive hazard of fly-ash are discussed in the response to the State of New York comment.

The impacts of waste disposal are discussed in Section 5.5.5, and estimates are made of the amount of land which will be needed for disposal. The impact is not evaluated as being minor, nor are rangelands discussed as being unproductive.

Oregon Fish and Wildlife

OREGON PROJECT NOTIFICATION AND REVIEW SYSTEM

STATE CLEARINGHOUSE

Intergovernmental Relations Division
306 State Library Building, Salem, Oregon 97310
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PNRS STATE REVIEW 1-12-78

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ENVIRONMENTAL IMPACT REVIEW PROCEDURES

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ENVIRONMENTAL IMPACT REVIEW
DRAFT STATEMENT

( ) This project does not have significant environmental impact.

(x) The environmental impact is adequately described.

( ) We suggest that the following points be considered in the preparation of a Final Environmental Impact Statement regarding this project.

12-73

Oregon Fish and Wildlife (continued)

( ) No comment.

- - - - - - - - - - - -

REMARKS

The environmental impacts of the Fuel Use Act are adequately described in the draft programmatic EIS. The adverse impacts of large-scale mining activities are identified in general terms and state regulations should govern the actual mining, transportation and combustion of coal.
State and local resource agencies should be consulted during the planning states to assist in minimizing environmental impacts and developing mitigation for those impacts which cannot be avoided.

State and local agencies are part of the review process for all site-specific analyses and many permitting processes. State and local information was utilized in compiling the EIS, as indicated by many of the references.

Agency Fish & Wildl. By James B. Has
ENVIRONMENTAL MANAGEMENT SECTION 12/21/78

PENNSYLVANIA

Department of Environmental Resources

Pennsylvania State Clearinghouse

P.O. BOX 1323 – HARRISBURG, PA. 17120 – (717) 787-8046
783-3133

PSC
Commonwealth of Pennsylvania

GOVERNOR'S OFFICE
OFFICE OF THE BUDGET

February 5, 1979

12-75

Steven A. Frank, Chief
Environmental Evaluations Branch
Division of Coal Utilization
Office of Fuels Regulation
Department of Energy
Room 7202, 2000 "M" St. NW
Washington, D.C. 20461

Dear Mr. Frank:

The Pennsylvania State Clearinghouse has received from Ruth C. Clusen by letter dated November 16, 1978, copies of the Draft Programmatic Environmental Impact Statement entitled Fuel Use Act (DOE/EIS-0038-D).

Attached to this letter please find the comments from our Department of Environmental Resources relative to the above Statement.

Please consider these comments the official response of the Commonwealth.

Sincerely,

Richard A. Heiss

Richard A. Heiss, Supervisor
Pennsylvania State Clearinghouse

RAH:ar

Attachments

cc: File (2)

COMMONWEALTH OF PENNSYLVANIA

DEPARTMENT OF ENVIRONMENTAL RESOURCES
POST OFFICE BOX 1467
HARRISBURG, PENNSYLVANIA 17120

The Secretary

January 23, 1979

SUBJECT: Review and Evaluation of PSCH No.: 255-78 Nov 006
Draft Programmatic Environmental
Impact Statement Fuel Use Act
Nationwide

TO: Richard Heiss, Supervisor
Pennsylvania State Clearinghouse

FROM: CLIFFORD H. McCONNELL
Acting Secretary of Environmental Resources

The Pennsylvania Department of Environmental Resources submits the following comments relating to the analysis of air quality impacts in the draft programmatic EIS on the implementation of proposed regulations for enacting the coal and alternate fuels use program which has been authorized by the Powerplant and Industrial Fuel Use Act of 1978.

1) The draft EIS does not adequately consider the impact of increased TSP concentrations which will result from the conversion of SO_2 into atmospheric sulfate. The impact of increased levels of atmospheric sulfates, which are particulates, is particularly significant in areas that are presently nonattainment for TSP or are at or near the national ambient standard for particulates. While the draft EIS does refer to a "constant percentage" relationship between an increase in SO_2 and increased concentrations of particulates at page 5-17, the draft EIS does not analyze the impact upon particulate levels of atmospheric sulfates that are produced by the conversion of SO_2.

The conversion of SO_2 to sulfates and the particulate concentrations resulting from that conversion are included in the analysis. Because no washout of sulfates was assumed, the concentrations are conservative. (See text revision, Sec. 5.2.4, p. 5-22.)

Pennsylvania has extensive particulate nonattainment areas. The increase in atmospheric sulfates from sources outside the state may adversely affect Pennsylvania's ability to attain NAAQS for particulate matter. Difficulty in attaining the NAAQS could result in limitations on new growth in nonattainment areas and could force imposition of extremely stringent control strategies in those areas.

The text has been modified to further discuss the potential direct and transport impacts of the Act on non-attainment areas (see Sec. 5.2.4).

2) Another serious impact which has received insufficient analysis in the draft EIS is the health effect associated with increased levels of SO_2 and particulates. John D. Bachmann of EPA's Research Triangle Park, N.C., recently told a technical conference in Philadelphia that studies leave "little doubt

See response to comment by California Energy Commission, p. 12-30.

Pennsylvania Department of Environmental Resources (continued)

that increased levels of sulfur oxides and associated particulates are related to increase morbidity and mortality in exposed populations." (BNA, Current Dvts. at 251, 6/16/78.) A study by EPA's Environmental Criteria and Assessment Office, "Air Quality Criteria for Particulate Matter and for Sulfur Oxides," states that "virtually all of the recent human health data indicates that detrimental effects occur when sulfur oxides and particulates are interacting." (BNA, Current Dvts. at 1283, 11/10/78.)

The draft EIS should acknowledge the potential for adverse health impact and indicate a need to continually evaluate implementation of the proposed regulations in light of developing health research.

3) A subject which has received no consideration in the draft EIS is the impact of increase atmospheric sulfate levels upon visibility protection. EPA Research Triangle Park studies suggest that "sulfates may be the principal cause of visibility reduction associated with air pollution" in many areas of the United States. (BNA, Current Dvts. at 251, 6/16/78.) EPA indicates that "sulfates may account for 50% of the total visibility reduction in the East" and are "significantly associated" with visibility reduction in the Southwest. (Id.)

The draft EIS indicates that PSD Class I increments should not be exceeded and that no pristine airsheds are "strongly affected" by the program, at page 5-22. However there is no mention of the impact of atmospheric sulfates upon PSD visibility requirements. This deficiency should receive immediate attention. The Clean Air Act requires protection of visibility in certain mandatory Class I areas under Sec. 169A of the Clear Air Act (42 U.S.C. Sec. 7491). Section 169A also authorizes states to establish their own visibility protection programs. By increasing atmospheric sulfate levels without a study of the impact upon visibility in the programmatic EIS, the Department of Energy may well preclude the ability of states to establish meaningful visibility protection programs.

In summary, the Department of Environmental Resources suggests that the draft programmatic EIS be expanded to include a meaningful analysis of the impact of increased levels of atmosphere sulfates associated with higher levels of SO_2 under the Fuel Use Act upon areas that are presently nonattainment for particulates and areas that are at or near the national ambient air quality standard for particulates. The EIS should also carefully consider the impact of increases in atmosphere sulfates associated with the Fuel Use Act upon visibility.

The text has been modified to further discuss the potential impacts of the Act on visibility in Class I areas (see Sec. 5.2.4).

TEXAS

Governor's Office of Energy Resources

OFFICE OF THE GOVERNOR

WILLIAM P. CLEMENTS, JR.
GOVERNOR

January 18, 1979

12-78

Ms. Ruth C. Clusen
Assistant Secretary for Environment
Department of Energy
Washington, D.C. 20461

Dear Ms. Clusen:

The Draft Programmatic Environmental Impact Statement for the Fuel Use Act has been reviewed by the Budget and Planning Office and by interested and affected State agencies.

The comments of the reviewing agencies are enclosed to assist your planning effort. If this Office can be of further assistance, please contact us.

Sincerely,

Tom B. Rhodes

Tom B. Rhodes, Director
Budget and Planning Office

Enclosures

Texas Governor's Office of Energy Resources (continued)

AGENCY REVIEW TRANSMITTAL SHEET

TO: Ken Gordon, Budget and Planning Office Contact

FROM: Governor's Office of Energy Resources   Date Sent: 12/20/78

Date Due: 1/5/79

SUBJECT: Draft Programmatic Environmental Impact Statement   Refer: EIS-8-012-(

Fuel Use Act

We have reviewed the cited document and our comments as to the adequacy of treatment c environmental effects of concern are shown below:

	Check (X) for each item	
	None	Comment enclosed
1. Additional specific effects which should be assessed:	X	
2. Additional alternatives which should be considered:	X	
3. Better or more appropriate measures and standards which should be used to evaluate environmental effects:	X	
4. Additional control measures which should be applied to reduce adverse environmental effects or to avoid or minimize the irreversible or irretrievable commitment of resources:		X
5. Our assessment of how serious the environmental damage from this project might be, using the best alternative and control measures:	X	
6. We identify issues which require further discussion or resolution:	X	

[X] This agency concurs with the implementation of this project.

[ ] This agency does not wish to comment on the subject document because:

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JAN 10 1979
Budget/Planning

Enclosure(s)

Wayne E. Dieter
Name and Title of Reviewing Official
Legal Counsel

12-79

Texas Governor's Office of Energy Resources (continued)

4. Additional control measures which should be applied to reduce adverse environmental effects or to avoid or minimize the irreversible or irretrievable commitment or resources:

COMMENT

The forced conversion from an oil and gas oriented economy to a coal oriented economy in Texas will cause a greater environmental impact on this state than almost any other.

Because coal has been a little used fuel in Texas this change will be intensified. Government officials and the public generally are not familiar with the technology of coal production and useage and the resulting environmental problems.

Two areas of major concern to Texas should be reclamation of areas that have been surface mined and the disposal of waste resulting from coal useage.

The extent of reclamation effort required by the Federal Surface Mining and Reclamation Act must be carefully analyzed and consideration should be given to enhancing reclamation standards.

The degree to which the waste disposal problem will be mitigated can only be determined by a close study of the Federal Regulations established by the Environmental Protection Agency under the Federal Water Pollution Control Act, the Safe Drinking Water Act, the Solid Waste Disposal Act and the Toxic Substance Control Act of 1976. All regulations promulgated under the above acts should be strengthened to deal specifically with low lying costal areas such as the Texas Gulf Coast.

The reclamation of surface mined land is discussed in Sections 5.5.1 and 5.6.1.1, and disposal of coal wastes is discussed in Section 5.5.5. Regulations for implementation of the Federal Surface Mining and Reclamation Act have been proposed and are presently being modified by the Office of Surface Mining Reclamation and Enforcement. Proposals for enhancement of reclamation standards is beyond the scope of the statement. Recently issued proposed regulations for disposal of hazardous wastes (Section 5.5.5) contain important provisions for protecting low-lying coastal areas, floodplains, and wetlands.

Railroad Commission of Texas, Oil and Gas Division

RAILROAD COMMISSION OF TEXAS
OIL AND GAS DIVISION

MACK WALLACE, Chairman
JON NEWTON, Commissioner
JOHN H. POERNER, Commissioner

BOB R. HARRIS
Chief Engineer
J. H. MORROW
Assistant Chief Engineer

ERNEST O. THOMPSON BUILDING • CAPITOL STATION - P. O. DRAWER 12967 • AUSTIN, TEXAS 78711

January 3, 1979

RECEIVED
JAN 9 1979
Budget. Planning

MEMORANDUM TO: Roger Dillon, Assistant Director
Finance and Procurement Division

SUBJECT: Draft Environmental Impact Statement
for the "Fuel Use Act"

Your letter dated December 1, 1978 attached a copy of the subject draft EIS.

We have reviewed this document and have no comments to offer inasmuch as it addresses an area not within the jurisdiction of the Oil and Gas Division.

As we discussed by phone, it appears likely that the Transportation, Surface Mining and Gas Utilities Divisions would likely be affected by the Fuel Use Act and they should have an opportunity to review the draft EIS and submit their comments to you. Accordingly, I am forwarding copies of the subject draft EIS to the Transportation and Surface Mining Divisions and requesting the former to forward the copy to the Gas Utilities Division upon completion of their review.

Yours very truly,

Jim H. Morrow
Assistant Chief Engineer

by Murray C. Moffatt
Murray C. Moffatt
Engineer

MCM:lc

12-81

Railroad Commission of Texas, Oil and Gas Division (continued)

Comments on:

Draft Environmental Impact Statement for the "Fuel Use Act."

1) The following report has not been cited: White, David M. and Olie B. Clemons, Coal and Lignite: Mining, Transportation, and Utilization Needs for Texas. Governor's Energy Advisory Council, June, 1977. This report might update Texas data.

The report was available and was reviewed during the preparation of the Draft. It has been included in the list of references for Section 5.

2) Page 5-3 of the study asserts that "Capital availability is not viewed as a critical constraint to most of those railroads" (west) "(e.g. Union Pacific, Burlington Northern)." Not all railroad analysts would agree. Forbes, October 30, 1978, indicates that the Burlington Northern management may be underestimating the task ahead.

Also see ICC judgment that the rate for the BN's freight to San Antonio from Wyoming should be increased substantially.

Person Conducting Review (Signature) Sandra V. Simmons

(Title) Transportation Counsel

Agency Railroad Commission of Texas Date 1/8/79

Railroad Commission of Texas, Surface Mining Division

RAILROAD COMMISSION OF TEXAS

SURFACE MINING DIVISION

JOHN H. POERNER, Chairman
MACK WALLACE, Commissioner
JAMES E. (JIM) NUGENT, Commissioner

ROY D. PAYNE
Director

ERNEST O. THOMPSON BUILDING • CAPITOL STATION – P. O. DRAWER 12967 • AUSTIN, TEXAS 78711

January 17, 1979

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JAN 18 1979
Budget/Planning

Mr. Ward C. Goessling, Jr., Coordinator
Natural Resources Section
Budget and Planning Section
Office of the Governor
Executive Office Building
411 West 13th Street
Austin, Texas 78701

Re: Draft EIS, Fuel Use Act

<u>Railroad Commission of Texas, Surface Mining Division</u> (continued)

Dear Mr. Goessling:

The document referenced above addresses the main areas of concern regarding the environmental effects of increased coal mining as anticipated upon implementation of the Fuel Use Act. The authors feel that the amount of additional environmental damage to be sustained due to this act is insignificant in comparison to the increase in coal use to be expected without implementation of this act.

While the added effect may be small in comparison, the total end product could be sufficient, even while discharges meet federal air and water quality standards, to lower ambient levels to pre-1970 levels. Thus, the length of time for assimilation of pollution products by the environment should be considered further.

The Railroad Commission of Texas concurs that encouragement of all alternate fuel sources, including coal and lignite burning, must be pursued for the economic well-being of our country for both short and long-term benefits.

Very truly yours,

Roy D. Payne
Director

RDP:lkm

As acknowledged in the text, local impacts due to the FUA may be significant. However, the overall, incremental effects caused by the program should be negligible. It is believed that the impacts will not be severe enough on a broad scale to reduce air and water quality to pre-1970 levels.

The length of time it takes for an added pollutant to be assimilated and possibly rendered harmless in the environment is a highly site-specific phenomenon which is dependent on such things as the ecosystem type and ambient pollutant levels. Such evaluations are beyond the scope of this document.

Texas Air Control Board

TEXAS AIR CONTROL BOARD

8520 SHOAL CREEK BOULEVARD
AUSTIN, TEXAS 78758
512/451-5711

January 18, 1979

Mr. Ward C. Goessling, Jr.
Natural Resources Section
Budget and Planning Office
Office of the Governor
411 West 13th Street
Austin, Texas 78701

Subject: Draft Environmental Impact Statement for the "Fuel Use Act"

Dear Mr. Goessling:

We support the basic goal of the Fuel Use Act, to reduce the United States balance of trade deficit by increasing the use of domestic solid fuel and thereby decreasing use of imported petroleum as boiler fuel.

We have concerns regarding: (1) the indicated anticipation that conversion of existing and construction of new natural gas and petroleum-burning facilities to use other fuels may impinge on local and regional plans and policies, (2) the indication that several federal policies and laws have the potential to be in conflict with individual conversion sites, and (3) we are aware that not enough is known about Houston air pollution as it exists now or as it may exist after a change in fuel; therefore, we have no way of knowing whether regulations written now for the implementation of the Fuel Use Act would be adequate to deal with air quality problems in the Houston area.

The Federal Clean Air Act controls decisions with respect to specific conversions and requires concurrence of the Environmental Protection Agency (EPA). EPA has delegated to the states the responsibility for enforcement plans and programs. Therefore, since it is indicated that conflicts which may arise related to specific individual sites will

Exemptions are available if violations of applicable Federal, state, or local standards would occur for which no feasible mitigation measures could offset.

12-84

Texas Air Control Board (continued)

be resolved prior to the Department of Energy (DOE) action, we recommend that applicable state agencies be identified and be involved in the decision making concurrently with EPA.

Thank you for the opportunity to review this document. If we can be of further assistance, please contact me.

Sincerely,

Roger R. Wallis, Deputy Director
Standards and Regulations Program

cc: Mr. Lloyd Stewart, Regional Supervisor, Bellaire

EPA must grant a permit for a new facility. Facilities are required to comply with the Clean Air Act to receive pre-construction permits. The FUA does not change the regulatory relationship between the U.S. EPA and the appropriate state and local agencies.

There is no legislative mandate for EPA concurrence for granting or denying almost all exemptions or for the issuance of a prohibition order. There are some exemptions which must be approved by EPA such as the peak-load type exemption. The states and EPA are given an opportunity to review all exemption petitions and all proposed prohibition orders during the public comment period.

TEXAS PETROLEUM RESEARCH COMMITTEE

Texas A&M University   Railroad Commission of Texas   University of Texas

PLEASE REPLY TO:
TEXAS A&M UNIVERSITY
COLLEGE STATION, TEXAS
77843

January 4, 1979

Mr. Kenneth G. Gordon
Economic Development and Transportation
Budget and Planning Office
Office of the Governor
Box 12528 Capitol Station
Austin, Texas 78711

RECEIVED
JAN 8 1979
Budget/Planning

12-86

Dear Mr. Gordon:

I am pleased to provide you with my views on the "Draft Programmatic Environmental Impact Statement - Fuel Use Act". My comments are attached.

With very best regards.

Yours very truly,

Paul B. Crawford

Paul B. Crawford
Assistant Director

PBC:jh
cc: Dr. John C. Calhoun, Jr.

attachments

Texas Petroleum Research Committee, Texas A&M University (continued)

AGENCY REVIEW TRANSMITTAL SHEET

TO: Ken Gordon, Budget and Planning Office Contact

FROM: Texas Petroleum Research Committee, Texas A&M University   Date Sent: 12/20/78

Date Due: 1/4/79

SUBJECT: Draft Programmatic Environmental Impact Statement   Refer: EIS-8-012-

Fuel Use Act

We have reviewed the cited document and our comments as to the adequacy of treatment of environmental effects of concern are shown below:

	Check (X) for each item: None	Comment enclosed
1. Additional specific effects which should be assessed:		X
2. Additional alternatives which should be considered:		X
3. Better or more appropriate measures and standards which should be used to evaluate environmental effects:		X
4. Additional control measures which should be applied to reduce adverse environmental effects or to avoid or minimize the irreversible or irretrievable commitment of resources:		X
5. Our assessment of how serious the environmental damage from this project might be, using the best alternative and control measures:	X	
6. We identify issues which require further discussion or resolution:	X	

[ ] This agency concurs with the implementation of this project.

[ ] This agency does not wish to comment on the subject document because:

Enclosure(s)

Paul B. Crawford

Name and Title of Reviewing Official
Paul B. Crawford, Assistant Director

12-86a

Texas Petroluem Research Committee, Texas A&M University (continued)

1. Additional specific effects which should be assessed:

If this program is to be put into effect, we will need to change our educational system here in the State of Texas so that people can be trained for work in the coal and lignite industries. It requires a minimum of four years for a person to get a degree in engineering and perhaps ten years of experience to be accepted as a seasoned employee. This would indicate that it would be about 1995 before we would have trained and experienced people in the coal and lignite field.

Several coal mines have been opened in Texas; at the Big Brown Generating Station of the Texas Electric Service Company many of the miners were hired without previous experience and were trained by the mine operator.

This program also means that additional funds should be added to University budgets to provide for training in coal and lignite mining, processing and use.

Most of the coal to be used in Texas will not come from Texas because of pollution. Coal to serve San Antonio and Houston is provided by contracts from northern states.

Texans now pay the 30% Wyoming severance tax on coal. This and the increased rail charges have had a chilling effect on promoting coal in Texas. The apparent economic advantages of using coal for electric power has appeared as an illusion. Real costs show coal to be losing to nuclear. A nuclear plant costs more, but coal power costs $1.80 per million BTU's and nuclear power costs $0.53 per million BTU's.

Future DOE projections indicate that Texas lignite will be extensively used in Texas in future years, because it can be combusted in compliance with applicable regulations. Higher coal prices in Wyoming and increases in railroad rates approved by the ICC will have the affect of increasing the advantage of using Texas coal rather than Wyoming coal. The decisions to use coal versus nuclear power will not be affected by the FUA. Nuclear power is an alternative for utility constructions.

2. Additional alternatives which should be considered:

Texas has 100 billion barrels of oil known to be in place but not recoverable under present techniques and crude oil prices which are suppressed by federal regulation. If the price of all oil produced from tertiary projects were deregulated to receive the market clearing price the petroleum industry stands ready to invest a billion dollars in West Texas alone to try to recover a part of this tertiary oil.

Texas Petroleum Research Committee, Texas A&M University (continued)

By tertiary oil recovery methods we could expect to recover 10 billion barrels more oil. If the market clearing price is not granted oil wells and reservoirs will be abandoned and the cost of redrilling wells will preclude the recovery of the crude oil. Texas needs this oil to run our state and petrochemical industry.

Oil prices have been rising since the oil embargo in 1974. Although crude oil is still regulated, higher prices are expected. Increased tertiary oil recovery would help to meet oil consumption needs in the 1980's and reduce the reliance on foreign sources. However, this oil is better used for gasoline, home heating fuel and feedstocks for petroleum-based products rather than as a fuel for electricity and industrial steam. Even with more oil produced, its most beneficial application is not in large boilers greater than 100 million Btu's heat input.

The market clearing price for tertiary oil is quite complementary to the FUA given that the U.S. is expected to import more than half its oil needs in 1985 (Energy Information Administration Projection series C). Both the FUA and higher prices for domestic oil will help reduce oil imports.

By promoting a coal economy one does not promote Texas. Texas power plants are importing coal from other states. Texas has substantial amounts of lignite - a low form of coal. Texas lignite presents a greater pollution problem than the imported coals, so coal is imported. A few strict air pollution rules and Texas lignite will not be a serious competitor for coal. Twenty percent of the cost of a clean coal burning plant now goes for scrubbers.

All coal combustion emission sources irregardless of coal origin will be required by the new Clean Air Act Amendments of 1977 to remove a certain percentage of SO_2 (see response on p. 12-80).

3. Better or more appropriate measures and standards which should be used to evaluate environmental effects:

The environmental impact statement provides considerable information on the effect of the process on plants and animals, however, these environmental impact statements rarely relate to the effect of implementation on the employment and remaining purchasing power of the people both upstream and downstream of the installation.

No changes in employment or purchasing power are expected upstream or downstream of a plant using coal unless more maintenance personnel are required to operate the installation. (See response to California Energy Commission Comment on page 12-33 pertaining to the regulatory analysis.)

Air pollution enforcement agencies told the officials running the lignite power plant at Fairfield to add 35 million dollars worth of scrubbers even though the flue gas met the air standards. This money has to come from the food, clothing and shelter budgets of the electrical power users. These are the downstream environmental effects.

The shift to coal may require additional capital to meet environmental regulations. The regulations allow that these costs be considered prior to any regulatory action to shift to coal. (See response to California Energy Commission comment on page 12-33 pertaining to the regulatory analysis.)

Should Texas switch from a petroleum to a coal economy it will have a very serious impact on our petroleum and petrochemical industry which employes about 200,000 people.

Coal used in boilers replaces petroleum that could be used as feedstocks rather than for heat, electricity, or steam. In this sense a coal switch should benefit Texas because Texas produces many petroleum-based chemicals.

Texas Petroleum Research Committee, Texas A&M University (continued)

Should Texas switch to a lignite economy it would do much more for us. We must have environmental standards which will permit Texas lignite to compete with clean burning, high BTU coal imported from other states.

4. Additional control measures which should be applied to reduce adverse environmental effects or to avoid or minimize the irreversible or irretrievable commitment of resources:

The development of markets for out-of-state coal should not be done at the expense of our established oil and gas industry nor fledgling lignite industry.

If our attention should be directed to developing a coal economy rather than the continuation of oil and gas we can expect an irretrievable loss of petroleum resources of the order of ten billion barrels of oil.

The return on investment to the petroleum industry, particularly as gas is deregulated and domestic oil prices rise, should be a more than adequate incentive to continue to invest in oil and gas because Texas produces many petroleum-based chemicals (see previous response pertaining to SO_2 removal).

Petroleum is a limited domestic resource. Petroleum not used in boilers probably will be utilized elsewhere, where some of its unique properties make it an even greater asset. This is consistent with the purposes of FUA (see Comment 2, p. 12-81).

VERMONT

State Energy Office

OFFICE OF THE GOVERNOR
STATE A-95 CLEARINGHOUSE

STATE PLANNING OFFICE
AREA CODE 802-828-3326

STATE OF VERMONT
MONTPELIER, VERMONT 05602

MEMORANDUM

To: Steven A. Frank, Chief, Environmental Evaluations Branch
Division of Coal Utilization, Office of Fuels Regulation
Department of Energy
Room 7202, 2000 M Street, N.W., Washington, D.C. 20461

From: John E. Holmberg, State A-95 Coordinator JEH

Date: January 15, 1979

Subject: Draft Environmental Impact State, Coal and Alternate Fuels Program, Fuel Use Act of 1978, DOE-EIS-0038-D

As the State Clearinghouse under OMB Circular A-95 we have notified other public agencies with a possible interest in your: Draft Environmental Impact Statement.

Copies of comments received are attached; from the Vermont State Energy Office.

JEH:en
encl.

12-87

VERMONT STATE ENERGY OFFICE
STATE OFFICE BUILDING
MONTPELIER, VERMONT 05602
Tel. 802 828-2393

MEMORANDUM

TO: John E. Holmberg, State A-95 Coordinator

FROM: Alan Turner, Wood Energy Specialist AET

DATE: January 8, 1979

SUBJECT: Comments on Environmental Statement for Fuel Use Act

---

No evaluation of environmental impacts due to the use of wood for energy is made. The reasoning given for this omission is both outdated and misinformed. On page 10-7, Section 10.2.2.3 Biomass, the following statement is made: "The present state of development of biomass technologies and anticipated production in commercially usable quantities indicates that there is little likelihood of major contribution to the industrial sector of process steam by the direct utilization of biomass by 1990." (The Department of Energy lists itself as the source of this information.) The foregoing statement is wrong.

In 1978, wood accounted for 1.64×10^{12} BTU's in Vermont industrial use, primarily for process steam. This is five (5) times the use in the previous year. This trend, at a somewhat lesser rate, is expected to continue both in Vermont and other rural, forested sections of the country. This will amount to the equivalent of many billions of barrels of oil annually and will represent a significant contribution to industrial energy needs. Concurrently, a like expansion in the production of electricity from wood fuel, primarily from cogeneration facilities, is anticipated.

The second paragraph of Section 10.2.2.3 states: "Wood, primarily from tree-crop plantation, ... is considered to be most feasible biomass feedstock..." Though wood is the most feasible, it will come from the vast amounts of existing cull material in the forest supplemented by both harvesting and mill residue, not from "tree-crop plantation" (a misnomer for energy plantation).

The third paragraph of Section 10.2.2.3 correctly points out that the environmental impacts of harvesting and burning wood will be significantly less than for coal. This should not be interpreted to mean, however, that those impacts are not significant in and of themselves. Following is a partial list of areas where environmental impacts from wood energy are considered a potential problem:

Soil Erosion	Traffic Congestion
Water Pollution	Ash Disposal
Nutrient Depletion	Wildlife Habitat Degradation
Soil Structure Breakdown	Aesthetic Impacts
Air Pollution from Combustion	
Air and Noise Pollution from Transportation	

AT/pr

The text has been expanded in response to this comment (see Sec. 10.2.2.3, p. 10-7).

OTHERS

American Gas Association

AGA American Gas Association

George H. Lawrence

781923B

February 9, 1979

Office of Public Hearing Management
Department of Energy
Box WA, Room 2313
2000 M. Street, NW
Washington, DC 20461

Gentlemen:

The American Gas Association, which represents some 300 natural gas distribution and transmission companies serving over 160 million U.S. consumers, is pleased to provide the Department of Energy with our industry's comments and recommendations on the Draft Environmental Impact Statement for the coal and alternative fuels program authorized by the Powerplant and Industrial Fuel Use Act of 1978, DOE-EIS-0038-D.

A.G.A. believes that the following issues were not adequately addressed in the draft impact statement:

1. The environmental impacts of the Fuel Use Act (FUA) were assessed in isolation. These environmental impacts should be assessed with reference to the projected increase in overall national coal use which results from diverse government regulations and policies, including the FUA, Energy Supply and Environmental Coordination Act (ESECA), Energy Policy and Conservation Act (EPCA).

2. Constraints on FUA implementation posed by other Federal laws and policy should be discussed (e.g., both the non-attainment and significant deterioration provisions of the Clean Air Act of 1977, Clean Water Act of 1977, Resource Conservation and Recovery Act, the Surface Mining Control and Reclamation Act, and others).

3. The relationship between projected cost and increased coal use should be detailed. Specifically, national inflationary impacts, site specific cost impacts, and negative balance of trade implications (including increasing the regulatory and cost burden associated with manufacturing in the U.S.) of the FUA should be examined for their own importance, and insofar as these induce environmental effects.

10 FEB 79 10:57

12-88a

American Gas Association (continued)

Office of Public Hearing Management
Page 2
February 9, 1979

4. The alternatives section (Chapter 10) should include examination of several natural gas options that could also achieve FUA objectives. The modest energy goals (1.4 quads in 1985 and 2.6 quads in 1990) projected from the implementation of the FUA could easily be achieved with any of several methane options, and could also be achieved with high-Btu coal gasification.

The Fuel Use Act Draft Environmental Impact Statement does recognize the constraints on the coal conversion program mandated by the Clean Air Act. The EIS states, "A major constraint to coal use in the future will be enforced attainment of air quality standards. In this analysis, all combustors shown technically and economically capable of burning coal and located in AQCRs considered to be in violation of air quality standards ("non-attainment") were treated as automatically exempt from the program, and were considered to be precluded from coal burning" (emphasis added) (Page 3-6). The proposed regulation implementing the Fuel Use Act for new facilities, however, does not at all provide automatic exemptions to facilities located in air quality control regions failing to achieve National Ambient Air Quality Standards. Rather, the proposed implementing regulations require companies seeking an exemption from the Fuel Use Act to go through a lengthy and difficult environmental permitting process. The proposed regulations and the Draft Environmental Impact Statement are, therefore, inconsistent with regard to this point. 12-88b

The A.G.A., therefore, submits the following recommendations to the Department of Energy regarding the Draft Environmental Impact Statement to the Powerplant and Industrial Fuel Use Act of 1978:

1. Re-examine the inherent natural gas supply projections underlying the FUA-EIS (e.g., statement on page 2-6) to recognize potential new gas production likely to result from implementation of the Natural Gas Policy Act of 1978 as well as additional supplies from supplemental sources including Alaskan gas, coal gasification, imports from Canada and Mexico, LNG, SNG, and various new unconventional gas technologies (e.g., geopressured gas, tight seams gas, Devonian Shale, biomass, etc.).

2. Quantify the limitations on coal conversion resulting both from the Clean Air Act's non-attainment and its significant deterioration provisions. In this regard ensure that the environmental exemptions examined in the EIS are consistent with those presumed in the FUA implementation regulations issued by ERA.

Office of Public Hearing Management
Page 3
February 9, 1979

3. Quantify all national environmental impacts that will result from all federal policies, which, taken together, encourage the use of coal by industry.

4. Contrast the above environmental impacts with those produced by a methane option designed to result in an amount of imported oil reductions that is equivalent to the reductions estimated to occur under FUA implementation.

5. Study and quantify the economic cost to key industries and the nation of displacing gas with coal for both existing and new industrial energy users versus the cost of providing high-Btu coal gas to these users.

Detailed comments on the Fuel Use Act EIS are attached. Please call me with any questions or comments on (703) 841-8600.

Sincerely,

George H. Lawrence

GHL:sl

12-88c

WRITTEN COMMENTS OF THE AMERICAN GAS ASSOCIATION

ON

THE DEPARTMENT OF ENERGY'S DRAFT

ENVIRONMENTAL IMPACT STATEMENT FOR

THE COAL AND ALTERNATIVE FUELS PROGRAM

AUTHORIZED BY THE POWERPLANT

AND INDUSTRIAL FUEL USE ACT OF

1978, DOE-EIS-0038-D

February 9, 1979

Introduction

The American Gas Association, which represents some 300 natural gas distribution and transmission companies serving over 160 million U.S. consumers, is pleased to provide the Department of Energy with our industry's comments and recommendations on the Draft Environmental Impact Statement for the coal and alternative fuels program authorized by the Powerplant and Industrial Fuel Use Act of 1978, DOE-EIS-0038-D.

Specific Comments and Recommendations

The American Gas Association feels the following issues were not adequately addressed in the draft impact statement:

1. The environmental impacts of the Fuel Use Act (FUA) were assessed in isolation. These environmental impacts should be detailed with reference to the projected increase in overall national coal use which results from diverse government regulations and policies, including the Fuel Use Act.

Base case projections of coal use were derived from a model created specifically to assess the impact of the proposed incentives included in the National Energy Plan. The coal use that would be attributable to ESECA and other energy policy options are included within the base case. Impacts are presented within the EIS for both base case and the proposed action.

The Clean Air Act and its amendments, the Resource Conservation and Recovery Act, the Surface Mining Act and other legislation and regulations tend to constrain coal use. Moreover, the Natural Gas Policy Act encourages the production of natural gas (not coal) and helps to reduce concern about gas availability. On balance, governmental policies, laws, and regulations would not indicate that base-case coal projections are a reflection of federal intent to encourage coal use.

American Gas Association (continued)

2. Constraints on FUA implementation posed by other Federal laws and policy should be discussed (e.g., both the non-attainment and significant deterioration provisions of the Clean Air Act of 1977, Clean Water Act of 1977, Resource Conservation and Recovery Act, the Surface Mining Control and Reclamation Act, and others).

The relationship of FUA to the cited Federal environmental statutes is discussed in Section 2.4 of the Draft EIS. Other statutes are discussed throughout the EIS. The direct impact of these statutes will be on a site-specific level, and these will be addressed in site-specific analyses for each application by the appropriate regulatory agency. The environmental exemption of FUA is designed to permit an exemption in those cases where compliance with applicable environmental standards is not possible.

3. The relationship between cost and increased coal use should be detailed. Specifically, national inflationary impacts, site specific cost impacts, and negative balance of trade implications (including increasing the regulatory and cost burden associated with manufacturing in the U.S.) of the FUA should be examined for their own importance, and insofar as these induce environmental effects.

A regulatory analysis of the program has been performed (Energy Information Administration, 1978, Analysis of Proposed U.S. Department of Energy Regulations Implementing the Powerplant and Industrial Fuel Use Act, DOE/EIA-0102/21, U.S. Department of Energy, Washington, D.C.). On a site-specific basis an exemption can be applied for when the cost of using coal or an alternate fuel "substantially exceeds" the cost of using imported oil.

4. The alternatives section (Chapter 10) should include examination of several natural gas options that could achieve FUA objectives. The modest energy goals (1.4 quads in 1985 and 2.6 quads in 1990) projected from the implementation of the FUA could easily be achieved with any of several methane options, and could also be achieved with high-Btu coal gasification.

See response to comment by State of New York, p. 12-67.

American Gas Association (continued)

The A.G.A., therefore, submits the following recommendations to the Department of Energy regarding the Draft Environmental Impact Statement to the Powerplant and Industrial Fuel Use Act of 1978:

1. Re-examine the inherent natural gas supply projections underlying the FUA-EIS (e.g., statement on page 2-6) to recognize potential new gas production likely to result from implementation of the Natural Gas Policy Act of 1978 as well as additional supplies from supplemental sources including Alaskan gas, coal gasification, imports from Canada and Mexico, LNG, SNG, and various new unconventional gas technologies (e.g., geopressured gas, tight seams gas, Devonian shale, biomass, etc.).

See response to USEPA comments about projected oil and gas savings and unconventional gas production.

2. Quantify the limitations on coal conversion resulting both from the Clean Air Act's non-attainment and its significant deterioration provisions. In this regard ensure that the environmental exemptions examined in the EIS are consistent with those presumed in the FUA implementation regulations issued by ERA.

The text has been modified to further discuss the potential impacts of the Act on non-attainment areas as well as PSD requirements (see Sec. 5.2.4). It is not possible to quantify the limitations on increased coal use because of non-attainment or significant deterioration provisions. These limitations will only become evident when permits for coal use due to FUA are applied for. The analysis performed within the EIS is developed as worst-case. Limitations due to non-attainment or PSD will only reduce the amount of coal use attributable to the program.

3. Quantify all national environmental impacts that will result from all federal policies, which, taken together, encourage the use of coal by industry.

DOE believes that the analysis done for the EIS reflects the best possible quantification of the environmental impacts which will result from the implementation of FUA, as well as synergistic impacts of FUA and other Federal programs. The agencies responsible for major Federal actions taken under other authorities will be required to comply with NEPA.

4. Contrast the above environmental impacts with those produced by a methane option designed to result in an amount of imported oil reductions that is equivalent to the reductions estimated to occur under FUA implementation.

See response to U.S. EPA comment about projected oil and gas savings and American Gas Association comment above on natural gas supplies. Combustion of methane would result in fewer environmental impacts. However, natural gas use is to be reserved for priority uses in keeping with the intent of the Act.

5. Study and quantify the economic cost to key industries and the nation of displacing gas with coal for both existing and new industrial energy users versus the cost of providing high-Btu coal gas to these users.

February 9, 1979

George H. Lawrence
President,
American Gas Association

An analysis of the environmental impacts associated with coal gasification are presented in the FUA/EIS as well as the ESECA/FES (Vol. I; p. VIII-165-177). Coal gasification is treated as an alternative within the proposed program and not as an alternative to the program. Consequently, the promulgation of the Act should provide a stimulus to the use of synthetic gas derived from coal or other alternative fuels.

High-Btu gasification, however, does not appear to be a significant commercially viable technology by 1990 and, therefore, is not analyzed in this EIS. This conclusion is based upon DOE analyses referred in the FUA/EIS.

February 9, 1979

ATTACHMENT

DETAILED COMMENTS ON DRAFT EIS

Chapter 1 - Summary

o Impacts of FUA should not be examined in isolation from other, related Federal actions (ESECA, Energy Tax Act, etc.) to promote coal use -- environmental impacts are, therefore, greatly understated.

See response to comment by American Gas Association, p. 12-89.

o Deterioration in national air quality, improving since 1970, should be more directly brought out and examined.

Air quality changes due to both base case and the increment are discussed for the time period of 1985 and 1990. Potential for deterioration is a function of the air quality regulations in effect, those presently being considered and future regulations plus the degree to which these will be enforced.

o Weather and climatic impacts, including acid rainfall and CO_2 build-up, should be examined with regard to total anticipated coal use.

The base-case environment is discussed in Section 4. Incremental increases over base-case environment are discussed in Section 5. The combination of the increment plus base case equals total anticipated coal use.

o Water quality problems associated with trace elements should be examined in greater detail. Anticipated incremental increases in toxic substances should be shown.

A discussion more detailed than the summary is found in Sections 5.4 and 5.6 of the text.

o Environmental trade-offs section should:

- cover all coal use
- discount the amount of gas which will be made available to high priority users by the FUA
- consider the load balancing cost and environmental impacts on gas consumers which result from the loss of industrial customers

The base case did represent total coal use without the program. The environmental trade-off section includes the increment associated with the program (see response to American Gas Association Comment 1).

American Gas Association (continued)

The EIS cannot discount the amount of gas made available to high-priority users. This availability of gas cannot be assured and consequently the benefits exist. (See response to California Energy Commission Comment 10, p. 1-13).

Although some pipeline customers lost due to the FUA may result in higher costs to remaining users of the system, the argument is hypothetical except on a site-specific basis. The cost depends on the extent of the system, growth in new customers, demand on the system, and actions by state regulatory agencies regarding addition of customers. The Natural Gas Policy Act may allow new customers and thereby offset any load-balancing costs.

Chapter 2 - Description of the Proposed Action

o The environmental benefits projected from implementation of the FUA are overly ambitious in that forecast increases in coal use are limited to 71 (1985) and 129 (1990) million tons per year.

It is believed that the environmental benefits are accurately reflected in the text.

o In the subsection on relationship to other federal actions there is:

- little mention of present and prospective Federal coal leasing activities
- no discussion on potential negative impacts on Federal efforts to develop domestic sources of oil and gas (e.g., EGR, EOR, Outer Continental Shelf, geopressurized methane, etc.)

See response to above AGA comment on quantification of the environmental impacts of all Federal policies.

Chapter 3 - Methodology

o The FUA-EIS correctly excluded the following combustors:

- non-boilers
- boilers with capacities less than 100 MMBtu/hr.
- existing boilers not designated to use coal
- boilers in non-attainment regions
- boilers for which the cost of using coal is substantially higher than the cost of using oil.

Boilers for which the cost of using coal is substantially higher than the cost of using imported oil can apply for an economic exemption. See the responses to USEPA comments about non-attainment (p. 12-9) and existing facilities (p. 12-33) and to the California Energy Commission comment about page 1-1 (boiler size) (p. 12-27) for responses to the remainder of the comment.

Nonboilers are not expected to have any noticeable impact on the magnitude of the projection as cited in Section 3.2.4.1. The worst-case environmental analysis will account for nonboiler coal use as a result of FUA.

American Gas Association (continued)

- o If any of the above categories are not exempted from the FUA, then the environmental impacts outlined in the EIS are understated.

See response to above AGA comment.

- o The EIS did not consider exemptions for combustors which may result from:
  - the significant deterioration provisions of Clean Air Act of 1977.
  - the cost differentials between coal and gas.

The EIS considers environmental and cost exemptions. The significant deterioration exemptions are included in the former and the cost differentials are included in the latter.

Cnapter 4 - Environmental Impacts

- o The FUA/EIS should try to quantify:
  - the restrictions on implementation of the FUA which result from the non-attainment provisions of the Clean Air Act.
  - restrictions on FUA implementation related to PSD increments.
  - incremental environmental residuals produced by increased coal burning vs. gas vs. oil.

Restrictions of non-attainment and PSD regulations on the program have been revised in Section 5.2.4. Predicted energy uses for 1985 and 1990 included coal, oil, gas, and other fuels. Emissions that would have been produced by using gas or oil instead of substituting coal or an alternate fuel were not subtracted. Emissions from all fuel types were used to predict the base-case environment in Section 4.

- o Water Quality
  - The potential constraints placed on FUA implementation by the Clean Water Act should be more fully discussed.

Compliance restraints are site-specific and are therefore not discussed.

- o Water Requirements
  - The FUA-EIS should examine legal and environmental constraints to increased coal use in regions 5, 6, and 8 (accounting for over 2/3 of the coal use increase projected from the FUA) which are water constrained.

Any facility which is regulated by the FUA (and those which are not) must comply fully with the Clean Water Act. Compliance restraints are site-specific and are therefore not treated in detail. The kinds of restraints which will likely occur include the need for individual facilities to obtain NPDES permits for effluents, special measures taken to prevent contamination of drinking water supplies, etc. The inability of a facility to meet the provisions of the Clean Water Act as a coal-burning installation may qualify that facility for an exemption on environmental grounds.

- o Solid Waste
  - The inflationary impact of RCRA on coal use should be quantified.

See response to comment by Baltimore Gas and Electric Company, p. 12-103.

- o Land Use
  - Strip-mining and coal leasing issues are not adequately covered.

Strip mining impacts on land use have been discussed in Section 5.5.1. The complex issue of coal leasing on federal lands is addressed in the Draft Environmental Statement, Federal Coal Management Program, issued by the Bureau of Land Management in December, 1978. It is not possible at this time to assess what impact coal leasing policy will have on the FUA, since the policy has not yet been finalized.

American Gas Association (continued)

o The health impacts subsection is too brief and should describe both occupational and non-occupational deaths and impairments that can be expected from implementation of the FUA.	See response to comment by California Energy Commission, p. 12-30.

Chapter 10 - Alternative Energy Technologies

o The following alternatives to the proposed FUA program were not mentioned: - increased gas use, promotion of domestic gas resources (including Alaskan gas) - LNG - Mexican and Canadian gas imports	The three items mentioned in the comment are not viable alternatives; see response to USEPA, p. 12-15.
o The following alternatives within the proposed FUA program were not mentioned: - high-Btu coal gas, of relatively small number of plants could achieve FUA goals more economically (no industrial end-user retrofitting or coal transportation investments) and environmentally cleaner according to DOE's own analysis.	See response to comment by American Gas Association, p. 12-92.
o Does not adequately examine listed alternatives. - no action alternative 1. EIS fails to recognize the environmental and economic advantages of this alternative over the FUA (i.e., coal is, and will be, more expensive and environmentally impacting than either gas or oil). 2. Timing of fossil fuel (especially gas) shortfalls incorrect. Does not recognize new gas production (gas bubble) resulting from passage of NGPA).	The "no-action" alternative is treated in substantially greater detail in the ESECA Final EIS (Volume I, pp. VIII-12 and -13; pp. VIII-27 through -47) and has been incorporated by reference. See response to comment by U.S. EPA, p. 12-15.
- the energy conservation alternative described is not an alternative, this option complements the FUA.	See response to comment of U.S. Department of Health, Education, and Welfare, p. 12-6.
- Petroleum from OCS is not an alternative -- presently proceeding at rapid pace.	The discussion of petroleum from the outer continental shelf (OCS) in Section 10.1.5 is directed towards an examination of this petroleum source as an alternative to the FUA rather than an alternative within the program. (See also the discussion of this subject in the ESECA Final EIS, p. VIII-16.)

American Gas Association (continued)

o the policy options discussed in the exemption process should:	
- consider exempting industrial gas sales, when those sales displace imported oil.	Exemptions for natural gas will be considered on a resource use basis rather than on a sales basis. Such considerations will involve fuel mixes, natural gas sources, and the cost of increased coal use.
- examine the inflationary impacts of setting the coal use penalty exemption very high.	See response to California Energy Commission (p. 12-33).
- underscore the true economic cost of using coal (i.e., increased capital and operating cost versus gas and oil).	The cost test on an individual basis will consider these factors. If the costs of using coal "substantially exceeds" the cost of using imported oil an economic exemption may be applied for.

Chapter 11 - Environmental Trade-Offs of Proposed Actions

o Examines environmental impacts of FUA in isolation of other Federal programs and regulations to promote coal use. Should take a broader look at environmental impacts of coal use in U.S.	This comment was previously addressed under the parallel comment that the programmatic FUA addressed coal use in isolation (p. 12-89).

Arizona State University **SIGNOFF**

OMB Approval No. 29–R0218

FEDERAL ASSISTANCE

2. Applicant's application — a. Number — b. Date 19 Year Month Day

3. State application identifier — a. Number AZ 78-80-0063 — b. Date Assigned Year month day 1978 12 01

Leave Blank JAN 11 1979

1. Type of Action (Mark appropriate box)
- ☐ Preapplication
- ☐ Application
- ☐ Notification Of Intent (Opt.)
- ☐ Report Of Federal Action

4. Legal Applicant/Recipient
- a. Applicant Name: Department of Energy
- b. Organization Unit: Division of Coal Utilization, Office of Fuels Regulation
- c. Street/P.O. Box: 2000 "M" Street, N.W., Room 7202
- d. City: Washington — e. County:
- f. State: D.C. — g. Zip Code: 20461
- h. Contact Person (Name & telephone no.): Mr. Steven A. Frank, Chief, Environmental Evaluations Branch (202) 254-6246

5. Federal Employer Identification No.

6. Program (From Federal Catalog)
- a. Number: 81.099
- b. Title: Unknown

Department of Energy

7. Title and description of applicant's project

FUEL USE ACT - DRAFT PROGRAMMATIC ENVIRONMENTAL IMPACT STATEMENT - DOE/EIS-0038-D

This impact statement deals with overall program impacts rather than site-specific impacts & is predicated on the assumption that coal will be the primary fuel substituted for oil & natural gas in the short term (until 1990). Site-specific environmental impacts will be addressed in subsequent documents, as appropriate.

8. Type of applicant/recipient
A–State, B–Interstate, C–Substate District, D–County, E–City, F–School District, G–Special Purpose District, H–Community Action Agency, I–Higher Educational Institution, J–Indian Tribe, K–Other

(Specify): Federal Agency — Enter appropriate letter [K]

9. Type of assistance
A–Basic Grant, B–Supplemental Grant, C–Loan, D–Insurance, E–Other — Enter appropriate letter(s) [ ][ ]

10. Area of project impact (Names of cities, counties, states, etc.)
Statewide, Arizona (Also Nationwide)

11. Estimated number of persons benefiting

12. Type of application
A–New, B–Renewal, C–Revision, D–Continuation, E–Augmentation — Enter appropriate letter [A]

13. Proposed Funding

a. Federal	$ 1.00
b. Applicant	.00
c. State	.00
d. Local	.00
e. Other	.00
f. Total	$ 1.00

14. Congressional Districts Of:
- a. Applicant
- b. Project: 01 02 03 04

15. Type of change For 12c or 12e
A–Increase Dollars, B–Decrease Dollars, C–Increase Duration, D–Decrease Duration, E–Cancellation, F–Other Specify: — Enter appropriate letter(s) [ ][ ][ ]

16. Project Start Date Year month day 19

17. Project Duration Months

18. Estimated date to be submitted to federal agency Year month date 19

19. Existing federal identification number

20. Federal agency to receive request (Name, city, state, zip code)

21. Remarks added ☐ Yes ☐ No

Section II - Certification

22. The Applicant Certifies That

a. To the best of my knowledge and belief, data in this preapplication/application are true and correct, the document has been duly authorized by the governing body of the applicant and the applicant will comply with the attached assurances if the assistance is approved.

b. If required by OMB Circular A-95 this application was submitted, pursuant to instructions therein, to appropriate clearinghouses and all responses are attached:

		No response	Response attached
(1)	Arizona State Clearinghouse	☐	☐
(2)		☐	☐
(3)		☐	☐

23. Certifying representative — a. Typed name and title — b. Signature — c. Date signed Year month day 19

Section III - Federal Agency Action

24. Agency name

25. Application received Year month day 19

26. Organizational Unit

27. Administrative office

28. Federal application identification

29. Address

30. Federal grant identification

31. Action taken
- ☐ a. Awarded
- ☐ b. Rejected
- ☐ c. Returned for amendment
- ☐ d. Deferred
- ☐ e. Withdrawn

32. Funding

a. Federal	$ .00
b. Applicant	.00
c. State	.00
d. Local	.00
e. Other	.00
f. Total	$ .00

33. Action date Year month day 19

34. Starting date Year month day 19

35. Contact for additional information (Name and telephone number)

36. Ending date Year month day 19

37. Remarks added ☐ Yes ☐ No

38. Federal agency A-95 action

a. In taking above action, any comments received from clearinghouses were considered. If agency response is due under provisions of Part 1, OMB Circular A-95, it has been or is being made.

b. Federal Agency A-95 Official (Name and telephone number)

424-101

Standard Form 424 Page 1 (10-75)

Prescribed by GSA, Federal Management Circular 74-7

12-97

Arizona State University (continued)

Dr. James Becker
Center for Public Affairs
Arizona State University
Tempe, Arizona 85281

State Application Identifier (SAI)

DEC 1, 1978 State AZ No. 78-80-0063

TO: Arizona State Clearinghouse
1700 West Washington Street, Room 505
Phoenix, Arizona 85007

No Comment
- Game & Fish
- Indian Affairs
- Ag. & Hort.
- Public Safety
- Solar Energy
- Environmental Studies
- Archaeological Research

Center for Public Affairs

No Comment
- Renewable Natural Resources
- Arizonans for Jobs & Energy
- Salt River Indian Clearinghouse
- Navajo Indian Clearinghouse
- OEPAD: V. Williams

Power
Health
Land
Parks

6 Regions

project is referred to you for review and comment. Please evaluate as to:

1) the program's effect upon the plans and programs of your agency
2) the importance of its contribution to State and/or areawide goals and objectives
3) its accord with any applicable law, order or regulation with which you are familiar
4) additional considerations

return THIS FORM AND ONE XEROX COPY to the clearinghouse no later than 17 working days from the date noted above.
contact the clearinghouse if you need further information or additional time for review.

] No comment on this project
] Proposal is supported as written
X Comments as indicated below

Comments: (Use additional sheets if necessary) A typical statement has a phrase such as "The potential impact...is negligible." No impact is negligible. There should be a better way to say the fact that is involved in such cases: and that better way should be adopted soon.

"The national consequences...will be largely undiscernable to the general public." So was the Viet Nam War. Such comments do not tell the story that is important.

Reviewer's Signature R. J. Becker

Prof. Center for Public Affairs

Date 12-9-78

965-3926
Telephone

DOE believes there will be negligible environmental impacts at the national and regional levels. There may be some greater local impacts.

Atlantic Richfield Company

AtlanticRichfieldCompany

515 South Flower Street
Mailing Address: Box 2679 - T.A.
Los Angeles, California 90051
Telephone 213 486 3?10

N. M. Smirlock
Manager
Governmental Controls Coordination

February 8, 1979

781933B

Office of Public Hearing Management
BOX WA, Department of Energy
Room 2313
2000 M Street, N.W.
Washington, D.C. 20461

Re: Draft Programmatic Environmental Impact Statement
FUEL USE ACT

Gentlemen:

9 FEB 79 [illegible]

Atlantic Richfield Company is pleased to comment on the Draft Programmatic Environmental Impact Statement (EIS) for the Fuel Use Act. Overall, we are impressed with the scope and depth of analysis contained in the EIS,

Atlantic Richfield Company (continued)

and we concur in the approach of analyzing "worse case" scenarios. There are, however, several points which are not entirely clear to us and which could cause confusion on the part of some readers. Accordingly, we recommend review and revision to insure maximum clarity in the final EIS on the following matters:

Sec. 1.2, Par. 1: We note that the predicted impacts of alternate fuel are not given due to uncertainty of this usage. This appears to be an acceptable approach since determination of quantities of alternate fuels which will be used is obviously impractical in light of the insufficiency of data on supply, cost, technology for use, and other factors. However, some indication of the relative impact of these fuels vis-a-vis coal on a unit basis would assist the reader evaluating their significance.

The text has been clarified in response to this comment (p. 1-4).

Table 1.1: The data given in Table 1.1 was calculated assuming the existence of a crude oil equalization tax. If this tax, which failed enactment, makes a difference in the calculation it should be corrected. If the tax makes no difference in the result, the reference to the tax should be omitted to eliminate the uncertainty occasioned by its presence.

The Crude Oil Equalization Tax is still public policy and may eventually become law although it was not passed as part of the National Energy Act. Its inclusion in the EIS was to equalize domestic and imported prices in the modeling efforts; however, the economic test is based on the price of imported petroleum and there is no impact on that price from the COET not being passed.

Sec. 1.33: We see trace contaminants mentioned under water but not under air quality. Are these contaminants important in either case? Omission from only one discussion is confusing in that the reader does not know what significance to attach to it.

The present state-of-the-art precludes prediction of trace metal contamination from airborne particulates. The problem is site-specific; its importance depends upon coal type, operating characteristics of the facility, atmospheric conditions, vegetative cover, soil type, and natural background concentrations as well as many other factors.

Sec. 1.3.4 mentions Resource Conservation and Recovery Act of 1976 but does not address the magnitude of costs to be incurred under its provisions and the related regulations. The cost of land reclamation may be significant enough to warrant specific mention in the EIS.

See response to comment by Baltimore Gas and Electric Company, p. 12-94.

Sec. 1.4 indicates that the program can force conversion to coal without the consumer paying for increased general fuel prices that would occur as a result of immediate price increases through taxes and natural gas deregulation. While it appears that the present cost of forced conversion is less than the cost of a general increase in oil and gas prices,

The question of whether "it is in the long-term national interest to shelter the consumer from the true cost of energy consumed" is a matter of national debate. A strictly economic view of long term (when all costs are variable) would probably be in agreement with the Atlantic Richfield Company view. Many economists are concerned, however, about the near-term inflationary impacts of wellhead oil and natural gas deregulation. Congress enacted the Fuel Use Act as part of the

Atlantic Richfield Company (continued)

we do not believe that it is in the long term national interest to shelter the consumer from the true cost of energy consumed. Continued restraint of fuel prices at artificially low levels encourages waste of scarce supplies, discourages development of new supplies, and tends to enlarge the severe balance of payments deficit at the expense of the entire economy. We believe these larger considerations are more significant than the short term cost shelter addressed in the EIS and that they should be acknowledged.

We hope these comments and suggestions will assist in the completion of this EIS. If we can provide further input, please let us know.

Very truly yours,

N M Smirlock

N. M. Smirlock

Baltimore Gas and Electric Company

BALTIMORE GAS AND ELECTRIC COMPANY

P. O. BOX 1475

BALTIMORE, MARYLAND 21203

D. PIERRE G. CAMERON, JR.
ASSOCIATE GENERAL COUNSEL
301-234-[illegible]

9 Feb 79 2:59

February 9, 1979

781931 B

Office of Public Hearing Management
Department of Energy
Box WA
Room 2313
2000 M Street, N.W.
Washington, D. C. 20461

Re: Draft Programmatic Environmental Impact Statement
Fuel Use Act
DOE/EIS-0038-D

Gentlemen:

Pursuant to the notices appearing in the Federal Register for Monday, November 13, 1978 (43 FR 52515-16) and for Tuesday, January 9, 1979 (44 FR 2004-5), Baltimore Gas and Electric Company (Company) submits these comments on the above-referenced Draft Programmatic Environmental Impact Statement (DEIS).

overall National Energy Act in which the opportunity to totally deregulate natural gas and oil on any timetable was rejected. Discussion of the "larger considerations" at this point would involve a complete review of the debate on the National Energy Act, and is therefore beyond the scope of the EIS.

The Company, a public utility engaged, *inter alia*, in the generation, transmission and distribution of electricity in the City of Baltimore and adjacent counties in Central Maryland, has presently under construction two (2) oil-fired steam electric generating units at its Brandon Shores site off Fort Smallwood Road in Anne Arundel County, Maryland. Since the continued construction and ultimate commercial operation of those units will be impacted by the Powerplant and Industrial Fuel Use Act of 1978 (Fuel Use Act), the form and content of both the DEIS and the subsequent Final Environmental Impact Statement prepared by the Department of Energy (DOE) assessing the environmental impacts of the Fuel Use Act and any final implementing regulations issued by DOE pursuant to the Fuel Use Act are of vital importance to the Company.

The Company's comments on the DEIS will focus upon two issues. The first concerns the analysis in the DEIS of the environmental impact of the collection and disposal of coal combustion wastes. The second concerns the analysis in the DEIS of the uncertainties associated with the Clean Air Act Amendments of 1977.

Combustion Waste Collection and Disposal

Inherent in the combustion of coal as a primary energy source is the creation and accumulation of large quantities of ash, both bottom ash and fly ash. When the pollution abatement process to remove the fly ash consists of the use of flue gas desulphurization equipment, an additional waste, colloquially called "scrubber sludge", is produced and its disposal is required. The DEIS in a number of different sections attempts to discuss and analyze the environmental impact of the collection and disposal of these wastes. However, due largely to developments beyond the control of DOE, a meaningful and realistic analysis of this impact does not appear now in the DEIS.

Since the initiation of the DEIS some months ago, various implementation activities under the Resource Conservation and Recovery Act of 1976 (RCRA), particularly with respect to hazardous substances, have occurred. RCRA requires the Environmental Protection Agency (EPA) to adopt guidelines and regulations relating to solid waste management, including hazardous substances management. While the references in Section 2.4.3.5 of the DEIS to EPA's Guidelines for Land Disposal of Solid Wastes (40 CFR 241) and its proposed Guidelines for State Hazardous Substances Programs (43 FR 4366), EPA has been required to adopt more specific regulations delineating the minimum requirements for the disposal of a variety of wastes, including fly ash, bottom ash and scrubber sludge.

See Section 5.5.5 for an expanded discussion of proposed guidelines and regulations under RCRA.

In its proposed rulemaking, Hazardous Waste Guidelines and Regulations, noticed in the Federal Register for December 18, 1978 (43 FR 58946), EPA identified, at 43 FR 58981-82, these three utility wastes, among others, as special wastes and deferred further rulemaking on special wastes until additional information has been developed. In addition, as a result of an order, issued January 3, 1979, by the U. S. District of Columbia in Illinois, et al v. Costle, Nos. 78-1689, 78-1715, 78-1734 and 78-1899, EPA has been given until December 31, 1979 to promulgate final regulations on the entire subject of waste management, including special wastes. Thus, until these final regulations are issued, DOE cannot properly evaluate the impact of the following critical factors.

1. The allowed method or methods of disposal.
2. The costs of such disposal method or methods.
3. The feasibility of such disposal method or methods, particularly in view of the potentially large volume of scrubber sludge generated by large size coal-fired plants.
4. On-site land requirements for temporary storage of such wastes.
5. Availability of land for off-site disposal, particularly on a local or regional level.

The Final Environmental Impact Statement is based on the latest available information. Any petitions for exemptions will be considered in light of the present regulatory climate at the time of exemption application.

6. Transportation requirements for off-site disposal.

7. Availability of suitable transportation equipment.

Unless and until EPA issues final regulations with respect to these wastes, it is really difficult to assess whether DOE's analysis of the environmental impact of the wastes generated by a coal-fired plant meets the required standards. While it is not necessarily productive to suggest a long delay before issuance of a Final Environmental Impact Statement, that is precisely what must be done here. Once the full cost impact of the handling and disposal of wastes generated by a coal-fired plant can be adequately gauged, then and only then will it be possible for the upcoming Final Environmental Impact Statement to affirm the statement made in table 1.5 on page 1-12 of the DEIS that the negative impact of increased solid waste and scrubber sludge will only be discernible. It is not too far beyond the realm of reason to suggest that that negative impact could well be significant. If so, then perhaps the entire coal conversion program may require a certain re-analysis.

One additional matter must be addressed in this letter of comments before passing to the uncertainties arising under the Clean Air Act Amendments of 1977. Table 5.22 on page 5-45 of the DEIS establishes the maximum land requirements for waste disposal of fly ash and scrubber sludge at approximately 1400 acres in 1985 and 2700 acres in 1990. Since the calculations represent only those acres required in the particular reference years, the requirements for the 40-year period 1980-2020 are considerably greater. Applying the same assumptions as applied to the national 40-year requirement of 108,000 acres, 3,720 acres in Region III alone will be required. A most startling understatement occurs when by footnote (4) to the table, it is learned that a ten-foot depth has been assumed. If the table were set forth in terms of acre feet, as is more commonly done in this type of calculation, the required land increases ten-fold. The national requirement then becomes over a million acres or 1700 square miles, roughly the size of the State of Delaware. For Region III, the revised calculation is more than 37,000 acres, a not insignificant total in and of itself. This perhaps is another instance in which a discernible negative impact may actually be something more akin to a significant negative impact.

The Clean Air Act Amendments of 1977

Another significant uncertainty, which the Company submits cannot have been fully assessed in the DEIS, is that produced by EPA's ongoing revisions of the New Source Performance Standards mandated by the Clean Air Act Amendments. In Section 5.2.4 of the DEIS, DOE assumes that emissions of SO_2, NO_x and particulates would meet the New Source Performance Standards and that any new standards resulting from the Clean Air Act Amendments would be at least as restrictive. These standards then provide the basis for ERA's "worst-case analysis".

The Company suggests that the aforegoing conclusion is not necessarily so. A more restrictive SO_2 standard will obviously necessitate an increased level of removal and result in an increase in the quantities of wastes requiring disposal. More restrictive standards requiring increased removal efficiencies will escalate the cost of emissions control equipment. One of the principal means to achieve increased removal levels is the broader use of energy consumptive flue gas desulphurization equipment. Since scrubbers consume energy at a rate of 5-10% of the installed capacity of an electric generating unit, an increased use of coal as an energy source will be required. If ten (10) 1,000 MW coal-fired plants are required to meet the demand for electric service and each plant requires up to 10% of its capacity for operation of its scrubber, the equivalent of eleven (11) rather than ten (10) plants will be required. Coal demand and consumption will increase by 5-10% and result in a 5-10% increase in overall environmental impact.

At the time of this writing, the increased cost of coal due to the Resource Conservation and Recovery Act (RCRA) is not well known. The cost primarily depends on whether EPA considers coal ash and scrubber sludge as hazardous and, if so, the control measures necessary to make it nonhazardous, and possible additional disposal costs necessitated by a new regulatory view of these kinds of wastes. The USEPA is responsible for conducting a regulatory analysis of the inflationary impact of the RCRA.

Revised estimates of land required for coal combustion waste are given in Table 5.22; a maximum of 170,000 acres is estimated to be needed. It is reasonable to assume, on a national level, that disposal depths of 10 feet will be used. Reclamation of landfill areas to productive uses such as rangeland is feasible and will reduce the impact in the long term.

The analysis was performed for a statutory deadline so that the EIS could serve as a decision-making document. The best available knowledge at the time of preparation was used. The assumption of 90% sulfur and 99% particulate removal and resultant waste production were more aligned with anticipated revisions of the Clean Air Act. Therefore, wastes generated due to FUA are not underestimated.

The example given by Baltimore Gas and Electric is not appropriate since utilities are anticipated to be minimally affected by the FUA.

Thus, the uncertainty of the anticipated revisions to the New Source Performance Standards is but one of the potential impacts of the Clean Air Act Amendments. Other unquantified impacts include the myriad of unresolved issues in connection with EPA's policy of prevention of significant deterioration, emissions offsets and the evaluation of the need for a short-term NO_x ambient standard. The final solutions to these issues are not yet at hand. The very nature of EPA's ongoing activities in implementing the Clean Air Act Amendments suggests a delay in the issuance of the Final Environmental Impact Statement for negative impacts now deemed discernible or minimal in the DEIS may have to be revised upward to significant or discernible respectively. The impact on this Company will, in any event, be significant and cannot be dismissed summarily, althougth the DEIS does not purport to be anything other than programmatic.

Conclusion

In summation, therefore, the Company contends that until these very real issues are resolved by Governmental agencies other than DOE, no complete and accurate assessment of the environmental impact of the Fuel Use Act can be finished. The DEIS must not, merely because of an obvious desire on the part of DOE to accelerate its final form, fail to consider what impact on the utility industry will result from EPA's final regulations. To do otherwise will amount to an abdication of the mandate of the National Environmental Policy Act so clearly applicable to the situation produced by the Fuel Use Act. DOE has the ready means to avoid any further contentions of that nature. It can and must delay presentation of a Final Environmental Impact Statement based on a questionably sufficient DEIS.

Respectfully submitted,

DPGC:nmo

DOE disagrees with the summarization, based upon the responses given to the above specific comments.

781902 B

ECONOMIC REGULATORY ADMINISTRATION

ENVIRONMENTAL IMPACT STATEMENT: Implementation of the Powerplant and Industrial Fuel Use Act of 1978 (FUA)

James Walter Hickerson
Administrative Assistant for
Citizens' Action for Safe
Energy, Inc. (CASE)

Citizens' Action for Safe Energy, Inc., (CASE) vigorously disagrees that the FUA - 1978 will protect the public health, safety and welfare by expanding the use of coal and nuclear energy as alternatives to natural gas.

We contend that federal price and use controls have created an artificial economic environment that has prevented the full development of existing clean energy sources, particularly natural gas and solar energy, and that further regulations such as FUA and Natural Gas Policy Act of 1978 (NGPA) will continue to exacerbate environmental problems.

It has been recognized by many leading authorities that we as a nation must not continue to allow the unlimited growth of our demand for energy. It is further understood that such an unlimited growth of demand for, and use of, energy will have detrimental effects on the continental (and global) economic and ecological environments.

CASE contends that past, present, and proposed future regulations control only the production (supply) and cost of energy, and actually encourage the increase of demand. This sort of action, coming at a time when we recognize the need for increased supply and decreased demand, is a bureaucratic and ecological insanity!

Citizens' Action for Safe Energy, Inc. (continued)

As CASE understands the situation, this law has been created due to the belief that existing natural gas reserves only amounted to "208 TCF in 1977" and are being depleted at a rate (demand) of 19 TCF a year which results in barely a 10 year supply. We contend that these figures are a gross error. An error that has been created by the aforementioned artificial economic environment. In this case, 25 years of federal price regulations on natural gas production.

It was stated by Mr. Robert A. Hefner, currently a managing partner of the GHK Companies, at the Aspen Institute Workshop on "R & D Priorities and the Gas Energy Option" on June 25th through the 29th, 1978, that:

> "I am very optimistic about the future of conventional U. S. natural gas supplies. I predict that by the year 2000, barring further government interference, the U. S. will produce 35 TCF of conventional natural gas per year..."
>
> * * *
>
> "Predicting gas production of 35 TCF by year 2000 requires a belief in a much larger natural gas resource base than is generally estimated. Most 'authoritative' and generally accepted projections forecast natural gas providing only 10 to 15 TCF by the year 2000."

He goes on to explain later in the same paper that "we find that most 'authoritative' projections of natural gas reserves have been made by 'experts' not actually in the business of exploring for onshore natural gas..." and "natural gas is the fuel of the future!"

It was further stated in Newsweek, October 30, 1978, that "if gas were priced at $4.00 per 1,000 cf, producers would be able to recover about 700 TCF from conventional sources. Experts at the Gas Research Institute in Chicago estimate that given economies of scale, producers can extract at least 350 TCF from unconventional sources at even lower prices."

Citizens' Action for Safe Energy, Inc. (continued)

With these estimates of real reserves of onshore natural gas it appears that the NGPA and FUA of 1978 are of purely economic motivation, and we the members of CASE contend that this placing of economic priorities over health, safety, and ecological priorities is a moral mistake of great magnitude, and to continue encouraging increased use of the two most dangerous fuels, coal and nuclear energy, known to man will only compound this moral mistake and greatly increase negative environmental consequences.

CASE recommends that a moratorium be immediately placed on further construction of nuclear facilities, that the prohibition of construction of new gas fired utilities and the conversion of existing gas fired utilities in gas producing areas be re-examined, and greater incentives be immediately provided for the development of new natural gas and solar energy.

Respectfully submitted,

James Walter Hickerson
Administrative Assistant of CASE

MAR 9 1979

Mr. Walter Hickerson
Administrative Assistant
Citizens' Action for Safe Energy, Inc.
P. O. Box 924
Claremore, Oklahoma 74017

Dear Mr. Hickerson:

Thank you for the copy of your testimony given in Fort Worth at the hearings on the Programmatic Environmental Impact Statement (EIS) for the Fuel Use Act (FUA). We regret the short notice of that hearing received by the Citizens' Action for Safe Energy, Inc. The Department of Energy published notices of the hearings in the <u>Federal Register</u>, called many parties which had expressed an interest in the hearings, and sent hundreds of letters to potential speakers.

Due to the rigorous time schedule necessary to implement the FUA program, additional EIS hearings are not envisioned and, therefore, any discussion about their format would be premature. However, the Office of Fuels Conversion intends to conduct all its future program hearings openly and with maximum public participation.

Sincerely,

Barton R. House
Assistant Administrator
Fuels Regulation
Economic Regulatory Administration

12-107

Commonwealth Edison

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Chicago, Illinois 60690

February 9, 1979

781935

Office of Public Hearing Management
Box WA, Department of Energy
Room 2313
2000 M Street, N.W.
Washington, D. C. 20461

Re: Draft Programmatic Environmental Impact Statement - Fuel Use Act (DOE/EIS 0038-D)

Commonwealth Edison (continued)

Gentlemen:

The following are Commonwealth Edison Company's (Commonwealth) comments on subject draft impact statement. Commonwealth has an interest in the proceedings due to its operation of several oil fired generating units and substantial commitment to units using alternate fuels (coal and nuclear).

15 FEB 79 **Subject impact statement presumes that conflicts between it and the fourteen federal policies and laws that are listed in Chapter 8, can be resolved. No mention is made as to how long it would take an individual site or plant to receive all final approvals so that conversion or new construction could commence. Also the economic and social impacts associated with the flow through of the huge costs to the consumers of electric power, manufactured goods and commercial services are not mentioned. We feel that these costs will divert capital needed to improve productivity and at the same time add to the current crisis of inflation. Thus the most significant impact on this country and its citizenry has been ignored.**

To the extent that FUA interacts with the implementation of the fourteen cited statutes, such interaction has been included in the modeling and analysis. The comment regarding the flow through of costs of increased coal use to consumers of electric power was previously addressed by a response to a similar comment by Public Service Electric and Gas of New Jersey. In addition, a regulatory analysis of the program has been performed (Energy Information Administration, 1978, Analysis of Proposed U.S. Department of Energy Regulations Implementing the Powerplant and Industrial Fuel Use Act, DOE/EIA-0102/21, U.S. Department of Energy, Washington, D.C.).

This draft statement is broad and glosses over site specific difficulties in implementation. It would be well to have illustrative examples of site specific problems and resolutions as without survival of individual trees you will not have a forest.

The generic nature of a programmatic EIS obviates the ability to examine site-specific problems. These will be addressed on a site-specific basis for those seeking exemptions and by the proper regulatory agencies during the permitting process.

The authors have presumed that ESECA has already been fully implemented (which it has not been) and, therefore, this act will have minimal additional impact. The full implementation of the FUA may be used to enforce ESECA and thus the economic and environmental impacts may be far greater than contained in this draft statement.

DOE has assumed in preparation of this EIS that the majority of existing utility powerplants have been affected by the implementation of the ESECA program. No significant rationale has been identified to DOE which causes a revision of this methodology. The FUA legislation is a successor to the ESECA in most cases. Utilities with outstanding ESECA prohibition orders on the effective day of the Act will continue to be processed under ESECA. The FUA is not designed nor being implemented to enforce ESECA.

Commonwealth Edison (continued)

The authors forecast that, "..... about 77 percent of the facilities using coal or an alternate fuel will be new boilers ....." in 1990. With the current ten year minimum requirement to amass data, prepare and submit PSD and environmental reports, public hearings, obtain construction permits, and finance and construct coal fired stations, the majority of the 1990 units would have to be in process at this time. This is very doubtful since the New Source Performance Standards and the vast majority of the new State Implementation Plans mandated by the Clean Air Act Amendments have not as yet been promulgated. Thus since the rules have not been determined, how can one play the game. The very slow pace of new plant commitments attest to the present chaotic energy regulation situation.

DOE assumed that 77% of the boilers using coal in 1990 would be in new facilities. This projection was based on a projected continued level of consumer demand in order to predict the worst-case environmental impacts of FUA in 1990. Such worst-case impacts may not be consistent with the actual number of permit applications for new facilities at this time. However, such methodology is consistent with Department of Energy's responsibilities under the National Environmental Policy Act to fully analyze the impacts of the FUA program. Any delay in the registering of impacts would result in a diminished environmental impact within the context of the EIS.

This draft statement is based on the assumption that there will not be an economic exemption unless coal is 44% more costly than use of imported oil. The rationale for selecting 44% is not clear. It is also not clear what costs are considered in making the comparison (i.e., scrubbers, baghouses, operating and maintenance, disposal of ash and scrubber sludge, etc.).

See response to California Energy Commission comment page 10-13.

The discussions in this draft concerning the waste disposal situation does not reflect the impact of regulations (existing and pending) such as a determination of hazard by the Department of Transportation, may seriously limit disposal of combustion by-products.

The text has been revised to further discuss RCRA regulations (Sec. 5:5.5.).

We have not prepared specific comments, at this time, on the many presumptions upon which this report is based. However, we hope that these general comments will be useful in preparing the final programmatic statement.

Very truly yours,

C. L. McDonough
Staff Assistant

CLMc:vs

Detroit Edison

Detroit Edison 2000 Second Avenue Detroit, Michigan 48226 (313) 237-8000

February 8, 1979

B. H. Schneider
Assistant Vice President
Planning and Research

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Department of Energy
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Washington, D.C. 20461

Re: Economic Regulatory Administration Draft
Programmatic Environmental Impact Statement

Dear Sirs:

The Detroit Edison Company has reviewed the Draft Environmental Impact Statement (DEIS) published by ERA in November 1978, which analyzes the impacts associated with the implementation of the Power Plant and Industrial Fuel Use Act of 1978 (FUA). As discussed more fully below, it is Detroit Edison's position that the ERA has failed to accurately assess the potential environmental impacts arising from the implementation of the FUA and, as a result, has not satisfied the requirements of the National Environmental Policy Act (NEPA) in the preparation of its Draft Environmental Impact Statement.

In general, ERA has failed to accurately analyze the economic benefits that would accrue in the form of fuel cost savings as a result of a nation-wide fuel conversion program compared to the costs that such a conversion program will impose on industry and the public.

See response to comment by the California Energy Commission, p. 12-33.

Detroit Edison does not take issue with the conclusion that the ultimate completion of a national fuel conversion program will result in long term economic benefits for the country, but rather, is critical

Detroit Edison (continued)

of several assumptions made by ERA to justify its specific regulatory program. In this respect, Detroit Edison questions the adequacy of the analysis with regard to the costs of converting to alternate fuels; the ability of the utility industry to finance conversion to alternate fuels, including the cost of pollution control equipment; and the ability of the electric-rate-paying public to absorb the costs of conversion.

More specifically, Detroit Edison has noted several areas of the DEIS which it considers deficient. In Section 1.4 entitled "Environmental Trade-Off of the Proposed Action", a statement is made that "the cost associated with fuel substitution will be much less than the cost to society of accepting a general increase in oil and gas prices" (p.1-11). This statement implies that the fuel cost savings due to the conversion by a utility from oil or gas to an alternate fuel more than offsets the capital needed to accomplish the fuel conversion. This statement also implies that the capacity factor of a unit to be converted does not vary significantly when converted from oil or gas to an alternate fuel. This is not necessarily true. Conversion studies performed by Detroit Edison generally indicate that the conversion to an alternate fuel is more costly than leaving the units on oil or gas. The reasons for this are: the high cost of equipment needed to burn an alternate fuel, the relative cost of an alternate fuel and differences in availability and capacity factor between a unit converted to coal and one not converted. A unit that is converted to coal tends to run more than a unit not converted if the coal being used is less expensive than oil. Thus, the total fuel cost for the unit may be the same, or higher, for the converted unit, as compared to its cost if left unconverted. However, while a converted unit may bring down the overall system fuel cost, if the alternate

The statement that "the cost associated with fuel substitution will be much less than the cost to society of accepting a general increase in oil and gas prices" was not restricted to fuel use by utilities. Rather, this statement refers to all uses of natural gas and oil.

To some extent, Congress allowed a gradual increase in gas prices in the Natural Gas Policy Act, but it refused to enact a similar provision for oil. Moreover, Congress did not pass a tax on oil and natural gas aimed specifically at utilities. For these reasons, the additional cost of conversion from oil and natural gas measured by the "substantially exceeds" index is substantially cheaper than an alternative price increase in all oil and natural gas. Moreover, a tax aimed at utilities may, in fact, be quite high, and higher for some utilities than the cost of the FUA.

For these reasons the statement stands. It does not contradict, however, Detroit Edison's view that specific units may continue using oil and gas at a cost cheaper than the conversion of that unit to coal, particularly when that unit is operated as a load-follower with low-capacity use.

Detroit Edison (continued)

fuel is relatively less costly, the reduced system fuel cost is generally not enough to overcome the capital cost of new equipment needed to burn the alternate fuel. The above rationale would be true for any utility that is not primarily oil-fired.

The failure of ERA to accurately analyze the costs of fuel substitution is carried forward in ERA's Transitional Facility Interim Rule (43FR54912, November 22, 1978). Detroit Edison firmly believes that the basis for ERA's cost analysis must be re-analyzed.

The environmental costs of the substitution are examined in the EIS. Actual project costs will be examined for each application. Costs in excess of the "substantially exceeds" criterion may be subject to an exemption.

Chapter 3, entitled "Fuel Conversion Analysis Methodology", understates the real effect of the ERA's Transitional Facilities Interim Rule. As a result of its misconstruction of Congressional intent in the FUA, ERA has instituted a requirement that major electric power plants and fuel burning installations which were not operational as of April 20, 1977, must apply as transitional facilities for existing unit status. Aside from the fact that Congress never intended that the definition of an existing facility incorporate a requirement that a unit be operational as of April 20, 1977, the insistence of ERA to adhere to this requirement could destroy the creditability of ERA's methodology.

See response to California Energy Commission comment about page 1-2, Table 1.1.

For example, under ERA's Transitional Facility Interim Rule, Detroit Edison's Greenwood Unit No. 1 must apply for an existing facility designation, even though it was 30% completed as of April 20, 1977. The increase in coal usage of Detroit Edison due to the conversion of this facility to coal burning capability would be approximately 1,150,000 tons in 1985 and 1,200,000 tons in 1990. In Table 3.9 of Chapter 3 of the DEIS are shown the projected figures of coal usage as

See response to California Energy Commission comment about page 1-2, Table 1.1. DOE information furnished by the East Central Area Reliability Coordination Agreement in April 1978, indicate that Greenwood Unit #1 is expected to be operational in 1979. A determination of its status without formal submission to DOE for a determination is premature.

Detroit Edison (continued)

a result of implementation of the FUA. Incorporating the usage figures of Greenwood Unit 1 into Table 3.9 would raise the figures 1.6 percent and .9 percent respectively for the years 1985 and 1990. This is the effect of just one unit of one utility company. However, it is not clear whether the DEIS reflects this possibility. It is highly unlikely that it does since at the time the data for Table 3.9 was compiled, ERA could not (and presently cannot) know for certain the number of facilities throughout the county which will ultimately be designated as existing units.

Along this same line, there is no indication in the DEIS whether ERA has considered the impact of those non-coal-fired units presently awaiting final action under ESECA.

The EIS assumes utilities under ESECA prohibition orders will be processed under ESECA.

ERA should re-evaluate its worst case scenario to include the effect of its Transitional Facilities Rules and, when finally promulgated, its Existing Facilities Rules, on all electric utility companies that have gas or oil-fired non-combustion turbine units that are on-line or that have not gone on-line, but which were under construction prior to April of 1977.

See response to comment by California Energy Commission (pp. 12-28 and -33).

In Section 3.2, entitled "The Industrial Sector", it appears that ERA assumes that all MFBI's are owned by non-electric utility industries. Under the definitions contained in the Fuel Use Act and ERA's proposed rules, electric utility auxiliary boilers (used at power plants to provide heating for various purposes) may be classified as MFBI's and thus subject to conversion orders. ERA should determine how many auxiliary boilers would be affected and incorporate the resulting increase in coal usage due to conversion of these units into its worst case analysis to indeed have an accurate worst case analysis.

While electric utility auxiliary boilers may be classified as MFBIs, because of their very low utilization factor, most of the units could apply for exemptions as peaking units and not be subject to mandatory coal combustion orders.

Detroit Edison (continued)

Section 10.2.2.2 of the DEIS discusses nuclear technology. The statement is made that "Process steam can be produced, however, the cost is quite high and there are major technological problems related to safety and disposal issues" (p. 10-7). This statement is not supported with any references. Furthermore, Detroit Edison believes that this statement is not true.

With regard to process steam, no mention has been made in any of the papers appearing in literature (Atomic Energy of Canada Limited Report 5117, Oak Ridge National Laboratory Report T5-5116, for example) of any major technological problems regarding the transmission of process steam, especially in the areas of safety and disposal. In addition, the previous studies that have been made do not show process steam produced by nuclear reactors being significantly higher in cost than if produced by other means such as oil-fired or coal-fired plants.

If the second part of the statement quoted above really refers to the generic nuclear plant safety question and not process steam, then it should be reworded to reflect this distinction. However, even then the statement would not be accurate. With regards to safety, generally accepted safety criteria indicate that the probability of having a serious nuclear accident is extremely low; tests of the Emergency Core Cooling Systems recently conducted at Idaho National Laboratories show that these systems work effectively in reducing the probability of a core meltdown, and the record of the nuclear plants in service clearly shows that no major accident has occurred. If the ERA is aware of unaddressed major technological problems regarding safety, they should be explicitly stated.

The statement objected to by Detroit Edison is misleading and has been changed (see p. 10-7). The statement is meant to refer to the difficulty of producing steam and electricity by nuclear power for smaller users at scattered sites. Because the FUA is directed to such users, nuclear units were not considered sufficiently competitive in price due to economies of scale. A sufficiently large user can have steam and electricity produced at prices competitive with coal.

The reference to safety should not have implied technological problems with steam production or waste disposal. The safety problem which was alluded to concerns Nuclear Regulatory Commission requirements and preferences regarding location of units in areas which are not highly urbanized. In such instances, the opportunities to locate a nuclear unit near an industrial user are few and may be a safety problem insofar as compliance with all NRC safety regulations is concerned. Furthermore, there is considerable concern about the environmentally acceptability of long-term waste disposal.

Detroit Edison (continued)

The same is true of disposal of nuclear wastes. Recent government studies have stated that there are no real technological problems regarding the storage of nuclear waste. The problems are of convincing people in a particular state to allow the building of a waste repository.

For the reasons stated above, Section 10.2.2.2 should be revised to accurately reflect the true relationship between the costs of production of electricity from nuclear powerplants and coal-fired power plants.

Finally, Section 10.3.4 discusses the cost test to be used by ERA when considering an exemption from the various prohibitions of the FUA based on a lack of alternative fuel supply. Statements are made to the effect that the level of economic penalty that is to be shouldered by a company to use coal, affects the coal usage; i.e., the greater the penalty, the more coal is used. As worded, these statements do not make any sense unless one is aware of the cost test ERA has incorporated into its proposed regulations to determine whether an exemption should be allowed. The cost test is a ratio test where the cost of using coal (which includes fuel, capital and O&M) is compared to the cost of using oil. ERA will establish a guideline ratio figure by which to determine if a facility is to be exempted. If the ratio for the facility is greater than the guideline, the unit is exempted; if the ratio is not, the unit must convert to coal. Thus, if the guideline is changed, the number of exemptions granted is changed. If it is raised, more units would be converted; if lowered, fewer units would be converted. In this particular subsection, an attempt is made to explain the effects of the cost test without defining the test.

The cost test and all its nuances have been detailed in the regulations as published in the Federal Register on November 17, 1978, and January 29, 1979. The EIS reflects the worst-case analysis by using a sufficiently high cost criterion that virtually all eligible combustors are posited to be affected by the FUA. Any lower test would result in fewer mandatory fuel switches and a diminished impact on the environment. Section 10.3.4 discusses the alternative cost levels and the national and regional impacts within this context, and provides information on which to base the final determination for the DOE regulations implementing FUA.

Detroit Edison (continued)

The result is a series of statements and a table of figures (Table 10.5 on p. 10-13), which are confusing. An explanation of the cost test is needed in this subsection in order to clarify ERA's position.

Furthermore, it is recommended that the ERA discuss the relationship of its proposed cost ratio and alternate ratios to the effects on various fuel consumptions, and thus, the environmental impacts.

See above response to Detroit Edison comment.

In conclusion, Detroit Edison believes that in its present form the DEIS fails to adequately analyze the true cost relationship between the use of oil and natural gas and alternate fuels. Moreover, some of the basic assumptions used in designing a methodology (and subsequently incorporated in ERA's proposed regulations), are not accurate. Detroit Edison submits that these areas must be corrected before the ERA's burden under NEPA can be satisfied.

DOE believes the responses to the above comments address these issues and that the EIS adequately satisfies NEPA requirements.

Very truly yours,

B. H. Schneider

Dow Chemical U.S.A., Texas Division

DOW CHEMICAL U.S.A.

TEXAS DIVISION
FREEPORT, TEXAS 77541

January 25, 1979

RECEIVED
JAN 31 1979

Mr. Mac Lacefield
Energy Department
Region VI
2626 Mockingbird Lane
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DRAFT PROGRAMMATIC ENVIRONMENTAL IMPACT STATEMENT, FUEL USE ACT (DOE/EIS-0038-D)

COMMENTS IN BEHALF OF DOW CHEMICAL U.S.A.

Section 2.4.3.1 states the purpose of this document is to meet the requirements of the National Environmental Policy Act of 1969 to "prepare detailed environmental statements on proposed federal actions which have the potential for significantly affecting the quality of the human environment."

Dow believes that the draft statement is premature and merits substantial revision and quantification in order to meet this objective. The following remarks are offered to aid the stated objective.

EFFECT OF REGULATIONS: Regulations pursuant to the FUEL USE ACT are presently undergoing public review and comment. Regulations regarding existing facilities have been made available only during the past week. Therefore, the IMPACT STATEMENT is premature and may present impact information which is not useful for decision making. Dow recommends that consideration of the IMPACT STATEMENT be postponed in order that it may truly reflect the effects of the regulations and provide information suitable for decision making.

The existing facilities regulations and the EIS were concurrently developed by personnel from the same organizational unit in the Department of Energy. The EIS was designed to reflect the impacts of all the Department's regulations and their impacts on all facilities subject to FUA and necessarily predated the promulgation of the regulations. The scheduling of the EIS and the regulations allows limited concurrent review between the EIS and the existing facility regulations; however, Section 901 of the FUA provides that the Act shall take effect on May 8, 1979. DOE considers it important both to have the EIS serve as a decision-making document in preparing the final regulations and to have the regulations and its EIS in final form by the May 8, 1979, date. The comment periods have been restricted by this latter consideration. Each existing facility receiving a FUA order will be examined on a site-specific basis to assess the environmental impacts of the proposed action and its alternatives.

Dow Chemical U.S.A., Texas Division (continued)

NOTIFICATION: Pages 1-13 and 1-14 list agencies and organizations from which comments were specifically requested. The list does not include organizations which represent owners of major fuel burning installations. Inasmuch as Summary paragraph 1.2 anticipates effects by the ACT on industries, other than utilities, comments from these industries should be requested and adequate time be allowed.

In addition to the agencies and organizations listed on pages 1-13 and 1-14, numerous copies were distributed to state agencies and the public through DOE regional offices and state clearinghouses. The document also was made available to the general public by Notices of Availability in the Federal Register, dated November 13, 1978, and January 9, 1979. Numerous public inquiries resulted in additional distributions to trade and professional organizations, interested companies, informational institutions, and private individuals.

AN OPERATING UNIT OF THE DOW CHEMICAL COMPANY

The list also does not include professional technical organizations such as American Chemical Society, American Society of Mechanical Engineers, American Institute of Chemical Engineers, National Society of Professional Engineers, American Institute of Mining and Metallurgical Engineers and others. Since it is the members of these national organizations who will apply technology to implement the ACT, their comments should be requested and adequate time be allowed.

BASES FOR IMPACT STATEMENT: The bases for the IMPACT STATEMENT are not consistent with the proposed regulations and actual legislation.

The economic bases for the model for the industrial sector (APPENDIX A) lists an after-tax rate of return of 15% on page A-4. The proposed regulations list 7% for MFBI's in Section 505.5.

The 15 percent stated in the EIS is the rate of return projected as required for a company to voluntarily construct for coal combustion rather than oil or gas combustion. This amount included a "hassle factor" for the extra managerial efforts required for coal combustion. The seven percent in the regulations is the company's cost of capital, and not comparable to the rate of return in the EIS, since DOE recognizes that the company will be making a profit on its investment. Furthermore, should the company use seven percent, rather than 15 percent, as an investment criterion, there would be more voluntary switching and the impacts of the program would be further diminished compared to the EIS projections.

The IMPACT STATEMENT itself (top page 3.3) states, "The assumptions used in the model do not reflect the actual decision variables to be used in the regulatory process. For example, no capital costs were used to model economic penalties associated with coal use." The capital cost premium over gas for maximum conversion by Texas utilities alone to coal/lignite for the 1975-1990 period was estimated to be 30.4 billion dollars*. The ACT provides for economic comparisons in the decision process for exemptions.

The EIS modeling includes capital costs, as indicated on pages A-3 and A-4.

Use of the Crude Oil Equalization Tax of $.21 per million Btu's is not consistent with legislation.

See responses to comment by Atlantic Richfield (p. 12-100) about Table 1.1 and by U.S. EPA about projections of oil and gas (p. 12-15).

The assumption, Section 3.2.1, that, "Gas prices will remain controlled - ", is not consistent with the NATURAL GAS POLICY ACT of 1978.

Section 2.3 (a)(1) of the ACT seems to offer mixed-fuel firing as an alternate; however, Section 3.2.4.3 of the STATEMENT is highly discouraging. "Little is known about the costs and reliability of mixed-fuel firing. — Until more is known, proving its applicability at any particular plant is unlikely."

IMPACTS ARE INCOMPLETE, CONFUSING

Social and Economic Impacts (Section 1.3.6 and 5.8) inadequately describe the total impacts of the ACT.

Section 1.3.6 states, "— coal production in Texas may produce boom town effects — ". Section 5.8.1 states, "no boom town impacts are expected — ".

The social and economic impacts associated with coal production nationally were presented in Appendix K. The assessment in this section shows the kinds of impacts expected from boom towns. If Texas expands coal production to meet its *existing* utility coal steam construction plans, then more mines will be opened. It *may* be expected that some boom town impacts would occur. With regard to FUA, however, *no* boom impacts are forecast because FUA is not expected to cause new mines to open to satisfy the industrial demand for coal. Rather, industrial users would likely purchase coal from existing mines, or mines opened for coal demand in excess of FUA.

No assessment is offered for the socioeconomic impact on those citizens who will be impacted by higher gas costs to their homes and businesses due to removal of utility and industrial gas from existing gas delivery systems.

See responses to comments by American Gas Association (p. 12-93) and California Energy Commission (p. 12-33).

Although Section 1. states, "Site-specific environmental impacts will be addressed in subsequent NEPA compliance documents — ", the STATEMENT appears to reach premature conclusions based on inadequate local documentation. An example is Section 1.3.4, page 1 - 8, with regard to the Gulf Coast of Texas and the conclusion, " — wastes will have to be transported to the west and north for disposal."

The assessment of waste disposal impacts on land use indicated that 65 to 67 percent of the coal waste produced as a result of the FUA could be in Demand Region VI (Section 5.5.5). Since much of the industry in this region is concentrated on the Gulf Coast, the identification of the generic problem of waste disposal in low-lying coastal areas, dominated by ricelands and wetlands, was considered important and therefore presented as an example of a regional problem.

Section 1.2 states that a basis of the IMPACT STATEMEMT is "that a maximum number of facilities would be designed for or would convert to coal — ". Table 3.4 shows 94,091 thousands of short tons called for in Demand Region VI in 1985. This is for five states, and parts of these states are suppliers; therefore, net import would be less (see Table 4.12 for 1975 production). This maximum projection of net imports for five states in 1985 is substantially less than the 125 million tons per year projected for Texas alone under a maximum conversion scenario**. These data should be reconciled with state data.

The purpose of Section 3.3 is to demonstrate the coal flow pattern associated with the changes in coal demand and supply as a result of the proposed action. Table 3.4 merely provides the information on general pattern of coal flow from coal supply regions to coal demand regions. Only the relative magnitudes of coal shipments to coal demand regions from various coal supply regions was set as input to construct Table 3.6. Therefore, the absolute amount of the coal demand and supply depicted in Table 3.4 was not directly applied in Section 3.3 and throughout this study.

Dow Chemical U.S.A., Texas Division (continued)

In the interest of economy and efficiency the socioeconomic impact of the adminstrative and procedural requirements of the regulations should be assessed and made available to the public before the regulations become final.

Yours truly,

W. A. Rollwage
Technical Manager
Energy Systems Tech Center
B-101 Building

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*PART II, TECHNICAL AND ECONOMIC EVALUATION OF VARIOUS ELECTRIC UTILITY NATURAL GAS REDUCTION PROGRAMS 1975-1990, Federal Power Commission, Bureau of Power, Fort Worth Regional Office, March, 1976, page 190.

**TEXAS ENERGY OUTLOOK, THE NEXT QUARTER CENTURY; Governor's Energy Advisory Council; March, 1977, page 13.

See response to comment by the California Energy Commission, p. 12-33.

Idaho-Region IV Development Association, Inc.

State Of Idaho
DIVISION OF BUDGET, POLICY PLANNING AND COORDINATION
EXECUTIVE OFFICE OF THE GOVERNOR

JOHN V. EVANS
Governor

Statehouse
Boise, Idaho 83720

STATE CLEARINGHOUSE
JANUARY 17, 1979

STEVEN A FRANK, CHIEF
ENVIRONMENTAL EVALUATIONS BRANCH, DIVISION OF COAL UTILIZATION
OFFICE OF FUELS REGULATION
DEPARTMENT OF ENERGY; ROOM 7202
2000 M STREET, N.W.
WASHINGTON, D.C. 20461

RE:FUEL USE ACT (OUR SAI#01181513)

SIR:

THE IDAHO STATE CLEARINGHOUSE HAS CIRCULATED THE FUEL USE ACT DEIS (OUR SAI#01181513) TO AGENCIES FOR REVIEW. THE FOLLOWING AGENCIES REVIEWED THE DEIS:

IDAHO OFFICE OF ENERGY
IDAHO DEPT. OF HEALTH & WELFARE-ENVIRONMENT
IDAHO PUBLIC UTILITIES COMMISSION
NATURAL RESOURCES BUREAU/DIVISION OF BUDGET, POLICY PLANNING & COORDINATION/STATEHOUSE

AREAWIDE CLEARINGHOUSES:
IDA-ORE REGIONAL PLANNING & DEVELOPMENT ASSOC.;WEISER, ID
REGION IV DEVELOPMENT ASSPC.;TWIN FALLS, ID ...SEE COMMENTS ATTACHED

AREAWIDE CLEARINGHOUSE, REGION IV, SUBMITTED SUPPORTIVE REMARKS. SPECIFIC CONCERNS EXPRESSED BY THE DIRECTOR OF REGION IV ARE ATTACHED FOR YOUR INFORMATION.

THANK YOU FOR THE OPPORTUNITY TO REVIEW THE DEIS. WE ANTICIPATE RECEIVING THE FINAL IMPACT STATEMENT UPON PUBLICATION.

SINCERELY,

Michelle Liebel

MICHELLE LIEBEL
STATE CLEARINGHOUSE COORDINATOR

EQUAL OPPORTUNITY EMPLOYER

REGION IV DEVELOPMENT ASSOCIATION, INC.

725 SHOSHONE STREET SOUTH
TWIN FALLS, IDAHO 83301
PHONE (208) 734-6586

TO : State Clearinghouse
Division of Budget, Policy Planning and Coordination
700 West State Street; 2nd Floor West
Boise, Idaho 83720

RE : Project Title: Fuel Use Act (Environmental Impact Statement)

State Application Identifier Number: 01181513

The above project has been reviewed and the following resulted:

No Comment	/__/	
Affirmative Finding	/X/	(see below or attached)
Negative Finding	/__/	(see below or attached)
Needs Attention	/__/	(possible duplication, etc.)

The following agencies and units of local government were contacted during the review period: (their written comments are attached)

Areawide Clearinghouse comments:

We urge the widest latitude be given to existing plants whether coal, oil or natural gas is the fuel source. Lead times on new plant construction, availability of coal supplies and capital availability may render the 1990 objectives of the Fuel Use Act as optimistic. Coal production is the key - we are concerned the deterients to strip mine capability, lack of trained work force, and mining and plant equipment demands will not be ready to meet the objectives of the Act.

Efforts made by Areawide Clearinghouse to solve issues, problems, answer questions, etc.:

Areawide Clearinghouse Representative [signature] Date 1.16.79

Serving South Central Idaho

The energy projections due to FUA were perhaps optimistic but it was necessary to provide a worst-case analysis. Less coal production associated with FUA would naturally reduce the environmental impacts.

Manufacturing Chemists Association

MANUFACTURING CHEMISTS ASSOCIATION

1825 CONNECTICUT AVENUE N.W. WASHINGTON D.C. 20009

ROBERT A. ROLAND
PRESIDENT

TELEPHONE (202) 328-4210
TELEX 89617 (MCA WSH)

819798

February 27, 1979

Office of Public Hearing Management
Box WA
Department of Energy
Room 2313
2000 M Street, N. W.
Washington, D. C. 20461

Subject: Draft Environmental Impact Statement

Gentlemen:

Herewith are the comments of the Manufacturing Chemists Association in response to the January 9, 1979, Federal Register Notice (pp. 2005) inviting public comments on the Department of Energy draft programmatic environmental impact statement (EIS) (DOE/EIS-0038-D), issued November 9, 1978.

The Manufacturing Chemists Association (MCA) is a nonprofit trade association having 191 United States company members representing more than 90% of the production capacity of a ic industrial chemicals within this country. The implementation of the Powerplant and Industrial Fuel Use Act of 1978 (FUA) and resultant environmental impact are of vital concern to our industry.

We believe the EIS inadequately reflects the impact of the regulations proposed November 17, 1978, 43 FR 53974, and January 29, 1979, 44 FR 5809, to implement the FUA for two significant reasons:

1. The regulations actually proposed are potentially much broader in scope than basic assumptions in the EIS and conflict with what MCA believes to be the intent of Congress. The study summary asserts that FUA only affects units with a fuel input heat rate of 100MM Btu per hour or greater (250MM in aggregate). In contrast, the proposed rules could affect thousands of smaller units.

See response to comment by California Energy Commission, page 12-27.

12-122a

Manufacturing Chemists Association (continued)

2. The EIS is based on an energy supply/demand forecast published by the Energy Information Administration (EIA) in early 1978. However, the forecast base data is three years old and does not reflect more recent trends in energy conservation in the industrial sector. On November 1, 1978, MCA commented in a letter from Mr. A. C. Clark to Mr. Lincoln Moses at EIA specifically about shortcomings in the data base subsequently used in the EIS. A copy is enclosed for your convenience.

A reworking of the EIS to reflect the actual regulations and a more up-to-date energy forecast would do much to enhance its value as an assessment of the impact of FUA. Please let us know if we can be of assistance.

Sincerely,

R. A. Roland

See response to comment by the U.S. Department of Health, Education, and Welfare on conservation, page 12-6. The energy forecasts presented in the EIS reflected DOE's position on future energy demand in the U.S. An underestimation of conservation in the industrial sector would mean an overestimation in the amount of future coal use both for the base case and the proposed program. The impacts identified within the EIS for increased coal use would therefore be less.

Public Service Electric and Gas Company (New Jersey)

PSE&G

Public Service Electric and Gas Company 80 Park Place Newark, N.J. 07101 201/430-6462

James R. Lacey General Solicitor

February 7, 1979

781940B

Office of Public Hearing Management
Box WA
Department of Energy
Room 2313
2000 M Street, N.W.
Washington, DC 20461

Re: "Implementation of Powerplant and Industrial Fuel Use Act [Draft Environmental Impact Statement Public Hearing and Extension of Comment Period] 44 Fed. Reg. 2004, January 9, 1979"

Gentlemen:

Public Service Electric and Gas Company (Public Service) submits the following comments *seriatim* in the above-entitled matter.

Chapter 1: SUMMARY

1.3.1 The potential environmental impact of diesel fuel combustion during transportation necessary to meet increased coal demand is described as negligible. Much coal will be transported through heavily urbanized areas contributing to greater local air pollution problems. Since many of these urbanized regions are already non-attainment areas, the contribution diesel exhaust would make to regional air pollution would be significant.

The regional ground level dispersion model shows a maximum increase of SO_2 from FUA implementation of 2.5 ug/m^3, this compares to a predicted 1985 national average concentration of 25 ug/m^3. The combustion of coal will thus increase ground level SO_2 by 10% nationally. The local or regional increases could be greater. The model does not evaluate the above ground differences nor consider air quality surrounding the coal burning plant. Each "demand region" should be evaluated separately, since there is much variation in air quality among and within the 10 regions. If it were not for the significant air quality differences, the differentation between attainment areas and non-attainment areas would not exist (Clean Air Act, 1977).

As can be seen in Table 5.12 of the Draft EIS, the percentage increases over base case in projected annual air pollutant emissions from transportation of coal resulting from the proposed action are greatest for the southwest and west regions (Supply Regions 6, 7, and 8). Since none of these regions are heavily urbanized areas, the contribution that diesel exhaust would make to regional air pollution as a result of the proposed action is insignificant.

A maximum SO_2 increase of 2.5 $\mu g/m^3$ is predicted, but only over a very small area. The national increase is far less than 10%, as discussed in Section 5.2.4. Those AQCRs most affected by the program are listed in Table 5.12a. Local differences in air quality are present, and local impacts will be addressed by the proper regulatory agencies before coal combustion begins.

Public Service Electric and Gas Company (New Jersey) (continued)

1.3.2 The concentration of atmospheric CO_2 and the potential increase from coal combustion remains to be determined. In Section 5.3.1, an explanation is made that the increase in CO_2 and particulate emissions could affect the earth's climate, consequently "affecting the human and biotic resources of the world". To discount the potential impacts caused by increased coal combustion and explain that it is "unlikely that the slightly accelerated rate of coal combustion due to the proposed action will affect the weather and climate of any demand region" when no demand region analyses have been performed is premature and unjustified.

The text has been modified to further discuss the potential impact of the Act on the global CO_2 budget (see Sec. 5.3.1).

1.3.3 Increased coal mining operations can result in increased acid mine drainage. The environmental impact on local supply region's water quality, aquifers and aquatic ecology must be investigated and evaluated. Acid mine drainage is considered a very significant problem. This is especially true in the extensively mined eastern U. S.

Acid mine drainage is discussed in the text (see Secs. 5.4 and 5.6).

1.3.4 The impact on local prime and unique farmland has not been investigated. Similarily, a supply or demand region terrestrial ecological impact analysis has not been performed. An overall programmatic impact statement cannot adequately address the environmental ramifications in earth region.

A programmatic analysis cannot address all the environmental ramifications of implementing the FUA. Analyses have been performed in Sections 5.5 and 5.6 to the level possible in a programmatic statement. Without more precise knowledge of where combustion of coal will occur, a more detailed analysis will not increase the precision of the assessment. More precise assessments of the impacts of implementing the FUA will have to be made on a site-specific basis.

1.4 Table 1.5 is a listing of the environmental trade-offs of the proposed action. Unfortunately, all negative listed impacts are environmental while the positive impacts are based on either economics or international trade. The table neglects the negative impact of price increase to the U. S. consumer because of increased transportation and added engineering or combustion costs. The positive impacts only address national policy and overall national impact, it doesnot address the negative impacts to the supply or demand regions or to the consumer. Since both air and water quality differ from region to region, the national environmental impacts of significantly increased coal combustion would not be as negative as they would be on a regional basis.

The cost impacts of the program will be incorporated into the price of coal. New requirements such as the Surface Mining Act of 1977 and the Resource Conservation and Recovery Act of 1976 and amendments to the Clean Air Act will increasingly internalize the environmental cost of using coal. As coal prices go higher, the program incorporates the decision to combust coal in the "substantially exceeds" index. Because the program is expected to have its greatest impact on industry rather than power plants, increases in the cost of generating steam and electricity represent a small but probably measurable increase in product cost to the manufacturer, but an imperceptible increase to the consumer, particularly as only a fraction of all industrial facilities are affected.

Chapter 3: FUEL CONVERSION ANALYSIS METHODOLOGY

3.2.4.4 As explained in this section, in order to comply with the intent of the Clean Air Act (1977), any boiler located in a "non-attainment" area should receive an exemption. Similarly, any PSD program requirements and State Implementation Plan that prevents or prohibits coal combustion should be considered in the exemption program. Considering present air quality, it is very difficult for any east coast coal burning facility to meet PSD program or SIP objectives.

Exemptions in non-attainment areas were assumed in the energy modeling analysis but the discussions on quality in environmental impact analysis include the feasibility of siting in non-attainment areas (Comment 12-9).

Coal-fired facilities are presently being constructed on the east coast in full compliance with PSD regulations. The impact of PSD requirements on coal combustion is discussed in Section 5.2.4.

Public Service Electric and Gas Company (New Jersey) (continued)

Chapter 5: ENVIRONMENTAL CONSEQUENCES OF THE PROPOSED ACTION

This chapter is entitled "Environmental Consequences of the Proposed Action". This DEIS admits that the environmental impacts are largely negative but suggests that the proposed action will comply with both the Clean Air Act and the Clean Water Act of 1977. However, the technology and methods required to achieve compliance with these laws are not adequately explained nor evaluated. Interestingly enough one of the "significant" positive impacts of the proposed program is the "Encouragement of the use of advanced coal combustion technology", but these technological advances are not specified in detail.

Under the regulations, those who indicate that the methods to comply with environmental regulations are too costly may apply for an exemption under the "substantially exceeds" criterion. The EIS would not be able to balance and weigh for each facility how environmental compliance can be achieved. Industrial users and utilities are well aware of the technology available and its suitability to meet local air and water requirements. The EIS does not specify technology because the issue will be resolved primarily on the basis of cost.

It is very difficult to claim that a method will comply with either the Clean Water or Clean Air Act, if the combustion method is not practical or feasible. In Section 10.2.1, coal liquification, high BTU gasification, and pressurized fluidized bed combustion are eliminated as alternates because of economic impracticality and unfeasibility by 1990. Only coal gasification and possibly atmospheric fluidized bed combustion are considered viable alternatives by the DEIS.

The text has been changed in response to this comment (Section 10.2.1).

As explained in Section 10.2.1.1, the major drawback to coal gasification using low and medium BTU gas is the poor transmission efficiency. For example, an industrial user of low BTU gas could be no further than one mile from the generating plant to make this method feasible. The DEIS does not address the difficulty of installing a gas pipeline in a highly urbanized environment, the number of plants required to generate additional power nor the necessary additional safety factors. The environmental impacts of these "pipelines would obviously be of paramount importance to the people living in close proximity to the coal burning facility".

Generally, low- and medium-Btu gas will be produced near or on industrial sites. It is not anticipated that transporting low- or medium-Btu gas through the construction of new pipelines in urbanized areas will be a viable option for industrial utility users.

The atmospheric fluidized-bed combustion (AFBC) method is in the pilot plant stage. To expect this method to be a "commercially available" alternative form of coal combustion "by 1981 or 1982", as described in the DEIS, is extremely optimistic. Obviously, any delay or project setback would greatly reduce the possibility of this method becoming an advanced coal combustion technology.

As can be seen in Section 10.2.2, the authors of this DEIS admit the alternate non-coal technologies that are "likely to be feasible for industrial use by 1990" are geothermal, nuclear, biomass conversion and municipal waste utilization. An evaluation of the "no change" oil combustion for present and future plants needs to be more carefully evaluated from the positive environmental side rather than the negative economic viewpoint. In many areas, especially on the East Coast, it would not be environmentally sound or economically feasible to convert present oil burning

See responses to comment of California Energy Commission and the USEPA (12-15).

stations to coal. Similarily, future plans should include both forms of fossil fuel, oil and coal, as alternatives for any proposed generating facility with both environmental and economic impacts in mind. A further detailed investigation of other "alternate" energy sources needs to be performed.

5.9.2 Occupational diseases such as pneumoconiosis would greatly increase with the increased coal mining. The length of underground service per miner would reflect increased incidence of disease. An evaluation of this impact, the added cost of health care, preventive medicine and enforcement of the Coal Mine Health and Safety Act should be included in both the environmental and economic impact sections.

Unless it is assumed that present coal mine health and safety legislation is inadequate for the protection of the mine worker, a stance not justified under the constraints of the FUA analysis, there is no substantive recourse other than to accept the regulatory assumption of a future mine work force free from coal worker's pneumoconiosis (CWP) contracted as a result of post 1975 exposures. Acceptance of this assumption does not mean a restriction to the wholly unrealistic supposition of a disease-free occupational population. Under a zero-incidence assumption, there will still be individuals who started their work exposures prior to 1975. CWP diagnosed in these individuals would be related to their early exposures (pre-1975 dust levels) and not considered to be a function of future production levels. Although these persons would require prolonged medical care and incur considerable expense in the treatment of their disease, their suffering would not be directly attributable to the FUA production levels.

If international economics dictate the positive environmental impacts, so must the increased cost of coal production and combustion to the regional U. S. consumer, be included under the negative environmental impacts.

Respectfully submitted,

James R. Lacey
General Solicitor
Public Service Electric
and Gas Company
80 Park Place
Newark, New Jersey 07101
(201) 430-6462

An appropriate change has been made in Table 10.2 to reflect the "substantially exceeds" criterion and consequent impact to the consumer of coal production and combustion. See response to comment by California Energy Commission, p. 12-33.

Southern California Edison Company

Southern California Edison Company
P. O. BOX 800
2244 WALNUT GROVE AVENUE
ROSEMEAD, CALIFORNIA 91770

WILLIAM H. SEAMAN
VICE PRESIDENT

TELEPHONE
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SCE

February 8, 1979

781937B

Office of Public Hearing Management
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2000 M Street, N. W.
Washington, D. C. 20461

15 FEB 79 4 : 04

Re: Draft Environmental Impact Statement - Powerplant and Industrial Fuel Use Act

Gentlemen:

This letter is in response to the invitation of the Economic Regulatory Administration (ERA) published in the January 9, 1979 issue of the Federal Register (44FR2004), to comment on the draft programmatic environmental impact statement (DEIS) which analyzes the impacts associated with implementation of the Powerplant and Industrial Fuel Use Act of 1978 (FUA).

INTRODUCTION

Southern California Edison Company (Edison) is a California corporation providing essential electric service to nearly eight million people in Central and Southern California, covering an area of 50,000 square miles, including services to defense installations, hospitals, food processing concerns and other essential industries. This service is provided through the generation of electricity from a variety of energy sources, including hydroelectric facilities as well as those fueled by coal, nuclear, oil and gas, with oil and gas providing an estimated 70% of currently installed capacity. This amounts to over 10,000 megawatts of oil-fired generating facilities, most of which are located in Southern California's South Coast Air Quality Management District.

The operation of Edison's oil- and gas-fueled plants has, for many years, been subject to stringent air pollution control regulations which now require use of low sulfur fuel oil containing not more than 0.25% sulfur by weight. Edison's requirement for such very low sulfur fuel oil has steadily increased as a result of a decline in natural gas supply. As one of the largest electric utilities in the State of California, Edison has a substantial interest in any legislation, rules, and/or regulations affecting fuels used for the generation of electricity and thus respectfully submits the following comments:

12-127

Southern California Edison Company (continued)

COMMENTS

Inasmuch as the DEIS is written to examine the overall FUA impacts on a generalized basis rather than defining site specific impacts, its concluding assessment of compliance with air and water quality standards are incomplete and will require further identification and examination prior to the implementation of any specific projects. The analyses of coal substitution for oil and natural gas required under the FUA must be based on site-specific conditions in order to provide a realistic and accurate evaluation of environmental degradation. As an example, under Section 1.3.1, Air Quality, the DEIS concludes that no regional air degradation is anticipated from the storage and on-site processing of coal and ultimate disposal of wastes from combustion. Edison does not agree with this conclusion. Insofar as the DEIS primarily addresses coal burn directly with post-combustion clean-up, it is unreasonable to expect that air quality in densely populated air basins will not be significantly affected.

The staff agrees that a programmatic analysis cannot address all the environmental ramifications of implementing the FUA. Analyses have been performed in Sections 5.5 and 5.6 to the level possible in a programmatic statement. Without more precise knowledge of where alternate fuel use will occur, a more detailed analysis will not increase the precision of the assessment. More precise assessments of the impacts of implementing the FUA will have to be made on a case-by-case basis.

Further, the DEIS addresses meeting National Ambient Air Quality Standards for non-attainment rather than the regulations of local air quality agencies. As a result, the study recognizes predicted non-attainment areas in the mid-Atlantic states, but does not recognize the current and potential air quality problems of the western states.

Increases is SO_2, TSP, and sulfates were calculated for the entire U.S. The impacts associated with these concentrations are discussed in Section 5.2.4. Impairment to visibility is a potentially major impact in the west but is not quantifiable. It is believed that the program will not affect the attainment or non-attainment status of the western states.

The impacts of the program were assessed on the basis that a maximum number of facilities would be designed for or would be converted to burn coal or waste products as alternate fuels. In cases of unacceptable impact, the DEIS fails to recognize that exemptions may be granted for specific projects by the Department of Energy (DOE) to burn oil or natural gas. The DEIS does not address the use of other alternate fuels such as solar, wind, uranium, shale oil, biomass and geothermal resources included in the alternate fuel definitions of the FUA and thus disregards the impact of the substitution of coal and its resultant waste products on the environment of a region where these alternate fuels may be difficult to use as a replacement for oil and natural gas. Edison recommends that the DEIS be expanded to address impacts associated with all alternate fuels identified in the FUA.

Alternate fuels are dicussed in Section 10.

In Table 1.1, Projected Maximum Oil and Gas Savings in 1985 and 1990 Achieved as a Result of the Proposed Action, the DEIS assumes no economic exemption unless coal is 44% more costly than imported oil, while an index of 1.5 (50% or more) was proposed under the FUA regulations. The basis for selecting an index of 1.44 has not been provided.

See response to comment by the California Energy Commission (p. 12-42).

In Section 1.3, Environmental Impacts, the concluding statement reads "Coal Supply Region No. 8 - Southwest is projected to increase production in excess of 10% over base case." This statement is misleading as the actual percentage, as shown in Table 1.2, is 15% by 1985 and 25% by 1990.

The text (Section 1.3) has been revised in response to this comment.

Lastly, Edison does not agree with the assumption in Section 3.1.1 that for existing electric utility boilers no additional coal use would result from the implementation of the FUA.

See responses to comments by the U.S. EPA regarding existing facilities (p. 12-10) and the California Energy Commission (p. 12-33).

Sincerely,

Southern California Gas Company (continued)

UNITED STATES OF AMERICA
BEFORE THE
DEPARTMENT OF ENERGY

COMMENTS OF SOUTHERN CALIFORNIA GAS COMPANY

ON

THE DRAFT PROGRAMATIC ENVIRONMENTAL IMPACT STATEMENT

FOR THE FUEL USE ACT

Southern California Gas Company (SoCal) respectfully submits its comments regarding the Draft Programatic Environmental Impact Statement (DPEIS) for the Fuel Use Act.

SoCal is a natural gas utility in the southern portion of the state of California. Southern California is widely known as an area with severe air quality problems, where the direct burning of coal is severely restricted and oil used by electric utilities must contain less than 0.25 percent sulphur. In addition to being the nation's largest distribution company, serving nearly 3.5 million residential customers, SoCal also provides nearly all the energy needs for large commercial and industrial consumers. Retail gas service is also provided to six large utility customers.

SoCal has reviewed the DPEIS and is seriously concerned that it fails to adequately describe the environmental consequences of switching from gas and oil to coal as set forth in the FUA and that it fails to thoroughly consider potential gas options as viable alternatives.

Southern California Gas Company (continued)

The DPEIS considers only the incremental environmental consequences arising out of the implementation of the FUA. It has assessed the FUA in isolation and does not consider the synergistic effects of diverse federal agency and public policy actions stimulating the increased use of coal. This restricted view understates the overall environmental impact and costs associated with the FUA.

See response to comment by the American Gas Association on the impact by other federal laws and the cumulative impact of federal policies (p. 12-89).

Further, the DPEIS appears to make unrealistic optimistic assumptions regarding future administrative actions approving environmental exemptions. As an example, the DPEIS states on Page 3-6 under Section 3.2.5.2 that:

> "A major constraint to coal use in the future will be enforced attainment of air quality standards. In this analysis, all combustors shown technically and economically capable of burning coal located in AQCR's considered to be in violation of air quality standards ("nonattainment") were treated as automatically exempt from the program.

See responses to comments by the U.S. EPA (p. 12-9) and Public Service Electric and Gas Company (p. 12-124).

However, the FUA does not guarantee such exemptions. It requires that an applicant applying for an exemption bear the burden of proof demonstrating the need for such an exemption. The law under Section 212 of the Act states:

> "...the Secretary shall, by order, grant a permanent exemption under this subsection with respect to natural gas or petroleum, if he finds that the petitioner has demonstrated that despite good faith efforts--(c) the prohibitions of subtitle A could not be satisfied without violating applicable environmental requirements."

Southern California Gas Company (continued)

The proposed ERA rules which would implement this section of the Act are even more stringent.

Therefore, it is difficult to believe that the optimistic assumption regarding environmental exemptions will hold up over the test of time. SoCal recommends a more conservative assumption be used to determine environmental exemptions for the construction of coal-fired facilities. It is clear that not all requests for exemptions will be granted nor will all coal facilities in a non-attainment region be exempted. Further, additional coal use which would result from a more conservative exemption assumption should be evaluated in relationship to the total environmental impacts brought about by the increased use of coal.

DOE believes its assumptions to be realistic and consistent with a worst-case analysis. See response to U.S. EPA comment (p. 12-9).

The DPEIS has failed to adequately consider several natural gas options. The DPEIS shows modest energy replacement goals brought about through the implementation of the FUA of 1.4 quads in 1985 and 2.6 quads in 1990. Increased production of natural gas by the year 1985 may come close to satisfying these goals. Dr. Schlesinger, in a statement before the Joint Economic Committee dated January 23, 1979, remarked that:

> "The steady real increase in the price of new gas provided by the Natural Gas Policy Act, the protection against inflation, the more stable and predictable regulatory and financial environment, the deregulation of high cost gas and the 'light at the end of the tunnel' for producers should after a transition period--ensure a high rate of drilling activity in the lower 48 states. We, consequently, expect that by 1985 annual lower 48 production will be at least 2 trillion cubic

See response to U.S. EPA comment (p. 12-15).

Southern California Gas Company (continued)

feet above that which would have pertained if the Natural Gas Policy Act had not been enacted."

The increase projected by DOE may alone satisfy the energy goals of the FUA.

Further, the DPEIS has failed to assess adequately the use of coal gasification. The lack of serious consideration of coal gasification runs counter to one of the basic tenets of the Act. The FUA contains as one statement of purpose--" (4) to the extent permitted by this Act, to encourage the use of synthetic gas derived from coal or other alternative fuels." The DPEIS dismisses high BTU gasification as not economically and/or technologically feasible by 1990. This alternative should be evaluated more extensively comparing the cost relationships between coal gasification and increased direct fired uses of coal. Additionally, the environmental trade-offs between the two uses of coal should be considered.

SoCal respectfully urges DOE to evaluate more carefully the alternatives to the direct burning of coal by examining the use of gas derived from coal. Also, SoCal believes the environmental impacts arising from the increased use of coal have been optimistically understated and should be re-evaluated using more realistic assumptions.

Respectfully submitted,

THOMAS D. CLARKE
JOHN S. FICK

By John S. Fick
John S. Fick

Attorneys for
Southern California Gas Company

Dated: February 8, 1979

The text has been revised to state that high-Btu gas is technologically feasible but is assumed not to be a commercially viable alternative by 1990.

Serious consideration was given to low- and medium- Btu gasification, and the environmental impacts are described in Section 10.2. The fuel choice decision with regard to an alternate fuel is up to the applicant and will be made based on the most economical alternative. The assumption of direct coal combustion within the impact analysis of the EIS presents a worst-case environment assessment.

Standard Oil Company (Indiana)

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312-856-7935

Ronald J. Ganim
Attorney

781903B

February 8, 1979

Office of Public Hearing Management
Box WA
Department of Energy
Room 2313
2000 M Street, NW
Washington, D. C. 20461

Gentlemen:

Comments on DOE/EIS - 0038-D

Attached are the comments of Standard Oil Company (Indiana) on this draft EIS.

Very truly yours,

Ronald J. Ganim

RJG/eew

Attachment

Comments of Standard Oil Company (Indiana)
on the Draft Programmatic Environmental
Impact Statement Under the Fuel Use Act
(DOE/EIS-0038-D)

Following are comments by Standard Oil Company (Indiana) concerning this Environmental Impact Statement

General Comments

1. The EIS provides only a very broad overview of major first order environmental impacts. It indicates that many of these issues will be resolved in implementing the program through

Standard Oil Company (Indiana) (continued)

the statutory requirement that environmental regulations may not be violated and other exemptions applicable to various facilities for site-specific reasons. In effect, this approach dismisses many major environmental impacts. The proposed regulations do not, by themselves, guarantee that environmental issues will be resolved in specific cases where the FUA is applied. All identifiable first and second order impacts resulting from the implementation of the FUA should be presented in the EIS along with an analysis of available tradeoffs.

The programmatic EIS cannot "guarantee that environmental issues will be resolved in specific cases." Because each individual coal use has different environmental hurdles, a description of all the possible conflicts could not be usefully listed in the programmatic statement. Overall, each facility for which an exemption is sought can demonstrate the cost of environmental compliance and, if it is excessive, can apply for an exemption on that basis.

2. The EIS indicates in several sections that increased coal utilization resulting from the implementation of the FUA will be minor with respect to total coal usage. Relative impacts resulting from the FUA are thereby considered to be minor and highly site-specific. In actuality, use of coal as a prime energy source has a greater environmental impact than does the use of any other fossil fuel. In effect, any action that results in a measurable increase in coal utilization should be expected to increase resulting environmental impacts to a measurable extent. By ignoring this fact, the present EIS is deficient.

DOE believes that coal usage has a greater environmental impact than any alternative fuel. This is the reason coal was chosen and the projected increment due to FUA was a worst-case analysis. The EIS has examined and highlighted, at the national, regional, and sub-state levels, the measurable production and combustion impacts of increased coal usage due to the FUA program.

3. In most instances the EIS defers the discussion and analysis of site-specific impacts to evaluations that will result from implementation of the FUA at individual locations. Many of the environmental issues discussed in the EIS were assumed to have little significance at the national or global scale. The corollary will not hold at the local level where any of a vast number of environmental issues could become significant. A

Standard Oil Company (Indiana) (continued)

sensitivity for the site-specific criticality of several environmental issues could be dealt with more satisfactorily by overlaying maps of coal supply/demand regions with PSD areas, non-attainment areas, and SMSA maps to identify those areas where environmental impact would be most critical. The EIS should then address these areas.

Overlays of PSD areas and non-attainment regions were used to produce Tables 5.12a and 5.12b, and the discussion in Section 5.2.4. Any other impacts would be site-specific, and will be addressed by the proper regulatory agencies before coal use begins.

4. The EIS generally assumes that, because of environmental restrictions, the FUA will not require conversions in non attainment areas and that new sources locating in such areas would not burn coal. However, most industries with boilers are located in such areas and if the Act is administered in such a way as to have any discernible impact on coal usage, it would have to be applied to such areas. The environmental consequences would be significant in such areas and should be evaluated further in the EIS.

See response to comment by U.S. EPA, p. 12-9.

5. The EIS does not assess the impact of consuming the available PSD increment by coal conversions. For example, the document assumes that Coal Demand Region VI will use high sulfur coal from the Midwest. This switch from relatively non-polluting natural gas and oil will in the case of a large installation consume the entire increment in a given area, thus precluding any other industrial development.

The text has been modified to further assess the potential impact of the Act on non-attainment and PSD areas (see Sec. 5.2.4).

6. The massive problems of sludge disposal have not been fully evaluated in the EIS. New waste disposal sites are politically unacceptable to many communities. The costs will be significant, particularly in the case of legislation such as the Resource

See revised Section 5.5.5. If adequate waste facilities are not available to an MFBI as a result of community opposition, either the facility cannot be operated or application for an exemption (cost, site limitation, and/or environmental) can be made. See response to comment by the U.S. EPA, p. 12-94.

Standard Oil **Company** (Indiana) (continued)

Conservation and Recovery Act (RCRA) which will probably treat sludge as a "hazardous waste" thus requiring special handling, disposal and site-protection. Further, water run off from sludge and ash pits, potential ground water contamination from sludge disposal and the impact of the Safe Drinking Water Act should be fully evaluated.

The issues of water runoff from sludge and ash pits and potential groundwater contamination from waste disposal are discussed in Section 5.4 (see in particular, Sec. 5.4.5). Further evaluations would require site-specific information. Each facility will be required to comply with the Safe Drinking Water Act.

Specific Comments

These comments are keyed to the appropriate sections of the EIS.

1.2 The list of industries expected to be affected by the program is incomplete. Because of the small size boiler cut-off, nearly every industry will be affected.

The industries affected by the program are indeed more diverse than those listed in the programmatic statement. However, the industries listed are likely to represent more than two-thirds of boilers affected by the program. A longer list may give a misleading impression of which industries will be faced with combusting coal.

1.3.1 The assumption in the EIS that there will be no regional air degradation from the storage, processing and disposal of coal and wastes is invalid. EPA recognizes in its regulations (e.g. PSD regulations) that fugitive emissions from such sources are significant.

See response to comment by California Air Resources Board, p. 12-24.

The EIS should also evaluate the impact of the program on the short term SO_2 standard. This impact will be far more significant than the annual average SO_2 calculations presented.

Violations of short-term pollutant standards are generally a local phenomenon. The prediction of such violations is site-specific, and will be addressed by other Federal, State and Local regulatory agencies in their permitting processes before coal combustion is allowed.

1.3.3 This section neglects to indicate that water resource quality in Coal Supply Regions six and seven (Coal Demand Region VIII) would be significantly impacted by surface mining operations in these states. Since water resources in these regions are limited in quantity, they do not have the capacity to absorb the impacts resulting from coal mining and use without resulting in a marked decrease in resource quality.

The main text contains information on this subject (see Secs. 5.4 and 5.6).

Standard Oil Company (Indiana) (continued)

1.3.4 Presently proposed RCRA regulations would control the manner in which scrubber sludges are disposed. In general these regulations will be more restrictive than those presently in force and will result in increased difficulties and costs associated with scrubber sludge disposal. Discussion of these issues and how they impact the FUA is important to the assessment of the program.

See Standard Oil General Comment 6.

1.3.5.1 Various regulations implemented as a result of the Clean Water Act Amendments of 1977, the Coastal Zone Management Act, and RCRA will make disposal of coal mining, cleaning, and combustion residues in wetlands impossible.

The text has been modified to indicate that federal regulations will mitigate the impacts of waste disposal upon wetlands (p. 1-8 and p. 5-55).

1.3.7 The projected casualties associated with coal extraction are based on insufficient data. Selection of one year's statistics for making future predictions is poor methodology in an industry having the highest annual average casualty statistics of the entire U.S. labor force. Furthermore, these casualties result from discrete events (major and minor accidents) which occur on a random basis in time but are known to be a function of production levels. That is, their frequency of occurrence is likely to increase with production. A more statistically valid approach for predicting future casualties would be based upon trend analysis of several years of casualty data under present safety regulations weighted (based) to production levels. This would minimize the possibility of underestimating future casualties when one year's data (in which there were no major U.S. accidents) is used as a statistical basis.

The 1973 casualty rates for coal extraction are reasonable and representative estimates of the recent U.S. coal industry injury experience. An underlying assumption in the analysis of anticipated injuries in the coal industry in the future, as presented in Section 5.9.1, is that the 1973 rates hold for future mine experience. Such an assumption should be viewed as conservative since it does not take into account future advances in mine safety and automation that will reduce the level of human exposure to mine hazards below that of the 1973 level. As a trend analysis based on a declining injury rate could show a near-zero rate at some future time which is desirable but probably unrealistic, it was decided to use the 1973 rate and therefore a worst case. The decision was therefore made to go with a representative level of injury experience.

Standard Oil Company (Indiana) (continued)

Table 1.5 A close reading of this table reveals that the negative impacts far out weigh the positive impacts of the program. The positive impacts are very general, cannot be quantified, and may not occur even if the program is successfully implemented. For example, the balance of trade is a measure of imports vs. exports. If imports of commodities other than oil are increased in the future while exports remain the same or decline, the balance of trade will not improve regardless of the Act. Similarly, the strength of the dollar is probably so much more dependent on the conduct of U.S. foreign relations that the FUA will have no impact at all.

The interpretation of Table 1.5 by Standard Oil is one that can be made, but is based on a prognosis of future economic conditions and a specific view of how national policy should be directed. However, DOE still concurs with its own interpretations.

Another "positive" benefit is described as "the encouragement of use of advanced coal combustion technology." However, this is not a positive impact from the Act but merely a necessary result of the coal conversion program. Without the Act, the use of the technology would not be necessary at the locations covered by the Act.

DOE considers the encouragement of advanced coal combustion technology to be a positive benefit of the FUA, whether additional incentives are provided or not.

The EIS has not demonstrated how the implementation of the FUA would significantly decrease the likelihood of oil spills in the short term. To draw this conclusion one must analyze the frequency of occurrence of spills as a function of volume and mode of transport. Estimated decreases in oil consumption resulting from implementing the FUA would then have to be disaggregated according to transport mode to determine what reduction in spill occurrence, if any, would result (see also 2.3.1).

The benefit from reduced oil spills was considered "minimal" and consequently an elaborate model of oil trade was not considered necessary to permit reaching a conclusion. Oil spills are less a function of oil volume in trade than the frequency and nature of oil transfer operations. No claims of a benefit are made about avoidance of a catastrophic accident, because the oil users affected by the program are not now recipients of huge volumes of oil. The statement on page 2.3-1 regarding the benefits of the program has been qualified.

Standard Oil Company (Indiana) (continued)

On the other hand, the negative impacts are significant, highly visible, quantifiable and site-specific. Increased particulates and SO_2 will be discernible to the citizen living near the converted facility as he views smoke where there previously was none, and as acid rain falls. Increased solid waste and scrubber sludge will be disposed of relatively near the industrial activity which is usually near the communities of those who work there. Increased use of water is highly significant in some western states. Increased costs to the consumer are particularly important during these inflationary times.

Generally, the benefits from FUA are economic and strategic. The conclusion drawn by ERA is that the FUA makes a positive and cost-effective contribution to reducing the reliance on foreign petroleum with acceptable environmental impacts. With proper pollution control technology and regulatory enforcement, the environmental impacts of the program are expected to be limited. Particulates and SO_x emissions will not be any more visible than emissions from oil-fired boilers. Acid rain may increase slightly in certain sections of the country, but is not expected to be a significant problem nationally (see Sec. 5.3.2). The other problems presented are addressed in Section 5. The inflationary costs were found to be minimal.

The Table further assumes that impacts due to coal-related labor strikes will be minimal. In the 1930's when the U.S. was very dependent on coal, strikes by coal miners had a significant impact on the operation of steel mills and power plants and were a factor in the ready acceptance of oil and gas as alternate fuels. The largely automated oil and gas industry, however, is for less vulnerable to even national labor strikes. The effect of railroad labor problems should also be listed as a negative impact. The recent 1978 railroad strike indicates that such problems have not gone away.

Table 1.5 has been amended to include railroad strikes as well as mining. The table was not meant to be restrictive.

2.4 EPA is currently developing NSPS for industrial boilers. These regulations will have a significant impact on the environmental viability of implementing the FUA and the cost of compliance. At present, EPA and DOE appear to be proposing regulations without communicating their respective goals and coordinating their activities. Closer interdepartmental communication appears to be essential in this area.

EPA and DOE are cooperatively developing the regulations affecting the two agencies.

Standard Oil Company (Indiana) (continued)

3.2.4.3 The exemption from regulation of those boilers not designed to burn coal is not borne out by draft regulations published in the Federal Register, November 17, 1978, which require that an operator demonstrate that a fuel switch to coal is technically infeasible before an exemption can be granted.

The assumptions in Section 3.2.4.3 reflect modeling analysis, including the assumptions that the existing boiler universe will not be appreciably affected by the FUA, for the reasons detailed in the section. Any boilers that would not be in compliance with this assumption are projected to be so few in number that their impacts would not noticeably affect the worst-case analysis described in the EIS.

3.2.5.2 While this analysis assumes that facilities in nonattainment areas would be exempt from the FUA, the proposed regulations would require an installation to demonstrate that needed offsets would be too expensive to obtain, making the fuel switch to coal economically infeasible.

See previous comment.

4.2.1.5 & 5.3.1 Since the C to H ratio is greater for coal than for any other widely used fossil fuel, the amount of CO_2 formed per pound of fuel burned is greater for coal. Any adverse climatic effects resulting from increased atmospheric CO_2 levels would therefore tend to be exacerbated by increased coal utilization under FUA.

The text has been modified to further discuss the potential impact of the Act on the global CO_2 budget (see Sec. 5.3.1).

5.1.2.1 This section overlooks the fact that coal slurry pipelines have to date largely been opposed on environmental grounds. Major anticipated environmental impacts resulting from implementing this technology include water resource depletion at the coal sources, interbased transfer of major water supplies, and effluent disposal problems in the coal using areas.

Due to the uncertainties involved in the prospects of coal slurry pipelines, the FUA EIS did not discuss details of this specific coal transportation mode except a general economic consideration among the alternative modes of coal transportation. However, the incremental coal demand from any given region as a result of the proposed action would not be large enough to affect significantly the prospects of coal transportation by slurry pipeline.

5.2.4 SO_2 emissions offset purchases in PSD and nonattainment areas will most probably be very difficult to obtain. Since offsets for a particular pollutant must be obtained in kind, the major

Emission off-sets for the pollutant exceeding ambient standards will be obtained from existing sources in the non-attainment area. Many non-attainment regions are presently heavily industrialized, with a large number of reducible pollution sources. In non-attainment regions where a single large emitter is the primary source of the pollutant of interest, off-sets must be obtained from that source.

Standard Oil Company (Indiana) (continued)

sources of the offsets for most AQCR's will be powerplants and MFBI's. Only AQCR's containing smelters and sulfuric acid plants will be able to spread the availability of potential offsets over a wider industrial base.

In any location, emission reductions will come from existing sources affecting the non-attainment area. Obtaining off-sets from these sources, required before coal combustion begins, will be based on the criteria deemed most important by the management of the new source.

5.4.1.1 & 5.4.1.3 One geographical area where there is significant potential for impact under the FUA is the Northern Great Plains. Although it has not been mentioned in the EIS, Northern Great Plains rangeland has limited hydrological capacity. Under the FUA this rangeland would become a major coal supplying region. Any major disruption of the existing hydrology could render rangeland unrestorable and result in irreversible environmental damage.

The general problem of reclamation on rangeland in the Northern Great Plains is recognized in Section 4.4, although the limited hydrological capacity is not mentioned specifically. As is noted in this section, careful evaluation of reclamation potential is needed prior to permitting of coal extraction.

5.5.1 The EIS mentions that the railroads plan to add coal hauling capacity in the future. There is no quantitative information presented to assure that sufficient coal hauling capacity will be available in the future. This is very important since approximately 70% of the coal is moved by railroad. If it is assumed that barging on waterways will increase, this method could be limited during severe winters by ice, particularly in the highly populated northern and northeastern parts of the country.

The coal hauling capacity availability in the future will be heavily dependent on the coal demand pattern, environmental regulations, financial climate and rate decisions (see Comments 1 and 7). The railroads have indicated that the problem of assurance of capacity is not a physical constraint but a financial problem. Section 803 q title VII of FUA authorizes additional amounts for railroad rehabilitation.

5.6.1 This section fails to discuss the impacts resulting from culm and coal waste piles. In addition to aesthetic problems, there are impacts resulting from acid run-off, and odor and health problems caused by the release of SO_2 and H_2S. There is also the possibility of wide-spread fires in the piles and underground.

This section does address impacts of coal waste upon nonhuman biota. The possible effects of acid and alkaline runoff, leaching of trace elements, spontaneous combustion, and sedimentation upon both terrestrial and aquatic biota are discussed on pages 5-46 through -51. Impacts on humans are addressed in Sections 5.8.1 and 5.9.1.

Regulations pertaining to proper disposal of culm and coal waste piles have been promulgated for the Surface Mine and Control Act of 1977 (Fed. Reg. 44(50):15311-15463).

Steel Hector & Davis

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February 9, 1979

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DIRECT DIAL NUMBER

Economic Regulatory Administration
U. S. Dept. of Energy
Room, 7202, 2000 "M" Street, N.W.
Washington, D.C. 20461

BY HAND

Attention: Mr. Stephen A. Frank

Re: DOE/EIS-0038-D

Gentlemen:

Our firm represents Florida Power & Light Company, (FPL), on whose behalf we are submitting these comments. We have reviewed your Draft Programmatic Environmental Impact Statement (Draft EIS) with respect to the Economic Regulatory Administration's (ERA) proposed regulations issued under the Powerplant and Industrial Fuel Use Act of 1978 (FUA).

The Draft EIS focuses on the impact that conversion to coal or alternate fuels will have on the environment in 1985 and 1990. It ignores completely the materially adverse impact that ERA's proposed regulations (43 Fed. Reg. 54912) will have on the environment prior to those times.

The Draft EIS is based on a false premise. Under Section 3 entitled "Fuel Conversion Analysis Methodology" at page 3-1 of the Draft EIS it is stated:

[1] The energy impact analysis methodology described in this section was designed to forecast the level of increase in the use of coal and alternative fuels in existing and new facilities as a direct result of the fuel conversion regulatory program resulting from the regulations indicated in Section 2.

. . .

[2] Nearly all of the impacts of the program will occur in the industrial sector . . . .

. . . .

[3] [I]ncremental coal use by utilities due to the program is assumed to be insignificant . . . [Emphasis Supplied.]

. . . .

[4] Existing utilities will not be affected by the proposed action because they have been evaluated for conversion to coal under the Energy Supply and Environmental Coordination Act of 1974 (ESECA . . . .

. . . .

[5] In other words, the requirements of the Systems Compliance Option will be met even without passage of the FUA. It is assumed that no additional coal use will result from this provision.

All five of these statements are incorrect.

If ERA's implementing regulations (43 Fed.Reg. 54912) (the "Regulations") under the FUA had followed the FUA the statements would have been correct. For the purposes of its analysis the Draft EIS defines "new facilities" at page 1-2 as "those which come on-line after 1980." However, the Regulations treat facilities which were not "operational as of April 20, 1977 as "new."

A clear example of ERA's sleight-of-hand between its Draft EIS and its Regulations is shown by the treatment of three of FPL's powerplants. Putnam 1 and 2 are presently operational. They were not operational on April 20, 1977. Martin 1 will become operational in 1980. All three of these powerplants are "existing" under the Draft EIS's definition of existing (Draft EIS p.1-2) but "new" under the Regulations treatment. (See letter of Mr. Barton R. House of ERA to Marshall McDonald of FPL received by FPL on Dec. 22, 1978) Since they are "existing" so far as the Draft EIS is concerned, the effect on the environment of converting these units to coal was not considered. These three units, along with Martin 2 which will come on line in 1981, were all exempt under ESECA because they were beyond the early planning process. If they were exempt from the requirements of ESECA, they were not evaluated for conversion to coal under ESECA.

We are informed that approximately 24 oil-and gas-fired steam electric generating units and approximately 65 combined-cycle and combustion turbine units have been classified by ERA as being "new." Ten of these units are located within the state of Florida. Under ERA's proposed regulatory scheme unless an exemption can be obtained, before May 9, 1979 (i) those units that are operational will have to be shut down; (ii) those under construction will have to cease construction and (iii) all will have to convert to coal or an alternative fuel. These units represent many thousands of megawatts of electric generating capacity. We do not believe that the Draft EIS prepared in connection with ESECA considered the material adverse impact that converting these units to coal would have on the nation's environment. In addition, and more significantly, the Draft EIS did not consider the effect which converting the 10 units located

DOE has not classified any units as being new. The assumption is that all units are considered new unless they apply for a classification as an existing facility. At that point, a determination will be made about whether the units are new or existing. In the absence of specific information, such determinations cannot be made.

Steel Hector & Davis (continued)

in Florida would have on Florida's environment. The immediate and adverse impact that conversion of the units would have on the environment was not considered in the Draft EIS. Had the Regulations followed the intent of Congress and the plain language of FUA, the Draft EIS would be adequate. The Regulations, however, far exceed the language of FUA and attempt to force many additional electric generating units to convert to coal. The Draft EIS does not support ERA's attempt at over-reaching.

Statement [1] is incorrect in that the analysis methodology was not designed to (and does not) forecast the level of increase in the use of coal in existing and new facilities as a direct result of ERA's regulatory program. In fact, it simply ignores ERA's attempt at forced conversion of many thousands of megawats of capacity not called for by the FUA.

DOE believes that the EIS modeling and analysis accurately forecast the level of increase in the use of coal in new and existing facilities.

Statement [2] is incorrect because it ignores the Regulations' effect on the utility industry.

See responses to comments by U.S. EPA (p. 12-10) and California Energy Commission (p. 12-33).

Statement [3] is incorrect because it ignores the millions of tons of coal that must be mined, transported and consumed annually by the powerplants that were not "operational" on April 20, 1977, and are therefore "new" under the Regulations.

The statement refers to the powerplants that would be considered new and converted under the FUA. The utility industry forecasts indicate that coal will be heavily used for the generation of electricity, but this will not be the result of the FUA but, rather, would have occurred without passage of the FUA.

Statement [4] is incorrect because no evaluation was made under ESECA for the powerplants classified as "new" under the Regulations.

See responses to comments by U.S. EPA (p. 12-10) and California Energy Commision (p. 12-33).

Statement [5] is so out of place it does not even deserve comment.

See response to comment by California Energy Commission (p. 12-33).

The Draft EIS totally ignores the impact on the environment of the Regulations. Its entire premise is flawed; it is hopelessly inadequate under Section 1022(c) of the National Environmental Policy Act.

Respectfully submitted,

Thos. E. Capps

Union Oil Company of California

Memorandum
Union Oil Company of California

UNION CPE-24

February 12, 1979

To: Members of the FUA Task Force

From: John L. Rafuse

UNION COMMENTS TO DOE ON THE
ENVIRONMENTAL IMPACT STATEMENT
(EIS) FOR FUA

Attached for your information are our comments on the Draft Programmatic EIS. Comments were due to be submitted by February 9.

Union comments on the regulations in general will be presented at a hearing in Tampa, Florida on February 21 or 22. You will receive a draft for your comments by the end of this week.

JLR:ec

Attachment

COMMENTS ON
THE DRAFT PROGRAMMATIC ENVIRONMENTAL IMPACT STATEMENT
FOR THE REGULATIONS IMPLEMENTING
THE POWERPLANT AND INDUSTRIAL FUEL USE ACT OF 1978
(DOE/EIS - 0038-D)

UNION OIL COMPANY OF CALIFORNIA

FEBRUARY 9, 1979

The Union Oil Company of California hereby offers comment on the Department of Energy's (DOE's) Draft Programmatic Environmental Impact Statement (EIS) for the regulations implementing the Power-plant and Industrial Fuel Act of 1978 (FUA).

Union Oil Company of California (continued)

As a general comment, Union feels that the EIS and the various sets of FUA regulatory proposals that have been published to date are almost totally unrelated. While the EIS is based upon the FUA, the regulations show almost no connection with that act. Therefore, since the EIS purports to be applicable to the regulations, it is inadequate in its assumptions, its analyses, its intent and its conclusions. As a result of this "disconnect" between the EIS and the regulations, we feel that the entire regulatory scheme as proposed to date should be redone and brought more closely into line with the FUA law itself, the intent of the act as demonstrated in the Legislative History, the assumptions underlying the EIS (assumptions provided by DOE's Economic Regulatory Administration (ERA), and with the EIS itself. Once the regulations have been completely restructured along those lines, thereby approaching the requirements of the National Environmental Protection Act (NEPA), implementing regulations set forth by the President's Council on Environmental Quality (CEQ), Presidential Executive Order #12044 concerning regulatory impacts, and the Administration's stated desire of bringing inflation under control, then a final EIS should be published and the remaining formal procedures followed to the point where the FUA regulations can be implemented.

The following comments are offered within the context of our overall concern about the "disconnect" and the accompanying regulatory excess.

NEPA and its implementing regulations have not been superseded by the FUA, and NEPA and those regulations

See response to comment by Dow Chemical, p. 12-117.

Union Oil Company of California (continued)

impose the requirement o federal agencies - including the ERA - to complete a final EIS and to allow thirty (30) days for public comment on the EIS before implementing the regulations. In the words of this EIS, "The principal objective of NEPA is to build into the agency decision-making process an appropriate and careful consideration of environmental aspects of proposed actions." Despite that clear objective and requirement the ERA issued on November 16, 1978, and made effective as of that date, Interim Regulations implementing the FUA. Those Interim Regulations required, and established procedures for, certification by ERA of "transitional facilities" as either new or existing under the FUA. The Interim Regulation and certification procedures can have profound effects on certain facilities that will be classified as "new" and thereby forced to burn coal or go through a long, expensive, redundant and probably unnecessary exemption procedure. NEPA and Council on Environmental Quality regulations are being ignored if the implementation of these regulations takes place before issuance of the final EIS. The DOE similarly ignored applicable law and regulations in the ERA issuance (January 5, 1979) and implementation of the Special Rule for Temporary Public Interest Exemption (SRTPI).

Regulations will not be finalized until the NEPA EIS process is complete.

The Draft Programmatic EIS does not accurately assess the impacts that could result from implementation of the FUA regulations as proposed. While the EIS summary

Union Oil Company of California (continued)

claims that "maximum substitution of coal was assumed in the analyses by systematic overstatement...." the actual case is one of enormous understatement in the EIS. The basic reason for the inaccuracy is that the EIS is based upon the act and upon reasonable assumptions related thereto, whereas the regulations are not. These stringent, broad, vague and unreasonable regulations differ so significantly from the law and its intent and provisions, that the basic assumptions of the EIS are incorrect and unjustified. Union will present more detailed comment upon the regulations at one of the public hearings scheduled for that purpose. For now, a few examples of the "disconnect" between EIS and the FUA regulations should demonstrate the point:

- The EIS clearly states as one of its basic assumptions that there will be no conversions (to coal or other alternative fuel), in nonattainment areas, and further, that environmental exemptions will be available or even automatic in some cases. The FUA regulations, however, impose the same requirements in nonattainment areas as elsewhere, closing the Catch-22 loop by requiring an EPA Final Determination for rejection before DOE will consider environmental exemptions. This particular disconnect defies logic, requires months of wasted time, will cost consumers and industry millions of dollars, and

See response to comment by U.S. EPA (p. 12-9) and California Energy Commission (p. 12-27).

Union Oil Company of California (continued)

will serve largely to slow both EPA and DOE in whatever work they should be doing. Further, DOE will collect excessive application fees for the unnecessarily generated applications for exemption.

- The EIS assumes (as the law mandates) that utility boilers and MFBI's covered by the regulations will be single units of 100 million BTU per hour input, or aggregations of 250 million BTU per hour. The regulations as they first came out (as applied to "New Facilities") were written to cover all units of 50MMBTU or larger. Subsequently, the "Existing Facilities" regulatory proposal has withdrawn the 50MMBTU minimum, and proposes to have no minimum for new or existing facilities. Further, Table 1.1 (footnote b) explains the EIS assumption that "New units are those coming on line in 1980 and after...", whereas the regulations actually reach back in time to eliminate units that would otherwise be considered "existing". Thus all assumptions in the EIS about size and time/existence of units are invalid and greatly understated. Clearly this contravention of the will of Congress and expansion of the regulatory coverage is extreme and ridiculous. Just as clearly, it means that all the figures for coal demand, oil and gas demand, price impact, land use, emissions, water

See response to comment by California Energy Commission, p. 12-27.

See responses to comments by U.S. EPA (p. 12-10) and California Energy Commission (p. 12-33).

Union Oil Company of California (continued)

quality, transportation, mining deaths, general mortality and morbidity and everything else considered in the EIS are wrong, probably by orders of magnitude. This means that the regulations themselves may be invalid because they so far exceed the law and that, as a result, that the EIS is inadequate.

- The EIS does not consider other legislation that effects the FUA, and vice-versa. For example, the price effects of the Natural Gas Act on both supply and demand are nowhere considered although they will definitely weigh in every calculation connected with the FUA. In addition, the Energy Tax Act provisions for tax credits for use of alternative fuels mesh neither with the FUA provisions and definitions nor with the EIS. CEQ regulations require that these and other such legal and regulatory effects be considered. The Energy Tax Act and the Natural Gas Act are both parts of the National Energy Act, as is the FUA. Since neither of those was considered in the FUA EIS, there is some question as to how many other relevant items were omitted.

See response to comment by U.S. EPA, p. 12-15.

See response to comment by American Gas Association, p. 12-89.

- The ERA has asked for comments on the inclusion of California heavy crude among the definitions of alternate fuels. This is nowhere considered in the EIS, which simple assumes that all oil "saved" under FUA would be imported oil.

See response to comment by U.S. EPA, p. 12-15.

Union Oil Company of California (continued)

- The present DOE policy encourages the use of natural gas through the SRTPI. This policy invalidates the EIS assumption that "one of the significant positive impacts of the FUA is increased flexibility in decisions regarding natural gas curtailment..."

See response to comment by American Gas Association, p. 12-15.

- The EIS fails to consider, or even make mention of, the potential impacts of the FUA regulations on sub-federal regions despite the fact that some, including the state of California, would be seriously and negatively effected by the regulations.

See response to comment by Public Service Gas and Electric Company, p. 12-124.

- The EIS seems to assume that one "site" would have some logical basis. The regulations, however, would say that any burners within a 10-mile radius of any other (regardless of ownership) could be grouped together for purposes of regulatory coverage. The combination of the "10-mile radius" provisions and the "no minimum BTU input" provisions theoretically mean that every unit in the country is to be covered by the FUA and regulated by DOE - perhaps including an individual gas stove in a home if it is used to boil water. This seems all the more likely considering the fact that the terms "boiler" and MFBI are so vaguely and broadly defined in the regulations that this absurd extreme could possibly be covered. While this is ridiculous in itself, it further demonstrates the total inadequacy of the EIS as applied to the FUA regulations as written.

The regulations indicate that ownership is a prime consideration and only units of the proper size and communal ownership are affected by the FUA. A site is defined as a contiguous and interconnected facility or one with a possibility of being interconnected in the future.

Union Oil Company of California (continued)

- The EIS does not address the "substantially exceeds" index as set forth in the proposed regulations, and therefore assumes the availability of economic exemptions. However, according to that index, conversion of facilities could be forced by DOE if the costs of conversion were 1.3 or perhaps 1.8 times the cost for similar oil or gas-fired facilities. This "index" approach totally changes the economics for nearly every facility and thereby forces the coverage of many not covered in the EIS analysis; therefore the EIS is inadequate in this regard and unrelated to the proposed regulations.

An index of 1.5 was assumed in the EIS. If this index is lowered, less coal would be used as a result of the FUA (see Table 10.5) and therefore a reduction in the environmental impacts.

- Environmental and other effects of increasing production and use of alternative fuels (such as shale oil, oil or gas from coal, petroleum coke, or others) are not considered in the EIS, though they are called for in the regulations. As a matter of fact, the EIS specifically states (Section 1.2) that "Predicted impacts of alternate fuels are not given due to uncertainty of their usage". NEPA requires full assessment and dis-disclosure of all reasonable program impacts.

Environmental impacts of alternative fuels are presented in Section 10.

- The policy option of price decontrol of domestic crude oil is not considered, although according to numerous estimates it would be cheaper for the economy and more beneficial for the environment, would result in more conversions to coal

See response to comment by U.S. EPA, p. 12-15.

Union Oil Company of California (continued)

and would have a considerable effect on oil imports. NEPA requires that all such alternative policy options be considered.

This set of examples is not intended to be exhaustive. It is intended, however, to demonstrate the seriousness of the "disconnects" between the EIS, the proposed regulations and the FUA and the resultant total inadequacy of the EIS.

Union Oil believes that the following steps should be taken before the FUA can or should be implemented:

- All of the regulations proposed for implementation of the FUA should be withdrawn and new regulations written so that the letter and intent of the FUA and the will of the Congress are met;
- The assumptions for the EIS on the FUA program should be rewritten in accordance with the rewritten regulations; and
- The EIS process should then be undertaken in accordance with NEPA and other applicable laws and relevant regulations before the FUA regulations are implemented.

Until these steps are taken, the legality and adequacy of the entire FUA process is open to question.

DOE disagrees, based on the responses to the comments above.

13. COMMENTS - NO RESPONSE

The following federal agencies, state clearinghouses, and others submitted notice of no comment by reviewing agencies at the time of review, or submitted comments which did not require a response.

U.S. Department of the Treasury

DEPARTMENT OF THE TREASURY
WASHINGTON, D.C. 20220

December 4, 1978

Dear Mr. Frank:

This is in response to Mr. House's November 13 request for comments on the draft environmental impact statement for the coal and alternate fuels program authorized by the Fuel Use Act. The Department has no comment other than to note that the statement appears to be a very comprehensive document.

Sincerely,

Anthony V. DiSilvestre
Assistant Director (Environmental Programs)
Office of Administrative Programs

Mr. Steven A. Frank
Department of Energy
Chief, Environmental Evaluations Branch
2000 M Street, N.W., Room 7202
Washington, D.C. 20461

STATE CLEARINGHOUSES

ARIZONA

SIGNOFF

OMB Approval No. 29–R0218

FEDERAL ASSISTANCE

2. Applicant's application — Number; Date 19 Month Day

3. State application identifier — a. Number AZ 78-80-0063; b. Date Assigned: Year 1978, month 12, day 01

Leave Blank: JAN 11 1979

1. Type Of Action (Mark appropriate box): ☐ Preapplication ☐ Application ☐ Notification Of Intent (Opt.) ☐ Report Of Federal Action

4. Legal Applicant/Recipient
- a. Applicant Name: Department of Energy
- b. Organization Unit: Division of Coal Utilization, Office of Fuels Regulation
- c. Street/P.O. Box: 2000 "M" Street, N.W., Room 7202
- d. City: Washington — e. County:
- f. State: D.C. — g. Zip Code: 20461
- h. Contact Person (Name & telephone no.): Mr. Steven A. Frank, Chief, Environmental Evaluations Branch (202) 254-6246

5. Federal Employer Identification No.

6. Program (From Federal Catalog) — a. Number 81.999; b. Title Unknown

Department of Energy

7. Title and description of applicant's project

FUEL USE ACT - DRAFT PROGRAMMATIC ENVIRONMENTAL IMPACT STATEMENT - DOE/EIS-0038-D

This impact statement deals with overall program impacts rather than site-specific impacts & is predicated on the assumption that coal will be the primary fuel substituted for oil & natural gas in the short term (until 1990). Site-specific environmental impacts will be addressed in subsequent documents, as appropriate.

8. Type of applicant/recipient
A–State, B–Interstate, C–Substate District, D–County, E–City, F–School District, G–Special Purpose District, H–Community Action Agency, I–Higher Educational Institution, J–Indian Tribe, K–Other (Specify): Federal Agency — Enter appropriate letter: K

9. Type of assistance
A–Basic Grant, B–Supplemental Grant, C–Loan, D–Insurance, E–Other — Enter appropriate letter(s)

10. Area of project impact (Names of cities, counties, states, etc.): Statewide, Arizona (Also Nationwide)

11. Estimated number of persons benefiting

12. Type of application
A–New, B–Renewal, C–Revision, D–Continuation, E–Augmentation — Enter appropriate letter: A

13. Proposed Funding	
a. Federal	$ 1 .00
b. Applicant	.00
c. State	.00
d. Local	.00
e. Other	.00
f. Total	$ 1 .00

14. Congressional Districts Of: a. Applicant; b. Project 01 02 03 04

15. Type of change (For 12c or 12e): A–Increase Dollars, B–Decrease Dollars, C–Increase Duration, D–Decrease Duration, E–Cancellation, F–Other Specify: — Enter appropriate letter(s)

16. Project Start Date: Year month day 19

17. Project Duration: Months

18. Estimated date to be submitted to federal agency: Year month date 19

19. Existing federal identification number

20. Federal agency to receive request (Name, city, state, zip code)

21. Remarks added ☐ Yes ☐ No

22. The Applicant Certifies That — a. To the best of my knowledge and belief, data in this preapplication/application are true and correct, the document has been duly authorized by the governing body of the applicant and the applicant will comply with the attached assurances if the assistance is approved.

b. If required by OMB Circular A-95 this application was submitted, pursuant to instructions therein, to appropriate clearinghouses and all responses are attached: — No response / Response attached
(1) Arizona State Clearinghouse ☐ ☐
(2) ☐ ☐
(3) ☐ ☐

23. Certifying representative — a. Typed name and title; b. Signature; c. Date signed Year month day 19

24. Agency name

25. Application received Year month day 19

26. Organizational Unit

27. Administrative office

28. Federal application identification

29. Address

30. Federal grant identification

31. Action taken: ☐ a. Awarded ☐ b. Rejected ☐ c. Returned for amendment ☐ d. Deferred ☐ e. Withdrawn

32. Funding	
a. Federal	$ .00
b. Applicant	.00
c. State	.00
d. Local	.00
e. Other	.00
f. Total	$ .00

33. Action date: Year month day 19

34. Starting date: Year month day 19

35. Contact for additional information (Name and telephone number)

36. Ending date: Year month day 19

37. Remarks added ☐ Yes ☐ No

38. Federal agency A-95 action — a. In taking above action, any comments received from clearinghouses were considered. If agency response is due under provisions of Part 1, OMB Circular A-95, it has been or is being made.

b. Federal Agency A-95 Official (Name and telephone number)

Section I - Applicant / Recipient Data; Section II - Certification; Section III - Federal Agency Action

424-101

Standard Form 424 Page 1 (10-75)
Prescribed by GSA, Federal Management Circular 74-7

Agriculture and Horticulture Department

FORM TO BE COMPLETED BY REVIEWING AGENCY

To: Mr. James R. Carter, Director
Agriculture & Horticulture Dept.
421 Capitol Annex West
Phoenix, Arizona 85007

State Application Identifier (SAI)
DEC 1, 1978 — State AZ No. 78-80-0063

From: Arizona State Clearinghouse
1700 West Washington Street, Room 505
Phoenix, Arizona 85007

Game & Fish
Indian Affairs
Ag. & Hort.
Public Safety
Solar Energy
Environmental Studies
Archaeological Research
Center for Public Affairs
Renewable Natural Resources
Arizonans for Jobs & Energy
Salt River Indian Clearinghouse
Navajo Indian Clearinghouse
OEPAD: V. Williams

Power
Health
Land
Parks

6 Regions

RECEIVED
DEC 04 1978
ARIZONA COMMISSION OF AGRICULTURE & HORTICULTURE

This project is referred to you for review and comment. Please evaluate as to:

(1) the program's effect upon the plans and programs of your agency
(2) the importance of its contribution to State and/or areawide goals and objectives
(3) its accord with any applicable law, order or regulation with which you are familiar
(4) additional considerations

Please return THIS FORM AND ONE XEROX COPY to the clearinghouse no later than 17 working days from the date noted above. Please contact the clearinghouse if you need further information or additional time for review.

☒ No comment on this project
☐ Proposal is supported as written
☐ Comments as indicated below

Comments: (Use additional sheets if necessary)

Reviewer's Signature: [signature]
Date: 12/4/78
Title: Director
Telephone: 271-4373

13-3

Arizona Power Authority

FORM TO BE COMPLETED BY REVIEWING AGENCY

To:

Mr. Les Ormsby, Admin.
Arizona Power Authority
1810 West Adams Street
Phoenix, Arizona 85005

State Application Identifier (SAI)

DEC 1, 1978 State AZ No. 28-80-0063

From: **Arizona State Clearinghouse**
1700 West Washington Street, Room 505
Phoenix, Arizona 85007

Game & Fish
Indian Affairs
Ag. & Hort.
Public Safety
Solar Energy
Environmental Studies
Archaeological Research
Center for Public Affairs
Renewable Natural Resources
Arizonans for Jobs & Energy
Salt River Indian Clearinghouse
Navajo Indian Clearinghouse
OEPAD: V. Williams

Power
Health
Land
Parks

6 Regions

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☒ No comment on this project
☐ Proposal is supported as written
☐ Comments as indicated below

Comments: (Use additional sheets if necessary)

Reviewer's Signature Les Ormsby

Date 12/4/78

Title

Telephone

Arizona Solar Energy Research Commission

FORM TO BE COMPLETED BY REVIEWING AGENCY

To:

Mr. James Warnock
Arizona Solar Energy
Research Commission
1700 W. Washington Room 502
Phoenix, Arizona 85007

State Application Identifier (SAI)

DEC 1, 1978 State AZ No. 28-80-0063

From: **Arizona State Clearinghouse**
1700 West Washington Street, Room 505
Phoenix, Arizona 85007

Game & Fish
Indian Affairs
Ag. & Hort.
Public Safety
Solar Energy
Environmental Studies
Archaeological Research
Center for Public Affairs
Renewable Natural Resources
Arizonans for Jobs & Energy
Salt River Indian Clearinghouse
Navajo Indian Clearinghouse
OEPAD: V. Williams

Power
Health
Land
Parks

6 Regions

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☒ No comment on this project
☐ Proposal is supported as written
☐ Comments as indicated below

Comments: (Use additional sheets if necessary)

Reviewer's Signature J. F. Warnock Jr.

Date 12/1/78

Title Dir.

Telephone 1 3882

13-3a

Arizona State Parks Board

FORM TO BE COMPLETED BY REVIEWING AGENCY

To:

Michael A. Ramnes, Director
Arizona State Parks Board
1688 W. Adams Room 109
Phoenix, Arizona 85007

State Application Identifier (SAI)

DEC 1, 1978 State AZ No. 78-80-0063

From: Arizona State Clearinghouse
1700 West Washington Street, Room 505
Phoenix, Arizona 85007

Game & Fish
Indian Affairs
Ag. & Hort.
Public Safety
Solar Energy
Environmental Studies
Archaeological Research
Center for Public Affairs
Renewable Natural Resources
Arizonans for Jobs & Energy
Salt River Indian Clearinghouse
Navajo Indian Clearinghouse
OEPAD: V. Williams

Power
Health
Land
Parks

6 Regions

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- [x] No comment on this project
- [ ] Proposal is supported as written
- [ ] Comments as indicated below

Comments: (Use additional sheets if necessary)

Reviewer's Signature [illegible] Date

Title Telephone

Central Arizona Association of Governments

FORM TO BE COMPLETED BY REVIEWING AGENCY

Mr. John Blackburn, Exec. Dir.
Central Arizona Association
of Governments
P.O. Box JJ (1810 Main St.)
Florence, Az 85232

State Application Identifier (SAI)

DEC 1, 1978 State AZ No. 78-80-0063

From: Arizona State Clearinghouse
1700 West Washington Street, Room 505
Phoenix, Arizona 85007

Game & Fish
Indian Affairs
Ag. & Hort.
Public Safety
Solar Energy
Environmental Studies
Archaeological Research
Center for Public Affairs
Renewable Natural Resources
Arizonans for Jobs & Energy
Salt River Indian Clearinghouse
Navajo Indian Clearinghouse
OEPAD: V. Williams

Power
Health
Land
Parks

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- [x] No comment on this project
- [ ] Proposal is supported as written
- [ ] Comments as indicated below

Comments: (Use additional sheets if necessary)

Reviewer's Signature [illegible] Date 12-13-78

Title Regional Energy Coordinator Telephone 848-5878

Department of Health Services

Dr. Suzanne Dandoy, Director
Department of Health Services
1740 West Adams Street
Phoenix, Arizona 85007

State Application Identifier (SAI)		
DEC 1, 1978	State AZ	No. 78-80-0063

Game & Fish	Power
Indian Affairs	Health
Ag. & Hort.	Land
Public Safety	Parks
Solar Energy	
Environmental Studies	
Archaeological Research	
Center for Public Affairs	
Renewable Natural Resources	
Arizonans for Jobs & Energy	
Salt River Indian Clearinghouse	
Navajo Indian Clearinghouse	
OEPAD: V. Williams	
	6 Regions

From: Arizona State Clearinghouse
1700 West Washington Street, Room 505
Phoenix, Arizona 85007

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- ☐ No comment on this project
- ☒ Proposal is supported as written
- ☐ Comments as indicated below

Comments: (Use additional sheets if necessary)

Reviewer's Signature: R. Bruce Scott
ASSISTANT DIRECTOR
HEALTH SERVICES

Date:

Title:

District IV Council of Governments

To: Mr. Frank Servin, Exec. Dir.
District IV Council of Gov'ts
377 South Main St., Room 202
Yuma, Arizona 85364

State Application Identifier (SAI)		
DEC 1, 1978	State AZ	No. 78-80-0063

Game & Fish	Power
Indian Affairs	Health
Ag. & Hort.	Land
Public Safety	Parks
Solar Energy	
Environmental Studies	
Archaeological Research	
Center for Public Affairs	
Renewable Natural Resources	
Arizonans for Jobs & Energy	
Salt River Indian Clearinghouse	
Navajo Indian Clearinghouse	
OEPAD: V. Williams	
	6 Regions

From: Arizona State Clearinghouse
1700 West Washington Street, Room 505
Phoenix, Arizona 85007

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(1) the program's effect upon the plans and programs of your agency
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- ☒ No comment on this project
- ☐ Proposal is supported as written
- ☐ Comments as indicated below

Comments: (Use additional sheets if necessary)

Reviewer's Signature: [illegible]

Date: 12-4-78

Title: Executive Dir.

Telephone: [illegible]

Game and Fish Department

FORM TO BE COMP[LETED BY REV]IEWING AGENCY

To: Mr. Robert Jantzen, Director
Game and Fish Dept.
2222 W. Greenway
Phoenix, Arizona 85023

State Application Identifier (SAI)
DEC 1, 1978 State AZ No. 78-80-0063

From: Arizona State Clearinghouse
1700 West Washington Street, Room 505
Phoenix, Arizona 85007

Game & Fish
Indian Affairs
Ag. & Hort.
Public Safety
Solar Energy
Environmental Studies
Archaeological Research
Center for Public Affairs
Renewable Natural Resources
Arizonans for Jobs & Energy
Salt River Indian Clearinghouse
Navajo Indian Clearinghouse
OEPAD: V. Williams

Power
Health
Land
Parks

6 Regions

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Please contact the clearinghouse if you need further information or additional time for review.

- [x] No comment on this project
- [ ] Proposal is supported as written
- [ ] Comments as indicated below

Comments: (Use additional sheets if necessary)

Reviewer's Signature [illegible] Date Dec 5, 1978
Title [illegible] [illegible]

Indian Affairs Commission

FORM TO BE COMPLETED BY REVIEWING AGENCY

To: Mr. Clinton M. Pattea
Executive Secretary
Indian Affairs Commission
1645 West Jefferson St.
Phoenix, AZ 85007

State Application Identifier (SAI)
DEC 1, 1978 State AZ No. 78-80-0063

From: Arizona State Clearinghouse
1700 West Washington Street, Room 505
Phoenix, Arizona 85007

Game & Fish
Indian Affairs
Ag. & Hort.
Public Safety
Solar Energy
Environmental Studies
Archaeological Research
Center for Public Affairs
Renewable Natural Resources
Arizonans for Jobs & Energy
Salt River Indian Clearinghouse
Navajo Indian Clearinghouse
OEPAD: V. Williams

Power
Health
Land
Parks

6 Regions

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Please contact the clearinghouse if you need further information or additional time for review.

- [x] No comment on this project
- [ ] Proposal is supported as written
- [ ] Comments as indicated below

Comments: (Use additional sheets if necessary)

Reviewer's Signature [illegible] Date 1-5-79
Title Telephone

13-6

Maricopa Association of Governments

To: 12/15
John J. DeBolske, Exec. Dir.
Maricopa Ass'n of Governments
1820 W. Washington Street
Phoenix, AZ 85007 12/18

State Application Identifier (SAI)		
DEC 1, 1978	State AZ	No. 78-80-0063

From: Arizona State Clearinghouse
1700 West Washington Street, Room 505
Phoenix, Arizona 85007

Game & Fish — Power
Indian Affairs — Health
Ag. & Hort. — Land
Public Safety — Parks
Solar Energy
Environmental Studies
Archaeological Research
Center for Public Affairs
Renewable Natural Resources
Arizonans for Jobs & Energy
Salt River Indian Clearinghouse
Navajo Indian Clearinghouse
OEPAD: V. Williams

6 Regions

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- [x] No comment on this project
- [ ] Proposal is supported as written
- [ ] Comments as indicated below

Comments: (Use additional sheets if necessary)

Reviewer's Signature [signature] Date 12/20/78

Title Staff Coordinator Telephone 254-6308

NACOG, Region III

To: Andy Sandoval, Exec. Director
NACOG, Region III
119 E. Aspen St.
Flagstaff AZ 86001

State Application Identifier (SAI)		
DEC 1, 1978	State AZ	No. 78-80-0063

From: Arizona State Clearinghouse
1700 West Washington Street, Room 505
Phoenix, Arizona 85007

Game & Fish — Power
Indian Affairs — Health
Ag. & Hort. — Land
Public Safety — Parks
Solar Energy
Environmental Studies
Archaeological Research
Center for Public Affairs
Renewable Natural Resources
Arizonans for Jobs & Energy
Salt River Indian Clearinghouse
Navajo Indian Clearinghouse
OEPAD: V. Williams

6 Regions

This project is referred to you for review and comment. Please evaluate as to:

N.A.C.O.G. DEC RECEIVED

(1) the program's effect upon the plans and programs of your agency
(2) the importance of its contribution to State and/or areawide goals and objectives
(3) its accord with any applicable law, order or regulation with which you are familiar
(4) additional considerations

Please return THIS FORM AND ONE XEROX COPY to the clearinghouse no later than 17 working days from the date noted above. Please contact the clearinghouse if you need further information or additional time for review.

- [x] No comment on this project
- [ ] Proposal is supported as written
- [ ] Comments as indicated below

Comments: (Use additional sheets if necessary)

Reviewer's Signature [signature] Date 12-19-78
I. Andy Sandoval, Executive Director, NACOG

Title Telephone 774-1895

13-7

Pima Association of Governments

FORM TO BE COMPLETED BY REVIEWING AGENCY

KC

To: Mr. Tom Swanson, Exec. Dir.
Pima Association of Gov'ts.
405 Transamerica Building
Tucson, Arizona 85701

State Application Identifier (SAI)
DEC 1, 1978 State AZ No. 78-80-0063

From: Arizona State Clearinghouse
1700 West Washington Street, Room 505
Phoenix, Arizona 85007

Game & Fish
Indian Affairs
Ag. & Hort.
Public Safety
Solar Energy
Environmental Studies
Archaeological Research
Center for Public Affairs
Renewable Natural Resources
Arizonans for Jobs & Energy
Salt River Indian Clearinghouse
Navajo Indian Clearinghouse
OEPAD: V. Williams

Power
Health
Land
Parks

6 Regions

This project is referred to you for review and comment. Please evaluate as to:

(1) the program's effect upon the plans and programs of your agency
(2) the importance of its contribution to State and/or areawide goals and objectives
(3) its accord with any applicable law, order or regulation with which you are familiar
(4) additional considerations

Please return THIS FORM AND ONE XEROX COPY to the clearinghouse no later than 17 working days from the date noted above. Please contact the clearinghouse if you need further information or additional time for review.

☐ No comment on this project
☐ Proposal is supported as written
☐ Comments as indicated below

Comments: (Use additional sheets if necessary)

Reviewer's Signature .... Date ....
Title .... Telephone ....

SEAGO

Mr. David Landrith, Executive
Director, SEAGO
11- Arizona Street
Bisbee, Arizona 85603

DEC 4 1978

State Application Identifier (SAI)
DEC 1, 1978 State AZ No. 78-80-0063

From: Arizona State Clearinghouse
1700 West Washington Street, Room 505
Phoenix, Arizona 85007

Game & Fish
Indian Affairs
Ag. & Hort.
Public Safety
Solar Energy
Environmental Studies
Archaeological Research
Center for Public Affairs
Renewable Natural Resources
Arizonans for Jobs & Energy
Salt River Indian Clearinghouse
Navajo Indian Clearinghouse
OEPAD: V. Williams

Power
Health
Land
Parks

780394

6 Regions

This project is referred to you for review and comment. Please evaluate as to:

(1) the program's effect upon the plans and programs of your agency
(2) the importance of its contribution to State and/or areawide goals and objectives
(3) its accord with any applicable law, order or regulation with which you are familiar
(4) additional considerations

Please return THIS FORM AND ONE XEROX COPY to the clearinghouse no later than 17 working days from the date noted above. Please contact the clearinghouse if you need further information or additional time for review.

☒ No comment on this project
☐ Proposal is supported as written
☐ Comments as indicated below

Comments: (Use additional sheets if necessary)

Reviewer's Signature [illegible signature] Date 12/20/78
Title .... Telephone 432-2571

13-8

ARIZONA

OFFICE OF THE GOVERNOR

OFFICE OF
ECONOMIC PLANNING AND DEVELOPMENT

1700 West Washington, Rm. 505 General Offices of OEPAD • 4th Floor

January 29, 1979

Mr. Steven A. Frank, Chief
Environmental Evaluations Branch
Dept. of Energy
Division of Coal Utilization
Office of Fuels Regulation
2000 M Street, N.W., Room 7202
Washington, D.C. 20461

Re: Fuel Use Act-Draft Programmatic Environmental Impact Statement
S.A.I. #78-80-0063 DOE/EIS-0038-D

Dear Mr. Frank:

Enclosed is a copy of a response concerning the above project which was received by us after our Signoff to you.

Sincerely,

Jo Youngblood/ss

Mrs. Jo Youngblood, Supervisor
Arizona State Clearinghouse
JY: ss
Encl.

Mailing Address: Executive Tower Room 505 • 1700 West Washington • Phoenix, Arizona 85007

State Land Department(Arizona)

To: State Land Dept.
1624 W Adams, 4th fl.
Phoenix, AZ 85007
ATTN: Jeff Yaeger

State Application Identifier (SAI)
DEC 1, 1978 State AZ No. 78-80-0063

Game & Fish
Indian Affairs
Ag. & Hort.
Public Safety
Solar Energy
Environmental Studies
Archaeological Research
Center for Public Affairs
Renewable Natural Resources
Arizonans for Jobs & Energy
Salt River Indian Clearinghouse
Navajo Indian Clearinghouse
OEPAD: V. Williams

Power
Health
Land
Parks

6 Regions

From: Arizona State Clearinghouse
1700 West Washington Street, Room 505
Phoenix, Arizona 85007

This project is referred to you for review and comment. Please evaluate as to:

(1) the program's effect upon the plans and programs of your agency
(2) the importance of its contribution to State and/or areawide goals and objectives
(3) its accord with any applicable law, order or regulation with which you are familiar
(4) additional considerations

Please return THIS FORM AND ONE XEROX COPY to the clearinghouse no later than 17 working days from the date noted above. Please contact the clearinghouse if you need further information or additional time for review.

☒ No comment on this project
☐ Proposal is supported as written
☐ Comments as indicated below

RECEIVED
DEC 4 1978
STATE LAND DEPT.
2/1

Comments: (Use additional sheets if necessary)

Reviewer's Signature [signature] Date 1/24/79

Title Telephone

13-9

ARIZONA OFFICE OF THE GOVERNOR

OFFICE OF
ECONOMIC PLANNING AND DEVELOPMENT

1700 West Washington, Rm. 505 General Offices of OEPAD • 4th Floor

February 20, 1979

Mr. Steven A. Frank, Chief
Environmental Evaluation Branch
Department of Energy
Division of Coal Utilization
Office of Fuels Regulation
2000 M Street, N.W., Room 7202
Washington, D.C. 20461

Re: Fuel Use Act - Draft Programmatic Environmental Impact Statement
S.A.I. #78-80-0063 DOE/EIS-0038-D

Dear Mr. Frank:

Enclosed is a copy of a response concerning the above project which was received by us after our Signoff to you.

Sincerely,

Jo Youngblood/ss

Mrs. Jo Youngblood, Supervisor
Arizona State Clearinghouse
JY: ss
Encl.

Mailing Address: Executive Tower Room 505 • 1700 West Washington • Phoenix, Arizona 85007

The University of Arizona

Mr. James E. Ayres
Associate Archaeologist
Arizona State Museum
The University of Arizona
Tucson, AZ 85721

State Application Identifier (SAI)
DEC 1, 1978 State AZ No. 78-80-0063

From: Arizona State Clearinghouse
1700 West Washington Street, Room 505
Phoenix, Arizona 85007

Game & Fish
Indian Affairs
Ag. & Hort.
Public Safety
Solar Energy
Environmental Studies
Archaeological Research
Center for Public Affairs
Renewable Natural Resources
Arizonans for Jobs & Energy
Salt River Indian Clearinghouse
Navajo Indian Clearinghouse
OEPAD: V. Williams

Power
Health
Land
Parks

6 Regions

This project is referred to you for review and comment. Please evaluate as to:

(1) the program's effect upon the plans and programs of your agency
(2) the importance of its contribution to State and/or areawide goals and objectives
(3) its accord with any applicable law, order or regulation with which you are familiar
(4) additional considerations

Please return THIS FORM AND ONE XEROX COPY to the clearinghouse no later than 17 working days from the date noted above.
Please contact the clearinghouse if you need further information or additional time for review.

- [ ] No comment on this project
- [x] Proposal is supported as written
- [ ] Comments as indicated below

Comments: (Use additional sheets if necessary)

Reviewer's Signature J. E. Ayres Date February 13, 1979

Title Associate Archaeologist Telephone [illegible]

13-10

DELAWARE

STATE OF DELAWARE
EXECUTIVE DEPARTMENT
OFFICE OF MANAGEMENT, BUDGET, AND PLANNING
DOVER DELAWARE 19901

OFFICE OF THE DIRECTOR

PHONE (302) 678-4271

January 19, 1979

Ms. Ruth C. Clusen
Assistant Secretary for
Environment
Department of Energy
Washington, D.C. 20461

Attention: Mr. Steven A. Frank

Dear Ms. Clusen:

RE: DRAFT ENVIRONMENTAL IMPACT STATEMENT ON THE FUEL USE ACT OF 1978, DOE-EIS-0038-D

The Office of Management, Budget and Planning, in its function as the State Clearinghouse, has reviewed the subject EIS and has no comments to offer at this time.

Thank you for the opportunity to review this document.

Sincerely,

Nathan Hayward III
Director

fb

FLORIDA

STATE OF FLORIDA

Department of Administration

Division of State Planning

Room 530 Carlton Building
TALLAHASSEE
32304
(904) 488-1115

R. G. Whittle, Jr.
STATE PLANNING DIRECTOR

Bob Graham
GOVERNOR

Jim Tait
SECRETARY OF ADMINISTRATION

February 5, 1979

Mr. Steve Frank
Division of Coal Utilization,
Room 7202
2000 "M" Street, N. W.
Washington, D. C. 20461

Dear Mr. Frank:

Functioning as the state planning and development clearinghouse contemplated in U. S. Office of Management and Budget Circular A-95, we have reviewed the following draft programmatic environmental impact statement: Fuel Use Act, SAI 79-0851E.

During our review we referred the environmental impact statement to the following agencies, which we identified as interested: Department of Environmental Regulation, Department of Natural Resources, Public Service Commission and State Energy Office. Agencies were requested to review the statement and comment on possible effects that actions contemplated could have on matters of their concern. Letters of comment on the statement are enclosed from: Department of Environmental Regulation and Department of Natural Resources. The Public Service Commission and State Energy Office reported no comment.

In accordance with the Council on Environmental Quality guidelines concerning statement on proposed federal actions affecting the environment, as required by the National Environmental Policy Act of 1969, and U. S. Office of Management and Budget Circular A-95, this letter, with attachments, should be appended to the final environmental impact statement on this project. Comments regarding this statement and project contained herein or attached hereto should be addressed in the statement.

We request that you forward us copies of the final environmental impact statement prepared on this project.

Sincerely,

R. G. Whittle, Jr., Director

RGWjr:WKm
Attachments
cc: Mr. Joseph W. Landers, Jr.
Mr. Loring Lovell
Ms. Victoria Tschinkel
Dr. Carlos A. Warren

STATE OF FLORIDA

Department of Administration

Division of State Planning

660 Apalachee Parkway · IBM Building

TALLAHASSEE 32304

(904) 488-2371

R.G. Whittle, Jr.
STATE PLANNING DIRECTOR

DIVISION OF STATE PLANNING, Bureau of Intergovernmental Relations
Reubin O'D. Askew
DEC 14 1978
Lt. Gov. J.H. Williams
RECEIVED
SECRETARY OF ADMINISTRATION
SAI NO.

RECEIVED
NOV 30 1978
EXECUTIVE DIRECTOR
DEPT. OF NATURAL RESOURCES

TO: Mr. Harmon Shields
Department of Natural Resources
202 Blount Street, Crown Building
Tallahassee, Florida 32304

DATE: 11-29-78

DUE DATE: 12-14-78

FROM: Bureau of Intergovernmental Relations

SUBJECT: SAI: 79-0851E

The attached "Advance Notification" of intent to apply for federal assistance is being referred to your agency for review and comments. Your review and comments should address themselves to the extent to which the project is consistent with or contributes to the fulfillment of your agency's plans or the achievement of your projects, programs and objectives.

If further information is required, you are urged to telephone the contact person named on the notification form. If a conference seems necessary, or if you wish to review the entire application, contact this office by telephone as soon as possible. If you have no adverse comments, you may wish to report such by telephone. Please check the appropriate box, attach any comments on your agency's stationery, and return to this office or telephone by the above due date. If we do not receive a response by the due date, we will assume your agency has no adverse comments. In both telephone conversation and written correspondence, please refer to the SAI number.

Sincerely,

Loring Lovell, Chief
Bureau of Intergovernmental Relations

Enclosure

****

TO: Bureau of Intergovernmental Relations
FROM: Department of Natural Resources
SUBJECT: Project Review and Comments, SAI: 79-0851E

[X] No Comments   [ ] Comments Attached

Signature: James H. Smith   Date: Dec. 13, 1978

Title: Administrative Assistant

TWIN TOWERS OFFICE BUILDING
2600 BLAIR STONE ROAD
TALLAHASSEE, FLORIDA 32301

STATE OF FLORIDA

REUBIN O'D. ASKEW
GOVERNOR

JOSEPH W. LANDERS, JR.
SECRETARY

DEPARTMENT OF ENVIRONMENTAL REGULATION

DIVISION OF STATE PLANNING, Bureau of Intergovernmental Relations
JAN 5 1979
RECEIVED
SAI NO.

January 4, 1979

Mr. Loring Lovell, Chief
Bureau of Intergovernmental Relations
Department of Administration
Division of State Planning
Room 530, Carlton Building
Tallahassee, Florida 32304

Dear Mr. Lovell:

U.S. Department of Energy, Draft Programmatic Environmental Impact Statement, Fuel Use Act, November 1978, DOE/EIS - 0038D, SAI No. 79-0851E

The environmental impacts and adverse effects discussed in this Environmental Impact Statement are those which may result from implementation of the proposed regulations for enacting the coal and alternate fuels use program, a program which has been authorized by the Powerplant and Industrial Fuel Use Act of 1978. The proposed action is a Congressionally mandated program prohibiting the construction of new powerplants without the capability for utilization of coal or alternate fuels and prohibiting the use of natural gas or petroleum as the primary energy source in new powerplants and MFBI boilers.

Although we have identified no major objections with this EIS it appears that a number of highly conservative and unrealistic assumptions have been made. A worse case impact assessment was then formulated which, in our opinion, would probably be no more significant than what may be expected under normal circumstances.

We are continuing to work with the Public Service Commission and others to help formulate a unified position for presentation to the new administration by January 22, 1979. We appreciate the opportunity to comment on the draft EIS.

Sincerely,

John B. Outland
Intergovernmental Programs
Review Section

JBO/mj

13-12

GEORGIA

TO: Steven A. Frank, Chief
Environmental Evaluations Branch
Division of Coal Utilization
Office of Fuels Regulation
Department of Energy, Room 7202
2000 M Street, N. W.
Washington, D. C. 20461

FROM: STATE CLEARINGHOUSE
OFFICE OF PLANNING AND BUDGET
INTERGOVERNMENTAL RELATIONS DIVISION
270 WASHINGTON STREET, S.W.
ATLANTA, GEORGIA 30334

DATE: November 22, 1978

SUBJECT: RECEIPT NEGATIVE DECLARATION/ENVIRONMENTAL ASSESSMENT OR DRAFT/FINAL ENVIRONMENTAL IMPACT STATEMENT

APPLICANT: U. S. Department of Energy

PROJECT: Draft EIS, Powerplant & Industrial Fuel Use Act of 1978

STATE CLEARINGHOUSE CONTROL NUMBER: 78-11-22-11

OFFICE OF PLANNING AND BUDGET CONTACT: C. Badger/S. Williams

The environmental information for the above project was received by the State Clearinghouse on November 22, 1978.

The State-level review on this project has been initiated and every effort is being made to insure prompt action. The document will be carefully evaluated relative to its consistency with State economic, social, physical goals, policies, plans, objectives and programs. You may expect to be informed by the State Clearinghouse of the results of the initial review by December 22, 1978.

In future correspondance regarding this document, please include the State Clearinghouse Control Number shown above. If you have any questions concerning this project, please call us at (404) 656-3855 or (404) 656-3829.

FORM SC-EIS-1
July 1975

HAWAII

EXECUTIVE CHAMBERS
HONOLULU

GEORGE R. ARIYOSHI
GOVERNOR

December 26, 1978

Ms. Ruth C. Clusen
Assistant Secretary for Environment
Department of Energy
Washington, D.C. 20461

Dear Ms. Clusen:

Thank you for the "Draft Programmatic Environmental Impact Statement" for coal and alternate fuels program transmitted by your letter of November 16, 1978. Since we do not use coal as a fuel in the State of Hawaii and our State is not included in the various Demand Regions, we are not in a position to provide meaningful comments.

We are concentrating our efforts on developing renewable resources available in Hawaii such as geothermal and solar energy, however, it is always possible that coal may be needed at some future time. Hence, we are interested in being informed of developments in the coal program on the mainland and would appreciate receiving future published comments or proceedings of hearings.

With warm personal regards, I remain,

Yours very truly,

George R. Ariyoshi

cc: Mr. Steven A. Frank

31362

ILLINOIS

(Comments were received from the State of Illinois subsequent to the letter below. These later comments, together with responses, are given in Section 12.)

STATE OF ILLINOIS
EXECUTIVE OFFICE OF THE GOVERNOR
BUREAU OF THE BUDGET
SPRINGFIELD 62706

January 8, 1979

Mr. Steven A. Frank, Chief
Environmental Evaluations Branch
Division of Coal Utilization
Office of Fuels Regulation
Department of Energy
2000 M Street, N.W. - Rm. 7202
Washington, D.C. 20461

Dear Mr. Frank:

RE: Draft Programmatic Environmental Impact Statement: Fuel Use Act
DOE/EIS-0038-D
SAI #78 11 28 61

The Illinois State Clearinghouse has reviewed the referenced subject pursuant to the National Environmental Policy Act of 1969, OMB Circular A-95, Revised and the administrative policy of the State. State agencies which are authorized to develop and enforce environmental standards have been given the opportunity to comment on this subject. No comments were received on the referenced subject.

Thank you for your assistance.

Respectfully yours,

T E Hornbacker/SED

T. E. Hornbacker, Director
Illinois State Clearinghouse

TEH/11

KANSAS

STATE OF KANSAS
Department of Administration
DIVISION OF STATE PLANNING AND RESEARCH
5th Floor--Mills Building
109 W. 9th
Topeka, Kansas 66612

OPERATIONS RP

January 10, 1979

Director
U. S. Dept. of Energy
Economic Regulatory Admn.
Office of Fuels Regulation
Washington, D.C. 20461

Re: Fuels Use Act - Draft
Environmental Statement
SAI#: 6365 - DES
Reviewed by: Fish & Game, Park & Resources

The referenced project has been processed by the Division of State Planning and Research under its clearinghouse responsibilities described in Circular A-95.

After review by interested state agencies it has been found that the proposed project does not adversely affect state plans. There has been concern expressed by the Kansas Fish & Game Commission, and Park & Resources Authority regarding final plans and specifications for construction. Should this project be funded by U. S. Dept. of Energy we request that the applicant work with the above listed state agencies in assuring that all expressed concerns are incorporated in the final plans and specifications.

Should you have qny questions please contact this office. Please refer to the State Application Identifier (SAI) Number above in all future correspondence.

Sincerely,

Paul V. DeGaeta
A-95 Coordinator

PVD:jc

Attachment

cc: Robert D. Wood, Kans. Fish & Game Comm.
Wayne Herndon, Planning Dept., Kans. Park & Resources Authority

Economic Development (Kansas)

STATE AGENCY A-95 TRANSMITTAL FORM

Return to:
Division of State Planning & Research, Department of Administration, Suite 501
Mills Building, Topeka, Kansas 66612

PROJECT TITLE: Office of Fuels Regulation, U.S. Dept. of Energy Draft Programmatic Environ. Stmt. Fuels Use Act

- [ ] Notification of Intent
- [ ] Preapplication
- [ ] Final Application

DATE REVIEW PROCESS STARTED	DATE REVIEW PROCESS ENDED	SAI NUMBER
11-27-78	12-18-78	6385 - DEIS

PART I Initial Project Notification Review (To be completed by Clearinghouse):

The attached project has been submitted to the State Clearinghouse under the provisions of the Federal OMB Circular A-95 revised. This form provides notification and opportunity for review of this project to the agencies checked below. Please fill in Part II and Part III below and return to the State Clearinghouse.

- x[x] Return by 12/15/78
- [ ] Expedite
- [ ] Add. Info. Avail.

REVIEW AGENCIES

- [ ] Aging
- [x] Agriculture - DWR
- [ ] Civil Rights Commission
- [x] Economic Development
- [ ] Education
- [x] Forestry, Fish & Game Commission
- [x] Health and Environment
- [x] Historical Society
- [ ] Human Resources
- [x] Kansas Corporation Commission
- [x] Park and Resources Authority
- [ ] Social and Rehabilitation Services
- [x] State Conservation Commission
- [ ] Transportation
- [ ] Water Resources Board
- [x] Planning & Research

PART II Nature of Agency review comments (To be completed by review agency and returned to CH):

Check one or more appropriate boxes. Indicate comments below. Attach additional sheet if necessary or use reverse side.

- [ ] Request clarification or additional info.
- [ ] Suggestions for improving project proposal

COMMENTS: No money involved. Review is to fill some federal requirement.

PART III Recommended State Clearinghouse Action (To be completed by review agency and returned to Clearinghouse):

Check one box only:

- [x] Clearance of the project should be granted
- [ ] Clearance of the project should be delayed until the issues or questions have been clarified by the Applicant
- [ ] Clearance of the project should not be delayed but the Applicant should (in the final application) address or clarify the questions or concerns indicated above
- [ ] Request the opportunity to review the final application prior to submission to the federal funding agency

Reviewer's Name	Div./Agency	Date
[signature]		

Historical Society (Kansas)

STATE AGENCY A-95 TRANSMITTAL FORM

Return to:
Division of State Planning & Research, Department of Administration, Suite 501
Mills Building, Topeka, Kansas 66612

PROJECT TITLE: Office of Fuels Regulation, U.S. Dept. of Energy Draft Programmatic Environ. Stmt. Fuels Use Act

- [ ] Notification of Intent
- [ ] Preapplication
- [ ] Final Application

DATE REVIEW PROCESS STARTED	DATE REVIEW PROCESS ENDED	SAI NUMBER
11-27-78	12-18-78	6385 - DEIS

PART I Initial Project Notification Review (To be completed by Clearinghouse):

The attached project has been submitted to the State Clearinghouse under the provisions of the Federal OMB Circular A-95 revised. This form provides notification and opportunity for review of this project to the agencies checked below. Please fill in Part II and Part III below and return to the State Clearinghouse.

- x[x] Return by 12/15/78
- [ ] Expedite
- [ ] Add. Info. Avail.

REVIEW AGENCIES

- [ ] Aging
- [x] Agriculture - DWR
- [ ] Civil Rights Commission
- [x] Economic Development
- [ ] Education
- [x] Forestry, Fish & Game Commission
- [x] Health and Environment
- [x] Historical Society
- [ ] Human Resources
- [x] Kansas Corporation Commission
- [x] Park and Resources Authority
- [ ] Social and Rehabilitation Services
- [x] State Conservation Commission
- [ ] Transportation
- [ ] Water Resources Board
- [x] Planning & Research

PART II Nature of Agency review comments (To be completed by review agency and returned to CH)

Check one or more appropriate boxes. Indicate comments below. Attach additional sheet if necessary or use reverse side.

- [ ] Request clarification or additional info.
- [ ] Suggestions for improving project proposa

COMMENTS: This is a general statement concerning the increased use of coal. Since specific projects are addressed, this agency has no comments.

PART III Recommended State Clearinghouse Action (To be completed by review agency and returned to Clearinghouse):

Check one box only:

- [x] Clearance of the project should be granted
- [ ] Clearance of the project should be delayed until the issues or questions have been clarified by the Applicant
- [ ] Clearance of the project should not be delayed but the Applicant should (in the final application) address or clarify the questions or concerns indicated above
- [ ] Request the opportunity to review the final application prior to submission to the federal funding agency

Reviewer's Name	Div./Agency	Date
Richard Pankratz	Historical Society	12-1-78

13-15

KENTUCKY

EUGENE F. MOONEY
SECRETARY

JULIAN M. CARROLL
GOVERNOR

COMMONWEALTH OF KENTUCKY
DEPARTMENT FOR NATURAL RESOURCES AND ENVIRONMENTAL PROTECTION
OFFICE OF THE SECRETARY
FRANKFORT, KENTUCKY 40601
TELEPHONE: (502) 564-3350

January 26, 1979

Ms. Ruth C. Clusen
Assistant Secretary for Environment
Department of Energy
Washington, D.C. 20461

RE: Comments on the Draft Environmental Impact Statement on Fuel Use Act

Dear Ms. Clusen:

The draft programmatic Environmental Impact Statement on the Fuel Use Act has been circulated to the Kentucky Environmental Review Agencies for their review. Enclosed are the comments that have been returned by our Division of Air Pollution Control on the statement. Any further comments received will be forwarded to your attention.

Sincerely,

Boyce R Wells

Boyce R. Wells
Environmental Review Coordinator
Office of Policy and Program Analysis

BRW:ksm

Enclosure

EUGENE F. MOONEY
SECRETARY

JULIAN M. CARROLL
GOVERNOR

COMMONWEALTH OF KENTUCKY
DEPARTMENT FOR NATURAL RESOURCES AND ENVIRONMENTAL PROTECTION
BUREAU OF ENVIRONMENTAL PROTECTION
A. L. ROARK
COMMISSIONER
FRANKFORT, KENTUCKY 40601

M E M O R A N D U M

January 5, 1979

TO: Environmental Review, Office of Planning and Research

FROM: John T. Smither JTS

SUBJECT: Fuel Use Act Environmental Impact Statement
DOE/EIS-003B-D

The Kentucky Division of Air Pollution Control has reviewed the subject draft EIS and offers the following comments.

Implementation of the Fuel Use Act (FUA) will have very little, if any, effect on the air quality impact from electric power plants in Kentucky. This is primarily due to the fact that very few power plants in Kentucky presently use natural gas or petroleum as a primary fuel. All of the new power plants in the State under construction or proposed will use coal as the primary fuel source.

The FUA would have a much greater effect on the air quality impact from Industrial Major Fuel Burning Installations (MFBI's). The primary fuel source for Industrial boilers in the state is natural gas or fuel oil. Thus, any MFBI with a heat input capacity greater than 100 mm BTU's and not located in a non-attainment area will be required to switch to coal as the primary fuel. Thus, various air contaminant emissions, namely particulate and sulfur dioxide, will increase as the result of the fuel switch. Although the EIS indicates that this fuel switch will have little effect on "regional" air quality, the impact of increased emissions on "immediate" air quality could be significant and in some cases could restrict future industrial growth in an area. However, each fuel switch must be evaluated on a case by case basis and at this point in time, it would be difficult to assess potential problem areas.

JTS:GLM:klg

RECEIVED
JAN 24 1979
DEPT. FOR NATURAL RESOURCES & ENVIRONMENTAL PROTECTION OFFICE OF PLANNING & RESEARCH

31648

EIS-4 (2 77)

Department of Transportation (Kentucky)

EUGENE F. MOONEY
SECRETARY

JULIAN M. CARROLL
GOVERNOR

COMMONWEALTH OF KENTUCKY
DEPARTMENT FOR NATURAL RESOURCES AND ENVIRONMENTAL PROTECTION
OFFICE OF THE SECRETARY
FRANKFORT, KENTUCKY 40601
TELEPHONE (502) 564-3350

February 20, 1979

Ms. Ruth C. Clusen
Assistant Secretary for Environment
Department of Energy
Washington, D. C. 20461

Re: Comments on the Draft Environmental Impact Statement on the Fuel Use Act

Dear Ms. Clusen:

Enclosed are the comments that were returned late by the Kentucky Department of Transportation on the Draft Environmental Impact Statement on the Fuel Use Act. I hope these comments will be of use to your agency.

Sincerely,

Boyce R Wells

Boyce R. Wells
Environmental Review Coordinator

BRW:bsc

Enclosure

Division of Systems Planning (Kentucky)

MEMORANDUM

TO:	Tom Scott, Assistant Director Division of Urban and Regional Planning
VIA:	Henry M. Bennett, Director Division of Systems Planning HB
FROM:	James W. Nelson, Manager Policy Planning Section Division of Systems Planning
DATE:	January 8, 1979
SUBJECT:	Review of Environmental Impact Statement U. S. Department of Energy, Fuel Use Act

In accordance with your suggestion, my office has reviewed the Environmental Impact Statement (EIS) of the Fuel Use Act which was done by the U. S. Department of Energy. We concentrated our efforts on how the Kentucky Department of Transportation would be affected by the implementation of the Fuel Use Act. Particular emphasis was given to the detrimental effects on Kentucky's transportation systems resulting from the projected increase in demand and supply of coal.

Please find attached a summary of that part of the EIS which is related to the coal haul problems of Kentucky.

This EIS verifies what the Secretary of Transportation has been espousing for some time now; that the projected increase of demand and supply of coal will cause severe transportation problems — particularly on the roads of Eastern Kentucky. The EIS explains the severity of road damages and the resultant financial problems associated with these road damages. It is estimated that $6.4 billion of the coal-related highway improvements needed between now and 1985 would be incurred by building or rebuilding roads used for hauling coal in Appalachia. Similarly, this EIS documents problems related to the increase in coal supply for the other transportation modes.

We are very impressed with the apparent quality of the EIS, especially with regards to the efforts in documenting related studies. We are also pleased that the conclusion reached by the EIS relative to problems of coal hauling are the same as those the Department reached much earlier. Perhaps this study and others like it can be used in building a case relative to the financial needs of the Department in this vital area.

We appreciate the opportunity of reviewing this document. If we may be of further assistance to you, please contact us at your convenience.

HMB:JWN:bdg

Attachment

cc: E. B. Gaither, Jr.

13-17

MISSISSIPPI

OFFICE OF THE GOVERNOR
Planning & Coordination
1503 Walter Sillers Building
JACKSON, MISSISSIPPI 39201
354-7018

CLIFF FINCH
GOVERNOR

JAMES A FLEMING
DIRECTOR

STATE CLEARINGHOUSE FOR FEDERAL PROGRAMS

TO: U.S. Department of Energy
Division of Coal Utilization
Office of Fuels Regulation
2000 M Street, Rm. 7202, N.W.
Washington, D.C. 20461

STATE CLEARINGHOUSE NUMBER

78113002

DATE: December 18, 1978

Attn: Steven A. Frank

PROJECT DESCRIPTION:

Draft Environmental Impact Statement for the coal and alternate fuels program authorized by the Powerplant and Industrial Fuel Use Act of 1978, DOE-EIS-0038-D. Texas, Louisiana, Arkansas, Oklahoma, and N. Mexico

The State Clearinghouse, in cooperation with the state agencies interested or possibly affected, has completed the A-95 review of the project described above.

None of the state agencies involved in the review had comments or recommendations to offer at this time. This concludes the State Clearinghouse review, and we encourage appropriate action as soon as possible.

A copy of this letter is to be attached to the application as evidence of compliance with the A-95 requirements.

Lester Howell

Lester Howell, Coordinator
Clearinghouse for Federal Programs

MISSOURI

I/NC

State of Missouri
OFFICE OF ADMINISTRATION
P.O. Box 809
Jefferson City 65102

Joseph P. Teasdale
Governor

William D. Dye, Director
Division of Budget and Planning

January 5, 1979

Mr. Steven A. Frank
Environmental Evaluations Branch
Division of Coal Utilization
Office of Fuels Regulation
Department of Energy
2000 M Street, N.W., Room 7202
Washington, D. C. 20461

Dear Mr. Frank:

Subject: 78110077

The Division of Budget and Planning, as the designated State Clearinghouse, has coordinated a review of the above referred draft environmental impact statement with various concerned or affected state agencies pursuant to Section 102(2)(c) of the National Environmental Policy Act.

None of the state agencies involved in the review had comments or recommendations to offer at this time.

We appreciate the opportunity to review the statement and anticipate receiving the final environmental impact statement when prepared.

Sincerely,

Lois Pohl

Lois Pohl
Chief, Grants Coordination

NEW JERSEY

State of New Jersey
DEPARTMENT OF COMMUNITY AFFAIRS

PATRICIA Q. SHEEHAN
COMMISSIONER

363 WEST STATE STREET
POST OFFICE BOX 2768
TRENTON, N.J. 08625

November 27, 1978

Mr. Steven A. Frank, Chief
Environmental Evaluations Branch
Division of Coal Utilization
Office of Fuels Regulation
Department of Energy
Room 7202
2000 M Street, N.W.
Washington, D.C. 20461

RE: OSRC-FY-79-596

Dear Mr. Frank:

This will acknowledge receipt of your recent Project Notification for the Fuel Use Act. The project has been designated application OSRC-FY-79-596 for all future references.

We have circulated this Project Notification to the appropriate State agencies for review and comment. We anticipate no problems during the review phase, but should any conflicts or issues arise, it will be necessary to schedule a conference in order to resolve the issues prior to the issuance of a Letter of Certification.

Very truly yours,

Jerry H. Eure, Sr.

Jerry H. Eure, Sr.
Supervising Program
Development Specialist
Project Review Section
Division of State and
Regional Planning

JHE:cp

NEW MEXICO

State of New Mexico
DEPARTMENT OF FINANCE AND ADMINISTRATION

State Planning Division
505 Don Gaspar Avenue

Coordination Bureau (505) 827-2073
Planning Bureau (505) 827-5191

Santa Fe, New Mexico 87503

January 15, 1979

Mr. Steven A. Frank
Office of Fuels Regulation
Department of Energy
Room 7202
2000 M Street, North West
Washington, D.C. 20461

Dear Mr. Frank:

Subject: Fuel Use Act Draft Programmatic Environmental Impact Statement

We have distributed copies of the above-named environmental impact statement to the Environmental Improvement Division, Energy Resource and Development Division, and the Department of Natural Resources. They have no comment.

We have reviewed the impact statement and have no comment at this time. We will welcome the opportunity to evaluate site specific cases.

Thank you for the opportunity to review this statement.

Sincerely,

Kate Wickes

Kate Wickes
Planning Bureau

KW:jeh

PLANNING DIVISION
(STATE CLEARINGHOUSE)

MIS2

PROJECT NOTIFICATION AND REVIEW SYSTEM

APPLICANT NOTIFICATION
of Receipt

PLANNING DIVISION
DEPT. OF FINANCE AND ADMINISTRATION
505 DON GASPAR
SANTA FE, NEW MEXICO 87503
(505) 827-2073

TO: Department of Energy
Office of Fuels Regulation
Washington, D.C. 20461
ATTN: Steven A. Frank

DATE: December 5, 1978

FROM: PLANNING DIVISION
DEPT. OF FINANCE AND ADMINISTRATION
Kate Wickes
(CONTACT PERSON)

SUBJECT: APPLICANT NOTIFICATION OF RECEIPT

SAI NUMBER: 9 12 11 009
FEDERAL CATALOG NUMBER: 80.000 / Powerplant & Industrial Fuel Use Act
FEDERAL FUNDING AGENCY: Dept. of Energy

This is to notify you that we have received your:

_______ Notification of Intent

_______ Preapplication

__XX__ Application and Standard Federal Form 424 with State Supplemental Information

_______ Your application does not require review, thank you for sending a copy to the Planning Division, please advise us when Federal action is taken on your application

You can expect to receive copies of the (Preliminary) ______________________

(FINAL) __X__ Review by ______ 1-3-79 ______
date

YOUR APPLICATION SHOULD ALSO BE SUBMITTED FOR REVIEW AND COMMENT TO THE SUBSTATE CLEARINGHOUSE(S) CHECKED:

_______ San Juan Regional Committee

_______ Southwest New Mexico Council of Governments

_______ McKinley Area COG

_______ Eastern Plains Council of Governments

_______ Middle Rio Grande Council of Governments

_______ North Central New Mexico Economic Development District

_______ Southeastern New Mexico Economic Development District

_______ Southern Rio Grande Council of Governments

2 - white
1 - for applicant
1 - review division
1 - yellow - SPD copy
1 - pink - COG's copy

MIS4

PLANNING DIVISION
(STATE CLEARINGHOUSE)
PROJECT NOTIFICATION AND REVIEW SYSTEM

Review of:
S.A.I. No. 9 12 11 009

GENERAL REVIEW AND COMMENT FORM

TO: Review Agency Bureau II Kate Wickes

Agency Address ______________ City ______________ Zip ______________

FROM: Planning Division, Department of Finance and Administration

Address 505 Don Gaspar City Santa Fe, NM Zip 87503

SUBJECT: (Project Title) Powerplant & Industrial Fuel Use Act

Because of your possible interest in this project it has been submitted to you for review and comment. Please complete this form and return to Planning Division, Dept. of Finance and Administration by 12-29-78
(date)

(To be Completed by the Reviewer)

1. Are you aware of any programs which have similar goals and objectives to the proposed plan? Yes_______ No __X__
   If yes, who provides these programs? What populations are being served?

2. In your estimation, do these programs preclude the need for the proposed program? Yes_______ No __X__

3. Is the proposed plan incompatible with existing or planned programs you are aware of? Yes_______ No __X__ If the answer is yes, in what way is the proposed program incompatible?

4. Does the proposed program conform with a comprehensive plan developed for the area in which it is located?
   Yes_______ No_______

5. In your opinion, is the population being served in critical need of, or large enough to warrant, the proposed action?
   Yes __X__ No_______ If no, explain.

6. Does the proposed plan conflict with any applicable statute, order, rule or regulation (federal, state, local) with which you are familiar? Yes_______ No __X__ If yes, cite the conflicting statute, order, rule or regulation.

7. Describe any suggestions on means of improving or strengthening the proposed program.

8. Is the information contained in the application and information forms consistent?
   Yes

9. On the basis of the above evaluation, convey your general conclusion by checking the appropriate statement or statements:
   _______ No interest in or comment on this project
   __X__ Proposal is supported
   _______ Proposal is considered nonessential, as explained below
   _______ Additional information is desired, as described below
   _______ Conference desired with applicant

10. Remarks or additional comments.

SIGNATURE OF REVIEWER Kate Wickes
TITLE Planner IV
DATE January 15, 1979

Approved July, 1978
Secretary, DFA

1 - white - to applicant
1 - yellow - SPD copy
1 - pink - Review Div. copy

13-20

NEW MEXICO STATE CLEARINGHOUSE
DEPT. OF FINANCE & ADMINISTRATION
PLANNING DIVISION

REVIEW CERTIFICATION

MIS—5

STATE PLANNING DIVISION
505 Don Gaspar, Greer Building
Santa Fe, New Mexico 87503
(505) 827-2073

TO: Department of Energy
Office of Fuels Regulation
Washington, DC 20461
ATTN: Mr. Steven A. Frank

DATE: January 15, 1979

SUBJECT: Review of SAI No.: 9 12 11 009

REVIEW ACTION ON:	PROJECT TITLE: Powerplant & Industrial Fuel Use Act Applicant: Department of Energy
___ Pre-application ___ Final Application ___ State/Area Plan X EIS	SOURCE OF FUNDS REQUESTED Federal Agency: Department of Energy Federal Program Title: Powerplant & Industrial Fuel Use Act of 1978 Federal Catalog No.: 80000 State Agency:
TYPE FUNDS: ___ Grant ___ Loan ___ State Block ___ State Appropriation ___ State Funds Only	Funds Requested: $ __________ Federal $ __________ State

REVIEW RESULTS

(LW) X The Application is supported.

___ The Application is not in conflict with State, Areawide, or Local plans.

___ Comments are attached for submission with this application.

___ The Application has no preview requirements. Thank you, however, for providing this courtesy information.

You may now submit your Application package, MIS-5, and review comments to the Federal or State Agency(s) from whom action is being requested.

Please notify the State Clearinghouse of any changes in this project. Refer to the SAI number on ALL correspondence pertaining to this project.

T/A/S Research

State Planning Director

NEW MEXICO PLANNING DISTRICTS AND CLEARINGHOUSE DIRECTORY

CODE NO.	CLEARINGHOUSE NAMES & ADDRESSES	COUNTIES	DISTRICT
20	State Planning Office Greer Building 505 Don Gaspar Santa Fe, New Mexico 87503 Telephone No.: (505) 827-2073	Statewide	Statewide
1a	San Juan Regional Committee San Juan County Courthouse Aztec, New Mexico 87410	San Juan	1
1b	McKinley Area COG 300 West Hill, Suite 2 Gallup, New Mexico 87301 Telephone No.: (505) 722-4327	McKinley	1
02	North Central New Mexico Economic Development District Post Office Box 4248 Santa Fe, New Mexico 87501 Telephone No.: (505) 827-2014	Colfax Los Alamos Mora Rio Arriba San Miguel Santa Fe Taos	2
03	Middle Rio Grande Council of Governments 505 Marquette, N.W., Suite 1320 Albuquerque, New Mexico 87101 Telephone No.: (505) 243-2819	Bernalillo Sandoval Torrance Valencia	3
04	Eastern Plains Council of Governments Curry County Courthouse Clovis, New Mexico 88101 Telephone No.: (505) 762-7714	Curry DeBaca Guadalupe Harding Quay Roosevelt Union	4
05	Southwest New Mexico Council of Governments Post Office Box 2157 Silver City, New Mexico 88053 Telephone No.: (505) 388-1974	Catron Grant Hidalgo Luna	5
06	Southeastern New Mexico Economic Development District Post Office Box 6639 RIAC Roswell, New Mexico 88201 Telephone No.: (505) 374-5425	Chaves Eddy Lea Lincoln Otero	6
07	Southern Rio Grande Council of Governments 575 S. Alameda City-County Office Building Las Cruces, New Mexico 88001 Telephone No.: (505) 523-7474	Socorro Sierra Dona Ana	7

Approved July, 1978
Secretary, DFA

NORTH CAROLINA

North Carolina
Department of Administration
116 West Jones Street Raleigh 27603

James B. Hunt, Jr., Governor
Joseph W. Grimsley, Secretary

Division of State Budget and Management
John A. Williams, Jr., State Budget Officer
(919) 733-7061

Nov. 28, 1978

MEMORANDUM

TO: Ruth C. Clusen

FROM: Chrys Baggett, CB Director, State Clearinghouse

SUBJECT: N.C. File # 148-78; Draft EIS, "Fuel Use Act".

We have received 4 copy/or copies of the above subject draft env. impact statement.

We have referred the statement to the appropriate State agencies for review and comment. Upon receipt of any substantive comments we will forward a copy of the comments or a letter transmitting a summarization of all comments received.

mw

NORTH DAKOTA

NORTH DAKOTA STATE PLANNING DIVISION

STATE CAPITOL NINTH FLOOR BISMARCK NORTH DAKOTA 58505
701 224 2818

December 28, 1978

STATE INTERGOVERNMENTAL CLEARINGHOUSE "LETTER OF CLEARANCE"
ON PROJECT REVIEW IN CONFORMANCE WITH OMB CIRCULAR NO. A-95

To: U.S. Department of Energy, Office of Fuels Regulation

STATE APPLICATION IDENTIFIER: 7811289M086

Mr. Steve Frank
Division of Coal Utilization
Room 7202, 2000 M Street
Washington, D.C. 20461

Dear Mr. Frank:

Subject: Draft EIS by U.S. Department of Energy, Office of Fuels Regulation for Draft EIS: Fuel Use Act.

This draft EIS was received in our office November 28, 1978.

In compliance with OMB Circular No. A-95, our office has reviewed this draft eis and hereby gives clearance to it without comment. The ND State Intergovernmental Clearinghouse requests the opportunity for complete review of applications for renewal or continuation grants or applications not submitted to or acted on by the funding agency within one year after the date of this letter.

Sincerely yours,

Bonnie A. Banks

Mrs. Leonard E. Banks
Associate Planner

LEB/aj

NORTH DAKOTA

North Central Planning Council

"Professional planning staff serving citizens and their governments in the counties of Rolette, [illegible]"

January 3, 1979

U.S. Department of Energy
Washington, DC 20013

Dear Sirs:

In the process of the A-95 review, the attached comments have been received for identifier #781208011 (Draft Programmatic Environmental Impact Statement for the Fuel Use Act) from Jim Thompson, RC&D Coordinator and Mike Sauer, Aquatic Biologist.

Please forward these comments to the proper source for documentation. This letter and attachments constitute the comment of the Regional Intergovernmental Clearinghouse, made in compliance with OMB Circular No. A-95. The Regional Clearinghouse requests the opportunity for complete review of applications for renewal or continuation grants, or applications not submitted to or acted on by the funding agency within one year after the date of this letter.

Sincerely,

Gayle Regan

Gayle Regan
A-95 Coordinator -
Region III

Attach.

224 S.W. 4th St. — Devils Lake, ND 58301 — 701-662-8131

CLEARINGHOUSE USE ONLY

SAI NO.
781208011

DATE RECEIVED

REVIEW RESPONSE
NDSIC FORM B (10-77)

DATE: December 8, 1978

TO: Jim Thompson - RC&D Coordinator
Devils Lake, ND 58301

PROJECT TITLE: Draft Programmatic Environmental Impact Statement for the Fuel Use Act.

APPLICANT: U. S. Department of Energy

The Clearinghouse has received an E.I.S. for review under OMB Circular No. A-95 for the above project. The attached project information is referred to your agency for your review and comment. Please review the proposal as it affects the plans and programs of your agency as well as those plans with which you are familiar, and indicate your comments below or on a separate sheet. Some general suggestions to assist in your review of projects are on the reverse of this form.

A copy of all of the material received by the Clearinghouse is attached.

Your cooperation is requested in completing your review and returning this form to our office within ten (10) days from the date of receipt. If no response or indication of your desire to comment is received within fifteen (15) days of date of notification, it will be assumed you have no comments on the proposal.

The proposed activities ( ) are / ( ) are not consistent with state, areawide, or local plans with which you are familiar

The proposed activities ( ) do / ( ) do not contribute to the implementation of those plans

( ) More review time is needed and comments will be forwarded by (date) ______

(✓) No identified conflict (no comment)

( ) Proposal is supported as written

( ) Requests a meeting with the applicant

( ) Desires to review final application

( ) Comments, identified issues, suggestions, recommendations or suggested stipulations are listed below or attached

( ) For the following reasons, (approval) (disapproval) of the project is suggested:

REVIEWER'S SIGNATURE: James R Thompson DATE: 12-20-78

TITLE: RC&D Coordinator TELE: 662-8144

RETURN TO: North Central Planning Council
Box 651
Devils Lake, ND 58301 (701-662-8131)

13-23

CLEARINGHOUSE USE ONLY

REVIEW RESPONSE
NDSIC FORM B (10-77)

SAI NO. 781208011

DATE RECEIVED

DATE: December 8, 1978

TO: Mike Sauer Aquatic Biologist
North Central Planning Council
Devils Lake, ND 58301

PROJECT TITLE: Draft Programmatic Environmental Impact Statement for the Fuel Use Act.

APPLICANT: U. S. Department of Energy

The Clearinghouse has received an E.I.S. for review under OMB Circular No. A-95 for the above project. The attached project information is referred to your agency for your review and comment. Please review the proposal as it affects the plans and programs of your agency as well as those plans with which you are familiar, and indicate your comments below or on a separate sheet. Some general suggestions to assist in your review of projects are on the reverse of this form.

A copy of all of the material received by the Clearinghouse is attached.

Your cooperation is requested in completing your review and returning this form to our office within ten (10) days from the date of receipt. If no response or indication of your desire to comment is received within fifteen (15) days of date of notification, it will be assumed you have no comments on the proposal.

The proposed activities ◯ are ◯ are not consistent with state, areawide, or local plans with which you are familiar

The proposed activities ◯ do ◯ do not contribute to the implementation of those plans

◯ More review time is needed and comments will be forwarded by (date) ______

◯ No identified conflict (no comment)

◯ Proposal is supported as written

◯ Requests a meeting with the applicant

☑ Desires to review final application

◯ Comments, identified issues, suggestions, recommendations or suggested stipulations are listed below or attached

◯ For the following reasons, (approval) (disapproval) of the project is suggested:

REVIEWER'S SIGNATURE: Michael T Sauer

DATE: 12/15/78

TITLE: Aquatic Biologist

TELE: 662-8131

RETURN TO: North Central Planning Council
Box 651
Devils Lake, ND 58301 (701-662-8131)

SUGGESTIONS FOR CONSIDERATION IN REVIEWING PROJECTS

Comments and recommendations made through the clearinghouse with respect to any project are for the purpose of assuring maximum consistency of such project with State, areawide and local comprehensive plans. They are also intended to assist the Federal agency (or State agency, in the case of projects for which the State under certain Federal grants has final project approval) administering such a program in determining whether the project is in accord with applicable Federal law, particularly those requiring consistency with state, areawide, or local plans. Comments or recommendations may include, but need not be limited to, information about:

a) The extent to which the project is consistent with or contributes to the fulfillment of comprehensive planning for the State, area, or locality.

b) The extent to which the proposed project:

1) Duplicates, runs counter to, or needs to be coordinated with other projects or activities being carried out in or affecting the area; or
2) Might be revised to increase its effectiveness or efficiency in relationship to other State, area, or local programs and projects.

c) The extent to which the project contributes to the achievement of State, areawide and local objectives and priorities relating to natural and human resources and economic and community development including:

1) Appropriate land uses for housing, commercial, industrial, governmental, institutional, and other purposes;
2) Wise development and conservation of natural resources, including land, water, mineral, wildlife and others;
3) Balanced transportation systems, including highway, air, water, pedestrian, mass transit, and other modes of the movement of people and goods;
4) Adequate outdoor recreation and open space;
5) Protection of areas of unique natural beauty, historical and scientific interest;
6) Properly planned community facilities, including utilities for the supply of power, water and communications for the safe disposal of wastes and for other purposes; and
7) Concern for high standards of design.

d) The extent to which the project significantly affects the environment including consideration of:

1) The environmental impact of the proposed project;
2) Any adverse environmental effects which cannot be avoided should the proposed project be implemented;
3) Alternatives to the proposed project;
4) The relationship between local short term uses of man's environment and the maintenance and enhancement of long term productivity; and
5) Any irreversible and irretrievable commitments of resources which would be involved in the proposed project or action, should it be implemented.

e) Effects of energy resource supply and demand.

f) The extent to which people or businesses will be displaced and the availability of relocation resource.

g) The extent to which the project contributes to more balanced patterns of settlement and delivery of services to all sectors of the area population, including minority groups.

h) In the case of a project for which assistance is being sought by a special purpose unit of local government, whether the unit of general local government having jurisdiction over the area in which the project is to be located has applied, or plans to apply, for assistance for the same or a similar type project.

i) Positive supportive comments are useful to the review process particularly when definite reasons for support are given.

OHIO

STATE OF OHIO
OFFICE OF THE GOVERNOR
COLUMBUS 43215

JAMES A. RHODES
GOVERNOR

November 27, 1978

Ms. Ruth C. Clusen
Assistant Secretary for
Environment
U.S. Department of Energy
Washington, D.C. 20461

Dear Ms. Clusen:

I am very appreciative of receiving a copy of the draft Environmental Impact Statement concerning the Fuel Use Act.

Thank you for your courtesy in providing me with this information report.

Sincerely,

James A. Rhodes

JAMES A. RHODES
Governor

OREGON

Executive Department
INTERGOVERNMENTAL RELATIONS DIVISION
ROOM 306, STATE LIBRARY BLDG., SALEM, OREGON 97310

January 16, 1979

Ruth C. Clusen
Assistant Secretary for Environment
Department of Energy
Washington, D.C. 20461

Dear Ms. Clusen:

RE: Fuel Use Act
PNRS 7812 4 230

Thank you for submitting your draft Environmental Impact Statement for State of Oregon review and comment.

Your draft was referred to the appropriate state agencies. The Departments of Fish and Wildlife, Lands and General Services offered the enclosed comments which should be addressed in preparation of your final Environmental Impact Statement.

We will expect to receive copies of the final statements as required by Council of Environmental Quality Guidelines.

Sincerely,

Kay F. Wilcox

Kay Wilcox
A-95 Coordinator

KW:cb

Enclosures

31502

AN EQUAL OPPORTUNITY EMPLOYER

OREGON PROJECT NOTIFICATION AND REVIEW SYSTEM

STATE CLEARINGHOUSE

Intergovernmental Relations Division
Room 306, State Library Building
Salem, Oregon 97310, Phone: 378-3732

P N R S   S T A T E   R E V I E W

Project #: 7812 4 230 Due Date: 1-12-79

To Agency Addressed: If you intend to comment but cannot respond by the return date, please notify us immediately. If no response is received by the due date, it will be assumed that you have no comment and the file will be closed.

PROGRAM REVIEW AND COMMENT

To State Clearinghouse: We have reviewed the subject Notice and have reached the following conclusions on its relationship to our plans and programs:

( ) It has no adverse effect.

( ) We have no comment.

( ) Effects, although measurable, would be acceptable.

( ) It has adverse effects. (Explain in Remarks Section)

( ) We are interested but require more information to evaluate the proposal.

( ) Please coordinate the implementation of the proposal with us.

( ) Additional comments for project improvement. (Attach if necessary)

- - - - - - - - - -

REMARKS (Please type or print legibly)

The Willamette Valley does have a serious air pollution problem. The attached material, as I interpret it from a brief review, relates to coal conversion as fuel for utilities and manufacturing. I believe there will be little impact or little conversion in the valley. Problems related to coal use are most common in the north central and north eastern states.

Agency General Svcs By [illegible signature]

TENNESSEE

TENNESSEE
STATE PLANNING OFFICE

660 CAPITOL HILL BUILDING
301 SEVENTH AVENUE, NORTH
NASHVILLE, TENNESSEE 37219
615-741-1676

February 5, 1979

Mr. Steven A. Frank, Chief
Environmental Evaluations Branch
Division of Coal Utilization
Office of Fuels Regulation
Department of Energy
Room 7202
2000 M Street, N. W.
Washington, D. C. 20461

RE: Programmatic Draft EIS - U. S. Department of Energy - Fuel Use Act.

Dear Mr. Frank:

Please find enclosed comments from the Tennessee Wildlife Resources Agency concerning the above referenced EIS. Any additional comments from other state agencies will be forwarded to you immediately upon receipt.

If the State Clearinghouse may be of further assistance, please do not hesitate to contact me.

Sincerely,

Bette A. Osborne

Bette A. Osborne
Natural Resources Section

BAO/fe

Enclosure

TENNESSEE WILDLIFE RESOURCES AGENCY

ELLINGTON AGRICULTURAL CENTER
P. O. BOX 40747
NASHVILLE, TENNESSEE 37204

Gary T. Myers, Executive Director
Roy H. Anderson, Ass't. Director

January 29, 1979

Ms. Bette Osborne
Natural Resource Staff
State Planning Office
660 Capitol Hill Building
Nashville, TN 37219

Dear Ms. Osborne:

Re: Programmatic Draft Environmental Impact Statement - U. S. Department of Energy - Fuel Use Act

The Tennessee Wildlife Resources Agency has reviewed the referenced document and offers the following comments. As stated in 1.1, page 1-1. "The proposed action is the issuance of regulations to implement the Full Use Act, a Congressionally mandated program prohibiting the construction of new powerplants without the capacity for utilizing coal or alternate fuels and prohibiting the use of natural gas or petroleum as the primary energy source in new powerplants and MFBI boilers. The FUA also restricts, through mandatory and discretionary prohibitions, the use of natural gas and petroleum as primary energy sources in existing powerplants and MFBI's." (Major Fuel-Burning Installations with a fuel input rate of 100 million Btu's per hour or greater).

The state of Tennessee ranked 11th out of the twelve major coal producing states in 1974 in total tons produced annually. In 1977 the State Department of Energy reported a total of 10,320,000 tons produced. This production comes from mines within the Bureau of Mines District 8 and 13, Central and Southern Appalachia portions of Tennessee. This coal is high Btu medium and high-volatile bituminous. The Cumberland Plateau physiographic region is the primary source of coal produced in Tennessee.

The impact of the FUA on the wildlife and fishery resources of Tennessee will be related to the increased coal production on the Cumberland Plateau and mountains. Secondary impacts are expected from increased haulage by trucks, rail and barge. Approximately 67% of the state's total annual production is transported by rail, 30% by truck and 2% by barge.

Increased coal mining activity in the plateau region has the potential for adverse impacts on the water quality of streams designated by the Department of Interior as critical habitat for the spotfined chub, Hybopsis monacha. In addition, several fish proclaimed threatened or endangered in the state may be impacted adversely.

The eight major coal-fired powerplants operated by TVA in the state presently consume over 20,000,000 tons of coal annually. We do not expect any significant increase in the consumption of coal in Tennessee from sources within the state due to FUA. Over sixty percent of the annual coal production of Tennessee is transported out-of-state to utilities in Florida, Georgia and North Carolina, while over thirty percent is burned at TVA coal-fired powerplants.

Both the Obed National Wild and Scenic River in Tennessee and the Big South Fork National River and Recreation Area in Tennessee and Kentucky are within the coal producing Appalachian Districts. Increased mining throughout this area potentially threatens the aesthetics, wildlife, fisheries and in general, the recreational resources of these areas.

Thank you for this opportunity for review.

Sincerely,

TENNESSEE WILDLIFE RESOURCES AGENCY

James F. Sharber, Jr.

James F. Sharber, Jr.,
Environmental Planner

JFS:ss

cc: Mr. John Kruzan
Mr. Hudson Nichols
Mr. Wilbur Vaughan
Mr. Larry McGinn
Mr. Reid Tatum
Mr. Harold Hurst

TEXAS

OFFICE OF THE GOVERNOR

WILLIAM P. CLEMENTS, JR.
GOVERNOR

January 18, 1979

Ms. Ruth C. Clusen
Assistant Secretary for Environment
Department of Energy
Washington, D.C. 20461

Dear Ms. Clusen:

The Draft Programmatic Environmental Impact Statement for the Fuel Use Act has been reviewed by the Budget and Planning Office and by interested and affected State agencies.

The comments of the reviewing agencies are enclosed to assist your planning effort. If this Office can be of further assistance, please contact us.

Sincerely,

Tom B. Rhodes

Tom B. Rhodes, Director
Budget and Planning Office

Enclosures

EXECUTIVE OFFICE BUILDING • 411 WEST 13TH STREET • AUSTIN, TEXAS 78701

Engineering Extension Service (Texas)

AGENCY REVIEW TRANSMITTAL SHEET

TO: Ken Gordon, Budget and Planning Office Contact

FROM: Engineering Extension Service Date Sent: 12/20/78

Date Due: 1/4/79

SUBJECT: Draft Programmatic Environmental Impact Statement Refer: EIS-8-012-(

Fuel Use Act

We have reviewed the cited document and our comments as to the adequacy of treatment o environmental effects of concern are shown below:

	Check (X) for each item: None	Comment enclosed
1. Additional specific effects which should be assessed:		
2. Additional alternatives which should be considered:		
3. Better or more appropriate measures and standards which should be used to evaluate environmental effects:		
4. Additional control measures which should be applied to reduce adverse environmental effects or to avoid or minimize the irreversible or irretrievable commitment of resources:		
5. Our assessment of how serious the environmental damage from this project might be, using the best alternative and control measures:		
6. We identify issues which require further discussion or resolution:		

[ ] This agency concurs with the implementation of this project.

[XX] This agency does not wish to comment on the subject document because:

As a technical assistance and training organization we do not have information or the expertise to effectively participate.

RECEIVED
DEC 28 1978
Budget/Planning

Enclosure(s)

Lee J. Phillips

Lee J. Phillips, Assistant Director
Name and Title of Reviewing Official

13-28

RAILROAD COMMISSION OF TEXAS
GAS UTILITIES DIVISION

JOHN H. POERNER, Chairman
MACK WALLACE, Commissioner
JAMES E. (JIM) NUGENT, Commissioner

JOSEPH J. PIOTROWSKI, JR. Director
THOMAS H. HILL Assistant Director

811 SOUTH CONGRESS • CAPITOL STATION - P.O. DRAWER 12967 • AUSTIN, TEXAS 78711

MEMORANDUM

RECEIVED
JAN 18 1979
Budget/Planning

TO: All Interested Parties

FROM: Jeff Browning, Hearings Examiner

DATE: January 15, 1979

SUBJECT: Response of Gas Utilities Division, Railroad Commission of Texas, to Environmental Impact Statement on the Issuance of Regulations Implementing the Fuel Use Act.

The purpose of this Memorandum is to submit the response of the Gas Utilities Division to the Environmental Impact Statement on the Issuance of Regulations Implementing the Fuel Use Act, which was directed to the Gas Utilities Division by the Governor's Office.

The Powerplant and Industrial Fuel Use Act of 1978 (hereinafter "Fuel Use Act"), passed by Congress as part of the National Energy Act, provides for the mandatory conversion of electric powerplants and major fuel burning installations (hereinafter "MFBI's") from the use of natural gas and petroleum to "alternate fuel sources," which includes any fuel other than natural gas or petroleum. This legislation directly impacts the operations of the Gas Utilities Division under Tex. R.R. Comm'n, Gas Util. Div. Substantive Rule (051.04.03.018), which prescribes the program for the elimination of natural gas as a boiler fuel in Texas. This program was originally expressed in the Amended Order on Reconsideration of Gas Utilities Docket No. 600 (March 3, 1976). In the following paragraphs, the basic provisions of the Texas boiler fuel program under Docket 600 and the federal coal conversion program under the Fuel Use Act are outlined. Then, the conflicts between these programs are discussed.

The Texas program was expressed during a period when the continuing and increasing shortage of natural gas was commonly accepted. The Order in Docket 600 was a direct outgrowth of the severe curtailment which occurred in the Texas intrastate market during the winters of 1973 and 1974. The Railroad Commission foresaw a need to convert the dwindling natural gas supplies from use as boiler fuel to use in residential and commercial service.

Therefore, the Commission expressed a program which provided for a gradual, orderly reduction of natural gas as a boiler fuel in Texas.

Docket 600 basically provides a schedule for the reduction of natural gas as a boiler fuel, which is based upon the peak use by any consumer of natural gas as a boiler fuel during the calendar years 1974 and 1975. The consumer is required to reduce his usage by 10% on January 1, 1981, and by 25% on January 1, 1985. However, several exceptions to this schedule are provided. First, the program is expressly applicable only to consumers who use in excess of 3,000 Mcf/D of natural gas as a boiler fuel. Secondly, existing natural gas sales contracts which extend into the periods provided in the schedule are exempt from reduction so long as the contracts are not modified so as to extend the term or increase the quantity of natural gas used as a boiler fuel. Finally, the Commission reserved the right to grant exceptions to the program if it determined that it is in the public interest for natural gas to be used as a boiler fuel.

The program provided in the Fuel Use Act is somewhat more broad in its application than Docket 600, since the Fuel Use Act applies to both natural gas and petroleum. The Fuel Use Act expressly applies to powerplants and MFBI's. The term "powerplant" is defined as any single electrical generating unit which has the design capability to consume at least 100 MMBTU per hour, or a combination of two or more electrical generating units which have the design capability of consuming at least 250 MMBTU per hour. The term "major fuel burning installation" is similarly defined as any installation, other than a powerplant, which has the design capability to consume at least 100 MMBTU per hour.

The Fuel Use Act distinguishes between existing powerplants and MFBI's, and "new" powerplants and MFBI's. New powerplants or MFBI's are prohibited from utilizing natural gas or petroleum as a primary fuel. However, existing power plants are allowed to utilize natural gas as a primary energy source until January 1, 1990. The Secretary of Energy is authorized to prohibit the use of natural gas or petroleum in an existing powerplant or MFBI if the Secretary determines that the powerplant or MFBI has or previously had the technical capability to use coal or another alternate fuel as a primary energy source without substantial physical modification of the unit or substantial reduction in the rated capacity of the unit, and that it is financially feasible to convert the unit from natural gas or petroleum to another fuel. Enumerable procedures are provided for the granting of exemptions to allow the continued use of natural gas or petroleum as a primary fuel in both new and existing powerplants and MFBI's.

The basic differences between the Texas program under Docket 600 and the Federal program under the Fuel Use Act are as follows:

Memorandum to All Interested Parties
January 15, 1979
Page 3

1. Docket 600 applies only to the use of natural gas as a boiler fuel whereas the Fuel Use Act applies to any use of both natural gas and petroleum as a fuel.

2. The area of applicability, as defined by the volume of use, is different for the two programs. In the Texas program, applicability is measured in terms of volume of natural gas used by an individual. Thus, an individual who utilizes 3,000 Mcf/D, or more, is covered by Docket 600. On the other hand, the federal program defines its application in terms of the volume of fuel which is consumed by a particular powerplant or MFBI. Otherwise, the required volume of use is fairly comparable for the two programs, since 100 MMBTU per hour is approximately equal to 2,400 Mcf/D.

3. Docket 600 makes no distinction between existing and new users of natural gas as a boiler fuel. All users of natural gas as a boiler fuel are required to comply with the schedule provided in Docket 600. On the other hand, the Fuel Use Act distinguishes between "new" and "existing" powerplants and MFBI's.

4. Finally, the time frames of the two programs are distinctly different. Docket 600 has no effect upon the consumption of natural gas as a boiler fuel by any person prior to January 1, 1981. At that time, the use of natural gas as a boiler fuel by that person must be reduced by only 10%. Thereafter, on January 1, 1985, the use of natural gas as a boiler fuel must be reduced by only 25%. Under the Fuel Use Act, on the other hand, new powerplants and MFBI's are entirely prohibited from utilizing natural gas or petroleum as a primary energy source. Existing powerplants are required to totally convert to alternate fuels by January 1, 1990.

Obviously, Docket 600 and the Fuel Use Act conflict in many respects. Certainly, whenever the Fuel Use Act provides a more stringent requirement, that Act will preempt the Texas program under Docket 600. For example, the Fuel Use Act certainly compels the elimination of natural gas as a primary energy source in new powerplants, which is not required in Docket 600. However, it is unclear whether the State of Texas can impose more stringent requirements under Docket 600 than are imposed by the Fuel Use Act. For example, Docket 600 would require a 10% reduction in the use of natural gas by an existing powerplant by January 1, 1981. The Fuel Use Act would not require any reduction in natural gas consumption by an existing powerplant until January 1, 1990.

The conflicts between the federal and state programs may be eliminated by a review of Docket 600 currently being conducted by the Commission under Gas Utilities Docket No. 1055. On the date of this Memorandum, the Commission issued an Order which initiates a rulemaking proceeding to determine whether Docket 600 should be

Memorandum to All Interested Parties
January 15, 1979
Page 4

repealed or otherwise modified. Undoubtedly, the passage of the Fuel Use Act influenced the Commission's action in Docket 1055. However, another primary factor was the surplus of natural gas which currently exists on the intrastate market.

The Gas Utilities Division of the Railroad Commission submits the above comments to the Environmental Impact Statement on the Issuance of Regulations Implementing the Fuel Use Act. Any further questions regarding this matter may be directed to the Staff of the Gas Utilities Division at the above address.

Jeff Browning
Hearings Examiner

JHB/db

TEXAS PETROLEUM RESEARCH COMMITTEE

Texas A&M University | Railroad Commission of Texas | University of Texas

PLEASE REPLY TO:
OFFICE OF THE DIRECTOR
TEXAS PETROLEUM RESEARCH COMMITTEE
TEXAS A&M UNIVERSITY
COLLEGE STATION, TEXAS 77843

January 4, 1979

RECEIVED
JAN 8 1979
Budget/Planning

Mr. Kenneth G. Gordon
Economic Development and
Transportation
Budget and Planning Office
Office of the Governor
Executive Office Building
411 West 13th Street
Austin, Texas 78701

Dear Mr. Gordon:

Your memorandum of December 20 to Paul Crawford, Texas Petroleum Research Committee at Texas A&M University, and others, asked for review and comment of the Draft Programmatic Environmental Impact Statement on the Fuel Use Act. Dr. Crawford called this to my attention and I wish to make one or two comments.

First, the report indicates (page 1-8) that the major terrestrial ecological impact will be in Supply Region S, which includes Texas. Based on this conclusion, I suggest that you might wish to have this Impact Statement reviewed by appropriate land management or agricultural people within the state.

Second, I note on page 1-11 a statement on costs associated with fuel substitution compared to costs related to oil and gas. You may wish to ask someone to examine this question further.

The question of substitution coal for gas involves predictions of natural gas supply and there is a great deal of recent thought that natural gas supplies have been underestimated. I enclose a copy of an Executive Summary of the workshop on "R&D Priorities and The Gas Energy Option" held in Aspen, Colorado, last summer. The conclusions of this workshop appear to show a greater promise for continued use of gas than was previously thought to be the case.

Gas may be obtained, of course, from the underground gasification of coal as well as from above-ground gasification of coal, but in either event, the electrical generating facility would burn gas and the environmental impacts would be different than if the coal were burned directly. You may wish to have someone examine this point more thoroughly.

From the standpoint of fossil fuel production, which is the primary responsibility of TRPC, there do not appear to be any relevant matters within the Draft Programmatic Environmental Impact Statement.

Sincerely yours,

John C. Calhoun, Jr.
Executive Vice Chancellor
for Programs

Attachment

cc: Dr. Paul Crawford

UTAH

Scott M. Matheson
Governor

Kent Briggs
State Planning Coordinator

STATE OF UTAH
Office of the
STATE PLANNING COORDINATOR
118 State Capitol
Salt Lake City, Utah 84114
(801) 533-5246

December 6, 1978

Ruth C. Clusen
Assistant Secretary for Environment
Department of Energy
Washington, D.C. 20461

Dear Ms. Clunsen:

The Utah State Environmental Coordinating Committee has reviewed the Draft Programmatic Environmental Impact Statement for the Fuel Use Act. The Committee offers no comment.

Thank you for the opportunity to comment.

Sincerely,

Lorayne Tempest
Lorayne Tempest
Assistant State Planning Coordinator

LT/jb E1

VIRGINIA

COMMONWEALTH of VIRGINIA
Office of the Governor
Richmond 23219

Maurice B. Rowe
Secretary of Commerce and Resources

November 28, 1978

Ms. Ruth C. Clusen
Assistant Secretary for Environment
Department of Energy
Washington, D. C. 20461

Dear Ms. Clusen:

On behalf of Governor Dalton thank you for giving us the opportunity to review and make comments on the Departmentof Energy's Draft Environmental Impact Statement for the coal and alternate fuels program authorized by the Power Plant and Industrial Fuel Use Act of 1978, DOE-EIS-0038-D.

We have been in contact with the Virginia State Clearinghouse and just as soon as they receive the draft it will be shared with the State agencies that will be involved.

Comments will follow as suggested.

Sincerely,

Edward H. Isbell
Assistant to the Secretary

cc: Dolly Collier
George L. Jones
Office of the Governor

COMMONWEALTH of VIRGINIA

Council on the Environment

J. B. JACKSON, JR.
ADMINISTRATOR

903 NINTH STREET OFFICE BUILDING
RICHMOND 23219
804-786-4500

February 14, 1979

Mr. Steve Frank
Department of Energy
Division of Coal Utilization
Room 7202
M Street, N.W.
Washington, D.C. 20461

SUBJECT: Fuel Use Act

Dear Mr. Frank:

Thank you for the opportunity to review the subject Draft Environment Impact Statement. It is a responsibility of the staff of the Council on the Environment to coordinate the State's review of Federal environmental impact statements and to transmit the comments of the State to the responsible Federal official. The State agencies which participated in the review of the subject document are listed below:

State Department of Health
State Air Pollution Control Board
State Water Control Board

At this time the Commonwealth of Virginia has no objections to the proposed action. The environmental impacts which are documented do not appear to be particularly significant at the generic level. Specific projects undertaken in response to the proposed action can and will be reviewed individually by agencies of the State as appropriate.

The individual comments of Virginia agencies are enclosed for your information. We look forward to reviewing the final document upon completion. Do not hesitate to contact me if you have any questions or if I can be of further assistance.

Sincerely,

J. B. Jackson, Jr.
Administrator

JBJr/gcj
cc: The Honorable Maurice B. Rowe, Secretary of Commerce and Resources

FEB 22 1979

COMMONWEALTH of VIRGINIA

Department of Health
Richmond, Va. 23219

JAMES B. KENLEY, M.D.
COMMISSIONER

MEMORANDUM

TO: Reginald F. Wallace, Environmental Impact Statement Coordinator

FROM: Oscar H. Adams, P. E., Deputy Assistant Commissioner for the Environment

DATE: February 2, 1979

SUBJECT: Draft Programmatic Environmental Impact Statement Fuel Use Act

The above referenced project has been reviewed by the Division of Water Programs and based on that review, it appears that the proposed project is compatible with the plans, objectives, and programs of the Virginia State Health Department. The Department endorses the project and recommends its approval. Comments are attached.

OHA/jc

13-33

Oscar H. Adams, Deputy Assistant Commissioner for the Environment

February 2, 1979

J. R. Sutherland, P.E., Director, Bureau of Wastewater Engineering
A. R. Hammer, P.E., Director, Bureau of Water Supply Engineering

Draft Programmatic Environmental Impact Statement
Fuel Use Act

Both of us have reviewed this project and find that although there will be increased adverse environmental impacts (due to increased coal mining and coal utilization at power plants), it appears that the proposed action must be concurred with in view of critical energy requirements. Specific cases that might endanger public water supplies or that might significantly affect stream water quality can still be addressed individually as they come up.

With the above in mind, we concur with the proposal.

JRS/ARH/RBT/djv

COMMONWEALTH of VIRGINIA

State Air Pollution Control Board

ROOM 1106, NINTH STREET OFFICE BUILDING
RICHMOND, VIRGINIA 23219
TELEPHONE: (804) 786-2378

W. R. MEYER
EXECUTIVE DIRECTOR

February 9, 1979

Mr. Reginald F. Wallace
Environmental Impact Statement Coordinator
Council on the Environment
903 Ninth Street Office Building
Richmond, Virginia 23219

Dear Mr. Wallace:

We have reviewed the draft EIS on the Fuel Use Act and have the following comments.

The document covers the air quality aspects of the proposal quite adequately. Increases in Virginia's SO_2 and Particulate concentrations are predicted as a result of this action. These increases are not expected to cause violation of any air quality standard.

The EIS also notes that each individual action resulting from this Act will need a review, and our regulations already provide for this. This review will ensure that the air quality impact of shifting to coal will be minimized.

Sincerely,

J. C. Ruehrmund
Director
Division of Operations and Procedures

JCR/WPP/pjg

"An Equal Opportunity Employer"

WASHINGTON

COMMONWEALTH of VIRGINIA

STATE WATER CONTROL BOARD
2111 Hamilton Street

R. V. Davis
Executive Secretary

Post Office Box 11143
Richmond, Virginia 23230
(804) 257-0056

January 26, 1979

Mr. Reginald F. Wallace
Environmental Impact Statement Coordinator
Governor's Council on the Environment
Ninth Street Office Building
Richmond, Virginia 23219

Council on the Environment

Dear Reggie:

RE: DEIS-Fuel Use Act

We have reviewed the above-referenced DEIS. Aside from the obvious effects mining has on water quality, we feel that the document has done an adequate job of addressing the water quality problems and proposing possible mitigating measures.

Thank you for the opportunity to review this EIS. If you have any questions, please feel free to call me.

Sincerely,

Dale E. Wright
Bureau of Surveillance
and Field Studies

/scc

cc: Raymond E. Bowles
EIS File

STATE OF
WASHINGTON

Dixy Lee Ray
Governor

DEPARTMENT OF ECOLOGY
Olympia, Washington 98504 206/753 2800
Mail Stop PV-11

December 28, 1978

Mike Mills, Policy Analysis Division
State of Washington Office of
Financial Management
House Office Building
Olympia, Washington 98504

Dear Mr. Mills:

This is in response to your request for comments on the Federal Department of Energy draft environmental impact statement concerning the Fuel Use Act. Our only comment is to echo the statements in the EIS concerning air quality. Since the Federal Clean Air Act sets specific increments of air pollution increase which shall not be exceeded, increases resulting from conversion to coal must be compensated for by applying additional controls to existing sources and/or restricting development of new sources. These are difficult tradeoffs and must be recognized as the Fuel Use Act is implemented.

Sincerely,

T. L. Elwell
Environmental Review Section

TLE:bjw

cc: U. S. Department of Energy

STATE OF WASHINGTON

Dixy Lee Ray
Governor

OFFICE OF FINANCIAL MANAGEMENT
House Office Building, Olympia, Washington 98504 206/753-5450

Orin C. Smith, Director

February [illegible], 1979

Mr. Steven A. Frank, Chief
Environmental Evaluation Branch
Division of Coal Utilization
Office of Fuels Regulation
Department of Energy
Room 7202
2000 M Street, N.W.
Washington, D.C. 20461

Dear Mr. Frank:

Review of the draft environmental impact statement for Fuel Use Act has been completed by agencies of the State of Washington. The review was coordinated by the Office of Financial Management, as the designated state clearinghouse. Comments were received from the Department of Ecology. The Department, in their concern on air quality standards, notes that since the Federal Clean Air Act sets specific increments of air pollution increases which shall not be exceeded, increases in air pollution resulting from conversion to coal must be compensated for by applying additional controls to existing sources and/or restricting development of new sources. These are difficult tradeoffs and must be recognized as the Fuel Use Act is implemented.

We understand that the Department of Energy will respond directly to the Department of Ecology's concern.

Thank you for the opportunity to review the document. We hope you find the comments useful in preparing the final EIS.

Sincerely,

T A Mahar

Thomas A. Mahar
Assistant Director

TAM:db

WEST VIRGINIA

STATE OF WEST VIRGINIA
GOVERNOR'S OFFICE
OF
ECONOMIC AND COMMUNITY DEVELOPMENT
CHARLESTON 25305

JOHN D. ROCKEFELLER IV
GOVERNOR

DONALD D. MOYER
DIRECTOR

February 2, 1979
File: PNRS-E

Mr. Steven A. Frank, Chief
Environmental Evaluations Branch
Division of Coal Utilization
Office of Fuels Regulation
Department of Energy
Room 7202
2000 M Street, N.W.
Washington, D. C. 20461

Re: Department of Energy - Draft Environmental Impact Statment for the Coal and Alternate Fuels Program

Dear Mr. Frank:

In accordance with Section 102(2) (C) of the National Environmental Policy Act of 1969, the State Clearinghouse has reviewed the above referenced project.

Copies of the comments of Mr. Thomas V. Reishman, Coal Policy Analyst, Governor's Office of Economic and Community Development, and Mr. Walter N. Miller, Director, West Virginia Department of Mines, are enclosed for your further use.

This will certify that the requirements of the U. S. Office of Management and Budget Circular No. A-95 have been met,.

Sincerely,

Dan S Green

Daniel S. Green, Manager
Program Support Services

DSG:am
Encls.
cc: Thomas V. Reishman
Walter N. Miller

13-36

GOVERNOR'S OFFICE OF ECONOMIC AND COMMUNITY DEVELOPMENT
PROGRAM SUPPORT SERVICES
WEST VIRGINIA STATE CLEARINGHOUSE
ROOM B-548, BUILDING #6
CHARLESTON, WEST VIRGINIA 25305

CLEARINGHOUSE USE ONLY

DATE: 11/27/78

FILE NO: PNRS-E

Comments concerning this DEI: should be received by this offic no later than: 12/29/78

(DRAFT) ENVIRONMENTAL IMPACT STATEMENT (DEIS)

TO: Walter Miller
Director
West Virginia Department of Mines

FROM: Daniel S. Green
Manager
Program Support Services

DEIS DESCRIPTION: Draft Programmatic Environmental Impact Statement-Fuel Use A

The attached (Draft) Environmental Impact Statement is referred to your agency for REVIEW and COMMENTS. If your agency has an interest in this Statement and desires to comment on it please CHECK THE APPROPRIATE BOX. Your cooperation is asked in returning this memo to the State Clearinghouse Office, indicating your interest or not, 10 days from its receipt.

- ☐ No comment (Please Indicate Reason In Space Below)
- ☐ Comments being developed
- ☒ Comments submitted herewith
- ☐ Comments should more appropriately (or also) come from Agency(s) as listed below.

RECEIVED
DEC 21 1978
STATE CLEARINGHOUSE OFFICE

(Please use reverse side if additional space is needed)

Reviewer's Signature Walter N. Miller Date December 15, 1978

Title Director, W. Va. Department of Mines Telephone 755-2051 & 755-2052

WALTER N. MILLER
DIRECTOR

State of West Virginia
Department of Mines
Charleston 25305

EDWARD JARVIS
DEPUTY DIRECTOR

Review of the Fuel Use Act

With the prime emphasis presently placed on a greater demand for energy, at an accelerated pace there must be many areas of speculation.

With a transition of a charge of fuel, new methods, new regulations, and the extreme vastness and outreach of the total world population which will to some degree affect each and every individual. I must admit, I possess a small amount of optomism in reviewing the Fuel Use Act.

It appears that west of the Mississippi new coal reserves in great numbers will be developed where mining has never occurred before.

Transportation of coal by rail, and water can certainly be expected to increase significantly.

The disposal of unwanted waste, both solids and gaseous will be necessary.

Disturbing the top soil from surface mining will drastically increase, as well as erosion, water problems, and subsidence problems from underground mining operations.

A stable working industry, performing at maximum efficienty will be vital.

Generally speaking, in my opinion there is no God given mineral, element, or substance created, that when the charactists change there

13-37

will always be some type of tangables. With this thought in mind, I wish to summarize my review with the following statement.

Immediate long range planning must begin as to the following:

Safety Regulations implemented in harmony with modern technology, tempered with a great deal of common sense.

A stable work force on the coal industry is vital. Setting into motion new systems and methods for the recovery of coal.

Taking corrective actions now, in abating the existing problems as to land subsidance, mine water drainage, waste disposal, both solid and gaseous, before compounding these problems with more and larger ones.

Adequate notification of persons who may be affected in any way with new development, and such developments be properly engineered.

Planning commissions in communities be included in such long range planning, as for future housing and industrial developments.

And finally I believe if the proper foresite is implemented, and procedures are properly put in motion now, any transition can come about, and be successfull, but great emphasis must be placed on proper preparation and adhearing very close to the proposals.

GOVERNOR'S OFFICE OF ECONOMIC AND COMMUNITY DEVELOPMENT
PROGRAM SUPPORT SERVICES
WEST VIRGINIA STATE CLEARINGHOUSE
ROOM B-548, BUILDING #6
CHARLESTON, WEST VIRGINIA 25305

CLEARINGHOUSE USE ONLY

DATE 11/27/78

FILE NO. PNRS-E

Comments concerning this DEIS should be received by this office no later than: 12/29/78

(DRAFT) ENVIRONMENTAL IMPACT STATEMENT (DEIS)

TO: Tom Reishman
Director's Office
Office of Economic and Community Development

FROM: Daniel S. Green
Manager
Program Support Services

DEIS DESCRIPTION: Draft Programmatic Environmental Impact Statement-Fuel Use Ac

The attached (Draft) Environmental Impact Statement is referred to your agency for REVIEW and COMMENTS. If your agency has an interest in this Statement and desires to comment on it please CHECK THE APPROPRIATE BOX. Your cooperation is asked in returning this memo to the State Clearinghouse Office, indicating your interest or not, 10 days from its receipt.

- ☐ No comment (Please Indicate Reason In Space Below)
- ☑ Comments being developed
- ☐ Comments submitted herewith
- ☐ Comments should more appropriately (or also) come from Agency(s) as listed below.

will submit comments to clearinghouse shortly.

RECEIV
DEC 12 1978
STATE CLEARINGHOUSE GOVERNOR'S OFFICE

(Please use reverse side if additional space is needed)

Reviewer's Signature Thomas V. Reishman Date 12/12/78

Title Coal Policy Analyst Telephone 342-0410

13-38

WISCONSIN

State of Wisconsin \ DEPARTMENT OF NATURAL RESOURCES

Anthony S. Earl
Secretary

BOX 7921
MADISON, WISCONSIN 53707

February 8, 1979

IN REPLY REFER TO: 1600

Mr. Steve Frank
Division of Coal Utilization
Department of Energy
2000 M Street, N.W. Room 7202
Washington D.C. 20461

Re: Draft Programmatic Environmental Impact Statement - Fuel Use Act (FUA)

Dear Mr. Frank:

The Department submits the following comments on this Draft Environmental Impact Statement.

Since the State of Wisconsin will not be affected directly by the actual mining of coal, we'll address the impacts created by using coal as an alternate or primary fuel.

The Department's Air Management Section is currently developing a State Implementation Plan (SIP) in cooperation with the Environmental Protection Agency. The initial comments in this letter reflect their concerns relative to air quality.

1. Pages 2-4 of the EIS provide that Congress has expressly indicated that the FUA would not be exempted from any existing or future environmental standards. Thus, all actions under the FUA in Wisconsin are to be consistent with applicable Wisconsin environmental requirements. However, the FUA allows latitude in the use of fuels in emergency situations. This is consistent with Wisconsin's practice in enforcement of air rules since we also provide for variances during emergency situations.

2. The effects of local concentrations of individual facilities was not addressed in the Draft EIS, but will be considered in each site specific assessment. At this point, the Department's Bureau of Air Management will become involved. This involvement would consist of the following:

a. Identifying the facilities, utilities or industries which burn oil or gas and have an order under the Energy Supply and Environmental Coordination Act (ESECA) or may be ordered under the FUA to convert to coal.

b. Studying the technological feasibility for fuel conversions. According to Wisconsin rules all sources modifying an existing emission source are required to obtain approval from the Bureau of Air Management, and thereby New Source Performance Standards could apply to these facilities.

c. Analyzing the air quality impacts of each proposed conversion.

d. Developing alternative air quality recommendations to each specific case of FUA orders, considering the possibility that several of these existing facilities may request exemptions on environmental or economic grounds.

e. Establishing a compliance schedule with an inspection and surveillance program.

f. Monitoring air quality using appropriate regulatory strategies to obtain or maintain National Ambient Air Quality Standards.

The above points enumerate the importance of developing an adequate program to process each action under the FUA as they develop.

A preliminary study by the Bureau of Air Managment has developed a list of sources which currently burn natural gas or oil and can also utilize coal or heavy oil. This list contains approximately 100 sources in Wisconsin, of which about 15 with greater than 100 million BTU per hour boiler capacity, exceed the Major Fuel Burning Installation (MFBI) criteria. These 15 sources may be affected by the FUA regulations and consequently will require Department interaction as listed in 2.c.

The above-mentioned study does not include sources which presently are burning oil and gas and lack the capability to use coal. These sources may also be affected by the FUA. Identification and resolution of their environmental concerns may also be required.

The following comments are related to some specific concerns we have on expanded coal use.

The Department is very aware of the associated problems in attempting to integrate separate yet interrelated programs. The overlap of these programs and agency functions may be difficult to coordinate from both a practical and procedural standpoint. The secondary impacts of an action very often have primary effects on other programs, or the environment itself.

Department of Natural Resources (Wisconsin), continued

An increased dependence on coal as a fuel source will affect the railroads and barge or ship traffic in Wisconsin, since they are the principal movers of these materials. Expanded barge and ship traffic may result in additional dredging permit applications, creating a greater need to find suitable dredge spoil diaposal sites. These actions alone may be significant enough to require an EIS.

Many, if not all, railroads in Wisconsin are experiencing difficult and often severe problems in operating at a profit large enough to ensure financial security. Currently under Department review is an EIS on a railroad plan for Wisconsin. This EIS document is attempting to deal with the myriad of problems associated with the economics and feasibilities of shutting down various unprofitable or rundown routes, and the rehabilitation of other lines. Elimination of various branch railroad lines may result in many utilities, industries and facilities having difficulties in obtaining coal as an alternate or primary fuel. While it may be difficult to identify affected users on a long-term basis, immediate or short-term problem areas could be identified.

The use of coal will also result in increased bottom and fly ash residuals. Additional or expanded landfill sites will be required thus creating more solid waste disposal problems. We feel the problems addressed in this letter are not unique to Wisconsin. Other states will also need to answer or develop ways of dealing with these concerns.

We thank you for the opportunity to comment on this Draft EIS. If you have any questions or comments, please feel free to contact us. Please forward three copies of the Final EIS when it is completed.

Sincerely,
Bureau of Environmental Impact

Howard S. Druckenmiller

Howard S. Druckenmiller
Director

cc: Robert Arnott
D. F. Gebken

Citizens' Action for Safe Energy, Inc.

CITIZENS' ACTION FOR SAFE ENERGY, INC.
P. O. Box 924
Claremore, OK 74017

Feb. 8, 1979

Dear Gentlemen and Ladies,

Again I thank you for the opportunity to speak to you at Fort Worth on Feb. 1st, and I would like to say that I was greatly encouraged by what I encountered there. For the first time in my experience with Federal Hearings, I saw a glimmer of light in our federal beureaucracy personnel.

Let me start by explaining that we received the notice of your meeting only three days before the actual event. We felt it imperative that our group be represented there, and it was a bit of a rush to prepare in time for the meeting. What I'm trying to say is that we had insufficient notice (for example, we never saw the environmental impact statement until I arrived) to prepare properly for the meeting. And I believe the same phenomena is occuring with the law itself (FUA). Not that such speed isn't necessary, if anything we need to change the national energy picture even faster. There appears to be insufficient public involvement in what you are doing. And this insufficiency is only partly due to the lack of prior notice as well as the general format of the meeting itself.

We feel that a large part of the energy problem that we are facing here, has been created in part, by a lack of communication between all parties concerned: government, industry and the people. And in this particular case, by the structure of the public hearings themselves. You have dealt quite effectively with the problem of hearing a large number of people in a short space of time. But in placing limits on time and direction of questioning on the speakers and limits of questioning on the part of the audience itself, you have unfortunately blocked much of the free and open communications of much of the learning process that should be taking place at such a hearing.

We finally recommend that all future hearings be based only on Roberts Rules of Order, without any lesser constraints as to time, directions of questioning, or preparations and copies necessary. We also recommend that future hearings be held in such places that will place no additional financial burdens on the lengths or costs of such hearings, (using public schools, libraries, etc.). We now believe you will find that on implementing the aforementioned suggestions, you will experience an increase in the time consumed by individual hearings, but actually decrease the time required for implementing any laws or regulations discussed at the hearings.

We further recommend that the greatest priorities be place on the time requirements of implementation of regulations, and not on the time consumed by specific public hearings. We vigorously suggest that every effort be devoted to increasing the rate of learning by the the public, especially at the interface of government, industry, and the people. Namely, the public hearings. We need to deregulate the hearings so we may better learn to regulate energy.

We appreciate your openmindedness and only hope that you will continue to hear the voice of the people, for therein lies the only true salvation for our country . Thank you for your time and concern.

Sincerely,

Walt Hickerson

Walt Hickerson
Administrative Assistant
Citizen's Action for Safe Energy

Copies to:

Mac Lacefield

Bob Davies

David Bardin

Steve Frank

Tom Wolfe

Ann Randolph

Sue Phillips

Clinton Spaatz

Curtis Carlson

WD/jmj

Government of Puerto Rico

Office of the Governor
La Fortaleza. San Juan. Puerto Rico

January 4, 1979

Ms. Ruth C. Clusen
Assistant Secretary for Environment
Department of Energy
Washington, D. C. 20461

Dear Ms. Clusen:

I would like to acknowledge receiving your recent letter with which you forwarded to me a copy of the Department of Energy's Draft Environmental Impact Statement for the coal and alternate fuels program authorized by the Powerplant and Industrial Fuel Use Act of 1978, DOE-EIS-0038-D. In accordance with your letter, copies of the Draft Statement were sent to the Puerto Rico Planning Board for review by agencies of the Government of Puerto Rico during the 60 day comment period.

I will be in contact with the President of the Planning Board to ensure that comments from the Government of Puerto Rico are submitted on time.

Cordially,

Carlos Romero Barceló

Carlos Romero Barceló

31335

1979 Year of the Panamerican Games

13-42

Edwin A. Jamback

EDWIN A. JAMBACK, D. D. S.
4 MECHANIC STREET
FARMINGTON, NEW HAMPSHIRE 03835
FARMINGTON : 603.755.2931

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DOE

Feb. 5, 1979

Office of Public Hearing Management
Docket No. ERA-R-78-19 Room 2313
2000 E Street N.W.
Washington, D.C. 20461

Dear DOE

As one who has been deeply concerned with environment and who has been teaching same for a no. of years, I will take the opportunity to make comments on this issue.

I see no objection to any alterations or rules for existing facilities under Fuel Use Act provided:

1. Somehow an impartial, nonfuel affiliated group be allowed to keep a "hooded eye" on the facilities as they are converted and developed. This to promote a fail safe = humanly infallible facility development. This is the hardest part of environmental cleanup. We have become so monetary oriented as to forget quality

EDWIN A. JAMBACK, D. D. S.
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2. If the facilities are to be conservation oriented, it seems reasonable (to me at least) that the alternatives be stressed. Burning of wood, trash, sewage & recycling be very strongly emphasized. I wrote garbage but that should be composted.

3. Coal is a good alternative provided the housewife near a coal burner is notified when the burner is being fired. I don't [illegible] that much has happened to change the method of coal burning.

These are a few comments of which #1 is the most important. I would be pleased to expound further if you wish. Please call on me.

Sincerely yours

Edwin A. Jamback, DDS
Environmentalist
[illegible] Adult Learning Center

Texas Electric Service Company

781901 B

UNITED STATES OF AMERICA
DEPARTMENT OF ENERGY
ECONOMIC REGULATORY ADMINISTRATION

IN THE MATTER OF THE DRAFT: PROGRAMMATIC ENVIROMENTAL IMPACT STATEMENT :	FUEL USE ACT DOE/EIS-0038-D

WRITTEN COMMENTS BY
TEXAS ELECTRIC SERVICE COMPANY

Texas Electric Service Company is an investor-owned electric utility providing electric service in 48 counties in north central and west Texas.

We at Texas Electric welcome you to Fort Worth and trust your stay here will be a pleasant one.

We also welcome the opportunity to participate in this hearing because we are concerned - not just about the draft environmental impact statement which is to be discussed today, nor just about the Powerplant and Industrial Fuel Use Act of 1978 - rather, we are concerned about the ever broadening scope and the attendant uncertainty and increased cost of federal regulation.

President Carter and his administration say they want the nation to reduce its dependence on oil and gas, primarily through increased use of coal. But the laws and regulations which are being passed or proposed are making it more and more difficult - nearly impossible in some cases - to mine and use coal.

We support the President's request. In fact, Texas Electric, Texas Power & Light and Dallas Power & Light are pioneers in the area of use of lignite-coal in powerplants. We placed in service in 1971 our first jointly owned lignite-coal fueled powerplant. This was the 575 Mw unit No. 1 at our Big Brown plant. Since then, we have built and placed in service six additional lignite-coal fueled units in sizes up to 750 Mw. One additional 750 Mw unit is currently in trial operation . . . two more 750 Mw lignite fueled units are under construction. And, we also have two jointly owned 1150 Mw nuclear units under construction.

Our program to reduce dependence on gas/oil began and was well underway before this law and all the rules and regulations were ever proposed. Not only that: we were doing a good job of reclaiming and re-planting our strip-mined land before the federal surface mining law and all of its rules were passed. Even further, we were doing a good job of cleaning the flue gasses before the EPA decided every unit should have a scrubber whether it needed it or not.

As far as we can see, the main environmental impact of all these laws and rules and regulations is to slow down our progress and make our customers' electricity more expensive.

The reclamation program initiated at the Big Brown plant, near Fairfield, Texas, in 1971 predated the Texas surface mining and reclamation law by two years and the federal law by six years. The program met, and continues to meet, all requirements of the state and federal regulations.

When the Big Brown plant construction began in 1968, one federal approval, one federal inspection, five state approvals and three state inspections were required.

A similar construction program today would involve:

-- Six federal approvals,

-- Eight federal inspections and reports,

-- Eleven state approvals, and

-- Seven state inspections and reports.

And what's even worse, the regulations and requirements for a lignite plant are relatively few compared to the new regulations, rules, requirements and design changes imposed before and during construction of a nuclear plant.

The United States was one of the first nations to recognize the need to preserve its environment and protect its people, wildlife and landscape from harmful pollution. This country was also one of the first to write such protections into laws.

But this desire to protect and preserve the environment has passed from the point of effectiveness to the point of over-saturation and what we call "over-regulation". Over-regulation is now causing the American people to be subject to economic deprivation, future energy shortages and social upheaval.

Gentlemen, some regulation may be considered essential in a society as large and complex as we have in the United

States. But, the government's regulatory apparatus has become so pervasive and so burdensome that we are convinced its costs far outweigh its benefits.

The Big Brown lignite plant, which I mentioned earlier, was completed in 1971-72 at a cost of about $125 per kilowatt of capacity. The company's newest lignite unit at the Martin Lake plant near Henderson, Texas, was recently completed at a cost of $272 per kilowatt. The $147 per kilowatt increase in construction costs was caused almost entirely by new regulations and by inflation.

Since there appears to be no change in the trend of over-regulation and inflation, the estimated cost of our next lignite-fueled plant to be completed in 1984 is $583 per kilowatt.

The Fuel Use Act and all the rules and regulations which may be passed pursuant to that Act will not create one barrel of oil or one ton of coal or one cubic foot of natural gas. As a matter of fact, many of the rules and regulations which may be passed pursuant to this law may be counterproductive. Let me give you an example. There is currently pending a proposed rule concerning what DOE/ERA has chosen to call "transitional units" which we have commented on in a separate proceeding. Without going into all the details of that matter and proposed rule, let me simply state that for one of our generating units, which we believe is clearly existing under the law as it was passed by Congress, this proposed rule would require the filing of a petition by our company and the completion of a very extensive engineering study at a cost of a quarter of a million dollars to simply have the Department of Energy-Economic Regulatory Administration grant "existing" status to what the law has already declared to be an existing unit. This is the type of rule and regulation which is counterproductive and ends up costing the consumer money for which they receive no benefit. Rules and regulations like these, while perhaps not impacting on the quality of air we breathe, surely impact the pocketbook of our customers; and therefore, do have an environmental impact in that they displace funds which could be used for productive purposes to needless, counterproductive paperwork.

So we urge you - in implementing the regulations associated with the Fuel Use Act of 1978 to:

1. Reduce regulation to the maximum degree possible.
2. Eliminate the filing of reports wherever possible.
3. Define regulatory goals in line with known and proven benefit levels and cost figures.
4. Allow for regional needs and capabilities to be considered.

Let me repeat my welcome to Fort Worth. Please let us know if we can be of assistance while you are here.

TEXAS ELECTRIC SERVICE COMPANY

W. M. TAYLOR
Vice President

February 8, 1979

Economic Regulatory Administration
Attn: Mr. Robert Davies
Fuels Regulation Program Office
Department of Energy
2000 M Street, N.W., Room 7202
Washington, D.C. 20461

Dear Mr. Davies:

We appreciated the opportunity to appear at the hearing on the draft Environmental Impact Statement regarding the Powerplant and Industrial Fuel Use Act of 1978 last week in Fort Worth.

At that hearing, Ms. Susan Phillips asked how many of the federal and state approvals, inspections and reports required for the construction of a lignite fueled power plant are environmental in nature.

On the attached pages we have listed the approvals, inspections and reports required. Except for the Federal Aviation Administration permit concerning stack and boiler structure heights, which we did not include as one of the required federal approvals in comments made at the hearing, all eighteen of the approvals are partially or totally of an environmental nature.

Nine of the fifteen inspections and reports are environmental in nature. They are made numerous times during the construction of a powerplant and, with few exceptions, are continued after the plant becomes operational.

Please let us know if we can provide additional information.

Very truly,

Wes Taylor

pjh
Enclosure
cc: Ms. Susan Phillips w/attachment

13-46

Texas Electric Service Company, continued

APPROVALS, INSPECTIONS AND REPORTS
REQUIRED FOR CONSTRUCTION AND OPERATION
OF A LIGNITE COAL FUELED POWERPLANT IN TEXAS

Federal Approvals

*1. Corps of Engineers - Section 404 permit for construction of dam and other plant facilities in waters of the United States.

2. EPA - Prevention of significant deterioration in air quality.

*3. EPA - NPDES permit for plant discharges.

*4. EPA - NPDES permit for mining discharges.

5. FAA - Permit for stack and boiler structure (height).

6. Department of Interior, Office of Surface Mining - mining permit.

*7. EPA - Permit for hazardous waste disposal.

State Approvals

1. Public Utility Commission - Approval of need for facility at specific site.
2. Texas Water Commission - Approval of water rights for plant.
3. Texas Water Commission - Permit for construction of cooling reservoir dam.
4. Texas Water Commission - Permit for supplemental water.
5. Texas Air Control Board - Construction permit for stack, boiler structure, fuel oil storage and lignite and fly ash handling systems.
6. Texas Water Commission and Texas Department of Water Resources - Approval of plans and specifications for dam.
7. Texas Water Commission and Texas Department of Water Resources - Water quality permit.
8. Texas Air Control Board - Approval of boiler and air control plans and specifications.

9. Texas Railroad Commission - mining permit.
10. Texas Department of Water Resources - solid waste disposal registration.
11. Texas Air Control Board - operating permit for stack, boiler, fuel oil storage and lignite and fly ash handling systems.

Federal Inspections/Reports

1. EPA - report start of construction.
2. OSHA - unannounced inspections during entire construction phase and reports as required.
3. EPA - report start of operation. Required EPA performance test of air emitting sources and reports of results performed at company expense at least twice per year.
4. EPA - records must be kept of amount of solid waste generated and amount stored. If classified hazardous, reports are made to EPA.
5. EPA - continuous monitoring and quarterly reports of monitoring data required to show NPDES compliance. Unannounced on-site inspections and reports as required.
6. Office of Surface Mining Reclamation and Enforcement - minimum of two unannounced on-site inspections annually and following reports.
7. OSHA - unannounced on-site inspections. Reports of all injuries occurring during operating phase.
8. Mining Enforcement and Safety Administration - minimum of two major and four spot health and safety inspections (on-site) per year, noise tests, dust tests, safety training and accompanying reports.

State Inspections/Reports

1. Texas Air Control Board - report of start of construction of boiler, fuel oil storage and fly ash and lignite handling systems.
2. Texas Department of Water Resources - report of start of dam construction.
3. Texas Department of Water Resources - continuous monitoring and monthly reports of data to show compliance with water discharge permit.

Texas Electric Service Company, continued

4. Texas Department of Water Resources - reports to confirm compliance with water use permit.

5. Texas Air Control Board - monitoring of air emitting sources during operating life of plant and reports to show compliance with permit limitations.

6. Texas Railroad Commission - unannounced on-site inspections to check compliance with mining permit.

7. Texas Department of Water Resources - record must be kept for inspection as deemed necessary and reports filed annually of solid wastes generated and stored.

*Environmental Impact Statement Required.

APPENDIX A. STRUCTURE OF THE COAL UTILIZATION MODEL FOR THE INDUSTRIAL SECTOR (CUMIS)

The five principal steps of the CUMIS are illustrated in Figure A.1. They are as follows:

1. Classification of PIES regional projections of baseline oil and gas consumption.
2. Identification of technical potential for coal use.
3. Creation of individual units.
4. Financial decision.
5. Aggregation and output.

A.1 CLASSIFICATION OF PIES REGIONAL PROJECTIONS OF BASELINE OIL AND GAS CONSUMPTION ("population")

Since both the technical potential and the costs of using coal differ significantly among classes of oil and gas use, the total industrial baseline consumption levels were broken into classes of energy use.

The PIES regional projections of oil and gas consumption were first disaggregated into nine industry categories. The disaggregation was done by independently projecting 1985 energy consumption off the 1974 Energy Consumption Data Base. Preliminary estimates were made for 1985, using DRI estimates of industry growth from 1974 to 1985, PIES projections of regional fuel shifts, and independent estimates of conservation. The independent projections which yielded relative sizes of the nine industry groups in each region were used to disaggregate the actual PIES regional projections by industry.

Industrial oil and gas consumption was then classified broadly into three energy use categories: boiler, nonboiler uses with coal potential, and other uses of oil and gas where coal probably cannot be used in place of oil and gas in a 1977-1985 time frame. Boiler uses include process steam uses and fuel used to generate electricity. The third category of nonboiler uses with no coal potential includes most oil and gas uses as feedstock for chemical manufacture and minor energy uses (such as mechanical drive and electrolytic processes). Boilers are estimated to account for 31 percent of oil and gas uses; nonboiler uses with coal potential constitute 43 percent and other uses with no coal potential are estimated to comprise the remaining 26 percent of oil and gas use in 1985.

A third broad distinction was made between energy consumption in new versus existing combustors. Existing 1975 boiler oil and gas consumption was adjusted to account for a 3 percent per year rate of decrease in energy consumption; this reflected the shutdown of old facilities and decreases in capacity utilization as older units are phased down or moved to standby capacity and new consuming units come on-line between 1975 and 1985. New energy uses reflect energy consumed in new combustors replacing old units, and expansion of industry to meet economic growth objectives. Classification of new and existing nonboiler use was done in a similar fashion, except retirement rates were industry-specific.

Existing energy uses were also broken down to identify oil and gas consumed in combustors originally designed to fire coal. These coal capable units were identified using the Federal Energy Administration's Major Fuel-Burning Installation Survey.

Consumption in existing boiler facilities was divided further into small and large facilities, with the breakpoint established at 100 million Btu's per hour design capacity (roughly 10 MWe). Although some combustors below 10 MWe currently use coal, for the purposes of this study all existing units below 10 MWe were assumed to be incapable of using coal.

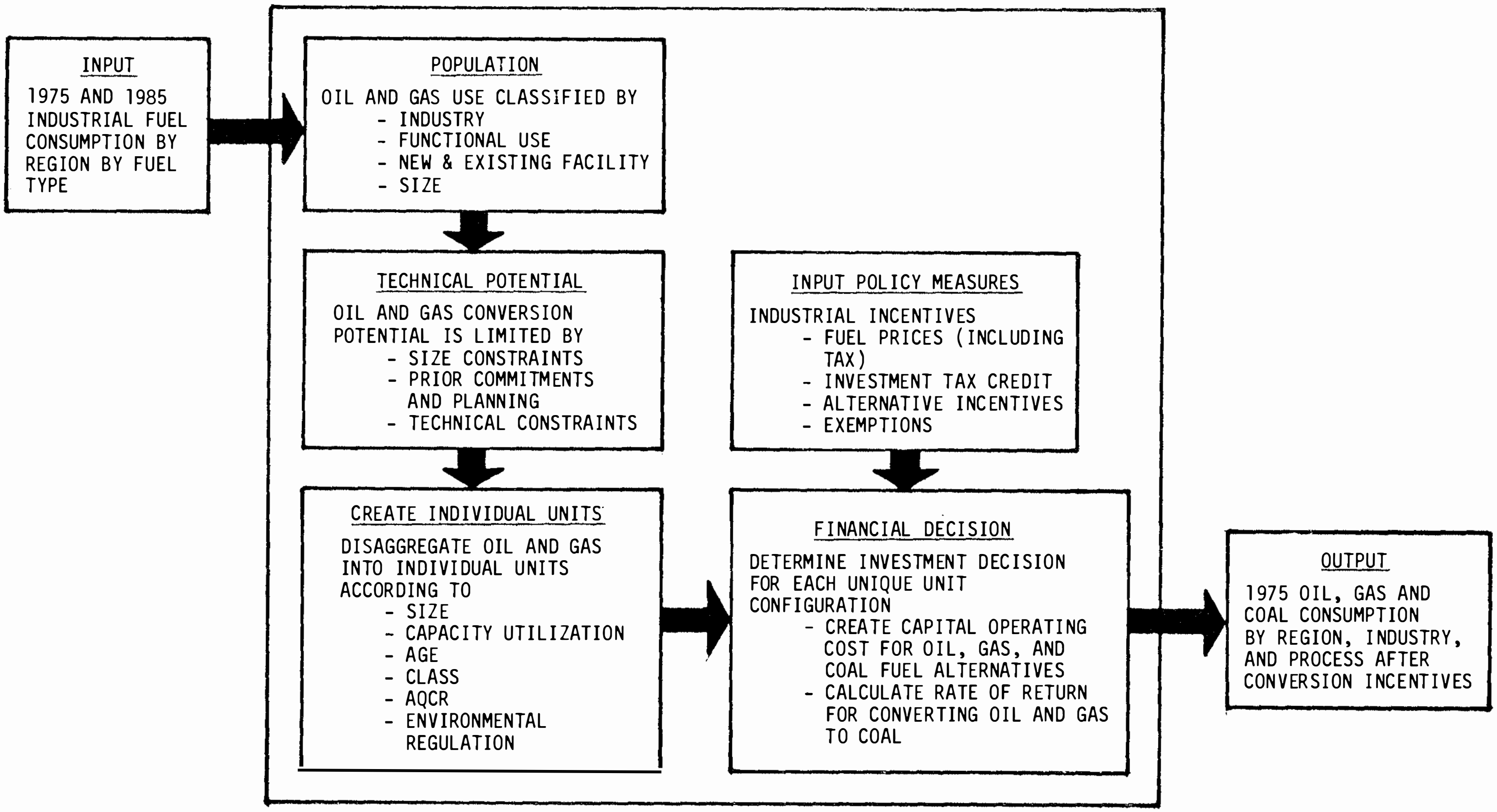

Fig. A.1. Industrial Coal Conversion Model

New energy uses were also categorized into uses scheduled to be coming on-line between 1975 and 1980 and those which would come on-line between 1980 and 1985. Decisions about the early installations have already been made by industry, and it was assumed that such new oil and gas combustors could not use coal. New boilers above 2.5 MWe of capacity were assumed to be technically able to use coal.

Based on this initial categorization, estimates of coal using potential were refined and costs of conversion were determined as described below.

A.2 IDENTIFICATION OF TECHNICAL POTENTIAL FOR COAL USE

Broad technical, economic, or timing considerations reduce those industrial oil and gas uses which can be considered serious candidates for conversion to coal. The following categories of industrial oil and gas use were assumed to have no potential for conversion to coal:

1. Feedstock and other noncombustor uses.
2. Boilers built prior to 1975 smaller than 10 MWe.
3. Boilers built between 1975 and 1980.
4. Boilers built between 1980 and 1985 smaller than 2.5 MWe.

Allocation of oil and gas use among new and existing boiler and nonboiler classes involved assigning gas a higher priority for certain uses. Because gas supplies were projected to grow more slowly than overall energy demand between 1975 and 1985, they were considered to be insufficient to meet all projected uses, based on historical use patterns. Gas allocation priorities used when such shortages occurred are listed below:

1. Gas allocated first to nonboilers according to historical usage patterns.
2. If there is not enough gas to maintain historical relationship between oil and gas for nonboilers, oil fills the gap.
3. Gas is allocated first to existing combustors according to historical patterns. If gas is insufficient for existing units, existing gas use shifts to oil.
4. Any gas remaining after allocation to existing combustors goes to new units.

A.3 CREATION OF INDIVIDUAL UNITS

Once technical potential is identified for any baseline, it is allocated to individual hypothetical combustors based on current distributions of combustor size and capacity utilization. Individual combustors are created for three purposes: first, distortions of combustor fuel consumption are avoided. For example, if distributions were used, a 50-MWe facility at 50 percent capacity utilization may receive one MW of fuel. Second, each combustor is assigned an environmental regulation, which differs by AQCR location and state for units not subject to nationwide federal standards. The economics of conversion to coal varies dramatically with the environmental control requirement. Third, the AQCR location of an individual combustor also determines whether it is prevented from converting to coal because air quality standards are currently being violated.

A.4 FINANCIAL DECISION

A.4.1 Approach

Standard industrial investment evaluation criteria were employed in evaluating how much of the technical potential might switch to coal given the stimulus of higher energy prices and the rebate incentive. Industry would view investments in coal-using equipment in terms of the rate of return or net present value of an investment, where the capital cost is the equipment cost of a coal facility less similar costs for oil or gas facilities. The revenue stream from such an investment would be viewed as the reduction in fuel costs (e. g., delivered cost of coal minus the delivered cost of oil) minus the higher operating cost associated with coal use. Industry decisions were assumed to be based on the after tax rate of return.*

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*Since the evaluation was made on an industrial combustor unit basis and could not consider investment within a corporate entity, rate of return criteria in such circumstances would be equivalent to present value criteria.

In most cases, industry would use oil as the opportunity cost in evaluating the economics of using coal. However, in order to remain consistent with the PIES framework, it was essential to use gas as the opportunity cost for those combustors identified as using gas as a primary fuel.

For any prospective project, the decision criteria would be that the coal-related investment is economically justifiable if the resultant rate of return is 15 percent or greater, in nominal terms. The breakeven after tax rate of return of 15 percent used in the NEP model was set approximately 25-50 percent higher than the current industry average to reflect a "hassle" premium associated with the difficulties of coal use.

A.4.2 Capital and Operating Costs

The incremental costs of converting to coal are calculated for each unique hypothetical combustor configuration. Costs included for these combustors classified as existing cover all costs of coal-related equipment. Costs for new combustors, however, cover only the incremental costs of coal-related equipment over those of oil- or gas-related equipment.

Pollution control equipment costs are included as dictated by combustor size and AQCR location considerations. In some instances, particularly for existing coal-capable boilers, these costs account for most of the total capital costs.

Boiler capital costs vary by such classifications as firing rate, new or existing, coal-capable or noncoal-capable, and environmental controls. Nonboiler process capital costs are also dependent upon SIC and process type.

Combustor operating costs used are the incremental costs of using coal instead of oil or gas. The operating costs include annual property taxes and insurance costs and, where necessary, sulfur control operating costs.

A.5 AGGREGATION AND OUTPUT

The energy used by all those combustors considered economically convertible is aggregated to yield the total amount of baseline oil and gas use which can be expected to convert to coal. This aggregation is accomplished along several classifications including region, industry, combustor, and fuel type. In addition, total coal conversion capital costs are aggregated to indicate the level of investment stimulated by the proposal considered.

In aggregating total conversions to coal, the effects of various exemptions can be examined by blocking certain types of conversions. Perhaps the most important of these exemptions is that prohibiting the use of coal in areas where air quality standards are violated. For this analysis, conversions were considered blocked in those areas estimated to be "nonattainment."* Other types of exemptions which can be considered in the model include combustor size and age.

*The area designations do not constitute any official EPA list but hopefully capture the aggregate impact of air quality problems on estimates of coal demand.

APPENDIX B. DEFINITION OF BITUMINOUS COAL- AND LIGNITE-PRODUCING DISTRICTS

DISTRICT 1 — EASTERN PENNSYLVANIA

Pennsylvania

Armstrong County (part) — All mines east of Allegheny River, and those mines served by the Pittsburgh and Shawmut Railroad located on the west bank of the river

Fayette County (part) — All mines located on and east of the line of Indian Creek Valley branch of the Baltimore and Ohio Railroad

Indiana County (part) — All mines not served by the Saltsburg branch of the Pennsylvania Railroad

Westmoreland County (part) — All mines served by the Pennsylvania Railroad from Torrance, east

All mines in the following counties:

Bedford	Centre	Forest	McKean
Blair	Clarion	Fulton	Mifflin
Bradford	Clearfield	Huntingdon	Potter
Cambria	Clinton	Jefferson	Somerset
Cameron	Elk	Lycoming	Tioga

Maryland — All mines in the state

West Virginia — All mines in the following counties:

Grant	Mineral	Tucker

DISTRICT 2 — WESTERN PENNSYLVANIA

Pennsylvania

Armstrong County (part) — All mines west of the Allegheny River, except those mines served by the Pittsburgh and Shawmut Railroad

Fayette County (part) — All mines except those on and east of the line of Indian Creek Valley branch of the Baltimore and Ohio Railroad

Indiana County (part) — All mines served by the Saltsburg branch of the Pennsylvania Railroad

Westmoreland County (part) — All mines except those served by the Pennsylvania Railroad from Torrance east

All mines in the following counties:

Allegheny	Butler	Lawrence	Venango
Beaver	Greene	Mercer	Washington

DISTRICT 3 — NORTHERN WEST VIRGINIA

West Virginia

Nicholas County (part) — All mines served by or north of the Baltimore and Ohio Railroad

All mines in the following counties:

Barbour	Jackson	Randolph	Webster
Braxton	Lewis	Ritchie	Wetzel
Calhoun	Marion	Roane	Wirt
Doddridge	Monongalia	Taylor	Wood
Gilmer	Pleasants	Tyler	
Harrison	Preston	Upshur	

DISTRICT 4 — OHIO — All mines in the state

DISTRICT 5 — MICHIGAN — All mines in the state

DISTRICT 6 — PANHANDLE

West Virginia — All mines in the following counties:

Brooke	Hancock	Marshall	Ohio

Appendix B. Continued

DISTRICT 7 — SOUTHERN NO. 1

West Virginia

Fayette County (part) — All mines east of Gauley River and all mines served by the Gauley River branch of the Chesapeake and Ohio Railroad and mines served by the Virginian Railway

McDowell County (part) — All mines in that portion of the county served by the Dry Fork branch of the Norfolk and Western Railroad and east thereof

Raleigh County (part) — All mines except those on the Coal River branch of the Chesapeake and Ohio Railroad and north thereof

Wyoming County (part) — All mines in that portion served by the Gilbert branch of the Virginian Railway lying east of the mouth of Skin Fork of Guyandot River and in that portion served by the main line and the Glen Rogers branch of the Virginian Railway

All mines in the following counties:

Greenbrier	Mercer	Monroe	Pocahontas	Summers

Virginia

Buchanan County (part) — All mines in that portion of the county served by the Richlands-Jewell Ridge branch of the Norfolk and Western Railroad and in that portion of the headwaters of Dismal Creek east of Lynn Camp Creek (a tributary of Dismal Creek)

Tazewell County (part) — All mines in those portions of the county served by the Dry Fork branch to Cedar Bluff and from Bluestone Junction to Boissevain branch of the Norfolk and Western Railroad and Richlands-Jewell Ridge branch of the Norfolk and Western Railroad

All mines in the following counties:

Montgomery	Pulaski	Wythe	Giles	Craig

DISTRICT 8 — SOUTHERN NO. 2

West Virginia

Fayette County (part) — All mines west of the Gauley River except mines served by the Gauley River branch of the Chesapeake and Ohio Railroad

McDowell County (part) — All mines west of and not served by the Dry Fork branch of the Norfolk and Western Railroad

Nicholas County (part) — All mines in that part of the county south of and not served by the Baltimore and Ohio Railroad

Raleigh County (part) — All mines on the Coal River branch of the Chesapeake and Ohio Railroad and north thereof

Wyoming County (part) — All mines in that portion served by the Gilbert branch of the Virginian Railway and lying west of the mouth of Skin Fork of Guyandot River

All mines in the following counties:

Boone	Kanawha	Mason	Wayne
Cabell	Lincoln	Minge	
Clay	Logan	Putnam	

Virginia

Buchanan County (part) — All mines in the county, except in that portion on the headwaters of Dismal Creek, east of Lynn Camp Creek (a tributary of Dismal Creek) and in that portion served by the Richlands-Jewell Ridge branch of the Norfolk and Western Railroad

Tazewell County (part) — All mines in the county except in those portions served by the Dry Fork branch of the Norfolk and Western Railroad and branch from Bluestone Junction to Boissevain of Norfolk and Western Railroad and Richlands-Jewell Ridge branch of the Norfolk and Western Railroad

All mines in the following counties:

Dickinson	Russell	Wise
Lee	Scott	

Appendix B. Continued

DISTRICT 8 — SOUTHERN NO. 2 (Continued)

Kentucky — All mines in the following counties in eastern Kentucky:

Bell	Greenup	Lawrence	Morgan
Boyd	Harlan	Lee	Owsley
Breathitt	Jackson	Leslie	Perry
Carter	Johnson	Letcher	Pike
Clay	Knott	McCreary	Rockcastle
Elliott	Knox	Magoffin	Wayne
Floyd	Laurel	Martin	Whitley

Tennessee — All mines in the following counties:

Anderson	Cumberland	Overton
Campbell	Fentress	Roane
Claiborne	Morgan	Scott

North Carolina — All mines in the state

DISTRICT 9 — WEST KENTUCKY

Kentucky — All mines in the following counties in western Kentucky:

Butler	Hancock	McLean	Todd
Christian	Henderson	Muhlenberg	Union
Crittenden	Hopkins	Ohio	Warren
Daviess	Logan	Simpson	Webster

DISTRICT 10 — ILLINOIS — All mines in the state

DISTRICT 11 — INDIANA — All mines in the state

DISTRICT 12 — IOWA — All mines in the state

DISTRICT 13 — SOUTHEASTERN

Alabama — All mines in the state
Georgia — All mines in the following counties:

Dade	Walker

Tennessee — All mines in the following counties:

Bledsoe	Marion	Sequatchie	White
Grundy	McMinn	Van Buren	
Hamilton	Rhea	Warren	

DISTRICT 14 — ARKANSAS-OKLAHOMA

Arkansas — All mines in the state
Oklahoma — All mines in the following counties:

Haskell	Le Flore	Sequoyah

DISTRICT 15 — SOUTHWESTERN

Kansas — All mines in the state
Texas — All mines in the state
Missouri — All mines in the state
Oklahoma — All mines in the following counties:

Coal	Lathner	Okmulgee	Rogers	Wagoner
Craig	Muskogee	Pittsburg	Tulsa	

DISTRICT 16 — NORTHERN COLORADO

All mines in the following counties:

Adams	Douglas	Jackson	Laruner
Arapahoe	Elbert	Jefferson	Weld
Boulder	El Paso		

DISTRICT 17 — SOUTHERN COLORADO

Colorado — All mines except those included in District 16
New Mexico — All mines except those included in District 18

Appendix B. Continued

DISTRICT 18 — NEW MEXICO

New Mexico — All mines in the following counties:

Grant	McKinley	Sandoval	San Miguel	Socorro
Lincoln	Rio Arriba	San Juan	Santa Fe	

Arizona — All mines in the state
California — All mines in the state

DISTRICT 19 — WYOMING

Wyoming — All mines in the state
Idaho — All mines in the state

DISTRICT 20 — UTAH — All mines in the state

DISTRICT 21 — NORTH DAKOTA-SOUTH DAKOTA

All mines in North Dakota and South Dakota

DISTRICT 22 — MONTANA — All mines in the state

DISTRICT 23 — WASHINGTON

Washington — All mines in the state
Oregon — All mines in the state
Alaska — All mines in the state

From Federal Energy Administration. 1976. Coal Mine Expansion Study. Washington, D.C.

APPENDIX C. SOCIOECONOMIC POPULATION PREDICTIONS

Total predicted population for each county in the socioeconomic analysis was derived using the conversion ratios given below.

Miners

1. Total predicted tons of coal for each county by mining type (strip or underground) by 1985 was estimated: 240,000 tons per year (Perry County); 330,000 tons per year (Mingo County), and 715,000 tons per year (Sweetwater county).

2. That figure was then divided by 10 (period of time for project, 1975-1985) to get the annual average total (National Bureau of Standards 1973).

3. Ratios of 30.0 tons per day per man for strip mining and 9.15 tons per day per man for underground mining were used (Charles River Associates 1977). These figures, respectively, were multiplied by 240 average work days per year.

4. Finally, total annual coal output was divided by total tons per year per man, for both underground and strip mining. This figure showed the additional work force that would be necessary for mining.

Mining families

Family and single worker totals were developed using the following formula:

1. Total annual workers × 0.85 = total workers with families × average family size (3.7) = total workers and families (U. S. Department of Housing and Urban Development 1976).

2. Total annual workers × 0.15 = total single, divorced, and widowed workers (Department of Housing and Urban Development 1976).

Secondary workers

Family and single secondary workers were determined using the following formula:

1. Total yearly workers × service multiplier (1.5) = total secondary workers (U.S. Department of Housing and Urban Development 1976).

2. Total secondary workers × .40 = total secondary workers with families × average family size (3.7) = total secondary workers and families (U.S. Department of Housing and Urban Development 1976).

3. Total secondary workers × .40 = total single, divorced, and widowed secondary workers (U.S. Department of Housing and Urban Development 1976).

All these figures were then multiplied by 10 years for total predicted population.

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APPENDIX D. REGIONAL AIR QUALITY IMPACTS OF COAL CONVERSION IN THE INDUSTRIAL SECTOR

D.1. REGIONAL ENERGY CONSUMPTION AND AIR EMISSION PROJECTIONS

Recently studies were initiated of the relationship between economic growth and energy, as was a comprehensive analysis of the price and structural responses of energy consumption to the changing energy environment. The literature is replete with many important and useful studies on such issues, but, in general, such studies concentrate on rather specific topics and are limited in scope. An example is the series of articles on electricity demand in the residential sector (Taylor 1975; Halvasen 1975; Chern forthcoming). While these studies provide a useful base for exploration of the studied topic, often a more comprehensive, if simpler, view is needed. This is the case for the general regional impact analysis considered in the current study.

The strategy followed in developing the Regional Energy Balance System (REBS) (Rice and Vogt 1977) was to establish an organized framework (initially invoking simplifying assumptions) to present the broad scope of energy consumption. However, the system is designed to incorporate the information available from more detailed studies (e.g., the electricity demand literature) as resources and information allow. Additionally, it is expected that exercise of the current model will help in deciding which areas need to be more extensively and urgently studied and incorporated in the model. Provision of a great deal of detailed information and analysis (especially in the regional context) is often easy; it is more difficult, however, to develop a broad base in which to put the detailed information in perspective. This is perhaps the most important contribution of the REBS system.

In the development of the regional consumption module, it was decided that more formal and better-developed regional models existed for projecting population and employment than for energy consumption. Indeed, regional analysis might reveal more about regional growth and development (excluding energy effects) than about regional energy consumption. This, of course, reflects the interest of past researchers (i.e., energy has only recently become an "interesting" issue). Therefore, in the development of the REBS consumption model, it was decided to use Oak Ridge National Laboratory's (ORNL's) regional population and employment projection model (MULTIREGION) as a base for developing the energy forecasts (Olsen et al. 1975). Thus, regional model activity was forecasted and then relatively simple procedures were used to convert the activity forecasts into derived demand for energy. The basic assumption is that the primary determinant of differences in regional energy consumption is the underlying regional structure of activity, rather than price differences. While this, of course, is an "heroic" assumption, it seems plausible that this should provide a first-order approximation and that the regional price differentials might be of a second-order nature. The current model projections are constrained to the projections of a national model, Project Independence Evaluation System (PIES) (Federal Energy Administration 1976), which does include estimates of price responses. As the PIES model reflects price differentials by Federal Energy Administration (FEA) regions, the assumption actually invoked in the REBS is that only within these aggregate regions do price differentials play a small part in explaining variations in energy consumption.

The regional projections in the current study are based on the recent "mid-mid" scenario of the PIES. The mid-mid scenario represents a mid-range forecast of economic activity combined with a mid-range energy consumption scenario; therefore, the term "mid-mid" (U.S. Department of Energy 1977).

D.1.1 MULTIREGION

Oak Ridge National Laboratory's MULTIREGION model, which utilizes the Bureau of Economic Analysis (BEA) area as the functional regional unit, provides the regional economic and demographic base for the energy consumption projections. MULTIREGION is a formal econometric/simulation model for projecting regional activity based on a national forecast. The details of the model and comparison with several alternatives are described elsewhere (Olsen et al. 1975). In this report, only several key structures of the model which make it especially useful for the REBS system will be presented.

The MULTIREGION framework is designed to project general regional trends rather than year-to-year fluctuations; thus, the model operates and produces projections of population and employment characteristics in five-year intervals. The model allows for different temporal adjustments in the equilibrating process which balances population/labor force participants and employment opportunities. Initial projections of population growth, migration, and employment growth are balanced within the five-year period. However, other forces, such as changing industrial composition, age structure of the population, and migration and employment opportunities can have long-term and continuous effects over a series of five-year time intervals. An example of the sector detail of MULTIREGION employment projection is presented in Table D.1 with national employment and population forecasts used in the current analysis.

Table D.1. U.S. Total Population and Employment Projections Based on MULTIREGION BEA Forecast (numbers of persons)

Sector	1975	1985	1990
Agriculture	2,457,151	2,196,955	2,002,958
Forestry and fish	101,198	115,998	119,998
Metal mining	87,799	86,999	82,999
Coal mining	142,498	151,998	147,998
Crude oil and gas	242,198	222,998	203,998
Nonmetal mining	111,396	115,996	111,996
Construction	4,804,316	5,806,918	6,014,918
Food and kindred	1,767,754	1,814,955	1,757,964
Textiles	859,194	897,994	874,994
Apparel	1,259,268	1,395,949	1,392,953
Printing and publishing	1,246,480	1,515,956	1,591,951
Chemicals	1,044,995	1,319,972	1,411,954
Lumber and furniture	948,794	1,023,995	1,009,994
Machinery	1,974,850	2,253,945	2,301,946
Electric machinery	2,043,046	2,630,934	2,835,933
Motor vehicles	894,695	1,034,994	1,057,994
Transportation equipment	1,134,291	1,138,992	1,115,990
Paper	706,794	838,994	862,994
Petro refining	249,896	268,995	263,996
Primary metals	1,098,291	1,067,991	1,016,995
Fabricated metals	1,738,448	2,011,953	2,065,950
Other manufacturing	2,790,628	3,392,918	3,543,921
Rail	524,994	414,995	358,995
Truck and warehouse	1,137,191	1,406,972	1,481,970
Transportation service	1,133,791	1,367,982	1,436,983
Communications	1,199,990	1,619,959	1,775,947
Utilities	1,322,079	1,595,967	1,668,962
Wholesale	3,294,329	4,045,321	4,206,728
Retail	13,177,521	16,181,517	16,827,104
Fire	4,275,813	5,697,922	6,177,915
Lodge and personal service	2,384,944	2,532,938	2,482,944
Business and repair	2,975,731	4,375,919	4,988,926
Amusement service	685,695	834,994	862,995
Private households	1,040,594	895,994	802,995
Professional	15,622,014	21,489,728	23,626,560
Public administration	4,463,326	5,785,917	6,329,913
Armed forces	1,678,736	1,566,754	1,566,754
Population	213,444,976	234,063,955	245,073,933

MULTIREGION generates BEA area projections of male and female populations for 16 age groups, although the REBS system currently utilizes only the total population projections. Employment is forecasted for 37 sectors categorized by basic structure (resource oriented — 6 sectors, manufacturing industries — 15 sectors, and service oriented — 16 sectors). The structure of the projection technique for each sector is determined generally by the basic structure. Resource-oriented industries are projected within a shift-share framework, manufacturing industries by a regional advantage approach, and service-oriented industries by a regional base model.

MULTIREGION recognizes interregional linkages through an economic potential (distance) approach, such that the projections for a given BEA area are determined in part by the level of activity in nearby areas. Similarly, each industry is linked spatially and structurally to other industries that are purchasers or suppliers of inputs to the industries' product. Interregional migration and labor force participants are both incorporated in the model and related to underlying changes in regional employment potential.

Importantly, MULTIREGION was designed as a simulation model and thus can provide base forecasts which can be updated quickly and easily, as well as a variety of regional forecasts based on different national economic projections. MULTIREGION was designed to use projections from the Inforum (Almon et al. 1974) national input-output model as the driving force for the regionalization. This choice provides MULTIREGION with the potential interindustry changes that come about under different assumptions about national economic forecasts. Other national projection models, however, can easily be used. The projections used in the current analysis have been made based on Office of the Bureau of Economic Research and Statistics (OBERS) national projections (U.S. Water Resources Council 1974).

The economic forecasts which are used in the PIES model are based on the Data Resource Incorporated (DRI) national and state forecasts (Federal Energy Administration 1976). To the extent that these two national projections differ, an inconsistency exists between the PIES energy projections and the regional projections presented here. However, it is not felt that this difference in the national series will result in serious problems in the patterns of regional energy consumption.

D.1.2 County Projection Algorithm

For the REBS systems to be able to provide projections for a wide variety of regions, it was necessary to increase the regional detail available from the MULTIREGION-BEA forecasts. Consequently, a computer algorithm that allocates the BEA area projections provided by MULTIREGION to the constituent counties of each BEA area has been developed. The model retains the detailed age/sex cohort structure and employment categories used in MULTIREGION. County population projections are made using 1970 census estimates of county populations by age/sex cohort (as a base for the first forecast period) and then aging the population - similar to the procedures used in MULTIREGION. Any differences in the projected BEA total (for each cohort) as computed from the summation of county forecasts and the MULTIREGION forecasts are allocated in proportion to each county share of the BEA population. These county projections are then used as the base for the next forecast period.

Similarly, employment projections are initialized by 1970 county/sector employment data, with any growth by sector allocated proportionally to the past employment patterns by sector. If a "new" industry appears in the BEA forecast, it is allocated on the basis of total county employment. Although the procedure is somewhat simple, it does allow for differential county growth, depending on which industries are growing in the BEA area.

Currently, there is no tie between the county population projections and employment growth. Consequently, jobs may be expanding in one county while presumably these workers may be living in other counties within the BEA area. Thus, we maintain the concept of the BEA area as the relevant region for interaction between supply and demand for labor rather than impose a county-level equilibrium. Although a formal balance between population and employment (by location) should not be imposed at the county level, a relationship between the two clearly exists. How counties develop within the framework of a multicounty environment is one of the research areas we wish to develop within the MULTIREGION framework. Such research, of course, is necessary before any significant improvement on the county-level projection model can be realistically expected. Any county projection model needs to be constructed within the framework of the broader regional activities in which a county is enmeshed, which suggests the use of a step-down approach. This approach forecasts for BEA areas and then uses these estimates of "regional" growth to determine the probable patterns of the constituent counties.

The current version of the model needs much more research and development before reliable detailed forecasts at the county level can be presented. Nonetheless, the model is currently an adequate tool to facilitate the remapping of regional forecasts from one scheme to another (e.g., converting BEA forecasts to state, aggregated water subarea (ASA), or air quality control region (AQCR) projections by disaggregating BEA projections to counties and adding up all counties to the desired region).

D.1.3 Regional Energy Consumption in the Final Demand Sectors

Energy consumed by final end uses in the residential, commercial, industrial, and transportation sectors is estimated on the basis of the projected regional employment and population model discussed above. The energy consumption submodel projects regional energy demand using base-year energy use patterns and forecasted economic activity. These estimates are generated separately for each fuel considered and for each of the employment sectors projected by the MULTIREGION model and the residential sector represented by total population. The regional unit utilized may be the county or any aggregate of counties. Because of the large number of fuels usually considered in any given analysis, multicounty regions are commonly regarded as the unit of analysis to facilitate the data processing. Such multicounty units are defined as the largest grouping of counties that will allow simple aggregation to the different grids required in a study. (For the current analysis, all counties in the same state, ASA, and AQCR are aggregated to form the regional unit of analysis.)

For the present discussion, estimates for an individual county are considered, although county data usually are not estimated as a practical matter. Using the county-level forecast of population and detailed employment provided by MULTIREGION and the county algorithm, we compute a demand for a fuel by the following simple equation;

$$\text{Demand} = \left(\frac{\text{Energy}}{\text{Employment}}\right)_{\text{Base}} \times \text{Employment}_{\text{Forecast}} \cdot$$

The forecasted employment population is multiplied by the per worker (capital) consumption exhibited in a base year. Currently, energy per worker indices have been computed on the basis of 1971-1972 data using state data from a variety of sources. (The data sources are discussed in each of the data volume supplements in the series *Energy Availabilities in State and Local Development*. The indices are currently being updated with 1975 data.) Thus, regional differences assumably are represented in the historic state data. Moreover, energy consumption patterns by industry are similar within individual states.

A simple interpretation of the procedure is that the demand estimates represent the amount of an energy product required if industries maintain their historic consumption patterns but have the activity (employment) forecasted. The individual demands can then be summed to the sectoral/ regional level contained in a scenario forecast. Because the scenario projections usually imply a change from historic consumption patterns, the sum of the demand estimates will need to be adjusted to match the projected energy consumption in the scenario. With the current procedure, each of the component demands is simply adjusted proportionately so that their total will equal the projected total in the controlling scenario.

Current research is directed toward developing state and substate equations to estimate and forecast energy per worker ratios for two-digit manufacturing industries so that the relative importance of the proportionate adjustment to the controlling scenario may be relaxed. Such an extension seems important from two aspects that have been raised by our experience with the simple procedure. First, the assumption of homogeneity within states appears untenable in some states, and substate information may be required. Whether intrastate differences are caused by price differentials or other factors still needs to be determined. Second, the potential for differential price response in each industry seems a likely occurrence that needs to be incorporated into the analysis. Nonetheless, the simple algorithm has presented us with a useful tool to estimate both historic substate data as well as scenario projections (Rice and Vogt 1977).

D.1.4 Regional Air Quality Impacts

Having estimated the regional patterns of fuel consumption, as described previously, projections for air emissions can be derived using standard emission loading coefficients. The levels of various emissions generated by the consumption of particular fuel forms are presented in Table D.2. These coefficients represent the permissible level of emissions for 1985 for each of the basic fuel types: liquids, gases, and solids. Because a single standard was used for all regions in the United States, it is assumed in the resulting projections that all regions will meet these emission requirements, regardless of current practices.

Table D.2. Emission Coefficients for Fossil Fuel Boilers

	Coefficients (lb/million Btu)		
	Total Suspended Particles	Sulfur Dioxide	Nitrogen Oxides
Liquids	0.1	0.8	0.3
Gases	0.0	0.0	0.2
Solids	0.1	1.2	0.7

From USEPA (1971).

The actual projections of fuel consumption and associated residuals were based on a very detailed categorization of fuel type and end use. The definitions of the separate fuels for which emis-emissions are estimated are available as supporting documentation (in the form of computer tapes or listings) from ORNL.

Base-case estimates of fuel consumption and emissions for total suspended particles (TSP), nitrogen oxides (NO_x), and sulfur dioxide (SO_2) are presented in Table D.3 for each of the major sectors in the United States. The emissions levels presented in Table D.3, however, are those for fossil fuel boilers, and consequently, their use for the residential and commercial sector is an approximation to the actual levels. Because of the very large difference in the potential emissions levels per Btu in consumptions of fuels in transportation use (especially NO_x), the emissions levels for the transportation sector are not reported. With appropriate coefficients for fuel use in the transportation sector, these emissions levels could be calculated within the current versions of the model. Similar tables were prepared for each AQCR, ASA, and state and were provided to the various study groups in the project for detailed interpretation and analysis.

Table D.3. Projections of Fuel Consumption and Residuals for the United States

		Residuals (Millions of Pounds Per Year)		
	Total Fuel Consumption (Trillions of Btus Per Year)	Total Suspended Particles	Sulfur Dioxide	Nitrogen Oxides
	1985			
Industrial[a]	26,888	931	8,585	6,329
Utility	31,692	1,923	21,748	12,557
Residential and commercial[a]	19,986	636	4,537	3,317
	1990			
Industrial[a]	32,278	1,133	10,194	7,379
Utility	38,174	2,188	25,170	14,572
Residential and commercial[a]	21,000	685	4,870	3,336

[a]Includes electricity consumption but excludes the transportation sector (see text).

D.1.5 Fuel Consumption and Air Emissions in the Electric Utility Sector

Fuel consumption and air emissions from electricity generators are estimated separately from the other sectors. A detailed approach is used for electric utilities because of the importance of the sector as well as the availability of more refined information than the estimated regional employment.

The regional forecasts of electrical generation are primarily based on the utilities' announced plans for capacity expansion and plant retirements. The scheduled capacity of the electric utility sector, as reported to the Federal Power Commission (FPC), is available on computer tape (catalogued as the Generating Unit Reference File) from the FPC in Washington, D.C. It is noted that ORNL has made many revisions and corrections to the original data and has spatially located many plants for which the county location was not indicated on the original computer tape.

The scheduled capacity as reported by the utility industry, however, must be reconciled with scenario forecasts. This task is accomplished by using the scenario aggregate projections of generation, capacity, and fuel consumption as regional control totals. The utilities' planned expansion for each region can then be compared with the scenario forecast for selected prime mover and fuel-type categories.

To compare actual utility plans and a scenario, information as to each generation source needs to be similarly structured. Consequently, a procedure was developed to classify each plant according to its prime mover and major fuel consumed. The categories considered are presented in Table D.4.

Table D.4. Classification of Electric Generation by Prime Mover and Fuel Type

Generation Class			Generation Characteristics[a]	
Class	Fuel Type	Prime Mover	Capacity Factor[b] (%)	Heat Rate[c] (Btu/kWh)
01	Coal	Conversional steam	62	10,247
02	Coal	Advanced (combine cycle)	36	9,750
03	Oil	Conventional steam	30	10,478
04	Oil	Combustion turbine	12	9,623
05	Gas	Conventional steam	33	10,386
06	Gas	Combustion turbine	6	15,845
07	Hydro	Conventional	58	11,000[d]
08	Hydro	Pump storage (and peaking)	9	11,000[d]
09	Nuclear	Conventional steam	65	11,000[d]
10	Nuclear	Advanced (breeder and high-temperature gas)	54	11,000[d]
11	Other	Geothermal	80	11,000[d]
12	Other	Solar	42	11,000[d]
13	Other	Waste heat (steam turbine)	36	11,000[d]
14	Other	Refuse (steam turbine)	36	11,000[d]

[a]1985 projections (United Stages averages); capacity factors and heat rates have been computed from the PIES Mid-Mid Scenario.

[b]The capacity factor measures the percent of forecasted annual generation to potential generation on the basis of installed capacity.

[c]The heat rate measures fuel consumption for the generation of electricity in Btu's of fuel consumed per kilowatt hours generated.

[d]Fossill fuel equivalent.

To modify the planned expansion of the utilities, a simple siting scheme was employed. For each of the substate regions considered in the demand analysis, an estimate of scheduled capacity was obtained by aggregating the FPC forecasts of each utility in the region, adjusting for annual retirements and proposed facilities.

The siting analysis then requires two basic steps. First, where the projects indicate the number of plants for a generating technology will be overbuilt, the scheduled capacity in all subareas within the census region was proportionally decreased. Each technology is treated separately, and changes in capacity are allocated regionally independent of excess demand. Second, where additional units are required, according to a scenario's projections, these plants are located proportionately to scheduled capacity.

A detailed siting analysis should consider many other factors in adjusting to scenario capacity. Oak Ridge National Laboratory has developed several extensive procedures to conduct such analyses at the county level; these procedures consider population density, water availability, seismic risk, and air quality standards, among other variables (for example, Dobson et al. 1977). In general, however, such a detailed approach is not done in the framework of the standard REBS model. Any given region can be analyzed in more detail, of course, on the basis of the information presented in these tables. To facilitate such a comparison, the standard output indicates the amount of adjustment made in each region.

Using utility-planned expansions, both generation and fuel consumption can be estimated. These forecasts, however, must be consistent with the "average technology" embedded in the controlling scenario. The assumption of an "average technology" in the electric utility sector is summarized in the assumed values for heat rates and capacity factors. For each category of generating technology considered, regional averages for heat rates and capacity factors are derived from the scenario projections.

Capacity factors indicate the average amount of generation relative to potential capacity. Turbine generators, for example, are used primarily to satisfy peaking requirements, operate infrequently, and have low capacity factors. Nuclear plants and conventional fossil-fired steam plants are generally base-load plants with high average utilization rates and high-load factors. Table D.4 presents as an example the national values for heat rates for each plant type as computed from the PIES mid-mid forecasts. The actual projections used regional (FEA region) estimates derived from the PIES scenario.

The average capacity factors are applied to the planned capacity of each plant to determine the probable generation of electricity. The plant estimates are then aggregated to provide total generation for each category in each control region.

Fuel consumption for each control region is estimated using average heat rates also computed from the scenario. A heat rate indicates the amount of fuel consumed to produce one kilowatt hour of electricity. By applying these heat rates to the plant generation estimates, total fuel consumption for each plant is derived. The estimates of fuel consumption, electric generation, and capacity are then constrained to the scenario projections.

Because of the nature of the approach used in our analysis, two considerations should be kept in mind when examining specific regional forecasts. The first relates to the use of "average" regional characteristics and the second to the implications of the simplified siting scheme.

Aggregate heat rates and capacity factors are used to maintain consistency with the controlling scenario. However, individual plants may have historically deviated from these averages. For example, a plant may be used to satisfy intermediate load requirements for a utility, although it is classified as a base-load plant. Each plant is treated as an "average" plant in the analysis. It would be extremely difficult to retain and use historical characteristics for each plant in the future. Consequently, assuming that each plant has average regional characteristics is the only feasible approach. The projections should remain consistent with the scenario, though individual plants may be incorrectly estimated. If a particular plant has a significantly different capacity factor and heat rate, its generation and fuel use may be misrepresented. For those regions in which there are few plants, the forecasts should be considred with utmost care. For those regions in which there are several plants, the totals presented for the region are more reliable.

The changes in the scheduled capacity planned by utilities and those necessitated by the PIES scenario are reported in Table D.5. The total changes for the United States (with generation capacity aggregated by type of fuel inputs) are listed as a summary example of the total modifications necessary to meet the scenario (Table D.5). Similar tables have been produced for each of the regional concepts used in the study.

In conclusion, the forecasts presented by the simple procedure for the electric utility sector provide baseline estimates of "average" characteristics consistent with the controlling scenario using the schedules of the utilities. When considering specific regional projections, the projections should be complemented by region-specific information.

The 16 regional estimates of fuel consumption by generation technology (derived above) and the emission coefficients (reported earlier in Table D.2) can be used to estimate the level of emissions. The estimates of fuel consumption and implied emission levels for the United States as a whole are presented in Table D.3.

The projections listed in Table D.3 are shown as an example; similar information has been provided to individual study groups for the various regional concepts required for analysis.

Table D.5. Scenario Adjustments to Scheduled Capacity in the United States

Fuel Type	Capacity (1000 MW) Scheduled by Utilities 1985	Scheduled by Utilities 1990	Modifications Made to Meet Scenario 1985	Modifications Made to Meet Scenario 1990
Coal	293.6	301.5	-10.8	40.7
Oil	154.6	154.2	24.1	47.3
Gas	69.7	69.3	9.4	11.4
Hydro — conventional	70.5	70.5	0.7	5.3
Hydro — pump	18.5	22.2	2.6	6.8
Nuclear — conventional	169.8	199.3	-70.8	-35.3
Nuclear — advanced	1.5	2.7	-1.5	-2.7
Geothermal	2.2	2.2	0.6	1.4
Solar	0.0	0.0	0.0	0.0

D.2 ESTIMATES OF THE AIR QUALITY IMPACTS OF COAL CONVERSION IN THE INDUSTRIAL SECTOR

Estimates of the amount of oil and natural gas consumption that would be converted to coal in the industrial sector were provided by the Department of Energy (DOE). These estimates (Tables D.6 and D.7) were based on an extension of the PIES model and provide separate projections of total oil and gas conversion for existing and new plants in each FEA region. (These projections were made by DOE specifically for the current analysis.)

D.2.1 Energy Consumption and Employment Changes

The aggregate estimates of fuel conversion were regionalized on the basis of the historic regional patterns of oil and natural gas consumption in the industrial sector using the methodology described earlier. To handle existing and new plants separately, two analyses were required for each projection year.

For this study, existing plants were defined by DOE as installations that would be brought on line by 1979. Existing plant fuel conversions were regionalized using the projected employment patterns for 1980 weighted by the historic industry consumption indices of residual fuel oil and natural gas consumption. The amount of decreased consumption of natural gas and oil was then assumed to be replaced by an equivalent amount (Btu's) of coal. The 1980 industrial employment patterns were used in both the 1985 and 1990 estimates of fuel conversion for existing plants.

To capture the regional impact of new plants that would be affected by the coal conversion program, an estimate of regional growth by industry was necessary. For the 1985 forecast, the employment growth between 1980 and 1985 was computed using the MULTIREGION projections. The 1990 estimates of new activity were based on the projected increase in regional employment between 1985 and 1990. These net changes in regional employment were then used as weights in the standard regionalization procedure, as described above, to estimate the regional fuel conversions for new plants. The projections represent the amount of projected increases in oil and natural gas consumption (due to increased economic activity, assuming regions followed their historic energy consumption patterns) that would be converted to coal.

Thus the estimates of regional conversion are based on projected changes in employment (from MULTIREGION) and historic energy consumption patterns similar to the base-case forecasts. Because the legislative effects of the coal conversion relate directly to fuel combustors, however, regional variations in plant size, as well as combustor size and composition, may bias the employment-based estimates. Consequently, each of the projected regional (AQCR) conversions from the employment-based model was cross-checked for feasibility with historic industrial plant-specific data. In several cases, limits on the amount of conversion allowed in a region were established on the basis of the historic plant structure information. When limits were imposed on an AQCR, the amount of oil or natural gas above the limit initially allocated to the region was redistributed to other AQCRs within the FEA region. The nature of these limits is described more fully in the next section.

Table D.6. Maximum Fuel Conversion Achieved in 1985 by Coal Conversion Regulatory Program[a]

Federal Region	Quads			
	Existing		New	
	Oil	Gas	Oil	Gas
1	0.008	0.001	0.026	0.001
2	0.003	0.002	0.025	0.007
3	0.012	0.003	0.028	0.004
4	0.017	0.044	0.070	0.044
5	0.069	0.035	0.009	0.003
6	0.011	0.111	0.141	0.506
7	0.003	0.015	0.006	0.001
8	0.000	0.005	0.009	0.000
9	0.001	0.021	0.059	0.043
10	0.001	0.001	0.007	0.000
Total (United States)	0.126	0.238	0.380	0.609

From Table 3.2.

[a]Assumes no economic exemption unless coal is 44 percent more costly than use of imported oil. Also, best available control technology (BACT) on 25 MW, trend long baseline, house screen (excludes units smaller than 10 MW and existing noncoal capable), AQCR screen. Oil price is weighted average of distillate and residual oil plus $0.021 per million Btus (to account for COET).

D.2.2 Limits Imposed on the Regional Disaggregation of Fuel Conversion

Several limits were imposed on the projected oil and gas conversion for each AQCR. The data used to establish these limits was the Major Fuel Burning Installation (MFBI) data file that was compiled by the FEA in 1975. These 1974 data gave the amount of oil, gas, and coal consumed in industrial combustors with design-firing rates greater than 99×10^6 Btu/hr (29 MW).

The quantity of oil or gas conversion to coal in existing industrial plants was limited to the quantity consumed in large combustors (greater than 99×10^6 Btu/hr) in 1974. For example, if an AQCR did not contain any large combustors, no conversion was allowed. If the quantity of oil or gas consumed in a region was less than the projected conversion, the conversion was limited to that consumed in 1974. If the amount of oil or gas consumed was greater than the projected conversion for 1985 but less than the total conversion projected for 1985 and 1990, the projected conversion for 1985 was permitted and the 1990 conversion limited to the residual left after subtracting the projected 1985 conversion.

Table D.7. Industrial Oil and Gas Conversions to Coal Achieved by 1990 Regulatory Program[a]

Figures Are Given in 10^{12} Btus

Region	Existing[b]			New[c]			Total		
	Oil	Gas	Total	Oil	Gas	Total	Oil	Gas	Total
1	1.7	0.2	1.9	16.7	3.1	19.8	18.4	3.3	21.7
2	0.9	0.6	1.5	19.5	7.3	26.8	20.4	7.9	28.3
3	1.0	1.7	2.7	25.7	11.7	37.3	26.7	13.4	40.1
4	3.4	20.0	23.4	84.0	38.5	122.5	87.4	58.5	145.9
5	0.0	2.7	2.7	22.4	3.7	26.2	22.4	6.4	28.9
6	3.7	199.3	203.0	108.5	502.7	611.3	122.2	702.0	814.3
7	0.0	1.8	1.8	2.5	10.4	12.9	2.5	12.1	14.7
8	0.0	1.3	1.3	6.0	4.7	10.7	6.0	6.0	12.0
9	6.9	7.4	14.3	15.1	50.1	65.2	22.0	57.5	79.5
10	0.0	0.3	0.3	7.2	0.0	7.2	7.2	0.3	7.5
Total (United States)	17.6	235.3	252.9	307.5	632.4	939.9	335.2	867.7	1192.8

From Table 3.2.

[a]BACT on 25 MWe, trend long baseline, AQCR screen.

[b]Existing units include conversion due to mixed fuel firing only. Storage space and 500-unit DOE manpower constraints accounted for.

[c]"New" units include new boilers of capacity greater than 10 MWe that are economically justified in converting to coal when the opportunity fuel cost is imported price of oil (average of residual and distillate oil plus COET).

Limits were also imposed on oil and gas conversion for new facilities. For this case, the basic model for projecting energy consumption in new facilities assumed that the location of these facilities followed existing industrial locations. Thus, no oil or gas conversion was permitted in AQCRs that do not contain large combustors. A second limitation on new facilities was that projected conversions which amounted to less than 400 x 10^9 Btu/year were not considered. The rationale for this restriction is that 400 x 10^9 Btu/year would represent a load factor of only 45 percent on the smallest combustor being considered and that such an addition would probably not be added or else a smaller unit would be built.

D.2.3 Projected Increased Emission Due to the Coal Conversion Program

Using the limits of allowable oil and natural gas conversion, a second-pass estimate of oil and natural gas that could be converted to coal was performed. The decrease in emissions resulting from the decreased uses of natural gas and residual oil was then computed for each region (using the emission coefficients tabulated earlier). Offsetting this reduction was the increase in emissions due to the shift toward coal. For each region (AQCR, ASA, and state), tables have been provided showing the regional changes in fuel consumption and emissions and a summary of the net increase in emissions due to increased use of the coal. In Table D.8, for example, the projections for the United States are presented. It might be noted that the net increase in emissions for the United States is a small percent of the total base. However, the impact for particular small regions may be much more significant. Interpretations of the regional impacts of the program are addressed by ANL and are reported elsewhere.

Table D.8. Net Increase in Emissions due to Industrial Coal Conversion in the United States

	Increased Coal Consumption[a] (Trillions of Btus Per Year)	Net Increase in Emissions (Millions of Pounds Per Year)		
		Total Suspended Particles	Sulfur Dioxide	Nitrogen Oxides
	1985			
New plants	989	61	883	456
Existing plants	363	24	335	169
Total		85	1218	625
Increase,[b] %		9	14	10
	1990			
New plants	940	63	882	439
Existing plants	253	24	289	125
Total		87	1171	564
Increase,[b] %		8	11	8

[a]The increased coal consumption is offset by an equivalent reduction of oil and natural gas consumption.

[b]Percent increase is relative to projected emissions in the industrial sector for the base case.

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APPENDIX E. DESCRIPTION OF COAL FUEL CYCLE AND RELATED HEALTH AND SOCIOECONOMIC CONSIDERATIONS

E.1 COAL RESOURCES AND PRODUCTION

E.1.1 Classification and Composition of Coal

Several different systems have been proposed for the classification of coal. The one most commonly used in the United States, the American Society for Testing and Materials (ASTM) rank classification system, is based on the degree of lithification and metamorphism of plant material (Rees 1966). According to this system, rank is determined primarily by the percentage of fixed carbon and the heat value (Btu* content) of the coal, calculated on a mineral-matter-free basis. Knowledge of moisture content and volatile material percentages is necessary for the calculation of fixed carbon percentages. Other determinations commonly made on coal samples include the ash, pyritic sulfur, and total sulfur contents. The various coals are classified in Table E.1 and compared by heat value, moisture content, and percentage of volatile matter in Figure E.1.

E.1.1.1 Ranks of Coal

Lignite is the lowest rank of coal. It has the lowest heat value per unit weight (6300-8300 Btu/lb) because it contains large amounts of water--up to 50 percent (American Society for Testing and Materials 1977). Larger quantities of lignite than of any other coal type would be needed to produce a specified amount of energy. The high moisture content makes lignite difficult to store or transport. Because it weathers upon exposure to air, lignite is generally used near the areas where it is mined.

Subbituminous coal contains less moisture (20 to 30 percent) (American Society for Testing and Materials 1977) and more carbon per pound than lignite. Its heat values range from 8,300 to 11,500 Btu/lb (American Society for Testing and Materials 1977).

Bituminous is the most abundant and widespread rank of coal in the United States (Averitt 1973). Heat values range from 10,500 to 14,000 Btu/lb (American Society for Testing and Materials 1977). Bituminous coal is commonly used for industrial purposes, steam generation, and space heating. Some bituminous coals, especially in the east, will form a coherent, cellular, porous, carbonaceous residue called coke when they are heated to a temperature of 816°C (1500°F) or greater. Coke is used primarily as a blast furnace fuel. Both coking and non-coking coals can be used for power generation.

Anthracite has the lowest moisture content, lowest percentage of volatile materials, and highest percentage of fixed carbon and highest heat content of all coals. The major uses for anthracite in 1975 were space heating, electric power generation, and miscellaneous uses in the primary metals industry (Westerstrom 1975).

E.1.1.2 Ash in Coal

Ash is the noncombustible residue that remains when coal is burned. Ash is formed by chemical changes in extraneous mineral matter or in inorganic and organic plant material during the combustion of coal. The extraneous mineral materials often include clay, calcite, pyrite, marcasite, and inorganic sulfides, chlorides, and fluorides (Rees 1966). Problems with efficient combustion, disposal of ash, boiler slagging, etc. increase in direct proportion to the ash content of the coal (Rees 1966).

E.1.1.3 Sulfur in Coal

Sulfur occurs in coal as sulfate, organic sulfur, and pyritic sulfur (Rees 1966). Perhaps 40 to 80 percent occurs as the minerals of pyrite and marcasite (FeS_2). The next most abundant source

*To convert Btu's to joules, multiply by 1054.8.

Table E.1. Classification of Coals by Rank[a]

Class	Group	Fixed Carbon Limits (%)[b] ≥	Fixed Carbon Limits (%)[b] <	Volatile Matter Limits (%)[b] >	Volatile Matter Limits (%)[b] ≤	Calorific Value Limits (btu/lb)[c] ≥	Calorific Value Limits (btu/lb)[c] <	Agglomerating Characteristic
	Meta-anthracite	98	..	..	2	...	...	
Anthracitic	Anthracite	92	98	2	8	...	...	Nonagglomerating
	Semianthracite[d]	86	92	8	14	...	...	
	Low-volatile bituminois coal	78	86	14	22	...	...	
	Medium-volatile bituminous coal	69	78	22	31	...	...	
Bituminous	High-volatile A bituminous coal	..	69	31	..	14 000[e]	...	Commonly agglomerating[f]
	High-volatile B bituminous coal	..	..	..	..	13 000[e]	14 000	
	High-volatile C bituminous coal	..	..	..	..	11 500	13 000	
						10 500	11 500	Agglomerating
	Subbituminous A coal	..	..	..	..	10 500	11 500	
Subbituminous	Subbituminous B coal	..	...	..	..	9 500	10 500	
	Subbituminous C coal	..	..	..	..	8 300	9 500	
								Nonagglomerating
Lignitic	Lignite A	..	..	..	..	6 300	8 300	
	Lignite B	..	..	..	..	...	6 300	

Modified from American Society for Testing and Materials (1977).

[a]This classification does not include a few coals, principally nonbanded varieties, which have unusual physical and chemical properties and which come within the limits of fixed carbon or calorific value of the high-volatile bituminous and subbituminous ranks. All of these coals either contain less than 48 percent dry, mineral-matter-free fixed carbon or have more than 15,500 moist, mineral-matter-free British thermal units per pound.

[b]Dry, mineral-matter-free basis.

[c]Moist, mineral-matter-free basis. Moist refers to coal containing its natural inherent moisture but not including visible water on the surface of the coal.

[d]If agglomerating, classify in low-volatile group of the bituminous class.

[e]Coals having 69 percent or more fixed carbon on the dry, mineral-matter-free basis shall be classified according to fixed carbon, regardless of calorific value.

[f]It is recognized that there may be nonagglomerating varieties in these groups of the bituminous class, and there are notable exceptions in high-volatile C bituminous group.

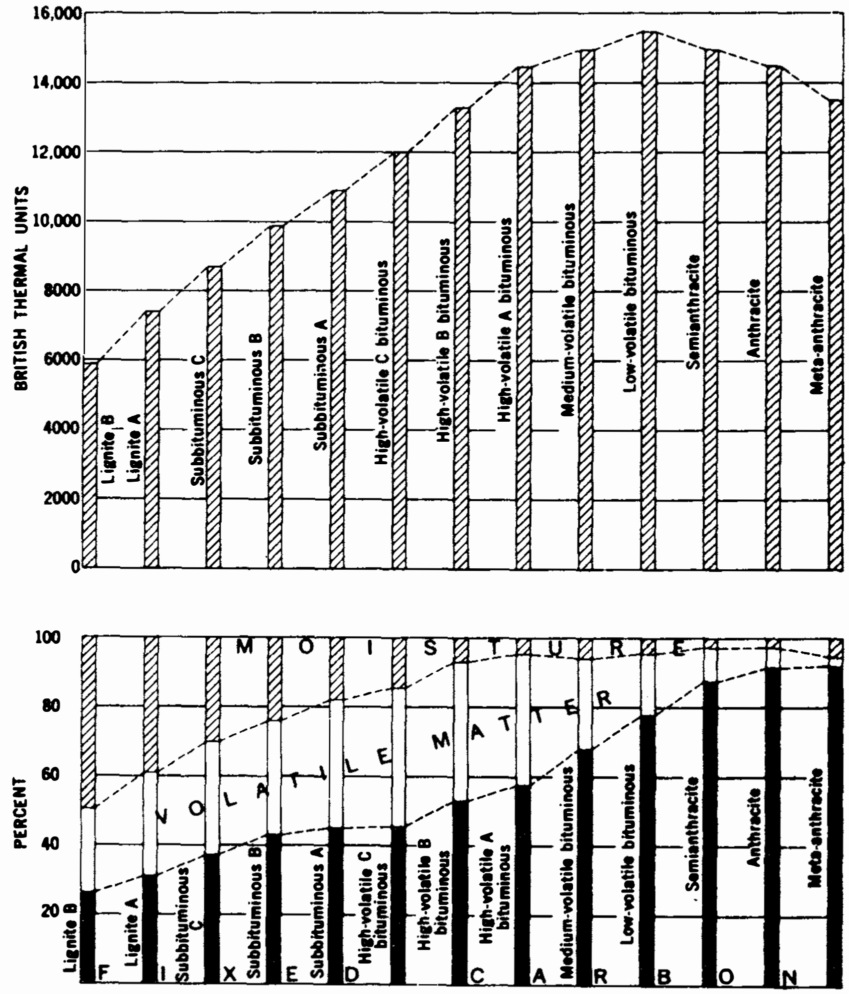

Fig. E.1. Comparison on Moist, Mineral-matter-free Basis of Heat Values and Proximate Analyses of Coal of Different Ranks. From Averitt (1975a).

is organic sulfur from the original plant material. Sulfates comprise only a very small percentage of the total sulfur. They occur as hydrous ferrous sulfate ($FeS_4 \cdot 7H_2O$) and as gypsum ($CaSO_4 \cdot 2H_2O \cdot$) (Walker and Hartner 1966). The principal application of sulfur content measurements is in the determination of whether coal cleaning or flue-gas desulfurization will be necessary to meet EPA air quality requirements. Pyritic sulfur is relatively easy to remove from coal by specific-gravity separation methods (described in Sec. E.2.4); organic sulfur is difficult to remove.

E.1.2 Coal Reserves and Resources

Coal-bearing rocks underlie about 13 percent of the land area of the conterminous United States (Fig. E.2) (Averitt 1975a). Many of the coal deposits occur in broad shallow basins. For example, coal in the Appalachian basin is generally less than 914 m (3000 ft) deep and covers a seven-state area. Interior basin coals are usually less than 610 m (3000 ft) deep, Great Plains coals less than 457 m (1500 ft) deep, Powder River coals less than 610 m (2000 ft) deep, San Juan coals less than 1219 m (4000 ft) deep, and Raton Mesa coals less than 610 m (2000 ft) deep. Deep coal deposits exist but are less common. Examples of these include the coals of the Unita Basin, which are 1829 m (6000 ft) deep; the Green River coals, which may be as deep as 4572 m (15,000 ft), and the Wind River and Big Horn coals, some of which are 6096 m (20,000 ft) deep.

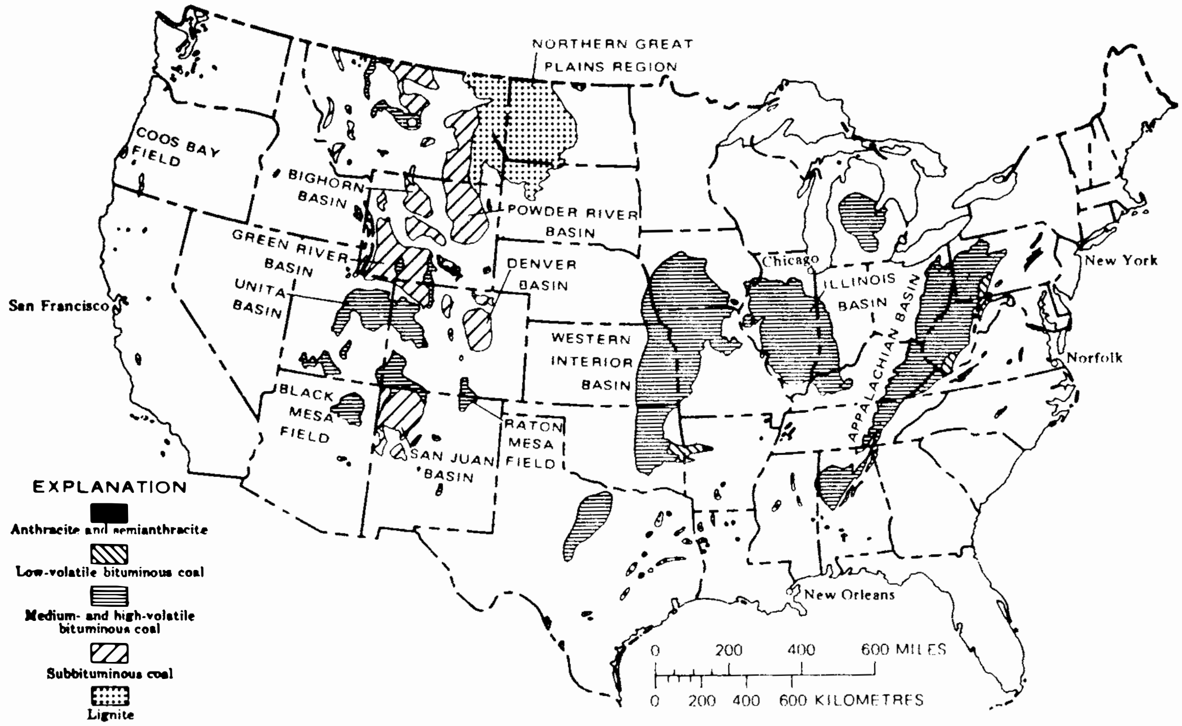

Fig. E.3. Coal Fields of the Conterminous United States. From Averitt (1975a).

According to the U.S. Bureau of Mines (1975a) definitions, a coal deposit can be considered as part of the nation's resources if its extraction is currently or potentially feasible. Reserves are that portion of the identified resources (resources of known location, quality, and quantity) which can be legally (i.e. the land is not closed to mining) and economically extracted at the time of determination. Resources which are believed to exist in a mining district under known geologic conditions but which are unconfirmed are called hypothetical resources.

Whether or not a coal deposit can be economically mined depends upon the coal market, the quality and quantity of the coal, and the mining method to be used. To facilitate adapting to changes in coal economics, the U.S. Geological Survey has suggested that coal resources and reserves be calculated and reported in three categories of seam thickness and three of overburden thickness termed major resource categories, and shown in Figure E.3 (Averitt 1975b). Coal quantities are specified by weight, usually in short tons. Thus the coal's specific gravity, which is a product of rank and composition, must be determined for each seam in order to quantify a coal resource. As of January 1, 1974, the United States contained the following identified resources less than 941 m (3000 ft) deep (Averitt 1975b):

Anthracite and semianthracite	19,662 million short tons*
Bituminous coal	747,357 million short tons
Subbituminous coal	485,766 million short tons
Lignite	478,134 million short tons

Both the reserves and the resources are quantified for each demand region in Volume I, Section 4.5.

Because not all coal can be recovered by current economical methods, coal reserves are depleted at a rate greater than the actual tonnages mined. Recoverability ranges between 40 and 90 percent, depending upon the mining method used, legal constraints, and the characteristics of the coal bed (Westerstrom 1975). More strip-mined coal is recoverable than coal mined by any other method, primarily because no coal must be left as a support for overburden.

*To convert short tons to metric tons, multiply by 0.90718.

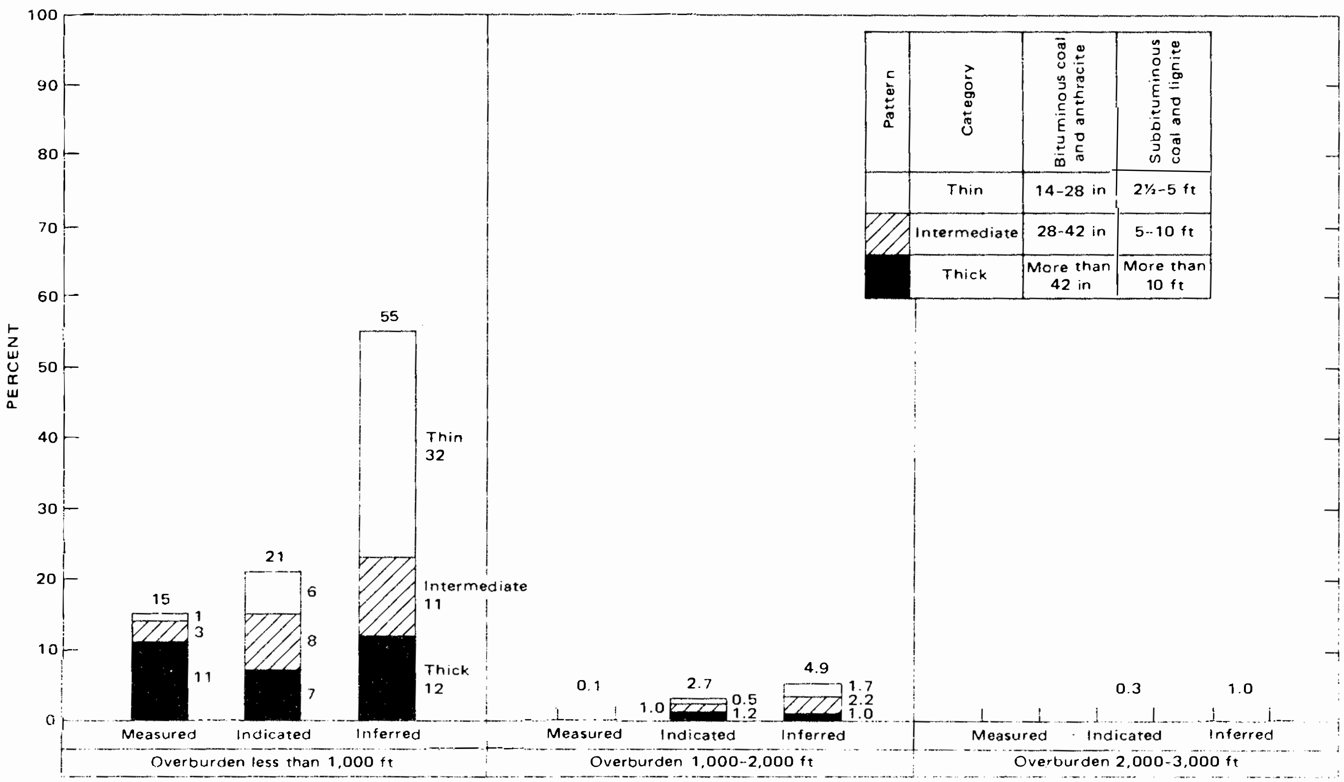

Fig. E.3. Summary of Percentage Distribution by Major Resource Category of Estimated Original Identified Coal Resources in 21 States. From Averitt (1975a).

E.1.3 Uses of Coal

As of 1976, the two industries using the largest amounts of coal were electric utilities and coke plants (Table E.2). Most of the coal used for coking would be suitable for steam generation.

Coking coals must be low in ash and sulfur contents, and must have good coking properties (Leonard 1977). The ash and sulfur contents may be lowered by coal washing or by mixing coals. Standard oven coke for blast furnace use is made from coal mixes containing up to 25 percent low-volatile coals blended with medium and high-volatile coals (Cooper 1974). Blending also permits the use of small quantities of high-sulfur coal for coking.

Coking coals were produced in 14 states in 1974. Ten of those--Pennsylvania, West Virginia, Kentucky, Illinois, Alabama, Colorado, Utah, Virginia, New Mexico, and Oklahoma--produced 98 percent of the total (Cooper 1974). Averitt (1975b) predicts that the amounts of impurities permitted in coking coals will increase and coking properties will decrease as the premium-quality reserves are depleted. If so, the resources of coking coal will be very large. About 35 percent of all identified reserves as of January 1, 1974, are suitable for use in coking-coal blends (Averitt 1975b). Most of the seams currently being mined for coking coal will probably continue to supply the coking industry and so that coal will not be available for steam generation.

The use of coal as an industrial energy source is limited primarily to those industries which depend upon a boiler to provide thermal energy. Industries in which a manufactured product must be directly exposed to gaseous and solid combustion effluents often do not use coals because of the potential for contamination from the sulfur and ash in the coal (Rubin and Medine 1977). The 1974 coal consumptions of several of the more significant industries are given in Table E.3 (Natural Gas Task Force Survey, undated).

E.1.4 Production

About 654 million short tons (a short ton is 2000 lb) of coal were mined from mines in 26 states during 1975.* Of this, 43 percent was mined from underground mines and 57 percent from surface mines (Mining Informational Services 1977). This is a record total production for the coal industry. Information on the coal mined in 1974 indicates that the total heat value of 603,406,000 tons of coal produced in that year totalled 14,302 trillion Btus--an average of 11,865 Btu/lb (Westerstrom and Harris 1974). Production totals for 1975 and average qualities are listed by federal demand region in Tables E.4 and -5, and in Section 4.5. Production data for 1975 were selected for use in this document because the data are complete and representative. Preliminary data indicate that about 669 million short tons of coal were mined in 1976 (Mining Informational Services 1977).

E.2 COAL FUEL CYCLE

E.2.1 Coal Extraction

Two general types of mining--surface and underground--are used in the United States to extract coal from the ground. Coal seams that are no deeper than 46-49 m (150-160 ft) from the surface are usually mined by the strip or auger methods of surface mining (Mining Informational Services 1977). Deeper coals are usually mined by underground techniques (Dvorak et al. 1977). Discrepancies from these generalizations may exist due to local geology, topography, or other variables.

E.2.1.1 Surface Mining

Surface mining, described in the simplest terms, is nothing more than the removal of topsoil, rock, and other strata to recover the underlying mineral or fuel deposits (Doyle 1976). Surface mining has several advantages over underground mining. It provides safer working conditions. It may make possible the recovery of some deposits which for physical reasons could not be mined underground. It usually results in a higher percent recovery (80 to 90 percent recovery is common in strip mines while 40 to 50 percent is more common in deep mines). Also, surface mining often can be done for a lower cost per unit of mined coal (Doyle 1976).

The surface mining technique most frequently used to recover coal is strip mining (area, contour, and mountaintop removal). Auger mining, a secondary recovery method, may be used to recover coal from a seam that becomes uneconomical to strip. Open-pit mining is used at a few scattered

*Mines with a production smaller than 1000 short tons per year are not counted or listed in Mining Informational Services (1977).

Table E.2. Coal Consumption by Use (thousands of short tons)

				Industry Mining and Manufacturing						
Year	Rank	Electric Power Utilities	Beehive and Oven Coke Plants	Steel and Rolling Mills	Sintering and Pelletizing	Other	Retail Consumption	Foreign Bunker Trade	Total Domestic Consumption	Reference
1950	Bituminous	88,262(19%)[a]	103,845(23%)	10,877(2%)	--	164,754(36%)	84,422(18%)	2,042(<1%)	454,202	National Coal Association(1975)
1960	Bituminous	173,882(46%)	81,015(21%)	7,378(2%)	--	86,804(23%)	30,405(8%)	945(N)[b]	380,429	National Coal Association(1975)
1970	Bituminous	318,921(62%)	96,009(19%)	5,410(1%)	--	82,909(16%)	12,072(2%)	298(N)	515,619	National Coal Association(1975)
1974	Bituminous	390,068(71%)	89,747(16%)	6,155(1%)	--	57,819(10%)	8,840(2%)	80(N)	552,709	National Coal Association(1975)
1975[c]	Bituminous	403,249(73%)	83,193(15%)	2,715(<1%)	--	59,759(11%)	5,682(1%)	24(N)	554,622	National Coal Association(1975)
1976	Bituminous	455,750(75%)	84,324(14%)	2,743(<1%)	--	57,750(10%)	6,900(1%)	12(N)	597,479	Mining Informational Services (1977)
1974	Anthracite	--	444($\sim$7%)	--	--	--	--	--	6,617	National Coal Association(1975) Cooper(1974)
1974	Anthracite	1,852(28%)	529(8%)	--	463(7%)	662(10%)	3,176(48%)	--	6,617	Federhoff(1974)

[a]Numbers in parentheses are percentages of total domestic consumption.

[b](N) = negligible percentage of total domestic consumption.

[c]Preliminary data.

Table E.3. Coal Consumption of Large Industrial Boilers in 1974

Industry	Coal Consumed (10^{12} Btu)	Total Fuel Consumed (10^{12} Btu)	Coal as % of Total Fuel
Food and kindred products	42.4	168.8	25.1
Petroleum refining	12.4	554.6	2.2
Nonferrous metals/misc.	0.9	90.5	1.0
Paper and allied products	125.0	601.4	20.8
Stone, clay, glass, and concrete	1.3	19.0	7.0
Chemicals and allied products	215.0	896.7	24.0
Primary ferrous metals	217.0	364.6	59.5
All manufacturing	965.5	3893.0	24.8
Other	274.0	848.5	32.2

Adapted from Natural Gas Task Force Survey (undated), App. D, Table 28; p. D-30. (As cited in Rubin and Medine [1977].)

Table E.4. Coal Production by Demand Region, 1975
(millions of short tons)

Demand Region	Mining Method					Total
	Underground	Strip	Auger	Strip and Auger	Culm Bank	
I	0	0	0	0	0	0
II	0	0	0	0	0	0
III (bituminous)	156.2	67.9	0.7	6.7	0	231.5
III (anthracite)	0.6	2.5	0	0	2.5	5.6
IV	77.1	71.0	1.9	24.5	0	174.5
V	47.5	77.5	0.5	5.9	0	131.4
VI	0.5	22.6	0	0	0	23.1
VII	0.4	6.3	0	0	0	6.7
VIII	10.8	58.7	0	0	0	69.5
IX	0	6.9	0	0	0	6.9
X	<1	16.0	0	0	0	16.1
	293.3	329.6	3.2	37.2	2.5	665.1
			Total Surface Mining = 372.450			

Table E.5. Coal Quality by Demand Region, 1975
(millions of short tons)

Demand Region	Avg % Sulfur in Coal Used to Produce Steam	Avg % Pyritic Sulfur in Coal Used to Produce Steam	Avg % Ash in Coal Used to Produce Steam	Btu/lb, All Coal
I	-	-	-	-
II	-	-	-	-
III (bituminous)	2.2	1.29	14.2	10,200-15,800
III (anthracite)	-	-	-	-
IV	1.8	0.83	10.8	8,542-15,140
V	3.9	2.3	14.0	9,600-1,500
VI	2.3	1.5	10.9	~10,445
VII	5.6	3.9	18.5	10,242-12,857
VIII	0.8	0.32	7.6	~10,092
IX	0.5	0.11	8.0	~12,325
X	-	-	-	-

locations. (The difference between strip and open-pit mining is that large quantities of overburden must be removed and discarded during strip mining while most of the material excavated in an open-pit mine is the desired mineral, rock, or fuel.) Anthracite may also be mined by dredging or by reworking culm banks for coal discarded by earlier operations.

Water diversion is sometimes a major problem with surface mining. Diversion ditches for surface water and groundwater which might flow to the pit are necessary to prevent flooding of the working area, to minimize erosion, and to minimize the potential for water pollution. Underdrains may be essential for slide prevention when spoils are deposited on steep terrain.

Area Mining

Area mining is the name given to strip mining done in areas with relatively flat topography and gently dipping stratigraphy (Doyle 1976). A trench or box cut is excavated with a power shovel (Fig. E.4), a dragline (Fig. E.5), a wheel excavator, or a bulldozer to the surface of the coal. The topsoil and overburden are stockpiled and the coal is removed. Another box cut is then made adjacent to the first. Spoils (the excavated overburden) are heaped in the cut previously mined and are covered with topsoil. Reclamation proceeds simultaneously with mining (Fig. E.6).

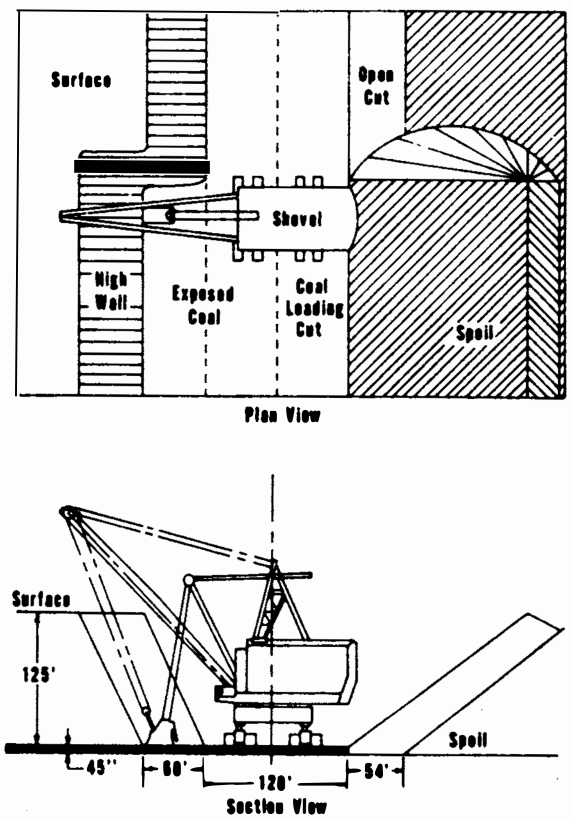

Fig. E.4.

Stripping with a Power Shovel. From Doyle (1976), with permission (see credits).

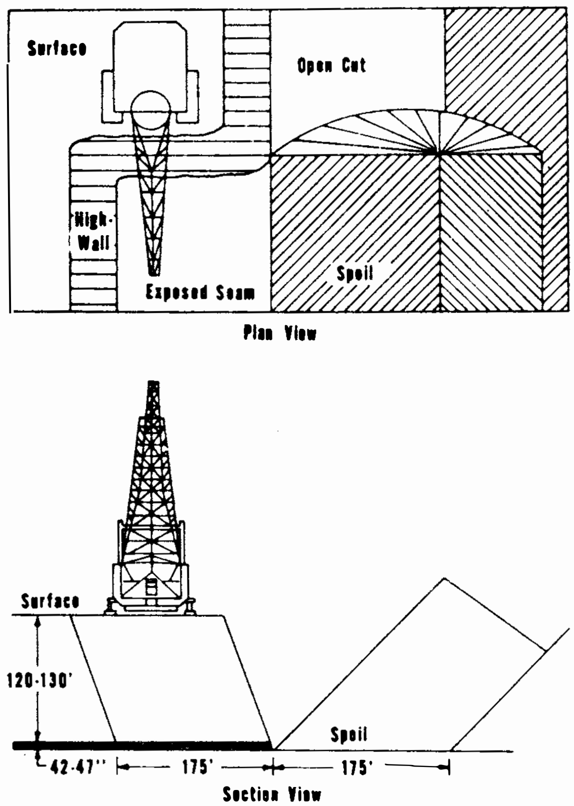

Fig. E.5.

Stripping with a Dragline. From Doyle (1976), with permission (see credits).

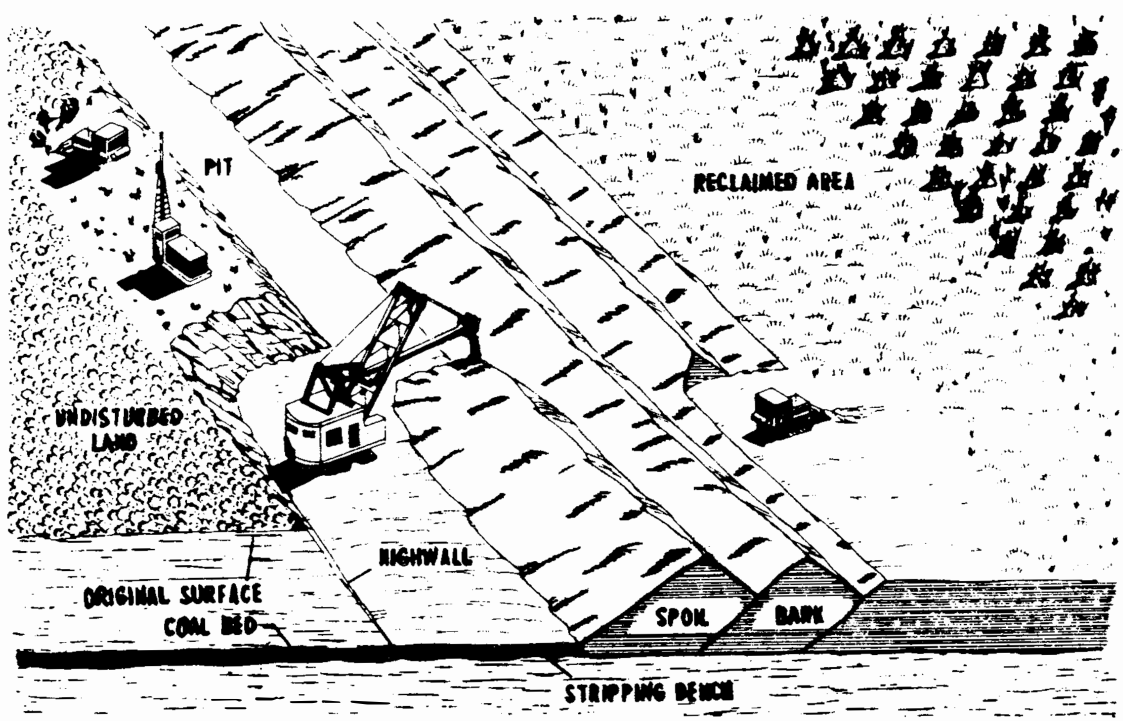

Fig. E.6. Area Strip Mining with Concurrent Reclamation. From Doyle (1976), with permission (see credits).

Contour Strip Mining--Block-cut Method

In hilly or mountainous terrain, strip mines follow the contour of the coal seam--hence the name contour mining. The first cut is made where the coal outcrops. Successive cuts and coal removal proceed deeper into the hill until the depth of overburden becomes so great as to economically prohibit additional mining.

Mine spoils are not to be dumped downslope of the cut. Instead they may be hauled back to a previously mined portion of the pit. This variation of strip mining is called the block-cut method (Figs. E.7 and E-8). The spoils are compacted, graded, and revegetated (USEPA 1973).

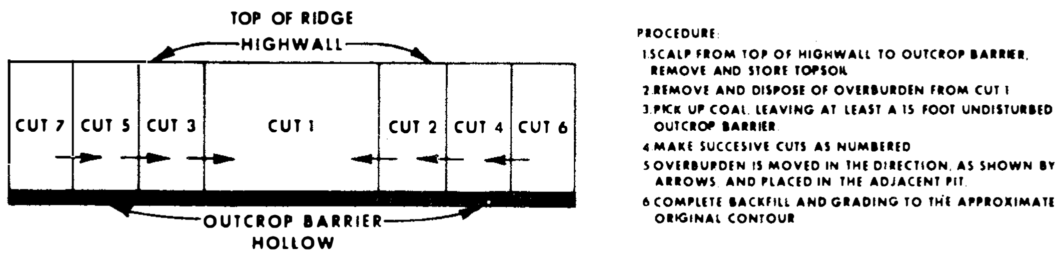

Fig. E.7. Cut Sequence in Block-cut Method. From Doyle (1976), with permission (see credits).

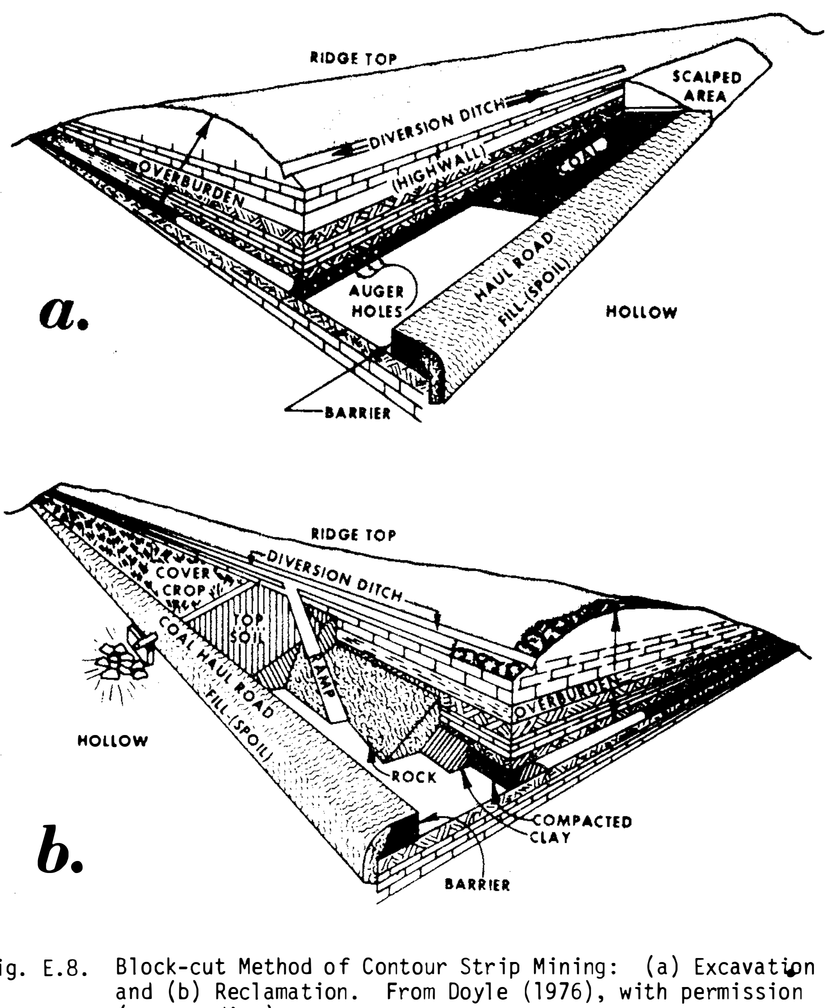

Fig. E.8. Block-cut Method of Contour Strip Mining: (a) Excavation and (b) Reclamation. From Doyle (1976), with permission (see credits).

Mountaintop Removal

Mountaintop removal is a combination of contour and area mining. It is used where coal seams lie near the tops of mountains, ridges, and hills. This method is initiated with cuts made as for a contour mine, but the mining progresses through the entire mountaintop, ultimately leaving a surface of spoil (Fig. E.9). Mountaintop removal mining may level some formerly steep terrain and increase its agricultural value.

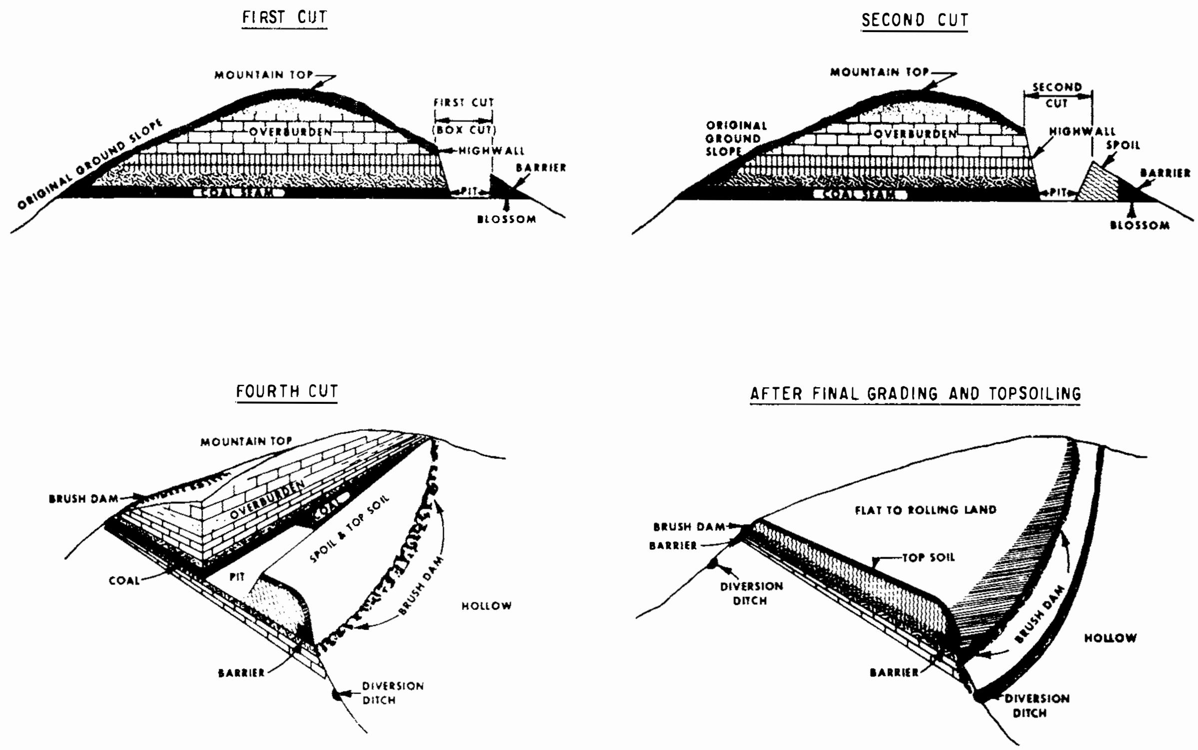

Fig. E.9. Mountain-top Removal Method. From Doyle (1976), with permission (see credits).

Auger Mining

When the overburden is too thick for economic removal, the life of a surface mine may be extended by reaming additional coal from the seam with augers. Cutting heads on some augers are as large as 2 m (7 ft) in diameter and their shafts may be 61 m (200 ft) long (Doyle 1976). Coal is removed from the auger like shavings from a drill bit. Spaces between auger holes vary from a few inches to a foot or more and average recovery is about 50 percent (Averitt 1975b).

E.2.1.2 Underground Mining

Room and Pillar

Coal is mined by underground methods when the overburden is so thick that coal cannot be profitably mined by surface techniques. Support or controlled collapse of the mine roof is of primary concern and distinguishes the different kinds of underground mines. Ninety-five percent of the underground coal mines are room and pillar (Mining Informational Services 1977). The roofs of these mines are supported by regular patterns of coal pillars that are not mined. Often as much as 50 percent of the original coal resources remain in the pillars (Averitt 1975b). When subsidence is permissible, the pillars may be removed by retreat mining, which allows the mine roof to collapse.

Some coal is still extracted from room and pillar mines by conventional mining methods (drill, blast, and muck operations), but recent trends have been toward mechanization (Mining Informational Service 1977; Westerstrom 1975). Nearly two-thirds of underground coal is now extracted by continuous mining machines, which cut coal from the seam and drop it onto conveyor belts

(Westerstrom 1975). Underground transportation still needs to be improved to keep pace with the high productivity of the continuous mining machines. Attempts are being made to combine a rock bolter to the mining machine so that the mining will not have to halt for the installation of roof supports.

Longwall and Shortwall

Longwall and shortwall mining differ from the room and pillar method in that the mine roof is supported hydraulically and is allowed to collapse progressively behind the mining. Longwall and shortwall mining are both done with continuous mining machines and conveyor systems. A typical longwall panel face (the surface of the coal to be mined) may be 85-100 M (260 to 305 ft) long, and a shortwall panel about 61 m (200 ft) (Hittman Associates 1976). The hydraulic roof supports are advanced with the mining machine. Explosives may be used to control roof collapse. Longwall mining can produce about 10 percent more coal per miner than can conventional excavation (Wisecarver 1978). This method is presently used to mine about 5 percent of the coal from underground mines in the U.S. It is especially useful where room and pillar mining is ruled out because of roof problems and poor recovery (Wisecarver 1978).

E.2.2 Reclamation

Coal mining operations often disturb surface areas and may adversely affect the utility of the land for commercial, industrial, residential, recreational, agricultural, and forestry purposes by contributing to erosion, landslides, flooding, water pollution, the destruction of fish and wildlife habitats, the damage of property, and the degradation or loss of natural resources (Surface Mining Control and Reclamation Act of 1977, Public Law 95-87). Technology has advanced to the point where mining and reclamation techniques can mitigate a large proportion of these adverse effects. Much of recent reclamation legislation is designed to encourage prompt, effective reclamation of mines and to regulate mining in areas where reclamation would be difficult.

E.2.2.1 Reclamation Legislation

In the forefront of federal surface mining reclamation legislation is the Surface Mining Control and Reclamation Act of 1977 (Public Law 95-87). Aside from creating a reclamation and enforcement office, providing for the funding of research, and establishing procedures for reclaiming abandoned mines, the purpose of this act is to control the environment by setting guidelines for reclamation.

The Surface Mining Control and Reclamation Act establishes a set of minimum reclamation standards which are to be met by each mine and enforced by an accredited state agency or, by default, the Office of Surface Mining Reclamation and Enforcement (OSMRE) (30 USC 1202). These standards include the establishment of plans by mine operators to restore the land of surface mines to their prior (or to higher) uses, restore the original contour (where possible), segregate and stockpile the topsoil, minimize hydrological disturbances, stabilize all waste piles, bury all acid-forming toxic or fire-prone materials, assure proper use of explosives, and accept the responsibility for revegetation (30 USC 1215).

This same act also sets standards for regulating the surface effects of underground mining (30 USC 1216). It requires mine operators to use available technology to control subsidence, seal holes and openings, stabilize or dispose of waste piles, minimize hydrological disturbances, minimize fire hazards, and revegetate any disturbed surface area.

Mining operations may be suspended by the regulatory agency, if necessary, to protect the stability or environmental quality of an urbanized area, a principal water source, or otherwise fragile land (30 USC 1215; 30 USC 1216). Areas may be designated as unsuitable for surface coal mining if mining (1) is incompatible with established land use plans, (2) would damage important historical, cultural, aesthetic, scientific, or natural systems, (3) would cause a substantial loss or reduction of long-range productivity of a renewable natural resource, or (4) could increase the potential for loss of life or property damage due to a natural hazard (e.g. flood or earthquake) which is already common to the area.

The first strip mine legislation was enacted in West Virginia in 1939 (Doyle 1976). Other states subsequently enacting legislation included Indiana (1941), Illinois (1943), Pennsylvania (1945), Ohio (1947), Kentucky (1954), Virginia (1966), and Tennessee (1967). Currently 33 states plus several counties and municipalities have surface mining and mined-land reclamation laws (Doyle 1976). Federal law takes precedence over the legislation in any state where the state law does not at least equal federal standards (30 USC 1201).

E.2.2.2 Reclamation Practices

Coal mining reclamation that is planned in advance of mining appears to be more effective and less costly than reclamation implemented after mining is terminated (Doyle 1976). The Surface Mining Control and Reclamation Act encourages preplanning by requiring the applicant to describe reclamation plans in the application for an operating permit (30 USC 1208). The ultimate goal is that the land be reclaimed to a condition that is at least as useful as it had been before the mining began. Steps that must be incorporated into the reclamation plan for a surface coal mine include stockpiling of topsoil, regrading, isolation of toxic spoils or horizons, water management, spoil and disturbed land stabilization, and revegetation. In mines where some of the mining practices described in Section E.2.1 are used (i.e., the haulback, mountaintop removal, and common area mining techniques), reclamation may be particularly easy because spoil and topsoil isolation, diversion ditch trenching, and regrading proceed with the mining. The Surface Mining Control and Reclamation Act does not allow spoils from contour mines to be disposed of on the downhill slope, and requires that backfilling be done to eliminate highwalls and spoil piles. Thus, conventional contour mining has become obsolete. However, reclamation of many of the mines conventionally mined remains to be done. Viable backfilling and grading alternatives for new mines include the ones mentioned above and the typical contour backfill (Fig. E.10). Backfilling to contour is preferred because it provides the best water pollution control and is the most aesthetically pleasing (USEPA 1973). However, it may also be the most expensive method because of the large volumes of spoils to be moved. A terraced backfill (Fig. E.11) which covers the highwall may be used if the volumes of spoils needed to return the land to its original contour do not exist. This technique creates some flat land surfaces which may give

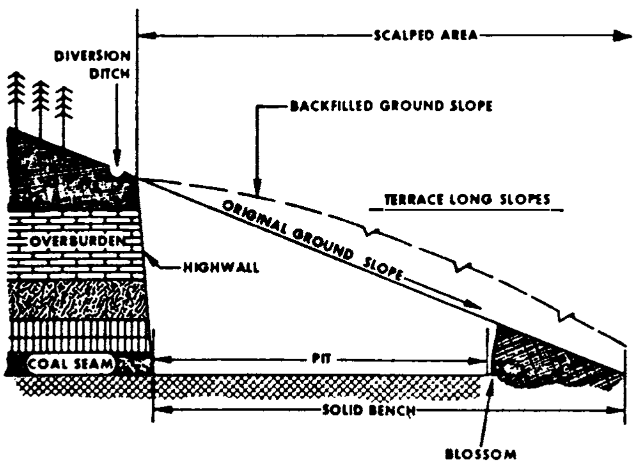

Fig. E.10.

Regraded Contour Mines. From Doyle (1976), with permission (see credits).

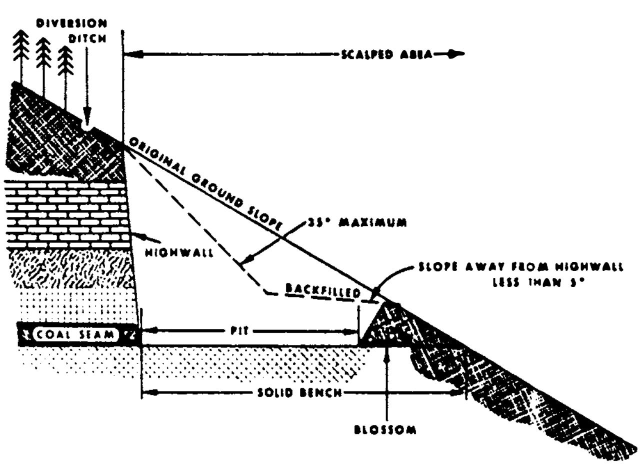

Fig. E.11.

Typical Terrace Backfill. From Doyle (1976), with permission (see credits).

the land a higher potential use than it had prior to mining. A more common situation is that a larger volume of spoils may exist due to bulking than can be used to recreate the original contour. In this case, the excess spoils should also be backfilled and compacted to a grade not exceeding the angle of repose or the geotechnical competency (30 USC 1215).

Regrading practices can affect the success of revegetation. Burial of toxic spoils and recovering of the surface with topsoil is critical to provision of the necessary supply of organic material for plant growth (Doyle 1976). Small terraces and slight depressions reduce erosion and increase infiltration, which facilitates plant growth (Doyle 1976). Mulches such as straw and wood chips or chemical binders may also be used to control erosion until the vegetation is established. Additives like lime, fertilizer, treated fly ash, sewage sludge, or compost may be used to condition acidic or nutrient-poor soils (Doyle 1976) A vegetative cover should be established as soon as possible after grading to minimize erosional losses. Fast-growing mixtures of legumes (to fix nitrogen in the soil) and grasses (to bind the soil surface) are preferred in the east (Doyle 1976). In Illinois, grading and revegetation must be completed within three years after June 30th of the fiscal year in which the mining took place (State of Illinois 1975). Estimates of the time required to reclaim Illinois row-crop farmland are as high as 10 to 30 years (Anonymous 1976). Low productivity from the land could be attained in much less time.

Revegetation is more difficult in the arid west where only about half of a 9- or 10-inch rainfall is available for plant utilization (Lang 1971). The planting of seedlings, sod, and transplants has been much more successful than has seeding in these areas (Doyle 1976). An estimated five years are required to return a Wyoming strip mine to productive cropland and ten years are required to return it to productive rangeland (Northern Great Plains Resource Program 1975).

E.2.3 Coal Cleaning

Coal cleaning is the removal of unwanted sulfur and other noncombustible materials (ash) from a coal. Coal is cleaned for a variety of reasons. For example, mining machines--particularly longwall miners used underground--are not selective in what is excavated, and significant amounts of shale may be removed with the coal (Schmidt 1975). Cleaning these coals reduces their bulk and shipping costs and increases heat content by removing noncombustible materials. Cleaning reduces the likelihood that sufficient slag will be produced to hinder the operation of the boilers (Papamarcos et al. 1977), and reduces the particulate and sulfur dioxide levels in flue gases emitted when the coal is burned. This is especially important because the emissions from new (since Aug. 17, 1971) steam generating plants are not allowed to exceed 1.20 lb SO_2/MM Btu (40 CFR 60.43). The Clean Air Act Amendments of 1977 (Public Law 95-95, Sec. III), when implemented, will also require a percentage reduction in emissions over those that would result from combustion of an untreated coal. Coal washing may be used to achieve part or all of the necessary sulfur reduction. The pounds of SO_2 per million Btus in flue gas from combustion of a specific coal can be estimated from Figure E.12. If the coal is not cleaned, or cleaning does not adequately reduce sulfur content, a higher percentage of removal will be required from flue gas desulfurization.

The sulfur in coal occurs as organic sulfur, sulfate, and pyritic sulfur (Sec. E.1.1). Most of the sulfur removed from coal by cleaning is pyritic sulfur. Pyritic sulfur occurs as the minerals pyrite and marcasite. These are heavy, with specific gravities of about 5, and can easily be removed by crushing and gravitationally separating the coal. Organic sulfur ranges from 30 to 70 percent and cannot be removed by direct physical separation (Cavallaro et al. 1976). The sulfate usually comprises less than 0.05 percent of the total coal material. Often it is water-soluble and thus easily removed in cleaning (Cavallaro et al. 1976).

Only mechanical cleaning methods have so far been termed practical and accepted by the industry. Chemical desulfurization is still in experimental stages. Gravimetric separation removes both pyritic sulfur and ash efficiently. Some of the heating capacity of the coal is also lost in the process, but the net result is an increase in the Btu/lb over that of the raw coal (Cavallaro et al. 1976). In 1974, 363.334 million short tons of raw coal were washed to produce 265.150 million short tons of cleaned coal (Tables E.6 and E.7) (Westerstrom and Harris 1974). This is about 44 percent of the total coal produced and made available for consumption in 1974. The amounts of coal cleaned in 1973 and 1974 by mechanical cleaning are given by method in Table E.8.

The efficiency of mechanical coal cleaning (coal washability) as it is practiced today varies regionally with differences in coal quality. The U.S. Bureau of Mines has conducted an extensive study to determine coal washabilities (Cavallaro et al. 1976). In summary, coals of the Northern Appalachian Region (Maryland, Ohio, Pennsylvania, and northern West Virginia) were especially amenable to pyritic sulfur reduction. The raw coals averaged 2.01 percent pyritic sulfur and 3.01 percent total sulfur. Cleaning produced an 80 percent reduction from the initial total sulfur concentration at 70 percent Btu recovery for coal crushed to the No. 14 mesh size.

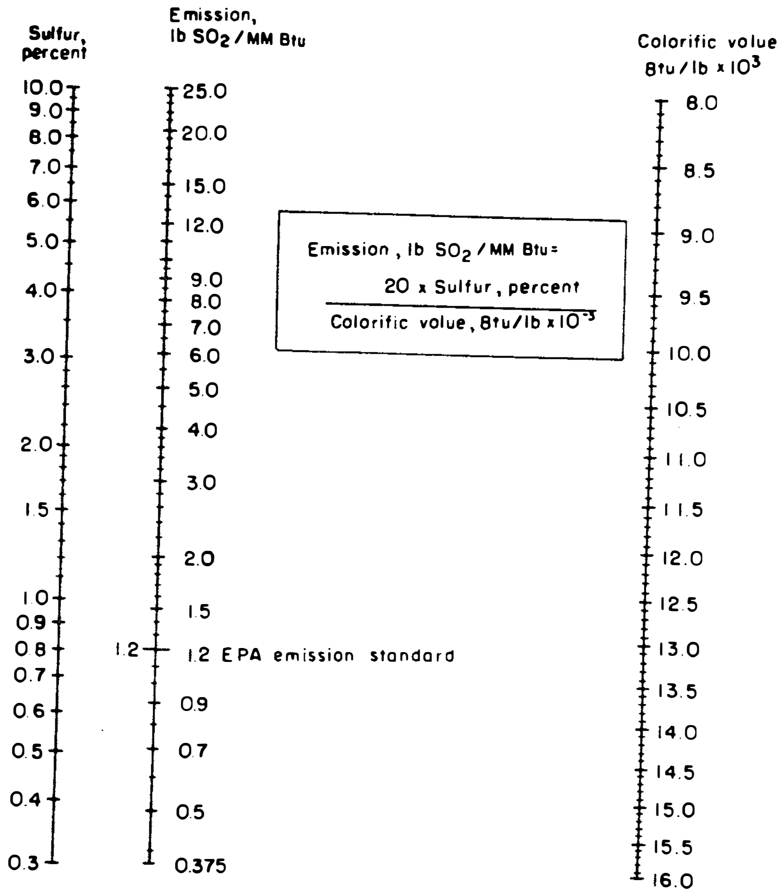

Fig. E.12.
Relation of Sulfur Content and Calorific Value in Coals to Pounds SO_2 Emission per Million Btu. From U.S. Department of the Interior (1976).

Table E.6. Mechanical Cleaning at Bituminous Coal and Lignite Mines in 1974 by State (thousands of short tons)

State	Total Production	Number of Cleaning Plants	Raw Coal	Cleaned Coal	Refuse
Alabama	19,824	22	18,099	11,726	6,372
Colorado	6,896	3	2,043	1,775	268
Illinois	58,215	36	58,520	45,313	13,207
Indiana	23,726	11	23,874	19,097	4,777
Eastern Kentucky	85,356	43	33,503	24,304	9,199
Western Kentucky	51,841	19	25,033	19,324	5,709
Ohio	45,409	17	19,142	13,617	5,525
Pennsylvania	80,462	68	57,676	41,302	16,374
Utah	5,858	6	3,890	3,401	488
Virginia	34,362	19	21,151	13,872	7,279
West Virginia	102,462	126	88,310	62,833	25,477
Other States[a]	89,030	17	12,093	8,584	3,509
Total[b]	603,406	387	363,334	265,150	98,184

[a]Includes Alaska, Arkansas, Iowa, Kansas, Maryland, Missouri, New Mexico, Oklahoma, Tennessee, Washington, and Wyoming.

[b]Data may not add to totals shown because of independent rounding.

Table E.7. Mechanical Cleaning at Bituminous Coal and Lignite Mines in 1974 by State and Type of Mining
(thousands of short tons)

State	Underground Mines		Strip Mines		Auger Mines		Strip-auger Mines		Total All Mines[a]	
	Total Production	Cleaned	Total Production	Cleaned	Total Production	Cleaned	Total Production	Cleaned	Total Production	Cleaned
Alabama	7,053	7,037	11,656	3,745	--	--	1,115	945	19,824	11,726
Colorado	3,260	1,752	3,636	23	--	--	--	--	6,896	1,775
Illinois	31,256	21,589	26,960	23,724	--	--	--	--	58,215	45,313
Indiana	139	64	23,587	19,033	--	--	--	--	23,726	19,097
Eastern Kentucky	40,509	22,126	16,503	427	1,546	517	26,798	1,234	85,356	24,304
Western Kentucky	22,988	7,162	28,853	12,162	--	--	--	--	51,841	19,324
Ohio	14,365	8,826	20,852	4,792	265	--	9,928	--	45,409	13,617
Pennsylvania	42,249	34,118	36,332	7,161	281	23	1,600	--	80,462	41,302
Utah	5,858	3,401	--	--	--	--	--	--	5,858	3,401
Virginia	22,767	13,285	7,874	141	767	--	2,918	446	34,326	13,872
West Virginia	82,220	58,807	15,758	3,166	415	22	4,070	839	102,462	62,833
Other States[b]	4,645	1,858	83,030	6,726	29	--	1,326	--	89,030	8,584
Total[a]	277,309	180,024	275,041	81,100	3,302	562	47,755	3,463	603,406	265,150

From Westerstrom and Harris (1974).

[a]Data may not add to totals shown because of independent rounding.

[b]Includes Alaska, Arkansas, Kansas, Maryland, Missouri, New Mexico, Oklahoma, Tennessee, Washington and Wyoming.

Table E.8. Mechanical Cleaning of Bituminous Coal and Lignite by Type of Equipment (thousands of short tons)

Type of Equipment	1973	1974
Wet methods		
Jigs	132,655	129,302
Concentrating tables	34,935	28,869
Classifiers	3,297	2,698
Launders	5,121	3,577
Dense-medium processes		
Magnetite	74,605	68,749
Sand	12,617	12,427
Calcium chloride	981	1,107
Flotation	14,201	10,863
Total wet methods[a]	278,413	257,592
Pneumatic methods	10,505	7,557
Grand total[a]	288,918	265,150

[a]Data may not add to totals shown because of independent rounding.

The 35 Southern Appalachian coals (east Kentucky, Tennessee, southern West Virginia, and Virginia) averaged 0.37 percent pyritic sulfur and 1.04 percent total sulfur. When crushed to the No. 14 mesh size, 63 percent of the coal samples would meet the present EPA standards. The accompanying Btu recovery rate is 50 percent. Alabama coals had 0.69 percent pyritic sulfur and 1.33 percent total sulfur. These coals do not wash readily. The Eastern Interior Region coals (Illinois, Indiana, western Kentucky) averaged 2.29 percent pyritic sulfur and 3.92 percent total sulfur. About 45 percent of the ash and 57 percent of the sulfur can be washed from these coals, but the combustion emissions from most of the coals from the major seams in this region need to be scrubbed to meet the EPA SO_2 allowable SO_2 standards. Western Interior coals (Arkansas, Kansas, Missouri, Oklahoma, and Iowa) contain an average of 3.58 percent pyritic sulfur and 5.25 percent total sulfur. The western coals (Arizona, Colorado, Montana, New Mexico, North Dakota, Utah, and Wyoming) contained an average of only 0.68 percent total sulfur. With the implementation of the Clean Air Act Amendments of 1977, western coal will have to be cleaned and/or its combustion emissions scrubbed despite its very low sulfur content. The SO_2 emission standards for burning coal may be met by flue gas desulfurization techniques when washing is impractical or insufficient.

Coal cleaning wastes consist of pyritic minerals, shales, clays, and various other silicates. Gob (the boulder, gravel, and coarse sand waste particles) is usually heaped into a pile. The Surface Mining Control and Reclamation Act (30 USC 1216) requires that all waste piles be compacted, contoured, and stabilized. Incombustible materials are to be included in the stabilization if necessary to prevent the gob pile from burning. A burning gob pile is a source of sulfur dioxide, hydrogen sulfide, carbon monoxide, carbon dioxide, nitrogen oxides, ammonia, hydrocarbons, and particulates to the atmosphere (Dvorak et al. 1977). Water percolating through gob piles tends to pick up iron (typically at a rate of 0.5-0.7 lb/acre/day) (USEPA 1971a), sulfate, and other dissolved and suspended solids. A typical gob pile may produce acid at an average rate of 1.5-2.0 lb/acre/day (USEPA 1971a), and rates as high as 305 lb/acre/day have been reported in Illinois (USEPA 1971a). Impermeable materials are to be incorporated into the gob pile when contamination from leachate is a problem (30 USC 1216). The pH of a gob pile is often less than 3.0, and sometimes less than 2.0 (Thompson and Hutnick 1971). Gob piles lack necessary plant nutrients and contain toxic levels of trace elements (Thompson and Hutnick 1971). Stabilization will usually require that the surface be covered with topsoil prior to revegetation.

The fine sand, silt, and clay-sized coal washing wastes are usually disposed of in slurry form. These are usually pumped to a natural depression, tailings pond, or an old mine if one is available. Acid drainage is a problem with slurried wastes. A liner may be necessary to prevent contamination of the subsoil and groundwater from seepage. Blowing of coal fines from unvegetated slurry lagoons can be minimized if the coal fines are kept wet. Abandoned slurry ponds should be compacted, contoured, and stabilized.

E.2.4 Transportation

The transportation industry currently moves 600-700 million tons of coal annually (U.S. Bureau of Mines 1976) and this figure is expected to increase by at least 400 million tons annually by 1985 (Bagge 1977). Planning for effective coal transport designed to meet this need will require analyses of the various transport alternatives, their costs and competitive advantages, by geographic region, and the environmental acceptability of each alternative. The most viable modes for long-distance transport are railroads, barges and ships (used alone or in tandem), and coal slurry pipelines. Trucks and overland belt conveyors are preferred for short-distance transport.

E.2.4.1 Railroads

Most railroad companies view coal transport as their main area of future growth, and are rapidly developing the concept of unit train coal shipment. Presently, 65 percent (U.S. Comptroller General 1977) of the U.S. annual coal production is moved at least partially by rail, and coal represents 29 percent (U.S. Department of Transportation 1978) of all the originating traffic shipped by rail in the U.S. (Graves 1974) (Fig. E.13). This percentage would increase if multimodal transport is considered.

The unit train, which is the principal method of coal transport by rail, consists of 70 to 100 open-topped hopper cars with a capacity of 85-110 tons each, driven by several diesel locomotives. Each unit train can haul approximately 10,000 tons. In large-scale operations, coal can be loaded at a rate of as much as 5000 tons per hour, which would permit shipment of three unit trains per day. As rail shipment costs increase (Krohm and Dux 1977) east of the Mississippi (to greater than half of the delivered price) due to multiple railroad management, a large percentage of the coal produced does not reach its final destination using this mode of transportation alone (Lewis and Stupka 1977). Terminal unloading points may therefore include transhipment facilities where the coal is stockpiled for transport by barge, freighter, or truck to industries or utilities using the coal for fuel. In either case, to avoid bottlenecks that tie up equipment and result in lost time, unloading facilities at transshipment points and large utilities and industries must have adequate unloading and storage capacity for coal shipped by unit train.

E.2.4.2 Barges and Ships

Inland waterways are currently used to transport 11 percent of the annual U.S. coal production (25 to 30 percent of coal utilizing multimodal transport) (Anonymous 1975a; U.S. Comptroller General 1977), and coal is the major commodity carried, comprising about 22 percent of the total tonnage shipped on inland waters (Anonymous 1974a). The inland waterway system consists of the Great Lakes (shipping 5 to 10 percent of the annual coal production) and 25,000 miles of navigable waterways on the Mississippi-Gulf Coast System, including the Ohio and Illinois rivers (Anonymous 1974a), which are used to transport the remainder of the coal shipped by water (Fig. E.14). A single barging operation usually consists of 10 to 20 barges of about 1000-ton capacity, pushed by a 100-hp towboat. In the open water of the lower Mississippi, as many as 36 open barges may be navigated. A new 20-million-tons per year (tpy) loading facility at Metropolis, Illinois, is indicative of current trends in the barge shipment of coal; 15 jumbo barges can be loaded in six hours with 22,500 tons of coal (Ross and Martinka 1975). These jumbo barges are limited to channels greater than 2.7 m (9 ft) in depth. Surface icing is also a limiting factor to barge shipments in northern climates.

The capacity of the Great Lakes System is increasing with the newly constructed Orba Corp. transshipment facility at Superior, Wisconsin. At peak capacity, this facility is expected to handle 20 million ton of western coal (Lewis and Stupka 1977). New superships of 1000-foot length and 62,500-ton capacity are self-unloading and can transport western coal from Lake Superior to points in the lower Great Lakes such as Detroit for $6-8 per ton less than the cost of rail transportation (Lewis and Stupka 1977). Only one such ship is now operating, but as the regional market demand develops, these carriers, along with associated transshipment facilities, are expected to promote shipping as an efficient mode of coal transportation to the Great Lakes regional market.

E..2.4.3 Coal Slurry Pipelines

There is only one operating slurry pipeline in the 48 contiguous states, and it carries coal 273 miles from the Black Mesa coal fields in Arizona to the Mojave power plant in southern Nevada. This 45-cm (18-in.) pipeline delivers 4.8 million tpy at about 4 mph and 660 tph, and requires about 379,000 m^3 (1 billion gal) of water per year. A slurry pipeline from Cadiz, Ohio, to Lake Erie was closed in the early 1960's. While only a small quantity of coal is currently shipped via pipeline, the feasibility of several large-scale installations in both the east and the west is being studied (Fig. E.15). The proposed western facilities will transport low-sulfur coal.

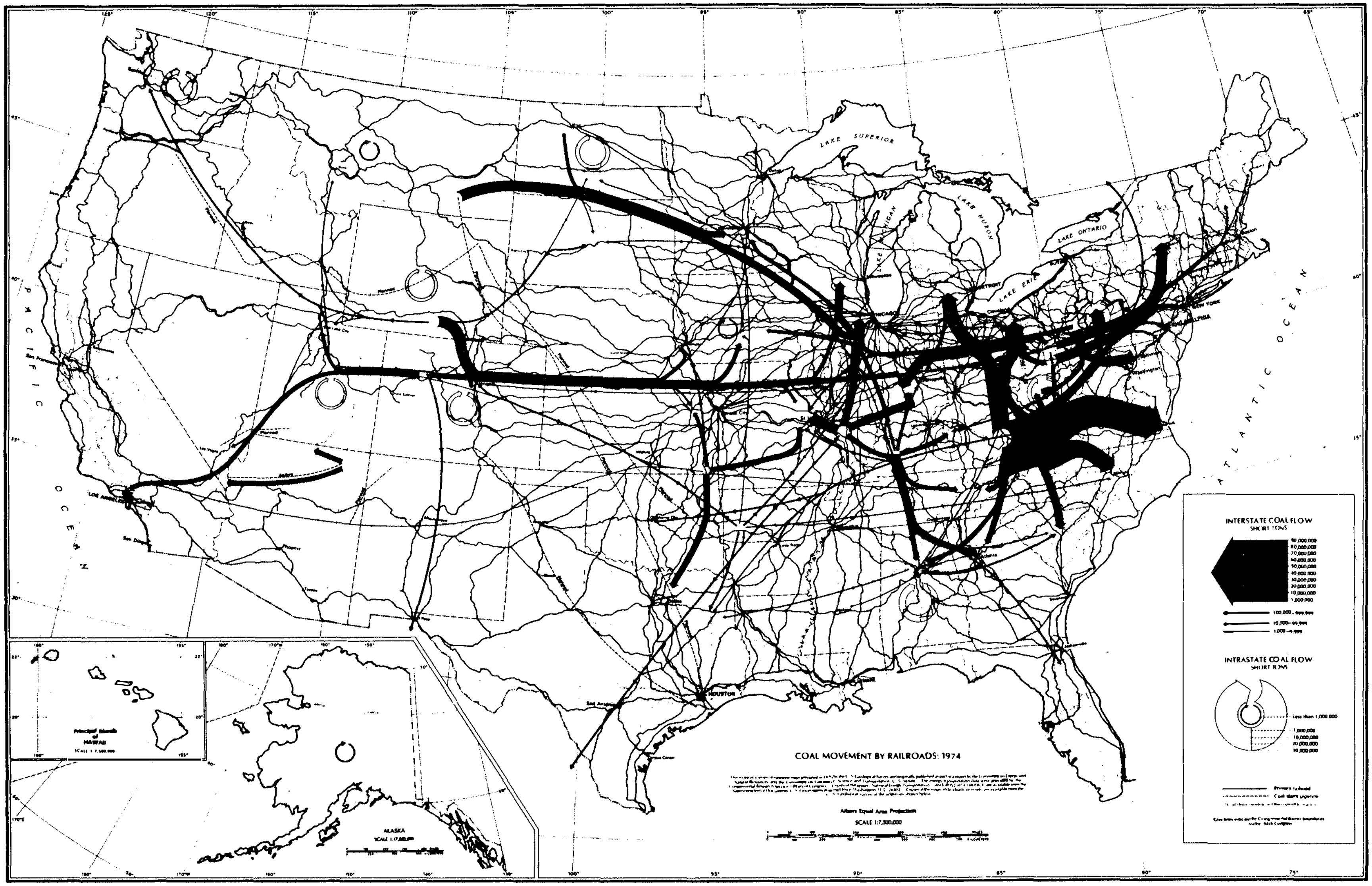

Fig. E.13. Coal Movement by Railroads, 1974. From U.S. Geological Survey (1977).

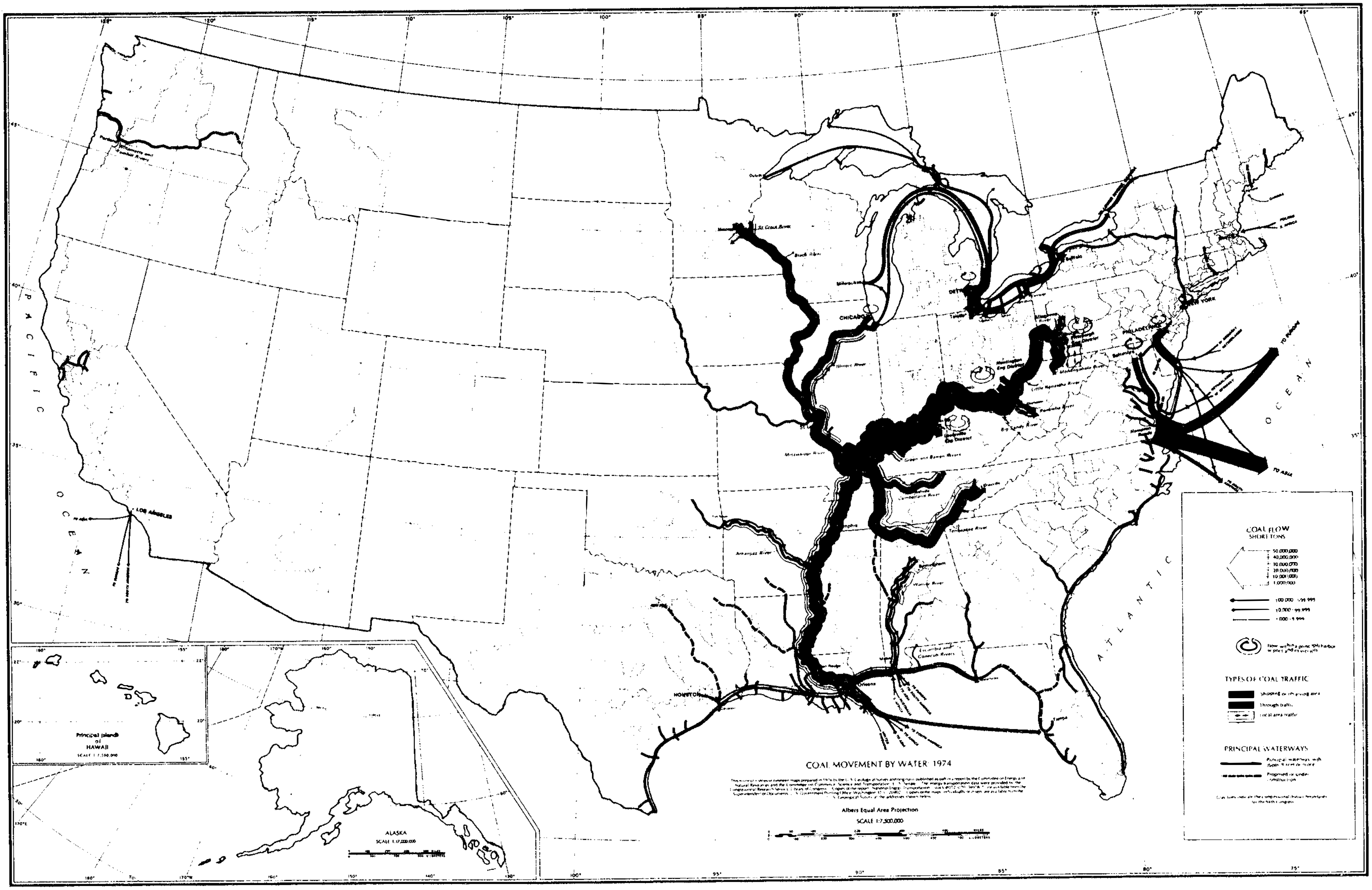

Fig. E.14. Coal Movement by Water, 1974. From U.S. Geological Survey (1977).

The routes and sizes of the proposed pipelines are given in Table E.9. Should these projects be completed they would account for 5 to 10 percent of the present annual U.S. Production (Anonymous 1977; Gray and Mason 1975).

There are major problems associated with the use of coal slurry pipelines and these problems differ by region. Western lines require huge amounts of water, which is in chronically short supply. Land use restrictions could make the acquisition of rights-of-way in both the east and the west difficult. An example of these restrictions is the easements across railroad rights-of-way when pipelines are in direct competition with them for coal shipment. The primary advantage to the use of slurry pipelines is that because maintenance is low, they are not affected by inflation. Interruptions in service would be mitigated by the same types of storage facilities common at power plants using coal shipped by rail or barge.

Effluent from coal dewatering at the pipeline terminus could be used for cooling water makeup, or treated for some other specific use. Dewatering facilities usually employ vacuum disc filters and thermal dryers in a system designed to produce filter cake and clear water. Should potable or high-quality water be desired, appropriate storage and treatment facilities would be necessary.

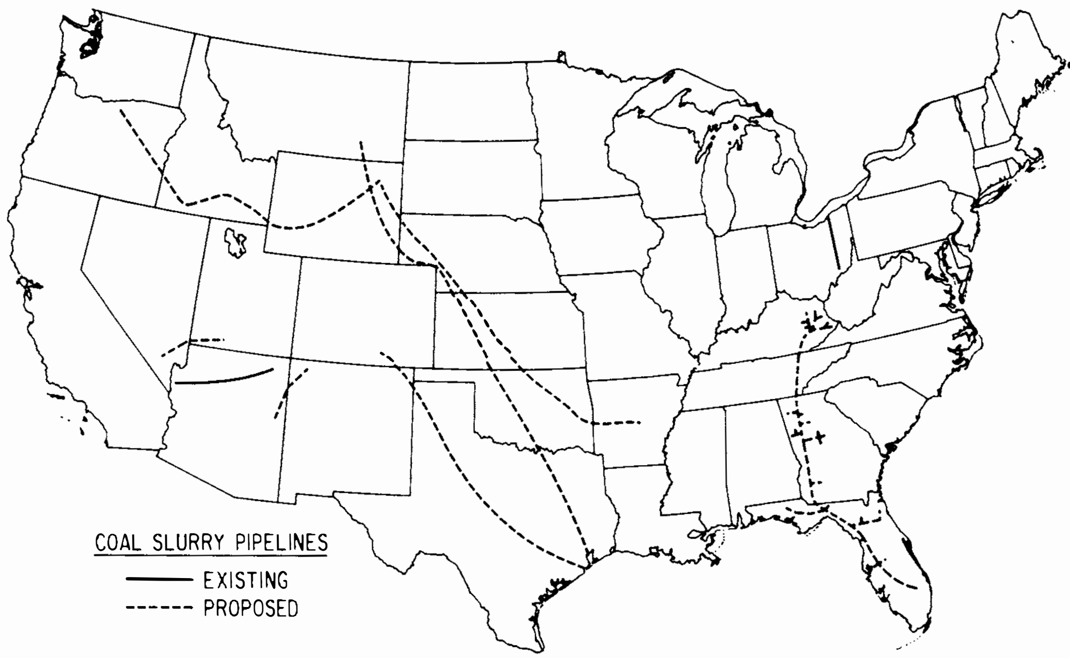

Fig. E.15. Existing and Proposed Coal Slurry Pipelines. From data in U.S. Geological Survey (1977) and Anonymous (1978).

Table E.9. Routes and Sizes of Proposed Coal Slurry Pipelines

Route	Pipeline Length	Pipeline Diameter	Capacity
	Western[a]		
Colorado to Texas	110 miles	45 cm (18 in.)	7 million tpy
Wyoming to Arkansas	1030 miles	97 cm (38 in.)	25 million tpy
Utah to Nevada	180 miles	61 cm (24 in.)	10 million tpy
New Mexico to Arizona	180 miles	41 cm (16 in.)	21 million tpy
	Eastern[b]		
Eastern Kentucky to Florida	(?)	71 cm (28 in.) or 122 cm (48 in.)	15 million tpy or 45 million tpy

[a]From Ross and Martinka (1975).

[b]From Anonymous (1978).

E.2.4.4 Truck Transport and Overland Belt Conveyors

Trucks and belt conveyors are used over short distances, usually to link the mine site with some mode of long-distance transport such as the unit train. Trucks (150- to 200-ton capacity) currently account for most of this short-distance (off-road) hauling. Trucks hauling coal by highway are limited in size to 20-30 tons net capacity. While much of truck transport is intrastate, truck transport may be interstate in the east, where states are small and the mine-mouth and consumer are in close proximity. Conveyor systems in large operations are becoming increasingly cost-competitive because of their low maintenance and ability to cover rough terrain (Anonymous 1974b). An operational example of a belt conveyor is the one at Black Mesa, Arizona, which transports coal from the mining area at 1400 tph to a unit train 610 m (2000 ft) below on the valley floor.

E.2.5 Coal Combustion

The features of coal combustion described in this section pertain only to the operation of coal-fired furnaces, and exclude the indirect aspects of the coal cycle, which are dealt with in other sections. Included are those ancillary facilities necessary to operation of the furnace.

E.2.5.1 Fuel Requirements

The major factors determining fuel requirements for any coal-fired furnace are the heating value of the coal and the design thermal capacity of the furnace. Heating value of the coal varies with its source (Table E.10), and depends upon its rank and content of ash, moisture, and sulfur. The thermal design capacity of the furnace is considerably larger than its net output due to variable thermal efficiency. For example, electric power plants operate at about 30 to 40 percent thermal conversion efficiency. In addition, ancillary equipment reduces efficiency. Ancillary equipment includes heat dissipation systems (when required), stack-gas cleaning equipment, and operational power consumption.

E.2.5.2 Furnace Types

Furnaces in common use include stoker-fired, cyclone-furnace-fired, and pulverized-coal-fired units (Dvorak et al. 1977). A stoker is a mechanism which feeds fuel onto a grate within a furnace; stokers are used primarily in furnaces of small size (350,000 lbs of steam/hr) (Babcock and Wilcox 1972). Cyclone furnaces burn crushed coal in a horizontal cylinder using a high-velocity stream of air injected through the cylinder to produce a cyclonic flame pattern. These furnaces produce relatively high concentrations of nitrogen oxides. Pulverized-coal furnaces mix powdered coal with air and blow it into the furnace. Most new large power plants use the pulverized-coal system. Both pulverized-coal burners and cyclone furnaces require oil or natural gas igniters during startup and shutdown and for flame stabilization (Dvorak et al. 1977; Dvorak et al. 1978).

E.2.5.3 Coal Storage (Live and Reserve)

Coal storage areas serve as the primary assurance of uninterrupted coal supply. While use in a typical furnace is continuous, deliveries typically arrive daily in one or two bulk shipments. These deliveries are subject to interruptions caused by labor problems, natural disasters, or breakdowns in transportation. Contingencies such as these are met by establishing two stockpiles--live storage and reserve storage--which serve different objectives. The size of the storage pile will vary not only with the size of the furnace but with the rank of the coal being used.

The objective of live storage is the maintenance of the smallest possible coal pile consistent with the size and requirements of the furnace. Freshly cut coal begins to oxidize slowly when it is brought in contact with air; thus the Btu content of the coal decreases over time. Since this low-temperature oxidation is largely surficial in extent, the amount of oxidation decreases over time. In addition, unless dissipated, the heat produced during oxidation can cause spontaneous combustion, resulting in large economic losses. Loose stacking of the piles maximizes heat dispersal but also maximizes surface area, which increases oxidation. Thus, to reduce the hazards of oxidation, the amount of coal in the live piles is kept to a minimum and used as quickly as possible.

A reserve storage stockpile of coal at the plant site is maintained so that plant operations can continue in the event of an unscheduled interruption in delivery. Normally, a 100-day reserve supply is maintained at electric generating facilities although the amount may be less at mine-mouth operations. Whether the end product is electricity or process steam, there is a need for adjacent areas to be set aside for coal storage (Dvorak et al. 1977).

Table E.10. Summary of Moisture, Ash, Sulfur and Heat Content of Coal from Some Major Coal-Producing Seams in the United States

Region/State	Seam	Moisture (%) Range	Moisture (%) Average[b]	Ash (%) Range	Ash (%) Average[b]	Sulfur (%) Range	Sulfur (%) Average[b]	Heat (Btu/lb)[a] Range	Heat (Btu/lb)[a] Average[b]	Reference
Northern Appalachian										
West Virginia	Pittsburgh	-	2.9[c]	4-20	7(M)	0.6-14	2.2(M)	11,400-14,800	13,800(M)	Arkle et al. (1975)
Pennsylvania	Pittsburgh	1.1-3.9	2.5(MR)	4.2-10.8	7.5(MR)	0.7-3.3	2.0(MR)	13,040-14,340	13,690(MR)	Edmunds (1975)
Southern Appalachian										
Eastern Kentucky	Upper Elkhorn #3	-	3.2[c,d]	-	3.9	-	0.9	-	14,200	Smith and McGrain (1975)
Tennessee	Upper Elkhorn #3 (Jellico)	2.0-7.6	4.8(MR)	1.9-10.5[e]	6.2(MR)	0.7-3.2[f]	2.0(MR)	12,630-14,290[g]	13,460(MR)	Luther (1975)
Virginia	Upper Banner	1.8-2.2	2.0(MR)	4.7-5.8	5.3(MR)	0.5-0.7	0.6(MR)	14,600-14,870	14,735(MR)	Calver (1975)
Alabama	Mary Lee	1.2-4.0[h]	2.6(MR)	4.9-19.8	12.4(MR)	0.5-2.6	1.6(MR)	11,570-14,700	13,135(MR)	Daniel (1977)
Eastern Interior										
Illinois	(No. 5) Harrisburg-Springfield	4-18	11(MR)	8-12	10(MR)	2-5	3.5(MR)	10,100-12,700	11,400(MR)	Simon et al. (1975)
Indiana	(No. 5) Springfield	-	-	5-30	12	0.7-7.3	3.3	9,100-14,000	12,800	Wier and Hutchinson (1975)
Western Kentucky	(No. 9)(No. 5 Ill.)	-	5.0	-	10.5	-	3.15	-	12,940	Smith and McGrain (1975)
Powder River Region										
Montana	Anderson-Dietz 1 & 2 and Anderson	-	-	4.0-5.3	4.6	0.29-0.5	0.37	7,925-9,652	8,633	Matson (1975)
Wyoming	Anderson & Canyon & Wyodak-Anderson	21.1-36.9	29.7	3.1-12.2	6.0	0.14-1.2	0.48	7,128-9,600	8,203	Glass (1975)
Fort Union Lignite										
North Dakota	Undefined	33.5-43.8	37.9	4.4-8.0	6.2	0.2-1.4	0.6	5,960-7,487	6,783	Carlson (1977)
Four Corners										
Arizona	Wepo	7.0-17.4	10.35	3.4-6.7	5.2	0.4-0.9	0.6	10,450-12,060	11,617	Pierce et al. (1970)
New Mexico	Navajo	-	13.2	-	20.4	-	0.72	-	9,200	Kottlowski (1975)

Adapted from Dvorak et al. (1978).

[a]To convert Btu/lb to J/kg, multiply by 2.324 × 10^3.

[b]Values are averages unless otherwise noted (MR = midrange; M = median).

[c]Walker and Hartner (1966).

[d]Synder and Aresco (1953).

[e]Excluding a value of 18.2.

[f]Excluding a value of 4.8.

[g]Excluding a value of 11,690.

[h]Excluding a value of 6.7.

There is relatively little low-temperature oxidation in reserve storage piles because they are well compacted to minimize contact of the coal with the air. The midrange of industry practice has provided a "typical" compaction factor which results in a density of 1750 tons/acre-ft. Surface oxidation nonetheless occurs, and the pile must be constantly checked for "hot spots." If these hot spots are not promptly removed to the boiler feed stream, spontaneous combustion will occur and result in sizable losses to the stockpile.

For those fuel-burning installations that are required to reduce SO_2 emissions and have stack gas scrubbers, facilities for storing and crushing limestone are also necessary. The amount of limestone needed varies directly with the sulfur content of the coal, and so storage areas will vary in size, depending on the rank of coal. Most western coals meet 1971 air quality standards for sulfur oxides (SO_x) when burned in existing facilities, so limestone scrubbers are not required. New Clean Air Act Amendments passed in 1977 require best available control technology (BACT) regardless of the type of coal burned. The possible effects of this law on regional coal use and demand, air quality, conversion, etc. are discussed in Section 6 of this impact statement.

E.2.5.4 Waste Products--Emissions and Effluents

Coal combustion results in stack gas emissions containing a variety of elements and compounds, including sulfur oxides (SO_x), nitrogen oxides (NO_x), fly ash, trace elements, radionuclides, hydrocarbons, carbon dioxide (CO_2), and carbon monoxide (CO) (Dvorak et al. 1977; Dvorak et al. 1978). The Federal Ambient Air Quality Standards and the 1977 amendments to the Clean Air Act requiring best available control technology (USEPA 1977) impose strict guidelines on the amount of particulates, SO_x, NO_x, CO, hydrocarbons, and photochemical oxidants that may be emitted by new facilities. Current coal consumers can meet these requirements in a number of ways.

One way the coal user may meet the requirements is by choosing a coal with properties that minimize the emission of pollutants.* Tables E.10 through E.12 summarize several parameters of coal on a regional basis. Table E.12 focuses on considerations important in determining the amount of coal needed. In general, western coals have high ash and moisture content coupled with low sulfur and heat content. Coals from the Appalachian Regions and the Eastern Interior Region vary in their sulfur content and usually have higher heat content and lower ash and moisture content than western coal. The average content of major trace elements in representative coals are listed by state and region in Table E.11. The uranium and thorium concentrations of representative coals from a number of different regions are listed in Table E.12. Actual values for these parameters are highly variable both among and within seams.

A wide array of air pollution control devices and techniques are available to reduce emissions to within allowable levels. A number of technologies are available to clean the stack emissions of specific pollutants (i.e., ash, SO_x, NO_x, etc.).

Of the ash produced during coal combustion, that portion which exits the stack is called atmospheric fly ash. Existing technologies to reduce fly ash emissions include wet scrubbers of the Venturi (99.0 percent efficient) or moving-bed (99.9 percent efficient) type, electrostatic precipitators (99.9 percent efficient), or fabric filter systems (99.9 percent efficient). The majority of ash produced by combustion does not exit the stack, and its disposition is discussed in the following section on solid waste. These efficiencies are nominal, and may be adjusted slightly, depending on coal type (Baruch 1976; Locklin et al. 1974; Phelan et al. 1976; Southern Research Institute 1975).

A number of near-term options for SO_x control have been developed which meet the emission standards set for coal-fired furnaces (Commerce Technical Advisory Board Panel 1975). These include (1) the use of low-sulfur coal,* (2) coal beneficiation,* (3) flue-gas desulfurization (FGD), and (4) a combination of coal beneficiation and FGD. Using low-sulfur coal is the most desirable option because it minimizes the need for complex and expensive technology.* However, only western coal meets the present New Source Performance Standard (NSPS) (USEPA 1971b) of 1.2 lb SO_2/million Btu. Western coal is in limited supply and is located far from the areas (the east and midwest) where demand has been the greatest. Coal beneficiation involves crushing and washing the coal, which removes some of the ash, trace metals, and pyritic-sulfur-bearing materials (inorganic sulfur) by physical or mechanical means (Commerce Technical Advisory Board Panel 1975). Beneficiation reduces the ash content by 65 percent and the sulfur content by 55 percent (on a Btu basis), and heat content is increased by 20 percent. FGD systems may be either "throwaway" (which produce waste sludge as a by-product) or "regenerable" (which regenerate the sorbent and yields sulfuric acid or elemental sulfur as a by-product). Four systems now in operation represent about 90 percent of the FGD technology installed or under construction: (1) lime-limestone scrubbing, (2) double alkali scrubbing, (3) magnesia scrubbing, and (4) the Wellman-Lord process (Ottmers et al. 1975). The first two are throwaway systems, with lime-limestone scrubbing receiving the widest application of the four (Commerce Technical Advisory

*May not be applicable under the 1977 Amendments to the Clean Air Act.

Table E.11. Average Trace-Element Concentrations (ppm) in Coal by State

	Northern Appalachian		Southern Appalachian				Eastern Interior			Powder River Region		Four Corners	
Element	W. Va.	Penn.	Eastern Ky.	Ala.	Va.	Tenn.	Ill.	Western Ky.	Ind.	Mont.	Wyo.	New Mexico	Ariz.
Arsenic	9	16	6	13	10	9	6	7	7	<6	1[a]	2[a]	2[a]
Barium	77	70	79	110	99	120	49	44	31	380	170	270	39[g]
Beryllium	1.2	0.8	1.5	0.74	1.1	0.58	1.3	1.4	1.7	1.5	2.4	0.94	0.97[g]
Boron	20	15	19	30	13	24	81	70	85	60	36	43	49[g]
Cadmium	-	-	-	-	-	-	2.9[b]	-	-	<0.1[f]	0.46[a]	<2.6[a]	<0.54[a]
Chromium	19	24	19	19	20	19	29	18	19	3	5.8	11	9.7[g]
Cobalt	17	18	15	18	14	13	15	16	24	7.7	5.2	15	-
Copper	11	13	11	14	13	11	8.3	8.8	9.7	3.2	4.4	5.9	4.9[g]
Fluorine	70	90	30	90	50	120	59[b]	-	50[g]	70	160[a]	160[a]	70[a]
Lead	4.9	5.2	4	3.7	6.1	4.9	33	6.4	7.2	4.8	0.61	4.7	3.9[g]
Lithium	44	64	78	75	34	36	45	16	24	27	19	16	19[g]
Manganese	21	21	26	19	42	23	73	19	26	57	14	19	9.7[g]
Mercury	0.12	0.20	-	-	-	-	0.18[d]	-	0.08	0.07	0.05[a]	0.08[a]	0.05[a]
Molybdenum	6.2	9.8	5.2	11	8.3	7.8	8.8	7.4	5.2	4.8	2.2	2.0	0.97[g]
Nickel	18	20	16	17	22	16	25	16	33	3.3	4.1	8.1	4.9[g]
Selenium	3.4[c]	3.7[c]	3.1[c,h]	5.1[c]	4.4[c]	4.9[c]	2[b]	3.1[c,h]	4[c]	3[c]	0.8[a]	2.0[a]	2.1[a]
Tellurium	-	-	-	-	-	-	-	-	-	-	0.025[a]	0.03[a]	<0.02[a]
Thallium	-	-	-	-	-	-	-	-	-	-	0.4[a]	0.24[a]	<0.2[a]
Tin	1.5	1.1	4.6	2.2	2.3	1.8	2.6	2.5	0.74	1.1	1.4	1.9	0.97[g]
Vanadium	30	33	29	31	33	34	35	32	35	12	15	25	9.7[g]
Zinc	17	22	15	22	23	23	140	48	73	42	37	19	9.7[g]
Zirconium	63	68	60	56	44	45	88	77	100	77	39	110	39[g]
Uranium range, not avg.	<10-30[e]	20-190[e]	10[e]	-	<10[e]	-	<10-80[e]	-	10[e]	10-340[e]	10-1000[e]	10-6200[e]	-
#Samples for data from Abernethy et al. (1969)	247	117	26	47	51	25	29	50	31	8	3	14	1

From Dvorak et al. (1977). Except for entries marked by superscripts "a" through "f", entries in this table are based upon data in Abernethy et al. (1969).

[a]Swanson (1972).

[b]Ruch et al. (1974).

[c]Lakin (1973).

[d]Ruch et al. (1971).

[e]Abernethy and Gibson (1963).

[f]U.S. Geological Survey (1974).

[g]Based on a single sample.

[h]Mean value for all of Kentucky.

Table E.12. Range of Uranium and Thorium Concentrations and Geometric Means (expected values) for Coal Samples Taken from Various Regions of the United States

Region	Coal rank	Number of samples	Uranium concentration (ppm)		Thorium concentration (ppm)	
			Range	Geometric mean	Range	Geometric mean
Pennsylvania	Anthracite	53	0.3-25.2	1.2	2.8-14.4	4.7
Appalachia[a]	Bituminous	331	<0.2-10.5	1.0	2.2-47.8	2.8
Interior[b]	Bituminous	143	0.2-43	1.4	<3 -79	1.6
Northern Great Plains[c]	Subbituminous, lignite	93	<0.2-2.9	0.7	<2.0-8.0	2.4
Gulf[d]	Lignite	34	0.5-16.7	2.4	<3.0-28.4	3.0
Rocky Mountain[e]	Bituminous, subbituminous	134	<0.2-23.8	0.8	<3.0-34.8	2.0
Alaska	Subbituminous	18	0.4-5.2	1.0	<3.0-18	3.1

From Swanson and Medlin et al. (1976).

[a]Pennsylvania, Ohio, Maryland, West Virginia, Virginia, Kentucky, Tennessee, Alabama.

[b]Michigan, Indiana, Iowa, Nebraska, Missouri, Kansas, Oklahoma, Arkansas.

[c]North Dakota, Montana, Wyoming.

[d]Alabama, Mississippi, Arkansas.

[e]Wyoming, Colorado, Utah, Arizona, New Mexico.

Note: The analyses for uranium and thorium were performed on whole coal. The arithmetic average concentrations of thorium and uranium in ppm for all coal samples and various ranks of coal for the whole United States are as follows:

Coal rank	Samples	Thorium (ppm)	Uranium (ppm)
All coal	799	4.7	1.8
Anthracite	53	5.4	1.5
Bituminous	509	5.0	1.9
Subbituminous	183	3.3	1.3
Lignite	54	6.3	2.5

Board 1975; Ottmers et al. 1975). Some SO_x (and NO_x) will leave the stack and may contribute to a condition known as acid rain (Dvorak and Pentecost et al. 1977). This phenomenon occurs when rainwater, which is already slightly acidic, is subjected to increased sulfates and nitrates in the atmosphere. The result is a drop in the pH of rain from a normal 5.7 to < 3.0.

Coal combustion remains the largest stationary source contributor (42 percent) to NO_x emissions (Brown et al. 1974). Nitrogen oxides (NO_x) are formed in the furnace by thermal fixation of atmospheric nitrogen and the conversion of chemically bound nitrogen in coal. The most viable means for minimizing NO_x formation is modification of the combustion process (Brown et al. 1974; Crawford et al. 1976). Two promising methods are the control of excess air in the combustion process, and staged combustion, where coal is burned in a primary reducing zone and a lower-temperature post-flame oxidizing zone. With these methods, NO_x emission reductions of 50 to 65 percent have been reported (Armento 1975; Crawford et al. 1976).

Other emission products include CO_2, CO, fluoride, hydrocarbons, trace metals, and radionuclides (Dvorak and Pentecost et al. 1977). Ambient concentrations of all these substances are increased in the vicinity of the emission source, and the resulting concentrations in air, land, and water depend on emission rate, stack height and diameter, plume rise, prevailing winds, topography, and meteorological conditions (Dvorak et al. 1978).

Aquatic effluents from coal combustion are wholly limited to thermal loading when heat rejection is required. If the boiler produces steam as a means of energy transmission, heat rejection will be required. When coal-fired boilers produce process steam (for a consumptive use such as heating), heat rejection may not be needed. However, alternate fossil fuels produce comparable amounts of waste heat, and nuclear fuels may produce as much as one-third more. Ancillary facilities such as coal and limestone storage piles, settling ponds (see Sec. E.2.5.5) and liquid waste streams may contribute additional effluents through runoff, seepage, and discharge of dissolved solids into the receiving water. Such effluents are usually monitored and regularly subjected to the equivalent of secondary sewage treatment as necessary before discharge into receiving water (Lewis and Stupka 1977).

E.2.5.5 Solid Waste Disposal

Solid wastes generated by burning of coal and by pollution abatement processes result from the noncombustible substances in the coal and include (1) slag and bottom ash, (2) fly ash, and (3) scrubber sludge.

Slag is that portion of the total ash that melts into a viscous fluid at burner operating temperatures. It is usually recovered by tapping the molten material into a tank of water, where it is converted into a glossy, uniformly sized material of No. 30 to No. 4 mesh. Bottom ash is dry ash that is too heavy to be entrained in the flue gas. It is recovered by sifting through a grate at the bottom of the boiler and being mixed with the slag to form a material called aggregate.

Fly ash is that portion of the total ash carried up the flue; up to 99.5 percent can be retained by pollution abatement equipment. Fly ash may comprise up to 80 percent of the total ash produced from burning coal (in pulverized burners), or as little as 25 percent (in cyclone furnaces), with aggregate making up the remainder (Dvorak et al. 1977). Fly ash is similar to sandy silt in texture, with a pH ranging between 6 and 11. Tables E.13 and E.14 list the major chemical and trace element constituents in coal ash. These chemical constituents may be grouped into three general classes (Klein et al. 1975a, 1975b), as follows:

- Class I. Elements that are not volatilized in the combustion zone, but instead form a rather uniform melt that becomes both fly ash and slag. These elements include Al, Ba, Ca, Ce, Co, Eu, Fe, Hf, K, La, Mg, Mn, Rb, Sc, Si, Sm, Sr, Ta, Th, and Ti.
- Class II. Elements that are volatilized on combustion, and condense or absorb on the fly ash as the flue gas cools, leading to depletion from the slag and concentration in the fly ash. These elements include As, Cd, Cu, Ga, Pb, Sb, Se, and Zn.
- Class III. Elements that remain almost completely in the gas phase. These elements include Hg, Cl, and Br.

Coal ash also contains radioactive elements that were originally present in the coal. These include uranium, thorium, and radium. Examples of radionuclides found in coal ash from a number of representative locations are given in Table E.15.

The prevalent method for disposing of fly ash is by wet sluicing from the electrostatic precipitators or fabric filters to onsite ash ponds. The water requirements for this operation range from 5,000 to 165,000 liters per metric ton (L/MT) (1200 to 40,000 gal/ton) of ash (Frascino and Vail 1976). The pond may be lined with an impermeable substance (e.g., clay) to retard seepage. The ash is allowed to settle out and in many cases the effluent is discharged directly into natural surface waters. Bottom ash may be combined with fly ash or disposed of separately. Where FGD is employed, ash is often mixed with scrubber sludge after it has been treated. After evaporation has occurred, these ash ponds are covered over with soil or excavated and the material trucked to a sanitary landfill. Where feasible, strip or deep mines may be used to dispose of this material (Dvorak et al. 1978).

Scrubber sludge is the waste material generated by throwaway FGD methods. The quantity of sludge produced depends on the sulfur content of the fuel and the amount of coal burned. Sludge consists mainly of calcium carbonate ($CaCO_3$), calcium sulfite ($CaSO_3 \cdot 2H_2O$), and calcium sulfate ($CaSO_4 \cdot 2H_2O$), with traces of calcium hydroxide [$Ca(OH)_2$] (Cooper 1975). Some trace elements from the flue gas may also be present. The proportion of solids and water in the sludges can vary from 30 to 70 percent by weight, depending on the process used in dewatering this material. The sludges are thixotropic (i.e., become fluid when disturbed, and set to a gel when allowed to stand), and for this reason are often treated with a fixative before ultimate disposal (Dvorak et al. 1977).

Table E. 13. Major Chemical Constituents of Coal Ash

Constituents	Range (%)
Silica (SiO_2)	20-60
Alumina (Al_2O_3)	10-35
Ferric oxide (Fe_2O_3)	5-35
Calcium oxide (CaO)	1-20
Magnesium oxide (MgO)	0.25-4
Titanium dioxide (TiO_2)	0.5-2.5
Potassium oxide (K_2O)	1.0-4.0
Sodium oxide (Na_2O)	0.4-1.5
Sulfur trioxide (SO_3)	0.1-12
Carbon (C)	0.1-20

From Dvorak et al. (1977). Data from Hecht and Duvall (1975).

Table E. 14. Trace-Element Constituents of Coal and Coal Ash

Element	Coal (ppm)	Bottom ash (ppm)	Precipitator ash (ppm)
Antimony	.08	< 1.0	4.4
Arsenic	.87	4.4	61.
Barium	440.	5600.	15,000.
Beryllium	.29	.40	5.2
Boron	37.7	83.2	1040.
Cadmium	.11	1.1	4.2
Chromium	1.8	15.6	8.9
Copper	5.2	68.	238.
Fluorine	78.5	44.6	2880.
Germanium	.48	< .1	9.2
Lead	.15	1.0	4.0
Manganese	26.2	56.7	374.
Mercury	.131	< .010	< .010
Molybdenum	.87	3.2	12.
Nickel	3.67	14.5	92.9
Selenium	.98	.14	16.4
Vanadium	< 13.	< 100.	< 100.
Zinc	16.2	< 8.0	386.

From Dvorak et al. (1977). Data from Holland et al. (1975). Data are for a particular batch of coal and are not necessarily representative of all coal. Sulfur content of the coal (4%) indicates use of Eastern coal.

Table E.15. Radioactivity in Fly Ash from Coal Combustion

Source of coal sample	Ra-226	Ra-228	Th-228	Th-232
Appalachia[a]	3.8	2.4	2.6	No analysis
Utah	1.3	0.8	1.0	No analysis
Wyoming	No analysis	1.3	1.6	No analysis
Alabama	2.3	2.2	2.3	No analysis
Unidentified power plant	4.3	2.9	2.9	2.9
Hartsville power plant[b]	2.3	3.1	No analysis	3.1
Colbert power plant[c]	3.1	6.9	1.6[d]	6.9[d]
Widows Creek power plant	1.6	2.7	2.8	2.7

From Dvorak et al. (1978). Adapted from McBride et al. (1977).

[a]Average values for samples of fly ash obtained from combustion of 6 samples of semibituminous coal from Appalachian mines.

[b]Average values for Ra-226 and Th-232 in 5 samples of fly ash; Ra-228 assumed in secular equilibrium with Th-232.

[c]Average of 12 samples; Ra-228 assumed in secular equilibrium with Th-232.

[d]One of these numbers appears to be in error. In secular equilibrium, the activities of Th-228 and Th-232 should be the same.

Scrubber sludge, whether disposed of separately or with other waste materials, must first be aerated and the calcium sulfate precipitated. The solids are tapped off to a clarifier where further settling occurs and the material is then ready for mixing with ash or pumping to a settling pond. It may be left in the ponds permanently, allowed to dry and trucked to a landfill, or combined with ash and covered with earth at an onsite or offsite location (Dvorak et al. 1978). Figure E.16 is a flow diagram of the potential disposal methods for ash and sludge waste materials.

E.2.6 Health Effects

The deleterious health effects which can result from coal use take the form of morbidity and mortality in the occupational and general populations. It should be noted that although many of the air pollutants generated in the coal fuel cycle are also produced by other sources such as internal combustion engines, industrial processes, etc., the effects of the pollutants on human health will be discussed in this assessment only as they pertain to coal production.

Occupational morbidities and mortalities can occur as the result of respiratory diseases and "on-the-job" accidental injuries. These can be quantified via presently available occupation-related vital statistics. Public health impacts may result from transportation accidents as well as effluents reaching air and water. Increased mortality from respiratory diseases can result from increased air pollution. Decrements in potable water quality are known to influence the incidence of infectious diseases and possibly non-infectious diseases as well (Kuzma et al. 1977; Page et al. 1976; USEPA 1976).

In this discussion the coal fuel cycle has been divided into five broad component areas: extraction, cleaning, transportation, combustion, and disposal. Each step in the cycle has its own complement of injuries and diseases. Accordingly, each step is discussed separately and distinctions are made between the occupational and public health risks. The incremental health impacts of each component will also be evaluated for their contribution to the overall coal fuel impact on human health.

E.2.6.1 Extraction

The greatest potential for human health impact is generally.from the extraction component of the fuel cycle. In underground mining, large worker populations are exposed to substantial physical hazard during the course of daily activities, with resultant injury rates which are higher than those found in most other industries. The debilitating effects of the mine environment may continue even after direct exposure ceases, as evidenced by the large number of ex-miners suf-

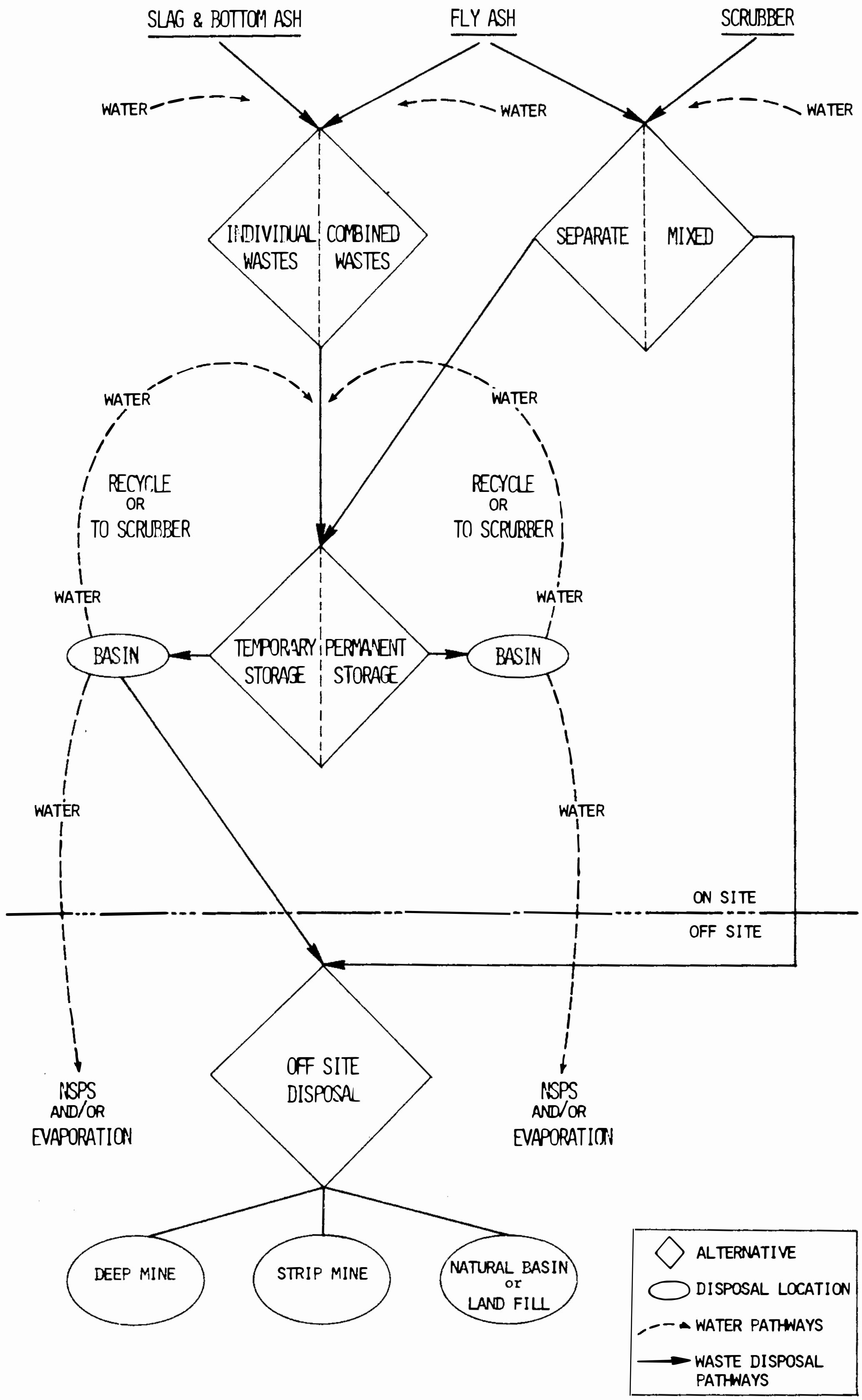

Fig. E. 16. Flow Diagram for Power Plant Ash and Scrubber Sludge Waste Disposal. From Dvorak et al. (1978).

fering from respiratory diseases after long-term exposure to mine conditions (Morgan 1975). Though continued mechanization of underground mining can reduce the hazards of the extraction process, the increased demand projected for future coal production may offset the potential reductions in health impacts for coal extraction. The introduction of large-scale surface mining operations has also mitigated extraction influences on health to a large degree. This technique has an injury rate less than one-quarter of that for underground mining (Council on Environmental Quality 1973). Additionally, the prevalence of lung disease is substantially reduced among surface miners.

The known public health effects of coal mining are limited. However, it is possible to conjecture potential hazards resulting from surface activities associated with extraction. Nonminer residents of coal-mining communities experience increased rates of respiratory disease (Dvorak et al. 1977). This disease rate is independent of cigarette smoking. Mine drainage can adversely affect water quality, posing a potential health hazard, particularly where drinking water is supplied by private wells. Increased coal production may have the effect of increasing environmental contaminants while simultaneously requiring exposure of larger populations in support of the enlarged extraction activities.

E.2.6.2 Cleaning

The quantity of coal which is cleaned represents half the annual U.S. coal production (U.S. Bureau of Mines 1975B). Accordingly, the occupational injuries associated with cleaning must be factored into the overall health impacts of the coal fuel cycle.

The public health impacts of coal cleaning are minimal. Proper impoundment and treatment of water and disposal of wastes protects water quality. Failure to do so can degrade the quality of nearby public water supplies.

E.2.6.3 Transportation

The major public health hazard from coal transportation also assumes the form of accidental injury. The risk associated with this hazard can be related to the quantity shipped multiplied by the distance over which it is transported. The population at risk can be divided between pedestrians on the railroad right-of-way (trespassers) and vehicle occupants injured in collisions at rail crossings or with coal-handling trucks. A potential public health hazard also may be posed to persons who live or work in proximity to coal transport routes. Exposure to fugitive dust (estimated to be approximately 1 percent of the total coal transported) can aggravate pre-existing disease states or could adversely influence susceptible individuals (Buehring 1975).

E.2.6.4 Combustion

In addition to the typical occurrences of accidental injuries during coal combusting, exposure to coal dust in the work place may result in increased rates of respiratory diseases and conditions in the combustion facility work force. Combustion process releases can induce serious adverse effects on human health (Commission on Natural Resources 1975). The body's response to these impacts may differ according to the age and condition of the victim, the nature of the noxious agent, and the duration of exposure. The clinical manifestations typically observed among persons exposed to airborne pollutants derived from coal combustion involve pulmonary disorders (Hub et al. 1977).

Inflammation of the pulmonary tissue and the general debility produced by toxic effects make both the upper and lower respiratory tracts more subject to infection. Thus, the incidence of colds, influenza, pneumonia, and acute pulmonary diseases tends to be elevated in exposed populations (Heimann 1967). Acute asthma attacks can be induced in susceptible persons by respired irritants, and the severity of an attack, whether pollutant-induced or not, can be markedly increased by the synergistic relationships found between the body's response to histamines (released in the initial phase of an asthma attack) and prior exposure to other irritants. Clinical experience and epidemiologic data both support the finding that attacks of asthma in children and adults are associated with acute episodes of air pollution exposure as well as respiratory infection (Green 1976).

Early inflammatory responses have been shown to lead to the development of obstructive lung disease after prolonged exposure to irritant particles. A person already in poor health from a condition such as chronic respiratory or cardiovascular disease, whether originally caused by the pollutants in question or not, is at much higher risk of suffering an acute or fatal episode when exposed to airborne irritant, as demonstrated in the classic air pollution episodes of Donnora, Pa., in 1948 and London, U.K., in 1952 (Williamson 1973). Prolonged exposure to irritants and toxins has been shown to lead to irreversible damage to lung tissue. Emphysema and chronic bronchitis have been shown to develop in a variety of experimental animals exposed to low levels of common pollutants. (These are also characteristic effects of chronic pulmonary injury seen, for example, after prolonged use of tobacco.)

E.2.6.5 Waste Disposal

The public health risk of the final phase of the coal fuel cycle, waste disposal, has two parts. They are the health risks from decreased water quality, which can result from ash pond overflow or ash pile runoff, and the public accident risk associated with transportation of combustion wastes to the disposal site. Transport of combustion wastes presents a recognizable public accidental injury risk. The nature of this risk is similar to that for fuel hauling.

Occupational injury resulting from combustion waste disposal activities is similar to that of sand and gravel quarry operations, including the possibility for transportation-related injuries. Only a fraction of the original mass and volume is handled through disposal. Occupational injury rates from materials handling should reflect this reduced transportation requirement.

E.3 SOCIOECONOMIC CONSIDERATIONS OF COAL USE

Coal conversion affects the coal industry in three ways. First, increased demand for coal leads to expansion of existing mines and opening of new ones. Second, increased demand for coal tends to maintain and stabilize local businesses and activities associated with the entire coal cycle (i.e. mining, cleaning, transportation, combustion, and waste disposal). However, increased production and stabilization of some local economic activities can produce social changes within particular coal regions. Third, coal production may become the new economic base in isolated areas, which could lead toward the urbanization of previously undeveloped areas.

E.3.1 Demography and Settlement Pattern

E.3.1.1 Mining

The primary issues affecting mine locations are land ownership, leasing agreements, and reclamation procedures. These factors are of particular importance in regions where much of the land is federally owned and regulated (Federation of Rocky Mountain States 1975).

Once mine locations have been determined and mining contracts agreed upon, other socioeconomic issues must be considered. These issues relate directly and indirectly to the labor requirements for mine operation. In regions where population densities are high and urban centers generally are within commuting distances, large in-migrations to mining areas are not likely. However, in small isolated communities rapid growth and changing social patterns can occur. Increased mining requires more in-migrant miners and settlement developments near mine sites. However, in spite of this influx, shortages in some mining and mining-induced occupations can occur (Hannah and Mosier 1977). Rapid population increases can produce various kinds of social, economic, and political impacts.

E.3.2 Social Issues

Social issues center on how in-migrants affect (1) the ability of local rural communities to meet increased social service demands and (2) the social system of the local area (U.S. Department of the Interior 1974; Gold 1974).

Service demands that must be met include schools, housing, sanitation, water, medical care, and police and fire protection. Since in-migrants bring with them new ideas, values, and behavior patterns, the sociocultural structure of the local community may be affected in different ways. In some cases, the older, more traditional order may collapse and disappear, particularly among populations having a single ethnic makeup, i.e., Indian, Hispanic, etc. (Lexington Institute for Mining and Mineral Research 1976; U.S. Department of the Interior 1974). Consequently, there may be a permanent loss in the cultural diversity of the language, arts, lifestyle, and folklore of a particular region (U.S. Department of the Interior 1974).

Social stress combined with insufficient social services reduces the quality of life for old residents and newcomers alike, thereby increasing stress in both populations. Social problems, such as increased crime, suicide attempts, alcoholism, broken homes, over-demands on mental health facilities, etc., have been reported in rapidly developing western boom towns (Federation of Rocky Mountain States 1975; Gilmore and Duff 1974; U.S. Department of the Interior 1974).

Boom towns are typically small, rural towns that have undergone rapid population increases and development associated with coal development that has already occurred in the region (Gilmore and Duff 1974, 1975; U.S. Department of Housing and Urban Development 1976).

E.3.3 Economic Issues

A major economic issue in the west concerns the effects that coal development will have on a traditional economic base in which agriculture and tourism are emphasized, in an area where mining has little historic precedent and may impact resources of national interest. This factor is particularly important in an area where the traditional agricultural base is closely tied to the social structure (U.S. Department of the Interior 1974; U.S. Comptroller General 1977). Intensive mining developments will produce economic benefits for the region and some communities. However, benefits may not be received by certain communities which need the money to compensate for fiscal spending required to meet the increased service demands of the new work force (Gilmore 1976; U.S. Comptroller General 1977). Furthermore, the economic benefits that a community may receive often begin after the time when substantial capital must be invested to improve the physical services (i.e., sewage, water, schools, etc.). Inflation and cost-of-living increases are also a concern in rapidly developing areas. For example, increased land values, rents, housing problems, and taxes were reported in the ethnographic study of the coal boom town of Forsyth (Gold 1974).

Another economic issue concerns those communities that have become highly dependent upon coal mining, such as those communities known from the Appalachian area. Absence of a diversified economic base links the social, economic, and political structure of its people to the regional and national trends in this industry. When production demands drop, entire communities are not able to quickly readapt to another source of economic activity and are strongly affected by periods of lowered production. For example, in the 1950's and 1960's, the Appalachian areas were characterized by low coal production, high unemployment, and a corresponding trend in higher out-migration (Appalachian Regional Commission 1975). Large out-migrations of this type will have extensive social and political consequences at the local family, group, and community levels.

E.3.4 Political Issues

Change in the political structure and existing political establishments is another issue (U.S. Department of the Interior 1974). The informal political systems of rural areas, which are distinguished by personalism in decision and policymaking, may formalize (U.S. Department of the Interior 1974; Northern Great Plains Resource Program 1974). Newcomers and national business interests may be able to politically dominate and displace the influence of the local residents and communities (Federation of Rocky Mountain States 1975; U.S. Department of the Interior 1974).

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APPENDIX F. WATER RESOURCE REGIONS

F.1 NEW ENGLAND WATER RESOURCE REGION

The New England basin, with an area of about 150,000 km^2 (59,000 sq mi) (U.S. Geological Survey 1977), includes major rivers (such as the Connecticut, Housatonic, Penobscot, and Kennebec) that flow into the Atlantic Ocean or Long Island Sound. In addition to major reservoirs (Quabbin and Scituate), the area also contains numerous natural lakes such as Moosehead and Winnipesaukee. Coastal areas include the mouths of the many seaward-draining streams, as well as large bays such as Narragansett and Boston.

Unpolluted surface waters in the New England region typically are soft ($\leq$60 ppm hardness as $CaCO_3$) with low levels of total dissolved solids (TDS) (>120 ppm except for southern Vermont and western Connecticut and Massachusetts, where TDS of up to a few hundred ppm are found) and low levels of total suspended solids (TSS) (<270 mg/L) (Water Information Center 1973). Regional water quality problems include increased suspended-solids loads from erosion, especially as a result of silviculture in New Hampshire and Maine, and excessive nutrient levels in Vermont, Maine, and New Hampshire waters. Toxic pollutants affecting regional water quality include heavy metals, pesticides, phenols, and PCBs (U.S. Environmental Protection Agency 1977a). The New England region is also described as having severe thermal pollution problems (Water Information Center 1973). The Naugatuck and Pemigewasset rivers, which have historically experienced water quality problems as a result of municipal and industrial discharges, have responded favorably to improved waste treatment programs; thus, fishery and recreational uses are returning (U.S. Environmental Protection Agency 1977a).

The New England Region includes the glaciated Appalachians and adjacent portions of New England. Bedrock aquifers are generally unproductive; exceptions are the Hudson section of the Valley and Ridge topographic province and the southern Adirondack Mountains. Here, Paleozoic limestones and minor sandstone formations function as aquifers. Fractured granitic and volcanic rocks associated with metamorphics along the mountain ranges yield small amounts of water to wells.

Buried and extant stream valley sediments comprised of sand and gravel constitute the most productive groundwater reservoirs in the region. The most areally extensive aquifers are glacial outwash deposits along the coasts of Maine and Massachusetts. They occur also in the Connecticut River valley. Glacial till and unstratified drift cover much of the region; however, well yields are low (Walton 1970).

In the New England Water Resource Region, average annual runoff is equivalent to 250 x 10^6 m^3/day [67 billion gal/day (bgd)]. Surface freshwater withdrawals in 1975 were estimated to be 17 x 10^6 (4.4 bgd); most of the 53 x 10^6 m^3/day (14 bgd) total off-channel water withdrawal (for public supplies, rural uses, irrigation uses, and self-supplied industrial and electrical generation uses)* was of saline water, which accounted for 35 x 10^6 m^3/day (9.3 gpd). Use of groundwater was relatively small, accounting for only 2 x 10^6 m^3/day (0.6 bgd). About 9 percent of the total fresh water withdrawn was consumed (evaporated or incorporated into products) (U.S. Geological Survey 1977).

The primary user of water in the region is the self-supplied industrial sector, including electricity-generating utilities (Table F.1). Saline water is used heavily (about five times as much as freshwater) for condenser and reactor cooling. Lesser withdrawals of water are accounted for by public supplies (which consume the most freshwater of any sector), rural uses, and irrigation. Generation of hydroelectric power uses approximately 490 x 10^6 m^3/day (130 bgd) of the national total of 12.5 x 10^9 m^3/day (3300 bgd), making the region the eighth-ranking in this respect (U.S. Geological Survey 1977). Projections to the year 2000 indicate probable water-supply problems for the region as a result of increased electrical generation. The Boston,

*Off-channel uses are to be distinguished from in-channel uses, that is, "uses taking place within the river channel itself ... (including) water used for hydroelectric power generation" and nonwithdrawal uses, that is, "water used for navigation, sport, fishing, freshwater discharge into estuarine areas in order to maintain proper salinity, and the disposition and dilution of waste water" (U.S. Geological Survey 1977).

Table F.1. Off-channel Water Withdrawals (million gpd)[a] in the Water Resource Regions, by Sector, 1975[b]

Water Resource Region	Withdrawals by Sector			
	Public Supplies (industrial, commercial, domestic)	Rural (domestic, livestock)	Irrigation	Self-Supplied Industrial and Electrical Generation
New England	1400 (180)	120 (44)	57 (57)	12,700 (160)
Mid-Atlantic	5300 (760)	470 (180)	230 (200)	46,000 (470)
Tennessee	330 (40)	79 (57)	7.2 (6.9)	10,000 (180)
South Atlantic-Gulf	3100 (930)	750 (560)	3,100 (1,500)	10,000 (750)
Great Lakes	3100 (410)	370 (140)	99 (94)	32,400 (420)
Ohio	2200 (240)	490 (300)	34 (32)	33,020 (640)
Upper Mississippi	3000 (170)	450 (300)	150 (140)	15,015 (190)
Lower Mississippi	750 (310)	130 (120)	4,900 (4,000)	10,300 (1,100)
Arkansas-White-Red	930 (330)	330 (310)	10,000 (8,000)	3,940 (370)
Texas Gulf	1400 (560)	240 (240)	7,100 (6,500)	13,400 (680)
Rio Grande	350 (190)	63 (54)	4,900 (3,200)	129 (75)
Souris-Red-Rainy	48 (20)	40 (27)	42 (41)	230 (6)
Missouri Basin	1200 (290)	620 (550)	28,000 (14,000)	4,736 (120)
Upper Colorado	77 (26)	23 (17)	3,700 (1,500)	255 (87)
Lower Colorado	510 (240)	85 (74)	7,520 (5,700)	430 (240)
Great Basin	380 (140)	76 (25)	6,000 (3,400)	396 (69)
California	3700 (1500)	230 (130)	35,000 (21,000)	11,800 (210)
Pacific Northwest	1200 (230)	310 (230)	28,000 (9,900)	3,441 (310)

From U.S. Geological Survey (1977).

[a]1 million gpd = 3.79 × 10^3 m^3/day.

[b]Data in parentheses represent freshwater consumption.

Massachusetts, area is presently stressed during prolonged drought periods, and increased demand on New England's water resources is forecast, particularly in the Connecticut River and Long Island Sound areas. Increased future water needs may have to be satisfied by more ocean cooling, expanded use of freshwater resources in southcentral Maine, and/or water resource development (Hyndman and Roach 1977).

The coastal portions of the region (Connecticut, Rhode Island, Massachusetts, southern Vermont and New Hampshire, and coastal Maine) have been identified by the Water Resources Council as among the nation's most critical areas where water supply problems may constrain energy development; water supplies may be inadequate for power generation and related cooling needs by 1985 (Water Resources Council 1974).

F.2 MID-ATLANTIC WATER RESOURCE REGION

The Mid-Atlantic basin, with an area of about 264,000 km^2 (102,000 sq mi) (U.S. Geological Survey 1977), includes major rivers (such as the Hudson, Delaware, Susquehanna, Potomac, James, and Rappahannock) that flow into the Atlantic Ocean and coastal bays, as well as an area in northeastern New York-northern Vermont where drainage is northward towards the St. Lawrence River in Canada. Major reservoirs generally do not constitute important surface-water features, although some tributaries to the Delaware and Hudson systems are impounded. The most prominent natural lakes are found in the northern parts of the region in New York (Lakes George and Champlain, the latter shared with Vermont) and Pennsylvania (Lake Wallenpaupack). Coastal areas include the Chesapeake drowned-valley system (Chesapeake Bay and the mouths of the Potomac, Rappahannock, York, and James rivers), Delaware Bay, the mouth of the Hudson River (including Upper and Lower New York Bay), and the extensive bays between the mainland and barrier beaches from Virginia to Long Island.

Surface waters in the Mid-Atlantic region are of medium hardness (60 to 120 ppm hardness as $CaCO_3$) in the James River basin, the lower Hudson and Delaware river basins, and portions of the upper Susquehanna and Potomac river basins. They are typically soft (<60 ppm hardness) elsewhere. Dissolved solids levels in surface waters may reach a few hundred ppm in the Mohawk-Hudson river system, in areas of eastern Pennsylvania and northern New Jersey, and in a belt including the highlands area of central Maryland and the Virginia—West Virginia border. Isolated areas in eastern Pennsylvania may have surface waters exceeding 350 ppm TDS. In other parts of the Mid-Atlantic region, TDS levels are generally below 120 ppm. Stream (TSS) levels, although generally less than 270 ppm throughout the region, may be higher (270 to 1900 ppm) in isolated Piedmont areas of eastern Pennsylvania, Maryland, and Virginia (Water Information Center 1973).

Regional water quality problems include severe thermal pollution loads, pesticides in the lower reaches of major river basins, and heavy metals, particularly in the more northern states (New York and Pennsylvania) (Water Information Center 1973). Other toxic pollutants of concern in the region include Kepone (James River), phenols, and PCBs (U.S. Environmental Protection Agency 1977a). Acid mine drainage in the anthracite coal area of northeastern Pennsylvania also adversely affects water quality. The combined acid discharged by the major river systems in eastern Pennsylvania actually exceeds that of the bituminous Allegheny-Monongahela river basin of western Pennsylvania (part of the Ohio Water Resource Region; see Sec. F.6) (U.S. Environmental Protection Agency 1977a). Increased nutrient loads and lake eutrophication have been reported as a problem in Maryland, Delaware, and New York (U.S. Environmental Protection Agency 1977a).

While major rivers such as the Hudson may deteriorate within a 129-km (80-mi) reach near Albany, New York, other rivers such as the Mohawk and Susquehanna in New York have shown improvement following the installation of water treatment plants (U.S. Environmental Protection Agency 1977a). Saltwater encroachment in coastal areas as a result of groundwater pumping may increase dissolved solids in groundwater to 3000 ppm (U.S. Environmental Protection Agency 1977a; U.S. Geological Survey 1970).

In the Mid-Atlantic Water Resource Region, average annual runoff is equivalent to 320 x 10^6 m^3/day (84 bgd). Of the total off-channel water withdrawal of 200 x 10^6 m^3/day (52 bgd) in 1975, surface freshwater withdrawals accounted for about 83 x 10^6 m^3/day (22 bgd), while saline water withdrawals averaged about 102 x 10^6 m^3/day (27 bgd). Groundwater contributed less than 11 x 10^6 m^3/day (3 bgd). About 7 percent of the freshwater withdrawn was actually consumed (U.S. Geological Survey 1977).

The primary user of water in the region is the self-supplied industrial sector, including electricity-generating utilities (Table F.1.). Almost twice as much saline water as freshwater is used for condenser and reactor cooling. In contrast to water withdrawals, the greatest freshwater consumption is accounted for by the public supplies sector. Generation of hydroelectric power uses approximately 830 x 10^6 m^3/day (220 bgd), with the Mid-Atlantic Region being the fifth-ranking region in this respect (U.S. Geological Survey 1977).

Projections to the year 2000 point to probable water-supply problems. Freshwater supply shortages, presently experienced in the Delaware and Potomac rivers, will probably be a factor in the Hudson and Susquehanna river areas as well. However, coastal siting, which is necessary for saline water use (and currently the practice in the Lower Hudson, Delaware, and Chesapeake Bay areas), may be limited by site availability (Hyndman and Roach 1977). The Water Resources Council has categorized the area including southeastern New York, New Jersey, Delaware, and eastern Pennsylvania as being among the nation's most critical energy-related water-supply problem areas. Available water supplies may be inadequate for power generation and related cooling needs by 1985 (Water Resources Council 1974).

The groundwater resources of the Mid-Atlantic region occur in consolidated sedimentary rocks, unconsolidated sediments, and crystalline and metamorphic rocks. Yields to wells are greatest in the unconsolidated material; the lowest yields are derived from the crystalline and metamorphic rocks.

Consolidated sedimentary rocks such as limestones and sandstones are locally significant aquifiers within the region. Sandstones underlying portions of New Jersey, as well as eastern Pennsylvania, are excellent aquifers, producing large well yields.

Crystalline and metamorphic rocks associated with the Appalachian Mountains complex function as aquifers. The fractured and jointed rocks produce groundwater, although in small quantities.

Thick sequences of unconsolidated sands and silts, interbedded with clays, underlie the coastal plain areas. Sediments are up to hundreds of meters thick, increasing in thickness seaward. Large amounts of high-quality groundwater are produced from these sediments; locally, seawater intrusion renders the aquifer unusable. Alluvium along streamcourses is an excellent, though areally restricted, source of high-quality groundwater within the region (Walton 1970).

F.3 TENNESSEE WATER RESOURCE REGION

The Tennessee River basin, with an area of about 106,000 km^2 (41,000 sq mi) (U.S. Geological Survey 1977), consists of the heavily impounded Tennessee River and its tributaries from headwaters in southwestern Virginia and western North Carolina to its confluence with the Ohio River at Paducah, Kentucky. Major impoundments include Norris, Watts Bar, Chickamauga, and Kentucky lakes. Principal tributaries to the Tennessee River include the Holston and French Broad rivers, which join to form the Tennessee River at Knoxville, Tennessee, and downstream tributaries such as the Clinch, Hiwassee, Sequatchie, Elk, and Duck rivers.

Surface waters in the Tennessee region vary from soft (<60 ppm hardness as $CaCo_3$) in western and southcentral Tennessee to medium (60 to 120 ppm) in east Tennessee and northern Alabama and Georgia. Some headwaters in southwestern Virginia have harder water (120 to 180 ppm). Dissolved solids are typically in the 120 to 350 ppm range, with waters of less than 120 ppm TDS draining the western slopes of the Appalachians along the Tennessee-North Carolina border. Impoundment of the Tennessee River system reduces suspended sediment (TSS) levels in the mainstem, although tributaries have TSS loads in the 270 to 1900 ppm range (Water Information Center 1973).

Eutrophication has been cited as a problem in some reservoirs that have long retention times. Sources of water quality degradation include industrial and municipal discharges, particularly in populated and developed areas such as the Chattanooga, Kingsport, and Knoxville, Tennessee, areas. Adverse effects on pH, dissolved oxygen levels, and suspended and dissolved solids have been reported (U.S. Environmental Protection Agency 1977a). Elevated levels of mercury in sediments and biota have been reported from the Tennessee River in northern Alabama and from the North Fork of the Holston River (U.S. Environmental Protection Agency 1977a). Water quality problems have been related to surface mining of coal in the Clinch River basin (U.S. Environmental Protection Agency 1977a).

The French Broad River, which had elevated biological oxygen demand (BOD), suspended solids, and heavy metals from industrial-municipal pollutants, has experienced improvement in water quality following construction of waste treatment facilities (U.S. Environmental Protection Agency 1977a).

In the Tennessee Water Resource Region, average annual runoff is equivalent to 160 x 10^6 m^3/day (41 bgd). Of the total off-channel water withdrawal of about 42 x 10^6 m^3/day (11 bgd) in 1975, surface freshwater withdrawals accounted for about 38 x 10^6 m^3/day (10 bgd), while groundwater withdrawals contributed less than 1 x 10^6 m^3/day (0.3 bgd). About 3 percent of the freshwater withdrawn was actually consumed (U.S. Geological Survey 1977).

The primary user of water (and consumer of freshwater) in the region is the self-supplied industrial sector, including electricity-generating utilities (Table F.1). Generation of hydroelectric power (the system is controlled by the Tennessee Valley Authority) uses approximately 910 x 10^6 m^3/day (240 bgd), the Tennessee River region trailing only the Great Lakes and Pacific Northwest regions in this respect (U.S. Geological Survey 1977).

Projection to the year 2020 indicates no major low-flow water supply problems primarily because of the Tennessee Valley Authority's ability to regulate streamflow. The ability of the region to accommodate additional water-consumptive power plants is forecast (Hyndman and Roach 1977).

The Tennessee Region is underlain by many different rock types, several of which are productive groundwater reservoirs. The west-central portion of the state has unconsolidated to semiconsolidated deposits of the fringe of the Mississippi Embayment. Central Tennessee is underlain by up to several thousand meters of consolidated sedimentary rocks of Precambrian to Paleozoic age. East Tennessee is the most hydrogeologically complex area, characterized by consolidated sedimentary rocks of Precambrian to Paleozoic age, metamorphic rocks, and crystalline rocks of the outcropping basement complex.

The unconsolidated to semiconsolidated Mesozoic and Cenozoic sediments of west-central Tennessee are some of the most productive aquifers. The sediments are up to several hundred meters thick, increasing in thickness southward and westward. The geologic section shows sands and silts interbedded with clays. The sands are the producing zones; clay formations act as locally confining beds.

Thick sequences of limestones, dolomitic limestones, and dolomites in central Tennessee have small to large yields. Production from, and storage in, these formations is dependent on the degree to which joints and solution openings occur. The Bigby-Cannon, Hermitage, Ridley, Murfreesboro, and Knox units are the best aquifers. The groundwater quality is poor at very shallow depths due to bacterial contamination and turbidity from the surface entering the aquifers through improperly cased wells and sinkholes. At depths of more than 20 to 30 m (66 to 98 ft), the quality is generally excellent. At depth and locally within the Knox group, poor quality groundwater exists (high TDS and sulfates).

Eastern Tennessee contains groundwater in perched aquifers within the Carboniferous section. The groundwater occurs in sandstone lenses between coal seams and shale formations. The groundwater quality is locally excellent, or can be iron- or sulfate-enriched. Yields to wells are small to moderate.

Farther to the east, groundwater occurs in upthrusted limestones and dolomites and a few sandstones. Most yields to wells are small; the quality is generally good. Fractured igneous and metamorphic rocks in extreme eastern Tennessee produce water in small amounts and at depths of less than approximately 150 m (490 ft). The groundwater quality is considered to be good.

F.4 SOUTH ATLANTIC-GULF WATER RESOURCE REGION

The South Atlantic-Gulf region, with an area of about 700,000 km^2 (270,000 sq mi) (U.S. Geological Survey 1977), includes 24 major river systems, draining the southern Appalachian Highlands southeastward and southward toward the Atlantic Ocean and the Gulf of Mexico and smaller coastal river systems including those of Florida. Prominent river systems include the Savannah, Roanoke, Chattahoochee, Apalachicola, Alabama, and Tombigbee. Major reservoirs include the John H. Kerr, Clark Hill, and Hartwell reservoirs, and Lakes Marion, Moultrie, Norman, Lanier, and Martin. Large natural lakes are not typical features except in central and southern Florida (Okeechobee is the second largest natural freshwater lake in the conterminous United States, excluding the Great Lakes) (Water Information Center 1970); the smaller lakes (Carolina Bays) of the southeastern Atlantic coast are of particular interest because of their obscure geologic origin (Yount 1966). The region has an extensive shoreline, and bays are prominent at the mouth of the many rivers and behind barrier beaches.

Surface waters in the South Atlantic-Gulf region are generally soft (<60 ppm hardness as $CaCO_3$), except for moderately hard (60 to 120 ppm) waters in northern Alabama and coastal areas in peninsular Florida. The Palm Beach, Florida, area has even slightly harder water (up to 180 ppm). Dissolved solids levels are generally less than 120 ppm, except for the Black Warrior-Lower Tombigbee waters (up to 350 ppm TDS) and surface waters in peninsular Florida (up to and exceeding 350 ppm TDS). Concentrations of suspended solids (TSS) are generally low in coastal areas (<270 ppm), with higher levels (up to 1900 ppm) inland (Water Information Center 1973).

Water quality problems in the region have resulted from sediment runoff from silviculture and mining, nutrient loading of surface waters, and municipal and industrial discharges (U.S. Environmental Protection Agency 1977a). Contamination of aquatic habitats with pesticides is a problem: the region has had particularly high use of DDT, and dieldrin and lindane have been found in surface waters (Water Information Center 1973). The Black Warrior drainage in Alabama has experienced acidification problems from coal mining operations. However, many surface waters in Georgia and Mississippi are naturally acidic as a result of local swamp conditions (U.S. Environmental Protection Agency 1977a). Trace elements have also contaminted surface waters: elevated arsenic levels have been found in the Cape Fear (North Carolina) and Catawba (North Carolina-South Carolina) river drainages, and elevated cadmium has been found in interior and coastal Mississippi and Alabama. Industrial mercury pollution has contaminated the lower Tombigbee-Alabama river basin, the lower Savannah River, and waters of coastal Georgia (Water Information Center 1973). Saltwater intrusion into groundwater aquifers has resulted from pumping, especially in Florida. In Florida, the canal systems associated with land development reduce wetlands. Construction of waste treatment facilities has resulted in improvement of many streams, such as the Pearl River, and lower reaches of the Savannah and Tombigbee rivers (U.S. Environmental Protection Agency 1977a).

In the South Atlantic-Gulf Water Resource Region, average annual runoff is equivalent to 747×10^6 m^3/day (197 bgd). Of the total off-channel water withdrawal of about 160×10^6 m^3/day (43 bgd) in 1975, surface freshwater withdrawals accounted for about 91×10^6 m^3/day (24 bgd), groundwater withdrawals about 21×10^6 m^3/day (5.5 bgd), and saline surface water about 53×10^6 m^3/day (14 bgd). About 13 percent of the freshwater withdrawn was actually consumed (U.S. Geological Survey 1977). The geographic distribution of water use is crucial in the region. Although the total runoff is the largest of all the eastern regions, many of the population centers (such as Birmingham, Alabama, Atlanta, Georgia, and Charlotte, Greenville, and Winston-Salem, North Carolina) are in inland headwater areas where low-flow problems result from periodic droughts. Important river mainstems, such as those of the Alabama, Tombigbee, and Apalachicola, pass through less populated areas. The disparity is also great in southern Florida, which has large population centers (Miami and Palm Beach) and high agricultural water use, but no major rivers. Rainfall there is both highly seasonal and variable from year to year (Hyndman and Roach 1977). Because of these geographic and flow-variation problems, it has been estimated that only about 190×10^6 m^3/day (50 bgd) of the runoff is currently available (Water Resources Council 1974).

The self-supplied industrial and electricity generation utility sector is the largest user of water in the region, although irrigation is the largest consumer of freshwater (Table F.1). Use of saline water for condenser and reactor cooling is almost as great as the use of freshwater.

Generation of hydroelectric power in the region uses about 800 x 10^6 m^3/day (210 bgd), making the region the sixth-ranking in this respect (U.S. Geological Survey 1977). Water supply projections for the region indicate that, while supplies are available along much of the coast, increased inland use will require water resource development and increased use in southern Florida will necessitate even greater reliance on saltwater withdrawals (Hyndman and Roach 1977). Peninsular Florida has been rated as one of the nation's most critical energy-related water supply problem areas by the Water Resources Council. By 1985, available water supply may be inadequate for power generation and cooling needs (Water Resources Council, 1974).

The South Atlantic—Gulf Region groundwater reservoirs are of various types: crystalline and metamorphic rocks, consolidated sedimentary rocks, and unconsolidated to semiconsolidated deltaic and fluvial material. The most productive of these aquifers are the mostly unconsolidated deposits.

The crystalline and adjacent metamorphic rocks of the Blue Ridge and Piedmont areas are the least productive of the aquifers, although they yield groundwater in quantities sufficient to provide adequate domestic and some municipal supplies. Groundwater is produced from fractures and joints, as well as from the residuum of the granites, gneisses, and schists.

Consolidated sedimentary rocks, mostly limestones and dolomitic limestones, are locally important aquifers, being most extensive in Florida and southeastern Georgia. Large quantities of groundwater are produced from solution openings within these formations.

Unconsolidated deltaic sequence sediments range in thickness from several tens of meters to several thousand meters, with the units thickening toward the coast. These sediments consist primarily of sands and silts interbedded with clays. Minor gravels and marls also occur. Production from these formations can be expected to range from moderate to large. Sand and gravel deposits in the larger river valleys are excellent local sources of potable groundwater.

The groundwater quality is good for the most part; however, saline water occurs at depth in the various aquifers, as well as in some shallow Florida aquifers where seawater intrusion has been induced or occurs naturally (Walton 1970).

F.5 GREAT LAKES WATER RESOURCE REGION

The Great Lakes region, with an area of about 325,000 km^2 (126,000 sq mi) (U.S. Geological Survey 1977), includes all of Michigan and portions of eight other states within approximately 161 km (100 mi) of the Great Lakes. In addition to the Great Lakes (Superior, Michigan, Huron, Erie, and Ontario) and the streams flowing into them (such as the Kalamazoo, Menominee, and Maumee rivers), and the St. Lawrence River, which is the outlet of the Great Lakes, the region includes the Finger Lakes area of central New York and Lake Winnebago.

The hardness of surface waters in the Great Lakes Water Resource Region varies widely with location, from soft (<60 ppm hardness as $CaCO_3$) to medium (60 to 120 ppm) to hard (>120 ppm). The lowest levels are generally found in those parts of Minnesota, Wisconsin, and the Upper Peninsula of Michigan that border on Lake Superior. Surface waters of moderate hardness are typically found in northern parts of Wisconsin, Michigan, and in western New York. Hard waters are present in most of the remaining portions of the region, with the hardest waters (180 to >240 ppm) in northwestern Ohio—southeastern Michigan. The hardness of the Great Lakes themselves ranges from soft (Superior) to moderate (northern Huron and Michigan and eastern Ontario) and to hard (Erie, southern Michigan and Huron, and western Ontario). Dissolved solids levels in surface waters of the Great Lakes region range from less than 120 ppm TDS (in those areas bordering the western shores of Lake Superior and that part of New York near the outlet of Lake Ontario) to greater than 350 ppm TDS (central Michigan, along the southwestern shores of Lakes Michigan and Erie, and along the southeastern shore of Lake Ontario). Other areas in the region are intermediate in dissolved solids (120 to 350 ppm). Suspended sediment (TSS) levels are generally low (<270 mg/L) except for the Maumee basin area of northwestern Ohio, where TSS levels are in the 270 to 1900 ppm range (Water Information Center 1977).

With the exception of portions of Lake Erie (where excessive nutrients are found), the open waters of the Great Lakes themselves are generally of good quality. Inshore, harbor, and developed areas suffer from a variety of water quality problems, which include excessive nutrient inputs, pesticides, bacterial contamination, erosion (both natural and aggravated), heavy metals, dissolved solids, phenols, PCBs, other organics, and asbestos. The Detroit and Cuyahoga rivers have been particularly impacted by industrial and municipal effluents; the Detroit River has been responding to waste treatment programs, but the assimilative capacity of the lowest reaches of the Cuyahoga River may continue to be overstressed, even when waste treatment has been fully instituted (U.S. Environmental Protection Agency 1977a). The Great Lakes region has been characterized as having severe thermal pollution problems comparable to those of the New England and Mid-Atlantic regions (Water Information Center 1977).

The aquifers of the Great Lakes Region are of three main types: crystalline bedrock of the Canadian Shield, consolidated sedimentary rocks, and unconsolidated glacial material. Intrusive igneous and metamorphic rocks in the Lake Superior area yield small supplies to wells from fractures. Sandstones and some limestones are significant aquifers. The sandstone bedrock of Wisconsin, northernmost Illinois, and Michigan produces water from primary porosity zones. Limestones, which are locally important aquifers, produce from permeable reef structures and secondary fractures.

Glacial drift varies from several meters to perhaps a hundred meters in thickness across the region. Much of the glacial material is relatively impermeable till; however, some sand and gravel deposits associated with the till are moderately productive. Glacial outwash deposits composed of sand and gravel are locally excellent aquifers. The most productive of all the aquifers in the region, though, are the ancient buried valley sediments, as well as the present courses of streams, which yield moderate to large supplies of groundwater (Walton 1970).

In the Great Lakes Water Resource Region, average annual runoff is equivalent to 280 x 10^6 m^3/day (75 bgd). Of the total off-channel water withdrawal of about 140 x 10^6 m^3/day (36 bgd) in 1975, surface freshwater withdrawals accounted for about 130 x 10^6 m^3/day (35 bgd); groundwater contributed about 6 x 10^6 m^3/day (1.6 bgd), one-fourth of which was saline. About 3 percent of freshwater withdrawn was actually consumed (U.S. Geological Survey 1977).

The primary user of water in the region is the self-supplied industrial sector, including electricity-generating utilities (Table F.1). This sector was almost equalled in terms of freshwater consumed by the public supplies sector. The saline groundwater withdrawals were by industry; fresh groundwater was withdrawn by all sectors. Generation of hydroelectric power uses approximately 1100 x 10^6 m^3/day (290 bgd), with the Great Lakes region second only to the Pacific Northwest region in this respect (U.S. Geological Survey 1977).

A projection of future water availability in this region indicated that the functioning of the Great Lakes as a large reservoir system would result in general availability of water for energy technologies, with no serious low-flow problems. (The lakes themselves have dampened seasonal changes, while the outflow through the St. Lawrence River is exceeded in the United States only by the Mississippi and Columbia rivers and is stable throughout the year.) However, large consumption rates might lower lake levels, and water quality problems in the populated industrialized centers might be aggravated (Hyndman and Roach 1977).

F.6 OHIO WATER RESOURCE REGION

The Ohio Water Resource Region, with an area of about 420,000 km^2 (163,000 sq mi) (U.S. Geological Survey 1977), includes the Ohio River and tributary systems (such as the Allegheny, Monongahela, Cumberland, Kanawha, Kentucky, Green, and Wabash rivers). Although the region includes scattered small natural lakes and moderate-sized reservoirs, major reservoirs are limited to the Cumberland River (Barkley, Center Hill, and Dale Hollow reservoirs and Lake Cumberland).

Surface waters of the Ohio Water Resource Region range from moderately hard (60 to 120 ppm hardness as $CaCO_3$) to hard (>120 ppm). The softer waters are generally found in the southern and eastern portions of the region. Surface-water hardness in parts of Illinois, Indiana, and Ohio fall in the 180 to 240 ppm range. Dissolved solids levels also reflect this distribution, with lowest values (<120 to 350 ppm TDS) found in the southern and eastern portions of the region, and the highest levels (>350 ppm) in parts of Illinois, Indiana, Ohio, and western Pennsylvania. Sediment (TSS) levels generally vary from less than 270 ppm to almost 2000 ppm. The southern Illinois area has the highest levels, exceeding 1900 ppm (Water Information Center 1973).

Water quality in the Ohio basin has suffered from both point-source and nonpoint-source pollutants. Agriculture (contributing pesticides, nutrients, and sediments), construction, urban runoff, stream channelization, and industrial and municipal discharges have degraded water quality (in terms of bacterial contamination, nutrients, heavy metals, and other toxicants) (U.S. Environmental Protection Agency 1977a). The region has been categorized as having major thermal pollution problems, although not as severe as the New England and Mid-Atlantic regions (Water Information Center 1973). The Ohio region has been particularly affected by coal mining drainage, with abandoned mines and the diffuse nature of the discharge exacerbating the situation (U.S. Environmental Protection Agency 1977a). The Environmental Protection Agency (EPA) has identified Pennsylvania, Maryland, northern West Virginia, Ohio, western Kentucky, and the Illinois-Indiana border area as being affected by acid/ferruginous drainage (U.S. Environmental Protection Agency 1977a). Coal mining in eastern Kentucky and the Cumberland region in Tennessee also results in acid mine drainage. Streams in mining areas of eastern Kentucky have suffered from elevated levels of dissolved solids, hardness, sulfate, acidity, and chloride. Even where neutralized mine wastes have been discharged, increased dissolved solids and sulfate have been reported. While identifiable point-source discharges such as industrial and municipal wastes have begun to be controlled with waste treatment facilities (with observed recovery of water quality), mine drainage has been identified as less amenable to control with "best available treatment" technologies (U.S. Environmental Protection Agency 1977a).

In the Ohio Water Resource Region, average annual runoff is equivalent to 474 x 10^6 m^3/day (125 bgd). Of the total off-channel water withdrawal of about 140 x 10^6 m^3/day (36 bgd) in 1975, surface freshwater withdrawals accounted for about 130 x 10^6 m^3/day (34 bgd); groundwater contributed about 7.2 x 10^6 m^3/day (1.9 bgd). About 3 percent of freshwater withdrawn was actually consumed. Primary groundwater users were the industrial and public supplies sectors (U.S. Geological Survey 1977).

Approximately 4.09 x 10^{11} m^3 (108,000 billion gal) of potable groundwater is available from storage in the aquifers of the Ohio region. Consolidated rock and minor unconsolidated aquifers contain 3.2 x 10^{11} m^3 (85,000 billion gal) of the total amount; outwash and alluvial aquifers may be stored as much as 8.7 x 10^{10} m^3 (23,000 billion gal) of potable groundwater.

The groundwater reservoirs in the Ohio region are of four general types: alluvium, outwash, glaciofluvial deposits, and bedrock. Alluvium of recent age, consisting of silt, sand, and gravel, occurs in the valleys of the larger streams. Sand and gravel glacial outwash deposits are found in the glaciated valleys of the main tributaries. Glaciofluvial deposits are comprised of both Pleistocene outwash and recent alluvium; these occur within the Ohio River valley as well as along its major tributaries. Well yields from the unconsolidated aquifers can exceed 31 L/s (500 gpm). Thick bedrock units varying in age from Precambrian to Tertiary underlie the region. The greatest thicknesses are coincident with the Appalachian and Illinois structural basins, in the east and west portions of the region respectively. Maximum well yields of consolidated aquifers range from 6 to 31 L/s (100 to 500 gpm). Characteristics of the significant aquifers in the Ohio region are given in Table F.2.

Table F.2. Characteristics of the Consolidated and Unconsolidated Aquifers in the Ohio Region and Ranking of Aquifers in Order of Decreasing Transmissivity

Aquifer	Hydraulic Conductivity (gpd/ft^2)	Storage Coefficient or Specific Yield
Mad River alluvial aquifer	4000-4500	0.25
Ohio River valley outwash and alluvial aquifer	400-8400	0.05-0.20
Miami River, Scioto River, Upper Muskingum River, and Whitewater River alluvial aquifers	2500-3000	0.15-0.20
Allegheny, Lower Wabash, and White River alluvial aquifers	2000	0.15-0.20
Hocking River, Lower Muskingum River, and Upper Wabash River alluvial aquifers	1500-2000	0.15-0.20
Beaver River alluvial aquifer and alluvial aquifers in the minor tributaries north of the Ohio River	500-1000	0.15
Alluvial aquifers in the major tributaries south of the Ohio River	500	0.10
Mississippian bedrock aquifer (Green River Basin)	>20	0.01-0.05
Mississippian bedrock aquifer with glacial cover	>20	0.01-0.05
Pennsylvanian bedrock (Allegheny and Pottsville Formations)	>20	0.01-0.05
Pennsylvanian bedrock with glacial cover	>20	0.01-0.05
Silurian bedrock with glacial cover	>20	0.01-0.05
Pennsylvanian bedrock (Conemaugh Formation)	>20	0.01-0.05
Pennsylvanian and Permian bedrock (Dunkard Group)	>20	0.01-0.05
Ordovician bedrock with glacial cover	>20	0.01-0.05
Silurian bedrock	>20	0.01-0.05
Mississippian bedrock	>20	0.01-0.05
Pennsylvanian bedrock (Monongahela Formation)	>20	0.01-0.05
Devonian bedrock with glacial cover	>20	0.01-0.05
Ordovician and undifferentiated Paleozoic rocks	>20	0.01-0.05
Devonian bedrock	>20	0.01-0.05

From Bloyd (1974).

Groundwater quality within the region varies primarily with depth. Shallow groundwater generally contains less than 1000 mg/L TDS. At depths greater than 150 m (500 ft), however, TDS concentrations may exceed 35,000 mg/L.

Recharge is primarily by infiltration of precipitation. Some seepage from streams takes place. The average annual regional groundwater recharge is about 1.3 x 10^8 m^3/day (35,000 mgd), which may be as much as 15 percent of the total annual precipitation. Discharge takes place through seepage to streams, pumpage, and underflow to adjacent areas.

The base-year (1960) use of groundwater for municipalities and rural demands was approximately 3.79 x 10^6 m^3/day (1000 mgd), or about 3 percent of annual recharge. Industrial use of groundwater was also equivalent to 3 percent of annual recharge. Table F.3 shows the projected use and recharge of groundwater by subbasin for the year 2020 (Bloyd 1974).

The greatest user of water and consumer of freshwater in the region is the self-supplied industrial sector, including electricity-generating utilities (Table F.1). Generation of hydroelectric power uses approximately 870 x 10^6 m^3/day (230 bgd), with the Ohio region ranking fourth in this respect (U.S. Geological Survey 1977).

Projections to the years 2000 and 2020 indicate that development of energy resources (coal, oil, gas, oil shale, and tar sands) in the Ohio River basin could stress available water supplies. Monthly flow varies considerably in the Ohio River basin, and some upper mainstem and tributary areas already experience low-flow problems. Increased energy development in the Allegheny, Monongahela, Muskingum, Scioto, Miami, Hocking, and Kentucky basins could exacerbate low-flow problems. Future energy demand has been seen as reducing the 7-day 10-year low-flow in the mainstem Ohio River by 15 percent in 2000 and 35 percent by the year 2020. Reservoir development (in addition to the importation of power) has been identified as a possible future need (Hyndman and Roach 1977).

Table F.3. Comparison of Projected Groundwater Withdrawals with Estimated Groundwater Recharge for the Year 2020

Subbasin	Total[a] Withdrawal (mgd)	Estimated Groundwater Recharge (mgd)
Allegheny	200	4,100
Monongahela	190	2,900
Upper Ohio River	290	1,600
Muskingum	210	1,600
Kanawha-Little Kanawha	320	5,100
Scioto	150	600
Big and Little Sandy-Guyandotte	100	1,300
Great and Little Miami	680	1,600
Lickin		4,800
White	790	2,500
Green-Salt-Lower Ohio River	40	3,300
Cumberland	100	4,700
Basinwide industrial use	930	
Total	4,060	35,400

Adapted from Bloyd (1974).

[a]Summation of estimated municipal and rural groundwater withdrawals in 1960 and estimated additional withdrawals.

F.7 UPPER MISSISSIPPI WATER RESOURCE REGION

The Upper Mississippi Water Resource Region, with an area of about 490,000 km^2 (190,000 sq mi) (U.S. Geological Survey 1977), includes the Mississippi from its headwaters in northcentral Minnesota downstream to the mouth of the Ohio River and intermediate tributary systems (such as the Minnesota, Wisconsin, Des Moines, and Illinois rivers). The region also includes the lowest reach of the Missouri River from its mouth near St. Louis, Missouri, upstream to the confluence of the Osage River. Natural lakes, found throughout the basin, are prominent features in central and northern Minnesota (such as Leech and Mille Lacs lakes), reflecting the glaciated history of the area. In addition to the large Red Rock Reservoir on the Des Moines River in Iowa, there are many smaller impoundments along other waterways.

Surface waters of the Upper Mississippi Water Resource Region are generally hard (>120 to 180 ppm hardness as $CaCO_3$), with some areas of even greater hardness in central Illinois and in the western section of the region. Low levels of dissolved solids (<120 ppm TDS) are generally found only in western and northern Wisconsin. High levels of TDS (>350 ppm) are found in central and northeastern Illinois, central and northern Iowa, and southwestern Minnesota. Intermediate levels of dissolved solids are found elsewhere in the region. Sediment (TSS) levels are low (<270 ppm) in most of Wisconsin and Minnesota and along the mainstem of the Mississippi River as far downstream as St. Louis, Missouri. The highest levels (>1900 ppm) are reported from a belt of tributary areas along the mainstem, including parts of Wisconsin, Iowa, Illinois, and Missouri, and from northeastern Missouri and southeastern Iowa. Intermediate levels (270 to 1900 ppm) are found in the remainder of Iowa, Missouri, and Illinois (Water Information Center 1973).

Water quality in the Upper Mississippi Water Resource Region has been adversely affected by a variety of point-source and nonpoint-source pollutants. Point-source pollutants, that is, industrial and municipal discharges, have caused elevated levels of heavy metals, such as the mercury contamination problem in some Wisconsin streams and cadmium and chromium contamination in the Mississippi mainstem (Water Information Center 1973; U.S. Environmental Protection Agency 1977a). Papermill wastes have also degraded water quality in Wisconsin. Diffuse discharges, such as construction and urban and agricultural runoff, have increased dissolved and suspended solids loads (U.S. Environmental Protection Agency 1977a). Pesticide residues have been detected in the mainstem of the Mississippi (Water Information Center 1973). The southwestern part of Illinois and, to a lesser extent, parts of Iowa and Missouri have experienced acid mine drainage, particularly after heavy rains and runoff (U.S. Environmental Protection Agency 1977a). The Upper Mississippi Water Resource Region has been categorized as having major thermal pollution problems, although not as severe as the Great Lakes, New England, or Mid-Atlantic regions (Water Information Center 1973).

Brines from manufacturing processes and oil fields have caused local water quality degradation. The Rubicon River has had chloride levels of over 600 ppm (Water Resources Council 1974).

In the Upper Mississippi Water Resource Region, average annual runoff is equivalent to 250 x 10^6 m^3/day (65 bgd). Of the total off-channel water withdrawal of about 72 x 10^6 m^3/day (19 bgd) in 1975, surface freshwater withdrawals accounted for 61 x 10^6 m^3/day (16 bgd); groundwater contributed about 9.1 x 10^6 m^3/day (2.4 bgd). About 4 percent of freshwater withdrawn was actually consumed. Public supplies and the self-supplied industrial sector were the primary users of groundwater. The greatest user of water in the region is the self-supplied industrial sector, including electricity-generating utilities (Table F.1). However, the greatest consumption of freshwater was accounted for by rural uses. Generation of hydroelectric power uses about 420 × 10^6 m^3/day (110 bgd), with the Upper Mississippi region (along with the Arkansas–White–Red Water Resource Region) trailing eight other regions in this respect (U.S. Geological Survey 1977).

The Upper Mississippi Region has an estimated 1.7 x 10^{11} m^3 (45,000 billion gal) of potable groundwater in storage in outwash and alluvial aquifers alone; in addition, several times this amount is probably in storage in other types of aquifers. The four major types of aquifers are Holocene (Recent) alluvium, outwash, buried valley deposits, and bedrock.

The alluvial aquifers are comprised of gravel, sand, and silt. These deposits are found in the Mississippi River valley and along the larger streams.

Outwash aquifers are somewhat more permeable than the alluvial aquifers, being composed of sand and gravel. These glacial deposits are most commonly found in Minnesota and Wisconsin. The alluvial and outwash aquifers range in thickness from 9 to 61 m (30 to 200 ft). They have the potential to yield more than 32 L/s (500 gpm) to wells.

Buried valley deposits are common in east-central Illinois, where at least 9600 m^2 (3700 sq mi) of area are known.

The Upper Mississippi Region is underlain by bedrock of various ages. Three major bedrock aquifers exist: the Mount Simon–Hinckley, the Cambro-Ordovician, and the Silurian-Devonian. The Mount Simon–Hinckley, which is of Precambrian to Cambrian age, is a sandstone aquifer underlying southeastern Minnesota, western and southern Wisconsin, northern Illinois, and eastern Iowa. The Cambro-Ordovician aquifer consists of a series of sandstones and dolomites. It underlies southeastern Minnesota, southern Wisconsin, northern Illinois, Iowa, northwestern Indiana, and eastern Missouri. The Silurian-Devonian aquifer is predominantly limestone and dolomite. It is a source of water for northeastern Iowa, northern Illinois, southeastern Wisconsin, and northwestern Indiana. The bedrock aquifers have the potential for yielding as much as 32 L/s (500 gpm) to wells.

Groundwater quality in the Upper Mississippi Region is generally considered good; the TDS concentrations are usually less than 1000 mg/L. In the bedrock aquifers, however, saline water occurs at depth. The greatest concentrations of TDS occur in southern and central Illinois and western Iowa, where deep sedimentary basins are present.

Recharge to the various aquifers occurs through infiltration of precipitation, interaquifer flow, and from influent streams (Table F.4). The major discharge areas are the Mississippi River valley, Lake Michigan, pumpage, and the Illinois structural basin. The rate of groundwater movement through the region ranges from a meter to perhaps a hundred meters per year.

Table F.4. Summary of Groundwater Recharge Computations

Sub-basin	Sub-basin Area (sq miles)	Estimated Groundwater Recharge		Sub-basin Precipitation (%)
		cfs[a]	mgd	
Mississippi headwaters	28,100	7,300	4,700	14
Chippewa-Black	13,100	3,400	2,200	12
Wisconsin	12,800	4,500	2,900	15
Rock	14,500	4,650	3,000	13
Illinois	29,600	4,450	2,900	6
Kaskaskia	7,000	1,100	700	6
Big Muddy	2,800	200	150	3
Meramee	7,00	1,900	1,250	9
Salt	4,500	250	150	2
Fox-Wyaconda-Fabius	3,000	150	100	2
Des Moines	14,800	1,050	700	3
Skunk	4,600	650	400	6
Iowa-Cedar	12,800	1,900	1,250	6
Turkey-Maquoketa-Upper Iowa-Wapsipinicon	8,800	2,200	1,400	10
Cannon-Zumbro-Root	5,700	1,250	800	10
Minnesota	16,900	850	550	3
Total			23,150	

From Bloyd (1975).

[a]cfs = cubic feet per second.

All base-year (1960) rural water was derived from groundwater reservoirs (Table F.5). The annual domestic, commercial, and rural use of groundwater was approximately 3.4 x 10^6 m^3/day (900 mgd), which is 4 percent of recharge [8.7 x 10^7 m^3/day (23,000 mgd)]. Industrial use of groundwater was only 3 percent of recharge in 1965, or 2.4 x 10^6 m^3/day (629 mgd) (Bloyd 1975).

Table F.5. Base-Year (1960) Domestic, Commercial, and Rural Groundwater Use (mgd)

Subbasin	Domestic and Commercial	Rural Domestic and Livestock	Total
Mississippi headwaters	56	41	97
Chippewa-Black	11	22	33
Wisconsin	23	24	47
Rock	83	30	113
Illinois	154	75	229
Kaskaskia	9	11	20
Big Muddy	0.4	5	5
Meramec	9	11	20
Salt	2	11	13
Fox-Wyaconda-Fabius	0.6	5	6
Des Moines	23	48	71
Skunk	8	16	24
Iowa-Cedar	37	52	89
Turkey-Maquoketa-Upper Iowa-Wapsipinicon	15	36	51
Cannon-Zumbro-Root	15	17	32
Minnesota	16	35	51
Totals	462	439	901

From Bloyd (1975).

A projection of water supply availability until the year 2020 has concluded that, on a regional basis, supplies will be adequate to accommodate expected demand. However, compared with most other eastern regions, precipitation and runoff are low and more variable. As a result, a large concentration of water demands could cause local low-flow problems, even on the mainstem of the Mississippi, until downstream tributary replenishment was sufficient (Hyndman and Roach 1977).

F.8 LOWER MISSISSIPPI WATER RESOURCE REGION

The Lower Mississippi Water Resource Region, with an area of about 250,000 km^2 (96,000 sq mi) (U.S. Geological Survey 1977), includes the lower mainstem of the Mississippi River, the largest river in North America, from southern Missouri to the delta in Louisiana. The region also includes the lower reaches of major tributary systems (Arkansas, Red, White, and Yazoo rivers), as well as smaller tributaries. Natural lakes are not important surface features of the region, except in coastal Louisiana. A noteworthy exception is Reelfoot Lake in northwestern Tennessee, which was formed by a nineteenth century earthquake. Reservoirs are abundant in the region, however, including those in Missouri (Wappapello Reservoir), Arkansas-Louisiana (Bayou Bodcau Reservoir), and Mississippi (Arkabutla Reservoir). The Louisiana coast has an abundance of bayous, bays, and coastal lakes.

Surface waters in the Lower Mississippi Water Resource Region are generally of moderate hardness (60 to 120 ppm hardness as $CaCO_3$) in the Mississippi River mainstem, lower reaches of tributary areas, and the delta area, except for below Baton Rouge, Louisiana, and above the mouth of the Arkansas River, where hard water (120 to 180 ppm) is found. Otherwise, portions of the region more than about 80 km (50 mi) from the Mississippi River are typically soft (<60 ppm). Dissolved solids along the Mississippi River mainstem, Red River, and in coastal Louisiana are generally in the 120 to 350 ppm range. Higher levels (>350 ppm TDS) are found along the Ouachita and Arkansas rivers. Otherwise, TDS levels are typically low (<120 ppm). Suspended sediment (TSS) loads are in the 270 to 1900 ppm range along the Mississippi River mainstem and in the upper Ouachita River basin. The highest levels (1900 ppm and above) are found in a belt of uplands running from southwestern to northern Mississippi. Otherwise, levels are low (<270 ppm) (Water Information Center 1973).

Nonpoint-source water pollution is a serious problem in the Lower Mississippi region, and one which is not easily controlled. The importance of agricultural operations in the region (reflected in water use) also largely determines the nature of water quality problems (U.S. Environmental Protection Agency 1977a). Agricultural runoff, especially runoff of bacteria, pesticides, and sediments, for example, may result in the failure of streams in Arkansas to meet water quality goals; pesticide residues have been found in the Mississippi mainstem and in lower tributary reaches (Water Information Center 1973; U.S. Environmental Protection Agency 1977a). Point sources, such as industrial and municipal waste discharges, may be controlled with waste treatment facilities; this has been shown, for example, in the control of municipal waste discharges by the state of Mississippi into the Mississippi River (U.S. Environmental Protection Agency 1977a).

Previous and continuing releases, however, have contaminated major streams with toxic elements such as arsenic, cadmium, and mercury (Water Information Center 1973). Surface waters in Arkansas have been adversely affected by acid drainage (from bauxite mines) and oil field brine point-source and diffuse releases (U.S. Environmental Protection Agency 1977a).

The Lower Mississippi Region is characterized by unconsolidated to semiconsolidated deltaic and fluvial material, which comprises the most productive aquifers underlain by consolidated sedimentary and crystalline rocks at depth. The sediments range in thickness from several tens of meters to several thousand meters, with the strata thickening toward the Gulf of Mexico. A typical geologic section shows primarily sands and silts interbedded with clays. Minor gravels and marls are also present in the section. Stream valley sediments are locally good aquifers. The Lower Mississippi Region contains some of the most extensive, prolific aquifers in the United States; the most well developed of these sand and gravel deposits are to be found in eastern Arkansas, western Tennessee, and southwestern Louisiana.

The groundwater quality is generally good across the region. Saline water occurs at depth and toward the mouth of the Mississippi (Walton 1970).

In the Lower Mississippi Water Resource Region, average annual runoff is equivalent to 300 x 10^6 m^3/day (79 bgd) (U.S. Geological Survey 1977). An additional 1330 x 10^6 m^3/day (352 bgd) flow into the region from upstream regions (Water Resources Council 1974). Of the total off-channel water withdrawal of about 61 x 10^6 m^3/day (16 bgd) in 1975, surface freshwater withdrawals accounted for about 42 x 10^6 m^3/day (11 bgd); fresh groundwater accounted for most of the remainder. About 34 percent of freshwater withdrawn was actually consumed. The greatest user of water in the region is the self-supplied industrial sector, including electricity-generating utilities (Table F.1). However, the greatest freshwater consumption was accounted for by irrigation. Generation of hydroelectric power uses about 16 x 10^6 m^3/day (4.1 bgd), making the region the fourth smallest user in the conterminous United States in this respect (U.S. Geological Survey 1977).

A projection of water supply availabilities to the year 2020 indicates that the region will probably have adequate supplies for expected energy development (electrical generation and other technologies), even if the region must supply power to the urban centers of Arkansas and southeastern Texas. However, maintaining sufficient flows in the Mississippi River (for saltwater repulsion at New Orleans, Louisiana, for navigation, and for environmental considerations) may be a problem if upstream regions consume large amounts of water (Hyndman and Roach 1977).

F.9 ARKANSAS–WHITE–RED WATER RESOURCE REGION

The Arkansas–White–Red Water Resource Region, with an area of about 685,000 km^2 (265,000 sq mi) (U.S. Geological Survey 1977), includes all but the lowest reaches of the Arkansas, White, and Red river systems and their tributary systems (Cimmaron, Canadian, Washita, and Neosho rivers). Although the region does not have an abundance of natural lakes, most of the major streams have been impounded. Prominent reservoirs exist on the Red River (Lake Texoma), Arkansas River (Kaw and Keystone reservoirs), and White River (Beaver, Table Rock, Bull Shoals, and Norfolk reservoirs), in addition to those on tributaries (such as Eufala on the Canadian River and Lake of the Cherokees on the Neosho River).

Surface waters of the Arkansas–White–Red range from soft to moderately hard (<60 to 120 ppm hardness as $CaCO_3$) in the eastern parts of the basin (southeastern Oklahoma, southern Missouri, and Arkansas) to moderately hard and to hard (60 to 240 ppm) in the central and upper reaches of the Arkansas and Red river systems. The hardest surface waters are found in northeastern Oklahoma and southeastern Kansas. Total dissolved solids in surface are typically high (>350 ppm) throughout the western parts of the region and in the lower mainstems of the Arkansas and Red rivers; portions of the upper Red River, Arkansas River, and Canadian River drainages have salinities exceeding 1000 ppm. Areas in southeastern Oklahoma and in Arkansas have low levels of TDS (<120 ppm), while intermediate levels of TDS are found in the transition zone (eastern Oklahoma, southeastern Kansas, southern Missouri, northwestern Arkansas). Distribution of suspended sediment (TSS) concentrations exhibits a similar pattern: highest values (>1900 ppm) in the western parts of the region, low to intermediate values (<1900 ppm) in the eastern parts (Water Information Center 1973).

Point sources (such as along the Arkansas River mainstem in Kansas) have been responsible for part of the surface-water quality problems in the region. However, the nonpoint sources are more important on a regional basis and more difficult to control. These include sources such as urban-industrial runoff, agricultural runoff, and natural mineralization. Salt and gypsum formations in Oklahoma contribute to the mineralization of surface waters; in Kansas, stream water use is limited by natural mineralization. The addition of dissolved solids and nutrients contributes to the overall degradation of water quality from headwaters to lower reaches (U.S. Environmental Protection Agency 1977a). Pesticide residues and elevated trace element (such as lead, arsenic, and cadmium) concentrations have been reported in surface waters (Water Information Center 1973).

In the Arkansas—White—Red Water Resource Region, average annual runoff is equivalent to 280 x 10^6 m^3/day (73 bgd). Of the total off-channel water withdrawal of about 57 x 10^6 m^3/day (15 bgd) in 1975, surface freshwater withdrawals only accounted for about 24 x 10^6 m^3/day (6.2 bgd); fresh groundwater contributed almost all the remainder. Surface-water withdrawals are dominant in the eastern part of the region, with groundwater withdrawals dominant in the western and central parts. About 60 percent of freshwater withdrawn was consumed. Irrigation is clearly the dominant user and consumer of all waters in the region (Table F.1) (U.S. Geological Survey 1977). Imports from the Upper Colorado region are used to augment surface waters in the fully appropriated upper Arkansas River basin (Colorado, New Mexico) (Water Resources Council 1974).

Generation of hydroelectric power uses about 420 x 10^6 m^3/day (110 bgd), causing the Arkansas—White—Red Water Resource Region (along with the Upper Mississippi region) to trail eight other regions in this respect (U.S. Geological Survey 1977).

Aquifers in the Arkansas—White—Red region contain an estimated 2.46 x 10^{12} m^3 (2 billion acre-ft) of freshwater in storage. These aquifers can be classified into four general types: alluvial, carbonate and gypsum, sand and sandstone, and undifferentiated consolidated rocks (Table F.6).

Alluvial aquifers include stream valley, terrace, and intermontane valley deposits, consisting primarily of sand and gravel. The total area covered by stream valley alluvium alone is more than 72,520 km^2 (28,000 sq mi). Alluvial thicknesses range from 15 to 1500 m (50 to 5000 ft). Well yields vary between 3 and 300 L/s (50 to 5000 gpm).

The sand and sandstone aquifers consist of unconsolidated sand along the Coastal Plain and consolidated sandstone underlying the High Plains and Central Lowland areas. Aquifer thickness is from 30 to 150 m (100 to 500 ft). Well yields typically range from 0.6 to 60 L/s (10 to 1000 gpm).

The carbonate rock aquifers are comprised of dense limestones and dolomites of Paleozoic age. Outcrop areas include the Ozark Plateaus of Missouri and Arkansas. Gypsum aquifers occur in southwest Oklahoma and northern Texas. Permeability within these aquifers is secondary because of dissolution of the bedrock along joints and bedding planes. Thicknesses range from 15 to 460 m (50 to 1500 ft). Well yields are from 3 to 60 L/s (50 to 1000 gpm).

Undifferentiated consolidated rock aquifers occur locally throughout the region. Thicknesses vary between 30 to 1500 m (100 to 5000 ft). Production is low; well yields typically do not exceed 3 L/s (50 gpm).

Groundwater quality varies from fresh to saline within the region, both geographically and with depth. In general, the TDS concentration is lowest in the eastern part of the region. Saline groundwater (TDS concentration exceeding 1000 mg/L) occurs at depths of less than 150 m (500 ft) over much of the region, as well as in areas underlain by shale and gypsum and where pollution by oil-field brine has occurred.

Recharge to the groundwater reservoirs varies across the region. In the semiarid western portion of the region, recharge may be as little as 0.0013 to 0.013 m/year (0.05 to 0.5 in./year). Recharge to aquifers in the humid eastern portion of the region may reach 0.51 m/year (20 in./year. Discharge takes place through evapotranspiration and contribution to stream flow.

Groundwater use in the Arkansas-White-Red averaged 3.3 x 10^7 m^3/day (8.8 bgd) (59 percent of total water use) in 1975. The primary use was for crop irrigation in portions of Texas, Oklahoma, Kansas, and Colorado. Other uses include providing rural and municipal supplies (Bedinger and Sniegocki 1976).

A projection to and beyond the year 1985 has indicated that water supplies in the Arkansas—White—Red region will be sufficient to meet expected energy needs. Areas of growing demand (the westernmost part of the region) do not have sufficient water supplies, but demands may be met by purchase of existing water outlets and by water development projects. Limitations on water use also exist because of natural and man-made pollutants. Local effects on groundwater levels and artesian pressures may result from increased pumping (Water Resources Council 1974).

F.10 TEXAS GULF WATER RESOURCE REGION

The Texas Gulf Water Resource Region, with an area of about 450,000 km^2 (175,000 sq mi) (U.S. Geological Survey 1977), includes river systems draining most of Texas and portions of southeastern New Mexico and western Louisiana. Drainage is towards the Gulf of Mexico, with the coastal area including bays at the mouths of the streams and behind barrier beaches. Prominent river systems include the Sabine, Trinity, Brazos, Colorado, and Nueces rivers. Major reservoirs are present in central and eastern Texas (Toledo Bend, Sam Rayburn, Whitney, and Belton reservoirs and Lakes Travis and Buchanan).

Hardness of surface waters generally increases in a southwestward direction from soft (<60 ppm hardness as $CaCO_3$) in the eastern parts of the region (Sabine and Neches river basins) to moderate (60 to 120 ppm) in the Trinity River basin and to hard (120 to 180 ppm) in the Brazos, Colorado, and lower Nueces river basins; hardness increases to very hard (180 to 240 ppm) in the upper Nueces River basin of southwestern Texas. Dissolved solids levels in surface waters are highest (>350 ppm TDS) along the coast and in the upper river basins of northwestern Texas. Moderate levels of TDS (120 to 350 ppm) are found in parts of eastern and central Texas, while lowest levels (<120 ppm) are found in the lower Neches River basin area in southeastern Texas (Water Information Center 1973). In general, water quality decreases with increasing aridity. Groundwater contributions high in salt and gypsum affect the upper Brazos River basin (Water Resources Council 1974). Stream sediment (TSS) levels generally range from low (<270 ppm) in the lower Neches mainstem to moderate (270 to 1900 ppm) in eastern, coastal, and northwestern Texas and to high (>1900 ppm) in central Texas and the upper Nueces River basin (Water Information Center 1973).

Heavy metals (including mercury) and pesticides have been identified as pollutants present in Texas waters (Water Information Center 1973). Brine disposal has also caused severe local salinity problems, although control measures have limited adverse effects (U.S. Environmental Protection Agency 1977a). Saltwater intrusion in the coastal groundwater of east Texas and west Louisiana has resulted from groundwater pumping (Water Resources Council 1974).

In the Texas Gulf Water Resource Region, average annual runoff is equivalent to 120 x 10^6 m^3/day (32 bgd). Of the total off-channel water withdrawal of about 83 x 10^6 m^3/day (22 bgd) in 1975, surface freshwater withdrawals only accounted for approximately 37 x 10^6 m^3/day (9.7 bgd); fresh groundwater [27 x 10^6 m^3/day (7.2 bgd)] and saline surface water [19 x 10^6 m^3/day (5.1 bgd)] contributed the remainder. About 47 percent of freshwater withdrawn was consumed (U.S. Geological Survey 1977).

Significant groundwater reservoirs underlie more than 80 percent of the land area in the Texas-Gulf region. There are twelve regionally important aquifers containing water with total dissolved solids concentrations less than 3000 mg/L.

The Hickory aquifer underlies portions of the Edwards Plateau and Llano Uplift of central Texas, for a total area of 12,950 km^2 (5000 sq mi). The aquifer, which consists primarily of sand and sandstone, is more than 122 m (400 ft) thick, extending downward for nearly 1520 m (5000 ft). Larger capacity wells completed in the Hickory yield between 13 to 32 L/s (200 to 500 gpm).

The Ellenburger—San Saba aquifer, which surrounds the Llano Uplift, has a surface area of 10,360 km^2 (4000 sq mi). The aquifer consists of more than 305 m (1000 ft) of limestone and dolomite, extending to depths of 914 m (3000 ft). Yields of larger capacity wells reach 63 L/s (1000 gpm).

The Santa Rosa aquifer is located east of the High Plains and has a surface area of 2590 km^2 (1000 sq mi). The Santa Rosa, which produces at depths as great as 137 m (450 ft), is comprised of sand and gravel. The average yield of large capacity wells is 16 L/s (250 gpm).

The Trinity aquifer's primary area of use is the Dallas—Fort Worth region. The surface area of the aquifer is approximately 51,800 km^2 (20,000 sq mi). The maximum thickness of the interbedded sand, shale, and limestone units is 366 m (1200 ft); they extend to a maximum depth of 1060 m (3500 ft).

The Edwards-Trinity (Plateau) aquifer underlies portions of the Edwards Plateau for an area of 38,200 km^2 (15,000 sq mi). The major producing zones are sand, sandstone, and honeycombed limestone; the maximum thickness is 305 m (1000 ft). Well yields can exceed 190 L/s (3000 gpm).

The Edwards (Balcones Fault Zone) aquifer lies between the Edwards Plateau and the Gulf Coastal Plain, along the Balcones Escarpment, for an area of 6470 km^2 (2500 sq mi). A 152-m (500-ft) thick zone of fractured limestone and dolomite provides the entire water supply for metropolitan San Antonio, Texas. Some wells yield more than 1000 L/s (16,000 gpm).

Table F.6. Principal Aquifers in the Arkansa-White-Red Region

Aquifer Type	Nature of Rock	Thickness (ft)	Areal Extent	Depth to Water (ft)	Hydraulic Conductivity (ft/day)	Well Yields (gpm)	Development and Use	Groundwater in Storage (acre-ft x 10^8)
Stream valley alluvium	Sand and gravel	50-200	Along large streams in flood plains. Extensive in Coastal Plain of Arkansas and Louisiana	0-30	100-1500	300-5000	Extensive; principal source of groundwater; frequently overdeveloped. Not used in some areas	2.8
Terrace alluvium	Sand and gravel	50-600	Plains of Texas, New Mexico, Colorado, Kansas, and Oklahoma	50-300	10-700	50-1000	Extensive subject to overdevelopment and water mining, particularly in High Plains of Texas	4.1
Alluvium of intermontane valleys and buried alluvial valleys	Sand and gravel	100-5000	Arkansas River basin in Colorado	0-50	10-700	50-1000	Extensive subject to overdevelopment and water mining, particularly in High Plains of Texas	0.2
Carbonate and gypsum	Limestone and dolomite and gypsum beds. Generally a dense rock, but subject to solution along fracture and bedding planes	50-1500	Limestone and dolomite in southern Missouri, northern Arkansas, southeastern Kansas, and Oklahoma. Gypsum in Oklahoma and Texas	30-450	50-1500	50-1000	Moderately to heavily developed; overlooked as a source of water in some areas. More subject to pollution than other aquifers because of cavernous nature	3.2
Sand and sandstone	Sand grains ranging from very fine to coarse. Generally cemented with siliceous material or carbonate. Unconsolidated in the Coastal Plain	100-500	Sandstone principally in Kansas, New Mexico, and Oklahoma Sand in Coastal Plain of Arkansas, Texas, and Louisiana	20-300	a	10-1000	Extensive; subject to overdevelopment and water mining. Loss of artesian head in many areas ranging from 2 to 300 ft	7.9

Table F.6 (continued)

Aquifer Type	Nature of Rock	Thickness (ft)	Areal Extent	Depth to Water (ft)	Hydraulic Conductivity (ft/day)	Well Yields (gpm)	Development and Use	Groundwater in Storage (acre-ft x 10^8)
Undifferentiated sandstone, carbonate, shale, or basalt	Consolidated rocks, including sandstone, interbedded shale, carbonate, and crystalline igneous rocks	100-5000	Sandstone, carbonate, and shale locally throughout region; basalt in parts of New Mexico, Colorado, and northwestern Oklahoma	1200	b	5-50	Mainly domestic use, not heavy, concentrated use, because of low permeability and low well yields. Difficult to predict well yields	2.2

From Bedinger and Sniegocki (1976).

[a]Generally less than 100 ft/day.

[b]Generally less than 10 ft/day.

The Woodbine aquifer underlies an area of 15,500 km^2 (6000 sq mi) near the inland extent of the Coastal Plain. The aquifer is comprised of a 183-m (600-ft) thick sequence of sand, sandstone, and shale, extending to a depth of 610 m (2000 ft). Maximum well yields are 44 L/s (700 gpm).

The Carrizo-Wilcox aquifer has a total area of 77,700 km^2 (30,000 sq mi), bounding the Coastal Plain in a band 48 to 129 km (30 to 80 mi) wide. The interbedded sand and clay reaches a thickness of 914 m (3000 ft). Some large capacity wells produce as much as 190 L/s (3000 gpm).

The Queen City aquifer has an effective surface area of 36,300 km^2 (14,000 sq mi), underlying portions of the Coastal Plain. Fresh water is produced down to 610 m (2000 ft) from a 152-m (500-ft) thick zone of interbedded sand and clay. Most well yields are considered to be low; however, some exceed 25 L/s (400 gpm).

The Sparta aquifer underlies the Queen City and overlies the Carrizo-Wilcox aquifers for an area of 23,300 km^2 (9000 sq mi). The production zone is an interbedded sequence of sand and clay up to 107 m (350 ft) thick, occurring to a maximum depth of 610 m (2000 ft). Yields generally range between 32 to 63 L/s (500 to 1000 gpm).

The Gulf Coast aquifer lies beneath the Coastal Plain inland for up to 193 km (120 mi). It is the region's most extensive groundwater reservoir, underlying an area of 90,600 km^2 (35,000 sq mi); it consists of a thickness of more than 1060 m (3500 ft) of sand, clay, and gravel. The Gulf Coast aquifer is most extensively developed in the Houston area, where well yields average 126 L/s (2000 gpm).

The Ogallala aquifer underlies 49,200 km^2 (19,000 sq mi) of the High Plains. Major production comes from 152-m (500-ft) thick sand and gravel. Depths to water range from 15 to 91 m (50 to 300 ft). Well yields vary from 6.3 to 63 L/s (100 to 1000 gpm) (Baker and Wall 1976).

In the Texas-Gulf region, groundwater quality varies with depths as well as geographical location. Generally, the lowest concentrations of dissolved solids occur in areas of greatest rainfall and least evaporation. The ranges in TDS concentrations for the regional aquifers are shown in Table F.7.

Potential recharge to groundwater reservoirs in the region increases from northwest to southeast, ranging from a fraction of an inch on the High Plains to several inches in the Sabine River basin. The calculated steady-state yields (Table F.8) are equivalent to the maximum annual recharge for each aquifer. The partly recoverable water in storage is in the form of freshwater bounded by saline water, which may or may not be economically practical to recover (Baker and Wall 1976).

Table F.7. Typical Range of Dissolved Solids in Water Used from Each Aquifer

Aquifer	Typical Range in Dissolved Solids (mg/L)
Alluvium	500-2000
Ogallala	400-1200
Gulf Coast	300-1000
Sparta	200-800
Queen City	200-800
Carrizo-Wilcox	200-1500
Woodbine	500-1200
Edwards (Balcones Fault Zone)	300-1200
Edwards-Trinity (Plateau)	400-1000
Trinity	500-1500
Santa Rosa	400-2500
Ellenburger-San Saba	400-2000
Hickory	300-700

From Baker and Wall (1976).

Table F.8. Quantities of Groundwater Available for Development[a]

Aquifer	Steady-State Yield (thousands (thousands of acre-ft)	Recoverable Water in Storage Above Depths of 400 ft (thousands of acre-ft)	Partly Recoverable Water in Storage Below Depth of 400 ft (thousands of acre-ft)
Alluvium	130	5,000	0
Ogallala	90	135,000	5,000
Gulf Coast	2,500	450,000	1,150,000
Sparta	130	20,000	65,000
Queen City	120	70,000	200,000
Carrizo-Wilcox	560	150,000	1,150,000
Woodbine	10	10,000	70,000
Edwards (Balcones Fault Zone)	410	2,000	13,000
Edwards-Trinity (Plateau)	540	70,000	70,000
Trinity	70	100,000	450,000
Santa Rosa	30	8,000	0
Ellenburger-San Saba	20	8,000	12,000
Hickory	40	10,000	100,000
Total (rounded)	4,650	1,038,000	3,285,000

From Baker and Wall (1976).

[a]Steady-state yield and recoverable water in storage from data in Alexander et al. (1964), Baker et al. (1963a,b), Brown and Signor (1973), Cronin et al. (1963), Mount et al. (1967), Peckham et al. (1963), Petitt and George (1956), Texas Water Development Board (1966a-r), Wood (1956), Wood et al. (1963), and other computations by U.S. Geological Survey. Specific yield of 2 percent used in computing recoverable water in storage in Edwards (Balcones Fault Zone), limestone part of Edwards-Trinity (Plateau), and Ellenburger-San Saba aquifers; specific yield of 15 percent used for other aquifers. Ogallala storage as of 1967 based on Cronin (1969).

The self-supplied industrial and electricity-generation utilities sector accounts for most of the regional water use, although irrigation clearly accounts for most of the freshwater consumption (Table F.1). About 85 percent of the irrigation demand is satisfied with groundwater (U.S. Geological Survey 1977). Groundwater in the northwestern part of the region (upper Brazos and Colorado basins) has been heavily pumped for agricultural needs. As a result, lowering of the water table has occurred (i.e., the groundwater has been "mined"). Groundwater is also used for domestic, public, industrial, and municipal supplies and for secondary oil recovery throughout the region (Water Resources Council 1974). Saline surface-water use in the region is for the self-supplied industrial sector; cooling of thermoelectric facilities is responsible for about 55 percent of this use. Generation of hydroelectric power uses about 68 x 10^6 m^3/day (18 bgd), with the Texas Gulf region ranking ahead of only five other regions in the conterminous United States in this respect (U.S. Geological Survey 1977).

In a projection of future water supplies for energy development, the Water Resources Council assessed the ground and surface waters of the region to be generally adequate to and beyond 1985; current and planned water development projects were taken into account (Water Resources Council 1974).

F.11 RIO GRANDE WATER RESOURCE REGION

The Rio Grande Water Resource Region, with an area of about 350,000 km^2 (136,000 sq mi) (U.S. Geological Survey 1977), includes the basin of the Rio Grande from headwaters in southern Colorado to its mouth on the Gulf at the U.S.-Mexican border. Prominent reservoirs along the Rio Grande include Elephant Butte and Falcon reservoirs and Devils Lake. The Pecos River, originating in New Mexico, is the most important tributary to the Rio Grande.

The hardness of surface waters in the Rio Grande region ranges from moderate (60 to 120 ppm hardness as $CaCO_3$) in the headwaters of southern Colorado to hard (120 ppm) in central New Mexico and to very hard (>180 ppm) in southern New Mexico and Texas. The hardest waters (>240 ppm) are found in the Pecos drainage from the headwaters in New Mexico to its confluence with the Rio Grande and in the Rio Grande mainstem below the mouth of the Pecos River. The lowest levels of dissolved solids (<120 ppm TDS) in the region are found in the Rio Grande headwaters in northern New Mexico and southern Colorado. Downstream from Albuquerque, New Mexico, however, high levels of TDS (>350 ppm) are the rule. Salinities exceeding 1000 ppm may be found in the Rio Grande mainstem below Albuquerque, New Mexico, downstream to the mouth of the Pecos River, and in the Pecos River mainstem over almost its entire length. Sediment (TSS) concentrations in headwaters and tributaries of the Rio Grande and Pecos rivers and in reaches of the Rio Grande mainstem along portions of the Mexican border generally exceed 1900 ppm. Moderate levels (270 to 1900 ppm) are found in the mainstem of the Rio Grande from southern New Mexico downstream to the Big Bend, in the lower Pecos River mainstem, and in the lowest reaches of the Rio Grande downstream from Laredo, Texas (Water Information Center 1973). Water quality problems in the region include reservoir eutrophication (such as in Elephant Butte Reservoir) from municipal discharges and pesticides and increased salinities from agricultural sources (U.S. Environmental Protection Agency 1977a).

Aquifers in the Rio Grande region contain approximately 7.1×10^{12} m^3 (5800 million acre-ft) of fresh to slightly saline water in storage. The groundwater reservoirs can be classified according to four major types: valley fill (primarily unconsolidated to semiconsolidated sand and gravel), volcanic rocks, consolidated sedimentary deposits (shale, sandstone, limestone, gypsum, and salt), and crystalline rocks.

The most important of the groundwater reservoirs is the valley fill material, which is found in intermontane valleys in all but the southeastern portion of the region. Sediment thicknesses range from very thin at valley perimeters to 2700 m (9000 ft); locally, deep basins with accumulations of more than 9100 m (30,000 ft) of sediments are encountered. Well yields are good and can be as great as 151 L/s (2400 gpm).

The volcanic rocks form the caprock for the plateaus, generally lying above the regional water table. They are only significant as aquifers where they occur in association with valley fill material.

Condolidated sedimentary rocks are found in the east-central and southeastern portions of the region, where they form most of the hills and low mountains. These rocks form aquifers where fractures and solution openings occur within the bedrock. Well yields are generally in excess of 20 L/s (300 gpm); however, yields of 60 to 220 L/s (1000 to 3500 gpm) are common.

Crystalline (intrusive igneous) rocks crop out in the north and north-central portions of the region in the mountainous areas. The rocks are very dense and evidently not extensively fractured because well yields are generally insignificant.

Groundwater quality varies from site to site. Water produced from valley fill aquifers has total dissolved solids concentrations between 52 and 13,800 mg/L; however, in some closed basin areas where evaporite deposits exist, the TDS concentration of the groundwater can be as great as 100,000 mg/L. The quality of groundwater derived from the consolidated sedimentary rock aquifers usually ranges from less than 1000 to more than 35,000 mg/L.

Recharge to the groundwater reservoirs takes place through infiltration of irrigation water, precipitation, and snowmelt. Discharge is by pumpage, evapotranspiration, seepage to streams, and minor underflow to adjacent water resource regions.

The average groundwater withdrawal in the region was 9.1×10^6 m^3/day (2.4 bgd) in 1975. Approximately 90 percent of this total was used for irrigation. An additional 5 percent provided public supplies. Incidentally, the entire public water demands of Albuquerque and El Paso are met by groundwater (West and Broadhurst 1975).

In the Rio Grande Water Resource Region, average annual runoff is equivalent to 20×10^6 m^3/day (5 bgd). Of the total off-channel water withdrawal of about 20×10^6 m^3/day (5.4 bgd) in 1975, surface freshwater withdrawals accounted for about 10×10^6 m^3/day (3 bgd). About 65 percent of the freshwater withdrawn was consumed. Irrigation accounts for most of the total regional water use and freshwater consumption (Table F.1). Generation of hydroelectric power uses about 4.6×10^6 m^3/day (1.2 bgd), the Rio Grande region ranking ahead of only the Souris–Red–Rainy region in the conterminous United States in this respect (U.S. Geological Survey 1977). Rio Grande waters are divided between the United States and Mexico by treaty and between Colorado, New Mexico, and Texas by compact. As is apparent from runoff and water-use data, the region does not currently have sufficient water resources to support present levels of development, and the Water Resources Council has listed the Rio Grande region as one of the nation's most critical energy-related water-supply problem areas. Diversion of water from the Colorado River basin to the Rio Grande region via the San Juan–Chama Project augments regional supplies. Although a projection of water supply availability to the year 1985 indicates that energy development may be satisified by existing utility water rights and by purchase of additional existing water rights, increased competition for water is expected (Water Resources Council 1974).

F.12 SOURIS—RED—RAINY WATER RESOURCE REGION

The Souris—Red—Rainy Water Resource Region, with an area of about 150,000 km^2 (59,000 sq mi) (U.S. Geological Survey 1977), includes areas of northern Minnesota, northeastern South Dakota, and northern and eastern North Dakota whose drainage is ultimately into the Hudson Bay via Lake Winnipeg in Manitoba. The Red River basin includes headwaters as far south as Lake Traverse on the South Dakota—Minnesota border. The mainstem forms much of the North Dakota—Minnesota border, with drainage northward toward Lake Winnipeg. The Souris River originates in Canada, flows southward, and drains a portion of northern North Dakota, and then flows northward again into Canada, joining the Assiniboine River, a tributary to the Red River. The Rainy River drains a lake-filled region along the Minnesota-Ontario border, connecting Rainy Lake with the downstream Lake-of-the-Woods; the Rainy River mainstem itself forms part of the international border. Drainage from the Lake-of-the-Woods is to Lake Winnipeg via the Winnipeg River. Important tributaries include River Des Lacs (to the Souris River), Sheyenne, Bois de Sioux, and Red Lake rivers (to the Red River), and Big Fork and Little Fork rivers (to the Rainy River). The Souris—Red—Rainy region includes numerous large natural lakes (such as Lake-of-the-Woods, Rainy Lake, Upper and Lower Red lakes, and Lake Traverse), in addition to many smaller ones. Major reservoirs are not common in the region, with notable exceptions being Lake Darling on the Souris River and Lake Ashtabula on the Sheyenne River.

Surface waters are very hard (>180 ppm hardness as $CaCO_3$) in the western half of the region (extreme western Minnesota, the Red River mainstem, and the Souris River basin), with levels exceeding 240 ppm in North Dakota. The Rainy River basin has moderately hard (60 to 120 ppm) waters, while the area in northern Minnesota tributary to the lower Red River has hard surface waters (120 to 180 ppm). Lowest dissolved solids levels are found in the Rainy basin above Rainy Lake (<120 ppm TDS); moderate TDS levels (120 to 350 ppm) are found in the lower Rainy basin and in some areas of western Minnesota tributary to the Red River. Otherwise, high levels of dissolved solids (>350 ppm) are found. Some saline surface waters (TDS >1000 ppm) are found in North Dakota's central drift plain in the Devil's Lake area. Suspended sediment (TSS) levels in streams of the region are generally low (<270 ppm) in the Rainy basin, upper Red River basin, and in the portion of the Sheyenne River affected by the impoundment of Lake Ashtabula; moderate levels (270 to 1900 ppm) are found elsewhere (Water Information Center 1973).

Toxic pollutants reported from waters of the region include pesticides (from the Rainy and Red rivers) and cadmium (from the Red River) (Water Information Center 1973). The Red River has been identified by the EPA as an example of stream recovery following waste discharge control; a stretch downstream from Fargo-Moorhead, North Dakota, had been severely impacted by municipal and industrial discharges from those cities. However, implementation of waste treatment resulted in a significant improvement in water quality (U.S. Environmental Protection Agency 1977a).

Much of the Souris—Red—Rainy region is underlain by consolidated bedrock, which constitutes some of the more important aquifers. Glacial material and valley fill comprise the remainder of the aquifer material. The Dakota Sandstone, which extends into parts of North Dakota, is a significant areally extensive aquifer. Eastern Minnesota is also underlain by sandstone groundwater reservoirs.

Much of Minnesota and portions of eastern North Dakota are covered by glacial drift. The well-sorted glacial outwash sand and gravel deposits are excellent producers of groundwater, capable of yielding large amounts to wells. The clay-rich, poorly sorted till yields only small amounts of groundwater to wells.

Buried stream valleys in southeast North Dakota produce moderate to large amounts of groundwater. Sediments of the larger tributary valleys of the Missouri River are locally significant aquifers (Walton 1970).

In the Souris—Red—Rainy Water Resource Region, average annual runoff is equivalent to 24 x 10^6 m^3/day (6.2 bgd). Of the total off-channel water withdrawal of about 1.4 x 10^6 m^3/day [360 million gal/day (mgd)] in 1975, surface freshwater withdrawals accounted for about 1.0 x 10^6 m^3/day (270 mgd) and fresh groundwater for about 0.3 x 10^6 m^3/day (90 mgd). About 25 percent of freshwater withdrawn was consumed (U.S. Geological Survey 1977).

The primary user of water in the region is the self-supplied industrial and electricity-generation utilities sector; most of the sector's withdrawals are for thermoelectric power generation (Table F.1). The primary consumer of freshwater, however, is irrigation. The region does not have major hydroelectric power capacity, making it unique among the regions of the United States in this respect (U.S. Geological Survey 1977).

Streamflow in the Souris-Red-Rainy region is shared with Canada by agreement. That part of the region located in North Dakota has been identified by the Water Resources Council as one of the most critical energy-related water supply problem areas in the nation, with localized water shortage and thermal pollution problems. Mining and use of western North Dakota lignite coal reserves would require the development of additional storage or groundwater sources (Water Resources Council 1974).

F.13 MISSOURI BASIN WATER RESOURCE REGION

The Missouri Basin Water Resource Region, with an area of about 1,330,000 km^2 (515,000 sq mi) (U.S. Geological Survey 1977), is the largest region in the conterminous United States. The region includes the Missouri River from its headwaters in western Montana to near its confluence with the Mississippi River. (The most downstream reach of the Missouri River, from the mouth of the Osage River in central Missouri, to its confluence with the Mississippi River near St. Louis, Missouri, is considered part of the Upper Mississippi region.) The region also includes major tributary systems (Yellowstone and Platte river systems) and other prominent river such as the James, Big Horn, Powder, Little Missouri, Belle Fourche, Niobrara, and Republican rivers. The region includes some of the largest reservoirs (in terms of storage capacity) in the country, such as the Oahe, Garrison, Fort Peck, and Fort Randall reservoirs on the Missouri River mainstem. Other major reservoirs are located on the Missouri River (Canyon Ferry Reservoir) and on tributary rivers, such as Tiber Reservoir (Marias River), Yellowtail Reservoir (Big Horn River), Seminoe and Pathfinder reservoirs and McConaughy Lake (North Platte River), Milford Reservoir (Republican River), Tuttle Creek Reservoir (Big Blue River), and Kaysinger Bluff Reservoir and Lake of the Ozarks (Osage River). Large natural lakes are not prominent features of the region, but scattered smaller lakes do exist.

Surface waters of the Missouri Basin Water Resource Region vary from soft (<60 ppm hardness as $CaCO_3$) in parts of northeastern Colorado to very hard in other parts of the region. In general, the hardest waters (>240 ppm) are found in the central and lower parts of the basin, from southeastern Montana and northeastern Wyoming through western and southern South Dakota and throughout large parts of Nebraska as far down the mainstem Missouri River as Kansas City, Missouri. Very hard waters (180 to 240 ppm) tend to be found in other parts of the lower and central basin, while moderately hard to hard waters (60 to 180 ppm) are typically found in the upper Missouri River basin. Dissolved solids levels are generally high (>350 ppm TDS) in the region; low to moderate levels (<120 to 350 ppm) are found in headwater areas in Montana, Wyoming, and Colorado. Moderate levels (120 to 350 ppm) are found in parts of the Platte River basin in Nebraska, although high levels are typical of the mainstem Platte, North Platte, and South Platte rivers. Salinities may exceed 1000 ppm in parts of the Powder, Big Horn, James, and North and South Platte rivers and in a large area covering southwestern North Dakota and western South Dakota. Suspended sediment (TSS) levels are typically low (<270 ppm) only in the Missouri River mainstem, in Fort Peck Reservoir, from near Garrison Reservoir downstream to the mouth of the Missouri River, the James River in and below Jamestown Reservoir, and in some headwater areas in Montana, Wyoming, and Colorado. Otherwise, moderate (270 to 1900 ppm) to high (>1900 ppm) levels are prevalent (Water Information Center 1973).

The most serious water quality problems in the Missouri Basin region occur as a result of nonpoint sources, some of natural origin. Headwaters, especially of snowmelt origin in Wyoming and Montana, are of excellent quality, but waters are degraded downstream (Water Resources Council 1974). Irrigation returns, crop and pastureland erosion, and feedlot wastes contribute sediments, bacteria, nutrients, pesticides, and salts. Dewatering of streams exacerbates these problems. Point sources, including municipal and industrial discharges, have been important in populated and developed areas, but such sources are seen as less severe and more easily controlled than nonpoint sources (U.S. Environmental Protection Agency 1977a). However, elevated levels of cadmium have been reported from the lower Missouri River basin (Water Information Center 1973). Natural sources of water quality problems account for about 13 percent of degraded stream miles in Montana; natural sources of suspended and/or dissolved solids are also identified as important in North Dakota, Kansas, and Missouri. Other water quality problems have been attributed to oil field wastes in Wyoming and mine drainage in Kansas. Eutrophication of sections of the North Platte and Laramie rivers in Wyoming has been reported. Increased population demands, industrial growth, and mining have been cited as threats to regional water quality (U.S. Environmental Protection Agency 1977a).

Groundwater aquifers in the Missouri Basin are of two general types: unconsolidated sediments and consolidated sedimentary rocks. Buried valley alluvium is probably the most prolific aquifer material, along with sediments associated with present-day stream courses.

Bedrock aquifers range in age from Precambrian to Recent. These sedimentary rocks include sandstones, siltstones, limestones, and shales. The shales, where highly fractured, yield only small amounts of water to wells. The remaining rock types have widely varying yields. Significant limestone aquifers, such as the Madison Limestone, underlie portions of Kansas, South Dakota, and Wyoming. Sandstones are also important aquifers. The Dakota Sandstone aquifer underlies the Dakotas. Some Kansas and Colorado groundwater production is derived from sandstone formations.

The groundwater quality is generally good in the unconsolidated aquifers. Much of the groundwater in the consolidated aquifers, however, is too highly mineralized to use. Freshwater generally occurs within the first few tens of meters of the surface (Walton 1970).

In the Missouri Basin Water Resource Region, average annual runoff is equivalent to 200 x 10^6 m^3/day (54 bgd). Of the total off-channel withdrawal of 130 x 10^6 m^3/day (35 bgd) in 1975, surface freshwater withdrawals accounted for about 95 x 10^6 m^3/day (25 bgd), and fresh groundwater accounted for the remainder. About 43 percent of freshwater withdrawn was consumed. Irrigation accounts for the majority of water withdrawals and freshwater consumption (Table F.1). Irrigation also is responsible for almost 35 x 10^6 m^3/day (9 bgd) of the total groundwater withdrawals. The Missouri Basin region uses about 570 x 10^6 m^3/day (150 bgd) for hydroelectric power, with the region ranking seventh in the nation in this respect (U.S. Geological Survey 1977). The Montana, North Dakota, and Wyoming portions of the Missouri Basin Water Resource Region have been identified by the Water Resources Council as being among the nation's most critical energy-related water-problem areas. In particular, the extraction and use of coal resources in these areas is seen as increasing agricultural vs industrial competition for water. Development of additional storage capability and importation of water from the Upper Colorado basin are suggested as augmenting dependable water supplies in the region (Water Resources Council 1974).

F.14 UPPER COLORADO WATER RESOURCE REGION

The Upper Colorado Water Resource Region, with an area of about 285,000 km^2 (110,000 sq mi) (U.S. Geological Survey 1977), includes the headwaters of the Colorado River and major tributary systems, such as the Green and San Juan river systems. Lees Ferry, Arizona, just downstream from the Glen Canyon Dam, is taken as the dividing point between the Upper and Lower Colorado River basins. Large natural lakes are not important features of the region. However, reservoirs are widespread, ranging from Lake Powell, the impoundment of Glen Canyon Dam (the second largest reservoir in the United States in terms of storage capacity) (Water Information Center 1973), to the many small reservoirs, such as Strawberry and Big Sandy reservoirs. Other major reservoirs include Flaming Gorge Reservoir on the Green River and Navajo Reservoir on the San Juan River.

Surface waters of the Upper Colorado Water Resource Region are of moderate hardness (60 to 120 ppm hardness as $CaCO_3$) only in the headwaters of the Colorado Rockies; elsewhere, waters are hard to very hard (120 to 240 ppm and above). The hardest waters (>240 ppm) are found along the Colorado River mainstem in southeastern Utah. Dissolved solids levels follow a similar pattern: low to moderate levels (<120 to 350 ppm TDS) in the headwaters of the Colorado Rockies, with high levels (>350 ppm) elsewhere. The mainstem Green and San Juan rivers and the Colorado River in extreme western Colorado and downstream are typically saline (TDS >1000 ppm). Sediment (TSS) levels are low (<270 ppm) in the Colorado Rockies headwaters, in the Green River mainstem in northeastern Utah and southwestern Wyoming, in Lake Powell, and in the upper San Juan River mainstem in New Mexico. Intermediate levels (270 to 1900 ppm) are found in other parts of western Colorado. Otherwise, high levels (>1900 ppm) are prevalent (Water Information Center 1973).

Regional water quality problems include high natural and man-made levels of suspended dissolved solids. Natural sources include diffuse sources (such as surface runoff), which increase sediment and salinity loads, as well as point sources (springs). Heavy surface-water consumption reduces the dilution capabilities of affected streams, exacerbating the problem. Irrigation return flows have also adversely affected surface-water quality (U.S. Environmental Protection Agency 1977a). In the Green River basin, for example, while waste water treatment and low population densities limit municipal and industrial pollution sources, irrigated lands yield an estimated 4500 to 13,450 kg/ha/year of salt (2 to 6 tons per acre per year) to surface waters via return flows (Wyoming Water Planning Program 1970). Control of point sources such as municipal discharges is more easily assured. For example, improvement of the San Juan River in New Mexico was evident following improved waste water treatment (U.S. Environmental Protection Agency 1977a). Problems with coliform bacteria, BOD, dissolved solids, sulfate, and particular metals (lead, cadmium, iron) have been reported from waters of the Colorado River system in Utah (U.S. Environmental Protection Agency 1977a).

The maximum volume of recoverable groundwater in storage in the upper 30.5 m (100 ft) of water-bearing material in the Upper Colorado region is estimated to be 6.2 x 10^9 m^3 (50 million acre-ft). Eighty-five percent of this amount occurs in sedimentary rocks; 5 percent is stored in unconsolidated material. The total amount of recoverable groundwater present in the entire aquifer sequences cannot easily be estimated but is thought to be many times the quantity stored within the upper 30.5 m (100 ft) of saturated rock material. Groundwater is stored in five general types of hydrogeologic units (Table F.9).

Table F.9. Estimated Recoverable Groundwater in Storage,[a] Upper Colorado Region

Geohydrologic Unit	Rock Type	Area (thousands of acres)	Estimated Specific Yield[b]	Saturated Thickness[c] (ft)	Estimated Amount of Water in Storage (thousands of acre-ft)	
					Minimum	Maximum
1	Unconsolidated deposits	800	5-15	50	2,000	6,000
2	Volcanic rocks	2,200	2-5	100	4,400	11,000
3	Sedimentary rocks	40,000	1-2	100	40,300	80,600
4	Sedimentary rocks	24,300	0.2-0.7	100	4,900	17,000
5	Igneous and metamorphic rocks	5,100	0-0.3	100	0	1,500
Total (rounded)					50,000	115,000

From Price and Arnow (1974).

[a]About 85% of the recoverable groundwater stored in the upper 100 ft of saturated rocks occurs in sedimentary rocks which have relatively low permeability and yield water slowly.

[b]The ratio of the volume of water that a saturated rock will yield by gravity to the volume of the rock.

[c]Groundwater storage is estimated for only 50 ft of the unconsolidated deposits because in many places the saturated thickness of this unit does not greatly exceed 50 ft. Groundwater storage is estimated for only 100 ft of the other geohydrologic units because the saturated thickness of the units is not known. In many places throughout the region, the saturated thickness is much more than 100 ft; thus, total recoverable groundwater storage in the region greatly exceeds the maximum amount shown in this table.

The unconsolidated deposits consist of gravel, sand, and clay. They occur primarily along the larger stream valleys. Depths to water are generally less than 15 m (50 ft). Yields to wells vary between 0.3 to more than 31.6 L/s (5 to more than 500 gpm).

The volcanic rocks consist primarily of lava flows, with some associated pyroclastic and intrusive igneous rocks. These aquifer units occur mostly along the east and west-central borders of the region. Well yields usually range from 0.3 to 3.16 L/s (5 to 50 gpm) but can locally range from 3.16 to 31.6 L/s (50 to more than 500 gpm).

The sedimentary rock aquifers are divided into two classes on the basis of origin: nonmarine and marine. Both types occur throughout the region. Depths to water are from several tens to more than 304.8 m (several hundred to more than 1000 ft). The nonmarine aquifers are more permeable and generally yield from 0.3 to 3.16 L/s (5 to 50 gpm) to wells. The aquifers of marine origin yield less than 0.6 L/s (10 gpm) to wells.

Granite, schist, gneiss, and quartzite comprise the igneous and metamorphic rocks. Their occurrence is primarily restricted to the eastern boundary, the northernmost, and the north-central portions of the region. Well yields rarely exceed 0.6 L/s (10 gpm).

The quality of groundwater in the region is good; a very few restricted areas have a TDS concentration exceeding 3000 mg/L. Shallow aquifers at higher elevations [above 2133.6 m (7000 ft)] provide water with less than 1000 mg/L TDS, as do the sandstone (Navajo and Dakota Sandstones) and limestone (Madison Limestone and Morgan Formation) aquifers at lower elevations. Shale and siltstone formations usually contain saline groundwater.

Four percent [4.9×10^9 m^3 (4 million acre-ft)] of the average annual precipitation in the region [1.2×10^{11} m^3 (95 million acre-ft)] enters the groundwater reservoirs as recharge. This recharge occurs through infiltration of precipitation, irrigation water, and influent streams. Discharge takes place through springs, areas of phreatophyte growth, and gaining reaches of (effluent) streams.

Groundwater withdrawals in 1970 totalled 1.5×10^8 m^3 (0.12 million acre-ft); consumptive use totalled 7.4×10^7 m^3 (0.06 million acre-ft). This is approximately 2 percent of the total volume of water withdrawn [7.0×10^9 m^3 (5.7 million acre-ft)] and consumed [4.4×10^9 m^3 (3.6 million acre-ft)] that same year. Of the total groundwater withdrawn, irrigation accounted for

46 percent, public supply for 27 percent, self-supplied industry for 15 percent, and domestic and stock for 12 percent. The amount of groundwater consumption can be attributed to irrigation, 52 percent; public supply, 25 percent; domestic and stock, 17 percent; and self-supplied industry, 6 percent (Price and Arnow 1974).

In the Upper Colorado Water Resource Region, average annual runoff is equivalent to 49 x 10^6 m^3/day (13 bgd). Of the total off-channel water withdrawal of 16 x 10^6 m^3/day (4.1 bgd) in 1975, surface freshwater withdrawals accounted for 15 x 10^6 m^3/day (3.9 bgd). Fresh groundwater was the other major contributor. About 41 percent of freshwater withdrawn was consumed. Irrigation accounts for the majority of water withdrawals and freshwater consumption (Table F.1). The Upper Colorado region uses about 49 x 10^6 m^3/day (13 bgd) for hydroelectric power, with the region ranking ahead of only four other regions in the conterminous United States in this respect (U.S. Geological Survey 1977).

The Upper Colorado Water Resource Region has been categorized by the Water Resources Council as being among the nation's most critical energy-related water-supply problem areas. Because of international agreement (with Mexico), interstate compact, and Federal and state laws, not all runoff in the region is available for use within the region. Although estimates of water availability in the region (based on required deliveries to Mexico and the Lower Colorado basin and on current use rates) indicate that about 8 x 10^6 m^3/day (2 bgd) of water supply are not being utilized in the region, not all of this figure is exploitable. In addition to environmental water needs (water quality, fish and wildlife, and aesthetics), uneven geographic distribution of supplies and demands and variable annual runoff cause water use problems. Water supplies have been over-appropriated in some areas, especially in Colorado and Utah, with existing water rights exceeding current use and estimated resources. Competition between agricultural and industrial demands is seen as a result. Development of more surface storage, interim use of groundwater, greater efficiency in water use, and resolution of water rights and allocations are seen as crucial to the satisfaction of anticipated water demands in the region (Water Resources Council 1974).

F.15 LOWER COLORADO WATER RESOURCE REGION

The Lower Colorado Water Resource Region, with an area of about 355,000 km^2 (137,000 sq mi) (U.S. Geological Survey 1977), includes the Colorado River and its tributary systems below Lees Ferry, Arizona, just downstream from Glen Canyon Dam. Major tributary systems include the Virgin River, Little Colorado River, Verde-Salt-Gila rivers, and the Bill Williams River. The region does not contain large natural lakes, but the Lower Colorado system is heavily impounded.

Lake Mead, behind Hoover Dam on the Colorado River mainstem, has the largest storage capacity of U.S. reservoirs (Water Information Center 1973). Other major reservoirs are located on the Colorado River itself (Lake Mohave and Havasu Lake) and on the Gila (Painted Rock and San Carlos reservoirs), Salt (Roosevelt Reservoir), and Bill Williams (Alamo Reservoir) rivers.

Surface waters of the Lower Colorado Water Resource Region are generally hard (120 to 180 ppm as $CaCO_3$) to very hard (180 to 240 ppm), with the hardest waters (>240 ppm) found in the Virgin River and Colorado River mainstem. Dissolved solids levels are generally high (>350 ppm TDS), with waters of saline levels (>1000 ppm) found along the Virgin, Little Colorado, Salt, and upper Gila rivers. Sediment (TSS) concentrations are low (<270 ppm) where affected by impoundment (along the Colorado River mainstem from below Lake Powell to the confluence of the Little Colorado River and in and downstream from Lake Mead and in portions of the Gila and Salt rivers), but, otherwise, concentrations are generally high (>1900 ppm) (Water Information Center 1973).

Regional water quality problems are dominated by nonpoint-source (in some cases natural) discharges. Agricultural and rural sources, including runoff and irrigation return flows, contribute nutrients, sediments, salts, and bacteria (U.S. Environmental Protection Agency 1977a). The overall increasing salinity in a downstream direction (mostly natural but accelerated by man's activities) is a major regional problem. The salinization of soils and groundwater is intimately related (Water Resources Council 1974). Metals contamination from mineralized areas, particularly abandoned mining operations, has been cited as a problem in Arizona (U.S. Environmental Protection Agency 1977a). Elevated levels of cadmium and mercury have been reported from the Gila River system (Water Information Center 1973). Eutrophication is reported to be a problem in Arizona (U.S. Environmental Protection Agency 1977a).

The principal aquifers of the Lower Colorado region are unconsolidated sediments and consolidated sedimentary rocks. Well yields range from very low to moderately high.

The southern and western portions of the region consist of alternating fault-block basins and mountain ranges. The aquifers are almost entirely unconsolidated valley fill material (alluvial fan deposits) eroded from adjacent mountains. The sediments are primarily sand and gravel interbedded with silts and clays. Thicknesses vary between tens of meters to more than 1000 m. The highest yields are produced from wells located at the mouths of mountain stream canyons.

The northeastern portion of the region is underlain by consolidated sedimentary rocks, such as sandstones, shales, and limestones. Some alluvial material is found in the stream valleys. The average well yields are very low; however, the Coconino Sandstone of Permian age is an excellent aquifer. Wells producing from the Cononino yield several tens of liters per second (hundreds of gpm) (Walton 1970).

In the Lower Colorado Water Resource Region, average annual runoff is equivalent to about 12 x 10^6 m^3/day (3.2 bgd) (U.S. Geological Survey 1977). By law, the Upper Colorado basin must deliver an average of 25 x 10^6 m^3/day (7.5 million acre-ft/year) to the Lower Colorado basin at Lees Ferry, Colorado, calculated on a ten-year averaging interval. However, not all this Colorado River water is available for use within the Lower Colorado Water Resource Region; it has been estimated that about 11 x 10^6 m^3/day (2.8 bgd) is available to the region (Water Resources Council 1974).

Of the total off-channel water withdrawals of about 32 x 10^6 m^3/day (8.5 bgd) in 1975, surface freshwater withdrawals accounted for about 13 x 10^6 m^3/day (3.5 bgd), while fresh groundwater contributed the remainder. Of the freshwater withdrawals, about 74 percent was consumed. The Lower Colorado Water Resource Region uses about 91 x 10^6 m^3/day (24 bgd) for hydroelectric power, ranking ahead of six other regions in the conterminous United States in this respect (U.S. Geological Survey 1977). Irrigation is the dominant water user and consumer of freshwater (Table F.1). Irrigation also accounts for almost 90 percent of groundwater use (U.S. Geological Survey 1977).

The Water Resources Council has identified the Lower Colorado Water Resource Region as one of the nation's most critical energy-related water-supply problem areas. The Colorado River system as a whole is seen as unable to continually supply demands in the Upper and Lower Colorado basins and Mexico as per treaty obligations. Use of groundwater currently exceeds recharge; overdraft has exceeded an average of 8 x 10^6 m^3/day (2 bgd) in the Gila River basin. The importation of water from areas such as Alaska, Canada, or the Pacific Northwest has been proposed. The conclusion is that energy-related water demands will compete with irrigation and municipal and industrial needs. Water development projects such as the Central Arizona Project, which will allow Colorado River water to be used by the Tucson-Phoenix, Arizona, area and enroute agricultural lands, are expected to alleviate distributional problems (Water Resources Council 1974).

F.16 GREAT BASIN WATER RESOURCE REGION

The Great Basin Water Resource Region, with an area of about 480,000 km^2 (185,000 sq mi) (U.S. Geological Survey 1977), includes large portions of Nevada and Utah and smaller portions of adjacent states. Drainage is land-locked. Large portions of the region are devoid of permanent surface waters. Saline lakes, ranging in size up to such major bodies as the Great Salt Lake, are widely distributed. Feeding these lakes are streams and stream systems that range in size from small ephemeral streams to large systems such as the Humboldt, Truckee, and Bear rivers. Lake Tahoe, an exceptionally deep freshwater lake, is fed by snowmelt from the Sierra Nevada Range. The region also contains many channels and basins (washes and playas) that contain water only ephemerally, as a result of precipitation events.

Surface waters of the Great Basin Water Resource Region tend to increase in hardness in an eastward direction. Soft waters (<60 ppm hardness as $CaCO_3$) are found in extreme western Nevada; most of Nevada has moderately hard (60 to 120 ppm) waters. The Carson Sink area and the eastern part of the Great Basin have waters ranging from hard to very hard (120 to >240 ppm), with the hardest waters occurring in southwestern Utah. Surface waters generally have high dissolved solids levels (>350 ppm), although moderate levels (120 to 350 ppm) are found in the western and northern extremes of the basin and in parts of southwestern Utah. The lowest levels (<120 ppm) are typical only around Lake Tahoe. Saline waters (>1000 ppm) are found in the Nevada-California border area (Pyramid, Mono, and Walker lakes) and in Utah (Great Salt Lake and Utah Lake). Stream sediment (TSS) levels generally range from low (<270 ppm) in the California-Nevada border area and in the Great Salt Lake Basin to moderate (270 to 1900 ppm) in northern Nevada and parts of Utah and to high (>1900 ppm) elsewhere in the Great Basin (Water Information Center 1973).

Water quality in the Great Basin is largely limited by natural nonpoint sources of mineralization. While municipal and industrial point-source discharges are of local significance (as in the Lower Provo and Jordan rivers in Utah), the diffuse salinity and sediment contribution of agricultural practices is of greater regional significance (U.S. Environmental Protection Agency 1977a). Cultural eutrophication has been noted in the ultraoligotrophic Lake Tahoe (Goldman 1972).

The volume of recoverable groundwater in storage within the upper 30 m (100 ft) of aquifers in the Great Basin region is estimated to be 3.7 x 10^{11} m^3 (300 million acre-ft). Total groundwater storage within the entire aquifer thickness is probably on the order of several trillion cubic meters (several billion acre-ft). The regional groundwater reservoirs are of three basic types: unconsolidated alluvial material, consolidated carbonate rocks, and consolidated volcanic rocks. Large capacity wells average yields of 63 L/s (1000 gpm).

The unconsolidated alluvial aquifers are primarily comprised of sand and gravel deposits; however, in the lowest portions of valleys, silt and clay deposits are common. The alluvial aquifers occur in the intermontane basins of the region. The potentiometric surface is relatively close to land surface in the lowest areas; depth to water may increase several tens of meters towards the mountains. Aquifer thickness varies from site to site, often exceeding 300 m (1000 ft).

The carbonate rock aquifers of the region are generally highly permeable and occur in the central and northeastern portions of the region. Large springs discharge water from carbonate aquifers in eastern Nevada and western Utah. Many perched groundwater bodies exist where the carbonates are discontinuous or blocked by faults.

Known volcanic rock aquifers of significant size occur only in the southeastern and extreme northeastern portions of the region. Large quantities of water can be obtained from the fracture openings within the volcanics.

Groundwater quality varies from fresh (less than 1000 mg/L) to briny (more than 35,000 mg/L) across the region. Freshwater is most commonly found at valley margins. Groundwater underlying small basins may be brackish; major deep valleys (sinks) are underlain by brackish to briny groundwater. Locally, thermal springs have water of poor quality.

The average annual precipitation in the Great Basin region is 1.1×10^{11} m^3 (88 million acre-ft). Of this amount, 3 to 7 percent [4×10^9 to 7×10^9 m^3 (3 to 6 million acre-ft)] recharges the groundwater reservoirs. Most recharge occurs through infiltration of precipitation in the mountains; some input from losing streams takes place. Groundwater discharge is through evapotranspiration, spring discharge, contribution to stream flow, and underflow to adjacent areas (Eakin et al. 1976).

In the Great Basin Water Resource Region, average annual runoff is equivalent to 28×10^6 m^3/day (7.5 bgd). Of the total off-channel water withdrawals of 26×10^6 m^3/day (6.9 bgd) in 1975, surface freshwater withdrawals accounted for about 20×10^6 m^3/day (5.4 bgd) and fresh groundwater withdrawals about 5.3×10^6 m^3/day (1.4 bgd). Of freshwater withdrawals, about 53 percent was consumed. The Great Basin region uses about 14×10^6 m^3/day (3.8 bgd) for hydroelectric power, greater in this respect than only the Rio Grande and Souris–Red–Rainy regions in the conterminous United States. Irrigation accounts for the majority of total withdrawals and freshwater consumption (Table F.1). Irrigation also accounts for about 70 percent of fresh groundwater use (U.S. Geological Survey 1977).

The Water Resources Council has designated the Great Basin Water Resource Region as one of the nation's most critical energy-related water-supply problem areas. Water-related problems result from the aridity of the region and the expense of water development. Importation of water from the Colorado River Basin to the Wasatch Front area of the eastern part of the Great Basin by construction of the Bonneville Unit of the Central Utah Project is seen as partly alleviating problems. However, water supplies are still expected to be inadequate in the western part of the region around Reno, Nevada. Additional water demands are considered limiting to increased energy development (Water Resources Council 1974).

F.17 CALIFORNIA WATER RESOURCE REGION

The California Water Resource Region, with an area of about 310,000 km^2 (120,000 sq mi) (U.S. Geological Survey 1977), consists largely of the river systems (Sacramento, San Joaquin, etc.) that drain the western slopes of the Sierra Nevada Mountains and flow toward San Francisco Bay. Reservoirs, such as Shasta Lake and Folsom and Pine Flat reservoirs, are located on headwaters of these streams. Other river systems, with drainage into the Pacific Ocean, include the Klamath, Russian, Salinas, Eel, Cuyama, and Santa Clara rivers. Large natural lakes include Upper Klamath Lake, Clear Lake, and Buena Vista Lake (at the terminus of the Kern River). The Salton Sea, in the Imperial Valley of southern California, was formed and is fed by water from the lower Colorado River. Major aqueducts and canals (Hetch Hetchy, Los Angeles, and San Diego—Colorado River aqueducts and the All-American and Coachella canals) provide for water transport to municipal, industrial, and agricultural demand centers along the coast and in the Imperial Valley.

Surface water hardness of the California Water Resource Region generally increases southward and coastward from soft (<60 ppm hardness as $CaCO_3$) in the Sierras and in northern California to moderate (60 to 120 ppm) at the foothills of the Sierras and along the northern coast and to hard (120 to 180 ppm) in the San Joaquin Valley and along the southern coast. Very hard waters (180 to 240 ppm) are found inland in southern California and along the coast in the Los Angeles-San Diego area. Dissolved solids levels also generally increase from lowest levels (<120 ppm TDS) in the Sierras and in northern California to higher levels (>350 ppm) to the southern interior and coast. Saline waters (>1000 ppm) are found scattered throughout southern California. The Salton Sea is the third largest saline lake [907 km^2 (350 sq mi) in the nation. Stream sediment (TSS) levels generally increase from low levels (<270 ppm) in northern California and the Sierras to moderate levels (270 to 1900 ppm) along most of the coast and to high levels (>1900 ppm) near San Diego and in southern interior California (Water Information Center 1973).

Although overall water quality in California is good, problem areas do exist. Point sources are seen as under control, both in terms of number and severity, as a result of construction and enforcement waste treatment facilities. Nonpoint sources are viewed as widespread, difficult to define, and related to established land use practices. Logging has contributed debris and sediments to surface waters. Increasing mineralization of groundwater and of surface water (Colorado River water used by the Imperial and Coachella Valley agriculture), pesticide residues, and heavy metals concentrations are major problems (Water Information Center 1973; U.S. Environmental Protection Agency 1977a). Elevated levels of mercury have been reported in the San Francisco Bay area and in the Merced River (Water Information Center 1973). Saltwater intrusion has degraded the quality of formerly usable aquifers along the southern coast (U.S. Environmental Protection Agency 1977a).

More than 139,000 km^2 (53,670 sq mi) or 45 percent, of the land area within the California region is underlain by groundwater reservoirs, both undeveloped and developed. Undeveloped reservoirs are those from which total annual withdrawal is less than 1.0 x 10^7 m^3 (8100 acre-ft). Groundwater reservoirs are listed for each of the nine subregions in Tables F.10 and F.11. Usable reservoir volumes have been estimated for 37 of the 52 recognized groundwater reservoirs (Table F.12); total usable reservoir capacity is at least 2.1 x 10^{10} m^3 (17 million acre-ft). Reservoirs are of two main types: alluvial and volcanic bedrock. The aquifers are the most reliable (and often the sole) source of potable water in many parts of the California region.

Table F.10. Summary of the Groundwater Reservoirs

Subregion	Undeveloped Groundwater Reservoirs		Developed Groundwater Reservoirs			
	Number	Estimated Area (km^2)	Number	Area (km^2)	Usable Capacity[a] (km^3)	Annual Pumpage (km^3)
North Coastal	6	2,300	7	2,800		0.2
San Francisco Bay	1	100	9	4,000	3	0.4
Central Coastal	1	700	10	7,900	9	1.0
South Coastal	0		13	7,800	26	1.7
Coastal basins	8	3,100	39	22,500	38	3.3
Tributary valleys	7	2,300	2	1,400		
Sacramento Basin				10,800		3.1
Delta Area			1	3,100		1.2
San Joaquin Basin				13,000		8.0
Tulare Basin				11,300		3.7
Central Valley	7	2,300	3	39,600	125	16
North Lahontan	3	3,400	0			
South Lahontan	38	18,800	10	14,100	43	0.7
Colorado Desert	23	22,200	3	2,200	4	0.2
Interior basins	64	44,400	13	16,300	47	0.9
Total	79	50,000	55	78,000	210	20

From Thomas and Phoenix (1976).

[a]Estimates of usable capacity have been made for only 37 of the 55 groundwater reservoirs listed, and these represent the investigators' judgment of what is technically and economically practical at the time.

Table F.11. Developed Groundwater Reservoirs

[From Bader (1969) and California Region Framework Study Committee (1971), revised and updated]

County	Groundwater Reservoir	Area (km^2)	Aquifer: Depth Zone (m)	Aquifer: Usable Capacity (km^3)	Withdrawals from Wells: Year	Withdrawals from Wells: Pumpage (10^6 m^3)	Withdrawals from Wells: Range in Dissolved Solids (mg/liter)[a]
	North Coastal subregion						
Del Norte, California	Smith River Basin:						
	Smith River plain	180	3-11	0.09	1968	7	30-200
Klamath, Oregon	Klamath River Basin:						
	Sprague River valley	440			1970	31	80-230
	Swan Lake Valley	120			1970	31	80-270
	Yonna Valley	120			1970	16	110-270
	Lower Klamath River valley	490			1970	100	130-880
	Lower Klamath River valley	410			1954	12	80-830
Siskiyou, California	Closed basin:						
	Butte Valley	470			1953	26	110-1,900
Humboldt, California	Eel River and Mad River basins:						
	Eureka plain	600	3-12	0.15	1962	18	50-2,000
	Mad River valley (1-8),						
	Eel River valley (1-10)						
	San Francisco Bay subregion						
Mendocino, California	Russian River basin:						
	Ukiah Valley	180	3-15	0.04	1954	12	110-1,120
Sonoma, California	Santa Rosa Valley and Healdsburg area	470	3-60	1.2	1954	22	90-800
	San Francisco Bay:						
	Petaluma Valley	340	3-60	0.25	1958	2	110-4,800
Napa, California	Napa Valley	210	3-60	0.30	1950	7	100-5,000
Sonoma, California	Sonoma Valley	100	5-60	0.05	1950	2	130-2,800
Solano, California	Suisan-Fairfield Valley	670	3-60	0.05	1949	10	300-1,350
Contra Costa, California	Pittsburg plain	100	30-60		1931	10	480-2,060
	Clay Valley	160	6-60	0.15	1930	10	210-2,170
	Ygnacio Valley (2-6)						

Table F.11 (continued)

County	Groundwater Reservoir	Area (km^2)	Aquifer: Depth Zone (m)	Aquifer: Usable Capacity (km^3)	Withdrawals from Wells: Year	Withdrawals from Wells: Pumpage (10^6 m^3)	Withdrawals from Wells: Range in Dissolved Solids (mg/liter)[a]
San Francisco Bay subregion							
Santa Clara, California	Santa Clara Valley:						
	South Bay	830	8-60	0.95	1969	220	240-960
	East Bay	470			1970	50	300-7,000
Alameda, California	Livermore Valley: Sunol Valley (2-11), San Ramon Valley (2-7)	570	8-60	0.25	1970	25	290-2,800
Central Coastal subregion							
Santa Cruz, California	Soquel Creek basin:						
	Soquel-Aptos area	260					180-700
Santa Clara, California	Pajaro River basin:						
	Pajaro Valley	360	6-90	0.03	1969	65	170-1,500
	Llagas Valley	210			1969	60	250-550
San Benito, California	Hollister Valley	670	6-60	1.0	1960	135	280-2,550
Monterey, California	Salinas River basin:						
	Salinas Valley	1,810	6-60	1.6	1960	370	240-3,000
San Luis Obispo, California	Paso Robles	2,330	15-75	2.1	1967	55	
	Santa Maria River basin:						
	Arroyo Grande Valley	100	30-240	0.15	1967	20	200-2,900
Santa Barbara, California	Santa Maria Valley	520	6-60	1.2	1967	140	230-3,200
	Cuyama Valley	600		0.5	1967	80	400-5,000
	San Antonio Creek basin:						
	San Antonio Creek valley	230		0.35	1967	14	300-3,000
Santa Barbara, California	Santa Ynez River basin:						
	Santa Ynez River valley	670	6-75	1.2	1967	50	400-2,000
	Santa Barbara Coastal basins:						
	Santa Barbara basin: Goleta Basin (3-16), Carpinteria Basin (3-18)	100	15-75	0.2	1967	9	340-1,400

Table F.11 (continued)

County	Groundwater Reservoir	Area (km^2)	Aquifer: Depth Zone (m)	Aquifer: Usable Capacity (km^3)	Withdrawals from Wells: Year	Withdrawals from Wells: Pumpage (10^6 m^3)	Withdrawals from Wells: Range in Dissolved Solids (mg/liter)[a]
		South Coastal subregion					
Ventura, California	Santa Clara River Valley	1,190		0.75	1951		270-4,700
Los Angeles, California	Los Angeles River and Santa Ana River Basins:						
	Coastal plain	1,300	WT-370	4.9	1970	350	140-1,340
	Central Basin	(600)			1970	(275)	
	West Basin	(410)			1970	(75)	
	San Fernando Valley	520			1970	135	220-2,130
	San Gabriel Valley	520	0-490	11	1965	250	110-1,000
	Raymond Basin	(100)	6-460	1.2	1961-69	35	150-700
San Bernardino, California	Upper Santa Ana Valley	1,680			1965	630	100-1,000
	Bunker Hill-San Timoteo	540		2.1			
	Chino-Riverside	1,110	6-210	6.8			
	Coastal Plain	930			1970	240	200-2,000
Orange, California	San Jacinto River basin:						
	San Jacinto basin	650					280-3,900
San Diego, California	Santa Margarita and adjacent basins:						
	Lower Valley	60	2-msl	0.07	1966	11	180-1,600
	San Mateo (9-2)						
	San Onofre (9-3)						
	Temecula Valley	100		0.65	1961	12	250-5,000
	Warner Valley (9-8)						
	San Luis Rey basin:						
	San Luis Rey Valley	100	6-35	0.06			300-9,000
	San Dieguito River basin:						
	San Dieguito area	210					250-5,000
	Escondido area (9-9)						
	San Pasqual Valley (9-10)						
	San Diego River basin:						
	San Diego area	130	3-35	0.12			160-4,500
	El Cajon (6-16)						
	Warner Valley	100	6-65	0.07			150-420

Table F.11 (continued

County	Groundwater Reservoir	Area (km^2)	Aquifer: Depth Zone (m)	Aquifer: Usable Capacity (km^3)	Withdrawals from Wells: Year	Withdrawals from Wells: Pumpage (10^6 m^3)	Withdrawals from Wells: Range in Dissolved Solids (mg/liter)[a]
		Central Valley subregion					
Lake, California	Sacramento River basin: Kelseyville Valley Upper Lake (5-13) Scott Valley (5-14) Burns Valley (5-17)	130	3-30	0.09	1951	17	80-660
Shasta, California	Redding basin	1,300	6-60	0.15	1955		120-1,700
Several, California	Sacramento Valley	11,000	6-60	35	1964	3,080	110-2,800
	Mokelumne area:						
San Joaquin, California	Delta	3,110			1966	1,230	300-3,500
Several, California	San Joaquin River basin: San Joaquin Valley	13,000	6-60	69	1966	8,010	90-5,000
Kern, Kings, and Tulare, California	Tulare close basin: Tulare Basin	11,700	6-60	46	1966	3,700	120-2,400
		South Lahontan subregion					
Inyo and Mono, California	Closed basins: Owens Valley	2,230			1970	40	100-brine
San Bernardino, California	Lower Mojave River valley	780	0-90	5.8	1963	85	190-2,340
	Middle Mojave River valley	1,090	0-90	11	1963	75	140-3,900
	Upper Mojave River valley	1,550	0-90	9.9	1963	55	80-2,760
Kern and Los Angeles, California	Antelope Valley	4,140	6-60	6.7	1960	380	120-7,700
	Divided basin: Cummings Valley:						
Kern, California	Tehachapi Valley West, Tehachapi Valley East	130			1961	20	350-570
San Bernardino, California	Closed basins: Fremont Valley	850			1958	40	350-brine
	Harper Valley	1,320	6-65	8.6	1963	15	320-10,700
Inyo and San Bernardino, California	Searles Valley	650			1962	6	8,000
		100			1962	12	35,000
Inyo, Kern, and San Bernardino, California	Indian Wells Valley	1,350	6-65	0.89	1968	15	140-brine

Table F.11 (continued)

County	Groundwater Reservoir	Area (km^2)	Aquifer: Depth Zone (m)	Aquifer: Usable Capacity (km^3)	Withdrawals from Wells: Year	Withdrawals from Wells: Pumpage (10^6 m^3)	Withdrawals from Wells: Range in Dissolved Solids (mg/liter)[a]
			Colorado Desert subregion				
San Bernardino, California	Closed basins:						
	Lucerne Valley	830			1952	20	340-5,000
Riverside, California	Coachella Valley:						
	Upper valley	620	WT-20	4.4	1958	55	149-1,000
	Artesian basin	520				130	750-3,200
San Diego, California	Borrego Valley	260	3-60			12	290-1,480

From Thomas and Phoenix (1976).

[a]Includes the range in dissolved-solids concentration in observation wells of the California state-wide water quality monitoring program.

Table F.12. Undeveloped Groundwater Reservoirs (withdrawals less than 8100 acre-ft/year)

County	Groundwater Reservoir	Estimated Area (km^2)	Natural Outflow[a]	Exploration Data			
				Year	Number of Wells	Depth Explored (m)	Range in Dissolved Solids (mg/liter)
			North Coastal subregion				
Klamath, Oregon[b]	Klamath River Basin:						
	Klamath Marsh	600	Williamson River	1970	12	205	50-110
	Langell Valley	180	Lost River	1970	10	150	130-170
	Upper Klamath Valley	750	Klamath River	1954	13	145	80-100
	Poe Valley	80	Lost River	1970	9	135	140-270
Siskiyou, California	Shasta Valley	650	Shasta River	1953	50	215	160-980
	Scott River Valley	210	Scott River	1953	5	65	30-420
			San Francisco Bay subregion				
Sonoma, California	Russian River basin:						
	Alexander Valley	100	Russian River	1954	40	135	220-1,300
			Central Coastal subregion				
San Luis Obispo, California	Closed basin:						
	Carrizo Plain	700	ET-Soda Lake	1954	8	305	340-4,300
			Sacramento Basin subregion				
Lake, Oregon[b]	Goose Lake Valley	410	ET-Goose Lake	1948	10	915	120-1,460
Modoc, California[b]		490		1964	15	230	100-450
Modoc, California	Pit River basin:						
	Alturas basin	230	Pit River	1964	25	305	150-500
Modoc and Shasta, California	Big Valley	260		1964	25	365	150-1,380
Shasta, California	Fall River Valley	260	Fall River	1964	50	215	100-550
Plumas and Sierra, California	Feather River basin:						
	Sierra Valley	360	Feather River	1964	20	425	120-1,400

Table F.12 (continued)

County	Groundwater Reservoir	Estimated Area (km^2)	Natural Outflow[a]	Exploration Data: Year	Number of Wells	Depth Explored (m)	Range in Dissolved Solids (mg/liter)
			San Joaquin Basin subregion				
San Benito, California	Panoche Valley	130	Panoche Creek			120	
Kern, California	Kern River Valley	70	Kern River		(Partly overlain by Isabella Reservoir)		
			North Lahontan subregion				
Modoc, California[b]	Closed basins: Surpise Valley	910	ET-Alkali Lakes	1954	60	245	165-2,000
Washoe, Neveda[b]		30					
Modoc, California	Madeline Plains	700	ET-Tule Lake	1964	10	260	100-245
Lassen, California[b]	Honey Lake Valley	1,270	ET-Honey Lake	1964	100	425	175-1,350
Washoe, Nevada[b]		490		1967	10	120	170-5,000
			South Lahontan subregion				
Mono, California[b]	Closed basins: Mono Valley	520	ET-Mono Lake	1960	2	290	2,000-brine
Mineral, Nevada[b]		80					
Mono, California	Adobe Lake Valley	160	ET-Adobe Lake	1962	4	10	130-280
	Long Valley	260	Lake Crowley	1954	8	25	90-1,500
Inyo, California	Centennial (Black Springs) Valley	130	GW to 6-12	1954			360
	Deep Springs Valley	100	ET-Deep Springs Lake	1955	4	235	
	Eureka Valley	410	ET-playa	1955	1	115	550
	Saline Valley	540	ET-Salt Lake	1955	1	15	3,700-brine
Inyo and San Bernardino, California	Death Valley	3,420	ET-Badwater	1961	7	305	550-brine
San Bernardino, California	Wingate Valley	180		1953			660
Inyo, California[b]	Middle Amargosa basin	1,350	ET-playa	1962	20	145	300-2,900
San Bernardino, California	Lower Kingston (Valjean) Valley	750	GW to 6-18	1954	1	No water to 130 ft	5,300-8,600

Table F.12 (continued)

County	Groundwater Reservoir	Estimated Area (km^2)	Natural Outflow[a]	Exploration Data			
				Year	Number of Wells	Depth Explored (m)	Range in Dissolved Solids (mg/liter)
		South Lahontan subregion					
San Bernardino, California	Upper Kingston (Shadow) Valley	700	GW to 6-21	1961	10	120	340-1,1000
	Riggs Valley	260	GW to 6-21	1954	1	45	1,740
	Red Pass Valley	390	ET-Red Pass Lake	1944	1	115	
	Bicycle Valley	310	ET-Bicycle Lake	1955	1	135	610-brine
	Avawatz Valley	180	ET-Drinkwater Lake				300-700
	Leach Valley	180	ET-Leach Lake	1917	22	335	300-6,300
Inyo, San Bernardino, California	Mesquite Valley	310	ET-Mesquite Lake	1959	22	335	300-6,300
San Bernardino, California[b]	Ivanpah Valley	780	ET-Ivanpah Lake	1960	19	260	290-2,200
San Bernardino, California	Kelso Valley	960	GW to 6-33	1961	2	195	250-750
	Broadwell Valley	310	ET-Broadwell Lake	1883	1	330	470-1,260
	Soda Lake Valley	1,530	ET-Soda Lake GW to 6-34	1961	20	150	240-3,400
	Silver Lake Valley	100	ET-Silver Lake GW to 6-23	1954	3	55	1,100-1,740
	Cronise Valley	390	ET-Cronise Lake	1961	13	230	450-3,100
	Langford Valley	130	ET-Langford Lake	1958	7	160	470-640
	Coyote Lake Valley	390	ET-Coyote Lake	1961	5	175	300-2,500
	Caves Canyon Valley	260	GW to 6-33	1961	5	65	200-1,300
	Troy Valley	340	ET-Troy Lake	1961	20	120	280-6,500
	El Mirage Valley	310	GW to 6-42	1961	75	295	320-2,600
	Superior Valley	440	ET-Superior Lake	1956	25	115	360-2,300
	Cuddeback Valley	340	ET-Cuddeback Lake	1956	30	90	370-4,700
	Pilot Knob Valley	520	GW to 6-58	1918	1		400
Inyo, California	Coso Valley	130	GW to 6-54	1946	1	35	
	Rose Valley	160	ET-playa		6	55	150-1,300
	Darwin Valley	180		1954	3	75	350-750
	Panamint Valley Brown Mt. Valley (6-76)	930	ET-Panamint Lake	1955	3	300	780-brine
San Bernardino, California	Lost Lake Valley	100	ET-Lost Lake	1953	0		360
Inyo and San Bernardino, California	California Valley	210	ET-playa	1953	2	15	350-500

Table F.12 (continued)

County	Groundwater Reservoir	Estimated Area (km^2)	Natural Outflow[a]	Exploration Data: Year	Exploration Data: Number of Wells	Exploration Data: Depth Explored (m)	Exploration Data: Range in Dissolved Solids (mg/liter)
	Colorado Desert subregion						
San Bernardino, California	Closed Basins:						
	Lanfair Valley	730	GW to 7-2	1952	18	270	230-2,000
	Fenner Valley	1,860	GW to 7-7	1952	5	285	280-870
	Ward Valley	1,990	ET-Danby Lake	1952	2	315	330-brine
Riverside, California	Chuckwalla Valley	2,250	ET-Palm Lake	1952	10	185	270-brine
	Pinto Basin	800	GW to 7-5	1937	3	170	120-830
San Bernardino, California	Cadiz Valley	1,110	ET-Cadiz Lake	1910	1	105	610-brine
	Bristol Valley	1,840	ET-Bristol Lake	1910	8	695	290-brine
	Dale Valley	670	ET-Dale Lake	1952	10		1,060-brine
	Twentynine Palms Valley Copper Mt. Valley (7-11) Warren Valley (7-12)	960	GW to 7-9	1952	50	150	100-1,180
	Deadman Valley Ames Valley (7-16)	750	GW to 7-10	1952	35		180-600
	Lavic Valley	100	ET-Lavic Lake	1917	1	40	1,680
	Bessemer Valley	180	ET-Galway Lake				
	Means Valley	100	ET-Means Lake		1		
	Johnson Valley	360	GW to 7-17	1952	1	45	340-610
Imperial, California	West Salton Sea basin	750	Salton Sea	1950	3		2,260-brine
	Clark Valley	100	ET-Clark Lake				
San Diego, California	Ocotillo Valley	210	GW to 7-30	1952	6	65	700
	San Felipe (Earthquake) Valley	160	San Felipe Creek	1952	3		1,060
	Vallecito and Carrizo Valleys	310	GW to 7-30				
Imperial, California	Coyote Wells Valley	260	GW to 7-30	1948	6	50	440-8,700
	Imperial Valley	4,840	Salton Sea		80	335	690-7,500
Riverside, California	Orocopia Valley	360	GW to 7-21	1952			350-1,500
	Chocolate Valley	310	GW to 7-33				350-brine
Riverside and Imperial, California	East Salton Sea basin	1,170	Salton Sea	1952	4	100	350-3,850

From Thomas and Phoenix (1976).

[a]Natural outflow: ET, evapotranspiration; GW, groundwater outflow.

[b]Interstate reservoir; data given apply only to part of reservoir in that state.

Alluvial sediments in the various valleys and plains comprise the most abundant groundwater reservoirs. Basaltic rocks, however, are prolific aquifers in the Cascade Range and Modoc Plateau areas, which encompass approximately 15 percent of the region. Consolidated rocks and residuum associated with the Sierra Nevada, Coast Ranges, and Basin Ranges are only locally important as groundwater reservoirs.

The alluvial aquifers in the Central Valley (Sacramento and San Joaquin basins subregions) occupy 10 percent of the region's land area. The predominantly sand and gravel water-bearing units are separated by silt and clay deposits, locally forming confined aquifers. Depths to water and pumpages from individual aquifers are given in Table F.11.

Folded and faulted sedimentary and metamorphic rocks constitute the Coast Ranges, which can be divided into four subregions: North Coastal, Central Coastal, South Coastal, and San Francisco Bay (Tables F.10 and F.11). The aquifers consist of stream and valley alluvium and faulted consolidated rocks.

The North and South Lahontan and Colorado Desert subregions are the most arid in the region, including the Mojave and Colorado deserts and the dry valleys of the Great Basin. The groundwater reservoirs are comprised of the valley-floor and alluvial fan deposits.

Thick sequences of lava flows and tuffs and volcanic cones occur in the northeastern portion of the region. Especially in the valley areas, such as the Klamath and Sacramento River basins, these volcanics are permeable enough to be considered prolific aquifers. The volcanic rocks constitute an area of more than 26,000 km^2 (10,000 sq mi) in the North Coastal, Sacramento River, and North Lahontan subregions (Tables F.10 and F.11).

The quality of groundwater generally decreases (as does total precipitation) from north to south within the region. Within any one subregion, the quality varies over a wide range from aquifer to aquifer (Tables F.10 and F.11). The concentrations in groundwaters of the North Coastal subregion vary from 30 to 2000 mg/L. The Central Coastal subregion has TDS concentrations between 170 and 5000 mg/L. Other subregional areas and ranges in groundwater TDS concentrations (in mg/L) are: San Francisco Bay, 90 to 7000; South Coastal, 100 to 9000; Central Valley (Sacramento and San Joaquin), 80 to 5000; North Lahontan, 100 to 5000; South Lahontan, 80 to 350,000; Colorado Desert, 100 to 35,000.

Recharge to the groundwater reservoirs takes place through infiltration of precipitation in the form of rainfall and of snowmelt from the high mountains. Some recharge occurs from downward-percolating irrigation water. Discharge takes place primarily through springflow, evapotranspiration, and underflow to lower valleys.

Groundwater in the California region is used most extensively for irrigation. Additional uses are for domestic, municipal, and industrial uses (Thomas and Phoenix 1976).

In the California Water Resource Region, average annual runoff is equivalent to 230 x 10^6 m^3/day (62 bgd) (U.S. Geological Survey 1977). Precipitation is subject to large seasonal, year-to-year, and geographic variation (Water Resources Council 1974). Of the total off-channel water withdrawals of 190 x 10^6 m^3/day (51 bgd) in 1975, surface freshwater withdrawals accounted for about 83 x 10^6 m^3/day (22 bgd), fresh groundwater about 72 x 10^6 m^3/day (19 bgd), and saline surface water about 38 x 10^6 m^3/day (10 bgd). About 56 percent of freshwater withdrawn was consumed. Irrigation is the greatest water user and consumer of freshwater in the region (Table F.1) (U.S. Geological Survey 1977). Colorado River water via the All-American and Coachella canals serves about 240,000 ha (600,000 irrigable acres) in the Salton Sea basin (Imperial Irrigation District). Thermoelectric power (condenser and reactor cooling) accounts for most of the saline surface-water use, while irrigation accounts for most of the groundwater use (U.S. Geological Survey 1977).

Hydroelectric power generation uses about 280 x 10^6 m^3/day (74 bgd), with the California region ranking ahead of seven other regions in the conterminous United States in this respect (U.S. Geological Survey 1977).

Temporal and spatial variation in water availability have been largely overcome by water development projects, especially the California State Water Project and Central Valley Project. Eventual increased competition for water is forecast, with possible limitations for agricultural development. However, the extensive water development of the region, coupled with increased use of lower quality waters for energy technologies, is seen as providing generally adequate water supplies for the region (Water Resources Council 1974).

F.18 PACIFIC NORTHWEST WATER RESOURCE REGION

The Pacific Northwest Water Resource Region, with an area of about 700,000 km^2 (271,000 sq mi) (U.S. Geological Survey 1977), includes the Columbia River and its major tributaries (Snake, Owyhee, Salmon, Deschutes, Willamette, Clark Fork, Kootenai, and Pend Oreille rivers), as well as other coastal rivers in Washington and Oregon (Skagit, Chehalis, and Rogue rivers). Large natural lakes include Flathead, Coeur d'Alene, Pend Oreille, and Jackson lakes in the headwaters of the Columbia River system; other natural lakes such as Malheur and Harney lakes are in the part of southeastern Oregon that is physiographically in the Great Basin. Crater Lake formed in the collapsed volcanic cone of Mount Mazama. The Columbia River system includes major impoundments, such as Franklin Roosevelt Lake (one of the ten largest in the nation in terms of storage capacity) (Water Information Center 1973) on the Columbia River and other major reservoirs on the tributaries. The Skagit River also includes a major reservoir, Ross Lake. Coastal areas include the mouth of the Columbia River, Puget Sound, and numerous other bays in Washington and Oregon.

Surface waters of the Pacific Northwest Water Resource Region are typically soft (<60 ppm hardness as $CaCO_3$) in Washington, Oregon, and northern Idaho. Moderate hardness (60 to 120 ppm) is more common along the Columbia River above the mouth of the Snake River, in the Snake-Owyhee boundary area between Oregon and Idaho, and in most of southern Idaho. Hard waters (120 ppm and above) are found in southeastern Idaho and in the Snake River near Boise, Idaho. Dissolved solids levels are generally lowest (<120 ppm TDS) in Washington, western Oregon, and northern Idaho. Moderate levels (120 to 350 ppm) are found in southern Idaho, eastern Oregon, and areas in eastern Washington. Salinities above 350 ppm are found in isolated areas in southeastern Oregon (physiographically in the Great Basin) and central Washington. Suspended sediment (TSS) levels are generally low (<270 ppm) in Washington, western and southern Oregon, northern Idaho, and some impounded and headwater reaches of the upper Snake River system. Highest levels (>1900 ppm) are found in parts of the Snake River Plain in Idaho. Intermediate levels (270 to 1900 ppm) are found along the Snake River mainstem and other parts of southern Idaho and in areas of eastern and central Oregon (Water Information Center 1973).

Nonpoint-source discharges are important in regional water quality degradation. Mineralization from mineral mining (Idaho), accelerated runoff from silviculture, and agricultural runoff (including pesticide residues) are major problems. Dissolved oxygen levels in the Willamette River, formerly stressed by ammonia wastes, are now under control. Several lakes in eastern Washington are eutrophic; in many cases, the lakes are naturally in advanced successional stages, while nonpoint-source pollution is also implicated. The Boise River and Middle Chehalis River are cited by the EPA as cases where waste treatment has resulted in water quality improvement (U.S. Environmental Protection Agency 1977a).

The Pacific Northwest region has groundwater supplies obtainable from igneous intrusive, igneous extrusive, metamorphic, and consolidated sedimentary rocks and from unconsolidated sediments. Well yields range from generally small to locally large.

The aquifers in the mountain range area are predominantly crystalline and metamorphic rocks and sedimentary rocks. The producing zones are coincident with fractures, joints, and faults. Residual material also produces small well yields. The best well yields are obtained from sand and gravel sediments in the intermontane valleys.

Much of the region is underlain by lava flows, which are interbedded with and mantled in places by fluvial and lacrustrine sediments. Individual flows range in thickness from less than 10 m to more than 100 m. The entire volcanic sequence varies between tens of meters to more than several hundred meters thick. The best production zones in the basalts are those in which lava tubes, abundant vesicles, shrinkage cracks, and unconformities exist. Permeable sands and gravels in the section also yield water to wells. The highest yielding aquifers are unconsolidated deposits along stream valleys, some of which are of glacial outwash origin (Walton 1970).

In the Pacific Northwest Water Resource Region, average annual runoff is equivalent to 800×10^6 m^3/day (210 bgd). Of the total off-channel water withdrawal of 130×10^6 m^3/day (33 bgd) in 1975, surface freshwater withdrawals accounted for 99×10^6 m^3/day (26 bgd); fresh groundwater contributed the remainder. About 33 percent of freshwater withdrawn was consumed (U.S. Geological Survey 1977).

Irrigation accounts for the major portion of water use and freshwater consumption (Table F.1). Irrigation and, to a lesser extent, industry dominate groundwater use. The Pacific Northwest region uses 5700×10^6 m^3/day (1500 bgd) for hydroelectric power, almost half the national total, and the greatest use of any region in the nation (U.S. Geological Survey 1977). Because of freezing conditions, runoff in the Columbia River system is lowest in the winter when power loads are highest; streamflow regulation has largely compensated for this imbalance (Water Resources Council 1974).

The Water Resources Council has projected a general availability of energy-related water supplies in the foreseeable future, particularly for the western portion of the region where major load centers are located (Water Resources Council 1974).

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APPENDIX G. LAND USE PATTERNS

Information on land use patterns for the conterminous United States is either very general or very specific. On the one hand, many detailed studies of relatively small areas in various parts of the country have been done. Much of this work cannot easily be applied to a more general analysis because different approaches to the problem, different scales of examination, and different classification systems result in data that are not comparable from one area to another. On the other hand, analyses that are general enough to cover the whole country often lack enough precise information to permit an assessment of a particular problem.

The following analysis of land use patterns has made extensive use of the Conservation Needs Inventory (CNI) data base because this base permits a national assessment of land use patterns using data gathered at the county level. The CNI data base is somewhat dated (1967), but this disadvantage is offset by the fact that regional patterns of land use are apt to change very slowly. Additional reports on potential cropland (Dideriksen et al. 1977), prime farmland (Schmude 1977), and surface-disturbed lands (U.S. Department of Agriculture 1977) were used to update the CNI information.

Farm production regions have been used as the basic framework for discussing land use patterns because most of the current information on agricultural lands is reported using this system. Figure G.1 is a map of the farm production regions. The ten demand regions used in the analyses in this impact statement are presented in Figure 3.3. Both regional systems use state boundaries to separate regions; thus, neither system reflects natural boundaries of resource areas. Austin's publication on land resource regions of the United States (1965) contains a more detailed discussion of land use in particular subareas.

The following text is a general description of land use for each farm production region (see Fig. G.2) and a brief description of some of the more important current impacts of coal mining on the regional land.

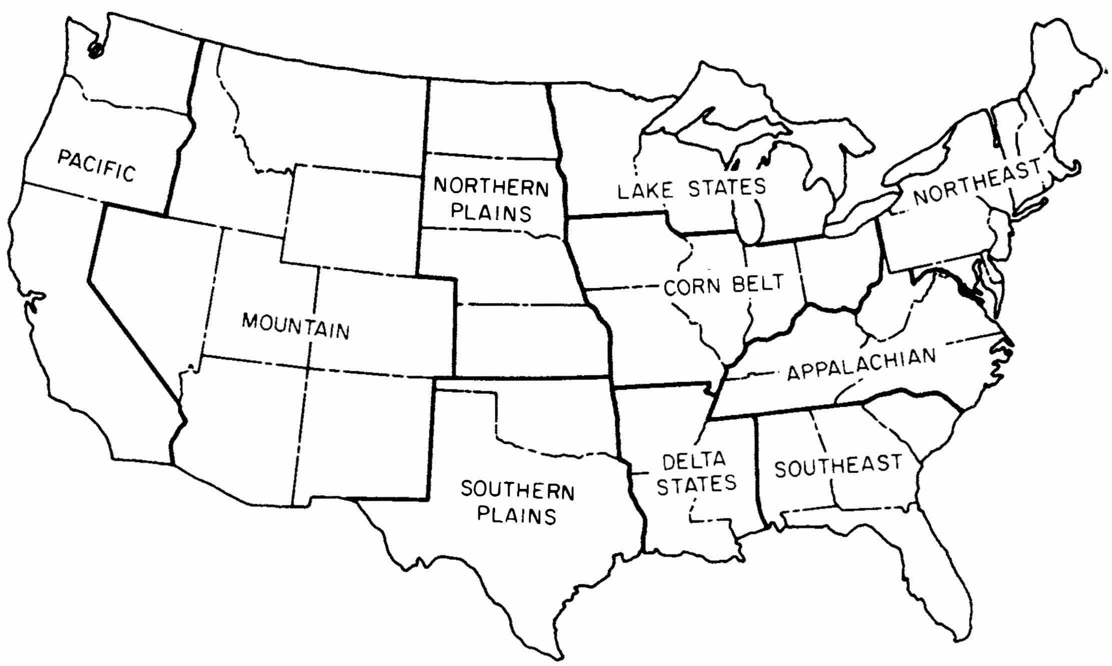

Fig. G.1. Farm Production Regions

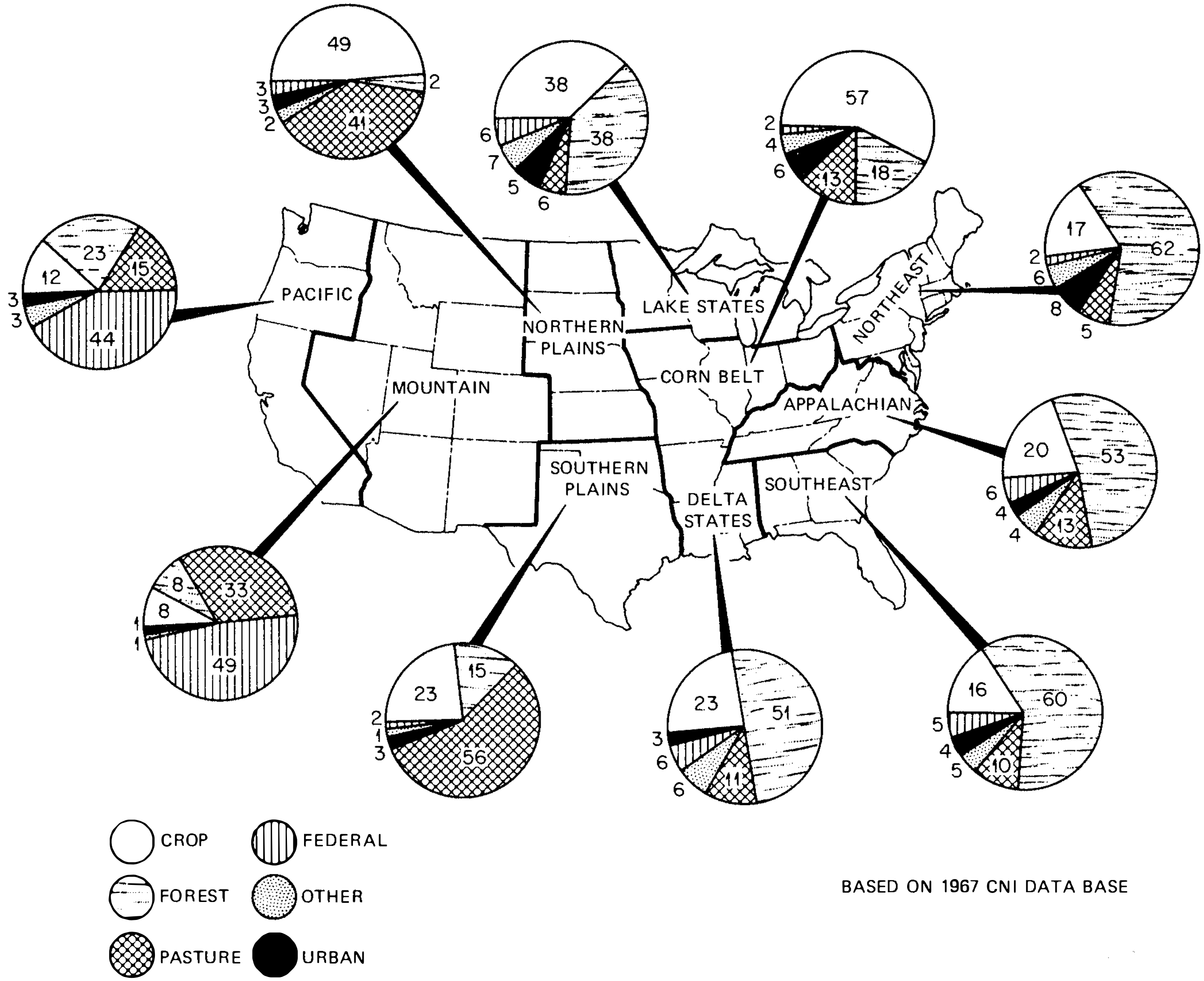

Fig. G.2. Land Use Patterns for Farm Production Regions of the United States. Based on data from U.S. Department of Agriculture (1969).

G.1 NORTHEAST FARM PRODUCTION REGION

The eleven states that form the Northeast Farm Production Region cover an area of approximately 45 million hectares (112 million acres). The area has a variety of physiographic features, including portions of the northern coastal plain and northern piedmont; the northern Appalachians with their associated plateaus, valleys, and ridges; and a portion of the central lowland that extends along the eastern shore of Lake Erie (Hunt 1974). The climate varies with Lake Erie, the Atlantic Ocean, and the Connecticut River Valley moderating local climates in various parts of the region.

Land use patterns in the northeast Farm Production Region (Fig. G.3) are discussed in some detail in Austin (1965). Forestland is the predominate land use in the region (Fig. G.2), with agricultural activities (i.e., cropland and pasture) accounting for 22 percent of the area. Farming throughout much of the region is restricted by mountainous and hilly terrain that has shallow, relatively infertile soils. However, in areas along the coastal plain, the piedmont, the shores of Lake Erie, and the Connecticut River Valley, relatively good soils and somewhat moderate climate permit a greater variety of crops to be grown. For much of the region, hay and forage for dairy herds account for much of the agricultural activity.

There are approximately 7 million hectares (18 million acres) of prime farmland in the eleven-state region, but only about 50 percent (3-1/2 million hectares [8.9 million acres]) was cropped in 1975 (Schmude 1977). An estimated 200,000 hectares (400,000 acres) could easily be shifted to crop use. Prime land not presently cropped is used for pasture or forest, or is being held for future urban expansion. Some of this uncropped prime land is of such small acreages that bringing it into production is not feasible.

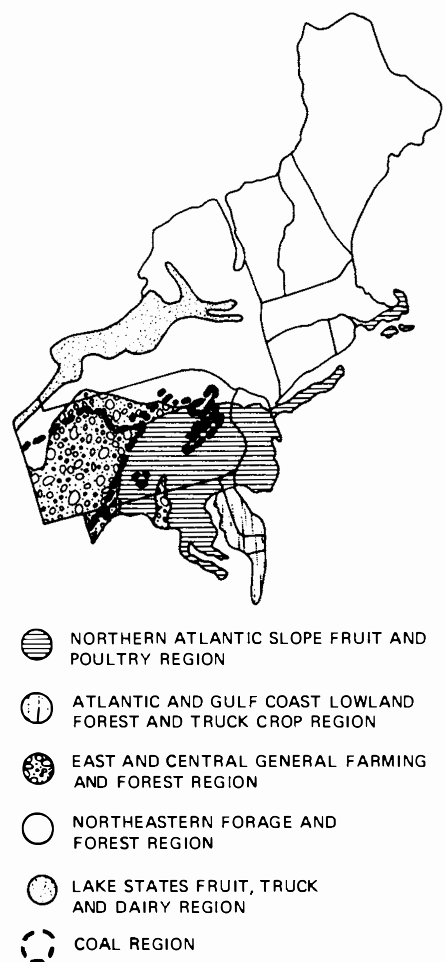

Fig. G.3. Land Resource Regions Within the Boundaries of the Northeast Farm Production Region. From Austin (1965).

The region is one of the most heavily populated and industrialized areas of the country. Urban land use accounts for 8 percent of the land in the region. From 1967 to 1975, an estimated 2 percent of the prime agricultural land in the region (approximately 384,000 hectares [948,480 acres]) was converted to urban use or covered by water and permanently removed from agricultural use.

Coal resources and production are essentially restricted to the states of Pennsylvania and Maryland. Land use patterns in the coal resource counties are essentially similar to those of the region, except that a slightly higher percentage of pastureland is found in the coal counties (Table G.1). Land used by all types of mining activities totaled about 239,000 hectares (591,000 acres) in the region (Paone et al. 1974) during the period 1930 to 1971, with 43 percent of this total resulting from mining for bituminous coal. In 1977, the U.S. Soil Conservation Service (SCS) reported that 124,849 hectares (308,507 acres) of land were sufficiently disturbed to require reclamation (U.S. Department of Agriculture 1977).

Table G.1. Percent of Regional Land Use in Coal Resource Counties

Region	% of Region Occupied by Coal Resource Counties	Crop	Forest	Urban	Federal	Pasture/ Range	Other
Northeast	17	17	17	14	13	21	18
Appalachian	26	16	32	20	22	23	25
Southeast	9	8	9	10	3	9	5
Delta States	10	6	11	9	22	10	3
Corn Belt	36	36	35	30	22	39	35
Lake States							
Northern Plains	13	13	15	15	22	12	12
Southern Plains	12	7	31	16	29	8	14
Mountain States	33	25	49	34	26	41	41
Pacific	4	2	7	7	3	2	3

Coal mining has had an important effect on land use in this region. Contour mining on hilly to mountainous terrain and mining for anthracite in western Pennsylvania have directly removed many forestlands from production and have created severe erosion on adjacent lands. Acid mine drainage is a severe problem in parts of the region; it has undoubtedly reduced the productivity of the lands affected by it. Although no detailed information is available, the amount of land influenced by these impacts is probably equal to an area as large as that which is actually mined.

G.2 APPALACHIAN FARM PRODUCTION REGION

The five states that make up the Appalachian Farm Production Region cover an area of about 50 million hectares (124 million acres) and include a wide variety of physiographic features. The region contains flat coastal plains; rolling uplands of the piedmont; the mountains of the Blue Ridge; and ridges, valleys, and dissected plateaus to the west (Hunt 1974). A discussion of land use within the land resource regions shown in Figure G.4 is given by Austin (1965). In general, the land use pattern is markedly affected by the varied terrain. Forestlands cover slightly more than half of the region (Fig. G.2) and range in size from small farm woodlots to extensive forest tracts owned by mining and timber interests. Approximately 90 percent of the region's forestlands are privately owned. Federal lands, which consist primarily of national parks and national forests, represent only 7 percent of the total forest area.

Agricultural land is generally restricted to the more level portions of the landscape, such as floodplains of major rivers and streams and rolling uplands. Major crops grown in the area include corn, other feed grains, and hay. Tobacco is an important cash crop in parts of the region, and production of fruits and vegetables for local markets is common. Pasture and range for cattle and other livestock represent about 13 percent of the regional land use.

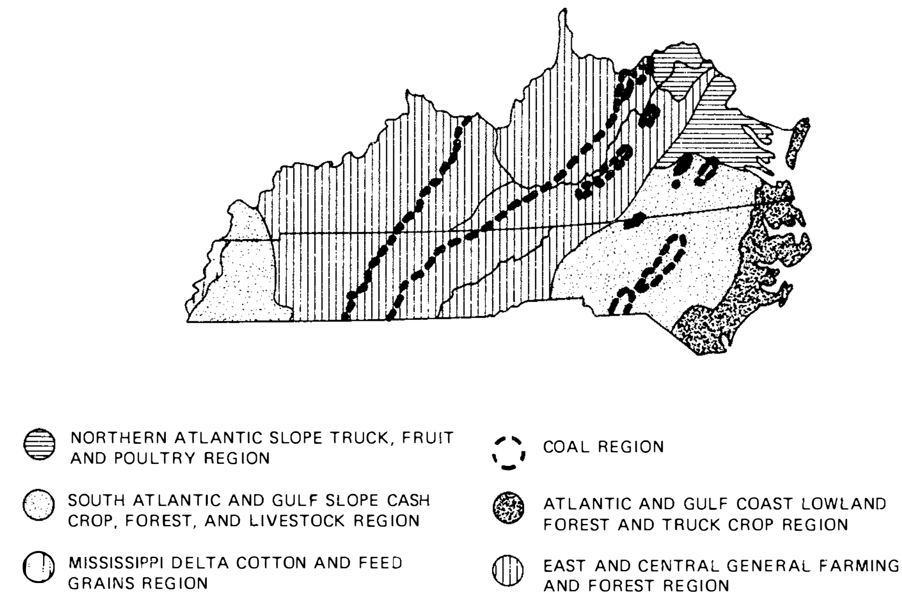

Fig. G.4. Land Resource Regions within the Boundaries of the Appalachian Farm Production Region. From Austin (1965).

A recent SCS study shows that in 1975 about 8 million hectares (20 million acres) of non-Federal land were used for cropland in this region. An estimated 11 million hectares (26 million acres) of prime farmland are present in the region, but only about 5 million hectares (13 million acres) are presently cropped. Although Appalachia has one of the highest potentials for shifting significant prime lands to cropland use, only about 2 million hectares (4 million acres) could be easily shifted. Present use of the noncropped prime lands is pasture and forest. Conversion of prime farmland to irretrievable uses during the period 1967 to 1975 is estimated at approximately 312,000 hectares (770,000 acres).

Coal mining in the Appalachian Farm Production Region has resulted in major land use impacts. Contour strip mining and deep mining in the rugged terrain of the mountains and associated hills are the most common types of mining operations in the region (U.S. Army Corps of Engineers 1974). Area strip mining does occur in parts of western Kentucky. As shown in Table G.1, most of the land area in the coal resource counties is forestland. The coal counties represent 26 percent of the total land area of the region, but contain 32 percent of forests in the region and only 16 percent of the croplands.

Contour strip mining is the most conspicuous coal operation throughout much of the region because it leaves broad scars across the hilly to mountainous terrain. This type of mining generally has an impact on forestlands, replacing them with excavations, spoil banks, buildings, storage facilities, waste disposal areas, coal processing facilities, and access and haul roads (Doyle 1976). This last use, in particular, can result in a significant amount of damage because of erosion potential. Deep mines generally produce less conspicuous impacts on the land. Excavation at the mine mouth, buildings, roads, and waste and storage areas account for the bulk of surface disturbance. However, a less obvious, but important, land use impact is subsidence associated with deep mine operations. Such disturbance can severely limit the future use of such areas.

A recent survey of surface disturbance associated with mining shows that coal mining in the Appalachian region has disturbed about 167,000 hectares (413,000 acres) of land in need of reclamation (U.S. Department of Agriculture 1977). Approximately 58 percent of this disturbed area (97,000 hectares [240,000 acres]) is abandoned mine land.

Less direct, but equally important, land use impacts resulting from coal mining in the Appalachian Farm Production Region include (1) landslides associated with unstable spoil banks; (2) erosion from excavations, spoil and waste piles, and roads; and (3) acid mine drainage emanating from mined areas and mine wastes. Erosion of soil and leaching by acid drainage waters have undoubtedly contributed to an overall reduction of the fertility and long-term productivity of lands adjacent to mined areas. However, little information is available on the types of land affected and the amount of damage done.

G.3 SOUTHEAST FARM PRODUCTION REGION

The Southeast Farm Production Region covers a four-state area of about 50 million hectares (124 million acres). The area includes coastal plain, rolling piedmont, and a southern extension of the Appalachian system to the north (Hunt 1974). Four land resource regions (Fig. G.5) are described by Austin (1965) for this production region.

Land use patterns in the Southeast Farm Production Region are dominated by forestlands (Fig. G.2). A large part of the coastal plain and piedmont is used for commercial forest production of lumber, pulpwood, and other timber products. Cotton is a major cash crop in much of the region, and a variety of feed grains and forage are produced for livestock. Dairy herds, especially in the vicinity of large population centers, are becoming an increasingly important element of regional agriculture. The southern two-thirds of Florida is well known for its citrus and fruit production as well as for the large amounts of winter vegetables grown there.

Prime agricultural land totals approximately 10 million hectares (24 million acres), of which only 4 million hectares (9 million acres) are presently cropped (Schmude 1977). An estimated 1 million hectares (3 million acres) could be easily shifted to crop production. Much of the noncropped prime land is presently used as pasture or forest, but especially in Florida, much is held for future urban-related developments. An estimated 645,500 hectares (1,600,000 acres) of prime farmland were converted to urban use or covered by water during the period 1967 to 1975.

Coal reserves in this region are restricted to a relatively small area in northern Alabama and adjacent Georgia. This area is part of the Appalachian system, and land use and impacts associated with coal mining are similar to those described for the Appalachian Farm Production Region. In 1977 the SCS reported that an estimated 42,185 hectares (104,241 acres) of land in need of reclamation have been disturbed by coal mining operations (U.S. Department of Agriculture 1977).

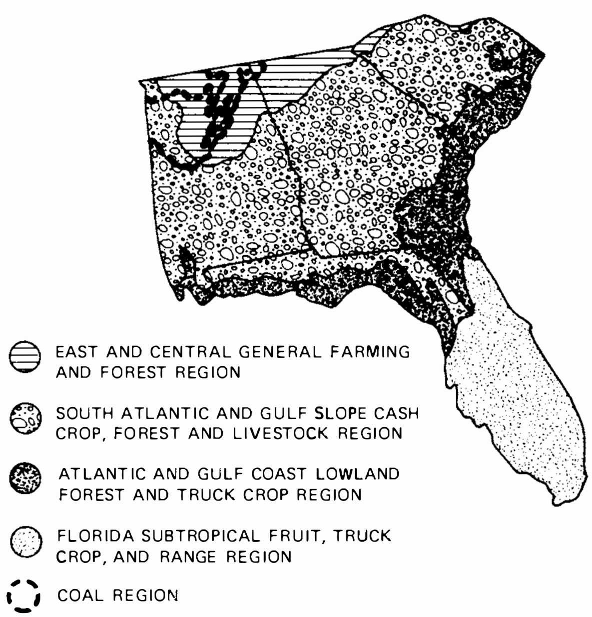

Fig. G.5. Land Resource Regions Within the Boundaries of the Southeastern Farm Production Region. From Austin (1965).

G.4 DELTA STATES FARM PRODUCTION REGION

The Delta States Farm Production Region includes three states and covers an area of approximately 37 million hectares (92 million acres). The four land resource regions described by Austin (1965) for these states are shown in Figure G.6. Much of the area is coastal plain, and land use is similar to that described for the coastal plain of the Southeastern Farm Production Region. The most productive agricultural lands are found along the Mississippi River where the fertile soil, when artificially drained, supports such crops as cotton, rice, sugar cane, and corn. The Ouachita Mountains and the Ozark Plateau in northwestern Arkansas are hilly to mountainous lands supporting forests. Agricultural activities are mainly restricted to valley bottoms.

There are approximately 12 million hectares (30 million acres) of prime farmland in this three-state region. About 51 percent of this land was used for cropland during 1975 (Schmude 1977). An estimated 1 million hectares (2 million acres) could be easily shifted to cropland use. However, the 202,344 hectares (500,000 acres) of prime land converted to urban use or covered by water during the period 1967 to 1975 have been permanently removed.

The coal resources of this region are predominantly lignite deposits scattered throughout the area, but a limited deposit of bituminous coal is present in western Arkansas. The land use pattern of the coal counties is generally similar to that of the region, except that the coal counties have a higher proportion of Federal land and a smaller proportion of cropland. The SCS has estimated that approximately 3000 hectares (7500 acres) of land in the Delta States need reclamation because of coal mining operations.

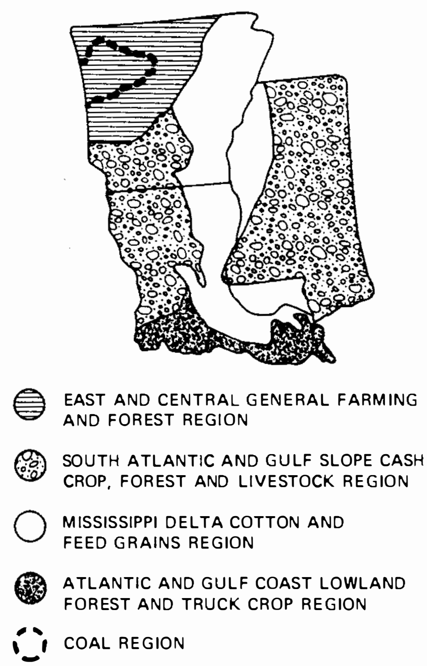

Fig. G.6. Land Resource Regions Within the Boundaries of the Delta States Farm Production Region. From Austin (1965).

G.5 CORN BELT FARM PRODUCTION REGION

The five states that form the Corn Belt Farm Production Region cover an approximate area of 67 million hectares (165 million acres). This region is one of the most important grain-producing areas of the world. The region's dominant physiographic feature is the central lowland, which is a vast plain covering a large portion of mid-America (Hunt 1974). To the south, the Ozark Plateau of southern Missouri forms a rolling upland. In southern Indiana and eastern Ohio, the dissected plateaus of the Appalachian system become the dominant element of the landscape.

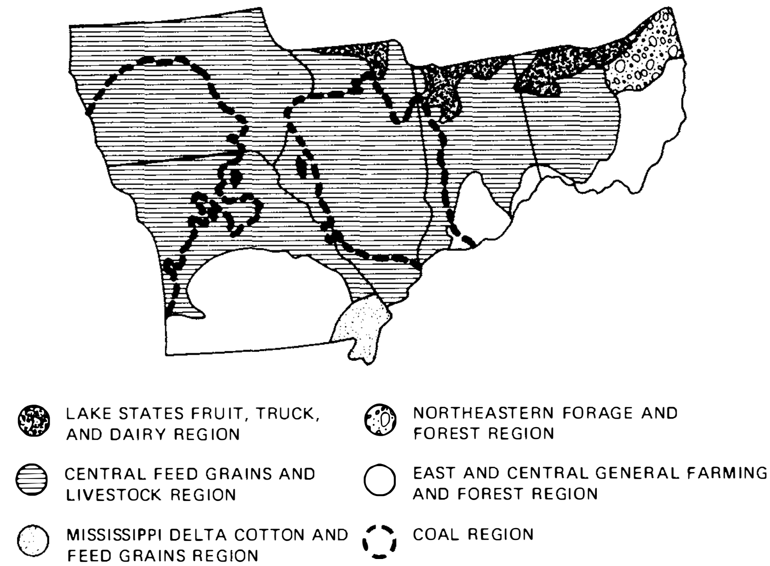

Fig. G.7. Land Resource Regions Within the Boundaries of the Corn Belt Farm Production Region. From Austin (1965).

Figure G.7 shows the land resource regions present in the five-state area. In general, cropland is the predominant land use in the region. Corn, soybeans, a variety of feed grains, hay, and winter wheat are the most important crops grown. In southern Indiana and Ohio, tobacco is an important cash crop. Along the Great Lakes, truck farming, fruit production, and dairy farming are associated with the rich soils and moderate climate found there. Forests occur as farm woodlots and along steep slopes of stream courses. The most extensive forest tracts in the region are in the Ozark highlands of Missouri and on the Western Allegheny Plateau of eastern Ohio. Major urban developments are associated with the shores of the Great Lakes and the Ohio River Valley.

Prime farmlands in this five-state region total 31 million hectares (77 million acres), of which 80 percent (25 million hectares [61 million acres]) was cropped during 1975 (Schmude 1977). Of the uncropped prime farmlands, an estimated 1 million hectares (3 million acres) could be easily shifted to crop production, but most of this potential is presently used as pasture. Such a shift would reduce livestock production in the region. About 583,000 hectares (1 million acres) of prime farmland in this region were converted to urban use or covered by water during the period 1967 to 1975.

The land use pattern of the coal resource counties in the five states is generally similar to that of the region as a whole. Federal and urban lands are somewhat less prevalent in the coal counties. During the period 1930 to 1971, an estimated 98 percent of regional mining was for bituminous coal (Paone et al. 1974). Of the approximate 373,000 hectares (921,000 acres) of land disturbed at the surface, about 69 percent was the result of actual excavation and clearing, and 24 percent was used for the disposal of mine wastes. The SCS has recently reported that there are about 254,000 hectares (627,000 acres) of land needing reclamation as a result of coal mining operations. Approximately 68 percent of this area (172,000 hectares [425,000 acres]) represents abandoned mine lands.

G.6 LAKE STATES FARM PRODUCTION REGION

The Lake States Farm Production Region is a three-state area of approximately 50 million hectares (123 million acres). The locations of the major land resource regions within these three states are shown in Figure G.8. In general, the land use pattern is closely related to the regional climatic pattern. In much of the northern portions of the region, agricultural activities are restricted by the short growing season, the relatively cool climate, and the poor soils. Much of this area is covered by forest, and production of timber products is important. Recreation and mining are additional land uses of note, with limited agriculture occurring locally. To the west and south, the somewhat better soils and more favorable climate make these areas better suited for agriculture. Spring wheat, potatoes, and sugar beets are important crops in northwest Minnesota, whereas corn, feed grains, alfalfa, wheat, and hay are more important further south

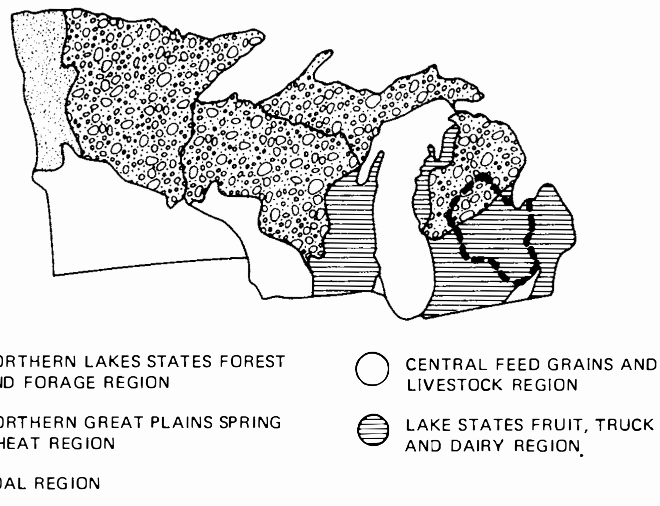

Fig. G.8. Land Resource Regions Within the Boundaries of the Lake States Farm Production Region. From Austin (1965).

and east. Forests become more conspicuous towards the east, eventually forming large woodlots or more extensive woodlands. The moderate climate and good soils associated with the Great Lakes permit truck farming and dairy farming to be major agricultural activities near the lakes. As shown in Figure G.2, cropland and forestland are the two most important land uses in the region.

Coal resources in this farm production region are limited to minor deposits in eastern Michigan, which are not expected to be exploited as an important resource. Therefore, no further discussion of coal mining will be included in this section.

G.7 NORTHERN PLAINS FARM PRODUCTION REGION

Four states covering an approximate 32 million hectares (79 million acres) make up the Northern Plains Farm Production Region. These states represent parts of the Great Plains and Central Lowlands physiographic provinces (Hunt 1974) and include portions of four land resource regions (Fig. G.9). Land use in this farm production region is mainly agricultural (Fig. G.2), with forestlands being restricted to the floodplains of streams and rivers or to areas of higher elevation such as the Black Hills. In the northern parts of the region, the shorter growing season and the pattern of precipitation favor the production of spring wheat as a major cash crop. To the south and west, the area is best suited for dry farming, with winter wheat, feed grains, and forage being major crops. Along the eastern border of the region, somewhat higher precipitation allows a greater diversity of crops to be grown, including corn, soybeans, oats, and other feed grains. Throughout the region, much of the land is used as rangeland, particularly where sloping terrain or poor soils do not favor farming.

The region has a total of 29 million hectares (72 million acres) of prime farmland, of which approximately 81 percent was farmed in 1975 (Schmude 1977). Of the noncropped prime land, 2 million hectares (4 million acres) could be easily shifted to cropland from their present predominant use as rangeland. In the period 1967 to 1975, about 210,000 hectares (520,000 acres) of the region's prime farmland were converted to urban use or covered by water. Although detailed information on the distribution of prime farmland within the region is not available, it is known that approximately 18 percent of the soils of Land Capability Classes I, II, and III are found in the counties having coal reserves.

Coal deposits in the Northern Plains Farm Production Region are located in the western and northwestern parts of North and South Dakota respectively. The deposits are mainly lignite and can at least be partially strip mined. Land use patterns in the coal counties are basically similar to those for the region, although a somewhat higher proportion of Federal land is present in the coal counties. Coal mining accounted for approximately 44 percent of all land used by the mining industry in this region during the period 1930 to 1971 (Paone et al. 1974). The SCS reports that lands that have been disturbed by coal mining and are presently in need of reclamation total 19,886 hectares (49,140 acres) (U.S. Department of Agriculture 1977). Area strip

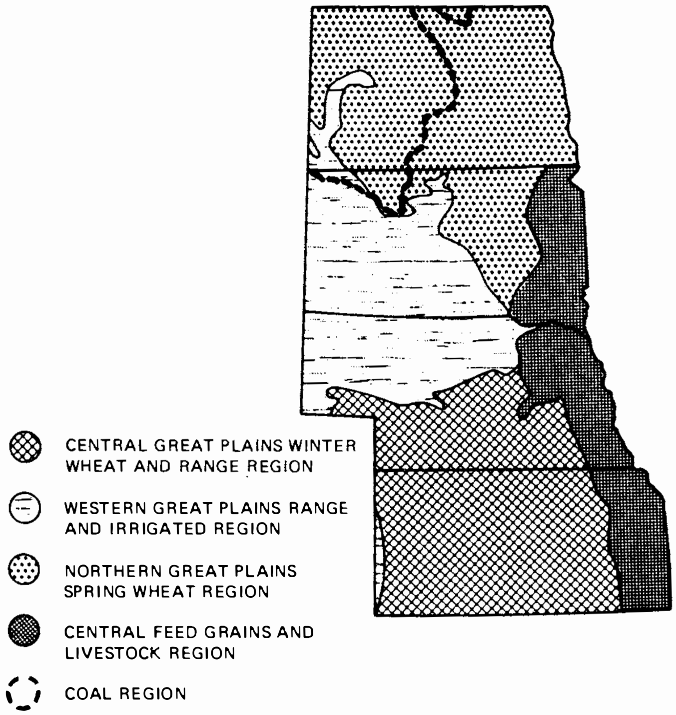

Fig. G.9. Land Resource Regions Within the Boundaries of the Northern Plains Farm Production Region. From Austin (1965).

mining is the most common type of operation in this region. Removal of prime agricultural land and competition for water resources are the two most significant impacts on land use created by coal mining.

G.8 SOUTHERN PLAINS FARM PRODUCTION REGION

The Southern Plains Farm Production Region includes two states and covers about 35 million hectares (86 million acres). The land resource regions shown in Figure G.10 indicate the diversity of the region, which is controlled in large part by patterns of climate and soils. Land use patterns change markedly from east to west. Forestlands prevail in the Piney Woods area of East Texas and in the Ouachita Mountains of eastern Oklahoma. The Gulf Coast Prairie in eastern Texas supports intensive agriculture of rice, cotton, sorghum and other grains, hay, and pasture. Cotton, citrus, melons, and a variety of other crops are grown on irrigated lands along the Rio Grande. Cotton, corn, and hay are produced on the Blackland prairies of east central Texas and Oklahoma. Abandoned croplands that are reverting to rangeland are characteristic of the Post Oak savannah in parts of the same central region (Radon Corporation 1977). In the west, rangeland is the predominant land use, with carrying (grazing) capacity being least in the dry parts of southwestern Texas. Scrub woodlands at higher elevations and short grass-shrub lands elsewhere characterize the Edwards Plateau.

Land use patterns in the coal resource counties deviate from those of the generalized region in that there is more forest and Federal land and less rangeland and cropland (Table G.1). The coal counties account for about 12 percent of the regional land area. During the period 1930 to 1971, approximately 46,000 hectares (113,500 acres) of land were disturbed by all types of mining activities (Paone et al. 1974). Of this total, about 13 percent (5,896 hectares [14,563 acres]) was used for coal mining operations. The most recent estimate of the amount of land disturbed as a result of coal mining shows that 19,803 hectares (48,913 acres) of land need reclamation in the region (U.S. Department of Agriculture 1977).

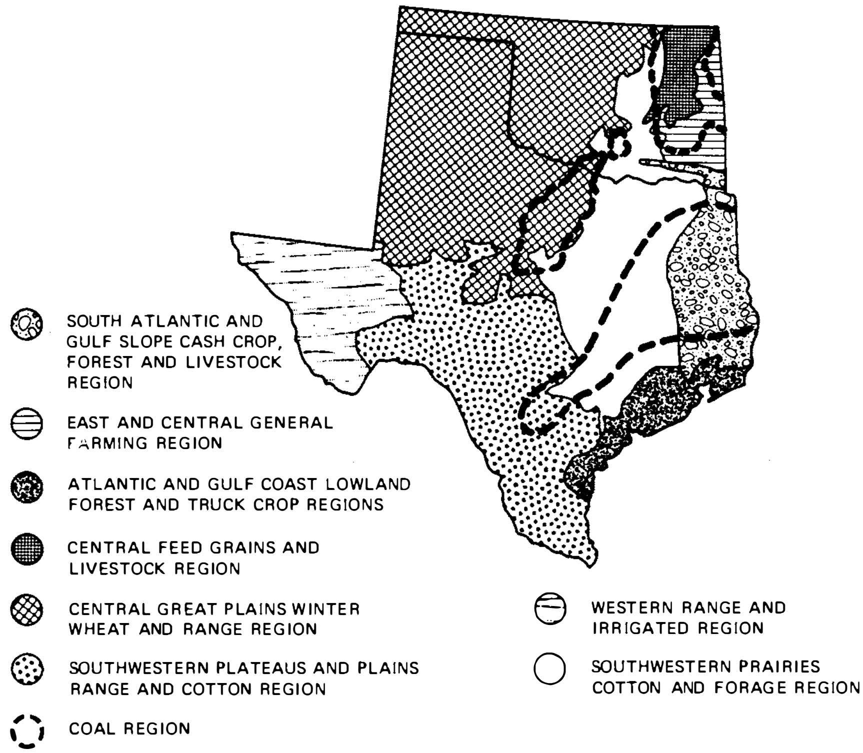

Fig. G.10. Land Resource Regions Within the Boundaries of the Southern Plains Farm Production Region. From Austin (1965).

G.9 MOUNTAIN STATES FARM PRODUCTION REGION

The Mountain States Farm Production Region covers an eight-state area of approximately 221 million hectares (547 million acres). Austin (1965) recognizes eight land resource regions (Fig. G.11), which reflect the diversity of the landscape. To the east, the Great Plains represent the dominant physiographic feature (Hunt 1974), with a characteristic low relief and a semiarid climate. Farther west, the main axis of the Rocky Mountains, with their associated foothills, is found rising to elevations greater than 4000 m (13,000 ft) in some places. At the lower elevations, the climate is semiarid, but as altitude increases, temperatures decline and precipitation increases. West of the Rocky Mountains, the Colorado Plateau is the most prominent feature, with elevations ranging from 1500 to 3000 m (5000 to 11,000 ft). The climate is generally semiarid, except at the higher elevations where more abundant precipitation and cooler temperatures prevail. Western Utah, Nevada, and southwestern Arizona include the Basin and Range physiographic province, which consists of blocky mountains separated by desert basins. Elevations range from below sea level to 3700 m (12,000 ft), causing major variations in climate. A lava plateau crossed by the Snake River is an important feature of the landscape of southern Idaho.

Land use on the Great Plains and in the semiarid lands of the rest of the Mountain States Farm Production Region is dominated by rangeland (Fig. G.2). Dryland farming for wheat and other grains is an important agricultural activity on the Great Plains and in parts of the other semiarid regions. Irrigated lands associated with rivers, wells, and reservoirs are used for production of sugar beets, feed grains, sorghum, beans, and hay. Spring wheat is a major cash crop in northern Montana. In southwestern Arizona, cotton and citrus fruits are grown along the Colorado and Gila rivers. Major urban development along the Colorado front range is removing considerable farmland from production. The forestlands of the mountains are used for timber production, mining, and recreation. Fishing, hunting, skiing, camping, hiking, and general sightseeing result in year-round recreational use of at least parts of the region. Grazing occurs in the more open forests of lower elevations, and sheep are moved to summer range on high-altitude alpine meadows and mountain parks in various portions of the region.

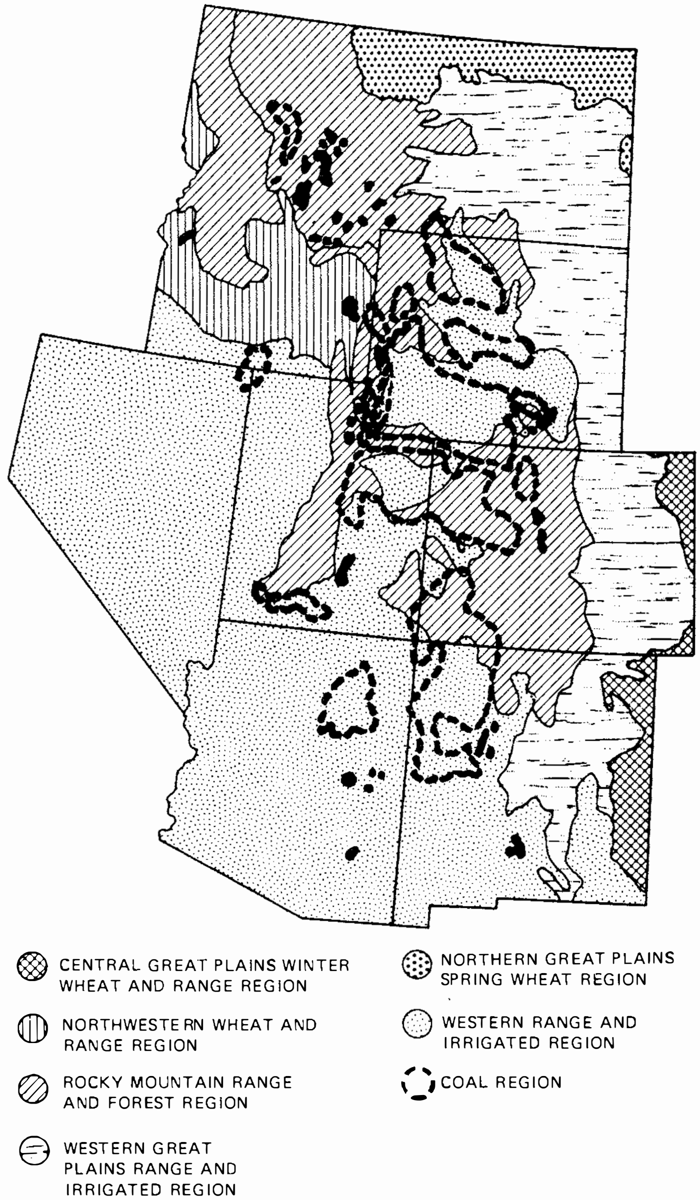

Fig. G.11. Land Resource Regions Within the Boundaries of the Mountain States Farm Production Region. From Austin (1965).

Figure G.2 shows that the major land uses for the Mountain States Farm Production Region are rangeland and federal land. A breakdown of federal land use shows that 59 percent (64 million hectares [160 million acres]) is used for grazing and 32 percent (35 million hectares [85 million acres]) is used for forests and wildlife (General Services Administration 1977). Indian lands account for 15,834 hectares (39,127 acres).

Prime farmland accounts for about 7 million hectares (18 million acres of the region, representing about 3 percent of the land area (Schmude 1977). Approximately 87 percent of this land is cropped. Although no detailed information is available on the distribution of this farmland, most of it would occur in the eastern portions of the region. Elsewhere it would occur only in highly localized situations.

Deep mining and surface mining for minerals and coal have been important land uses in the Mountain States since they were first explored. A 1974 study shows that the total land used for deep and surface mine operations during the period 1930 to 1971 was 169,483 hectares (418,800 acres) (Paone et al. 1974). A more recent study by the SCS shows that in 1977, reclamation was needed for 37,065 hectares (91,589 acres) of land because of coal mining in the region (U.S. Department of Agriculture 1977).

The most common type of coal mine operation in this region is area strip mining (Atwood 1975). The semiarid to arid climate where deposits are located presents major problems in reclaiming the mined and waste areas (National Academy of Science 1974). Some success has been achieved in revegetating part of these lands, but wind erosion, grazing, and lack of water place severe limitations on the success of such ventures (Dirks 1974; Verma and Thomas 1975). The potential for successful reclamation should be carefully examined prior to exploitation of these areas. Rangelands are the major type of land to be affected by development of these resources.

G.10 PACIFIC FARM PRODUCTION REGION

The three-state area that forms the Pacific Farm Production Region covers approximately 83 million hectares (204 million acres). Austin (1975) recognizes five land resource regions within regional boundaries (Fig. G.12). Located in the eastern parts of Oregon and Washington are the northern Rocky Mountains, where timber production and recreation are the major land uses. In central Washington and Oregon, dry farming for wheat, peas, and lentils is a major agricultural activity. The region immediately to the east of the mountains is very arid, and except where irrigation is

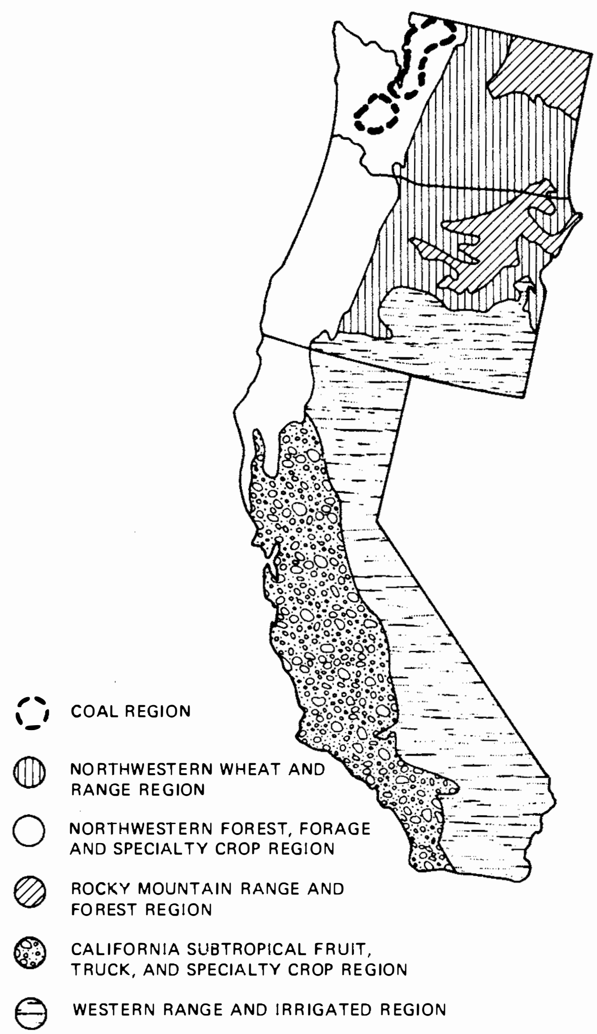

Fig. G.12. Land Resource Regions Within the Boundaries of the Pacific Farm Production Region. From Austin (1965).

possible, agriculture is very limited. The Cascade Mountains in the northern part of the region and the Sierra-Nevada range in California are covered mainly by forests. Land use in these mountains is related primarily to forest industries and recreation. About 83 percent of the federal lands of the Pacific Farm Production Region are used for forest and wildlife (General Services Administration 1977), with national parks and national forests in the mountains accounting for much of this land. In eastern California, the area is an extension of the Basin and Range physiographic province described for the Mountain States Farm Production Region. In western California, the low mountains, broad valleys, and warm, dry climate favor a wide variety of crops including citrus, cotton, sugar beets, various grains, rice, hay, and many others. Large populations and expanding urban centers displace considerable agricultural land use.

Coal resources in this three-state region are restricted to five counties in western Washington. Land use patterns in these counties deviate from the regional patterns in that forest and urban lands are more prominent in the coal counties and pasture/range and croplands are less so. The counties having coal reserves represent 4 percent of the regional land area. According to SCS estimates, the land area needing reclamation because of coal mining activities is approximately 500 hectares (1234 acres) (U.S. Department of Agriculture 1977). The coal resources of this region are limited, and it is not expected that they will be exploited within the time frame of this study.

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APPENDIX H. TERRESTRIAL BIOTIC RESOURCES

H.1 INTRODUCTION

The terrestrial biotic communities of the United States form a broad array, from dry, open scrubland to humid, dense subtropical forests. Figure H.1 illustrates the distribution of some of the major community types. These community types are based upon the potential climax community (the most mature developmental stage) that would be expected for a particular regional climate (Shelford 1963; Garrison et al. 1977). Edaphic (soil) or topographic conditions may allow disclimaxes (local variations) in community types. In addition, many areas are disturbed by natural events (e.g., fire, tornado, or flood) or human activities (e.g., farming, grazing, or logging), and communities in these areas persist in various preclimax stages of succession. However, the classification of a region by the biota of its potential climax does provide a convenient method of classification that will be followed here. In the succeeding discussion, descriptions of community structure and function will refer to ecosystems of potential climatic climaxes.

The eastern third of the country is dominated by communities of the temperate deciduous forest biome, or ecological unit (Braun 1950; Shelford 1963; Kendeigh 1974). This biome includes the oak-hickory, oak-pine, oak-gum-cypress, elm-ash-cottonwood, maple-beech-birch, and aspen-birch community types described by Garrison et al. (1977). These communities have poorly to richly developed understories of shrubs, vines, grasses, and forbs (herbaceous plants other than grasses). The soils of these forests are mainly inceptisols (moist soils containing weakly developed horizons with little accumulation of metal oxides) and ultisols (moist soils with a horizon of clay accumulation and with a low base supply) (Brady 1974). The deciduous forests of the Great Lakes are underlain by alfisols (soils with gray to brown surface horizons, medium to high base supply, and subsurface accumulation of clays). Average annual precipitation ranges from about 75 to 125 cm (30 to 50 in.), and the number of frost-free days ranges from 100 to 300 per year. Potential annual vegetative production in this biome ranges from 10 to 15 megagrams per hectare (Mg/ha) (Rodin et al. 1975). Plant and animal diversity is variable among stands in these forests. The multiple vegetation layers provide a variety of microhabitats for the fauna of these communities. White-tailed deer make use of these habitats, especially at the forest edge where appropriate cover and browse are available. Several small mammals forage in the tree stratum, while others forage on the ground. Birds forage in strata ranging from the ground surface to the canopy, or tree foliage, each species tending to forage in its own manner. The forest provides microhabitats for a diversity of arthropods (such as insects) in all strata of the vegetation.

Temperate, evergreen forests dominate the coastal plains of the southeastern United States (Braun 1950; Shelford 1963; Kendeigh 1974; Garrison et al. 1977). Longleaf-slash pine and loblolly-shortleaf pine are major community types within this area. The dominant soils are alfisols (Brady 1974). Average precipitation is about 100 to 150 cm (39 to 59 in.) per year; the annual frost-free period ranges from 200 to 300 days in length. Potential productivity in these communities reaches 15 to 30 Mg/ha/yr (Rodin et al. 1975). Several game mammals and birds occupy these communities; these include white-tailed deer, eastern cottontail, bobwhite, and wild turkey. The tree and shrub strata are used extensively by birds. Many species of waterfowl, aquatic reptiles, and amphibians are found in or near standing water.

Oak-gum-cypress community type and broadleaf, evergreen forests dominate the bottomlands of the Mississippi River and other waterways of the eastern coast (Braun 1950; Shelford 1963; Kendeigh 1974; Garrison et al. 1977). The soils of these communities are diverse, ranging from young entisols to well-developed ultisols (Brady 1974). Organic soils or histosols have developed where the ground is waterlogged. These communities are often very diverse, especially along the Gulf coast. Productivity is known to exceed 50 Mg/ha/yr in the more subtropical communities of the Gulf coast (Rodin et al. 1975). Epiphytes (plants that derive moisture from air and rain and usually grow on other plants) are very common in these communities, and the understory is usually dense. The frost-free season extends for more than 200 days per year, and average precipitation ranges from about 90 to 150 cm (35 to 59 in.) annually. The subtropical fauna includes such diverse species as the opossum, chameleon, and alligator. A number of waterfowl are present in flooded areas. Arthropods are very abundant, but little information is available on their distribution.

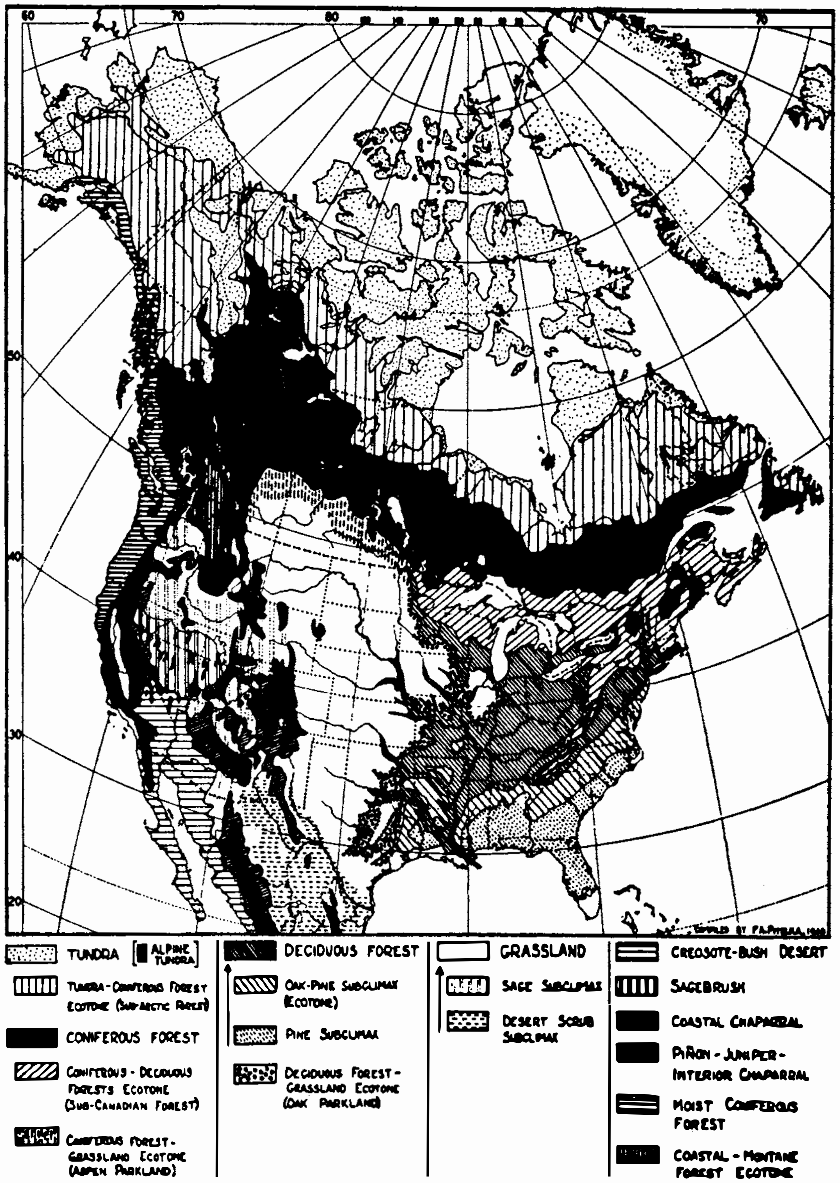

Fig. H.1. The Biomes of North America, with Extensive Ecotones and Certain Subregions (Zones) Indicated. From Odum (1971), with permission (see credits).

The central United States is dominated by communities of prarie and plains grasslands (Carpenter 1940; Shelford 1963; Weaver 1968; Kendeigh 1974; Redmann 1975; Garrison et al. 1977), extending to the eastern foothills of the Rocky Mountains. The soils of the grasslands are mollisols, with deep, dark surface horizons forming a crumbly or granular structure (Brady 1974). Perennial grasses are the dominant vegetation of these communities, making up a single vegetation layer. Forbs are subdominant in grasslands, and woody species are rare. Many of the grasses characteristic of the true prairies are sod formers, and ratios of roots to the above-ground parts of the plant are high when compared to other types of communities. Average precipitation in these grasslands ranges from 25 to 100 cm (10 to 39 in.) per year, and the frost-free period ranges from 100 to 300 days per year. Potential annual production in these grasslands is 8 to 15 Mg/ha (Rodin et al. 1975). Plant and animal diversity is moderate to low, compared to the eastern forests. Animals of grasslands are characterized by one or more of the following attributes: grazing behavior, swift running, ground nesting, or burrowing activity. Most of the large grazing mammals have been extirpated and replaced by livestock. Insects are abundant in grassland, and forage primarily in the herb layer of the community.

The arid southern and southwestern margins of the grasslands are invaded by shrubs, forming shrubsteppe, savanna, and desert grasslands communities (Buffington and Herbel 1965; Shelford 1963; Garrison et al. 1977). Soils here are varied but dominated by mollisols and alfisols (Brady 1974). These communities have poorly to richly developed layers of shrubs or low trees, with an understory dominated by perennial shortgrasses. Average rainfall ranges from 20 to 75 cm (8 to 30 in.) per year; the frost-free period ranges from 100 to well over 300 days. Potential productivity in this region ranges from 6 to 8 Mg/ha/yr (Rodin et al. 1975). The fauna of these communities represents a transition from the grasslands to the desert scrub communities. Collared peccary and armadillo extend into these areas from the subtropical communities to the south. The additional cover of the woody vegetation results in a higher variety of fauna in these communities than in the grasslands.

Desert scrub communities occur throughout most of the lowlands of the southwest and intermountain region (Shelford 1963; Cronquist et al. 1972; Armstrong 1972; Kendeigh 1974; Brown and Lowe 1974; Garrison et al. 1977). These communities are underlain by aridisols, with little organic material, light color, and accumulations of salts (Brady 1974). The dominant community types in this biome are creosote scrub, sagebrush scrub, and shadscale scrub. Perennial shrubs are the dominant life forms in these communities, where the vegetation is open and often covers less than 10 percent of the ground surface. Most of the shrubs are drought-deciduous (i.e., they lose their leaves during the dry season); the rest have small leaves adapted for water retention. Annual forbs and grasses comprise the understory. Diversity of these communities is relatively low, the only strata being the shrub and ground-surface levels. Average annual precipitation is only 10 to 25 cm (4 to 10 in.); the frost-free period ranges from 100 days in the north to 200 days in the south. Productivity ranges from zero to 2.5 Mg/ha/yr (Rodin et al. 1975). The fauna is dominated by granivorous (feeding on grains) or carnivorous species because herbaceous vegetation is abundant only briefly and sporadically. Most of the small mammals burrow and many hibernate, thereby reducing the effects of climatic extremes. Many mammals are adapted for water conservation, whereas others are dependent upon succulent vegetation and may be confined to riparian habitats. The reptilian fauna is very abundant and diverse in desert communities. Insects are primarily shrub- or ground-dwelling forms.

Pinyon pine-juniper communities, or pygmy forests, occupy much of the lower slopes and plateaus of the western United States (Shelford 1963; Cronquist et al. 1972; Armstrong 1972; Brown and Lowe 1974; Kendeigh 1974; Garrison et al. 1977). Soil-types are varied, but aridisols are most prevalent (Brady 1974). The trees form an open to dense woodland. A moderately well-developed understory of shrubs may be found in the more open stands of this community type. Grasses and forbs form the lowest vegetational stratum. Productivity is intermediate in the area between the coniferous forests of higher elevations and the desert scrub of lower elevations (Whittaker and Niering 1975). The fauna is composed of elements influent from adjacent habitats. Fauna of the moister and cooler habitats is similar to that of the mountain coniferous forests, whereas the fauna of the drier and warmer habitats is more like that of the desert. The abundance of arthropods is relatively low within pinyon pine-juniper communities.

The northern coniferous biome extends across southern Canada, extending down into the northern United States and following high mountain ranges southward (Shelford 1963; Armstrong 1972; Cronquist et al. 1972; Kendeigh 1974; Garrison et al. 1977). The northeastern coniferous forests are dominated by spodosols (soils with accumulations of organic materials and aluminum and some iron oxides, and which tend to be acidic) (Brady 1974). Soils underlying the coniferous mountain forests of the west are predominantly alfisols and inceptisols. A number of community types are included within this biome, e.g., the arid ponderosa pine associations and the moister Douglas fir and spruce-fir associations. Understories of small trees and shrubs can be well developed where light filters through the tight canopy of these forests. The frost-free season lasts 240 days in the southwest, and only 80 days in the northwest. Average precipitation throughout this biome varies from about 40 cm (16 in.) in the southwest to 200 cm (79 in.) in the northwest. Productivity of these communities varies with rainfall and growing season. The variety and complex structure of coniferous forests provides habitats for a varied fauna. Many mammals and birds exploit different strata of the vegetation, from the ground surface to the canopy. Large mammals make use of forest edge communities for forage. Most of the birds of the northern forests are migratory, whereas most of the birds of the mountainous forests are not. Insects are abundant, but ground-dwelling arthropods are uncommon. There are few reptiles, but some amphibians are widespread.

H.1.1 Demand Region I

H.1.1.1 Vegetation

The vegetation of this region is dominated by communities from the eastern deciduous and northern coniferous forest biomes (Braun 1950; Shelford 1963; Bormann et al. 1970; Kendeigh 1974; Garrison et al. 1977). Common tree associates within the deciduous forests can include white and black oak, sugar maple, American beech, shag bark and bitternut hickory, balsam fir, eastern hemlock, red spruce, yellow birch, tulip tree, basswood, and eastern white pine. Common associates within the coniferous forests include red spruce, balsam fir, eastern hemlock, sugar maple, paper birch, tamarack, white cedar, and eastern white pine. These communities have been disturbed by human activities for over 300 years. Many areas have been cleared for cropland or timber (see Section 4.4 and Appendix G). Little virgin forest exists, and most communities are in various stages of secondary succession. The vegetation of the urbanized southern sections of the region is predominantly disturbed stands of the oak-hickory forest community-type.

H.1.1.2 Animals

The natural fauna has been reduced to some extent by the activities of humans in the region. White-tailed deer make extensive use of many of the forest communities, especially in ecotonal areas (Shelford 1963; Kendeigh 1974). Moose and black bear are common in some areas. The woodland caribou formerly ranged into the coniferous forests of this region (Blair et al. 1968). Among the small mammals are snowshoe hare, eastern gray squirrel, flying squirrel, and white-footed mouse. Wild turkey, ruffed grouse, bobwhite, and mourning dove can be found in many of the communities. Breeding birds of the deciduous forests include tufted titmouse, wood thrush, ovenbird, red-eyed vireo, scarlet tanager, blue jay, and wood pewee. Birds of the coniferous forests include spruce grouse, olive-backed thrush, white-throated sparrow, and several warblers (Shelford 1963; Kendeigh 1974). Major predators include coyote, bobcat, wolverine, gray fox, weasel, great horned owl, red-tailed hawk, and sparrow hawk (Shelford 1963; Kendeigh 1974).

H.1.2 Demand Region II

H.1.2.1 Vegetation

The vegetation of this region is dominated by communities from the eastern deciduous forest biome (Braun 1950; Shelford 1963; McIntosh 1972; Wales 1972; Kendeigh 1974; Garrison et al. 1977). Maple-beech associations cover most of the area, while oak-hickory communities occupy smaller portions of the region to the south. Common associates of these communities include eastern hemlock, American elm, white ash, willow, and birch. Productivity and understory development are similar to other communities of the eastern deciduous forest. A pine disclimax enters into the southeastern portions of this region, near the coast.

The southern portion of this region is heavily urbanized (see Section 4.4 and Appendix G). As is true of most of the eastern states, the communities of this region have been severely disturbed by human activities, including farming and lumbering. The expected climax of this area is oak-hickory forest.

H.1.2.2 Animals

The fauna of this region is similar to the fauna of the New England deciduous forests (Kendeigh 1946; Shelford 1963; Kendeigh 1974). White-tailed deer occur throughout much of the region. Skunk, red and gray fox, coyote, raccoon, cottontail, fox squirrel, and smaller rodents occur here. Ruffed grouse and bobwhite are common gamebirds. Resident songbirds include red-eyed vireo, ovenbird, blue jay, hermit thrush, scarlet tanager, black-capped chickadee, and wood pewee.

H.1.3 Demand Region III

H.1.3.1 Vegetation

The flora of this region belongs to the eastern deciduous forest biome. The oak-hickory communities are the most widespread members of this biome in the region (Braun 1950; Shelford 1963; Keever 1973; Kendeigh 1974; Garrison et al. 1977). Pine-oak, maple-beech, and loblolly-shortleaf pine also occur in this region. Common associates within these communities include sweetgum, yellow poplar, white ash, eastern hemlock, basswood, and white pine.

H.1.3.2 Animals

The fauna here are a transition from the elements of the deciduous forests to the north and pine disclimaxes to the south.

H.1.4 Demand Region IV

H.1.4.1 Vegetation

This region, too, is dominated by the eastern deciduous forest biome. The northwestern half of the region tends toward oak-hickory, oak-pine, or mesophytic forest communities (Braun 1950;

Nelson 1957; Shelford 1963; Mowbray and Oosting 1968; Garrison et al. 1977). These forests are fairly diverse, being composed of several codominant species. Associates include buckeye, basswood, yellow poplar, beech, birch, dogwood, hemlock, red spruce, red maple, and sweet gum. The southeastern half of this region is dominated by pine disclimaxes of the deciduous forest biome. Common associates include loblolly pine, short-leafed pine, longleaf pine, slash pine, oak, hickory, sweet gum, sour gum, red maple, ash, and swamp cypress.

Coastal areas and watercourses have wetland and broadleaf-evergreen communities (Braun 1950; Shelford 1954; Nelson 1957; Shelford 1963; Monk 1965; Delcourt and Delcourt 1977). These communities include live oak, black and red mangroves, sweet gum, bald cypress, pond cypress, magnolia, water elm, and red maple. Mosses, lichens, epiphytes, and climbing vines, are common vegetation in these subtropical communities.

The wetlands communities of southern Florida are notable for their diversity and productivity (Loveless 1959; Shelford 1963; Garrison et al. 1977). They are dominated by species characteristic of subtropical and tropical communities. Some of the major tropical and subtropical vegetation of the forests are gumbo limbo, West Indies mahogany, thatch palm, cabbage palmetto, and red mangrove. Saltwater cord grass, pickleweed, salt grass, sedge, rushes, and cattails are dominant species along a gradient from the saltwater to freshwater marshes. The Everglades contain associations of spike rush, tall sawgrass, shrub-covered islands, palmetto islands, marl and rock prairies, and cypress ponds and woodlands. Man has encroached on these areas for the past hundred years or more.

The natural vegetation of this region has suffered marked disturbance since the arrival of Europeans in the 17th century. A large proportion of the area is undergoing secondary succession from abandoned cropland and lumbering (see Section 4.4 and Appendix G).

H.1.4.2 Animals

The distribution centers of several kinds of animal are in the forests of the southeast (Shelford 1963; Kendeigh 1974; Garrison et al. 1977). Common small mammals include swamp rabbit, raccoon, opossum, eastern spotted skunk, gray squirrel, rice rat, and several mice. White-tailed deer and black bear utilize some of the forest communities. Resident birds include Carolina wren, mockingbird, scrub jay, Carolina chickadee, and white-eyed vireo (Johnston and Odum 1956; Kendeigh 1974). Dominant predators include gray fox and many snakes.

The marshes of southern Florida provide a habitat for a number of birds, many with tropical origins (Shelford 1963; Kendeigh 1974). White-crowned pigeon, zenaida dove, smooth-billed ani, and black-whiskered vireo are representative of tropical influents in these communities. Many waterfowl of tropical origin occur here. Black bear, mountain lion, deer, spotted skunk, and raccoon are conspicuous mammalian inhabitants. The reptilian and amphibian fauna of the marshes is diverse. The most conspicuous reptile is the alligator. Invertebrates are numerous in most of the marsh communities, and exploit most of the available vegetational strata.

H.1.5 Demand Region V

H.1.5.1 Vegetation

The climax communities of this region belong to the eastern deciduous forest and northern coniferous forest biomes. Communities represented include members of the oak-hickory, maple-beech, elm-ash-cottonwood, and aspen-birch forests (Braun 1950; Shelford 1963; Goff and Zedler 1968; Reiners 1972; Grigal and Ohmann 1975; Garrison et al. 1977). Common associates of the forests of the southern Lake States can include basswood, willow, ash, river birch, walnut, and wild cherry. In the northern Lake States, associates can include pine, hemlock, yellow birch, fir, white-cedar, and spruce. Relict stands of prairie grassland intrude into the southwestern portions of this region (Carpenter 1940; Shelford 1963).

The area has been extremely disturbed and few virgin associations still exist. However, remnant stands of prairie are found in northern Illinois.

H.1.5.2 Animals

The fauna of this region represents a transition from the eastern, deciduous forest to the western, prairie grasslands.

H.1.6 Demand Region VI

H.1.6.1 Vegetation

This region has a very diverse biota, extending from the floodplain vegetation of the Mississippi River to the desert scrub vegetation of southern New Mexico (Braun 1950; Shelford 1963; Kendeigh 1974; Garrison et al. 1977). The eastern portion of this region is dominated by communities of the eastern deciduous forest and broadleaf evergreen forests. The central sections tend toward grassland communities in the southern sections of the grasslands; shrubs and small trees become more prevalent and form a savanna-like community (Shelford 1963; Smeins et al. 1976). Mesquite, acacia, juniper, yucca, cactus, and oak form the upper strata of these associations. The perennial grasses of the grasslands form the lower strata. The western communities are more dominated by the shrub and tree life forms. Desert scrub, desert grassland, and southwestern shrubsteppe are the predominant communities of the lowlands of the western parts of this region. The mountainous areas of New Mexico are covered primarily by ponderosa pine and pinyon pine-juniper associations. The majority of this area is used as rangeland, cropland, and timberland (see Section 4.4 and Appendix G).

In most of the desert grasslands communities, grazing pressure has reduced the dominance of perennial grasses such as galleta, black grama, blue grama, and tobosa (Buffington and Herbel 1965). Mesquite, creosotebush, cactus, and other shrubs make up the shrub stratum. The aridity of these areas reduces the success of reclamation after mining.

The coastal wetlands communities of this region are very diverse (Shelford 1963; Garrison et al. 1977). They have been disturbed by human activities and can be sensitive to disruption. The marshes of the coastal wetlands are dominated by grasses, rushes, and sedges, including salt-water cord grass, spike grass, black rush, sawgrass and maiden-cane. Live oaks, red bay, and other woody species invade as sedimentary deposits from dry islands in the marshes.

H.1.6.2 Animals

The fauna of the deciduous forests and pine forests of the eastern sections is an extension of Region IV. The southern grasslands fauna is characterized by a number of species adapted to an arid environment (Shelford 1963; Garrison et al. 1977). Conspicuous mammals include the jackrabbit, pronghorn antelope, banner-tailed kangaroo rat, and white-throated wood rat. Birds of these communities include horned lark, black-throated sparrow, scaled quail, grasshopper sparrow, loggerhead shrike, and nighthawk (Wiens 1973). Characteristic predators include the coyote, bobcat, badger, red-tailed hawk, prairie falcon, and various snakes. Grasshoppers, ants, and true bugs are prevalent insects.

The fauna of the coniferous forests and desert scrub associations of New Mexico is similar to that of the Rocky Mountain forests to the north and the deserts to the west, respectively.

The fauna of the coastal wetlands is very diverse (Shelford 1963). White-tailed deer, peccary, raccoons, and small rodents occupy the drier sites. Otters and muskrats are present in some marsh communities. A large number of birds, mostly waterfowl, utilize these communities. Insects are abundant and highly diversified.

H.1.7 Demand Region VII

H.1.7.1 Vegetation

The land area of Missouri is covered predominantly by communities of the eastern deciduous forest biome (Braun 1950; Shelford 1963; Kuchler 1974; Kendeigh 1974; Garrison et al. 1977). These are similar to the vegetation to the east and south. The balance of the region was originally covered by the prairie and plains grasslands (Carpenter 1940; Tomanek and Albertson 1957; Kuchler 1974; Garrison et al. 1977). Common associates in the true prairie include big and little bluestem, Indian grass, needlegrass, prairie dropseed, and switchgrass; mixed prairies contain several grama grasses, buffalo grass, western wheatgrass, bluestem, and other species. Elm-cottonwood associations penetrate the grasslands along the floodplains of waterways (Shelford 1963; Johnson et al. 1976). Areas of undisturbed native vegetation are rare in this region. Most of the area has been in use as cropland or rangeland since the late 19th century (see Section 4.4 and Appendix G).

H.1.7.2 Animals

The fauna of the deciduous forests is similar to that of the forests of adjacent regions. The grassland fauna tends not to be as diverse as that of the forest (Carpenter 1940; Shelford 1963). The most conspicuous inhabitant of the grasslands is the pronghorn antelope, which is found in the western portions of the region (O'Gara 1978). White-tailed deer can be abundant along watercourses, where woody vegetation occurs (Shelford 1963; Garrison et al. 1977). Rabbits, prairie dogs, ground squirrels, pocket gophers, and other rodents make up the small mammal component of the ecosystem. Coyotes and badgers are the major mammalian predators. Several species of gallinaceous birds can be found in the grasslands, including bobwhite, sharp-tailed grouse, and greater prairie chicken (Shelford 1963; Kendeigh 1974). Song birds found in the grasslands include horned lark, western meadowlark, and lark bunting (Shelford 1963; Wiens 1973). Insects are fairly abundant in grassland ecosystems.

H.1.8 Demand Region VIII

H.1.8.1 Vegetation

The vegetation of Demand Region VIII varies from the plains grasslands in the eastern portions to the mountain coniferous forests of the Rocky Mountains and the desert scrub of the southwestern part of the region (Carpenter 1940; Shelford 1963; Cronquist et al. 1972; Armstrong 1972; Kendeigh 1974; Garrison et al. 1977).

The grasslands communities are dominated by short- and midgrasses such as western wheatgrass, blue grama, needlegrass, and buffalo grass (Carpenter 1940; Shelford 1963). These grasslands have been extensively grazed by livestock, and little undisturbed grassland remains. In some areas overgrazing has resulted in the invasion of shrubs and cacti into the grasslands. The sagebrush communities of this region overlay a number of coal deposits. These communities are dominated by big sagebrush; however, rabbitbrush, bitterbrush, blackbrush, Mormon tea, and hopsage are common shrub associates (Shelford 1963; Cronquist et al. 1972; Redmann 1975). Associated perennial grasses include wheatgrass, bluegrass, fescue, Indian ricegrass, and squirreltail. Heavy grazing has reduced the importance of perennial grasses in many of these communities. Perennial and annual herbs are of less importance in the sagebrush scrub.

The pinyon pine-juniper associations of this region form a transition from the grassland and scrubland communities into the mountain coniferous forest (Shelford 1963; Cronquist et al. 1972). The understory commonly contains big sagebrush, bitterbrush, snowbrush, rabbitbrush, oak, and Mormon tea. Common perennial grasses include wheatgrass, bluegrass, fescue, Indian ricegrass, and needlegrass. A variety of forbs are also found in the understory of the pinyon pine-juniper communities.

The mountain coniferous forests occupy the higher slopes of the Rocky Mountains and associated mountain ranges within the Region (Shelford 1963; Cronquist et al. 1972; Armstrong 1972; Despain 1973). Ponderosa pine, lodgepole pine, larch, Douglas fir, and fir-spruce associations are the predominant communities of this biome in the region. Ponderosa pine associations are the most widespread within this region covering the drier slopes of the Rocky Mountains, and several patches occur as islands in the grasslands of the Northern Great Plains. Snowbrush, deerbrush, manzanita, rabbitbrush, hairy dropseed, muhly, and squirreltail are common components of the understory.

The floodplains of waterways passing through the grasslands of this region provide the opportunity for the invasion of various deciduous forest species (Shelford 1963; Johnson et al. 1976). These habitats increase the diversity of biota within the region. Cottonwood, elm, ash, and willow are characteristic components of these forests. Perennial grasses of the grasslands and shrubs make up the sparse understory of this community.

H.1.8.1 Animals

Bison were originally one of the dominant grazers of the plains grasslands prior to their extirpation by the white man (Carpenter 1940; Shelford 1963; Kendeigh 1974; Garrison et al. 1977). Today, the only native large grazer is the pronghorn antelope. Common small mammals of the grasslands include cottontail rabbit, jackrabbit, pocket gopher, and several mice. The black-tailed prairie dog is a major food staple for several predators, including the endangered black-footed ferret. Nesting birds of the grasslands include the western meadowlark, horned lark, grasshopper sparrow, and lark bunting (Shelford 1963; Kendeigh 1974; Wiens 1973). The major predators are coyote, badger, kit fox, prairie falcon, golden eagle, ferruginous hawk, and prairie rattlesnake.

The sagebrush communities are important to several animals as foraging and nesting sites. Mule deer and elk make use of these communities as winter foraging areas (Mackie 1970). Pronghorn are highly dependent upon sagebrush associations for forage (O'Gara 1978). A number of birds nest in the sagebrush zone. Sage grouse are associated with dense stands of sagebrush (Eng and Schladweiler 1972). Best (1972) suggests that the Brewer's sparrow is dependent upon sagebrush for nesting sites. Important predators are coyote, kit fox, golden eagle, Cooper's hawk, prairie falcon, burrowing owl, and several snakes.

The fauna of the pinyon pine-juniper communities is transitional between the faunas of the lower and higher elevations (Shelford 1963). The higher coniferous forests provide a varied habitat for exploitation by a large number of animals. Mule and white-tailed deer, elk, and moose make use of the forests and forest-edge communities for forage and protection from climatic extremes. Chipmunks, tree squirrels, wood rats, and several mice are common inhabitants of these forests (Shelford 1963). Resident birds include Stellar's jay, mountain chickadee, mountain bluebird, pigmy nuthatch, and several warblers. The dominant predators include bobcat, mountain lion, weasel, flammulated owl, golden eagle, and pygmy owl (Shelford 1963).

The deciduous forests that extend along floodplains in the grasslands add a diverse fauna to the comparatively simple fauna of the grasslands (Shelford 1963). White-tailed deer use these forests extensively. Cottontails, raccoons, striped skunk, and jumping mice are some of the small mammals found in these ecotonal forests. Nesting birds include bobwhite, mourning dove, red-shafted flicker, crow, and nighthawk. Among the predators are the red fox, long-tailed weasel, red-tailed hawk, Cooper's hawk, screech owl, and several species of snakes.

H.1.9 Demand Region IX

H.1.9.1 Vegetation

The vegetation of this region is highly varied, because the area is dissected by a number of mountain ranges and is affected by both Pacific and Gulf climatic patterns (Munz and Keck 1949; Shelford 1963; Garrison et al. 1977; Cronquist et al. 1972; Brown and Lowe 1974). Desert scrub communities cover a major proportion of the interior lowlands. In the southern, warmer deserts, dominant shrubs include creosotebush, bursage, joshua tree, yucca, and several cacti. Many communities of the Arizona deserts are characterized by the presence of saguaro cactus, ocotillo, palo verde, and agave. Several perennial grasses such as big galleta and bush muhly occur in these habitats. The northern, colder deserts are characterized by such shrubs as big sagebrush, shadscale, hopsage, blackbrush, greasewood, winterfat, rabbitbrush, and Mormon tea.

Two particularly unique types of trees occur in these forests. The giant sequoia, one of the largest trees in existence, is found in forests of the southwestern slopes of the Sierra Nevada. The bristlecone pines are some of the oldest trees in existence. These trees occur in the subalpine habitats of many of the arid, windblown mountain ranges east of the Sierra Nevada.

The original annual grasslands of the California valley floors are essentially extinct (Shelford 1963). They have been replaced by exotic grasses, such as oats, or cropland. Large areas of broadleaf, sclerophyllous (with thickened, hardened leaves) scrub communities still remain. Many of these communities are adjacent to the heavily urbanized areas of California. These communities are dominated by shrubs and small trees adapted for the prolonged summer drought that is characteristic of this area (Munz and Keck 1949; Shelford 1963). Common plants of these communities include chamise, coastal sagebrush, manzanita, black sage, mountain mahogany, wild buckwheat, and live oak. Community types range from chaparral with a dense canopy of shrubs to the more open woodlands with understories of exotic grasses influent from the adjacent grasslands.

Redwood forest associations occupy the low, coastal mountains of northern California and overlap the northward extension of urbanization (Shelford 1963). Most of these forests have been logged in the past, and logging interests are still removing redwoods in some areas. Some of these trees are the tallest on record. These forests are highly dependent upon moisture from coastal fog, particularly in the summer. Douglas fir is associated with these forests. Tanoak, California laurel, Pacific madrone, and alder are commonly present. The shrubby understory includes rhododendron, box blueberry, hazel, salal, and several ferns.

H.1.9.2 Animals

The variety of habitats in this region has resulted in the evolution of a highly varied fauna (Shelford 1963; Kendeigh 1974; Garrison et al. 1977). Dominant mammals of the desert scrub habitats are rodents, including the kangaroo rat, wood rat, and grasshopper mouse, and lagomorphs, such as the black-tailed jackrabbit (Shelford 1963). Characteristic birds include the Gila woodpecker, roadrunner, sage sparrow, cactus wren, and loggerhead shrike. Dominant predators are coyote, kit fox, red-tailed hawk, burrowing owl, and several species of rattlesnakes. Lizards are abundant in the desert (Pianka 1967); common species are leopard lizard, side-blotched lizard, horned lizards, whiptailed lizard, and desert iguana. Desert tortoises are found in some desert scrub communities. Spadefoot toads inhabitant areas where ephemeral standing water is likely to occur after rain.

Mule deer utilize the broad sclerophyll woodlands and dense chaparral edge for forage (Shelford 1963). Ground squirrel, wood rat, pocket gopher, and cottontail are common small mammals. Avian residents include California quail, hummingbirds, wrentit, common bushtit, and western kingbird. Dominant predators are coyote, sparrow hawk, red-tailed hawk, and rattlesnakes.

The fauna of the redwood forests is similar to that found in coniferous forests of higher elevation and latitude (Shelford 1963). Mule deer and black bear can be found in these forests. A number of small rodents provide a food source for red-tailed hawk, screech owl, and great horned owl. The blue grouse is the most common ground-nesting bird. Other birds of the redwood forests include pileated woodpecker, olive-sided flycatcher, gray jay, brown creeper, and hermit warbler.

H.1.10 Demand Region X

H.1.10.1 Vegetation

The lowland areas of this region are dominated by sagebrush scrub communities continuous with this community type in Nevada, Utah, and Wyoming (Shelford 1963; Cronquist et al. 1972; Kendeigh 1974; Garrison et al. 1977). The balance of the area is covered by associations of coniferous forests that include ponderosa pine, lodgepole pine, larch, western white pine, Douglas fir, Englemann spruce, silver fir, and mountain hemlock. The coastal, mesophytic forests of Oregon and Washington are dominated by western hemlock and sitka spruce. These coastal communities have a dense undergrowth dominated by salal, vine maple, salmon-berry and devil's club.

H.1.10.2 Animals

The fauna of the sagebrush zone is continuous with the fauna of sagebrush communities in Nevada, Utah, and Wyoming (Shelford 1963; Kendeigh 1974; Garrison et al. 1977). The conspicuous herbivores of the mountainous coniferous forests and meadows include mule deer, elk, moose, mountain goat, and mountain sheep. Several small mammals serve as food for coyote, bobcat, weasel, and wolverine. Birds include spruce grouse, boreal chickadee, pine grosbeak, and white-winged crossbill. The fauna of the coastal forests is derived from the coniferous mountain forests.

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APPENDIX I. AQUATIC BIOTIC RESOURCES

I.1 NEW ENGLAND WATER RESOURCE REGION

This region contains the states of Maine, Vermont, New Hampshire, Massachussetts, Connecticut, and Rhode Island (Vol. I, Fig. 4.19). In this area, major factors that influence the characteristics of the aquatic resources are the sparsity of sedimentary rocks and the fact that the entire area was glaciated (Geraghty et al. 1973). This has resulted in the occurrence of numerous lakes, ponds, bogs, and streams of relatively low hardness and low natural productivity (Brooks and Deevey 1966). Water bodies in southern New England are generally higher in total hardness because of the occurrence of some limestone. In addition, their higher natural nutrient levels and the addition of large quantities of municipal wastes make them the most productive.

The bogs that are prevalent throughout much of the region are very similar to those found in the northern Midwest, in the alpine zone of the Rockies, and on the Coastal Plain. Their water is typically acid (pH 4-7), very low in buffering capacity, and high in humic acids (Brooks and Deevey 1966). Few fish exist in northern bogs because of their shallowness and low pH, but a great diversity of phytoplankton and zooplankton often occurs (Macan 1974).

Freshwater marshes in the region are typical of those found in the temperate United States. Most are dominated by cattail (*Typha* spp.) and are generally highly productive, particularly in comparison to adjacent lakes (Reid 1961). Because of the shallowness of these marshes and their tendency to become seasonally anoxic, few fish exist year-round, although minnows and bullheads are common in the deeper marshes. However, numerous algal, angiosperm, and invertebrate species exist in such environments. Because of the quantity of autotropic biomass that these systems produce, they serve as efficient purifiers of the water that trickles through them; thus, they likely provide some degree of protection against pollutants to adjacent water bodies (Hynes 1971).

Most lakes in the region are of glacial origin, although a few artificial impoundments exist. The greatest density of lakes and the largest lakes occur in the north where three with an area of >100 km^2 (>39 sq mi) exist (Brooks and Deevey 1966). Many of the northern New England lakes are still relatively pristine, although increased recreation, lumbering, agriculture, and an expanding population have compromised their quality. The largest lakes are typically highly oligotrophic and contain little macrophyte development and few benthic invertebrates. These possess a cold-water sport fishery dominated by whitefish, trout, and freshwater salmon (Brooks and Deevey 1966).

Several relatively large rivers occur in the region but most have received considerable stress from industrial, agricultural, and municipal wastes that have greatly modified the biota (Brooks and Deevey 1966). Numerous smaller streams that are more isolated from perturbations also exist, particularly in northern New England. These are typically cold and well-oxygenated, and they commonly contain stable populations of brook trout (Brooks and Deevey 1966).

Several estuaries and bays exist in the region, many of which display naturally high productivity. However, the influx of large quantities of heavy metals, pesticides, and other wastes has greatly altered the biota of most of these areas (Reid 1961).

A regional problem that has the potential to affect adversely the biota is the increased acidity of surface waters due to acid rain. This phenomenon has been documented to affect more severely those waters that are poorly buffered, such as those found in the New England Water Resource Region (WRR) (Hornbeck,et al. 1977). The causal factors are generally airborne sulfates and nitrogen oxides from smelting, fossil fuel combustion, and industrial processes that are brought to earth in rain as acids. Increased fossil fuel combustion, if not coupled with desulfurization equipment, can be expected to exacerbate the acid rain problem.

In general, heavy metal toxicities are also greater in poorly buffered waters than in those with high carbonate-bicarbonate concentrations (National Academy of Sciences, National Academy of Engineering 1972). This WRR is thus more susceptible than many to toxic effects from coal pile and ash pile leachates.

I.2 MID-ATLANTIC WATER RESOURCE REGION

The Mid-Atlantic WRR contains a wide variety of physiographic features including ridge and valley topography, Blue Ridge mountain terrain, piedmont, coastal plain, and glacial plains (Strahler and Strahler 1976). Consequently, the area's aquatic ecological resources are diverse. The upper portion of the region, including parts of New York, New Jersey, and Pennsylvania, was glaciated and is rich in lakes, wetlands, and streams (Berg 1966). Most of these water bodies (particularly those in the Adirondack and Catskill mountains) are edaphically highly oligotrophic, and their low nutrient levels severely limit fish production (Berg 1966). Other lakes in the area are highly productive, particularly those in lowlands where some limestone occurs to provide hardness (usually medium) and where municipal sewage and fertilizer runoff are inputted (Berg 1966). These areas, which include New York's Finger Lakes, contribute greatly to the four million areas of fishable freshwaters that this WRR and the New England WRR comprise together (Geraghty et al. 1973). Major fishing resources in the glaciated area include brook and brown trout (in the mountain streams) and muskellunge and centrarchids in the mesotrophic lowland lakes (Berg 1966).

Unglaciated portions of the region contain far fewer water bodies and virtually no natural lakes. Hot springs occur in a few areas, but their total water volume is insignificant. From an ecological standpoint, however, they are of great interest as research areas because the biotic communities they harbor are very different from those in adjacent waters (Yount 1966). The coastal plain area (particularly of New Jersey) has several bogs similar to those found in the New England WRR (Berg 1966). The region also contains numerous highly productive estuaries that are important nursery grounds for many commercial and sport fish and shellfish.

This WRR receives the greatest municipal sewage loading of any region (Geraghty et al. 1973), which has caused severe biotic degradation of its major rivers and of many of its lakes (Berg 1966). Coal mining in Pennsylvania and Virginia has also caused considerable harm by completely eliminating trout from some areas and by essentially eliminating all biota from others (Berg 1966). Major factors contributing to this degradation include increased sedimentation, acid drainage, and heavy metals. Heavy metals from industries, pesticides, and the highest regional output of thermal effluents have contributed to the demise of the major rivers (Geraghty et al. 1973). Although few are actively fished and recreation is curtailed on many, some recent progress has been made in reversing the degradation (Berg 1966).

I.3 SOUTH ATLANTIC-GULF WATER RESOURCE REGION

This WRR encompasses much of the eastern coastal plain and piedmont areas. Most of the southern part of the region is characterized by very soft water whereas Florida (particularly the southern half) generally contains moderately hard to hard waters. Natural productivity of these waters is roughly directly proportional to their hardness (Yount 1966).

Rivers in the northern portion of the region typically arise as mountain streams that become warmer, slower, and more turbid in the Piedmont (Yount 1966). After crossing the fall line, these rivers enter the Coastal Plain and become broad, slowly flowing streams with relatively less silt content. Many of them terminate in swamps and marshes near the coast (Yount 1966). The natural biota of these rivers changes markedly along their length; that is, trout are prevalent in the undisturbed headwaters whereas only species capable of tolerating very high temperatures [up to 35°C (95°F)] occur in the marshy areas near the rivers' mouths (e.g., minnows, centrarchids) (Hynes 1972).

Aside from several reservoirs, the only major lakes in the north are the Carolina bays. These are small lakes that have peat and sand bottoms, low pHs, and low productivity, but diverse fish communities (Yount 1966). In contrast, the solution lakes of Florida (of which there are thousands) are typically highly productive and alkaline and often contain dense growths of duckweed (*Lemna*), water hyacinth (*Eichornia*), water lettuce (*Pistia*), and water fern (*Salvinia*). The smaller ones are typically anoxic a short distance below the surface, and the only fish present are minnows (particularly *Gambusia affinis*) (Yount 1966). Florida's large lakes harbor a good sport fishery dominated by largemouth bass; the entire region claims the greatest area of fishable freshwaters of any WRR [1.89×10^6 ha (4.68×10^6 acres)] (Geraghty et al. 1973).

The region has the greatest areal extent of freshwater swamps and marshes of anywhere in the country (Geraghty et al. 1973). Additionally, much of its coastline consists of salt marshes and mangrove swamps. The inland swamps are typically devoid of large fish but contain many amphibians, invertebrates, algae, and angiosperms. Their water is typically highly colored from humic substances and is acidic (Yount 1966). The freshwater marshes are highly productive and usually contain clear, alkaline water; they do not harbor large fish but contain a diversity of other aquatic biota (Reid 1961). Grasses, sedges, reeds, and rushes are the emergent macrophytes of these areas, and the community is much different than that found in more temperate locations of the country (Fassett 1957).

A habitat common to portions of this region is the artesian spring. These springs primarily occur in the karst area of Florida and represent some of the most productive areas in the country (Yount 1966). Their waters are nearly homothermal year-round and are generally hard. In addition to the large standing crops of fish that they produce, these springs contain large quantities of angiosperms (chiefly *Sagittaria lorata*) and algae (Yount 1966).

Major perturbants of ecosystems in the region include high pesticide inputs, municipal waste additions, and turbidity from logging and agriculture. These are responsible for making the region one of the highest in the number of fish kills (Geraghty et al. 1973). Turbidity increases have been particularly destructive in the north, where suspended solids levels of 1200 mg/L and greater are not uncommon (Yount 1966). Siltation is frequently implicated in the destruction of bottom organisms (by creating food shortages for fish) and in the direct destruction of fish (by gill clogging, covering of spawning grounds, etc.) (Hynes 1971).

I.4 TENNESSEE WATER RESOURCE REGION

This WRR largely contains steep topography, and none of it has been glaciated (Geraghty et al. 1973). Hence, few natural lakes or wetlands exist in the area; the water resources are dominated by streams, the larger of which have been extensively impounded (Patterson 1970). The waters are of generally low natural productivity; total dissolved solids and hardness concentrations range from low to moderate.

Mountain streams in the area are typically clear, cold, and shallow and harbor a diverse invertebrate assemblage (Hynes 1972). Red algae have been reported from these habitats (Parker 1976), and rainbow, brown, and brook trout are locally abundant (Gerking 1966). Many of the higher-altitude streams are still relatively pristine, but several have been extensively polluted from acid mine drainage (Gerking 1966). The result of this disturbance has been a simplification of the food chain with the occurrence of a few species (sometimes abundant) that are tolerant of low pHs, high dissolved solids, high turbidity, and increased levels of metallic and organic toxicants (Hynes 1972).

The larger rivers have been greatly altered from their original condition. The construction of many dams has stabilized stream flows (which used to vary considerably during the year) and has resulted in a long series of artificial lakes where flowing water used to exist. The effect on the biota as a result has been profound. For example, plankton are more numerous, and species of benthic invertebrates and fish have changed (Gerking 1966). These reservoirs provide an active warmwater sport fishery dominated by bass, blue gill, crappie, and walleye, and tailrace waters provide trout habitat in some areas (Gerking 1966). In this WRR, 377,000 ha (930,000 acres) of freshwater exist for fishing (Geraghty et al. 1973).

Major effluent problems that have affected the biota of the larger streams include municipal waste addition (causing nuisance plant growth) and heavy metal additions from industrial facilities (Geraghty et al. 1973).

I.5 OHIO WATER RESOURCE REGION

The Ohio Water Resource Region contains some of the same habitats found in the Tennessee WRR. Mountain streams such as those described in Section E.4 are common in some parts of Pennsylvania, West Virginia, Tennessee, Kentucky, and Ohio (Patterson 1970). Because these areas are also heavily mined for coal, many of the same types of mine drainage problems exist here. Although some of the more remote streams have escaped degradation, much of the Appalachian portion of this region has been greatly impacted (Gerking 1966). Consequently, the natural biota has been largely displaced by more tolerant forms. Thus, trout that were once abundant locally have been virtually eliminated.

The region contains several large rivers that, because of their slow-flowing characteristics, more nearly resemble turbid lakes, in many respects. The Ohio River, for example, contains reproducing plankton populations in several areas (Gerking 1966). A warmwater fishery of considerable sport value occurs in many of these rivers, despite the problem of progressive water quality degradation (Migdalski 1962). Fish commonly caught include carp, catfish, drum, bass, and bluegill. Although commercial fishing (e.g., for walleye) once occurred extensively on a few of the larger rivers, little is done today (Gerking 1966). One of the greatest obstacles to successful fishing in some areas is the presence of bioaccumulated toxicants in fish tissue (e.g., mercury, DDT), which has required limitations on the amount of fish a person can safely consume (Hynes 1971).

The upper one-third to one-half of this WRR was glaciated, and most of the natural lakes occur in this area. Because of the great numbers of people living nearby, these lakes receive considerable fishing pressure and are constantly enriched with anthropogenic nutrients (Geraghty et al 1973). Some of the more shallow lakes have become overgrown with macrophytes (as a result of eutrophication) to the extent that frequent anoxic conditions develop that cause many sensitive organisms to disappear (Gerking 1966; Gerking 1950). Some progress has been made in alleviating this problem by increased sewage treatment capabilities, weed harvesting, and in-situ nutrient inactivation (Hynes 1971).

The region contains several wetlands (particularly in the glaciated area). Marshes are most common, but some bogs occur in northern Indiana and Ohio (Geraghty et al. 1973).

I.6 GREAT LAKES WATER RESOURCE REGION

The dominant water resource in this region is the Great Lakes. These vast bodies of water are of low to moderate hardness and have very low to moderate natural productivity (Beeton and Chandler 1966). Typical deepwater invertebrate fauna of the lakes include *Pontoporeia affinis* (an amphipod), *Mysis relicta* (oppossum shrimp), oligochaetes (largely *Limnodrilus*), and the molluscs *Pisidium* and *Sphaerium* (Beeton and Chandler 1966; Ricker 1959). The shallow-water benthic fauna is much like that of adjacent smaller bodies of water of the same productivity; the average density of organisms is roughly 1200/m^2 for Lakes Huron and Michigan (Beeton and Chandler 1966). Diatoms dominate the phytoplankton, even in the highly eutrophic portions of Lake Erie, but Lake Erie and Lake Ontario are known to develop extensive blue-green and green algal populations also (Hutchinson 1967). Copepods are the most common zooplankters, followed by cladocerans (Beeton and Chandler 1966).

Salmonids, which dominated the early sport and commercial fisheries of the Great Lakes, still account for most of the sport-fishing enthusiasm (Beeton and Chandler 1966). Lake trout and the coregonids (whitefish, lake herring, chubs) have been the most important commercial species in the upper lakes, whereas shallow waters and the lower lakes have largely produced perch and catfish (Smith 1972). The fish fauna has changed greatly in the past century because of the following major anthropogenic factors (Smith 1972): (1) intensive selective fishing pressure, (2) invasion by marine species and successful establishment of stocked species, (3) modification of the drainage systems entering the lakes, and (4) progressive physicochemical changes. Because of these influences, the production rates for the oligotrophic, cold-water fish have fallen, and mesotrophic species (e.g., several of the percids) are much more prevalent. Additionally, exotic species are common and, in many areas, constitute a large percentage of the total fish standing crop (Christie 1974). Carp and smelt are introduced fish that have some commercial value (Beeton and Chandler 1966). The alewife and the sea lamprey are species that gained entrance into Lakes Erie, Huron, Michigan, and Superior after completion of the canal bypassing Niagara Falls. Both species are regarded as nuisance organisms, although some effort is being made to commercially harvest the alewife (Beeton and Chandler 1966), and control efforts have largely eliminated sea lamprey effects (Christie et al. 1972). Three sport fish that have been recently introduced are apparently well established in the more pristine areas of the lakes. Rainbow trout, coho salmon, and chinook salmon are actively sought by anglers, and the latter two have been successful in cropping some of the alewife production in Lake Michigan (Stauffer 1976; Christie et al. 1972; Christie 1974).

The Great Lakes have incurred considerable alteration by virtue of the high human population density and industrial activity nearby. Thermal inputs are greater than those in nearly any other region, toxicant additions are very heavy locally, and the addition of nutrients via sewage and other high-BOD wastes has accelerated eutrophication considerably (Geraghty et al. 1973). Although Lake Superior has escaped much of the change that has occurred in the other lakes, it too has demonstrated biotic changes as a result of man's activities. Interestingly, not all of the changes can be easily categorized as undesirable because increased eutrophication has increased fish production and harvests in some areas (Beeton and Chandler 1966).

Other water bodies within this region include bog lakes (much like those of New England); soft water oligotrophic lakes; hard water eutrophic lakes; large turbid streams; clear, shallow trout streams; and marshes (Strahler and Strahler 1976). In general, those lakes found in the southern portion of the region (southern Wisconsin, southern Michigan, northern Indiana, and northern Ohio) are eutrophic, due to the addition of municipal wastes, feedlot wastes, etc. Although several of these support dense stands of macrophytes (Swindale and Curtis 1957) and have engendered little sport-fishing interest, many are highly productive and heavily fished (Knight et al. 1962; Tanner 1960). The lakes in the northern part of the WRR are largely undisturbed and are similar to those found in the northeast portion of the Souris–Red–Rainy WRR (Tanner 1960). This glacially modified area contains numerous oligotrophic waters (it has one of the highest concentrations of lakes in the world) (Fassett 1930). Aside from the tremendous ecological value of this area's biotic resources, their major use is recreation-related (Johnson and Hasler 1954).

I.7 SOURIS-RED-RAINY WATER RESOURCE REGION

This WRR contains a wide variety of aquatic habitats because it encompasses several distinctly different physiographic features. The eastern portion of the region contains Precambrian bedrock with an overlay of nutrient-poor glacial drift, and it receives a relatively large amount of precipitation. The surrounding natural vegetation is predominantly coniferous forest. In contrast, the western portion of the WRR contains substrates that are much higher in dissolvable minerals, it receives much less precipitation, the surrounding vegetation is largely prairie, and the drainage system is much better developed (because the area has gone longer without glaciation) (Patterson 1970). Consequently, soft water lakes, bogs, and trout streams typify the eastern area, and saline, high-sulfate lakes typify the west (Eddy 1966).

The bog lakes and marshes of the eastern portion of this WRR are very similar to those described in Section F.1. The soft water lakes of northeast Minnesota are likewise similar to those found in Maine. In general, these lakes are characterized by small littoral zones (due to steep, rocky shorelines), very low natural productivity, little macrophyte production, and little plankton production (Eddy 1966). The plankton is dominated by diatoms (*Tabellaria, Fragilaria,* and *Asterionella* predominantly) and copepods. Profundal bottom areas often display large densities of *Pontoporeia affinis*, whereas the littoral benthic fauna is scarse. The deeper lakes contain cold-water fish species such as lake trout, ciscoes, and whitefish. Northern pike, yellow perch, burbot, and walleye are also found, and these are the dominant species in the shallower lakes that cannot support a cold-water fish fauna due to low dissolved oxygen (DO) values during the summer (Eddy 1966).

The southeastern portion of the WRR contains hard water, eutrophic lakes, and several marshy areas. Many of the lakes display summer anoxia in the hypolimnia; thus, a resistant profundal benthic fauna of chironomids and oligochaetes is common (Dineen 1953). The littoral areas of these lakes are highly developed; the standing crop of summer fauna is roughly ten times that of the soft water lakes of northeast Minnesota (Eddy 1966). Plankton are abundant, with blue-green algae dominant during the summer months. Most of the lakes support large fish populations (Dineen 1953). The larger bodies of water are dominated by walleye; the medium-sized by bass, crappie, and sunfish; and the smaller lakes by bullhead and carp. The lakes produce, on the average, 90 to 160 kg of fish per hectare (summer standing crop), and some of the shallower ones have been estimated to produce greater than 400 kg of fish per hectare. These estimates compare to an average of 35 kg of fish per hectare for fish standing crops in nine oligotrophic lakes in the extreme eastern portion of the WRR (Eddy 1966).

The prairie lakes within this WRR are high in sulfates, carbonates, chlorides, sodium, and calcium. Their salinity is highly variable. Some are more saline than ocean water, although the ionic proportions are usually quite different (Wilson 1958). These environments are usually highly buffered and display pH values of 8.4-9.0 (Reid 1961). Brackish-water emergent plants are common, with *Ruppia occidentalis* and *Nais marina* often predominating (Eddy 1966). The plankton is commonly a mixture of freshwater and brackish-water species, and the benthos is typically dominated by a few chironomid species. Several of the larger lakes are highly productive (particularly of rough fish). Shallower areas either support no fish, because of seasonal freezing, or largely contain bullheads. Certain aquatic species appear to thrive in these environments (Wilson 1958). The amphipod *Hyalella azteca*, for example, is often found in abundance in the vegetated littoral areas (Eddy 1966).

Direct anthropogenic disturbances are largely restricted to the southern and western portions of this WRR where municipal waste additions and agricultural runoff have been largely responsible for biotic changes (Geraghty et al. 1973). Increased eutrophication and pesticide accumulation in aquatic species have been documented for these areas (Eddy 1966). Although the northeast portion of Minnesota has largely remained pristine, the preponderance of very soft waters makes this area exceedingly susceptible to acid rain effects and toxic metal effects.

I.8 UPPER MISSISSIPPI WATER RESOURCE REGION

The most prominent water resource features of this WRR are the Mississippi River, several smaller rivers, and several lakes of glacial origin (particularly in the northern half of the region) (Strahler and Strahler 1976). This region contains the Mississippi River from its source in central Minnesota to its confluence with the Ohio River at the southern border of Illinois Along this stretch, the river changes from a swift, relatively shallow stream to a large, slow-moving and turbid system. The biota in the upper reaches is markedly different from that downstream. In central Minnesota, the Mississippi contains an abundant and diverse bottom fauna, largely because of the shallowness of the water and the abundance of dissolved oxygen. Downstream stretches have much less diverse communities, although some species (e.g., chironomids) are locally abundant (Eddy 1966; Carlander et al. 1966). The velocity of the river below central Minnesota has been further slowed by the construction of several impoundments. These have created pooled areas that resemble, in many respects, medium-hard-water lakes in the vicinity (Hynes,1972). Plankton populations, for example, are seasonally extensive in these areas, with diatoms and blue-green algae generally dominant (Eddy 1966). Fish in the backwater areas surrounding these pools are likewise more lacustrine than riverine, and centrarchids are common. In contrast, the more free-flowing downstream reaches include a typical large-river fauna of paddlefish, sturgeon, and species of *Carpiodes*, and the reproducing plankton population is relatively scant (Eddy 1966).

The Mississippi receives large quantities of wastes from the Twin Cities area down (Geraghty et al. 1973). In terms of biotic effects, the largest problem has been the addition of municipal wastes that have caused severe deoxygenation in some areas (Eddy 1966). The effect of the lowered oxygen levels has been to select for a more resistant biota; the most conspicuous change has been the greater proportion of rough fish that inhabit the river (Hynes 1972). Other rivers in the area have experienced similar problems, although in several the high-BOD source is paper-mill wastes. Other rivers have received considerable inputs of heavy metals that have resulted in the limitation on the amount of fish flesh safely consumable per unit of time (Geraghty et al. 1973; Eddy 1966). Mine drainage in parts of Illinois has greatly altered the biota of several streams there. In several areas, fish have been completely eliminated and only a highly resistant fauna and flora exist (Hynes 1971).

The natural lakes in this WRR occur mainly in the highly glaciated areas of central-northern Minnesota and Wisconsin (Patterson 1970). The lakes tend to be soft and unproductive in the eastern half of this area and hard and eutrophic to the west. The soft water lakes are similar to those described for northeast Minnesota in Section F.7, and the hard water lakes are essentially the same as those described for the southeastern portion of the Souris-Red-Rainy WRR (Sec. F.7). Natural lakes that occur in the southern portion of the Upper Mississippi WRR are generally highly productive, and many contain large warmwater sport fisheries (Carlander et al. 1966; Gunning 1966). Anthropogenic eutrophication has degraded several of these lakes, however, and mine drainage has greatly affected others, although the hard water of these lakes makes them somewhat resistant to the effects of moderate mine effluent inputs (Hynes 1971; National Academy of Sciences, National Academy of Engineering 1972; Carlander et al. 1966; Gunning 1966).

I.9 LOWER MISSISSIPPI WATER RESOURCE REGION

Large natural lakes are not a prominent feature of this WRR, largely because the area has not been glaciated (Strahler and Strahler 1976). Several impoundments occur in the area, however, and oxbow lakes, coastal lakes, and small ponds are common. In general, these waters are moderately hard and highly productive (Moore 1966). Many support active warmwater fisheries [the region has 0.62×10^6 ha (1.52×10^6 acres) of fishable freshwater], although the shallower ponds and lakes often suffer from deoxygenation with resultant frequent fish kills (Geraghty et al. 1973). Cultural eutrophication of these waters is a serious problem affecting the biota; the major nutrient additions come from fertilizer runoff and municipal wastes (Moore 1966). A biotic problem particularly acute in the extreme southern United States and greatly affecting this region is the introduction and success of exotic species, many of which are of tropical origin. The water hyacinth, for example, has virtually overgrown many of the smaller benthic environments, causing considerable habitat alteration. Dense mats of this species cause subsurface deoxygenation and dense shading, resulting in the degradation of the natural communities (Moore 1966).

Marsh and swamp lands are locally abundant in the lower Mississippi basin, particularly near the coastal mouths of rivers (Geraghty et al. 1973). Many of these have alternate freshwater–brackish-water infusions, and the biota of the most seaward ones is very euryhaline (Reid 1961). Despite these stressful conditions, these habitats are highly productive; many serve as important nursery and spawning grounds for coastal marine organisms (Macan 1974). Thus, their ecological integrity is highly important to the region. Some of the inland wetlands are dystrophic and resemble northern bogs in their chemical makeup and low productivity (Moore 1966).

Although several large rivers exist in this WRR, the Mississippi is the most conspicuous one by far. In many respects its biota is much the same here as it is in the lower reaches of the Upper Mississippi WRR (Sec. F.8) (Moore 1966). Although its volume increases markedly along its length, velocities are roughly the same as those encountered in southern Illinois because the elevational gradient from the Twin Cities to the Gulf of Mexico is slight (Strahler and Strahler 1976). Deoxygenation problems become greater along its course, however, due to additional inputs of sewage, fertilizer, etc. Similarly, heavy metal and pesticide accumulation in organisms generally increases downstream (Moore 1966). The higher silt load (largely from erosion) carried by the river in its lower reaches inhibits plankton production in some of the impounded areas, but a greater proportion of productive backwater areas makes up for this loss. Fish are locally abundant, especially near backwater areas, and sport fishing is common (Moore 1966).

I.10 TEXAS-GULF, RIO GRANDE, AND LOWER COLORADO WATER RESOURCE REGIONS

The southwestern portion of the United States contains a variety of limnological features, but few of them have been studied extensively (Cole 1966). The eastern portion of the area composed of these three water resource regions is characterized by relatively high rainfall and low evaporation; in general, the aridity increases westward as do water hardness and total dissolved solids (Strahler and Strahler 1976). In eastern Texas, bog remnants occur that are similar in several respects to their northern counterparts. Mountainous areas within these regions likewise contain occasional bogs where rainfall is sufficient and drainage is impeded (Cole 1966).

Reservoirs are a conspicuous aquatic resource in these regions. Most have highly variable physicochemical conditions, because of the variability of precipitation. In general, they are warm, monomictic water bodies with relatively high Na^+, Cl^-, SO_4^{2-}, and Ca^{2+} levels (Harris and Silbey 1940). The plankton is generally scant, although dinoflagellate or blue-green algal blooms sometimes occur in late summer. *Daphnia* is usually the most common cladoceran, and warm-water fish (e.g., centrarchids, shad, carp) are prevalent. Trout are frequently found in tail-race waters. Macrophytes are poorly developed, largely because of the fluctuating water levels, and benthic standing crops generally contain less than 100 organisms per square meter (Cole 1966).

Natural lakes in these regions are relatively scarce (Strahler and Strahler 1976). Solution basins (largely in gypsum deposits) sometimes contain water and often harbor large populations of a few species. Particularly common are *Hyalella azteca* and marginal stands of *Potamogeton* (Cole 1966). Several mountain lakes exist; these are generally dimictic and relatively unproductive. However, many contain sizable trout populations and diverse invertebrate assemblages (Juday 1907). Volcanic lakes occur on the Colorado Plateau that contain a diverse biota, including considerable macrophyte development (Cole 1966). Playas and other ephemeral lakes are common in certain areas and contain a specialized biota highly resistant to dessication. Algae and zooplankton are seasonally numerous in these, as are some aquatic insect larvae (Macan 1974; Reid 1961).

Springs occur throughout these regions. Most are very high in dissolved solids and contain little plankton (due to the flow rates). Mats of filamentous green algae are common, however, and ostracods, snails, and fly larvae are prevalent. Many of these springs contain a highly endemic fauna; several of their fish, in particular, are on endangered species lists (Cole 1966).

Several large rivers occur in these water resource regions. Those in eastern Texas are the lowest in dissolved solids and are more typical of rivers in Louisiana than of those farther west (Cole 1966). Coastal bays, estuaries, and swamps in Texas are also much like those in the Lower Mississippi WRR. The rivers in the more arid areas of the Southwest contain high dissolved solids levels and high turbidities. Benthic organisms are largely restricted to peripheral areas where scouring is not excessive; most fish spawning and plankton production also occur in these areas. The sport fishery of these rivers is substantial and is dominated by warmwater species, except in tailrace areas and mountainous tributaries (Minckley 1973).

Extensive irrigation canals occur in the Southwest. Most ditches that return water from the fields have increased salinities from evaporation and soil salt solubilization (Strahler and Strahler 1976). Although these can support a diverse freshwater biota, including a productive warmwater fishery, some of the more saline ditches develop substantial populations of euryhaline algae and other brackish-water species (Reid 1961; Minckley 1973).

Anthropogenic (man-made) disturbances have greatly altered the aquatic habitats of this region. Eutrophication of surface waters from fertilizer and feedlot runoff has been acute (Geraghty et al. 1973). Salinity increases caused by agricultural operations have modified biotic communities, and pesticide additions have caused bioaccumulation problems and direct toxicities (Cole 1966). Probably the greatest impact on biota has resulted from the extensive damming of the rivers, causing altered flow characteristics that favor species preferring slower velocities. As a result, several endemic species inhabiting these rivers have experienced declining populations (Minckley 1973). Numerous exotic species have been introduced into waters in the Southwest, many of which have become well established, at the expense of the indigenous biota (Minckley 1973).

I.11 ARKANSAS—WHITE—RED WATER RESOURCE REGION

Although few natural lakes exist in this region, it contains a diversity of aquatic habitats. As in those regions described in Section F.10, aridity, hardness, total dissolved solids, and turbidity generally increase to the west.

The eastern portion of the region contains the Ozark highlands where numerous small streams exist that arise from the uplands as runoff or artesian spring discharge (Carlander et al. 1966). These are typically clear, cool, and relatively swift and contain biota similar to that found in more northern trout streams (Hynes 1972).

The streams to the west that drain the prairie areas are markedly different. These are characterized by high turbidities, highly fluctuating flows, sandy bottoms, and a paucity of biota (Carlander et al. 1966). Several flow only within the sand streambed during the low water months, thus causing fish and other nonburrowing fauna to be stranded in the occasional pools that persist in riverbed depressions. As a result, there has been selective pressure for those organisms able to withstand periodic crowding and low oxygen levels (Carlander et al. 1966). Even so, numerous fish die each year in these pools, and virtually no sport fishery exists in those rivers subject to extreme seasonal drawdown. Because of the unstable substrate, few benthic organisms exist. The high turbidities limit the development of primary producers, although diatoms become abundant in the wet sand during drawdown (Carlander et al. 1966).

Most of the larger rivers of the region originate in the mountains to the west and have somewhat more stable flow regimes (Strahler and Strahler 1976). Many of these are now heavily impounded and regulated (Geraghty et al. 1973). Nevertheless, substantial reservoir level variations are common. These variations have limited the ability of macrophytes to establish themselves in such lakes and have hampered the spawning success of shallow-water nest builders, such as centrarchids (Carlander et al. 1966). The new reservoirs nonetheless tend to be highly productive and provide a good warmwater fishery for the first few years of their existence (Macan 1974; Patriarche and Campbell 1958). After five years or so, however, several species tend to become overabundant, the growth rates slow, and fishing success drops off unless stringent management efforts are maintained.

Although a few natural lakes exist in the region, numerous farm ponds have been constructed, particularly in Oklahoma. These ponds tend to be very eutrophic and often harbor large algal standing crops, including toxic blue-greens. Bass, bluegill, and bullheads are often abundant in these ponds, although winter deoxygenation with resultant fish kills is common (Carlander et al. 1966).

Silt pollution is perhaps the greatest problem affecting the aquatic biota in this region. Although silt additions to waterways occur as a natural phenomenon in waters that drain the fine prairie soils, agriculture and construction have greatly exacerbated the condition (Geraghty et al. 1973; Carlander et al. 1966). The main effects are decreased photosynthesis and production by the primary producers (with effects on the entire food chain), gill clogging of fishes, smothering of benthic organisms, and decreased feeding and reproductive ability for several of the fish species (Hynes 1971; Hynes 1972). Fertilizer runoff has contributed to eutrophication problems, particularly in the reservoirs and small ponds, and pesticide additions have caused excessive accumulations in some riverine fish (Carlander et al. 1966). Heavy use of the river waters for irrigation in the western portion of this region has caused increased dissolved solids concentrations, which in some cases have changed the natural biota to a more euryhaline assemblage (Sec. F.10) (Minckley 1973).

I.12 MISSOURI BASIN WATER RESOURCE REGION

Although this region is the largest in the country, it contains comparatively few natural lakes. Rivers, however, are a conspicuous aquatic resource, and most of the Missouri River is contained within this WRR.

The headwaters of the Missouri River in the mountains of Montana are quite different in character than the downstream waters. Near its origin the river flows over a substrate of rock and gravel and a typical trout stream biota exists (Hynes 1972). However, most of the river lies within the Great Plains and Central Lowland provinces where the water is silt-laden, the substrate consists of soft sediments, and the biota is impoverished (U.S. Nuclear Regulatory Commission 1977).

The river has been greatly altered by human activity. Channelization and damming, for example, have greatly reduced the average surface area and have created stronger currents (with resultant bottom scour) and greater siltation and turbidity than existed a century ago (U.S. Nuclear Regulatory Commission 1977). Although the water is moderately hard to hard and nutrient levels are generally high, the river is relatively unproductive, largely because of the lack of favorable habitats (U.S. Nuclear Regulatory Commission 1977). The phytoplankton is dominated by diatoms and greens; average densities are on the order of 10^7–10^8 cells per cubic meter. The development of greater densities is impeded by swift flows and high turbidities, and many of the organisms likely represent washout form upstream reservoirs. Copepods and rotifers dominate the zooplankton, but total numbers are low. The macroinvertebrates in the drift and in benthic areas primarily consist of caddis fly larvae, mayfly larvae, and midgefly larvae (U.S. Nuclear Regulatory Commission 1977). Channel catfish, buffalo fish, and carp are actively fished commercially. The most abundant fish species present include carp, freshwater drum, grizzard shad, river carpsucker, shortnose gar, paddlefish, crappies, and shiners (U.S. Nuclear Regulatory Commission 1977).

Many of the same organisms exist in the impounded areas of the river, but the current velocities and turbidities are lower, thus permitting the development of a more biologically productive system (Hynes 1972). Likewise, peripheral areas in these reservoirs provide some spawning habitat for other warmwater fishes, such as centrarchids. In areas where nutrient inputs are large, substantial blue-green algal blooms can develop (Pennak 1949).

The smaller prairie streams within this WRR are similar to those in the Arkansas–White–Red WRR (Sec. F.11) and the small prairie lakes are like those in the Souris–Red–Rainy WRR (Sec. F.7).

The extreme western portion of this region contains high altitude areas with mountain streams and lakes. These are described in Sections F.10 and F.13.

In addition to stream alteration via damming and channelization, major anthropogenic disturbances that have disrupted the natural biota in this region include siltation, pesticide and fertilizer inputs from agricultural operations, and municipal waste additions. In static, nonturbid water, excessive eutrophication effects are common, because of high nutrient inputs (Carlander et al. 1966). Several polluted farm ponds and natural waters have been responsible for the deaths of wildlife and livestock when blooms of toxic blue-green algae developed (Hynes 1971). Mine drainage effects (particularly from coal strip mining) occur and are severe in some areas; however, the aridity of the areas in which mining takes place limits runoff (Hynes 1972; Carlander et al. 1966).

I.13 UPPER COLORADO, GREAT BASIN, AND CALIFORNIA WATER RESOURCE REGIONS

These water resource regions are treated together in this section because they share many of the same habitat types. Prominent physiographic features that largely determine the occurrence of particular habitats in this area include mountains, plateaus, and low, arid basins.

Mountainous areas within these regions contain hundreds of small natural lakes. Many of these have a constant flow of water through them whereas others lack any permanent outflow. The former types generally display very low productivities, but the latter ones are frequently moderately productive, because of the buildup of nutrients that gradually occurs in the closed basins (Juday 1907). Those lakes found at the highest altitudes are designated alpine lakes; they usually occur in rock and gravel basins and have high inflow and outflow rates. The biota of these lakes is typically depauperate because of the combination of a number of stresses imposed on the system, that is, long periods of time with ice cover, the addition of glacial "milk," and low temperatures (Pennak 1966). The phytoplankton densities are commonly less than 100,000 per liter, and the benthos generally consists of a sparse assemblage of dipteran larvae and little else. Fish are often absent from these lakes, but endemic copepod species are common (Pennak 1966).

Montane lakes occur at lower altitudes and are generally more fertile. The benthos is often very diverse, and rooted aquatic plants are common. Blue-green algal blooms and summer bottom oxygen depletion occur in the more eutrophic lakes. These water bodies are commonly found in spruce-fir forests or alpine meadows (Pennak 1966).

Few lakes occur in the foothills region of the mountains, but many of the larger streams have been dammed to create reservoirs. In general, these impoundments resemble those described in Section F.10 (Pennak 1949).

The more arid portions of these water resource regions contain numerous saline lakes and playas. The saline lakes lack a diverse biota but typically contain large standing crops of a few species. Particularly common are the brine shrimp (*Artemia salina*) and the algae *Stichococcus bacillaris* and *Dunaliella* sp. (Edmonson 1966). The Salton Sea, a large saline lake that receives considerable fertilizer runoff, periodically contains large densities of diatoms and dinoflagellates, as well as an assemblage of rotifers, copepods, and a few marine species. The benthic invertebrates of these lakes are largely restricted to a few species of dipteran larvae (Edmonson 1966).

The rivers that occur in the more arid portions of this area are similar to those described in Section F.10. Many of the smaller streams are ephemeral and do not support a stable biota (Edmonson 1966).

Increased siltation and turbidity in surface waters caused by land disturbances are major problems in this area. Another factor that has contributed greatly to habitat alteration and destruction is the extensive channelization and impounding that have occurred (Minckley 1973; Edmonson 1966). Parts of the area have experienced extreme eutrophication from fertilizer runoff, and biotic accumulation and/or direct toxic effects of pesticides are persistent problems in agricultural regions (Edmonson 1966).

I.14 PACIFIC NORTHWEST WATER RESOURCE REGION

This WRR contains many of the same habitats described in Section F.13. Much of the area is mountainous, and a great portion of it is arid. The greatest physiographic difference between this area and the preceding region is the occurrence of lower average temperatures.

The upland areas in the Pacific Northwest contain mountain lakes and streams similar to those previously described. Likewise, saline lakes and playas much like those in adjacent water resource regions occur in the more arid areas (Edmonson 1966).

Before being extensively impounded, the principal rivers in the region (e.g., the Snake and Columbia rivers) had characteristics similar to those of the upper Colorado River. That is, currents were swift, and water levels fluctuated greatly. In their original state, these rivers contained few phytoplankton or periphyton, had limited populations of benthic invertebrates (except in the headwaters), and contained large seasonal populations of salmon. Impounding has greatly stabilized flows and has significantly altered the biota. Dense plankton populations now develop in certain portions of the rivers, and the bottom fauna is rich and dense (in several places standing crops are greater than 2500 organisms per square meter). A fishery has developed that is more typical of warm, static waters than cool riverine areas, and the salmon spawning runs have been greatly impeded by the dams (Edmonson 1966).

In the coastal areas the precipitation is considerably greater than in the interior regions and a few soft, oligotrophic lakes occur (Edmonson 1966). Estuaries in this WRR (and along the California coast) serve as important spawning and nursery areas for many marine organisms. However, because of low temperatures and fewer coastal marshes, Pacific coast estuaries are much less productive than those emptying into the Gulf of Mexico (Reid 1961).

Major man-induced changes that have altered the biota in this WRR include channelization and impounding of many of the rivers; the addition of agricultural runoff that has contributed pesticides, nutrients, and salts; and municipal waste discharges that have exacerbated eutrophication (Edmonson 1966). Some areas that were previously severely affected have been at least partially restored. Lake Washington, for example, has experienced a slowing in the rate of eutrophication by extensive lake renewal and waste diversion efforts (Edmonson 1966).

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APPENDIX J. ENDANGERED AND THREATENED TERRESTRIAL AND AQUATIC BIOTA

Table J.1. Federally Designated Endangered and Threatened Terrestrial Flora and Fauna of the Conterminous United States

Species	Distribution	Demand Region	Commonly Associated Plant Communities
Mammals			
Indiana bat, *Myotis sodalis* (E)	Eastern and Midwestern United States	I,II,III,IV V,VI,VII	Deciduous forest
Indiana bat, *Myotis sodalis* (CH)	IL,IN,KY,MO, TN,WV	III,IV,V,VII	Deciduous forest
Eastern cougar, *Felis concolor cougar* (E)	Eastern United States	I,II,III,IV, V,VI	Swamps, forestland, rugged mountain areas
Columbian white-tailed deer, *Odocoileus virginianus leucurus* (E)	CR,WA	X	Dense forest, brushy areas
Key deer, *Odocoileus virginianus clavium* (E)	FL	IV	Tropical hardwood hammocks
Black-footed ferret, *Mustela nigripes* (E)	MT,ND,SD,WY, CO,NM,OK,NB, KS	VI,VII,VIII	Short-, midgrass prairie
San Joaquin kit fox, *Vulpes macrotis mutica* (E)	CA	IX	Arid desert areas
Salt-marsh harvest mouse, *Reithrodontomys raviventris* (E)	CA	IX	Coastal salt-marsh areas
Florida panther, *Felis concolor coryi* (E)	FL	IV	Swamps, forestlands
Utah prairie dog, *Cyonmys parvidens* (E)	UT	VIII	Short-grass prairie
Sonoran pronghorn, *Antilocapra americana sonoriensis* (E)	AZ	IX	Prairie, sagebrush plains
Morro Bay kangaroo rat, *Dipodomys heermanni morroensis* (E,CH)	CA	IX	Sagebrush
Delmarva Peninsula fox squirrel, *Sciurus niger cinereus* (E)	MD	III	Deciduous forest
Gray wolf, *canis lupus* (E)	AZ,ID,MI,MT,NM ND,OR,WI,WY, TX,WA	V,VI,VIII,X	Wilderness forest, tundra
Gray wolf, *Canis lupus* (T,CH)	MN	V	Wilderness forest, tundra
Red wolf, *Canis rufus* (E)	TX,LA	VI	Brushy and forested areas
Birds			
Masked bobwhite, *Colinus virginianus ridgewayi* (E)	AZ,NM	VI,IX	Grasslands, shrubs
California condor, *Gymnogyps californianus* (E)	CA	IX	Cliffs, mountain areas

Table J.1. (continued)

Species	Distribution	Demand Region	Commonly Associated Plant Communities
	Birds		
Mississippi sandhill crane, *Grus canadensis pulla* (E,CH)	MS	IV	Fields, marshes, open pinelands
Whooping crane, *Grus americana* (E,CH)	TX,ID,NM,OK, KS,NB,CO	VI,VII, VIII,X	Freshwater bogs, coasts, prairies
Eskimo curlew, *Numenius borealis* (E)	TX,NJ,SC	II,IV,VI	Grasslands, eastern marshes
Bald eagle, *Haliaeetus leucocephalus* (E)	48 conterminous United States (except below)		Forestlands, shores, etc.
Bald eagle, *Haliaeetus leucocephalus* (T)	WA,OR,MN,WI MI	V,X	Forestlands, shores, etc.
American peregrine falcon, *Falco peregrinus anatum* (E)	Western United States	VIII,IX,X	Coasts, mountains, woods
Arctic peregrine falcon, *Falco peregrinus tundrius* (E)	Eastern and Central United States	I,II,III, IV,V,VI, VII	Forestlands and tundra
Aleutian Canada goose, *Branta canadensis leucopareia* (E)	CA,OR,WA	IX,X	Marsh area
Florida Everglade kite, *Rosthrhamus sociabilis plumbeus* (E,CH)	FL	IV	Freshwater marsh areas
Thick-billed parrot, *Phynchopsitta pachyrhyncha* (E)	AZ,NM	VI,IX	Coniferous forest
Attwater's greater prairie chicken, *Tympanuchus cupido attwateri* (E)	TX	VI	Mid- and tall-grass prairies
California clapper rail, *Rallus longirostris obsoletus* (E)	CA	IX	Coastal salt-water marshes
Yuma clapper rail, *Rallus longirostris yumanensis* (E)	AZ,CA	IX	Coastal salt-water marshes
San Clemente loggerhead shrike, *Lanius ludovicianus mearnsi* (E)	CA	IX	Shrub community
Cape sable sparrow, *Ammospiza mirabilis* (E,CH)	FL	IV	Brackish marshes
Dusky seaside sparrow, *Ammospiza nigrescens* (E,CH)	FL	IV	Short-grass tidal marshes
San Clemente sage sparrow, *Amphispiza belli clementae* (T)	CA	IX	Sage-scrub community
Santa Barbara song sparrow, *Meolspira melodia graminis* (E)	CA	IX	Coastal sage community
California least tern, *Sterna albifrons browni* (E)	CA	IX	Coastal beaches
Bachman's warbler, *Vermivora bachmanii* (E)	VA,SC,AL,MO, AR,KY,FL	III,IV,VI, VIII	Deciduous forest
Kirtland's warbler, *Dendroica kirtlandii* (E)	MI	V	Tracts of jackpine, deep forests
American ivory-billed woodpecker, *Campehilus p. principalis* (E)	TX, Southeastern and South Central United States	IV,V,VI, VIII	Southeastern deciduous forests
Red-cockaded woodpecker, *Dendrocopos borealis* (E)	OK,AR,KY,VA, TX,LA,MS,AL,GA, NC,SC,TN,FL	IV,VI,III	Southeastern pine forests

Table J.1. (continued)

Species	Distribution	Demand Region	Commonly Associated Plant Communities
Reptiles			
American alligator, *Alligator mississippiensis* (E)	Southeastern United States (except below)	IV,VI	Great river swampy bayous, marshes
American alligator, *Alligator mississippiensis* (T)	FL, certain areas of CA,LA,SC,TX	IV,VI	Great river swamps, bayous, marshes
American crocodile, *Crocodylus acutus* (E)	FL	IV	Salt or brackish waters
Blunt-nosed leopard lizard, *Crotaphytus silus* (E)	CA	IX	Arid and semi-arid plains
Island night lizard, *Klauberina riversiania* (T)	CA	IX	Grasslands, rocky beaches
Atlantic salt marsh snake, *Nerodia fasciata taeniata* (T)	FL	IV	Gulf coastal salt beaches
Eastern indigo snake, *Drymarchon corais couperi* (T)	FL,GA,MS,SC, AL	IV	Unsettled areas of dense vegetation
San Francisco garter snake, *Thamnophis sirtalis tetrataenia* (E)	CA	IX	Ponds, marshes, woods
Amphibians			
Pine barrens tree frog, *Hyla andersonii* (E,CH)	FL	IV	Swamps, bogs
Desert slender salamander, *Batrachoseps aridus* (E)	CA	IX	Desert plains
Red hills salamander, *Phaeognathus hubrichti* (T)	AL	IV	Cool, moist, forested ravine
Santa Cruz long-toed salamander, *Ambystoma macrodactylum croceum* (E)	CA	IX	Coastal chaparral
Texas blind salamander, *Typhlomolge rathbuni* (E)	TX	VI	Cave waters
Houston toad, *Bufo houstonensis* (E,CH)	TX	VI	Gulf coastal prairies
Insects			
Bahama swallowtail butterfly, *Papilio andraemon bonhotei* (T)	FL	IV	Hardwood hammock community
El Segundo blue butterfly, *Shijimiaeoides battoidos silyni* (E)	CA	IX	Coastal stand community
Lange's metalmark butterfly, *Apodemia moro langei* (E)	CA	IX	Woody shrubs around sand dune community
Lotis blue butterfly, *Lycaeides argyrognomon lotis* (E)	CA	IX	Stagnant bogs
Mission blue butterfly, *Icaricia icarioides missionensis* (E)	CA	IX	Coastal sage-scrub community
San Bruno elfin butterfly, *Callophrys mossii bayensis* (E)	CA	IX	Coastal sage-scrub community
Schaus swallowtail butterfly, *Papilio aristodemus ponocanus* (T)	FL	IV	Hardwood hemmock community
Smith's blue butterfly, *Shijimiaeoides enoptes smithi* (E)	CA	IX	Coastal sand dunes, rocky coastal bluffs

Table J.1. (continued)

Species	Distribution	Demand Region	Commonly Associated Plant Communities
Land Snails			
Chittenango ovate amber snail, *Succinea chittenangoensis New York* (T)	NY	II	Spray zone, talus, and rocks under Chittenago Falls in Madison County
Flat-spired three-toothed snail, *Triodopsis platysayoides* (T)	WV	III	Isolated patches of undisturbed litter and sheltered re-treats among rocks
Iowa Pleistocene snail, *Discus macclintocki* (E)	IA	VII	Cave mouths in small area of Copper's Rock, Monongahela County
Noonday snail, *Mesodon clarki nanthahala* (T)	NC	IV	Occurs only in Nantahala Gorge
Painted snake coiled forest snail, *Anguispira picta* (T)	TN	IV	Requires good cover
Stock Island tree snail, *Orthalicus reses* (T)	FL	IV	Stock Island natural habitat
Virginia fringed mountain snail, *Polygyriscus virginianus* (E)	VA	III	Rockslide habitat
Plants			
Virginia round-leaf birch, *Betula uber* (E)	VA	III	Along Cressy Creek in Smyth County
San Clemente broom, *Lotus scoparius* (E)	CA	IX	Coastal sage, scrub, chaparral and coastal strand
San Clemente Island bushmallow, *Malacothamnus elementinus* (E)	CA	IX	Rocky canyon walls, coastal sage scrub
Antioch Dunes evening-primrose, *Oenothera deltoides* (E)	CA	IX	Endemic to Antioch Dunes community in Contra Costa County
Eureka evening-primrose, *Oenothera avita* (E)	CA	IX	Restricted to base of Eureka Dunes Com-munity in Inyo County
Eureka dune grass, *Swallenia alexandrae* (E)	CA	IX	Restricted to base of Eureka Dunes Com-munity in Inyo County
San Clemente Island indian paintbrush, *Castilleja grisya* (E)	CA	IX	Bluffs, coastal sage scrub
San Clemente Island larkspur, *Delphinium kinkiense* (E)	CA	IX	Grassy places
Santa Barbara Island liveforever, *Dudleya traskiae* (E)	CA	IX	Endemic to Santa Barbara Island Community
Furbish lousewort, *Pedicularis furbishiae* (E)	ME	I	Endemic to St. John River Valley Community
Rydberg milk-vetch, *Astragalus perianus* (T)	UT	VIII	Mountainous terrain at Fish Lake and Dixie National Forest
Northern wild monkshood, *Aconitum noveboracense* (T)	IA,NY,OH,WI	II,V,VII	Restricted to moist soil pockets at bot-tom of sandstone or limestone cliffs

Table J.1. (continued)

Species	Distribution	Demand Region	Commonly Associated Plant Communities
	Plants		
Hairy rattleweed, *Baptisia arachnifera* (E)	GA	IV	Low sandy ridges in open pine woods
Persistent trillium, *Trillium persistens* (E)	GA,SC	IV	Most individual plants in Tallulah Gorge and surrounding ravines
Contra Costa wallflower, *Erysimum capitatum* (E)	CA	IX	Endemic to Antioch Dunes Community in Contra Costa County
Texas wild-rice, *Zizania texana* (E)	TX	VI	Within aquatic community only from upper San Marcos River

From Jorgensen and Sharp (1971), U.S. Department of the Interior (1973), and U.S. Fish and Wildlife Service (1975-1978).

[a]The letters E, T, and CH (in parentheses following the species name) indicate whether the species is considered endangered or threatened and whether critical habitat has been designated for the species.

Table J.2. Federally Designated Endangered and Threatened Aquatic Fauna of the Conterminous United States[a]

Species	Distribution	Demand Region	Water Resource Region
Fish			
Pahranagat bonytail, *Gila robusta jordani* (E)	NV	IX	Great Basin
Alabama cavefish, *Speoplatyrhinus poulsoni* (T,CH)	AL	IV	Tennessee
Humpback chub, *Gila cypha* (E)	AZ,UT,WY	VIII,IX	Lower Colorado, Upper Colorado
Mohave chub, *Gila mohavensis* (E)	CA	IX	California, Great Basin
Slender chub, *Hybopsis cahni* (T,CH)	TN,VA	III,IV	Tennessee
Spotfin chub, *Hybopsis monacha* (T,CH)	VA,TN,NC	III,IV	Tennessee
Longjaw cisco, *Coregonus alpenae* (E)	Lakes Michigan, Huron, and Erie	II,III,V	Great Lakes
Cui-ui, *Chasmistes cujus* (E)	NV	IX	Great Basin
Kendall Warm Springs dace, *Rhinichthys osculus thermalis* (E)	WY	VIII	Upper Colorado
Moapa dace, *Moapa coriacea* (E)	NV	IX	Lower Colorado
Bayou darter, *Etheostoma rubrum* (T)	MS	IV	Lower Mississippi
Fountain darter, *Etheostoma fonticola* (E)	TX	VI	Texas Gulf
Leopard darter, *Percina pantherina* (T,CH)	OK,AR	VI	Arkansas-White-Red
Maryland darter, *Etheostoma sellare* (E)	MD	III	Mid-Atlantic
Okaloosa darter, *Etheostoma okaloosae* (E)	FL	IV	South Atlantic—Gulf
Slackwater darter, *Etheostoma boschungi* (T,CH)	AL,TN	IV	Tennessee
Snail darter, *Percina tanasi* (E,CH)	TN	IV	Tennessee
Watercress darter, *Etheostoma nuchale* (E)	AL	IV	South Atlantic—Gulf
Big Bend gambusia, *Gambusia gaigei* (E)	TX	VI	Rio Grande
Clear Creek gambusia, *Gambusia heterochir* (E)	TX	VI	Texas Gulf
Pecos gambusia, *Gambusia nobilis* (E)	TX	VI	Rio Grande
Pahrump killifish, *Empetrichthys latos* (E)	NV	IX	Great Basin
Scioto madtom, *Noturus trautmani* (E)	OH	V	Ohio
Yellowfin madtom, *Noturus flavipinnis* (T,CH)	TN,VA	III,IV	Tennessee
Blue pike, *Stizostedion vitreum glaucum* (E)	Lakes Erie and Ontario	II,III,V	Great Lakes
Comanche Springs pupfish, *Cyprinodon elegans* (E)	TX	VI	Rio Grande
Devil's Hole pupfish, *Cyprinodon diabolis* (E)	NV	IX	Great Basin
Owen's River pupfish, *Cyprinodon radiosus* (E)	CA	IX	California, Great Basin
Tecopa pupfish, *Cyprinodon nevadensis calidae* (E)	CA	IX	Great Basin
Warm Springs pupfish, *Cyprinodon nevadensis pectoralis* (E)	NV	IX	Great Basin
Colorado River squawfish, *Ptychocheilus lucius* (E)	AZ,CA,CO,NM,UT WY	VI,VIII,IX	Upper Colorado, Lower Colorado
Unarmored threespine stickleback, *Gasterosteus aculeatus williamsoni* (E)	CA	IX	California

Table J.2. (continued)

Species	Distribution	Demand Region	Water Resource Region
	Fish		
Shortnose sturgeon, *Acipenser brevirostrum* (E)	Atlantic coast	II,IV	Mid-Atlantic, South Atlantic—Gulf
Gila topminnow, *Poeciliopsis occidentalis* (E)	AZ	IX	Lower Colorado
Arizona trout, *Salmo apache* (T)	AZ	IX	Lower Colorado
Gila trout, *Salmo gilae* (E)	NM	VI	Lower Colorado
Greenback cutthroat trout, *Salmo clarki stomias* (T)	CO	VIII	Missouri Basin, Arkansas—White—Red
Lahontan cutthroat trout, *Salmo clarki henshawi* (T)	CA,NV	IX	Great Basin
Little Kern golden trout, *Salmo aquabonita whitei* (T,CH)	CA	IX	California
Paiute cutthroat trout, *Salmo clarki seleniris* (E)	CA	IX	California, Great Basin
Woundfin, *Plagopterus argentissimus* (E)	AZ,NV,UT	VIII,IX	Lower Colorado
	Clams		
Alabama lamp pearly mussel, *Lampsilis virescens* (E)	AL	IV	Tennessee
Appalachian monkeyface pearly mussel, *Quadrula sparsa* (E)	VA,TN	III,IV	Tennessee
Birdwing pearly mussel, *Conradilla caelata* (E)	VA,TN	III,IV	Tennessee
Cumberland bean pearly mussel, *Villosa trabilis* (E)	KY	IV	Ohio
Cumberland monkeyface pearly mussel, *Quadrula intermedia* (E)	VA,TN	III,IV	Tennessee
Curtis' pearly mussel, *Dysnomia florentina curtisi* (E)	MO	VII	Arkansas-White-Red
Dromedary pearly mussel, *Dromus dromas* (E)	VA,TN	III,IV	Tennessee
Fat pocketbook pearly mussel, *Potamilus capax* (E)	AR,MO	VI,VII	Arkansas-White-Red, Lower Mississippi
Finerayed pigtoe pearly mussel, *Fusconaia cuneolus* (E)	AL,VA,TN	III,IV	Tennessee
Greenblossom pearly mussel, *Dysnomia torulosa gubernaculum* (E)	VA,TN	III,IV	Tennessee
Higgins' eye pearly mussel, *Lampsilis higginsi* (E)	MN,WI,IL,MO	V,VII	Upper Mississippi
Pale lilliput pearly mussel, *Toxolasma cylindrella* (E)	AL,TN	IV	Tennessee
Pink mucket pearly mussel, *Lampsilis orbiculata orbiculata* (E)	AL,WV,TN,KY	III,IV	Tennessee, Ohio
Rough pigtoe pearly mussel, *Pleurobema plenum* (E)	KY,VA,TN	III,IV	Tennessee, Ohio
Sampson's pearly mussel, *Dysnomia sampsoni* (E)	IN,IL	V	Ohio
Shiny pigtoe pearly mussel, *Fusconaia edgariana* (E)	AL,VA,TN	III,IV	Tennessee

Table J.2. (continued)

Species	Distribution	Demand Region	Water Resource Region
	Clams		
Tan riffle-shell mussel, *Epioblasma walkeri* (E)	VA,TN,KY	III,IV	Tennessee, Ohio
Tuberculed-blossom pearly mussel, *Dysnomia torulosa torulosa* (E)	KY,IL,TN,WV	III,IV,V	Ohio, Tennessee
Turgid-blossom pearly mussel, *Dysnomia turgidula* (E)	TN	IV	Tennessee
White cat's paw pearly mussel, *Dysnomia sulcata delicata* (including *D.s. perobliqua*) (E)	OH,MI,IN	V	Great Lakes
White warty-back pearly mussel, *Plethobasus cicatricosus* (E)	AL,TN	IV	Tennessee
Yellow-blossom pearly mussel, *Dysnomia florentina florentina* (E)	TN	IV	Tennessee
Orange-footed pimpleback, *Plethobasus cooperianus* (E)	AL,TN	IV	Tennessee
	Mammals		
Florida Manatee, *Trichechus manatus latirostris* (E,CH)	FL	IV	South Atlantic—Gulf
	Crustaceans		
Socorro Isopod, *Exophaeroma thermophilus*	NM	VI	Rio Grande

From Jorgensen and Sharp (1971), U.S. Department of the Interior (1973), and U.S. Fish and Wildlife Service (1975-1978).

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APPENDIX K. SOCIOECONOMIC IMPACTS OF MINING

Coal conversion is expected to increase the demand for coal in Western Plains and Texas and the increased coal mining may result in social and economic changes in local areas. Furthermore, mining is likely to result in distinctive regional impacts because of the following factors: (1) population size and density, (2) environmental setting, (3) socio-cultural background of communities affected by mining, (4) economic history, and (5) job opportunity and employment. Given these five factors, the strongest contrasts among federal regions is believed to exist between the coal-bearing areas of Appalachia and the Western Plains. The Texas lignite area may also represent a regional variation.

So that some of the major regional issues could be identified, the Appalachian and Western regions were more intensively reviewed. Impacts expected in the Texas area may include those listed for both regions; however, it is presently thought that potential impacts in Texas will more closely reflect those identified for the western regions. This similarly is proposed on the basis of settlement pattern and historic emphasis on a range-oriented economy.

K.1 CENTRAL APPALACHIA

Central Appalachia contains rich bituminous coal deposits which were developed in the early 20th century. Coal mining, in addition to forestry and subsistence agriculture, has become part of the traditional economic base for this area; however, regional employment tends to be concentrated in the coal industry, making local employment patterns sharply sensitive to national coal demand (Anonymous 1974a). This factor has contributed to the establishment of a unique socio-cultural setting. The topography has resulted in a scattered population, producing transportation and social service problems and limiting growth in the area (Anonymous 1974a,b; McFarland-Johnson Engineers, Inc., 1976). The cultural patterns of the area have a strong kinship base and a way of life emphasizing self-sufficiency and unity of people with a similar background (Anonymous 1974a,b; Shackelford and Weinberg 1977). The coal companies directly or indirectly control the land use of extensive areas in some counties (McFarland-Johnson Engineers, Inc., 1976). It is expected that community structure and function has remained traditional and informal, particularly in the more isolated areas.

Unlike the west, larger local populations and numbers of unemployed in the Appalachian region would mean that the work force can be recruited within the region. Case studies of new mines in selected Appalachian counties have shown that large in-migrations are not expected (Dixon-Davis et al. 1977; Stenehjem and Metzger 1977). Benefits such as steadier revenues, increased income and employment, recruitment of young people, and return of local out-migrants may occur in certain counties (McFarland-Johnson Engineers, Inc., 1976; Gould 1978. Some benefits, such as increased income and revenues, would be comparable to those expected in the western regions.

Housing for miners is a major problem which is expected to continue (Spence and Tuck 1976; McFarland-Johnson Engineers, Inc., 1976). Moreover, poor schools, inadequate health care, and strip mine damage to potential recreational areas remain a characteristic problem in parts of this region (Gould 1978; McFarland-Johnson Engineers, Inc., 1976). Other potential impacts are inflation, lifestyle changes, social problems, and clashes with newcomers (McFarland-Johnson Engineers, Inc., 1976).

In addition to these regional problems, there are potential problems associated with the people who have been historically tied to mining. Many miners are unionized. The United Mine Workers Union remains a strong organization, although thre are recognized financial and leadership problems (Gould 1978). Mine productivity is dropping, absenteeism is high, safety stoppages are high, and work days lost to strikes are the highest in American industry. It is possible that extended labor unrest may make it difficult to substantially increase Appalachian coal production (Gould 1978).

As a group, many miners did not choose their occupation and do not want their sons in the mines. Historically, Appalachian miners are considered by some to represent a captive labor force without other viable economic alternatives. In the poorer mining areas, there is an attitude of apathy and resignation where the people have historically perceived themselves as having been exploited by outside economic forces. Mining capital has not been returned to the local area in the form of investment in other industries, nor have employment opportunities diversified.

K.2 THE WESTERN PLAINS

Coal mining on an extensive scale is relatively new to most areas of the west when compared to Appalachia. The major economic activity with the longest traditions and greatest influence is agriculture (U.S. Department of Commerce 1975). Moreover, much of the land is in the public domain.

Coal development will affect nearly every sector of the region's economic, institutional, and social structure (U.S. Department of Commerce 1975). Population growth associated with this development will be extensive both in terms of magnitude and the speed with which it will occur. Moreover, there are also political impacts associated with a boom and bust cycle (Murphy 1975).

The increase in population--the boom part of the cycle--will create an increased demand for housing and services, whereas the bust part of the cycle will create local problems in maintaining permanent services (i.e., water, sewage systems) expanded during the boom. However, there are other changes that accompany rapid population growth and a community will undergo these changes regardless of how carefully it has planned or how adequately it has been financed (Murphy 1976). In some cases, life in the community changes as rapid growth produces symptoms of urbanization such as a quickened pace of life, congestion, inflation of prices, and scarcity of amenities (U.S. Department of Housing and Urban Development 1976). Particularly important is the consideration of impacts of tensions between long-time residents and newcomers, and the lack of activities for spouses of project workers. Moreover, traditional lifestyles will be disrupted or even disappear (U.S. Comptroller General 1977). Impacts to residents and the cultural traditions represented on Indian reservations must be given detailed study and consideration.

K.3 SAMPLE STUDY

The coal requirements for converted facilities will produce some sociocultural and economic impacts as mining is increased in various federal regions. At the time of writing, data were not available on the specific counties which would contribute coal in each region. Therefore, representative counties were selected for study in order to identify some of the coal mining impacts that might be evident throughout many counties in the region. Selection was also based, in part, on data availability. Although the study counties were believed to have some characteristics thought to be typical for other counties in a region, these are not necessarily the counties that will produce the coal for the converted facilities. The counties selected and their respective regions are as follows: (1) Mingo County, West Virginia (Appalachia), (2) Sweetwater County, Wyoming (Northern Great Plains), and (3) Perry County, Illinois (Midwest).

It is also true that coal production attributable to the regulatory program is expected to be less than 10 percent of the 1985 production in each production region except the Northern Great Plains (Region 8) and Texas (Region 5). In the Northern Great Plains, coal production due to the program is expected to represent a 15 percent increase in total production; in Texas, production will represent a 36 percent increase.

Despite the significant increase in Texas production, Texas was not examined for boom town impacts. Texas currently has only three operating mines (Susskind and O'Hare 1977, p. 41), so direct examination of Texas coal towns to provide evidence of future conditions would not be possible. A second consideration is that the coal required for the program is mainly for industrial boilers, and due to the dispersed location of these boilers, specific identification of new mine locations is purely speculative.

In the following section, each of these study counties is discussed, with emphasis on social service capabilities; the discussion is divided into two parts. The first is a profile of the present county situation under coal mining conditions. In this profile, it was assumed that all or part of the coal now produced would be used for coal conversion and that the impacts which are described are therefore associated with coal conversion. In the second part, the social service and associated cost demands are projected for each county in 1985. Two assumptions were made. First, that coal production steadily increases in each county, requiring 40 to 120 new miners per year, depending on the county, and that all new miners are in-migrants from a nearby county (see Appendix A).

Given the size of the work force, the projections represent conservative worst-case estimates for impacts caused by in-imigrants. The second assumption was that all increases in coal mining will result from demands by newly constructed facilities. However, it is impossible that any one county will be the sole contributor for coal conversion within a region. Therefore, the

1985 service and cost projections will be spread across several of the coal-producing counties in a region.

K.3.1 Mingo County, W. Va., Study (Baseline 1970 to 1976)

K.3.1.1 Demography and Settlement Pattern

Population size in Mingo County has fluctuated since the early 1900s. Because of a decline in coal production from 1950 to 1970, Mingo lost approximately 35 percent of its population. Now, due to the recent emphasis on coal production, the county's population is once again increasing, and as of July 1, 1976, Mingo had 35,500 residents, a gain of approximately 8 percent since 1970. Generally, Mingo has a young population, with about 90 percent of its residents less than 64 years of age (Arnett and Balliet 1978, pp. 4-8).

Within Mingo County, there are five major population clusters--the municipalities of Williamson (population 5,300), Debarton (population 1,000), Kermit (population 960), Matewan (population 920), and Silbert (population 710). During 1970-1975, Williamson and Matewan had a combined loss of population of about 13 percent, while the combined increase of Delbarton, Kermit, and Gilbert was approximately 50 percent. Williamson is the county seat, and commercial and health center (Arnett and Balliet 1978, pp. 5-8).

K.3.1.2 Social Organization

Education

The county has twenty-four grade schools, six high schools, and three junior high schools. The pupil-teacher ratio is approximately 24:1, which is above the national average of 20:1 (Foster 1978). The average per-pupil capital expenditure is about $900 annually, which is below the national average of $1,400 (Arnett Balliet 1978, pp. 26-27).

Sewage and Water

The county is responsible for water and sewage systems in the unincorporated areas. The municipalities own and operate independent systems, all of which are at their capacity levels. Although most of the municipalities have new water systems, sewage systems are still in the planning stages (Arnett and Balliet 1978, pp. 33-36).

Medical, Fire, and Police

Fire protection is provided by each municipality in cooperation with the county, which participates with revenue-sharing funds. A county ambulance is provided, run by a private operator using county-owned equipment. The county also provides a sheriff's department (Arnett and Balliet 1978, pp. 31-33).

Public Health

The county supports a health department which employs two public health employees, two nurses, two clerks, and a custodian. The nurses provide medical services to the various municipalities and schools on a rotating basis. There is one privately owned hospital available to county residents. The only health clinic, a new facility, was destroyed by recent floods but is currently scheduled to be rebuilt. Physician-to-patient ratio in the county was 1:1917 (1974 figures), which is more than double the national average (1:576) (Arnett and Balliet 1978, pp. 36-39; American Medical Association 1977, p. 23).

D.3.1.3 Political Organization

The county is governed by a three-member board of county commissioners who are elected by popular vote. Currently, there is a new county commissioner and a county planner who are in the process of developing a multipurpose center to help provide for more adequate services for the county residents. Other such plans for future development are now being made (Arnett and Balliet 1978, pp. 69-71).

K.3.1.4 Economic Organization

Mingo County's primary industry is coal, ranking twelfth in the state and producing 4 percent (4,434,673 tons) of the state's total production (Arnett and Balliet 1978, pp. 4, 15). Of this 1976 total tonnage, approximately 14 percent (638,147 tons) was from strip mines and the remaining 86 percent (3,796,526 tons) was mined underground (Arnett and Balliet 1978, p. 15).

The county operates on an annual budget of approximately $1 million, with two supplementary sources of money derived from federal revenue-sharing and a coal tax, totaling $.5 million. This revenue, in part, finances many of the services provided by municipalities; however, its primary purpose is to pay for services offered by the county (i.e., sheriff's department, health department, ambulances, county landfill, etc.) (Arnett and Balliet 1978, pp. 31-33).

K.3.1.5 Projected Impacts on Social Service Demands (1985)

Mingo County and its municipalities will have to expand their social services to provide for the incoming miners and service workers and their families by 1985 (see Table K.1). Although it is impossible to predict exactly where the in-migrants will settle in the county, and therefore, what impacts will be generated for each municipality, it is possible to make an estimate of the social service demands placed upon the county by the new in-migrants. Education will create the largest financial impact on Mingo County, costing approximately $9,382,090 to $10,973,875 for school expansion, additional teachers, and maintenance costs. Other expenses the county will incur are an increase in recreational facilities and employment of more deputy sheriffs. Altogether, Mingo's total actual cost over ten years will be approximately $9,724,840 to $11,316,625. These figures may be overestimates of the actual impact costs to the county, since the municipalities and county may share a portion of the expenses.

K.3.2 Sweetwater County, Wyoming, Study (Baseline 1970 to 1976)

K.3.2.1 Demography and Settlement Pattern

Currently, there is a rapid population increase in Sweetwater County due to mining. In 1970, the county's population was 18,391 and has since more than doubled (108 percent) to a population size of 38,310 in 1976 (U.S. Department of Commerce 1976, p. 3; U.S. Department of the Interior 1978, pp. R2-64). The median length of residence in the county is approximately 8.3 years, with nearly one-fourth of the residents having lived there less than one year and approximately 40 percent having arrived since the beginning of the energy development boom in 1970 (Bickert 1974, p. 6). Of the 1976 population, approximately 82 percent are married, with over half of these families having children of school age or younger (Bickert 1974, p. 7).

Within Sweetwater County, about 84 percent of the current population resides in two municipalities--Rock Springs* (population 21,232) and Green River (population 11,000). The remaining population (6,078) resides in either the rural, unincorporated areas or the smaller communities in the county (U.S. Department of the Interior 1978, p. R2-64).

K.3.2.2 Social Organization

Education

The county is divided into two school districts. School District 1 provides services to the city of Rock Springs and its surrounding area, while District 2 serves the community of Green River and the surrounding area. The pupil-teacher ratio for both districts is 20:1, with an average per-pupil capital expenditure of about $1,590, which is below the nation's average of $1,740 (U.S. Department of the Interior 1978, p. R2-64; Foster 1978).**

Currently, District 1 (enrollment 4,574) has some excess classroom space and has hired enough personnel to adequately accommodate about 10 percent more students. Because of a serious need for additional classroom space, District 2 (enrollment 2,872) has added new classrooms to old schools, constructed a high school, and is replacing a temporary elementary school with a permanent structure (U.S. Department of the Interior 1978, p. R2-75).

*About 2 years ago, "60 Minutes" did a story on Rock Springs in regard to its boom in population. Apparently, crime increased rather dramatically.

**For consistency, the per-pupil expenditures for Mingo County were compared to available data (1970).

Table K.1. Predicted Service Demands 1975-1985 in Representative Counties of Demand Regions Most Affected by Conversion to Coal[a]

	Region III Mingo County, West Virginia	Region V Perry County, Illinois	Region VIII Sweetwater County, Wyoming	Comment[b]
Population				Total predicted population to migrate into county over ten-year period (1975-1985).
Married	3770	2150	6450	Includes nonlocal miners and their families and nonlocal secondary workers and their families at 3.7 family members per incoming worker (Charles River Assoc. 1977, pp. 4-28; U.S. Department of Health, Education and Welfare 1976, p. 5).
Single	520	300	900	Includes nonlocal miners and secondary workers who are single, widowed, or divorced (Charles River Assoc. 1977, pp. 4-28; U.S. Department of Health, Education and Welfare 1976, p. 5).
Total	4290	2450	7350	
Education				The range of the figures show the initial cost if all in-migrant pupils were to attend elementary school (low figure) and all attend secondary school (high figure). These figures thus would be inclusive of a division between pupils (e.g. 50 percent to high school, 50 percent to elementary school. It is the staff's opinion that these figures show a reasonable minimum-to-maximum education expenditure the county will be confronted with in the future.
Student	1600	915	2740	
Teacher	85	45	135	Assumes teacher-student ratio of 1:20 (Foster 1978).
Structure	192,000-240,000 ft^2	109,800-137,250 ft^2	328,800-411,000 ft^2	Allows approximately 150 square feet per high school pupil and 120 square feet per elementary pupil (Real Estate Research Corp. 1974, pp. 110-111).
Structural cost	\$6,816,000-8,280,000	\$3,987,900-4,735,125	\$11,672,400-14,179,500	Structural cost (including profit, overhead, and fees) assumes \$34.50 per square foot for high school, and \$35.50 per square foot for elementary school (Real Estate Research Corp. 1974, pp. 110-111).

Table K.1. (continued)

	Region III Mingo County, West Virginia	Region V Perry County, Illinois	Region VIII Sweetwater County, Wyoming	Comment[b]
Education (cont'd)				
Maintenance cost	$27,840,000	$15,921,000	$47,676,000	Teacher, operating, and maintenance assumes estimated annual average cost expenditure per student of $1740 (Foster 1978).
Recreation				Based on 3.5 acres per 1000 people (DeChiara and Koppelman 1975, p. 12-3)
Park	Additional 15.0 acres	Additional 7.5 acres	Additional 25.0 acres	
Development	$153,750	$ 80,000	$250,000	Approximate cost per acre for facilities and development is $10,000 (includes profit, overhead, engineering and design facilities, and site improvement) (Real Estate Research Corp. 1974, p. 109).
Personnel	$100,000	$100,000	$200,000	Assumes one employee per 10-15 acres. Community park acreage determined using 3.5 acres per 1000 inhabitants (DeChiara and Koppelman 1975, p. 12-3).
Operating and Maintenance costs	$ 26,000	$ 26,000	$ 52,000	Operating and maintenance costs assume salary 80 percent of total expenditure: $10,000 Annual salary per employee 2,600 Operating and maintenance cost $12,600 Approximate total expenditure per employee (Real Estate Research Corp. 1974, p. 109).
County sheriff	8 officers $832,320	5 officers $520,000	15 officers $1,560,000	Officer's salaries approximately $10,404 annually. Police needs determined assuming 2.08 officers per 1000 inhabitants (International City Management Assoc. 1978, pp. 147, 149).
Fire protection	Municipally owned and operated (county contributes revenue-sharing funds).	Municipally and county-(through districts) owned and operated.	Municipally owned and operated.	

Table K.1. (continued)

	Region III Mingo County, West Virginia	Region V Perry County, Illinois	Region VIII Sweetwater County, Wyoming	Comment[b]
Sewage and water systems	County responsible for unincorporated areas only. Assessment would be required to determine if systems are adequate for in-migrants.	Municipally owned and operated.	Municipally owned and operated.	
Hospital	No county-owned hospital. One privately owned, which would require expansion of approximately 20 beds to adequately provide for in-migrants.	11 beds $3,564,000	35 beds $11,340,000	Assumes approximately $19,000 per hospital personnel and approximately $13,400 for other expenses. Hospital need determined using 4.5 beds per 1000 inhabitants (Real Estate Research Corp. 1974, p. 130; American Hospital Assoc. 1977, p. vi).
Total cost (actual cost over 10 years)	$35,758,070-37,232,070	$24,108,900-24,946,125	$72,258,100-72,750,500	

[a]All numbers are rounded to the nearest fifth.

[b]All cost estimates were derived using 1977 dollars, which were developed at 7% a year, simple interest, and then rounded to the nearest fifth.

Sewage and Water

Water and sewage systems are all municipally owned and operated. There are currently inadequacies in both systems. The municipalities are aware of these problems and have plans for improvement (U.S. Department of the Interior 1978, p. R2-86).

Social Services, Fire, and Police

Sweetwater County has a welfare office which provides both social services and counseling to its residents. The staff of seventeen helps the residents acquire services through referral, outreach, transportation, escort, nutrition, health, education, and recreation programs. Fire protection is provided by each municipality using the services of both volunteer and paid firemen. The county also provides a county sheriff's department, but has a difficult time attracting and keeping experienced deputies because salaries are not competitive with private employers (U.S. Department of the Interior 1978, pp. R2-80 to 86).

Public Health

The county owns and operates a 97-bed facility, Sweetwater County Memorial Hospital, in Rock Springs. Currently, a new 100-bed hospital is being constructed and this action has received criticism from the county's residents because some believe that it will be too small (U.S. Department of the Interior 1978, pp. R2-75 to 80).

K.3.2.3 Political Organization

The county is governed by a three-member board of county commissioners who are elected by popular vote. There is also a county planner who is hired by the board. Currently, the commissioners and planner are formulating goals for developing more services for the county residents (Bescoe 1978; Watt 1978).

K.3.2.4 Economic Organization

The county's 1977-1978 budget is $12,772,357, which is appropriated by the state. This revenue is used to pay for services offered by the county to its citizenry (i.e. sheriff's department, county library, hospital, recreation, airport, fair, etc.) (Bescoe 1978).

K.3.2.5 Projected Impacts on Social Service Demands (1985)

By 1985, Sweetwater County will experience a rapid increase in the in-migrant mining population, in addition to a tremendous demand for increased social services to its new and old residents. Certain services are provided by the county to its citizenry, and regardless where the in-migrants may settle in the county, the services still must be adequate to meet their needs. Estimated service demands and costs for 1985 are provided in Table K.1. The greatest capital demand for county services will be in education, and will cost $14,823,400 to $17,330,500 over the next ten-year period. Other services that will need to be expanded are recreation, the county sheriff's department, and the hospital. By 1985, the total cost for all services (including education) will be $56,074,400 to $58,581,500.

K.3.3 Perry County, Illinois, Study (Baseline 1970-1975)

K.3.3.1 Demography and Settlement Pattern

Perry County's population was fairly constant from 1910 to 1950. The only major population fluctuation was during the 1950s, when the county's population declined 12 percent due to an out-migration trend of younger people (age 15 to 40). Since then, the median age of the county has increased to 35. As of July 1, 1975, Perry County's population was 20,545, a gain of approximately 3.5 percent over 1970 (Arnett and Balliet 1978, pp. 5-6; U.S. Department of Commerce 1977, p. 38).

There are six major population clusters within Perry County--the municipalities of DuQuoin (population 6,414), Pinckneyville (population 3,300), Tamaroa (population 922), and Willisville (population 788). Cutler, DuQuoin, and Pickneyville had a combined loss of about 10.5 percent, while St. Johns, Tamaroa, and Willisville experienced a combined increase of approximately 40 percent since 1970 (U.S. Department of Commerce 1977, p. 38).

K.3.3.2 Social Organization

Education

The county has ten elementary schools, two junior high schools, and three high schools distributed throughout eight school districts. School costs are financed by the residents through taxes paid to the county, which in turn appropriates that money to the different school districts. The average yearly per pupil capital expenditure is $1,100, which is below the nation's average of $1,740. The pupil-teacher ratio is about 25:1, substantially higher than the nation's average of 20:1. According to the Regional Superintendent for Perry County, the school system would be able to accommodate additional students (McCormick 1978; Millikin 1978; Foster 1978).

Sewage and Water

All sewage and water systems within the county are municipally owned and operated, and are presently providing adequate services for the residents (Millikin 1978).

Medical, Fire, and Police

There are two types of fire protection in the county: municipal (owned and operated by the municipality) and three fire protection districts (owned and operated by the rural area of the county and funded through "fire" taxes). The municipal fire department operates with both an employed staff and volunteers, while the district's departments have only volunteer forces. There are two different ambulance services in the county which are volunteer and privately owned. The county also provides a sheriff's department. These services are adequate for the county's residents (Millikin 1978).

Public Health

Perry County supports a health department, which is staffed by three nurses who provide home services. There is one privately owned 60-bed hospital and a county-owned 55-bed hospital. Both hospitals and the health services adequately provide for the citizenry (Millikin 1978; American Hospital Association 1975, pp. 79, 83).

K.3.2.3 Political Organization

Perry County is governed by a three-member board of county commissioners who are elected by popular vote. There is no county planner. There is an appointed industrial committee whose function is developing plans to attract new business to the community. The commissioners and industrial committee currently are developing plans (e.g., a new shopping center) to provide more adequate services for the county residents (Millikin 1978).

K.3.2.4 Economic Organization

The county's budget for 1977-1978 is approximately $1,500,000, which is adequate to keep pace with expenditures. This revenue is used solely for county expenses to provide services for residents (i.e., operating the county court clerical offices, road construction and maintenance, general assistance, mental health department, etc.) (Millikin 1978; Arnett and Balliet 1978, p. 7).

K.3.2.5 Impacts on Social Service Demands (1985)

By 1985, the population of Perry County will increase steadily due to the in-migration of new miners, service personnel, and associated families that will in turn create new county service demands (Table D.1). School district enrollments will cause the greatest financial burden to the county, costing the taxpayers $14,000,000 to $15,000,000 for 1985 for school construction, hiring of additional faculty members, and general maintenance costs. The county will also be responsible for hiring additional sheriff's deputies, improving recreational facilities, and expanding the county hospital, at a total cost of about $4,120,000 over the ten-year period. Expansion due to coal development could possibly cost the county's taxpayers a total of more than $18,000,000 by 1985.

K.4 SUMMARY

Current coal production is affecting the social service demands differently in all of the counties studied. In some areas, present demands appear to be met in the counties experiencing the least rapid population growth. Projected service demands and costs are associated with in-migrant miners and costs may place a severe burden on some counties.

It has been generally observed that in boom towns the revenues raised from energy development are available after the boom effects have already occurred (Teter 1978; Gilmore and Duff 1974). Outmigration has occurred in many Appalachian counties. Generally, Appalachia has had less than the national average level of public service delivery and this has occurred despite booms in local production in the past.

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APPENDIX L. ESTIMATION OF SOLID WASTE GENERATION

The worst-case analysis of coal combustion waste was based on the following assumptions:

1. Tons of coal produced taken from Tables 3.7 and 3.8 for 1985 and 1990, respectively.

2. Ash and sulfur percentages of coal derived from information discussed in Section 4.5.

3. It was assumed that essentially all of the ash and 90% of the sulfur is removed as waste.

4. Ash was calculated as 40 lb/ton coal/% ash. This assumes no ash is being released and that the waste that is generated is 50% solids and 50% water.

5. Sulfur waste is calculated as 195 lbs waste/ton coal/% sulfur. This value is in the general range of the value of 180 lb waste/ton coal/% S used elsewhere (Federal Energy Administration 1977), and was derived as follows. A 2% sulfur content yields 267 tons of sludge per MW-yr (731 tons dry sludge per day) (Dvorak et al. 1977). The coal required to produce this amount of sludge is approximately 7479 tons (approximately 9.75% by weight of dry sludge for 2% sulfur coal). At 50% solids/50% water by weight, the value becomes 9.75% by weight of coal at 1% S. This is equivalent to 195 lb of waste per ton coal per % S.

6. Sample calculation

   For coal from Supply Region 1, burned in Demand Region I:

   Ash generated =

   $$1.454 \times 10^6 \text{ tons coal} \times 0.107 \ (\% \text{ ash}) \times 2 = 0.311 \text{ tons of ash waste.}$$

   Sulfur sludge generated =

   $$1.454 \times 10^6 \text{ tons coal} \times \frac{195 \text{ lbs}}{\text{ton coal-\% sulfur}} \times 2.6\% \text{ S} \times \frac{1 \text{ ton}}{2000 \text{ lb S}}$$

   $$= 0.3686 \times 10^6 \text{ ton sludge.}$$

7. Acre-feet sludge

   A range of solid waste densities of 2000-3000 lbs/m^3 (Federal Energy Administration 1977) is used:

   2000 lbs/m^3 = 1233 tons/acre-ft, and

   3000 lbs/m^3 = 1850 tons/acre-ft.

   Sample calculation

   $$\text{Total acre-feet of sludge produced in 1990} = \frac{52.5 \times 10^6 \text{ tons waste}}{1850 \text{ tons/acre-foot}}$$

   $$= 28{,}378.38 \text{ acre-ft.}$$

   If this is disposed of in a waste pond or land fill to a depth of 10 feet, the land required will be 2838 acres.

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APPENDIX M. CREDITS

Argonne National Laboratory gratefully acknowledges the courtesy of the individuals and organizations who granted permission to use illustrations in this document. Sources of these illustrations are listed below.

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