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Final Environmental Impact Statement

COAL LOAN GUARANTEE PROGRAM

(P.L. 94-163)

U.S. Department of Energy

July 1978

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Final Environmental Impact Statement

COAL LOAN GUARANTEE PROGRAM

(P.L. 94-163)

Responsible Official:

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U.S. Department of Energy
Washington, D.C. 20545
July 1978

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PREFACE

This is the Final Environmental Impact Statement (EIS) supporting the Coal Loan Guarantee Program which was authorized under Section 102 of the Energy Policy and Conservation Act (EPCA) of 1975 and amended by Section 164 of the Energy Conservation and Production Act (ECPA) of 1976. This loan guarantee program was created to help small, low sulfur coal producers finance the development of new underground coal mines, the expansion of existing underground coal mines, and the reopening of closed underground coal mines. The Draft EIS originally was prepared by the Federal Energy Administration and was issued in March 1978, by the Department of Energy which has assumed responsibility for developing and administering the program.

Comments concerning the scope and adequacy of the EIS suggested that the geographic area under consideration be expanded from Appalachia to include several western States which have or may develop small, underground, low sulfur coal mines. DOE's analysis indicates that the number of potential program participants in the West is not likely to be large enough to produce significant cumulative impacts on the program-wide level. However, loan guarantees can be issued to qualified western producers under the current EIS, after completion of a site-specific environmental review. If, in the future, DOE should determine that the number of program participants in the West poses potential areawide problems, then a supplemental evaluation will be performed.

In response to other comments on the description of the proposed action and its potential impacts, some changes (discussed in Chapter XI) have been made in the document. None of these comments required major changes in the Draft EIS.

In preparing the Final EIS, the organization of the document was changed pursuant to DOE NEPA guidelines issued since the draft was prepared. As a result, the description of the proposed action and the characterization of the existing environment are presented as separate chapters. In addition, the assumptions used in the analysis and the statement of program purposes have been consolidated from various parts of the Draft EIS and stated more clearly.

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CHAPTER I

SUMMARY

A. Introduction

The Energy Policy and Conservation Act of 1975 (EPCA, PL 94-163) as amended by Section 164 of the Energy Conservation and Production Act of 1976 provides for a coal loan guarantee program to encourage the production of low and high sulfur coal by small underground coal producers.[1/] A loan guarantee ceiling of 750 million dollars has been set -- 80 percent of the loans for any given year are restricted to financing low sulfur coal production (0.6 lbs sulfur/MMBtu or 1.2 lbs SO_2/MMBtu). These funds may be used by small underground coal producers to: 1) open new underground mines and 2) expand or reopen existing underground mines. The funds also may be used for facilities at the mine site, e.g., coal preparation plants. The emissions resulting from the combustion of coal produced at mines financed by the program must be environmentally acceptable as defined by the Clean Air Act, and mining operations must comply with existing Federal health and safety regulations. The Administrator of the Federal Energy Administration (FEA) initially was responsible for carrying out the program; however, these responsibilities were transferred to the Department of Energy (DOE) in October, 1977.[2/]

1/ See Chapter II-B for definition of small producers.

2/ References to FEA or to the Administrator should be read as DOE and the Secretary, respectively.

The National Environmental Policy Act of 1969 (NEPA) requires Federal agencies to prepare environmental impact statements (EIS's) on major Federal actions significantly affecting the human environment. Because the Coal Loan Guarantee Program may affect the environment significantly, this EIS has been prepared to address the potential impacts of its implementation.

B. Methodology

The potential environmental impacts of the proposed Coal Loan Guarantee Program are considered in the following sequence:

1. Identify the geographic areas where coal production and coal use will be most directly affected by the program.
2. Quantify the extent to which coal production and use will be affected in these areas.
3. Quantify, for a typical mine, steam coal preparation plant and coal combustion facility, the extent to which environmental residuals (i.e., pollutants) will be affected.
4. Aggregate the environmental residuals produced by such facilities for the geographic regions identified to assess the regional environmental impacts of implementing the program.
5. Consider alternatives to the program.

Several assumptions were necessary in analyzing the environmental impact of the Coal Loan Guarantee Program. These assumptions include the amount of coal produced from mines financed by the program; the number of mines financed; the proportion of steam coal production currently processed by coal preparation plants; and the type of coal combustion facility which will consume coal produced from program-financed mines.

C. Summary of Environmental Impacts of the Program

1. Affected Geographic Area

a. Coal Production

The geographic area of coal production most directly affected by implementation of the program is the Central Appalachian region, including southern West Virginia, east Kentucky, Virginia, and Tennessee. This region has the largest portion of eastern low sulfur deep-mineable coal reserves, and small coal producers are more predominant in this region than in other parts of the country. Program implementation, therefore, will result in greater low sulfur coal production by small producers in the Central Appalachian region than would result without the program.

Another geographic area of coal production and processing affected by the program is the Northern Appalachian region, including northern West Virginia, Pennsylvania, Ohio, and Maryland. Relatively little program activity is anticipated in these States because of the limited low sulfur coal reserves in this region.

b. Coal Use

The Coal Loan Guarantee Program primarily influences coal use in the East North Central and the South Atlantic areas because they have the largest proportions of planned low sulfur coal-fired utility generating capacity and existing generating capacity out of compliance with existing environmental standards.

Other geographic areas of coal use less affected by implementation of the program are the states in the Middle Atlantic and the East South Central regions. These regions plan some new coal-fired generating capacity, and the East South Central region has significant existing nonconforming coal-fired generating capacity. In all geographic areas, control strategies practiced by the utilities result in pollutant loadings that, for the most part, are the same whether loan program coal or non-loan program coal is used.

2. The Program's Effect on Coal Production and Coal Use

a. Coal Production

The Coal Loan Guarantee Program is projected to guarantee loans for 25 new mines and 60 expansions or reopenings of existing mines by 1980, which will produce 12.25 million tons of coal. By 1985, the program is projected to issue 95 guarantees for new mines and 160 guarantees for expansions or reopenings of existing mines, financing total annual incremental coal production of 39.75 million tons.

By 1985, 0.8 million tons of production capacity is projected to be financed by the program in Northern Appalachia, and 39.0 million tons in Central Appalachia, based on the assumption that 1985 low sulfur coal production financed by the program is equiproportional to 1985 projected regional production of low sulfur coal without the program.

b. Coal Use

The program is projected to supply low sulfur coal to existing and new generating plants in the eastern United States. For existing plants, the program is projected to finance low sulfur coal production for plants currently receiving deliveries of higher sulfur coal than permitted by the applicable State Implementation Plan (SIP) sulfur emission standard. Total 1985 demand for low sulfur coal by certain eastern existing plants is estimated at 50 million tons per year, based on extrapolation to 1985 of the quantity of low sulfur coal estimated by the Federal Power Commission to have been required for blending with existing high sulfur coal supplies to bring existing coal supplies into compliance with the SIP sulfur standard. This provides a conservative estimate of demand for program coal from existing powerplants.

For new generating plants, the program is projected to finance low sulfur coal production for new generating plants already under construction which are required to achieve the existing New Source Performance Standard (NSPS) sulfur emission limit of 0.6 pound sulfur per million Btu. Federal Power Commission utility survey data indicate total coal demand from eastern new plants to be in operation by 1980 at 50 million tons per year, and by 1985 at an additional 112 million tons per year, of which 20 and 61 million tons, respectively, are not yet under contract.

The total 39.75 million tons per year projected to be financed under the program by 1985 is projected to be consumed by some combination of demand from new generating plants and existing nonconforming generating plants.

3. Typical Environmental Residuals from Program Implementation

a. Coal Production

Residuals from a typical program coal mining operation were quantified assuming a 250,000 tons per year underground mine. One-third of program-financed mines were assumed to operate a 250,000 tons per year coal preparation plant.

Air emissions examined included particulates, nitrogen oxides, sulfur dioxides, hydrocarbons, and carbon monoxide. Increased emissions were slight because electrically powered equipment will be used and particulates will be retained within the underground mine; however, in some individual projects, some increases in fugitive dust levels may result from increases in traffic on haulage roads.

Water pollutants examined included net acidity, total dissolved solids, and suspended solids. Applying the more stringent of Federal or State regulations to predict pollutant loadings from program mines indicated negligible contributions of acidity or suspended solids and unknown (because unregulated) contributions of total dissolved solids pollutants; however, some increases in acidity might result from individual projects in the event of non-compliance with applicable State or Federal regulations.

Land use impacts examined included land requirements for disposal of spoil and refuse from mining and preparation, for disposal of sludge generated by water treatment, and for subsidence caused by underground mining. The typical mine required 16 acres of fixed land requirements and approximately 63 acres per year for spoil and refuse disposal. Coal preparation required about 95 acres of fixed land requirements and approximately 0.3 acres per year for refuse disposal.

Socioeconomic impacts examined included employment, fatality and injury rates, and availability of medical services. A typical underground mine was estimated to produce 125 jobs and to provide increased income and public tax revenues to support additional medical services. Some injuries or fatalities are likely to occur in mining projects financed by the program. Other potential impacts examined include effects on ecosystems and esthetics, as well as historic, cultural, and recreational sites.

While it is possible that the program may cause some impacts on coal transportation, involving some shift in coal transportation patterns within Northern and Central Appalachia, analysis of these impacts must be deferred to site-specific analyses, because origination/destination data is not available at a sufficient level of detail to permit programmatic environmental impact analysis.

b. Coal Use

Coal users were assumed to be operating either existing or new 570 MWe generating plants. The residuals from new generating plants burning higher sulfur coal with flue gas desulfurization devices (scrubbers) were compared with the residuals from burning low-sulfur program coal without scrubbers.

Existing generating plants were examined to compare the residuals from burning the higher sulfur coal without scrubbers with the residuals from burning low sulfur coal without scrubbers. The existing generating plants examined were restricted to plants located in Air Quality Control Regions whose sulfur emission limit was in the range of 1.2 to 1.7 lbs SO_2/MMBtu, i.e., the sulfur dioxide resulting from burning coal with a sulfur content of 0.6 to 0.85 pounds of sulfur per million Btu.

Air emissions examined included particulates, sulfur dioxide, nitrogen oxides (NO_x), carbon monoxide, hydrocarbons, and trace elements. For new generating plants, the program will not affect particulate and sulfur dioxide requirements because all new plants must meet existing NSPS emission limits. Nitrogen oxides will be affected somewhat by the program because scrubbers remove up to 10 percent of NO_x emissions and program coal could displace scrubbers at some new plants. Carbon monoxide and hydrocarbon emissions will be unchanged. For existing nonconformance generating plants, sulfur dioxide emissions will be the same whether program low sulfur coal is used or scrubbers are used with higher sulfur coal.

Water pollutant sources include coal pile runoff, ash handling water, and leachate from ash or scrubber sludge disposal. Use of program coal rather than high sulfur coal will result in less sulfuric acid runoff from coal piles of similar size. The heavy metals residuals from ash handling water will be slightly lower with the program; leachate will be somewhat lower. These findings are similar for both new and existing generating plants.

Land use impacts examined include land requirements for ash versus scrubber sludge disposal. For new plants, the program significantly reduces land requirements for disposal because the ash requires only 20 percent of the disposal land which is required for scrubber sludge. For existing plants, there is no difference in land use requirements with or without the program, assuming identical SIP particulate emission limits.

4. Aggregate Regional Impacts

a. Coal Production

The air impacts with the program are similar to impacts without the program, because there are no significant emissions from underground mining and because current MESA and ambient air quality standards will limit incremental emissions from coal preparation plants. However, for some individual projects, significant increases in fugitive dust levels may occur because of increased traffic on haulage roads. Similarly, for some individual projects, significant air emissions may result from operation of coal preparation plants which are not in compliance with air quality standards. Since it is not possible to analyze these impacts on a programmatic basis, these potential impacts will be examined in site-specific environmental analyses.

The water impacts with the program are few and largely beneficial. However, for some individual projects, noncompliance with existing NSPS and effluent limitations may result in some increased acid mine drainage. These potential impacts can be examined only on a site-specific basis.

The program will slightly increase land disturbance (chiefly subsidence) in Central and Northern Appalachia. Subsidence impacts may be significant in Central Appalachia, although the region's terrain characteristics have minimized human habitation in areas extensively mined.

The transportation impacts of the program may be significant in northern Appalachia and central Appalachia. New mines financed through the program will require some building of access roads and extension of railroad spurs, but for the most part, existing facilities can be used. These potential impacts can be analyzed only on a site-specific basis when the point of origin and the destination of program coal have been established.

The socioeconomic impacts of the program may be significant, especially in central Appalachia where large numbers of miners are projected to be employed in program-financed mines. Similarly, fatalities and injuries in central Appalachia may be significant because of the inherently greater dangers to health and safety of underground mining in comparison to surface mining.

b. Coal Use

As noted earlier, environmental impacts of coal use are quantified, first assuming all program coal is consumed by new generating plants already under construction, and second assuming all program coal is consumed by existing generating plants currently not in compliance with applicable SIP sulfur emission limits. The actual impacts from implementation of the program are therefore "bracketed" by this approach.

The air pollutant loadings are essentially identical for new plants with or without the program for particulates, sulfur dioxide, hydrocarbons, and carbon monoxide. NO_x emissions are approximately 10 percent less for a plant with scrubbers than for one without scrubbers. For existing plants, sulfur dioxide emissions will be the same with either program quality coal or with scrubbers and higher sulfur coal.

The total water pollution impact is $\pm$ 1 percent for such pollutants as aluminum, iron, zinc, nickel, and total suspended solids. Program coal slightly reduces copper (3.9%), chromium, manganese, and magnesium discharges. For new plants, groundwater, rather than surface water, may be affected since existing NSPS severely limit discharges into surface water; for some individual new plants, surface water may also be affected in the event of noncompliance with NSPS. For existing plants, surface water impacts may be significant. Such potential impacts will be examined in site-specific environmental analyses.

Land use requirements for new plants are reduced approximately 50 percent with the program because scrubber sludge disposal will not be required. For existing plants, land use impacts are essentially unchanged, except that higher ash, nonprogram coal slightly increases the amount of land required for ash disposal.

D. Program Alternatives

Four alternatives to the program are considered: 1) no action, 2) direct cash subsidies, 3) income tax incentives, and 4) increased enforcement strategies.

Because the loan guarantee program is multi-purpose and highly directed at small, underground, low sulfur coal producers, the alternatives are primarily financial in nature. Those examined proved to be either much more expensive, or much less effective than a loan guarantee approach. From an environmental perspective, the impacts of alternative approaches are virtually identical, on a per ton of coal production basis, because the alternative programs do not affect mining technology, but only the level of underground low sulfur utility steam coal production by small underground coal producers. These alternatives are discussed generally and relative to one another in Chapter X.

CHAPTER II

DESCRIPTION OF PROPOSED ACTION

A. Current U.S. Energy Situation

1. General Background

It has been over four years since the Organization of Petroleum Exporting Countries (OPEC) imposed an embargo on shipments of crude oil to the United States. Some actions have been taken by Congress and the Administration to reduce the United States' vulnerability to future embargoes. Oil prices have been allowed to increase; outer Continental Shelf leasing has been accelerated; Alaskan oil is being produced; the Energy Supply and Environmental Coordination Act (ESECA) providing authority to convert power plants and major fuel-burning installations (MFBI's) from oil to coal was extended; the Nonnuclear Energy Research and Development Act of 1974 was passed, permitting research into advanced energy technologies; and the Energy Policy and Conservation Act established energy conservation as a viable policy option for the future. However, despite these actions, the United States' dependency on foreign imports continues to grow both in absolute and relative terms.[1/]

The new Administration has articulated two major priorities in its proposed comprehensive energy policy. Energy conservation will be stressed to reduce demand for all forms of energy, and coal development will be encouraged by an effort to increase coal utilization in the utility and industrial sectors.

1/ In 1973, the U.S. was importing roughly 5.5 million barrels per day (MMBD) of crude oil and petroleum products from foreign sources. By March of 1976, the U.S. was importing over 8.0 MMBD, although national total energy consumption was at or below 1973 consumption levels.

2. Historical Energy Requirements

The demand for energy in the United States grew at an average rate of 3.2% per year between 1947 and 1973.[1/] As shown in Figure II-1, most of the growth in consumption has been satisfied by increased petroleum and natural gas supplies. Table II-1 indicates that the U.S. dependence on petroleum products has increased from 39.8% in 1950 to 46.3% of total energy consumed in 1973. Natural gas showed the most significant increase, accounting for 18.2% of total consumption in 1950 and 30.8% in 1973.[2/]

This increased dependence on natural gas and petroleum products was characterized by a significant increase in imported petroleum products. As Table II-1 indicates, U.S. dependence on foreign sources of oil and gas increased from 12.6% of total supply in 1950 to 36.2% in 1973. This trend has accelerated during the last few years. Between 1970 and 1973, imports of refined products grew by 18.8% per year. During the same period, outputs of petroleum products derived from domestic crude oil and natural gas plant liquids decreased by 1.7% per year. Consequently, oil imports doubled over the 1970-73 period.

The consequences of the trend toward increased dependence on foreign oil were made apparent by the Arab oil embargo in 1973 and subsequent increases in the price of oil levied on importing nations by OPEC. Efforts to avert further dependency on foreign imports since the embargo have not been adequate to prevent imported supplies from increasing. Prospects for improvement continue to deteriorate with the Federal Energy Administration's

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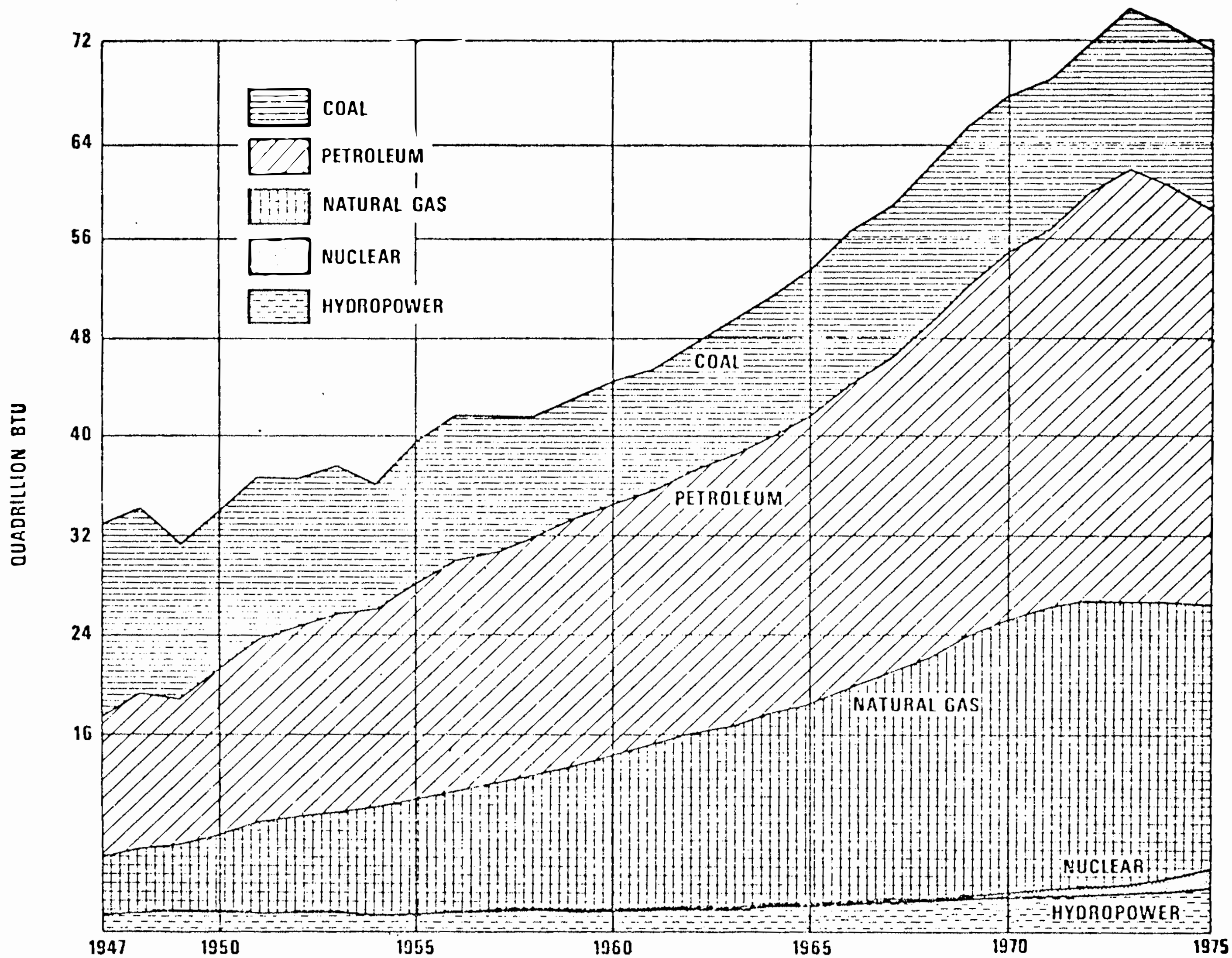
1/ U.S. Department of Interior, Bureau of Mines, "U.S. Energy Through the Year 2000" (revised), December, 1975.

2/ In 1972, natural gas consumption was even higher, accounting for 32.1% of total energy demand.

FIGURE II-1

UNITED STATES GROSS ENERGY CONSUMPTION BY SOURCE, 1947-1975



SOURCE: Department of Interior, Bureau of Mines.

TABLE II-1
U.S. ENERGY CONSUMPTION
1950-1973

Source	1950	1970	1973
	-------- (10^{12}	Btu per year)	--------
Coal	12,912	12,921	13,337
Petroleum	13,489	29,615	34,471
Domestic	(11,789)	(22,744)	(21,989)
Imported	(1,700)	(6,871)	(12,482)
Natural Gas	6,150	22,029	22,959
Other	1,440	2,879	3,731
TOTAL	33,858	67,444	74,538
	------------(%	of total)	-------------
Coal	38.1	19.6	17.9
Petroleum	39.8	43.9	46.3
Domestic	(87.4) 1/	(76.8)	(63.8)
Imported	(12.6)	(23.2)	(36.2)
Natural Gas	18.6	32.7	30.8
Other	4.3	4.3	5.0
TOTAL	100.0	100.0	100.0

1/ Percentages refer to total petroleum demand.

SOURCE: U.S. Bureau of Mines.

(FEA) prediction of a sharp increase in imports, up to 45.2% of total U.S. oil demand, in 1977. It is clear that, despite the warning signals of the 1973 embargo, the U.S. has become even more dependent on foreign sources to meet its energy requirements.

3. Current Coal Use and Development

a. Supply

For a number of years, the Federal Government has been stressing the need for additional coal production to reduce the nation's dependence on foreign oil and on increasingly scarce domestic oil and gas. The President's proposed National Energy Plan (NEP) calls for an increase in coal production to 1265 million tons per year (MTPY) by 1985.[1/] Because some coal mines will be closing, resulting in lost capacity of 253 MTPY, at the same time that new ones are opening, increased production must offset losses from existing production as well as add to overall coal production as shown in Table II-2.

TABLE II-2

CHANGES IN PRODUCTION, 1975-1984

(MTPY)

1975	Baseline projection	+ 639
1975-1984	New capacity required	+ 879
1975-1984	Lost capacity	- 253
1984	Projected production	+1265

SOURCE: President's Energy Initiatives Scenario (Run A158569C) and FEA, National Energy Outlook, 1976.

The 1265 MTPY of 1985 production capacity is expected to be distributed among eastern and western mines and surface and deep mines as shown in Table II-3.

1/ This analysis is based on coal supply/demand figures in the original NEP issued by President Carter in April, 1977; it does not reflect subsequent revisions to those projections.

TABLE II-3

PROJECTIONS OF NEW COAL PRODUCTION, 1975-1984

(MTPY)

	Surface	Deep	Total
Eastern*	292	538	830
Western	373	62	435
Total	665	600	1265

* East of the Mississippi River.

SOURCE: FEA, President's Energy Initiatives Scenario, 1976.

Sixty-six percent of the expected 1985 production is projected to occur in the East. Eighty-eight percent of the nation's 5,247 mines are now located in the East, but they supply only 55% of the nation's coal (Table II-4). In 1974, the output of the average eastern mine was 71.6 thousand tons per year, while western mines averaged 447.4 thousand tons per year, or over six times the eastern per mine production.

TABLE II-4

(U.S. VS. EASTERN)

NUMBER OF MINES AND 1974 PRODUCTION

	Eastern1/	% of Total	U.S.	% of Total	Eastern as % of Total U.S.
Total					
# Mines	4,641	100	5,247	100	88
Tonnage*	332.3	100	603.4	100	55
Underground					
# Mines	1,910	41	2,039	39	94
Tonnage	197.9	60	277.3	46	71
Surface					
# Mines	2,731	59	3,208	61	85
Tonnage	134.3	40	326.1	54	41

1/ Appalachian region. * Million Short Tons.

The data in Table II-5 indicate the preponderance of small and underground mines in the east. Ninety-seven and one-half percent of the eastern mines produce less than 500,000 TPY while only 74% of the western mines are in this category. In the east, mines producing less than 50,000 TPY contribute 17% of all tonnage while in the west, mines in this size class contribute only 1.5%. Ninety-four percent of all the nation's underground mines are located in the east, yet they produce only 71% of the nation's coal. These underground mines, therefore, also tend to be smaller than those found in the west.

The coal industry is much less concentrated than most major manufacturing industries, and in the eastern States it is even less so. While the largest 15 companies in the coal industry produce 46.5% of total output, the 20 largest companies in the paper, petroleum, and steel industries produce respectively 97%, 84%, and 83% of all shipments.[1/] An examination of data in the Keystone Coal Manual shows the preponderance of small companies in addition to small mines in the east. For example, Virginia contains 72 companies operating 682 mines and producing 34.3 MTPY of coal while Illinois produces 58.2 MTPY of coal with only 15 companies operating 55 mines. In West Virginia and eastern Kentucky, small companies are even more prevalent.

b. Demand

Projections of coal demand for 1980, 1985, and beyond made by the Federal government, coal consumers, and others all point toward an increase of one third in coal demand from 1975 to 1980 and a near doubling by 1985. While the various forecasts differ somewhat, they agree in indicating a rapid growth rate of about 6% per year compounded. Table II-6 compares various projections of domestic demand.

1/ 1967 Census of Manufacturers: Concentration Ratios in Manufacturing.

TABLE II-5

PRODUCTION BY SIZE OF MINE

(thousand tons)

	> 500		200-500		100-200		50-100		10-50		< 10		Total	
	#Mines	Tons	#Mines	Tons	#Mines	Tons	#Mines	Tons	#Mines	Tons	#Mines	Tons	#Mines	Tons
Eastern 1/														
Underground	102	86,426	165	52,036	177	25,590	214	14,987	751	17,877	500	2,107	1,910	197,994
Surface	12	9,701	93	27,029	199	26,809	478	34,313	1,298	33,287	651	3,173	2,731	134,315
Total	115	96,126	258	79,036	376	51,399	692	49,302	2,049	3,169	1151	5,280	4,641	332,300
Western														
Underground	59	69,478	18	6,829	10	1,520	13	954	15	445	14	60	129	79,315
Surface	99	159,363	51	16,436	54	7,502	71	4,391	116	3,035	86	459	477	191,783
Total	158	228,842	69	23,295	64	9,022	84	5,943	131	3,474	100	518	606	271,090
U.S. Total														
Underground	162	155,904	183	58,865	187	26,110	227	15,941	766	18,322	514	2,167	2,093	277,309
Surface	111	169,064	144	43,465	253	34,311	549	39,304	1,414	36,322	737	3,632	3,208	326,098
Total	273	324,969	327	102,331	440	60,421	776	55,745	2,180	54,643	1,251	5,798	5,247	603,406

1/ Appalachian region.

TABLE II-6

PROJECTIONS OF TOTAL DOMESTIC
COAL DEMAND FOR THE U.S.
(million tons)

Projection	Year 1974	1980	1985
U.S. Department of Interior January 1972	--	--	947.2
National Petroleum Council July 1971	--	--	748.9
Shell Oil Company February 1972	--	--	936
Oil and Gas Journal November 1971	--	--	893.6
Chase Manhattan Bank June 1972	--	--	928.6
Projected Energy Consumption U.S. Bureau of Mines June 1974	--	832	1092
Department of the Interior (Energy Through the Year 2000) December 1975	556.5(615.6)a/	736(806)a/	923(998)a/
ICF, Inc. August 1975	(612-634)a/	(793)a/	--
FEA Energy Outlook 1976	551(611)a/	719(799)a/	960(1040)a/
FEA President's Energy Initiatives Scenario	586b/	N/A	1176
Actual U.S. Bureau of Mines Data (ICF Report)	549.3(609.3)a/	--	--

a/ Parentheses indicate total U.S. demand (domestic and exports).

b/ 1975 demand.

Table II-7 summarizes the demand sectors and their past size.

TABLE II-7
COAL CONSUMPTION BY SECTOR
(million tons)

Year	Electric Utilities	Metallurgical Use	Industry	Residential/ Commercial	Exports	Total
1970	319	96	88	12	71	586
1971	326	93	74	11	57	561
1972	349	87	72	9	56	573
1973	387	94	67	8	53	609
1974	388	90	64	9	60	611
1975	406	83	64	7	64	624

While the various forecasts of electricity demand all predict annual growth rates of 5-7% through 1990, the net growth in generation from 1973 to 1974 was zero, and from 1974 to 1975, less than 2%. This is at least partly due to the impact of sharply higher electricity prices and the severe economic recession. Some utilities found that household electricity use increased significantly, while industrial demand fell sharply (see Table II-8). It now seems that growth in electricity production and related coal demand have resumed as the economy continues to recover and industrial production grows. The President's Energy Initiatives Scenario projects growth in coal demand at 7.5% annually through 1985 largely because of industrial and utility conversions to coal from oil and natural gas.

Offsetting the effect on coal demand of the recent slow growth in demand for electric power are the small increases in nuclear capacity, from 1974 to 1975, of only 3000 megawatts (MW), or 9%. Each 1000 MW of nuclear capacity produces electricity

TABLE II-8
PERCENT INCREASE (DECREASE) IN
DEMAND FOR ELECTRICITY BY CONSUMING SECTOR

	1964-1969	1970	1971	1972	1973	1974	1975
Residential	9.3	9.8	7.0	6.8	8.4	0.1	6.2
Small Light & Power	9.3	9.1	6.7	8.4	9.7	(1.1)	7.0
Large Light & Power	6.4	2.8	3.5	7.9	7.5	0.3	(4.7)
TOTAL CONSUMPTION	8.0	6.4	5.4	7.6	8.0	(0.1)	2.0

SOURCE: FEA, National Energy Outlook, 1976, p. 227.

equivalent to that generated by 2.8 million tons of coal per year. If nuclear capacity continues to lag, coal combustion by utilities may increase further in 1985.

The availability of natural gas to utility boilers is to be increasingly restricted in the proposed NEP. During 1975, utilities (mostly in the south) purchased gas equivalent to 138 million tons of coal. The proposed NEP tax penalties on the use of natural gas by utilities and the coal conversion tax incentives are likely to shift much of the natural gas combustion to coal by 1985.

The two issues discussed above suggest the potential for higher demand for coal. The most serious offset to this demand growth is the possibility that electricity demand will grow at a slower pace, as it did in 1974-1975. Were this to occur, overall growth in coal demand would be lower, too, because coal-fired production of electricity accounts for 70% of coal demand.

Another impetus to demand is projected to be the ESECA program. Under the FEA Coal Conversion Order Program authorized by the Energy Supply and Environmental Coordination Act, FEA has issued 92 prohibition orders (most of which are not yet effective) to 43 existing generating stations. These utilities would generate a total increased coal demand of 21.5 MTPY; however, only a portion of these converted units will require program quality coal.

In 1975, for the first time in a decade (and in a year of recession), industrial coal consumption did not drop. Table II-9 shows this pattern.

TABLE II-9

INDUSTRIAL SECTOR COAL CONSUMPTION

(MTPY)

Year	Coal Consumed
1970	88
1971	74
1972	72
1973	67
1974	64
1975	64

To some extent, this trend may have reversed because of curtailments of natural gas and, to some extent, because of a switch from oil to coal for economic reasons. Based on FEA's recent survey of major fuel-burning installations, only a small fraction (about 5%) of gas users can convert easily to coal. On the other hand, the Federal Power Commission (FPC) reports curtailments of natural gas approach an annual rate of 2 trillion cubic feet (TCF) or about 10% of supply. The effect of these curtailments is felt by industry, which uses about 9 TCF. If any substantial fraction of this gas were diverted from industrial users as contemplated in the proposed NEP, coal demand could rise sharply, by about 40 million tons for each 10% reduction in industrial gas consumption.

B. Description of the Proposed Action

1. Purpose and History of Legislation

Section 102(d) of the Energy Policy and Conservation Act of 1975 (Public Law 94-163) directs the Administrator of the Federal Energy Administration [now Department of Energy (DOE)] to "prescribe such regulations as may be necessary or appropriate to carry out" the provisions of Section 102 of the Energy Policy and Conservation Act. This section authorizes the Administrator to oversee the creation and administration of a Federal loan guarantee program for the purpose of accelerating the development by small coal producers of underground coal mines whose output would be environmentally acceptable as defined by the Clean Air Act and whose operations would be in compliance with existing Federal health and safety regulations.

Under Section 102 of the Act, a maximum of $750,000,000 in loan guarantees may be outstanding at any time. Eighty percent of the funds guaranteed must be for mines which produce low sulfur coal. "Low sulfur coal" is defined as coal containing no more than 0.6 lbs of elemental sulfur per million Btu's (lbs/MMBtu) after the application of any coal preparation process. This restriction is identical to allowing the emission of only 1.2 lbs/MMBtu sulfur dioxide (SO_2) or the use of 0.7% sulfur coal assuming a heat rate of 11,800 Btu/lb. The remaining 20% of the funds guaranteed may be used for opening new underground mines which produce coal which is not low in sulfur content.

Under Section 102, the applicant may receive such a guarantee only if the Administrator of DOE determines that:

- the applicant is capable of successfully developing and operating the proposed mine;
- the applicant has demonstrated that the proposed mine will be constructed and operated in compliance with

provisions of the Federal Coal Mine Health and Safety Act;

- it is reasonable to assume that the loan will be repaid;
- the applicant has obtained a contract to sell the coal to a person certified by the Administrator of the Environmental Protection Agency (EPA) as capable of burning such coal in compliance with the requirements of the Clean Air Act;
- such a contract must be for at least the duration of the period during which the loan is required to be repaid;
- the loan will be adequately secured;
- the applicant would be unable to obtain financing without a loan guarantee;
- the loan will enhance competition and/or encourage new market entry; and
- the applicant has adequate coal reserves to cover any aforementioned commitments.

In addition to the above, the applicant can be considered eligible for a loan guarantee only if the applicant (together with all affiliated persons):

- did not produce more than 1,000,000 tons of coal in the year preceding the year in which he applies for a loan guarantee;
- did not produce more than 300,000 barrels of crude oil or own a refinery in the preceding calendar year; and
- did not have gross revenues in excess of $50,000,000 in the preceding calendar year.

If the applicant meets all of the above requirements, then he will be eligible to apply for a Federal loan guarantee covering 80% of the lesser of: 1) the principal balance of the loan, or 2) the cost of developing the underground mine. For example, if a bank required a 20% equity investment by the coal producer and agreed to provide a loan for the remaining 80%, then the government guarantee would cover only 64% of the project costs (i.e., 80% of the bank loan which finances 80% of the project). In this case, the money at risk would be 20% equity, 16% bank loan funds, and 64% bank loan funds guaranteed by the government. In addition, the equity holders in the debtor company may be required to provide personal or other guarantees for a portion of the loan amount. The above example is merely illustrative of the relative loan-to-equity share which would vary from project to project depending on financial merits. No person or groups of affiliated persons can receive guarantees for more than $30,000,000.

2. Related Law and Legislation

The Clean Air Act, the National Environmental Policy Act, and the Federal Coal Mine Health and Safety Act are the primary laws related to implementing the Coal Loan Guarantee Program. In regard to the Clean Air Act, the Environmental Protection Agency must certify that coal produced under the loan guarantee program can be burned by the customer in compliance with existing New Source Performance Standards (NSPS) and State Implementation Plans (SIP's). The Act specifies, as a sales contract condition, that the Administrator of the Environmental Protection Agency certify that the consumers of coal produced under the guarantee program will be able to burn such coal in compliance with all applicable requirements of the Clean Air Act and any applicable implementation plan. Certain types of certifications could induce utilities and lending institutions to participate in the program. The Clean Air Act, as amended in August, 1977, will exert different regulatory demands on coal-fired power plants depending on when they were or will be built. For the most part, existing power plants are governed by emission limitations specified in SIP's. Power plants currently under construction are subject to existing NSPS for fossil fuel-fired steam electric facilities. Power plants currently without construction permits will have to comply with NSPS to be proposed sometime in the summer of 1978.

Coal sales contracts normally contain a provision allowing the contract to be terminated if the coal cannot be burned in compliance with air quality standards. Action by EPA, States, or local air quality control boards could cause a contract to be voided. Any assurances provided by EPA to reduce the uncertainty would increase the program's attractiveness. Given the probable legal and practical constraints on EPA, the certification probably would not be a firm commitment, but a judgment based on the analysis of factors determining compliance for a specific consumer over a set period of time. As such, the EPA certification does not guarantee that the coal can be burned in compliance with air quality standards.

The National Environmental Policy Act requires that DOE determine whether or not the issuance of a loan guarantee is a major Federal action significantly affecting the environment, thus requiring a site-specific environmental impact statement (EIS). To make the determination, DOE will analyze data about the site and the project in an environmental assessment (EA) and will use the EA to decide whether an EIS is necessary. DOE has created a Proposed Borrower's Environmental Impact Questionnaire, which is attached as an appendix to this EIS. The questionnaire would serve as an initial information source to determine whether a site-specific EIS is necessary and requests data on the potential air, water, solid waste, land use, and other environmental impacts of the proposed mining project. The questionnaire is designed to supplement existing questionnaires already required by other governmental bodies in their application materials for certain permits. DOE will establish procedures with the appropriate divisions within DOI to ensure unique cultural and biological resources are preserved, and will coordinate with other Federal agencies as necessary.

It is planned that this information will be prepared by the borrower or on his behalf for submission as part of the application for a loan guarantee. Certain data will be validated in the field by program staff or by independent consulting firms. Based on this information, supplemented as required, DOE will determine the level of site-specific environmental analysis required. It is anticipated that many projects will require either environmental assessments or environmental impact statements.

Every effort will be made in the implementation of the program to assign priority for the review and approval of individual loan guarantee applications based on environmental impact criteria, as well as on financial risk and other criteria.

Finally, in order to obtain a coal guarantee, the applicant must construct and operate the mine in compliance with the provisions of the Federal Coal Mine Health and Safety Act.

3. DOE's Implementation Plan

The rate of program implementation will depend largely upon the resources devoted by DOE to the program. Additional personnel to solicit and evaluate loan applications could potentially increase the program's effectiveness.

Based upon a moderate program activity projection developed by FEA, loan guarantee approvals and low sulfur coal production due to the program will be initiated in 1978. The program is assumed to guarantee 80% of the total investment cost of projects stimulated by the program, and an additional 20% equity contribution is assumed. Therefore, the program will guarantee 64% of the total investment cost of projects stimulated by the program. Principal payments are assumed to be paid at the annual rate of 12.5% of the total initial guaranteed loan amount beginning in the first year after the guarantee is issued, i.e., constant annual principal payments over 8 years. As loans are retired at an annual rate of 12.5%, these funds are assumed to be reinvested in new projects. Table II-10 summarizes the projected annual growth in low sulfur underground coal production from 1978 to 1985 under FEA's moderate program activity projection.

TABLE II-10

MODERATE PROGRAM ACTIVITY PROJECTION

	Fiscal Year							
	1978	1979	1980	1981	1982	1983	1984	1985
Guarantee Approvals								
New Mines	5	10	10	10	15	15	15	15
Reopen/Expansions	20	20	20	20	20	20	20	20
Total	25	30	30	30	35	35	35	35
Approximate Increase in Annual Coal Production* (10^6 tons)								
New Mines	1.25	2.50	2.50	2.50	3.75	3.75	3.75	3.75
Reopen/Expansions	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00
Total	3.25	4.50	4.50	4.50	5.75	5.75	5.75	5.75
Cumulative Annual Production (10^6 tons)	3.25	7.75	12.25	16.75	22.50	28.25	34.00	39.75

* Assumes no time lag from issuance of guarantee to coal production.

SOURCE: Projections for 1978-1982 from FEA. Growth assumed to remain constant from 1982-1985.

Table II-11 summarizes the projected number of mines and their associated annual coal production in 1980 and 1985. The program should increase annual low sulfur coal production by 12.25 million tons in 1980 and by 39.75 million tons in 1985. Approximately one-third of this coal is assumed to be cleaned in order to meet the 0.6 lbs/10^6 Btu sulfur emission standard (0.7% by weight sulfur content assuming an average heating value of 11,800 Btu/lb).

TABLE II-11

PROJECTED LOW SULFUR COAL PRODUCTION
DUE TO PROGRAM IN 1980 AND 1985

	Cumulative Number of Projects		Cumulative Annual Low-Sulfur Coal Production (10^6 tons)	
	1980	1985	1980	1985
New Mines	25	95	6.25	23.75
Reopen/Expansions	60	160	6.00	16.00
Total Mines	85	255	12.25	39.75
Steam Coal Preparation Plants				
at New Mines	8	31	2.08	7.88
at Reopen/Expansions	8	21	2.00	5.30
Total Plants	16	52	4.08	13.18

DOE intends to add staff during 1977 and begin issuing guarantees in 1978. By 1979, the program will be fully operational, approving approximately 30 applications per year. This rate will increase to 35 applications per year beginning in 1982, assuming that proceeds from repayments are reinvested.

C. Description of Technologies Involved

1. Coal Production Technologies

a. Surface Mining

There are three basic types of surface coal mines: contour, area, and auger mines. Of these, contour and area strip mining are the two major surface coal mining techniques. These mining techniques are distinguished primarily by the different topographies and seam thicknesses in which they are employed. Contour strip mining is practiced in hilly or rolling terrain and on steep slopes in which the coal seam outcrops along the flank of a hill or mountain. This method of surface mining is employed in the mountainous regions of Central Appalachia. The overburden is removed from above the coal seam using draglines, power shovels, or other earth moving equipment, and the coal is removed. Mining proceeds around the hillside following the outcrop of the coal seam, creating a ribbon-like pattern. Before strict reclamation laws were enacted, the spoil material from contour mines usually was cast down the hillside, creating a spoil outslope much steeper than the natural slope of the land. Such unconsolidated spoil banks often are unstable and can create severe erosion and landslide problems and associated water pollution and flooding. Current State reclamation laws require that all acid or toxic materials be buried under clean overburden, the mine be backfilled and graded to a terrace configuration or to the approximate original contour, and that a good vegetative cover be established to stabilize the area and control erosion and water pollution.[1/]

Area strip mining is practiced on relatively flat or gently rolling terrain where many cuts can be taken between the outcrop and the point at which mining is no longer economically feasible. With this method, a trench or box cut is made through the overburden to expose the coal, and the overburden is cast next to the pit, forming a spoil ridge. As each successive cut is made parallel to the initial trench, the overburden is deposited in the trench from each previous cut. If left unreclaimed, the overburden forms a series of parallel ridges in the mined area resembling a gigantic washboard. State reclamation laws usually require that toxic materials be buried under clean overburden and that the area mine be regraded to the approximate original contour or, in some States, to a rolling topography, and revegetated. All States require that soil supplements (e.g., fertilizer, lime, mulch, seed) be applied to establish an adequate vegetative

1/ This study was prepared before the Surface Mining Control and Reclamation Act of 1977 was passed, which requires all States to comply with Federal reclamation standards to be promulgated (tentatively) in August, 1978.

cover, and many States now are requiring that topsoil also be saved and reapplied to the regraded mine site.

Auger mining is a method of coal extraction frequently used in conjunction with contour mining after contour strip mining is no longer feasible. Auger mining entails the use of large augers to extract coal by boring horizontally into the coal seam from its exposed edge. In addition to the regular contour mine reclamation discussed above, reclamation techniques usually include plugging auger holes to prevent the formation of acid drainage. Because it accounts for a small percentage of surface mining in the States affected by the Coal Loan Guarantee Program,[1/] the environmental impacts of auger mining are not addressed in this EIS.

b. Underground Mining

Underground mining methods are those in which access to the coal seam is made via shaft (vertical), slope (inclined), or drift (horizontal) entries. Underground mining generally is employed where the coal seam is too deep to be mined economically by surface mining methods. Room-and-pillar and longwall mining are the two most common underground methods of coal extraction.

As mining advances in room-and-pillar mining, rooms are excavated in the coal seam, and the strata above are supported by pillars of coal left in place. Recovery efficiency is about 57%.[2/] When the ground above is allowed to subside, the coal pillars can be removed by "retreat" mining, which increases recovery efficiency and allows the roof to collapse after the mining operation.

1/ DOI, Bureau of Mines, "Coal -- Bituminous and Lignite in 1975," February 10, 1977, Table 17, pp. 20-23.

2/ University of Oklahoma, "Energy Alternatives: A Comparative Analysis," prepared for CEQ, ERDA, EPA, FEA, FPC, DOI, and NSF, May, 1975, pp. 1-47.

Longwall mining starts with sets of entries cut into the panel areas. The longwall machine laterally shears or plows coal from the entire face of the longwall blocks, allowing recovery efficiencies of about 85%.[1/] The roof is allowed to cave behind the advancing work area. Longwall mining accounts for about 3% of U.S. coal production;[2/] therefore, for the purposes of analysis, all underground coal production stimulated by the program is assumed to be extracted by the room-and-pillar method.

c. Steam Coal Preparation

Coal markets have greatly influenced the degree of preparation required for coal produced from any particular mining operation. Traditionally, utility (steam) coal has not been prepared as extensively as metallurgical coal; however, in the future, it may have to be cleaned and prepared more thoroughly because of increased enforcement of sulfur dioxide emission limitations for power generating plants. Thus, coal feeds which are uniform with respect to sulfur and ash content and heating value will become more desirable.

Steam coal preparation for the utility coal market incorporates crushing, sizing, and washing of the coal. The raw coal is crushed and screened to about 8 to 10 centimeters (3-4 inches) top size. Coal usually is cleaned by jigs using a pulsating fluid flow, which induces particle stratification via alternate expansion and compaction of a bed of raw coal. This results in a density stratification with the dense impurities (pyrite, tramp iron, etc.) on the bottom layers and the clean coal in upper layers of the particle bed. The clean coal and refuse is dewatered. Settling ponds or drag tanks and thickeners are used to remove coal fines from process waters. A primary objective of steam

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1/ University of Oklahoma, _op_. _cit_.

2/ _Ibid_., pp. 1-31.

coal preparation is to remove liberated mineral matter by cleaning with high density fluids. This provides a uniform product with reduced ash and sulfur content.

Fine coal (less than 3/8 inch or one centimeter) usually is not cleaned and bypasses the cleaning process to be mixed directly with clean coarse coal. However, steam coal preparation plants can be modified to include fine coal cleaning by either wet or dry processing to provide additional quality control. A very limited number of fine coal cleaning circuits employ shaking tables, hydrocyclones, or heavy media cyclones for cleaning, and extreme fines are discarded as refuse or blended with coarse coal. Mechanical drying (centrifuge) usually is required with wet cleaning. Thermal dryers are used for fine clean coal only when necessary.

d. Coal Transportation

Except for local deliveries, which are made primarily by truck, most coal in the Appalachian region is delivered to power plants by railroad and/or barge. Coal is transported by rail using either unit or mixed trains. Unit trains transport only coal, whereas mixed trains carry other freight as well. When coal is transported by conventional trains, the Interstate Commerce Commission (ICC) general rates apply. A special rate almost 1/3 less applies to unit trains. Unit trains offer several other advantages -- they utilize equipment more efficiently, eliminate standard railroad tie-ups such as classification yards and layover points, and promote better coordination between mine production and consumers, particularly consumers dependent on coal being supplied by a single mine.[1/] In some areas, such as the Ohio River Valley, barges can be loaded directly from the

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1/ University of Oklahoma, "Energy Alternatives: A Comparative Analysis," May, 1975, pp. 1-123.

mine. When mines are not located adjacent to a navigable river, the coal is transported to the barge loading facility by truck or train (usually by train). Table II-12 shows average coal transportation distances for Northern and Central Appalachia.

TABLE II-12

AVERAGE COAL TRANSPORTATION DISTANCES

Origin	Method	Average Haul Distances (miles)
Northern Appalachia	Unit Train	320
	Conventional Train	320
	Barge	800
Central Appalachia	Unit Train	395
	Conventional Train	275
	Barge	300

SOURCE: University of Oklahoma, "Energy Alternatives: A Comparative Analysis," May, 1975, Table 1-55.

2. Coal Use Technologies

In the United States, electricity is produced by one of three methods: fossil fuel combustion, hydroelectric generation, or nuclear generation. The Coal Loan Guarantee Program will affect the production of electricity by the first method only.

Two methods of fossil fuel combustion are used to produce electricity. The first method employs fossil fuel combustion to produce steam which, in turn, is used to drive an electric generator. In the second method, a fossil fuel combustion engine directly drives an electric generator. The advantage of steam electric generation is that it requires less energy to produce a kilowatt-hour of electricity. The heat rate of fossil fuel-fired steam electric units ranges from 9000 to 12,000 Btu/kWh, while that of direct combustion engines driving generators ranges from 14,000 to 17,000 Btu/kWh. Steam units for the most part are large units, from 250 to 1300 MW, and generate base or intermediate load electricity. Thus, these units produce by far the bulk of electricity generated by fossil fuel combustion. Direct combustion units, on the other hand, are generally small, between 5 and 50 MW, and generate peak load electricity only.

Direct combustion peaking units (e.g., turbines, jet engines, or internal combustion engines) burn gas or oil. Since coal cannot be used to operate these units, they will not be affected by the Coal Loan Guarantee Program. Steam electric units burn coal, oil, or natural gas, either in combination or individually. Only steam power plants which burn coal will be affected by the loan program.

At coal-fired power plants, coal is stored onsite in large open-air piles and is transported to the boiler by a series of conveyor belts. To prepare the coal for combustion in the boiler, the coal is pulverized to a fine powder, which then is blown into the combustion chamber of the boiler. As in oil or gas power plants, the combustion heat is used to produce steam, which in turn is used to operate a generator and produce electricity. The residue from coal combustion, ash, either remains in the bottom of the boiler (bottom ash) or escapes up the stack with the flue gas (fly ash) where particulate control equipment entraps as much 99%. Bottom and fly ash then are transported from the boiler and flue stack for disposal. Often a water slurry is used, but the ash also can be handled dry through a variety of pneumatic mechanisms. Ash handled wet usually is sluiced to an onsite pond for disposal or to dewatering bins where the ash is dewatered and hauled to an offsite disposal site. Sluicing water can be recycled or discharged from the pond. The remaining operations of a coal-fired steam electric power plant, including operating the generator and cooling the boiler, are similar to those at oil- or gas-fired generating stations.

D. Scope and Methodology of the EIS

As stated earlier, the Coal Loan Guarantee Progam was created primarily to encourage small underground producers of low sulfur coal[1/] (20% of the loan guarantees made in any one year can be allocated to small underground producers of high sulfur coal). The analysis assumes that 100% of the funds go to low sulfur coal and that the 20% allowance for high sulfur coal would be used to accommodate seam variability. For the purposes of analysis, assumptions were made in order to determine the geographic area affected by the program, the increase in low sulfur coal production and use as a result of the program, and the impacts of this increase on a unit facility (i.e., unit mine, preparation plant, and coal combustion facility) and regional basis. Specific assumptions used to determine the impacts of the program on coal production and use are discussed below.

1. Determining the Impacts of the Program on Coal Production and Use

The impact analysis is based principally on the 1985 coal supply and demand projections generated by a Project Independence Evaluation System (PIES) scenario which estimates the effects of the President's initiatives in the proposed National Energy Plan. This scenario estimates 1985 coal demand from existing coal-fired facilities, construction of new coal-fired utility and industrial facilities, and conversion of existing oil- and gas-fired utility and industrial facilities to coal. The PIES model matches coal demand with existing and incremental coal supplies from various regions. This matching of supply and demand is

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1/ Defined as coal meeting the NSPS of 1.2 lbs SO_2/MMBtu without SO_2 controls.

based on a linear programming methodology which minimizes coal supply costs considering such factors as the supply curves of incremental coal production (differentiating between surface and underground coal, high and low sulfur coal, expanding existing mines and developing new mines, etc.), the transportation costs from supply to demand areas, and other factors. This analysis extends the assumptions used in the PIES model so that the PIES supply and demand figures can be used to determine the impact of the Coal Loan Guarantee Program on 1985 low sulfur coal supply and demand. These assumptions are discussed in the following pages.

- 98% of the program coal will be mined in Central Appalachia; the remaining 2% will be mined in Northern Appalachia.

Central Appalachia[1/] contains the largest number of small, low sulfur coal, underground mines. Approximately 75% of all eastern U.S. deep mineable low sulfur coal reserves are found in West Virginia and eastern Kentucky. This area corresponds to Bureau of Mines districts 7 and 8, where the largest proportion of coal is produced by small coal mine operators. Virtually all western low sulfur coal producers are excluded from this analysis because the vast majority of western coal is produced from surface mines by large producers. The majority of underground-mined coal in Northern Appalachia[2/] is high sulfur, i.e., greater than 0.6 lbs sulfur/MMBtu. However, a small portion of this coal will meet the low sulfur coal standards of the Loan Guarantee Program.

1/ Southern West Virginia, Virginia, eastern Kentucky, northeastern Tennessee.

2/ Eastern and western Pennsylvania, Maryland, northern West Virginia, Ohio.

- Program coal is allocated to Northern and Central Appalachia according to the PIES model 1985 projections.

The PIES model predicts that 312 million tons of low sulfur and premium coal will be produced in Northern and Central Appalachia in 1985. Approximately 39.75 million tons of low sulfur coal are expected to be produced under the program (12.8% of the total 312 million tons projected). This analysis allocates these 39.75 million tons of coal between Northern and Central Appalachia according to the 1985 PIES projections.

- Approximately 1/3 of the coal produced under the program will be washed in preparation plants constructed with loan guarantee funds.

Washed low sulfur coal is highly desirable since it permits the coal producer to command a premium price, increases the amount of coal reserves which can become low sulfur coal, reduces the amount of ash in the coal, and improves the consistency of the final washed coal product.

There are no readily available data on the quantity of steam coal now washed. In 1974, Bureau of Mines data indicated that 47% of all coal produced in the U.S. was mechanically cleaned. When adjusted to eliminate those States excluded from the Guarantee Program supply/demand regions and assuming that all metallurgical coal is washed, these data indicate that approximately 10% of Appalachian steam coal is washed. Because of the increasing demand for low sulfur coal and because the program will increase the financial capability of small coal producers, it was assumed that 1/3 of the program coal mines will operate with coal preparation plants. This analysis assumes that all of the coal produced under the program in Northern Appalachia is washed and that the remaining portion of the 1/3 of the program coal assumed to be cleaned is washed in Central Appalachia.

- Program coal is assumed to be used by new coal-fired utilities under construction by 1978 and operational by 1985 (meeting NSPS for SO_2 of 1.2 lbs/MMBtu) or existing utilities currently violating SIP emission standards ranging from 1.2 - 1.7 lbs SO_2/MMBtu.

Demand for program coal likely will come from new eastern coal-fired utilities already under construction before revised NSPS under the Clean Air Act Amendments of 1977 are promulgated, existing eastern utilities violating Clean Air Act SO_2 emission limits, existing industrial MFBI's (either coal-fired or with coal firing capability), and new industrial MFBI's or utilities converting either voluntarily or under ESECA conversion orders from oil and natural gas to coal.

The environmental analysis assumes only new and existing non-conformance utilities demand program coal because demand from industrial MFBI's and utilities and MFBI's converting to coal cannot be projected reliably at this time. Some of the uncertainties include: (1) the form new authorizing ESECA coal conversion legislation will take; (2) the economic and environmental feasibility of converting individual industrial and utility generating plants from oil and natural gas to coal; (3) the extent of litigation initiated by facilities ordered to convert to coal and the subsequent time delays; (4) the magnitude of tax and other financial penalties to be imposed on utility and industrial oil and gas consumers; and (5) the number of potential coal conversion candidates which are legislatively exempted from coal conversion orders or taxes and other financial penalties imposed on oil and gas use.

The eastern U.S. is considered the largest demand area since it contains the largest proportion of new coal-fired utilities under construction and the largest proportion of existing non-conformance coal-fired utilities. This area currently receives only small amounts of coal from the western States, e.g., only 23 million tons or 6.6% of total eastern utility coal was delivered from the west to this region in 1976. Almost all of the western coal was delivered to the East North Central region, particularly Illinois and Indiana. A survey published in January, 1977, by the Federal Power Commission (FPC) indicates that eastern utilities plan to obtain approximately 80% of their coal from eastern coal producers through 1985.

Based on review of partial construction status data in FEA's Trends in Utility Capacity and Utilization, January, 1977, and because new utility plants require construction lead times of at least 7 or 8 years, it is assumed that all new utilities projected to be operational by 1985 by FPC will be under construction before revised NSPS under the Clean Air Act Amendments of 1977 are promulgated. New utilities under construction before these revised NSPS are passed will be exempt from them. It is recognized that these amendments likely will result in revised NSPS requiring more SO_2 control than at present. If the revised NSPS currently under consideration by EPA are promulgated, the assumptions concerning new utilities will be revised accordingly.

The demand for program coal from existing utilities is confined to those in violation of SIP SO_2 emission limitations. Because SIP's vary by State and, sometimes, by facility, the non-conformance utilities were limited to those with SIP's between 1.2 and 1.7 lbs SO_2/MMBtu because it was felt that utilities with less stringent SIP's would not use program quality coal to meet the standards (i.e., through blending). An FPC computer analysis indicated that, for the year ending October, 1976, 55.6% (189 million tons) of coal delivered to eastern utilities was non-conformance, i.e., contained sulfur in excess of the applicable SIP SO_2 emission limit. Section 118 of the Clean Air Act Amendments of 1977 provides for penalties for major sources not in compliance with SIP emission limits equal to the cost of complying to the owner or operator. Such penalties likely will increase substantially the enforcement of SO_2 emission limits and therefore the use of low sulfur coal by existing utilities.

- The environmental impacts analysis of increased coal use assumes that all program coal is consumed first by new utilities, and second, by existing non-conformance utilities.

The demand for program coal is expected to exceed the supply; therefore, the above assumption encompasses environmental impacts of the two program cases.

- The program is anticipated to allocate all $750 million by 1985.

The program is expected to fund the mining of 39.75 million tons of low sulfur coal by 1985, the peak year of program impact. At this time, all $750 million is expected to be allocated. Virtually all mines financed by the program are expected to be operating at full capacity.

2. Determining the Environmental Impacts of Coal Production and Use Stimulated by the Program

a. Coal Production

- The environmental impacts section analyzes residuals produced from surface and underground mines and coal preparation plants on both a unit and regional basis.

Although the program will not encourage mining at surface mines, the environmental impacts of surface mining are presented so that they can be compared with those resulting from underground mining.

- Unit surface (area and contour) and underground (room-and-pillar) mines producing 250,000[1/] tons per year of coal and a unit coal preparation plant cleaning 250,000 tons per year of coal are analyzed.

It is assumed that both mines and preparation plants will meet all applicable standards, although worst case, uncontrolled conditions are discussed generically in the text when applicable.

- Regional impacts are determined for underground mines and steam coal preparation plants.

The regional impacts of underground low sulfur coal mining are based upon the production split of program coal between Northern and Central Appalachia and are determined for 1985. The analysis reflects only the environmental impacts of the underground mining and preparation of low sulfur program coal. It does not reflect other mining activities (i.e., surface mining) also occurring in 1985, or the displacement of mining impacts caused by the program. The 39.75 million tons of low sulfur coal produced under the program were determined from Tables III-14 and III-17 (steam coal production with and without the program for 1985 by sulfur content and mine type). The residuals resulting from the mining and preparation of this tonnage are allocated between Northern and Central Appalachia according to the 2%:98% assumed production split.

b. Coal Use

The environmental impacts of loan program coal use are presented with and without the program for new and existing non-conformance power plants (where applicable) on a unit and regional basis.

1/ The impacts of reopening or expanding existing mines (assumed to produce 100,000 tons of coal/year) are not specified, since it was assumed they would be less than the impacts of a 250,000 tons/year mine.

- Unit impacts with the program are quantified for a new 570-MW coal-fired power plant.

As stated earlier, it is assumed that program coal will be used without scrubbers by new utilities under construction before 1978 and operational by 1985 (subject to the existing NSPS for SO_2 emissions of 1.2 lbs/MMBtu) and by existing non-conformance power plants violating SIP's in the range of 1.2 - 1.7 lbs/MMBtu. Impacts are quantified for a unit new power plant meeting the NSPS of 1.2 lbs SO_2/MMBtu; impacts when existing power plants burn program coal are discussed generically in the text and compared with the impacts of new sources when applicable.

Section 109(c) (6) of the Clean Air Act Amendments of 1977 exempts fossil fuel-fired stationary sources from compliance with proposed revised clean air standards if these sources are under construction when the revised standards are promulgated by July, 1978. This section also indicates that these new sources can comply with environmental requirements by burning low sulfur coal without scrubbers.

An unpublished FPC Bureau of Power staff analysis surveyed utility plans for achieving Clean Air Act compliance and found that of the 23,000 MW generating capacity planned by eastern utilities to be operational by 1980, 12,100 MW capacity (approximately 53%) planned to achieve compliance by using low sulfur coal without scrubbers and 9600 MW capacity (approximately 42%) planned to burn higher sulfur coal using scrubbers. The remainder of eastern capacity was either unknown, under litigation, or undecided by the utility.

While it takes about 7 years to construct a power plant, from initiation to completion, construction of a scrubber takes only 2 to 3 years. A utility, therefore, has some discretion during construction periods to change its mind about how it will control sulfur emissions. A change in the selected approach to emission limit compliance, however, must be within the regulatory framework of the State in which the facility is being built. Any change in design probably would prohibit a net increase in air emissions from the levels agreed to in the original permit to construct.

That program coal producers continued to have an opportunity to obtain coal sales contracts to these new utility generating facilities is indicated by the analysis summarized in Tables III-6 and III-7, which show that 81 million tons of coal per year to be required by this coal-fired capacity are not yet under contract.

- Unit impacts without the program assume that both existing non-conformance and new power plants burn high sulfur coal using scrubbers (flue gas desulfurization) to meet the NSPS and SIP's for SO_2 emissions.

High sulfur coal is assumed to contain 2.25% sulfur by weight, corresponding to the average sulfur content of coal delivered to utilities from Northern Appalachian Bureau of Mines districts in 1976 ranging from 2.02 to 3.85% by weight. Low sulfur coal was not assumed for use with scrubbers because of the current price premium for low sulfur coal (e.g., TVA's October 1976 bids for low sulfur coal ranged as high as $35 per ton compared with 1976 average cost of $19 per ton).

The assumption that new and existing non-conformance power plants will use scrubbers and higher sulfur coal without the program presents a worst case analysis for the solid waste impacts without the program, since many utilities probably will resist installing scrubbers because of their high cost. In addition, at existing non-conformance power plants, many of the plants may continue to violate standards in the absence of the program, despite the non-compliance penalties.

- Without the program, both new and existing non-conformance power plants are assumed to control air emissions to the minimum legal degree required (i.e., 1.2 lbs SO_2/MMBtu for new sources; 1.2 - 1.7 lbs SO_2/MMBtu for existing non-compliance sources).

This assumption reflects the control strategy employed at most utilities. Although control beyond the standard is achievable by scrubbing all stack gases, by-pass of part of the exhaust so that the composite stream only just meets the standard will give savings in water use, lime/limestone, sludge to be disposed, and reheat needed for plume rise.

- Neither new nor existing non-compliance units blend program coal with higher sulfur coal to meet the existing NSPS or applicable SIP for SO_2.

Given the assumption that utilities meet applicable air standards to the minimum legal level required, existing non-conformance utilities could blend program coal with high sulfur coal to meet the NSPS and SIP's for SO_2 emissions.[1/] However, given the time constraints of this study, the analysis was simplified to assume no blending.

If the analysis did assume blending, existing utilities likely would blend cheaper, high sulfur coal with program coal

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1/ New utilities could not blend program coal with higher sulfur coal and still meet the existing NSPS for SO_2, since it is assumed that program coal just meets the NSPS of 1.2 lbs SO_2/MMBtu.

to just meet the NSPS for SO_2. Approximately 62 million tons of non-conformance coal would have to be blended with 50 million tons of program coal to meet applicable SO_2 emissions limits without scrubbers (for the 1980-1985 program period. See Table III-8).

For example, on a State level, it is assumed that 50 million tons of coal are delivered to Ohio during 1980-1985, of which 38 million tons would be non-conformance coal after allowing for possible blending. Of these 38 million tons, 8.8 million (23%) are delivered to utilities whose sulfur emission standards are between 1.2 and 1.7 lbs SO_2/MMBtu. Approximately 6.9 million tons of program coal would have to be blended with these 8.8 million tons of high sulfur coal to meet the SIP's in this range (assuming that the same quality high sulfur coal will be burned in 1980-1985 as is presently burned).

- Only controlled emissions are quantified for the unit and regional impact analyses.

Since coal-fired utilities will have to meet applicable emission standards with or without the program, only controlled emissions are quantified for the unit and regional impacts analyses. Uncontrolled, worst case conditions are discussed generically in the text when applicable.

- Regional impacts are allocated to new and existing power plants according to the proportion of each (new versus existing) in each State.

Program impacts will vary by State because the number of existing versus new sources varies by State. Because it is assumed for purposes of analysis that both new and existing utilities have to meet existing emission standards, will employ the same level of particulate control, and will not blend program coal which has an emission rate of 1.2 lbs SO_2/MMBtu, the total, regional emissions will be the same whether new power plants or existing non-conformance power plants burn the program coal. However, the proportion of emissions from new sources versus existing sources in each State will not be equal.

CHAPTER III

CHARACTERIZATION OF THE EXISTING ENVIRONMENT

This chapter describes the existing environment for the area affected by the Coal Loan Guarantee Program. For purposes of analysis, the area affected by the loan program is defined as the area of the eastern United States stretching from New York to Georgia and encompassing the eastern seaboard States (except New England) plus the inland States of Ohio, Kentucky, West Virginia, and Tennessee. Environmental effects due to mining associated with the loan program will be confined to the Appalachian Region, which extends 500 miles from Pennsylvania to Alabama, and includes portions of Pennsylvania, Maryland, Virginia, West Virginia, Ohio, Tennessee, Kentucky, and Alabama. Impacts due to the use of loan-program coal will extend throughout the eastern United States, excluding New England.

A. Air

1. Climate

The climate of the entire affected region is characterized by frequent changes of weather, strongly marked seasons, high humidity, and plentiful rainfall. Annual precipitation averages from about 35 inches in the northern portions to over 55 inches in the southern portions, with some mountainous areas of Appalachia receiving 60 to 80 inches. The average daily temperature during January is about 25°F in the northern portions and 45°F in the southern portions. Summer average temperatures are in the 70's and 80's; however, they average in the 60's in the higher mountains. Evaporation from open water surfaces ranges annually from about 25 inches in the northern portions to about 42 inches in the southern portions. Potential evapotranspiration annually averages 24 to 36 inches throughout most of the region.

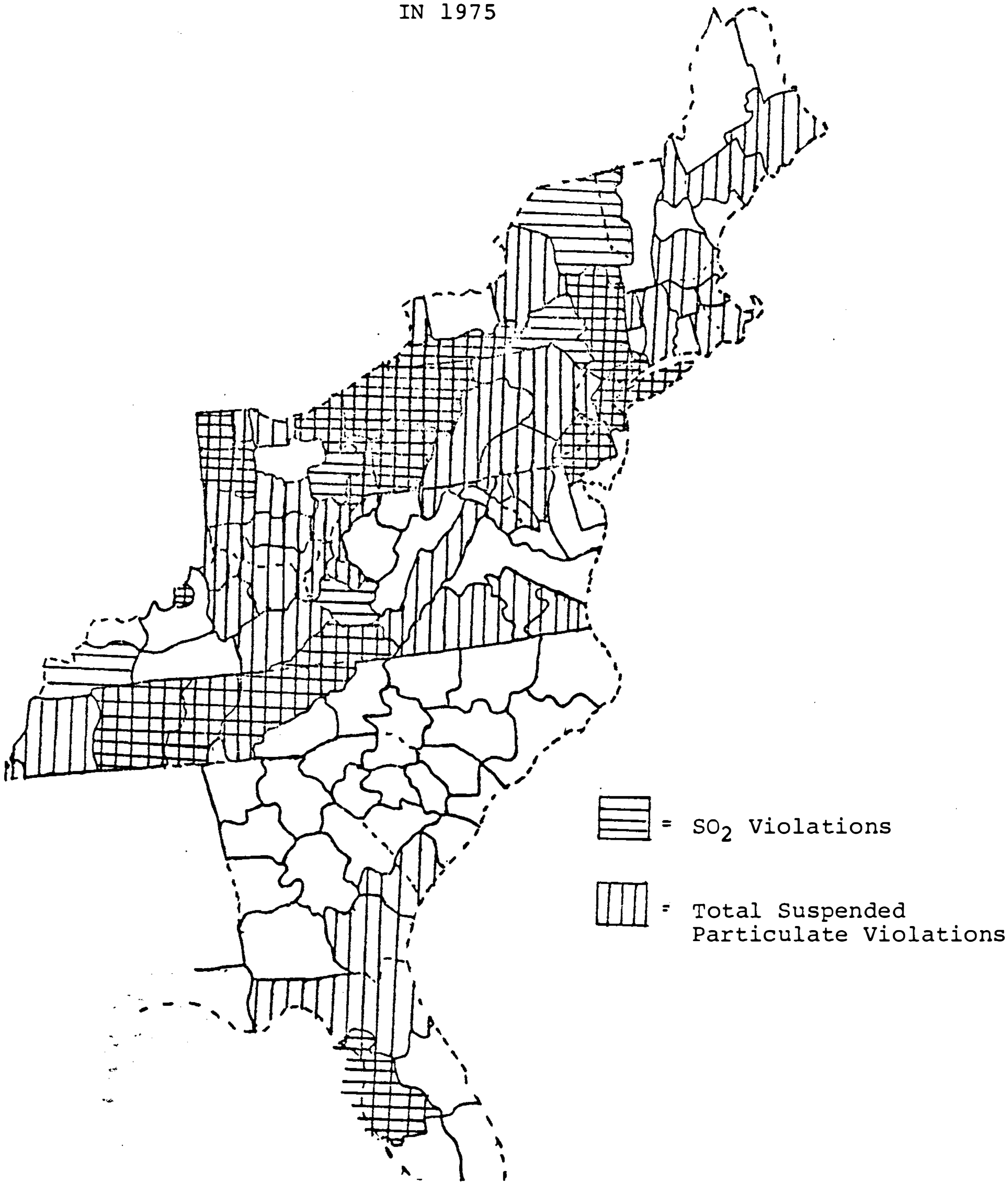
2. Quality

The eastern seaboard is characterized by large industrial concentrations and urban centers. Industrialization is particularly heavy in parts of Appalachia and in urban centers in the northeast. Consequently, these areas suffer from a high degree of air pollution. The concentrations of industry, cars, and people in the urban centers of the east, particularly Baltimore, New York, Cleveland, and Pittsburgh, create severe pollution problems, especially during stagnant weather periods that encompass the areas each summer. In the mountainous regions of Appalachia, air pollution problems caused by industry are compounded by the rugged, mountainous topography of the area. When the slopes and mountaintops become cool at night, cold dense air flows into the valleys, producing a strong air inversion which prevents vertical mixing of polluted air. The valley and ridge topography also limits horizontal dispersion. Air pollution problems are particularly severe during prolonged air inversions in the heavily industrialized areas in the valleys, when air pollutants from powerplants and industries remain trapped. Pollution is highest during the summer months when afternoon ventilation is at a minimum. Figure III-1 summarizes the Air Quality Control Regions (AQCR's) in the eastern United States that were in violation of SO_2 and particulate standards in 1976.

Six pollutants are of potential concern in the region affected by the loan program: particulate matter, sulfur dioxide (SO_2), carbon monoxide (CO), oxidant/ozone, nitrogen dioxide (NO_2), and hydrocarbons (HC). EPA has established ambient air quality standards for these pollutants (Table III-1). Other pollutants of concern are sulfates and trace elements. Emissions affected by the loan program will affect ambient particulate, SO_2, CO, NO_x, and trace element levels throughout the East.

FIGURE III-1

EASTERN AIR QUALITY CONTROL REGIONS IN VIOLATION OF NATIONAL AMBIENT AIR QUALITY STANDARDS FOR SULFUR DIOXIDE AND TOTAL SUSPENDED PARTICULATES IN 1975



SOURCE: "State Air Pollution Implementation Plans, Progress Report," EPA #450-2-76-026, October, 1976.

TABLE III-1
CURRENT NATIONAL AMBIENT AIR
QUALITY STANDARDS

Pollutant	Time Period of Measurement	Maximum Permissible Concentration[a] Primary Standard	Secondary Standard
Total Suspended Particulates (TSP)	1 year	75 $\mu g/m^3$	60 $\mu g/m^3$ [b]
	24 hours[c]	260 $\mu g/m^3$	150 $\mu g/m^3$
Sulfur Dioxide (SO_2)	1 year	80 $\mu g/m^3$	80 $\mu g/m^3$
	24 hours[c]	365 $\mu g/m^3$	365 $\mu g/m^3$
	3 hours[c]	----	1300 $\mu g/m^3$
Carbon Monoxide (CO)	1 hour[c]	40 mg/m^3	40 mg/m^3
	8 hour[c]	10 mg/m^3	10 mg/m^3
Oxidant/Ozone (Ox/Oz)	1 hour[c]	160 $\mu g/m^3$	160 $\mu g/m^3$
Nitrogen Dioxide (NO_2)	1 year	100 $\mu g/m^3$	100 $\mu g/m^3$
Hydrocarbons (HC)	6-9 am[c]	160 $\mu g/m^3$	160 $\mu g/m^3$ [b]

a/ $\mu g/m^3$ = microgram per cubic meter, mg/m^3 = millogram per cubic meter.
b/ These are guidelines for formulating implementation plans, not standards.
c/ Not to be exceeded more than once a year.

SOURCE: Code of Federal Regulations, 40 CFR 50-99, revised as of July 1, 1974.

a. Particulates

Particulate matter is emitted by a large variety of sources. One of the largest sources of particulate emissions, accounting for 33.9 percent of the total nationwide emission for 1968, is forest fires and agricultural burning. In the east, large, man-made sources of particulates are coal-fired stationary power plants, construction activity, and industrial processes. Coal-fired power plants affect ambient particulate levels by emitting fly ash in small or large quantities, depending on air emission standards. New power plant sources are limited by existing New Source Performance Standards to a stringent particulate emission rate of 0.1 lbs/MMBtu.

The composite national annual average air quality for particulates has decreased from 1970 to 1974, dropping from 80 $\mu g/m^3$ to 66 $\mu g/m^3$, or 17 percent (the emissions for this same period were estimated to have dropped 29 percent). This improvement was generally reflected throughout the nation and in the east, but specific localities are still experiencing particulate levels above the standard, particularly urban areas in the northeast. The principal sources of the attainment problem are: 1) fugitive particulate emissions from industrial processes; 2) wind-blown dust from barren terrain; and 3) miscellaneous grit, sand, other detritus, and secondary pollutants formed from gaseous precursors.

b. Sulfur Dioxide (SO_2)

Sulfur dioxide is formed when material containing sulfur is burned, allowing the sulfur to oxidize. The largest source of SO_2 is fossil fuel combustion, mainly at power plants. Other sources are chemical plants, nonferrous smelters, and incinerators.

Sulfur dioxide concentrations have declined from a national annual composite average of 38 $\mu g/m^3$ in 1970 to 26 $\mu g/m^3$ in 1974. Most monitoring sites were in urban areas. The reduction in concentration (32%) is far in excess of the reduction in estimated emissions (only 8%), and the monitored reduction may reflect a shift in SO_2 emitters away from the cities to suburban and rural areas where there are few SO_2 monitors. This is particularly true in the east. In many regions the reduction leveled off from 1972 to 1974. The future trends will be determined by the types of fuel available and the emission controls associated with fuel combustion. Among the remaining control problems for SO_2 are the large point sources, such as power plants and nonferrous smelters, which can cause localized violations until they comply fully with emission regulations.

c. Nitrogen Oxides (NO_x)

Nitrogen oxides (both NO_2 and NO which will further oxidize to NO_2 in the atmosphere) are formed from the oxidation of both atmospheric nitrogen and nitrogen compounds in fuel. This oxidation process occurs mainly at high temperatures, and the major source of these oxides is motor vehicles, followed by electric power plants and large energy conversion processes.

The monitoring technology for nitrogen oxides has been in a state of flux for several years, and as a result, there are very few historically consistent and reliable data for nitrogen oxides. Both Philadelphia and Los Angeles have monitored nitrogen oxides since the mid-sixties, and they have observed a 30% increase in concentrations. On the national level, nitrogen oxides have increased by 10% from 1970 to 1974. The majority of this increase is due to motor vehicles.

d. Carbon Monoxide (CO), Hydrocarbons (HC), and Oxidants

Carbon monoxide, hydrocarbons, and oxidants are principally vehicle-related pollutants. Both carbon monoxide and hydrocarbon emission levels have decreased from 1970 to 1974. A major reason for these reductions is the Federal Motor Vehicle Control Program. As the vehicle controls become more stringent and as more uncontrolled vehicles are replaced by newer, controlled vehicles, these emissions will decrease further. EPA estimates that all but six or seven AQCR's will attain the air quality standards for carbon monoxide within the legislated time frame.

Control of photochemical oxidants is considered one of the biggest problems in attainment of the National Ambient Air Quality Standards. As the number of monitoring sites increases, the number of violations detected also increases. Recent data show widespread violations in many rural locations in the midwest and east. Although the peak oxidant levels show some improvement, future projections of oxidant levels indicate that extensive control of hydrocarbons (and possibly nitrogen oxides) will be necessary to attain the oxidant standard.

e. Sulfates

Suspended sulfates, as commonly measured, include sulfuric acid, water-soluble sulfate salts, absorbed sulfur dioxide, and sulfites. Most sulfates are formed through secondary chemical reactions in the atmosphere, and only a small proportion are emitted directly. On a global level, most of the airborne sulfur compounds are believed to have originated from natural sources such as volcanic action or sea salts. On the national level, due to the numerous sources of sulfur emissions in the U.S., the man-made sources for sulfates are believed to be more significant than the natural sources.

The annual sulfate concentrations for 1970 in much of the eastern U.S. were about 7 $\mu g/m^3$, but in parts of New England, the annual 1970 urban sulfate concentrations exceeded 13 $\mu g/m^3$. In 1972, despite a drop in urban sulfur dioxide emissions, the sulfate levels remained fairly constant. For the 24 States east of the Mississippi, the annual average urban concentration was 13.6 $\mu g/m^3$ (ranging from 10 to 25 $\mu g/m^3$), and the nonurban annual sulfate concentration averaged in excess of 10 $\mu g/m^3$ (ranging from 8 to 14 $\mu g/m^3$). For the 24 States west of the Mississippi, the average 1972 urban concentration was 7.8 $\mu g/m^3$ and the non-urban concentration was 4.4 $\mu g/m^3$. In these western States, there were some high localized sulfate levels, but the regional values were all less than for the eastern States.[1/]

The high sulfate levels in the northeastern States correlate spatially with high SO_x emission densities, high rainfall acidity patterns, and a high density of power plant sites. In New England, the acidity of the rainfall and the rate of deposition of sulfates have been increasing since 1968.[2/] Although urban sulfur dioxide emissions and locally formed sulfate levels have decreased, the increase in nonurban sulfur dioxide emissions and sulfate formation has caused increases in regional sulfate levels.

Sulfates formed locally from the sulfur dioxide emissions of large stationary sources such as power plants are strongly influenced by the amount of sulfur dioxide emitted, and a relationship between emissions and oxidation can be postulated. However, the regional and background sulfate concentrations are influenced by sulfur oxide transport and various oxidation mechanisms. In some

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1/ EPA, "Position Paper on Regulation of Atmospheric Sulfates," September, 1975.

2/ Nisbet, "Sulfates and Acidity in Precipitation," National Academy of Sciences, Washington, D.C., March 1, 1975.

of these oxidation mechanisms the reaction is more dependent on the concentration of the catalytic agent (such as atmospheric ammonia or metal particles) than on sulfur dioxide.

f. Trace Metals

Trace metals occur in coal and coal ash and include arsenic, beryllium, cadmium, zinc, lead, mercury, and others. Although large mineable deposits of these elements occur, the usual concentrations of these substances in the earth's surface layer are quite small - rarely over a few parts per million. These metals are released into the atmosphere by wind and water erosion and by many of man's activities such as agriculture, mining, fuel burning, and manufacturing. Many of these metals can be transported long distances through air and water and can be passed along the food chain with little change in chemical properties. Most of these materials are not toxic in their elemental form, but many of their ions and compounds can be quite harmful. In general, these elements are emitted in greater quantities as more coal is consumed. In the future, therefore, as coal consumption increases, these pollutants (from any source, including fossil-fuel combustion) and their effects may cause increasing concern.

B. Water

1. Resources

Water is relatively abundant in the eastern United States. High surface water discharges are caused by relatively high rainfall, high runoff, and low evaporation which characterizes the eastern regions of the U.S. As shown in Figure III-2, the east has an annual average rainfall of between 35 and 55 inches. The mountains of Appalachia and the southern Gulf Coast have higher

FIGURE III-2

AVERAGE ANNUAL PRECIPITATION
(inches)

SOURCE: DeWiest, R.J.M., Geohydrology, John Wiley and Sons, Inc., New York, 1965.

amounts of rainfall (up to 80 inches annually) than other eastern regions.

The east also experiences high runoff rates (see Figure III-3). In the mountainous regions, runoff rates are among the highest in the U.S., ranging from 20 to 40 inches per year. This high runoff rate causes stream flows of more than 150 billion gallons per day from the Appalachian region. The major river systems draining the Appalachian Region are shown in Figure III-4 and their discharges are shown in Table III-2. Streams draining the region generally originate from the interior highlands. More than half of the Ohio River Basin is contained within the Appalachian Region. The east has among the lowest evaporation rates in the U.S. As shown in Figure III-5, evaporation rates are generally higher in the south and west.

Groundwater availability varies throughout the region. The coastal areas have plentiful groundwater supplies from aquifers of sand and gravel. In other eastern regions, groundwater is found primarily in consolidated rock aquifers of sandstone and limestone. Groundwater is less abundant inland, and therefore, the inland regions with consolidated rock aquifers are more likely to depend upon surface water rather than groundwater for their water supplies.

2. Quality

Surface water quality in the eastern U.S. varies depending upon climate, rock types, degree of weathering, flow conditions, topography, and changes in both water and land use patterns. Waters in the east tend to be low in minerals and buffering capacity. In about 90% of the region, levels of dissolved solids are within levels acceptable for most water uses. Only in the

FIGURE III-3

AVERAGE ANNUAL RUNOFF
(inches)

SOURCE: DeWiest, op. cit.

FIGURE III-4

MAJOR RIVERS OF THE APPALACHIAN REGION

TABLE III-2

RUNOFF CHARACTERISTICS OF SELECTED RIVERS IN THE APPALACHIAN REGION

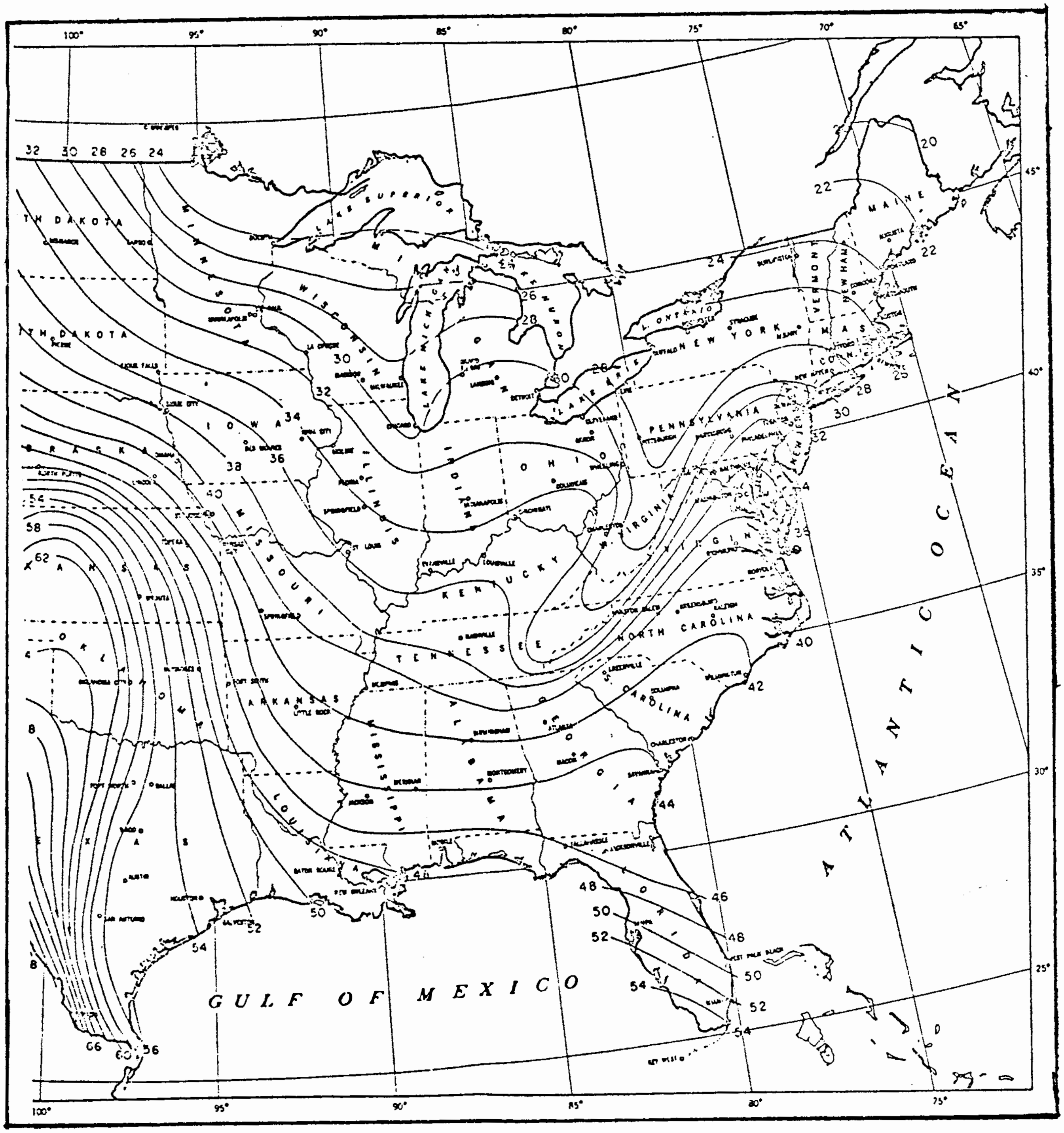
River	Aver. Discharge (cfs) a/	Max. Instantaneous Discharge (cfs)	Min. Daily Discharge (cfs)	7 Day Aver. Once In 10-Yr. Low Flow (cfs)	1 Day in 30 Yrs Low Flow (cfs)
Pennsylvania					
Susquehanna River at Harrisburg	34,000	52,607	16,920		
Allegheny River at Natrona	19,490	238,000	922	1,096	732
Monongahela River at Greensboro	8,168	140,000	204	384	208
Beaver at Wampum	2,365	50,106	74	232	
Ohio					
Ohio River at Sewickley	32,740	574,000	1,800	2,370	5,580
Muskingum River at McConnelsville	7,282	126,000	218	565	397
Kentucky					
Ohio River at Marysville	91,550	63,500	53,250	5,795	10,750
Big Sandy River at Louisa	4,228	89,400	1,510	59	29
Kentucky River at Winchester	5,223	92,400	10 (est.)	33	29
Cumberland at Rowena	8,867	162,000	0	325	28.5
West Virginia					
Kanawha River at Charleston	10,367	216,000	1,030	1,200	880
Ohio River at Parkersburg	50,730	440,000	2,290	3,590	7,520
Guyandotte at Branchland	1,573	40,400	3.6	20	10.3
Virginia					
New River (Kanawha) at Glenlyn	4,929	226,000	700	1,050	735
Maryland					
North Branch Potomac River at Cumberland	1,264	1,650	640	41	
Alabama					
Black Warrior River at Tuscaloosa	7,640	224,000	37	92	51
Coosa River at Gadsden	9,264	76,900	100	1,430	840

a/ cfs = cubic feet per second.

SOURCE: Hittman Associates, Inc., Baseline Data Environmental Assessment of a Large Coal Conversion Complex, Interim Report Vol. II, August 1974.

FIGURE III-5

ANNUAL EVAPORATION RATES IN U.S.



SOURCE: DeWiest, <u>op</u>. <u>cit</u>.

north central area and parts of Florida do these levels exceed 500 mg/l, a limit set by the U.S. Public Health Service for drinking water.[1/]

With the exception of areas along the eastern seaboard, pH values of streams lie between 7 and 8.[2/] Such pH values are well within the limits set by Federal criteria. The regions of low pH in West Virginia and Pennsylvania are caused primarily by acid mine drainage. In the southeast, the low buffering capacity of the Coastal Plain sands and the ecological dynamics of swamps contribute to the low pH (<6.9) of surface waters.

Generally, heavy metal levels are lower in the east than the west due to the differences in urban and agricultural activities. EPA water quality criteria designate the following levels of heavy metals for the protection of public water supplies: arsenic, 50 µg/l; cadmium, 10 µg/l; lead, 50 µg/l; and zinc, 5000 µg/l. Only in a few river basins in the East are these criteria violated.

Mine drainage pollution in the Appalachian Region is a major cause of surface water quality degradation. In 1974, the National Strip Mine Study reported that more than 10,000 miles of stream in the Appalachian region were significantly affected by mine drainage pollution. A total of 6300 miles of stream in Appalachia are estimated to be polluted continually by acid mine drainage; this represents about 93 percent of the total for the nation.[3/] The large majority of streams degraded by acid mine

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1/ CEQ Analysis of data from the U.S. Geological Survey's National Stream Quality Accounting Network.

2/ Ibid.

3/ Appalachian Regional Commission, "Challenges for Appalachia: Energy, Environment and National Resources," Washington, D.C., October, 1976, p. 497.

drainage is in Northern Appalachia. The problems in the Monongahela, Allegheny, Susquehanna, and North Branch of the Potomac Basins are caused primarily by acid mine drainage from underground mines. Mine drainage pollution is most severe and widespread in the Monongahela Basin. Almost 20 percent of the total stream miles in the Monongahela Basin are significantly affected due to mining-related pollution.[1/] The water quality problems of the Kanawha, Cumberland, Big Sandy, and Kentucky River Basins in Central Appalachia primarily are associated with high sediment loads resulting from contour strip mining on steep slopes.[2/]

Outside the Appalachian region, water quality impacts are created by municipal, industrial, and agricultural sources. Along the eastern seaboard, rivers, such as the James, are polluted primarily by municipal and industrial activity. In the midwest, water quality problems are the result of agricultural runoff.

Groundwater quality varies according to aquifer characteristics. In coastal areas, the quality is generally good except in places where the groundwater has been contaminated by salt water. In other areas where limestone and sandstone are the primary aquifers, the quality is generally poor. Iron and hardness are common problems, requiring that the water be treated prior to use.

1/ EPA, "Mine Drainage Report to Conferees," Enforcement Conference, Monongahela River and Its Tributaries, 1971, p. 7.

2/ Army Corps of Engineers, The National Strip Mine Study, Vol. 1, July 1974, pp. 41-43.

C. Land

1. Geology

The area of the eastern United States that will be affected by the Coal Loan Guarantee Program can be divided into six physiographic provinces: the Coastal Plain, Piedmont, Blue Ridge, Valley and Ridge, Appalachian Plateaus and Interior Lowlands Plateaus Provinces (see Figure III-6). The latter four provinces all lie within the Appalachian Region and will be discussed together.

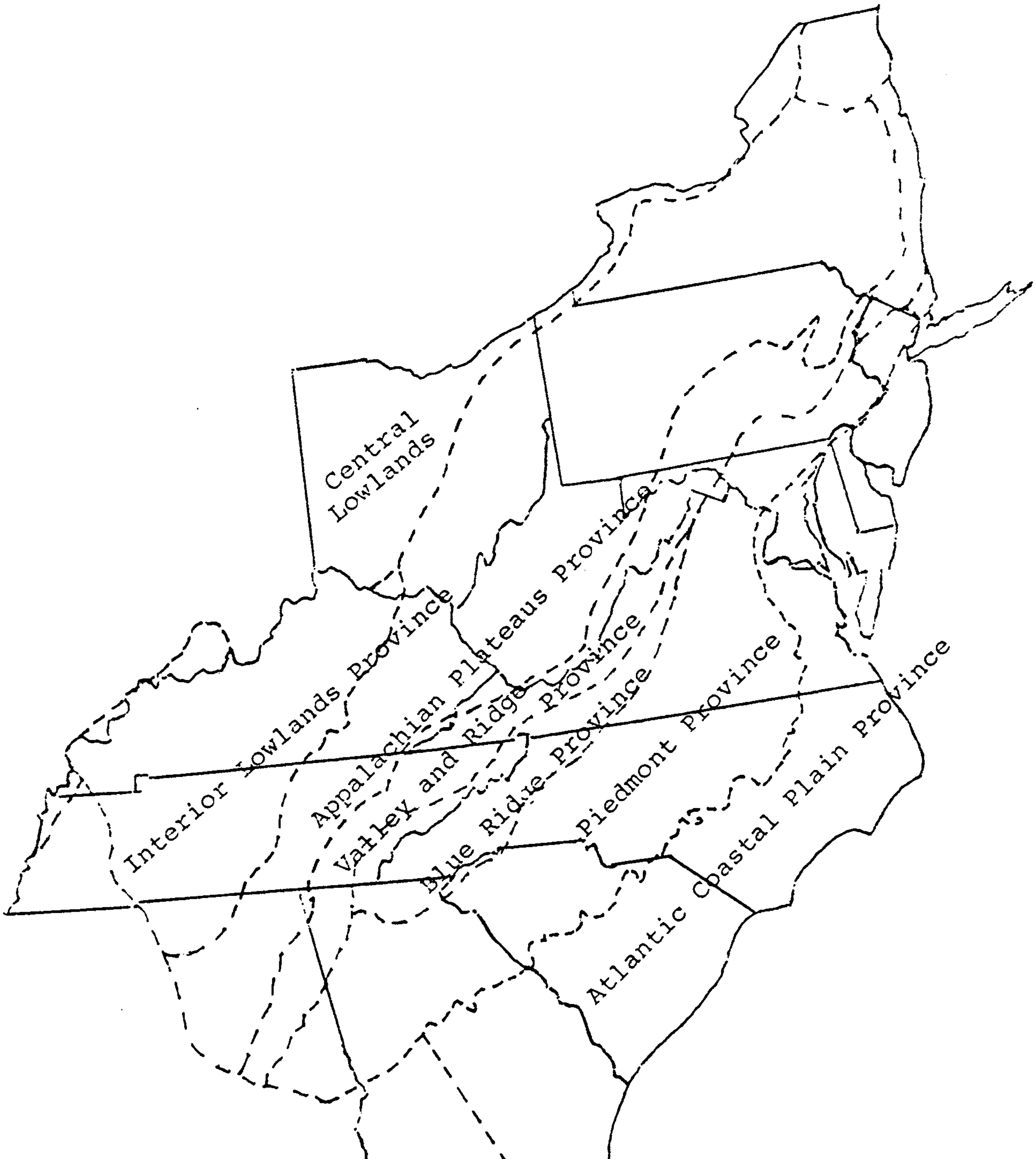
The Appalachian Region is made up of an elongated structural basin, or trough, which is filled with an assortment of thick sedimentary rock units. The eastern edge of the basin is bounded by the Pidemont and Blue Ridge physiographic provinces and extends westward to central Tennessee, Kentucky, and western Ohio. The basin terminates to the south in Alabama, where it is overlapped by sediments of the Coastal Plain Province, and extends northward into New York and Canada.

The strata along the easternmost margin of the Appalachian Basin are strongly folded and faulted. The intensity of these structural deformations decreases to the west. Along the western margin of the basin, the strata are nearly horizontal.

The bituminous coal seams of the Appalachian Region are of Permian and Pennsylvanian age and are located within five groups or formations. They are, in descending order, the Dunkard Group, the Monongahela Formation, the Conemaugh Formation, the Allegheny Formation, and the Pottsville Group. The uppermost Dunkard Group, comprised of shaly clastics, has a number of bituminous coal seams which are generally thin and only mined locally. The Monongahela Formation, consisting of red and gray shale, non-marine limestone,

FIGURE III-6

PHYSIOGRAPHIC PROVINCES OF THE EASTERN UNITED STATES



sandstone, and coal, contains several important coals including the Pittsburgh, Redstone, and Sewickly Seams. The Conemaugh Formation, containing predominately minor seams, is present only in the Northern Appalachian field and is comprised primarily of shale, clay, siltstone, and some limestone. The Allegheny Formation has some of the most significant coal seams in the Appalachian Region, containing upper and lower Freeport coals, the Clarion coal, and the upper, middle, and lower Kittaning coals. It consists primarily of sandstone and gray shale and lesser amounts of coal and limestone. The lowermost Pottsville seams are the Upper Mercer, Stockton-Lewiston, Sewell, Beckley, and Pocahontas seams. The group consists primarily of sandstone and gray shale with abundant coals and lesser amounts of limestone. Attitudes of the seams vary from flat to gently dipping with local steepening in some folds.[1/]

The Appalachian Region contains about one-quarter of the nation's identified coal reserves.[2/] The coal reserves, primarily bituminous in rank, occur throughout the region in an area of about 70,000 square miles. The coal-bearing region encompasses parts of Pennsylvania, Ohio, Maryland, West Virginia, Virginia, eastern Kentucky, Tennessee, and Alabama. Most of the reserves, however, are concentrated in the four States of Pennsylvania, West Virginia, Ohio, and Kentucky.

The reserves in the Appalachian Region are in at least 90 bituminous seams capable of being mined. The thickness of the seams varies from less than two feet to around six feet, with the average seam thickness being approximately four feet.

1/ Meyer, G., "Geology and Mineral Resources of the Appalachian Region," U.S. Department of the Interior, Geological Survey, Washington, D.C., 1965.

2/ U.S. Department of the Interior, Bureau of Mines, "Coal - Bituminous and Lignite in 1975," February 10, 1977, p. 7, Table 4.

The greater quantities of coal reserves in the Appalachian Region are located in two areas of concentration. The geographical distribution of the areas and the demonstrated surface and underground reserves within these concentrated areas are given in Table III-3. The first area is in the northern part of the Appalachian Region and comprises the States of West Virginia, Ohio, and Pennsylvania, the eastern portion of Kentucky, and smaller portions of Maryland, Virginia, and Tennessee. The second area is of smaller concentration and is not included in this analysis. It is located in Alabama in the very southern part of the region.

The most recent Bureau of Mines estimates of reserves (January 1, 1974), in the northern part of the Appalachian Region and primarily in the major coal-bearing States of West Virginia, Ohio, Pennsylvania, and eastern Kentucky, indicate there are over 14 billion tons of surface reserves and almost 95 billion tons of underground reserves. Of the underground reserves, more than 23 billion tons are low sulfur (<1.0% S). Approximately 12 percent of the U.S. low sulfur reserves are located in Appalachia.[1/]

The nature of the coal varies considerably in the Appalachian Region. Most of the coal lying within the region is bituminous and ranges from low volatile to high volatile coals. The average heat content of utility coal shipped from the region in 1975 was approximately 11,800 Btu per pound of coal.[2/] The sulfur content varies from low sulfur (less than one percent) to high sulfur

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1/ Ibid.

2/ Federal Power Commission, Bureau of Power, "Annual Summary of Cost and Quality of Steam-Electric Plant Fuels, 1975," Staff report, May, 1976.

TABLE III-3

DEMONSTRATED COAL RESERVES IN THE APPALACHIAN REGION ON JANUARY 1, 1974 (million tons)

State	Surface Reserves	Underground Reserves
Alabama	1,183.7	1,798.1
Eastern Kentucky	3,450.2	9,466.5
Maryland	146.3	901.9
Ohio	3,653.9	17,423.3
Pennsylvania	1,181.4	29,819.2
Tennessee	319.6	667.1
Virginia	679.2	2,970.7
West Virginia	5,212.0	34,377.8
TOTAL	15,826.3	97,424.6

SOURCE: U.S. Department of the Interior, Bureau of Mines, *op. cit.*, pp. 5 and 6, Tables 2 and 3.

(greater than 3 percent) throughout the region. Most of the region's low sulfur coal is in eastern Kentucky, Virginia, and southern West Virginia. The ash content of the region's coals ranges from a minimum of 2 percent to as high as 50 percent. The average ash content of Appalachian coals is generally around 8 percent.[1/]

The Piedmont Region lies between the Appalachian Region and the Coastal Plain and stretches from southern New England to Alabama. It is characterized by older metamorphic and igneous crystalline bedrock and has a more mature topography than the younger Appalachian Region; gentle, rolling hills predominate in this region. The Piedmont Region's soil, a product of the weathering of metamorphic and igneous rock, is slightly acidic, and although it is usually well drained, has good water retention properties. The Piedmont Region abruptly ends at the Fall Line, the western boundary of the Atlantic Coastal Plain.

The Atlantic Coastal Plain stretches from Massachusetts to Georgia in a band 75 to 100 miles in width. The geology of the Coastal Plain is distinctly different from that of the Appalachian and Piedmont Regions. Except for the southern sandhill region, the Coastal Plain is characterized by flat-lying unconsolidated sediments of Cretaceous, Tertiary, and Quaternary ages which slope gently seaward and are underlain by older metamorphic and crystalline rock similar to those exposed in the adjacent Piedmont Region. Marine sediments of Cretaceous age lie at the inner edge of the Coastal Plain, which was submerged under the

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1/ Appalachian Regional Commission, <u>Appalachia</u> (Journal of the Appalachian Regional Commission), Vol. 5, No. 4, February-March, 1972.

Atlantic Ocean during the Cretaceous period 135 million years ago. Sediments become younger closer to the Atlantic Ocean, progressing through the Tertiary and Pleistocene, when the glacial era caused fluctuations in sea level, to recent sediments. Sediments are a mixture of marine, fluvia, and glacio-fluvial deposits ranging in texture from fine clays to coarse sands and gravels.[1/]

There are four types of soils common to the Coastal Plain: Utisols, Histosols, Entisols, and Inceptisols, all of which are moderately acidic and have good water retention properties. The drainage of these soils varies with the local topography.

2. Seismicity

As indicated in Figure III-7, it is unlikely that a major earthquake would occur in the eastern United States, with the exception of southern South Carolina. The Appalachian Region has a moderate amount of low-level earthquake activity, with the axis of principal activity roughly parallel to the coast. Minor damage may be expected in the northern parts of Appalachia, while moderate damage could occur in the southern portion.

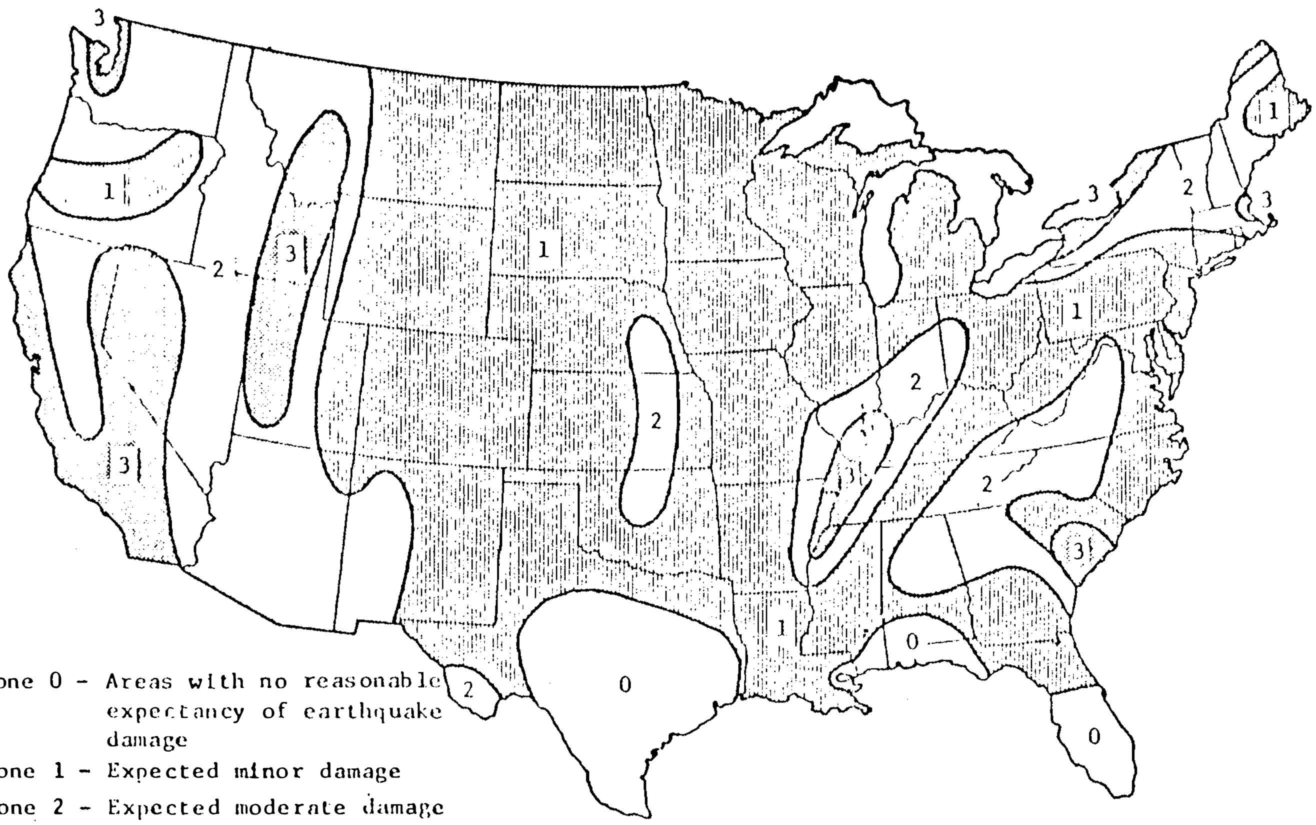
3. Topography

The Appalachian Region includes major portions of the Blue Ridge, Valley and Ridge, and Appalachian Plateau Provinces. The Blue Ridge Province is characterized by maturely dissected mountains with accordant altitudes in the northern section to subdued mountains in the southern section. Narrow and broad valleys with depths of 1000 to 1500 feet below the ridge tops, peneplains, trellised drainage patterns, and incised rivers charac-

1/ Gerlach, A.C. (ed.), "The National Atlas of the United States of America," U.S. Government Printing Office, Washington, D.C.

FIGURE III-7

SEISMIC RISK MAP FOR CONTERMINOUS UNITED STATES



Zone 0 - Areas with no reasonable expectancy of earthquake damage

Zone 1 - Expected minor damage

Zone 2 - Expected moderate damage

Zone 3 - Where major destructive earthquakes may occur

SOURCE: Disaster Preparedness, Executive Office of the President, Office of Emergency Preparedness, Report to the Congress, January, 1972.

terize the Valley and Ridge Province. The Appalachian Plateau Province, making up the major portion of the region, is a submature to maturely dissected broad plateau area of moderate to strong relief and contains several mountainous sections of strong relief. Relief may range from 200 to 300 feet in some sections to 1000 to 3000 feet in mountainous areas. Northern Appalachia is characterized by gently rolling to hilly topography in Ohio and Pennsylvania and becomes more rugged in northern West Virginia, where approximately 75 percent of the land has slopes exceeding 25 percent.[1/2/] Central Appalachia is characterized by extremely steep and rugged mountains dissected by numerous deep and narrow valleys.

The relief patterns of areas in the Piedmont region depend on their proximity to the Appalachian mountain area. The western Piedmont region is more dissected and generally has a higher relief pattern than the eastern section. In general, however, the Piedmont area is comprised of gentle, rolling hills suitable for agriculture.

The most striking topographical feature of the Coastal Plain is its flatness. Except for the sandhill regions of the south and the occasional terraces which mark the former shorelines of the Atlantic, most of the plain shows low relief and little dissection. Consequently, most of the area's rivers run sluggishly and soils are often poorly drained.

4. Land Use

Most of the land in the Appalachian Region is devoted to forestry, pasture, and cropland. In Northern Appalachia, approximately 55 percent of the land is forest and woodland, 10 percent

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1/ Lawrence A. Alexander & Company, Inc., "Comprehensive Planning Program -- Future Land Use Plan," prepared for the Marion County Planning Commission, Marion County, W. Va., 1973-74.

2/ "Monongalia County, West Virginia: Phase I of the Comprehensive Plan -- Basic Research, Surveys, Analyses," 1968-69.

grazing and pastureland (private and public-owned), and 25 percent cropland (including cropland used only for pasture). The remaining 10 percent of the land is used for special uses, including urban and other built-up areas, parks, special facilities, swamp or marsh, and mining. In Central Appalachia, because of the very steep and rugged topography, most land is too steep to be used for anything other than forest land. Over 80 percent of the land is forest or woodland, 5 percent is cropland, and about 5 percent is pasture. The remaining 10 percent is used for urban or built-up areas, parks, special facilities, wetland, wasteland, and mining.[1/]

Although much of the land along the eastern seaboard is also used for agriculture and forestry, the area as a whole is much more industrially and residentially developed. The Middle Atlantic Region (i.e., New Jersey, Pennsylvania, and New York) has the highest population density in the nation: 371 people per square mile.[2/] The South Atlantic region, the area south of Pennsylvania and east of Appalachia, has a population density of 126 people per square mile, well above the national average.

Most of the residents of these States are concentrated in a fairly small area. Eighty-eight percent of the residents of the Middle Atlantic States live in metropolitan areas, as do 65 percent of the residents of the South Atlantic Region.[3/] Therefore, much of these intensively-developed regions are still used for agriculture and forestry. Thirty-one percent of the Middle Atlantic Region.[4/] In the western areas of both regions, large tracts of land are used for commercial forestry.

1/ U.S. Department of the Interior, Geological Survey, The National Atlas of the United States of America, Washington, D.C., 1970.

2/ Bureau of the Census, Statistical Abstract of the United States, Washington, D.C., 1976.

3/ Ibid.

4/ Ibid.

D. Ecosystems

1. Terrestrial Ecosystems

Because most of the Appalachian Region is sparsely populated and the rugged terrain makes large-scale agriculture impractical, most of the area is still covered with forests. The type of forest growing in a particular region usually is determined by the elevation, soil, and moisture of that region.

Oak-type forests usually dominate the higher regions which have Podzolic or Sol Brun Acid soils. Chestnut-oak, yellow-poplar, and hickory trees are most common in these forests, although secondary growths of birches, beeches, maples, white and red pines, aspens, and hemlocks are also common. Beneath the canopy of the dominant trees, mountain laurel, rhododendron, red bud, fringe tree, wildberry, viburnums, and other understory plants are distributed according to light levels, soil types, and moisture.

In the lower, well-watered, alluvial soil regions the oak-poplar-hickory type forest is replaced by river bottom forests dominated by elm, ash, cottonwood, gum, and cypress trees. The understory of this type of forest usually consists of spice bush, ninebark, sumac, holly, huckleberry, buttonbush, hydrangea, bladder nut, and a variety of other plants.

Although some animal species are cosmopolitan to the entire Appalachian Region, most animals are distributed by fairly specific habitat requirements and preferences. Big game animals such as black bears and European wild boars need large, fairly undisturbed grazing and foraging territories, so they are mainly restricted to the less developed areas of the Appalachian Region. The same is true for the wild turkey, the only large game bird found in the area. However, most of the smaller mammals, such as rabbits, foxes, gray and red squirrels, minks, otters, skunks, and others do not have such stringent range-area needs and are distributed fairly evenly in accordance with habitat preference and availability. Ninety-six species of reptiles are distributed through the Appalachian Region in a similar manner. An even wider variety of birds is found there. Bird populations are usually dominated by the families Fringillidae (grosbeaks, sparrows, finches, cardinals) and Parulidae (warblers), but many other species are found, including game birds such as ruffed grouses, bobwhites, pheasants, doves, and several species of migratory waterfowl.

Many of the animals listed above, especially the smaller reptiles and birds, are habitat specialists, that is, their distribution is restricted to a specific forest-type or a particular set of environmental conditions. Thus the specific composition of a particular area's wildlife population will be somewhat site-specific.

Several endangered or threatened species, including the eastern cougar, Virginia big-eared bat, red cockadid woodpecker, bald eagle, peregrine falcon, and the bog turtle are known to inhabit the Appalachian Region.

Under natural conditions, the types of ecological communities found in the eastern seaboard region are determined by soil and topographical characteristics, the amount of rainfall, latitude, and proximity to the ocean. If ecological community types were determined only by these and other physio-chemical factors, the Piedmont Region and the northern coastal plain would be covered with oak-hickory and bottomland hardwood forest; the southern sand hill region and other well-drained areas would support a mixture of pine and hardwood forests. However, the effects of human activity play an equally and often more decisive role in determining the ecological composition of many eastern seaboard areas. Intensive tobacco and cotton growing caused widespread nutrient depletion and erosion in many southeastern areas, so scrub pine forests replaced the natural hardwood communities. Commercial logging, which reached its peak in the 1920's, has caused a similar proliferation of pine forests. Many other types of activities have caused subtle and acute ecosystem changes.

2. Aquatic Ecosystems

The fish inhabiting the Appalachian Region's waters are one of the region's most important resources. Although there is no substantial commercial fishery, the streams, rivers, and lakes are used intensively by sport fishermen, who catch a wide variety of game fish in these waters.

More than any other factor, water temperature determines which species of fish will inhabit an unpolluted stream. In the coldest streams, only brook trout and sculpin thrive. As the water warms, more brown and rainbow trout, daces, and creek chub are able to inhabit a stream. The warmest and largest flowing waters support populations of smallmouth and largemouth bass, channel catfish, walleyes, carp, carp suckers, and several non-game species. Smallmouthed and largemouthed bass, bluegills, crappies, pike, pickerel, and muskellunge also are commonly found in natural lakes and impounded reservoirs. Natural and stocked cold water trout streams are the most intensively fished waters in the region, but most of the fish-producing waters are used at least moderately.

However, not all of the Appalachian waters support productive sport fisheries. It is estimated that more than 10,000 miles or rivers and streams are affected by mine drainage pollution.[1/] This type of pollution often makes a productive stream completely unable to support fish life. The Black Water River near Davis, West Virginia, for example, had a natural population of brown trout until acidic water concentrated in an old deep mine was accidentally released by strip miners into nearby Beaver Creek. The Black Water River presently supports few living things and no brown trout.[2/]

Eroded sediments also diminish the fish-producing capability of many streams and rivers. Suspended solids diminish the primary productivity of an aquatic community by reducing the amount of light available for photosynthesis and by making feeding and respiration difficult for many fish. Also, even though high turbidity levels seldom kill or totally displace the fish in a stream, high sediment levels often destroy a stream's recreational value. Many game fish are "sight-feeders" that is, they must be able to see their prey clearly when they feed. Few fish in a silty stream will strike a fisherman's lure or bait. The West Virginia Fish and Game Commission has discontinued stocking several streams because of sediments from strip mines.

The aquatic communities in the upland, freshwater Piedmont and Coastal Plain rivers and lakes are roughly similar to the warm-water aquatic communities of Appalachia, since many fish species are cosmopolitan in distribution. The productivity of these communities is determined by temperature, nutrient supply, and water quality, which vary considerably within the regions.

As the large rivers approach the ocean, the number of fish species in them is increased by the influx of anadromous (breed

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1/ U.S. Army Corps of Engineers, The National Strip Mine Study, Vol. 1, July, 1974.

2/ Mr. Donald Pheras, Fisheries Biologist, Jefferson National Forest, personal communication.

in fresh water, mature in salt) and catadromous (breed in salt water, mature in fresh) species. The total productivity and therefore the degreee of commercial utilization of the aquatic ecosystem is increased by the addition of these species. The most productive areas are the mouths of large rivers and brackish water marshes, which have the highest degree of salt-freshwater mixing and the largest number of resident and transient species.

The way in which an aquatic ecosystem's productivity is harvested changes as the water becomes more saline. The upland freshwater systems are used mostly for recreational fishing, whereas the brackish and marine systems are utilized more commercially, although they provide recreational fishing as well.

E. Socioeconomic Conditions

1. Population

Until about 1970, populations of most of the counties in the Appalachian region had been steadily decreasing. According to the Bureau of the Census, most of these counties had their peak populations between 1930 and 1960.[1/] Emigration from these counties exceeded immigration to them by 6.5 percent, and the area had a substantially larger population over age 65 and under age 5.[2/]

However, population estimates for 1975 indicate that this trend has been reversed. As shown in Tables III-4 and III-5, all Central Appalachian states made significant population gains from 1970 to 1975, and immigration accounted for most of the increase (except in West Virginia). Only Northern Appalachian

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1/ Bureau of the Census, "Status," July, 1976.

2/ Department of Commerce, Bureau of the Census, 1973, County and City Data Book, 1972. U.S. Government Printing Office, Washington, D.C.

TABLE III-4

ANNUAL RATES OF POPULATION CHANGE IN APPALACHIA FROM 1959-1975

Subregion & State Part	Annual Rate of Change 1970-75 (%)	1965-70 (%)	1959-65 (%)
Appalachian Region	0.8	0.2	0.4
Northern	0.25	0.01	0.04
Maryland	0.4	0.2	1.1
New York	0.4	0.07	1.0
Ohio	0.9	-0.2	0.4
Pennsylvania	0.01	0.05	-0.1
West Virginia	0.6	-0.3	-0.5
Central	1.5	-1.0	-0.5
Kentucky	1.6	-0.9	-0.1
Tennessee	1.7	-0.2	0.6
Virginia	1.8	-1.7	-1.2
West Virginia	0.9	-1.5	-2.0
Southern	1.5	0.7	1.1
Alabama	0.9	0.2	1.2
Georgia	3.1	2.1	1.7
Mississippi	1.2	0.1	0.5
North Carolina	1.4	0.7	1.3
South Carolina	1.9	1.7	0.6
Tennessee	1.4	0.7	1.0
Virginia	0.8	-0.3	0.3

SOURCE: Dr. Jerome Pickard, Demographer, Appalachian Regional Commission.

TABLE III-5

POPULATION AND MIGRATION IN APPALACHIA, 1970-1975

	Population in Thousands			1970-1975 Rate of Change		
	July 1, 1975 p/	April 1, 1970 r/	Net Migration	Total Change (%)	Natural Change (%)	Net Migration (%)
Appalachian Region	19,026.7	18,217.1	291.8	4.4	2.8	1.6
Northern	9,860.4	9,734.0	-53.5	1.3	1.8	-0.5
Maryland	213.7	209.3	0.5	2.1	1.8	0.2
New York	1,079.1	1,056.6	-2.9	2.1	2.4	-0.3
Ohio	1,184.0	1,129.9	22.1	4.8	2.8	2.0
Pennsylvania	5,932.8	5,930.5	-81.7	0.04	1.4	-1.4
West Virginia	1,450.9	1,407.7	8.6	3.1	2.5	0.6
Central	1,886.0	1,744.9	75.4	8.1	3.8	4.3
Kentucky	952.3	876.5	41.0	8.6	4.0	4.7
Tennessee	365.4	334.6	20.8	9.2	3.0	6.2
Virginia	216.3	197.3	11.1	9.6	4.0	5.6
West Virginia	352.0	336.5	2.5	4.6	3.8	0.8
Southern	7,280.2	6,738.2	269.9	8.0	4.0	4.0
Alabama	2,242.5	2,137.4	23.4	4.9	3.8	1.1
Georgia	956.4	813.8	97.3	17.5	5.6	12.0
Mississippi	446.5	418.6	8.9	6.7	4.5	2.1
North Carolina	1,119.4	1,039.0	44.8	7.7	3.4	4.3
South Carolina	726.0	656.4	39.4	10.6	4.6	6.0
Tennessee	1,504.8	1,399.9	51.2	7.5	3.8	3.7
Virginia	284.7	273.0	4.9	4.3	2.5	1.8
State Parts	1,870.2	1,734.5	72.0	7.8	3.7	4.1
Tennessee (C+S)	1,870.2	1,734.5	72.0	7.8	3.7	4.1
Virginia (C+S)	501.0	470.3	16.0	6.5	3.1	3.4
*West Virginia (N+C)	1,802.9	1.744.2	11.1	3.4	2.7	0.6

*entire state p/ provisional 1975 Census estimates, r/ revised 1970 Census data.

SOURCE: Dr. Jerome Pickard, Demographer, Appalachian Regional Commission.

populations showed continuing emigration. The 1970-1975 growth rate for the entire Appalachian region, 4.4%, still lagged behind the national 1970-75 growth rate, 4.8%, but the 1970-75 increase represents a significant change in the dynamics of the region. The factors influencing this reversal include:

- increased job opportunities;
- increased attractiveness of rural life-style;
- shortages of housing and employment in outside areas;
- return of military personnel and the end of selective service; and
- substantial increases in social welfare payments.

Although population growth trends changed substantially between 1970-75, many of the characteristics of the general population have remained the same. The region still has the highest illiteracy level in the nation, and 45% of the people continue to live in rural areas, as compared to the national rural population average of 12%.[1/]

As in the Appalachian area, population densities and growth rates in the eastern United States are distributed unevenly and have changed radically from 1970 to 1975. In 1975 the Middle Atlantic Region, historically the most urbanized area in the United States, had a high population (37,199,000) and the highest population density (371 residents/mi^2) in the country, but the region's growth lagged behind the rest of the nation. The national annual average growth rate for 1970 to 1975 was 0.9 percent, yet the growth rate for the Middle Atlantic Region was below 0.05 percent. During this period, emigration out of the Middle Atlantic region exceeded immigration into the area by 758,000.[2/]

1/ "Questions for Appalachia," in Appalachia, Vol. 10, #2, Appalachian Regional Commission, Washington, D.C., October, 1976.

2/ Bureau of the Census, "Status," op. cit.

The South Atlantic Region, on the other hand, had a lower population (30,671,000) and population density (126.3/mi^2) than the Middle Atlantic Region in 1975, but had a much higher growth rate. The annual growth rate in 1970-1975 for the South Atlantic Region was 1.8%, roughly double the national average. In the same period, the region gained 1,859,000 residents through immigration.[1/]

2. Economic Conditions and Employment

The area of the eastern United States that will be affected by the Coal Loan Guarantee Program can be divided into two economic districts: Appalachia, where coal mining is an important industry, and the more effluent eastern seaboard states which depend primarily on an industrial/agricultural economy.

Appalachia is one of the nation's largest "poverty pockets." Per capita income levels are usually 20-25 percent below national levels; 18 percent of Appalachian family incomes are below the Federal poverty level, as opposed to the national average of 14 percent.[2/] Many of the area's people live in substandard housing (Figure III-8), and malnutrition is common in some of the poorest counties.

However, increased availability of jobs, improved transportation facilities, Federal and private assistance grants, and other factors have recently been diminishing the income gap between Appalachia and the nation. As shown in Table III-6, the Appalachian per capita income as a percent of the national average has increased by 4.2% between 1959 and 1972. Figure III-9 illustrates the related decline in the percentage of poverty-level persons. An examination of these tables reveals that the

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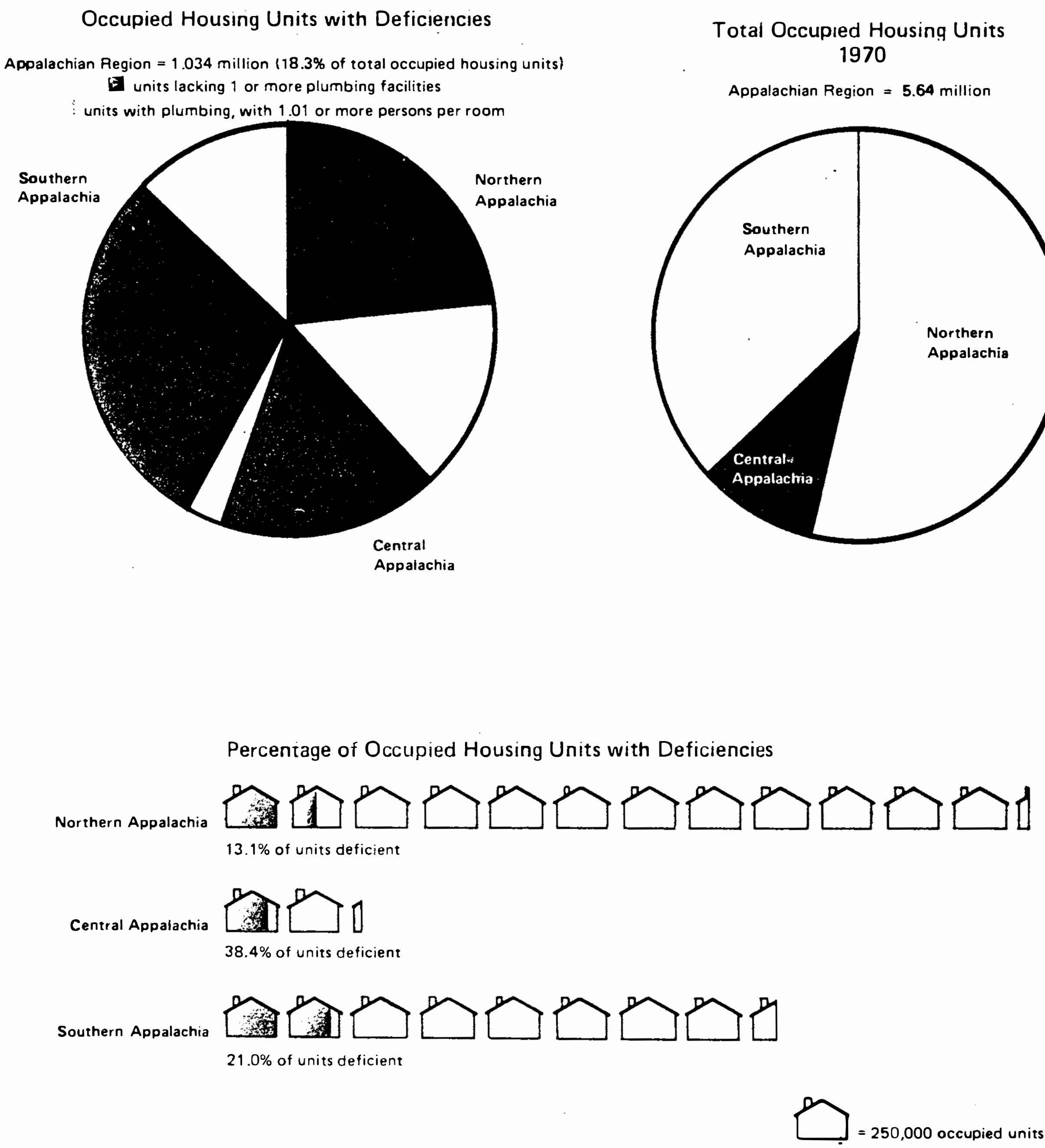
1/ Ibid.

2/ Appalachian Regional Commission, Appalachia, Vol. 10, No. 2, Washington, D.C., October, 1976.

FIGURE III-8

SUBSTANDARD HOUSING IN APPALACHIA



SOURCE: Appalachian Regional Commission, "Questions for Appalachia," in Appalachia, Vol. 10, No. 2, October, 1976.

TABLE III-6

CHANGES IN APPALACHIAN PER CAPITA INCOME AS A PERCENTAGE OF U.S. LEVEL 1959-72 BY SUBREGION AND STATE PART

	Per Capita Income as Percent of U.S.			Percentage Points of Annual Change	
	1959	1969	1972	1959 to 1969	1969 to 1972
Region	77.7%	80.3%	81.9%	0.3	0.5
Northern	88.6	86.5	86.6	–0.2	0.0
Maryland	85.6	83.3	84.8	–0.2	0.5
New York	95.4	91.2	88.3	–0.4	–1.0
Ohio	79.0	78.3	78.0	–0.1	–0.1
Pennsylvania	91.9	89.5	89.5	–0.2	0.0
West Virginia	78.6	77.6	80.5	–0.1	1.0
Central	50.6	58.5	62.5	0.8	1.3
Kentucky	46.8	55.5	58.2	0.9	0.9
Tennessee	51.6	61.9	64.7	1.0	0.9
Virginia	49.0	57.9	66.3	0.9	2.9
West Virginia	59.6	63.0	69.4	0.3	2.1
Southern	68.7	77.0	80.4	0.8	1.1
Alabama	71.3	77.9	81.8	0.7	1.3
Georgia	64.5	77.6	80.9	1.3	1.1
Mississippi	46.8	59.7	63.9	1.1	1.4
North Carolina	69.8	78.1	82.9	0.8	1.6
South Carolina	73.3	82.4	85.4	0.9	1.0
Tennessee	72.6	78.2	80.5	0.6	0.8
Virginia	61.6	71.4	71.7	1.0	0.1
Tennessee (Central and Southern)[1]	68.3	75.0	77.4	0.7	0.8
Virginia (Central and Southern)[1]	55.8	65.7	69.4	1.0	1.2
West Virginia (Central and Northern)[1]	74.5	74.8	78.3	0.0	1.2

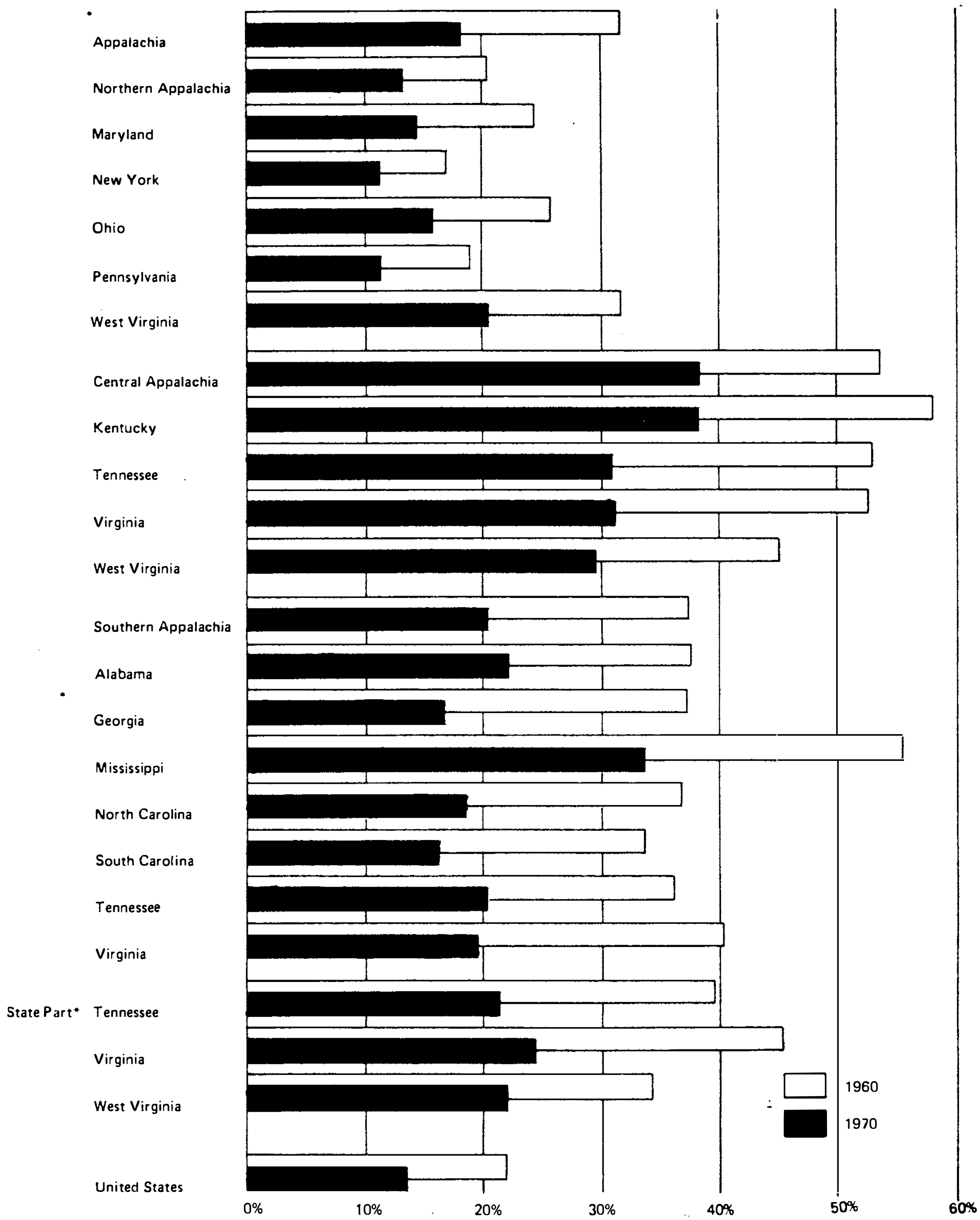
Income estimates prepared by Bureau of Census for Office of Revenue Sharing, Treasury Department, for 1972. Per capita incomes are calculated for 1972 income and July 1, 1973 population. Earlier data are based on 1960 and 1970 Censuses of Population. Per capita incomes are calculated for 1969 income and April 1, 1970, population and 1959 income and April 1, 1960, population.

[1] Figures for the two subregional portions of these states, the only three which fall in two subregions, are combined here.

SOURCE: Dr. Jerome Pickard, "Per Capita Income Gap Between Appalachia and U.S. Diminishes" in Appalachia, Vol.8, No. 6, June, 1976.

FIGURE III-9

PERSONS BELOW POVERTY LEVEL
AS A PERCENTAGE OF HOUSEHOLD POPULATION
1960 AND 1970



*Three states, Tennessee, Virginia and West Virginia, fall into two subregions each. Percentages are given for each subregional portion of these states, and for the Appalachian parts of the states as a whole (the entire state, in the case of West Virginia).

SOURCE: Dr. Jerome Pickard, "Per Capita Income Gap Between Appalachia and U.S. Diminishes", in Appalachia. Vol. 8, No. 6, June, 1976.

most dramatic economic gains have been made in Central and Southern Appalachia, but the per capita incomes of these regions still remain low and the percentage of people with below poverty-level incomes remains high. Income levels and poverty cases in Northern Appalachia, the wealthiest region, have been relatively stable.

Appalachian employment patterns, along with population and income levels, have been significantly altered. Prior to the last decade, most of the region's people lived on small subsistence-level farms. Between 1965 and 1973, more than 800,000 new jobs have been created, as shown below:

EMPLOYMENT IN APPALACHIA
(in thousands)

	1965	1973	Change
Manufacturing*	1,861	2,108	+13%
Trade	853	1,141	+34%
Services	497	745	+50%

* includes mining

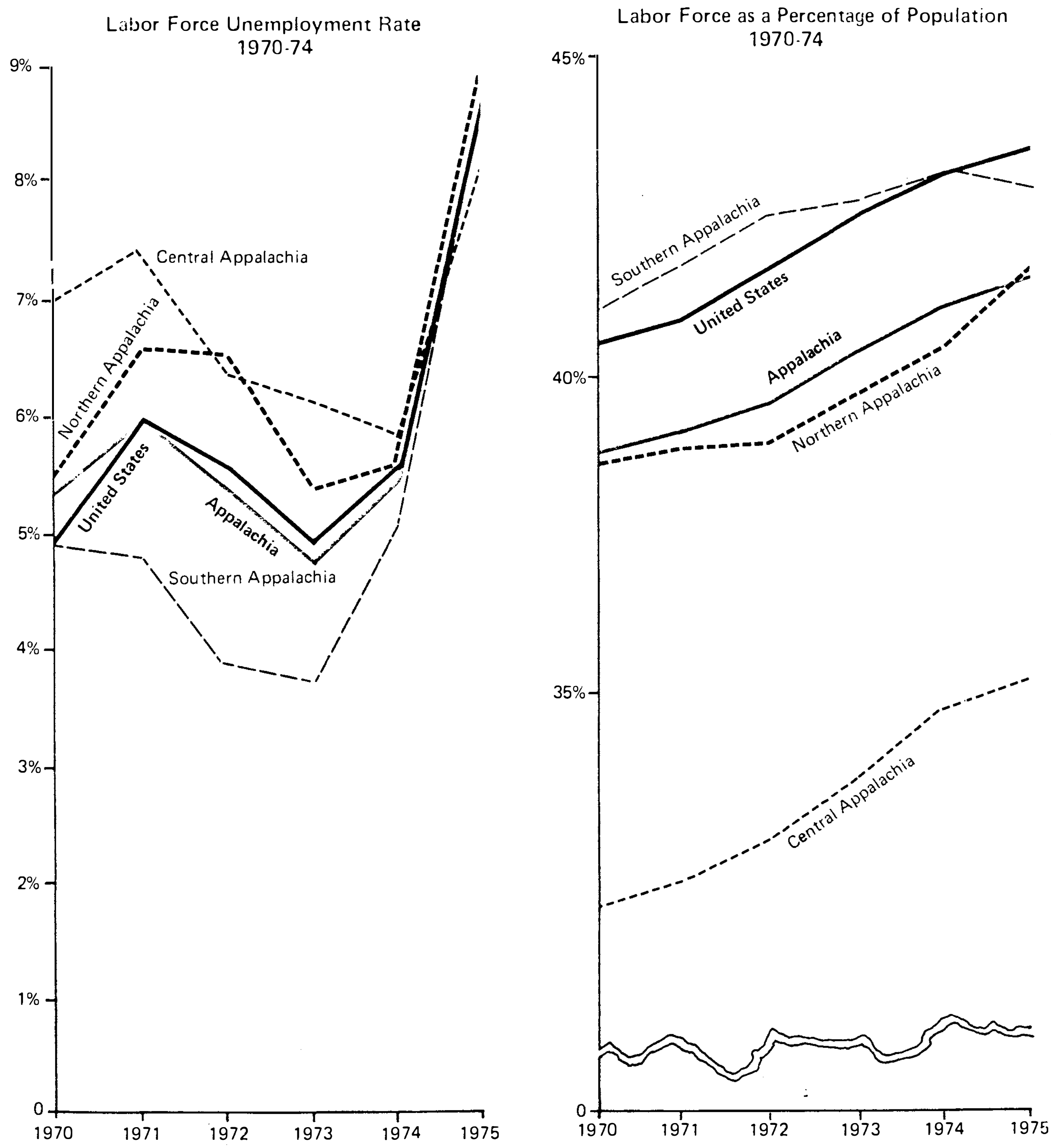
SOURCE: Appalachian Regional Commission, "The State of the Child in Appalachia," Washington, D.C., 1977.

Unemployment in Appalachia, which was once consistently above national levels, now roughly follows national trends, as shown in Figure III-10. However, the accuracy of unemployment statistics for the region is jeopardized by difficulties in acquiring rural unemployment data and the inconsistent working patterns typically followed at the smaller coal mines.

In the eastern seaboard region, the Middle Atlantic area is more intensively developed than the South Atlantic area, so it has the greater proportion of industrial workers and the higher

FIGURE III-10

UNEMPLOYMENT IN APPALACHIA



SOURCE: Appalachian Regional Commission, "Selected Facts About Appalachia," in Appalachia, Vol. 10, No. 2, October, 1976.

level of per capita income. Manufacturing workers made up 20% of the labor force in the Middle Atlantic Region in 1973, as opposed to 14 percent in the South Atlantic Region.[1/] Income per capita in the Middle Atlantic Region in 1975 was 109 percent of the national average, whereas it was 92.6 percent in the South Atlantic.[2/]

However, economic growth in the Middle and South Atlantic Regions has recently (1960-1975) been concentrating in the South, as has been noted in Appalachia. Per capita income as a percent of the national average has been increasing in the South and declining in the Middle Atlantic area as shown below:

PER CAPITA INCOME AS A PERCENT OF NATIONAL AVERAGE[3/]

	1960	1970	1975
Middle Atlantic	116.2	112.8	109.3
South Atlantic	83.0	91.1	92.6

From 1970 to 1975, only 147,000 new housing units were authorized in the Middle Atlantic Region, whereas 303,600 new units were authorized in the South.[4/]

The increase in demands for electric power in these two regions roughly follow their respective economic growth rates. The amount of electricity generated in the South Atlantic Region between 1970 and 1975 increased by an annual rate of 6.1 percent whereas in the North it increased by only 2.1 percent annually in the same period.[5/]

1/ Bureau of the Census, "Status," op. cit.

2/ Ibid.

3/ Ibid.

4/ Ibid.

5/ Ibid.

3. Health and Safety

Appalachia's poverty and the isolation of much of its population have increased the difficulty of providing adequate sanitary services and health care facilities, so the health of Appalachia's people is poorer than the average American's. Infant and general mortality rates in Appalachia are higher than national averages.[1/]

Many of the region's health problems can be attributed to the lack of health manpower. As Table III-7 shows, most of Appalachia, particularly the Central and Southern regions, is suffering from a health manpower shortage. Figure III-11 shows the counties in Central and Southern Appalachia which are characterized as "medically underserved" areas by HEW.

Poor environmental quality also causes health problems. Approximately 16% of the region's houses lacked indoor plumbing in 1971, and sewage treatment facilities are inadequate in many regions, so the incidence of waterborne communicable diseases is high.

The dangers of coal mining contribute to the area's high mortality rate. An average of .36 fatalities and 43.0 injuries occurs for each million tons of coal extracted from an underground mine and .09 fatalities and 7.9 injuries occur for each million tons of coal extracted from a surface mine.[2/] Additionally, miners suffer from "black lung" and other occupational diseases.

1/ Bureau of the Census, American Almanac, Grosset and Dunlap, 1974, New York.

2/ Bureau of Mines, "Coal - Bituminous and Lignite in 1974," U.S. Department of Interior, Washington, D.C., 1976.

TABLE III-7

HEALTH MANPOWER DATA

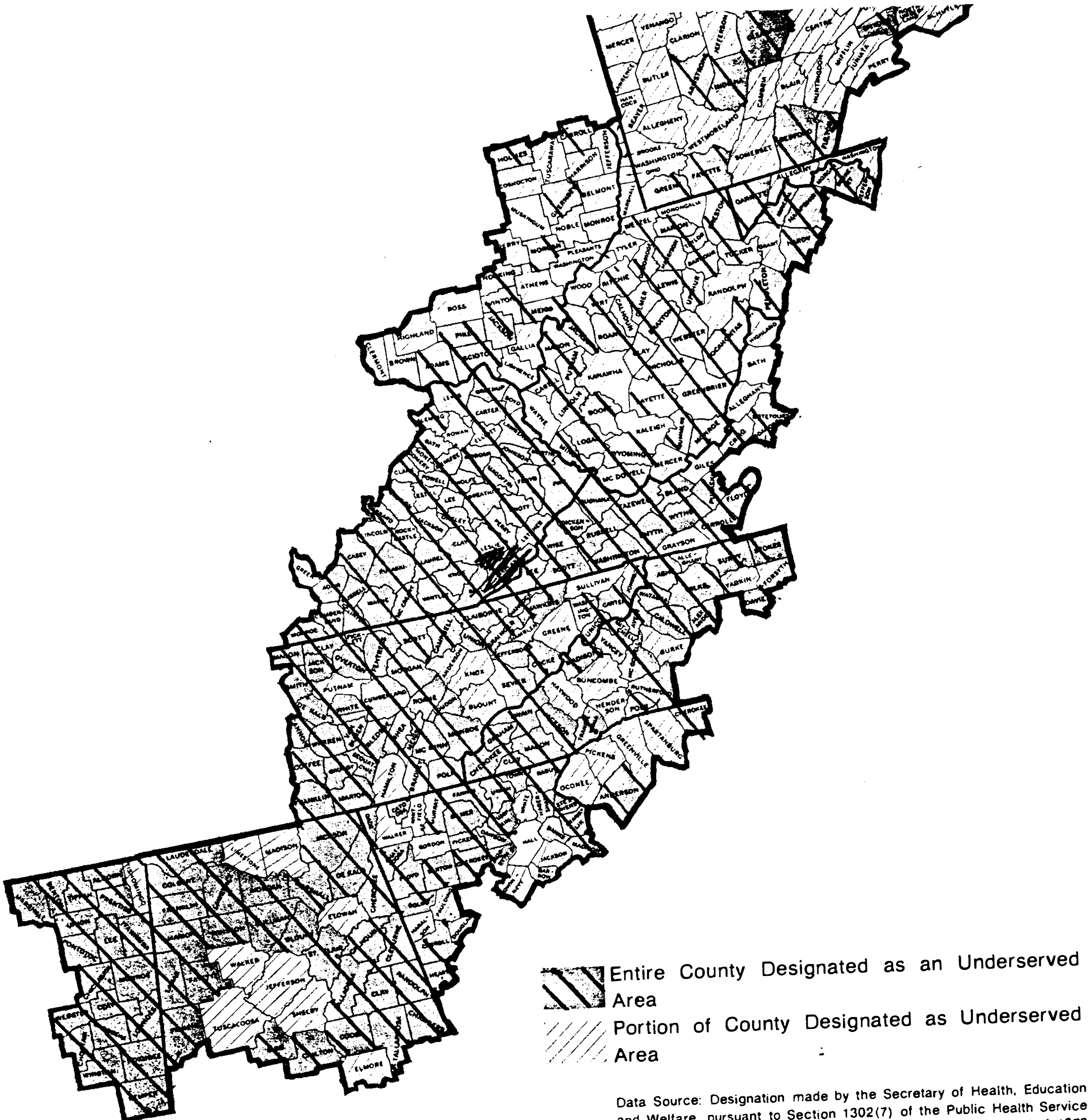
(1975)

	U.S. Average/Total	Appalachian Region Total	Appalachian Subregion Totals: Northern	Central	Southern
Physicians/100,000 pop.:	149	98	106	66	93
# MD's	5	2	4	1	1
# OD's	154	100	110	67	94
Total Physicians	53	40	48	23	32
Dentists/100,000					
Nurses:	295	284	396	109	167
# RN's/100,000 pop.	120	139	164	94	114
# LPN's/100,000	415	423	560	203	281
Total Nurses/100,000	121.1	37.3	45.0	25.3	24.8
# RN/100 Hospital beds	49.2	18.3	18.6	21.7	17.0
# LPN/100 Hospital beds	170.3	55.6	63.6	46.9	41.8
Total Nurses/100 Hospital beds	18.070	1,357	849	103	405
Total Optometrists	106,606	7,805	4,658	488	2,659
Total Pharmacists	8,342	484	417	9	58
Total Podiatrists	25,743	1,558	920	89	549
Total Veterinarians	5,999	610	278	87	245
Number General Hospitals (Total)	153	135	169	77	117
(Number Beds/Hospital)	453	452	484	384	425
(Number Beds/100,000 pop.)	1,213	105	60	7	38
Number Other Hospitals					

SOURCE: Appalachian Regional Commission, "State of the Child in Appalachia", January, 1977, Washington, D.C.

FIGURE III-11

MEDICALLY UNDERSERVED AREAS IN CENTRAL AND SOUTHERN APPALACHIA



Data Source: Designation made by the Secretary of Health, Education and Welfare, pursuant to Section 1302(7) of the Public Health Service Act as enacted by the Health Maintenance Organization Act of 1973 (PL 93-222). Refer to *Federal Register*, Vol. 40, No. 170, September 2, 1975.

The health of the residents of the eastern seaboard region, as expressed in mortality and morbidity statistics, is generally better than the health of Appalachian residents.[1/] More health care facilities are available and sanitary systems, nutrition, and other preventive measures are usually better, although the quality of these factors varies considerably by region and by socioeconomic group.

Although the health of urban dwellers in the eastern seaboard is improved by better health care and sanitary facilities, it is impaired by the pathogenic effects of air and water pollution. Unfortunately, the degree to which pollution affects community health has not been adequately documented. Although the Community Health and Environmental Surveillance Studies (CHESS) of EPA have established some correlation between ambient levels of pollutants and morbidity rates, most of the standards for allowable concentrations of pollutants are based on experiments in which large doses are administered to organisms over a short time or on studies of people who are exposed to high levels of pollutants in their working environment.

F. Esthetics

1. Visual Values

Although large areas of Appalachia have been damaged by uncontrolled surface mining and approximately 10,000 miles of the area's streams are affected by mine drainage pollution, most of the region still retains a rural and ecologically pristine atmosphere. This atmosphere enhances the recreational value of the area and is highly prized by both residents and tourists.

1/ Bureau of the Census, Statistical Abstract of the United States, Washington, D.C., 1976.

Although, unlike Appalachia, the eastern seaboard region as a whole is not generally known for its pristine attributes, many areas in the region are prized for thier esthetic qualities, particularly the seashore. In urbanized areas where the demand for recreational land is high and land values are sensitive to the effects of esthetically unappealing development, the esthetic impacts of a proposed project are scrutinized and debated.

2. Historic, Cultural, and Recreational Values

The Appalachian Region has been inhabited by Indians since prehistoric times, and the region is dotted with relics of their culture. Remains of Eastern Archaic, Mound Builder, and Mississippian traditions, which included the Chickasaw, Creek, Yucchi, Cherokee, and Shawnee tribes, are scattered throughout the region. However, most of these remains are found on the most desirable land by the lowland riverbeds. Most of the early white settlers also concentrated in these riverbed areas. However, due to the region's isolated nature, the vestiges of the few people who did settle in the more mountainous areas are largely intact today, and the people who live there have often retained the crafts, customs, and attitudes of the early settlers. These people are culturally unique and their crafts, music, and lifestyle are now making them tourist attractions.

Although the eastern seaboard has been more developed, many early settlements and buildings have been preserved. On the whole, the region is one of the most history-conscious areas in the United States. For example, about 380 sites in Virginia are listed in the 1976 National Register of Historic Places, whereas only about 70 sites in West Virginia were listed in the same document. Many State and local historic agencies and societies, as well as Federal agencies, are dedicated to the preservation of these sites.

Appalachia's picturesque land and the wide variety of recreational activities it offers are important tourist attractions. Because the revenue that tourists provide is important to the area's economy and the local residents prize their hunting lands and fishing waters, Federal, State, and local agencies make extensive efforts to preserve and advertise the undisturbed character of the land. Large areas of parkland and State and national forests dot a map of the region and the populations of game animals and fish are monitored closely. Some especially popular trout streams in West Virginia are stocked 8 times a year.[1/] In recent years, the increasing popularity of sports like white-water boating, spelunking, hiking, and skiing has led to even greater recreational use of the area, and this intensified use will probably continue to grow.

Although the eastern seaboard region does not have as many large tracks of undisturbed land as Appalachia, the region does provide a wide variety of outdoor recreational activity. The parklands in this region are often extensively used, and the demand for such areas has been steadily increasing.

1/ Donald Pheras, Fisheries Biologist, Jefferson National Forest, personal communication.

CHAPTER IV

PROBABLE IMPACTS OF THE PROPOSED PROGRAM ON COAL PRODUCTION AND USE

A. Introduction

The objective of the Coal Loan Guarantee Program is to increase the production of low sulfur coal from underground mines and to encourage coal cleaning to produce "complying" low sulfur coal (0.7% sulfur by weight assuming a heat content of 11,800 Btu/lb). The potential impacts of the Coal Loan Guarantee Program will be evaluated relative to a baseline coal demand projection for 1985 based upon FEA PIES data (1985 Initiatives Scenario).

The impact analysis focuses on the coal supply and demand regions primarily affected by the program. Section B describes current coal supply and demand patterns. Section C discusses the baseline projections, and Section D describes the potential impacts of the Coal Loan Guarantee Program in 1985 relative to the baseline projections.

B. Description of the Present Coal Market

1. Present Coal Consumption

In 1975, approximately 647 million tons of coal were consumed. As shown in Table IV-1, electric utilities accounted for 66.4% of that total. Excluding coal exports and metallurgical coal, electric utilities accounted for about 85% of the total steam coal consumption.

TABLE IV-1

COAL CONSUMPTION IN 1975

Consuming Sector	Millions of Tons	% of Total
Electric Utilities[a/]	429	66.4
Coke Plants[b/]	83	12.8
Industry[b/]	64	9.9
Residential/Commercial[b/]	7	1.1
Exports[b/]	64	9.8
TOTAL	647	100.0

a/ SOURCE: Federal Power Commission, 1976.

b/ SOURCE: Bureau of Mines.

Coal-fired powerplants comprise a significant portion of electric energy production. Coal has maintained its share of the market in the utility sector due to increasing oil prices, natural gas curtailments, and limited nuclear capacity expansions resulting from siting, licensing, and financial problems. As shown in Table IV-2, the East is heavily dependent on coal for generation of electricity. Oil is the primary fuel source for electric generation in New England, gas in the West South Central region, and hydropower in the Pacific division. These regions are illustrated in Figure IV-1.

With respect to low sulfur steam coal production and use in the East, utilities in the states of Alabama and Indiana purchased almost exclusively western low sulfur coal; Florida imported most of its coal; and Michigan and Ohio used 30-40% western coal. The remaining states purchased only eastern low sulfur coal.[1/] Table IV-3 summarizes the percentage of coal from the Northern and

1/ Federal Power Commission, "Annual Summary of Cost and Quality of Steam Electric Plant Fuels, 1975," Staff Report by the Bureau of Power, May 1976.

TABLE IV-2

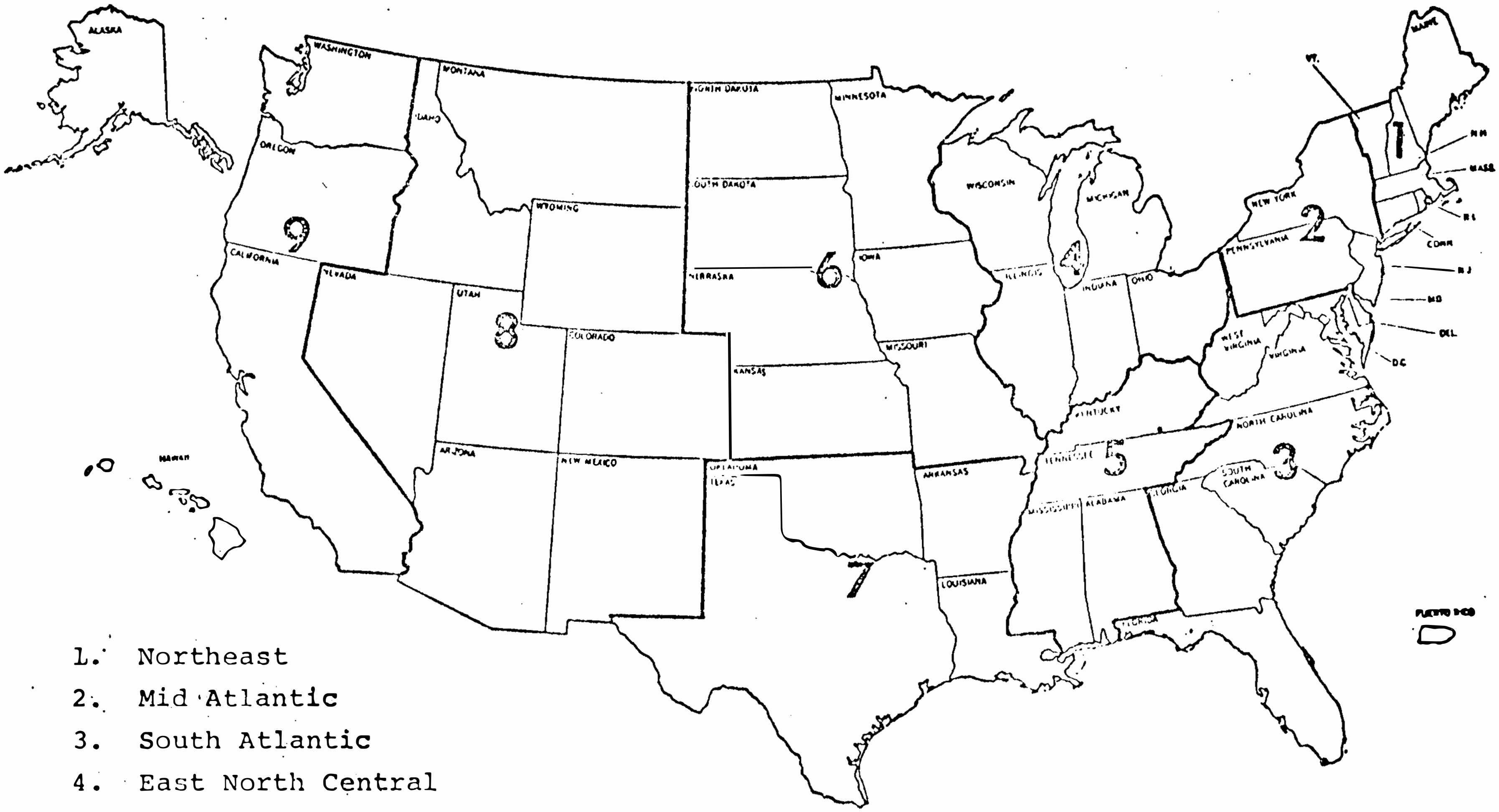
PERCENTAGE OF 1974 NET ELECTRICITY PRODUCTION
GENERATED BY COAL, BY CENSUS REGION

Region Number	Region	% Electricity Production
1	New England	7.4
2	Middle Atlantic	42.7
3	South Atlantic	54.9
4	East North Central	82.0
5	East South Central	76.5
6	West North Central	54.4
7	West South Central	3.0
8	Mountain	46.3
9	Pacific	1.7
	National	44.5

SOURCE: National Energy Outlook, FEA, February, 1976. p. 241.

FIGURE IV-1

CENSUS REGIONS



1. Northeast
2. Mid Atlantic
3. South Atlantic
4. East North Central
5. East South Central
6. West North Central
7. West South Central
8. Mountain
9. Pacific

TABLE IV-3

FY 1975 EASTERN UTILITY LOW SULFUR COAL DELIVERIES FROM NORTHERN AND CENTRAL APPALACHIA

Coal Destination Regions	State	% Produced from Central Appalachia[1/]	Percent Produced from Northern and Central Appalachia[2/]
2	NY/NJ/DE/MD/DC	14	91
3	VA	100	100
4	NC	100	100
5	SC/FL/GA	78	78
6	AL[3/]	0	0
9	PA[4/]	21	100
10	OH	68	69
11	MI	60	60
12	IN	1	1
14	KY	100	100
15	TN	100	100
22	WV	93	99
TOTAL		62%	68%

1/ Bureau of Mines (BOM) Districts 7&8 approximate the Central Appalachian region.

2/ BOM Districts 1, 2, 3, 6, 7 & 8 approximate the Northern and Central Appalachian regions.

3/ Alabama consumed 1.1 million tons of low sulfur coal produced by BOM District #13 in FY75.

4/ One MTPY of Pennsylvania consumption is anthracite.

SOURCE: Effects of Air Quality Requirements on Coal Supply, Bureau of Mines, May 1976.

Central Appalachian regions delivered to powerplants in the eastern U.S.

2. Present Coal Supply

Approximately 45 million tons per year of low sulfur coal, or 65% of the U.S. low sulfur steam coal production, are produced in Northern and Central Appalachia. Approximately 90% of this was from Central Appalachia. Table IV-4 summarizes national steam coal production in 1974 by production region and sulfur content. Figure IV-2 illustrates the coal production regions in the U.S.

Coal cleaning (physical removal of pyritic sulfur) prior to combustion also contributes to the low sulfur coal supply. In 1974 there was a total of 387 coal cleaning plants producing 265 million tons of clean coal annually at bituminous coal and lignite mines. Pennsylvania, Ohio, eastern Kentucky, Virginia, and West Virginia (Table IV-5) contain 273 (70%) cleaning plants producing almost 156 million tons of cleaned coal annually.

The number of plants cleaning metallurgical coal versus utility steam coal is not known. However, the premium for metallurgical coal, coupled with the need for consistent high quality, has resulted in a disproportionately large share of coal cleaning devoted to that type of coal. With the construction of new coal-fired electric plants and increased enforcement of SIP's, the demand for clean, low sulfur coal is expected to increase. In addition, new powerplants will require more uniform coal feeds with respect to size, sulfur content, ash content, and heating value, and therefore will increase the demand for cleaned coal.

TABLE IV-4
1974 NATIONAL STEAM COAL PRODUCTION
BY REGION AND SULFUR CONTENT
(10^6 tons)

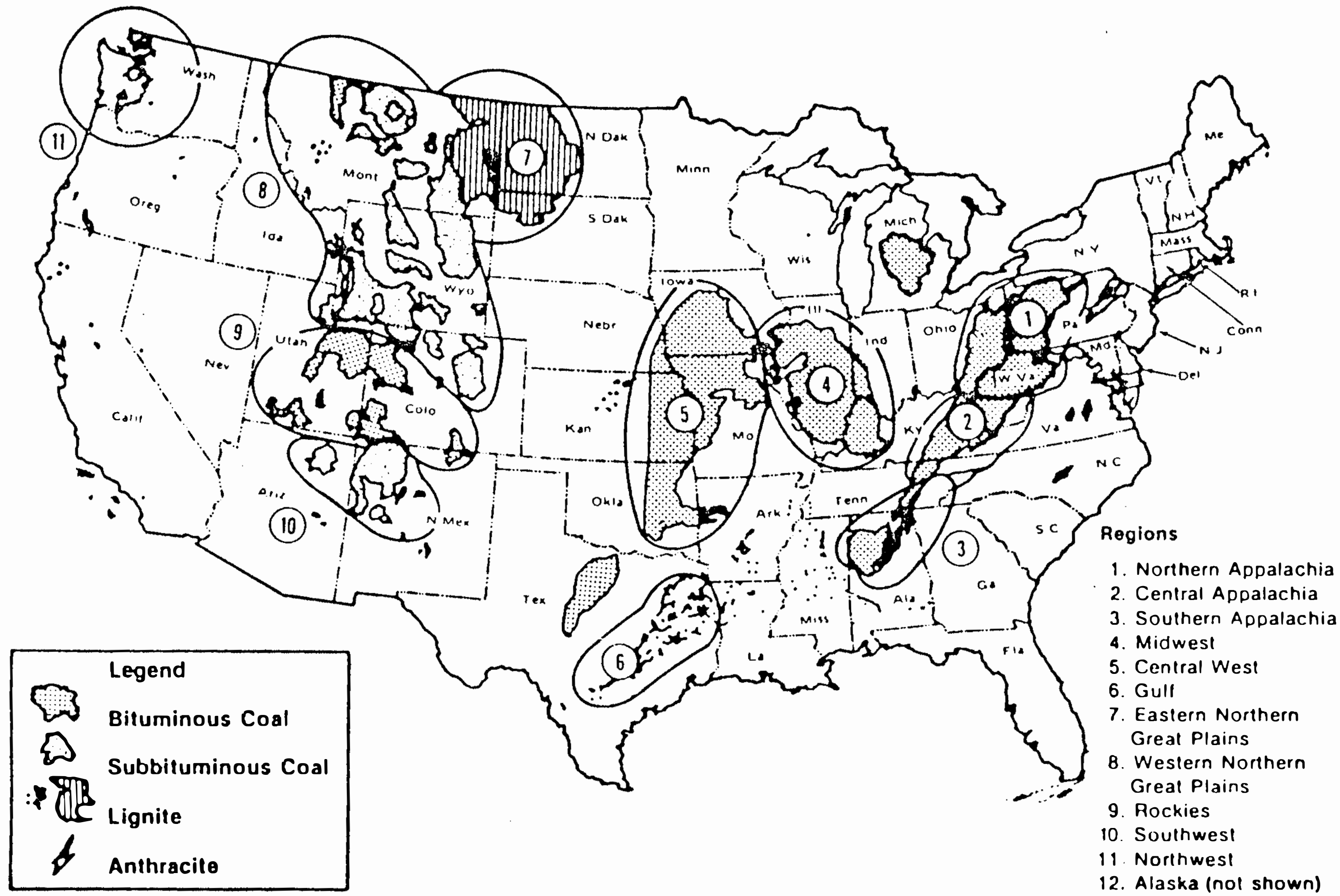
Region	Low-Sulfur	High-Sulfur
Northern Appalachia	6.1	155.6
Central Appalachia	22.0 [1/]	30.7
Southern Appalachia	5.8	9.8
Midwest	5.5	133.0
Central West	--	7.9
Gulf	--	7.7
Eastern Northern Great Plains	1.7	6.1
Western Northern Great Plains	2.1	32.2
Rockies	6.9	--
Southwest	1.2	14.8
Northwest	--	4.0
Alaska	0.7	--
National	52.0 [1/]	401.8

[1/] NOTE: The NEO document estimates that 60 MTPY of low sulfur coal were produced in Central Appalachia in 1974. Energy and Environmental Analysis data derived from "Effects of Air Quality Requirements on Coal Supply," Bureau of Mines, May, 1976, and Bureau of Mines, "Bituminous Coal and Lignite Shipments" indicate production of only 22 MTPY of eastern low sulfur coal. The results were adjusted accordingly.

SOURCE: Federal Energy Administration, 1976 National Energy Outlook, February, 1976, p. 207, Table IV-37.

FIGURE IV-2

PIES COAL SUPPLY REGIONS



SOURCE: 1976 National Energy Outlook, Federal Energy Administration.

TABLE IV-5

MECHANICAL COAL CLEANING AT BITUMINOUS COAL AND LIGNITE MINES IN 1974

State	Number of Cleaning Plants	Cleaned Coal (10^6 tons)
Eastern Kentucky	43	24.3
Ohio	17	13.6
Pennsylvania	68	41.3
Virginia	19	13.8
West Virginia	126	62.8
Appalachian Total	273	155.8
National Total	387	265.2

SOURCE: U.S. Department of the Interior, Bureau of Mines, "Coal--Bituminous Lignite in 1974," January 27, 1976, p. 44, Table 31.

C. Baseline Projection: 1980 and 1985 Steam Coal Demand and Supply

1. Background

This section examines the availability of low sulfur steam coal supplies in 1980 and 1985 in the absence of the Coal Loan Guarantee Program. Projections of potential coal supply and demand are shown by sulfur content and mine type.

Demand for program coal may come from four sources:

- new utility generating units which begin construction prior to the time that NSPS requirements become effective;
- existing generating units subject to SIP requirements of 1.2-1.7 lbs SO_2/MMBtu;
- existing utility generating units ordered to convert to coal under the ESECA program; and
- new or existing industrial boilers which convert to or currently burn coal.

2. Demand for Program Quality Coal

a. New Electric Utility Powerplants

This evaluation focuses on coal demand by new generating stations already under construction because:

- most new powerplants (already under construction) can comply with all applicable air pollution requirements for SO_2 without scrubbers, using coal produced under the program;
- applicants must have long-term contracts which are issued primarily by utilities; and

- utilities are the largest coal consumers and will constitute the bulk of new demand.

The potential eastern new generating unit demand for program quality coal by 1980 and 1985 is presented in Tables IV-6 and IV-7, respectively.

In 1980, the total potential demand for program coal by new eastern generating plants is 50.3 million tons per year (MTPY). Utilities have not yet issued contracts for 20.1 MTPY of their coal needs. By 1985, the total potential demand is estimated to be 112.1 MTPY. Approximately 60.8 MTPY of this demand is not yet under contract. These estimates represent potential demand. The data have not been adjusted to account for utilities which will use high sulfur coal plus scrubbers to comply with existing NSPS.

b. Demand from Existing Utilities

Table IV-8 summarizes the potential demand for program quality coal by existing plants. Only plants which met the following criteria were counted as potential users of coal from this program:

- currently out of compliance with existing SIP's even after blending;
- located in States that do or could use eastern low sulfur coal; and
- subject to SIP's of 1.2-1.7 lbs SO_2/MMBtu.

The last column of Table IV-8 indicates the quantity of program quality coal that would be required for blending with existing coal supplies to meet the applicable SIP. While a few plants may

TABLE IV-6

DEMAND FOR PROGRAM QUALITY COAL
FROM NEW (ALREADY UNDER CONSTRUCTION) GENERATING PLANTS BY 1980

(10^3 tons)

Region	No. of Plants	MW Capacity	Total Demand	Demand w/o Contracts	%	Existing Contracts	Source			
							Eastern	%	Western	%
Middle Atlantic										
New York			0	0		0	0		0	0
Pennsylvania	4	3077	10300	3000	14.9	7300	10300	25.8	0	0
Total	4	3077	10300	3000	14.9	7300	10300	25.8	0	0
East North Central										
Illinois	5	1736	3145	805	4.0	2340	3145	7.9	0	0.0
Indiana	7	3698	340	3358	16.7	9990	6640	16.6	3700	35.9
Michigan	5	1081	2749	2749	13.7	0	1650	4.1	1099	10.7
Ohio	4	2090	4250	1700	8.4	2550	4250	10.6	0	0.0
Wisconsin	3	1457	3730	2500	12.4	1230	0	0.0	3730	36.1
Total	24	10062	24214	11112	55.2	16110	15685	39.2	8529	82.7
South Atlantic										
Delaware	1	400	800	800	4.0	0	800	2.0	0	0
Florida	2	904	987	0		987	987	2.5	0	0
Georgia	1	896	1551	0		1551	1551	3.9	0	0
Maryland	0	0	0	0	0	0	0	0	0	0
North Carolina	1	720	1410	71	0.4	1339	1410	3.5	0	0
South Carolina	1	280	463	0		463	463	1.2	0	0
West Virginia	2	1252	1500	1500	7.4	0	1500	3.7	0	0
Total	8	4452	6711	2371	11.8	4340	6711	16.8	0	0
East South Central										
Alabama	4	1786	1980	897	4.4	1083	1980	5.0	0	0
Kentucky	5	2000	4810	1864	9.3	3046	4810	12.0	0	0
Mississippi	4	1396	2286	890	4.4	1396	506	1.2	1780	17.3
Total	13	5182	9076	3651	18.1	5525	7296	18.2	1780	17.3
Total Eastern U.S.	49	22773	50301	20134	100.0	33275	39992	100.0	10309	100.0

SOURCE: Status of Coal Supply Contracts for New Electric Generating Units 1976-1985, FPC, January 1977.

TABLE IV-7

DEMAND FOR PROGRAM QUALITY COAL
FROM NEW GENERATING PLANTS BY 1985
(10^3 tons)

Region	No. of Plants	MW Capacity	Total Demand	Demand w/o Contracts	%	Existing Contracts	Source: Eastern	%	Western	%
Middle Atlantic										
New York	3	2400	5900	5900	9.7	0	5900	6.3	0	0
Pennsylvania	5	3877	12200	4900	8.1	7300	12200	13.0	0	0
Total	8	6277	18100	10800	12.8	7300	18100	19.3	0	0
East North Central										
Illinois	8	3236	6835	910	1.5	5925	6835	7.3	0	0.0
Indiana	11	5543	15400	7332	12.1	8068	11700	12.5	3700	20.1
Michigan	10	800	8149	4149	6.8	4000	2650	2.8	5499	29.8
Ohio	9	4760	10150	5750	9.5	4400	10150	10.8	0	0.0
Wisconsin	6	2737	6470	5240	8.6	1230	0	0	6470	35.0
Total	44	17076	47004	23381	38.5	23623	31335	33.4	15669	84.9
South Atlantic										
Delaware	1	400	800	800	1.3	0	800	0.8	0	0.0
Florida	4	1658	3870	2651	4.4	1219	3820	4.1	0	0.0
Georgia	5	4196	8751	3200	5.3	5551	7751	8.3	1000	5.4
Maryland	1	800	1500	1500	2.4	0	1500	1.6	0	0.0
North Carolina	3	2160	4464	2857	4.7	1607	4464	4.8	0	0.0
South Carolina	3	840	1407	1407	2.3	0	1407	1.5	0	0.0
West Virginia	2	1252	3000	3000	4.9	0	3000	3.2	0	0.0
Total	19	11306	23792	15415	25.3	8377	22792	24.3	1000	5.4
East South Central										
Alabama	6	3152	6398	3071	5.0	3327	6398	6.9	0	0.0
Kentucky	11	4840	13799	7225	11.9	6574	13799	14.7	0	0.0
Mississippi	4	1396	3052	890	1.5	2162	1272	1.4	1780	9.7
Total	21	9388	23249	11186	18.4	12063	21469	23.0	1280	9.7
Total Eastern U.S.	92	44047	112145	60782	100.0	51363	93696	100.0	18449	100.0

SOURCE: Status of Coal Supply Contracts for New Electric Generating Units 1976-1985, FPC, January 1977.

TABLE IV-8

DEMAND FOR PROGRAM QUALITY COAL FROM EXISTING GENERATING PLANTS BURNING NONCONFORMANCE COAL (1980-1985)

Region	No. of Plants	Range of SIP's (lbs/MMBtu)	Total Quantity Received	Quantity Nonconformance After Blending	Quantity Required for Blending
Middle Atlantic					
New Jersey	3	1.61 - 1.64	2370	2370	441
East North Central					
Ohio	10	1.20 - 1.70	10502	8820	6878
Michigan	10	1.54 - 1.70	11332	7626	4779
Indiana	10	1.20	18023	14638	14326
Wisconsin	5	1.20	2669	2669	698
South Atlantic					
Florida	2	1.50	3415	3323	2947
Maryland	5	1.49 - 1.70	2740	2214	1323
North Carolina	13	1.60	19630	2007	892
West Virginia	1	1.61	1026	0	0
East South Central					
Alabama	1	1.20	4250	2009	1052
Kentucky	4	1.20	8275	8275	8275
Tennessee	2	1.20	7979	7979	7979
TOTAL			92211	61930	49590

SOURCE: Special FPC Computer Analysis, January, 1977.

choose to install scrubbers, existing data indicate that retrofit will not be widespread.

c. Demand from ESECA Utility Conversions

Table IV-9 presents the potential demand for NSPS quality coal resulting from ESECA "first round" utility prohibition orders, i.e., orders for which Notices of Intent were issued prior to January, 1977. It is assumed that a utility converting to coal under an ESECA prohibition order will act as follows:

SIP Requirement (% sulfur)	Action
$\leq$.7	Use high sulfur coal and scrubbers.
.7-2	Blend existing NSPS quality coal and high sulfur coal.
$\geq$2	Use high sulfur coal.

Under these assumptions, an estimated 10,086 MTPY potentially would be required due to prohibition orders. Demand from ESECA utility conversions has not been considered in this environmental anlaysis for the reasons explained in Section II-D.

d. Industrial Coal Consumption

Estimates of industrial coal demand are beyond the scope of this assessment except in terms of a sensitivity analysis. In lieu of data on how the proposed National Energy Plan would impact industrial coal consumption, data from the MFBI program were used. Table IV-10 summarizes the potential demand for program quality coal due to ESECA MFBI conversions and new MFBI's in the eastern U.S. New and converting MFBI's could account for an additional 29.79 MTPY of program quality coal demand by 1980. Demand from industrial coal consumption has not been considered in this analysis for the reasons explained in Section II-D.

TABLE IV-9

DEMAND FOR PROGRAM QUALITY COAL BY 1980
FROM ESECA PROHIBITION ORDERS (EXISTING UTILITIES)

Region	Number of Generating Stations	MW Capacity	Projected Annual Coal Demand	SIP (% Sulfur by Weight)	% NSPS Coal Required for Blending	Blending Demand for NSPS Coal
New England						
New Hampshire	1	100	228	2.4	0.0	0
Total	1	100	228			0
Mid-Atlantic						
New Jersey	1	299	682	1.0	62.5	426
New York	2	786	1792	-	0.0	0
Danskammer			(880)	0.5	0.0	0
Albany			(912)	1.5	0.0	0
Total	3	1085	2474			426
East North Central						
Illinois	1	28	64	1.08	100.0	64
Michigan	1	816	816	0.5	0	0
Wisconsin	1	171	171	None	None	0
Total	3	1015	1051			64
South Atlantic						
Florida	1	965	2201	0.9	91.0	2010
Georgia	2	351	800	3.0	0.0	0
Maryland	4	2064	4727	1.0	77.0	3640
North Carolina	1	646	1474	1.3	0.0	0
Virginia	3	2380	5429	-	0.0	0
Yorktown			(858)	1.5	100.0	858
Portsmouth			(1483)	0.25	0	0
Chesterfield			(3088)	1.0	100.0	3088
Total	11	6406	14631			9596
South Central						
Alabama	1	25	57	2.3	0.0	0
Total	1	25	57			0
Total Eastern U.S.	19	8631	18441			10086

SOURCES: Implementing Coal Utilization Provisions of Energy Supply and Environmental Coordination Act, FEA, April 1976.
Effects of Air Quality Requirements on Coal Supply, Bureau of Mines, May 1976.
State Implementation Plan Regulations for Sulfur Oxides: Fuel Consumption, EPA Report 450/276-002, March 1976.

TABLE IV-10

DEMAND FOR NSPS QUALITY COAL FROM ESECA BY 1980
(EXISTING AND NEW MFBI'S)
(10^3 tons)

Region	Existing MFBI's	New MFBI's	Total Coal Demand
New England	1763	200	1963
Mid-Atlantic	5965	865	6830
East North Central	9656	1060	11116
South Atlantic	4955	1078	6033
South Central	3298	552	3850
Total Eastern U.S.	25637	4155	29792

SOURCE: Coal Conversion Program: Environmental Impact Statement (Draft Revised), FEA, February 1977.

e. Summary

The potential demand for program quality coal in the eastern U.S. is summarized in Table IV-11. Actual demand will fall below potential demand because some utilities and industries will use western low sulfur coal and scrubbers. In the calculation of environmental residuals, ESECA and industrial coal demand were eliminated as discussed previously.

3. FEA PIES Projection: Steam Coal Supply and Demand Without the Program in 1985

A national steam coal demand projection by sulfur content is shown in Table IV-12. The Appalachian low sulfur coal demand will be primarily in the eastern U.S. The Appalachian region contains large reserves of low sulfur, underground coal which supply the majority of low sulfur coal to utilities in the eastern U.S. Therefore, for the purposes of analysis, the impact of the Coal Loan Guarantee Program on coal production is assumed to be in the Appalachian region, specifically in Northern and Central Appalachia.

Table IV-13 presents the demonstrated low sulfur coal reserves in Northern and Central Appalachia. Approximately 23,664 million tons (90%) of the low sulfur coal reserves in the eastern U.S. are located in the Northern and Central Appalachian states, and of these reserves 18,925.8 million tons (80%) are underground reserves. These reserve estimates do not account for recoverability factors or for those reserves which are metallurgical coal. Assuming a somewhat conservative recovery efficiency of 50%, and assuming that half of the reserves are metallurgical coal, potential low sulfur coal production would be about 5916 million tons of coal, a rather substantial reserve.

TABLE IV-11

SUMMARY OF POTENTIAL PROGRAM QUALITY COAL DEMAND

	1980	1985
	(million tons/year)	
New generating plants (demand without contracts)	20.1	80.9
Existing utilities	49.5	49.5
ESECA prohibition orders	10.0	10.0 1/
ESECA MFBI new and conversions	29.8	29.8 1/
TOTAL	109.4	170.2

1/ 1985 demand projections are not available; therefore, the 1980 demand data is presented to illustrate a minimum demand.

TABLE IV-12

PROJECTED 1985 UTILITY STEAM COAL DEMAND
BY FEA REGION
(10^6 tons)

Region		Total	Low Sulfur 1/	High Sulfur 2/
1	Northeast	14.4	1.2	13.1
2	New York-New Jersey	41.4	2.6	38.8
3	Middle Atlantic	100.4	13.1	87.2
4	South Atlantic	163.6	24.4	139.1
5	Midwest	183.0	59.6	123.4
6	Southwest	144.3	78.9	65.5
7	Central	58.7	18.8	40.1
8	North Central	28.7	22.6	6.1
9	West	25.9	21.8	4.1
10	Northwest	4.1	4.1	0.0
	National Total	764.5	247.1	517.4

1/ Low sulfur coal meets the emission standard of 1.2 lbs SO_2/MMBtu.

2/ High sulfur coal exceeds the emission standard of 1.2 lbs SO_2/ MMBtu.

SOURCE: Federal Energy Administration, PIES, 1985 Initiatives Scenario, Run #A158569C, April 15, 1977.

TABLE IV-13

DEMONSTRATED LOW SULFUR COAL RESERVES
AS OF JANUARY 1, 1974
(10^6 tons)

Production Region	Sulfur Content (% by weight) <1.0%	Percent of Total
East Kentucky	6,558.4	25.0
Pennsylvania (Bituminous)	668.6	2.6
Tennessee	204.8	0.8
Virginia	2,140.1	8.2
West Virginia	14,092.1	53.8
Sub-Total	23,664.0	90.3
All Other Eastern U.S.	2,543.2	9.7
TOTAL Eastern U.S.	26,207.2	100.0%

SOURCE: Bureau of Mines, "Coal-Bituminous and Lignite in 1974," January 27, 1976, p. 7, Table 4.

Table IV-14 presents the projected baseline steam coal production in Northern and Central Appalachia in 1985 by sulfur content and mining method. Unfortunately, the divisions by coal type in the data provided were not sufficient to identify the program quality coal. Figure IV-3 describes the methodology used to distribute eastern low sulfur steam coal production by coal type, region, and mine type.

Approximately 98% of the eastern low sulfur coal production in 1985 is predicted to occur in Central Appalachia, and 48% of this is produced from underground mines. Northern Appalachia accounts for slightly more than half of the total production of medium sulfur coal and almost 88% of the total production of high sulfur coal. Slightly more than 60% of the coal production in all sulfur categories in Northern Appalachia is from underground mines.

FEA demand and supply projections for 1985 indicate that eastern demand will exceed the supply of low sulfur steam coal from the Appalachian regions. New utilities in the Northeast, Middle Atlantic, South Atlantic, and Midwest census regions and the FEA New York-New Jersey region will need a total of 162 MTPY. However, the combined Northern and Central Appalachian regions are predicted to produce a total of 132.7 MTPY of utility steam coal by 1985, approximately 48% of which will be from underground mines.

D. Impacts of the Coal Loan Guarantee Program

1. Background

The proposed program implementation schedule is based upon the rate and level at which FEA projected loan guarantees will be issued through 1985. In this analysis, the estimated amount of obligations issued by 1980 and 1985 is translated into borrower capital investments, equivalent tons of production, and coal cleaning capacity. Building from the baseline projections of

TABLE IV-14

PROJECTED ANNUAL STEAM COAL PRODUCTION
WITHOUT THE PROGRAM IN 1985
BY SULFUR CONTENT AND MINE TYPE
(10^6 tons)

Region	Production
Northern Appalachia	208.9
<0.67 lbs S/MMBtu	2.6
Underground	1.1
Surface	1.5
0.67-1.68 lbs S/MMBtu	77.6
Underground	53.4
Surface	24.2
>1.68 lbs S/MMBtu	128.7
Underground	75.4
Surface	53.3
Central Appalachia	218.3
<0.67 lbs S/MMBtu	130.1
Underground	62.7
Surface	67.4
0.67-1.68 lbs S/MMBtu	70.4
Underground	51.9
Surface	18.5
>1.68 lbs S/MMBtu	17.8
Underground	15.1
Surface	2.7
Regional Total	427.2
<0.67 lbs S/MMBtu	132.7
Underground	63.8
Surface	68.9
0.67-1.68 lbs S/MMBtu	148.0
Underground	105.3
Surface	42.7
>1.68 lbs S/MMBtu	146.5
Underground	90.5
Surface	56.0
Grand Total	427.2
Underground	259.6
Surface	167.6

SOURCE: Federal Energy Administration, PIES 1985 Initiatives Scenario, Run #A158569C, April 15, 1977.

FIGURE IV-3

METHODOLOGY FOR CALCULATING
EASTERN UTILITY STEAM COAL PRODUCTION

	Utility Low Sulfur Steam Coal	Utility Premium Steam Coal	Total Utility Steam Coal
Northern Appalachia			
Surface	.3	.8	1.1
Underground	.4	1.1	1.5
Central Appalachia			
Surface	18.0	49.4	67.4
Underground	16.7	46.0	62.7
TOTAL	35.4	97.3	132.7

ASSUMPTIONS:

1. 70% of low sulfur coal production is utility steam coal.
2. 100% of export coal (90 MT) is from Appalachia, and 70% of this is premium coal (63 MT).
3. 70% of eastern met coal demand (96.9 MT) is premium coal (67.8 MT).
4. Of the remaining Appalachian premium coal production, the split between industrial and utility use is proportional to their national coal use:

   $$\frac{\text{U.S. utility coal demand}}{\text{utility \& industry coal demand}} = \frac{779}{779+382.9} = \frac{779}{1162} = 67\%$$

   Therefore, total Appalachian premium coal used for utility steam coal demand is:

   276.0 (total Appalachian premium coal production)
   \- 63.0 (exports)
   \- 67.8 (met coal)

   145.2 (industrial and utility premium coal)
   \- 47.9 (industrial demand)

   97.3 (utility shipments)

5. Premium utility steam coal production is divided among regions and mine types in the same proportions as low sulfur coal.
6. All low sulfur coal is utility coal.

coal supply, the impact of the loan program on coal production was defined by coal type, mine type, and location. The analysis assumes that coal resulting from the program can be consumed by existing generating plants required to comply with applicable air pollution requirements or new powerplants already under construction. In Chapter V, a sensitivity analysis is provided to indicate the environmental impact of low sulfur coal usage at existing plants.

2. Program Impact on Low Sulfur Coal Production

Based upon FEA's moderate program activity projection, low sulfur coal production due to the program will begin in 1978. The program is assumed to assist in financing mining projects where 20% of the required investment capital is provided by equity contributions and 80% by debt financing. Of the 80% debt financing, the program is assumed to guarantee 80% of the debt, or 64% of the required investment capital, with the remaining 20% of the debt, or 16% of the required investment capital, unguaranteed. Principal payments are assumed to be paid at the annual rate of 12.5% of the total initial guaranteed loan amount beginning in the first year after the guarantee is issued, i.e., constant annual principal payments over 8 years. As loans are retired at an annual rate of 12.5%, these funds are assumed to be reinvested in new projects. Table IV-15 summarizes the projected annual growth in low sulfur underground production from 1978 to 1985 under FEA's moderate program activity projection.

Table IV-16 summarizes the projected number of mines and their associated annual coal production in 1980 and 1985. The program should increase annual low sulfur coal production by 12.25 million tons in 1980 and by 39.75 million tons in 1985. Approximately one-third of this coal is assumed to be cleaned in order

TABLE IV-15

MODERATE PROGRAM ACTIVITY PROJECTION

Guarantee Approvals	1978	1979	1980	FY 1981	1982	1983	1984	1985
New Mines	5	10	10	10	15	15	15	15
Reopen/Expansions	20	20	20	20	20	20	20	20
Total	25	30	30	30	35	35	35	35
Approximate Increase in Annual Coal Production* (10^{o} tons)								
New Mines	1.25	2.50	2.50	2.50	3.75	3.75	3.75	3.75
Reopen/Expansions	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00
Total	3.25	4.50	4.50	4.50	5.75	5.75	5.75	5.75
Cumulative Annual Production (10^{6} tons)	3.25	7.75	12.25	16.75	22.5	28.25	34.0	39.75

* Assumptions:

1. No time lag from issuance of guarantee to coal production.
2. average annual capacities and initial investment costs:
   - new underground mine 250,000 TPY
   - expanded underground mine 100,000 TPY
   - steam coal preparation plant 250,000 TPY

SOURCE: Projections for 1978-1982 from FEA. Growth assumed to remain constant from 1982-1985.

TABLE IV-16

PROJECTED LOW SULFUR COAL PRODUCTION
DUE TO PROGRAM IN 1980 AND 1985

	Cumulative Number of Projects		Cumulative Annual Low-Sulfur Coal Production (10^6 tons)	
	1980	1985	1980	1985
New Mines	25	95	6.25	23.75
Reopen/Expansions	60	160	6.00	16.00
Total Mines	85	255	12.25	39.75
Steam Coal Preparation Plants				
at New Mines	8	31	2.08	7.88
at Reopen/Expansions	8	21	2.00	5.30
Total	16	52	4.08	13.18

SOURCE: Projections for 1978-1982 from FEA. Growth assumed to remain constant from 1982-1985.

to meet the 0.6 $lbs/10^6$ Btu sulfur emission standard (0.7% sulfur content by weight assuming an average heating value of 11,800 Btu/lb).

3. Projected Steam Coal Supply with the Program

Building from the baseline coal production projections for 1985 (Table IV-14) and the annual low sulfur coal production supported by the program (Table IV-16), the impact of the program on coal production by mine type, sulfur content, and production region was estimated. Table IV-17 summarizes the projected impacts of the Coal Loan Guarantee Program on coal production. Approximately 98% of the underground low sulfur coal production stimulated by the program will be produced in Central Appalachia (BOM regions 7 and 8) accounting for an incremental increase in annual low sulfur coal production in this region of 38.95 million tons in 1985. Only 2% of the low sulfur coal stimulated by the program will be produced in Northern Appalachia.

4. Impact on Coal Use

The impact of the Coal Loan Guarantee Program on coal use is estimated on a regional basis. For the purposes of analysis, all coal from mines receiving loan guarantees is assumed to be consumed in the eastern U. S. by existing or new powerplants to come into compliance with all applicable air pollution requirements without using scrubbers. As explained in the Chapter II assumptions, the program will allow some existing utilities to comply with stringent SIP's and thereby reduce SO_2 emissions. Presumably, many older units could not justify FGD investments and would either shut down or negotiate for more lenient SIP's or compliance date extensions. New units not yet operational might avoid scrubber investments by purchasing program coal.

TABLE IV-17

PROJECTED ANNUAL STEAM COAL PRODUCTION
WITH THE PROGRAM IN 1985
BY SULFUR CONTENT AND MINE TYPE
(10^6 tons)

Region	Production
Northern Appalachia	174.7
<0.67 lbs/MMBtu	3.4
Underground	1.9
Surface	1.5
0.67-1.68 lbs/MMBtu	77.6
Underground	53.4
Surface	24.2
>1.68 lbs/MMBtu	93.7
Underground	54.9
Surface	38.8
Central Appalachia	252.7
<0.67 lbs/MMBtu	169.1
Underground	101.7
Surface	67.4
0.67-1.68 lbs/MMBtu	70.4
Underground	51.9
Surface	18.5
>1.68 lbs/MMBtu	13.2
Underground	11.2
Surface	2.0
Regional Total	427.4
<0.67 lbs/MMBtu	172.5
Underground	103.6
Surface	68.9
0.67-1.68 lbs/MMBtu	148.0
Underground	105.3
Surface	42.7
>1.68 lbs/MMBtu	107.0
Underground	66.1
Surface	40.8
Grand Total*	427.4
Underground	275.0
Surface	152.4

* May not total due to independent rounding.

SOURCE: See Table IV-14.

E. Effect of the Coal Loan Guarantee Program in the West

1. Background

Applications for the Coal Loan Guarantee Program will probably be received from western coal producers and some guarantees may be issued. However, the aggregate environmental impacts of mining activity in the West occurring as a result of the program are not expected to be significant enough to require treatment in the form of a programmatic environmental impact statement. Environmental impacts will be considered on a site-specific basis.

There are three reasons for addressing environmental concerns on only a site-specific basis in the West. First, the number of loan guarantees issued to western producers will be small because the number of eligible producers is small. Second, they will be widely distributed because the mining activities of eligible producers cover a large area and thus the impacts of multiple producers should not produce significant cumulative effects. Third, the environmental problems associated with underground western coal production are different and generally less severe than those found in Appalachia where the bulk of the loan guarantees are expected to be issued.

2. Number of Eligible Applicants

A review of the 1977 Keystone Coal Manual and the most current Bureau of Mines publication on Coal and Lignite Production were used to determine the potential number of western applicants.

BOM data indicate that 45 of the 2,292 underground coal mines in the nation are located in western states. These mines account for less than four percent of total U.S. underground production. As shown below, they are located in five states, Colorado, Wyoming, Utah, New Mexico, and Washington.

WESTERN UNDERGROUND COAL PRODUCTION

State	Total Underground # of Mines	Total Underground Production (000 TPY)	For Eligible Underground Producers of less than 1MTPY # of Producers	# of Mines	Production
Colorado	18	3,446	4	4	1,001
Wyoming	5	436	0	0	0
Utah	20	6,961	4	6	1,958
New Mexico	1	500	0	0	0
Washington	1	13	0	0	0
TOTAL	45	11,356	8	10	2,959

To determine eligibility for the program among underground operations, those producers were eliminated who produced more than 1MTPY of coal, were subdivisions of companies with greater than $50M per year in revenue, or produced only metallurgical coal. Using these criteria, only eight producers located in Colorado and Utah were found to be eligible. Certainly new producers could enter the market, but this provides some basis for comparison with eligible producers elsewhere in the country. A similiar analysis for the East identified 338 eligible producers in Pennsylvania, West Virginia, Kentucky, Virginia and Tennessee.

Assuming that the West with 2.3 percent of the number of eligible producers opens 2.3 percent of the new mines, then by 1985, only seven new mines and three to four expansions could have occurred in the West. Even doubling these figures does not obviate the need for a programmatic assessment. These numbers are small because most of the western coal is surface mined and mined by large producers. Much of the underground coal is also owned by large producers and mined for metallurgical use.

3. Location of Eligible Applicants

The eligible producers are split equally between Utah and Colorado (see map). In Colorado, the producers are widely dispersed in four different locations. In Utah they are more concentrated in the area around Price but appear to be spread out over an area of approximately 50 sq. miles. However, considering that the few new mines resulting from the program will be spread out among the many operations of existing larger producers, the incremental impact of the program is questionable.

4. Environmental Impacts

The environmental impacts from the underground mining of coal in the western United States are significantly less than the impacts from underground coal mining in the eastern states. Most coal mined in the western states lies in thick seams close to the surface and is mined using surface or "strip" techniques. Nonetheless, a small number of underground coal mines are found primarily in Colorado and Utah.

Problems with acid mine drainage, which are widespread in eastern underground mines, are insignificant in western locations. Many of the western mines are dry because the water table lies below the coal seam. Western coals are generally low in sulfur (less than 1.2 percent) particularly the acid producing pyritic sulfur. Also, the surrounding rocks and soils tend to be alkaline, so that in the cases where there is a leachate, it is unlikely to be acidic. It is also less likely that this leachate will contaminate any surface waters since the hydraulic gradient is generally less steep in western coal fields.

Coal cleaning is another area where western underground coal mines produce less environmental impact than eastern mines. Western coal generally occurs in thick seams with little parting, so that on-site coal cleaning is rarely necessary. Cleaning is necessary at many eastern mines because of frequent partings and impurities in the coal and also because of the unavoidable increase in waste rock which occurs when mining thinner seams. Less coal cleaning means a corresponding reduction in refuse and gob to be disposed of, and as a result, less land use impacts. In addition, there is more accessible flat terrain in most western locations which makes it easier to construct surface facilities and to find a suitable and environmentally safe disposal site.

Subsidence is one environmental problem which can be more serious in western locations. As mentioned previously, the coal seams tend to run thicker and closer to the surface than back East, lending themselves to good conditions for spontaneous combustion, which weakens the rock above. There is, of course, tremendous variability in these conditions and a detailed study of the site-specific geologic conditions is crucial at each site.

SOURCE: Mine locations based on Keystone data.

CHAPTER V

PROBABLE ENVIRONMENTAL IMPACTS OF THE PROPOSED ACTION

A. Introduction

This chapter discusses the environmental impacts associated with the Coal Loan Guarantee program. Potential impacts are presented from both the qualitative and quantitative perspective.

The environmental impact analysis of the Coal Loan Guarantee program is based upon the direct impacts of the program on coal production and use discussed in Chapter IV. Figure V-1 and Table V-1 summarize the regions for which environmental impacts are estimated in this analysis for both coal production and coal use. For purposes of analysis, the regions subject to impacts of the program for coal production (mining, preparation and transportation) are Northern and Central Appalachia, since the program is expected to have the greatest impact on production in these two regions. Impacts of the program resulting from coal use are expected to be greatest in the East; therefore, the environmental impact analysis of coal use is limited to the eastern States receiving most (97% in 1975)[1/] of the coal shipped from Northern and Central Appalachia.

B. Coal Production

1. Introduction

As discussed in Chapter IV, the majority (98%) of the tonnage of underground low sulfur coal stimulated by the

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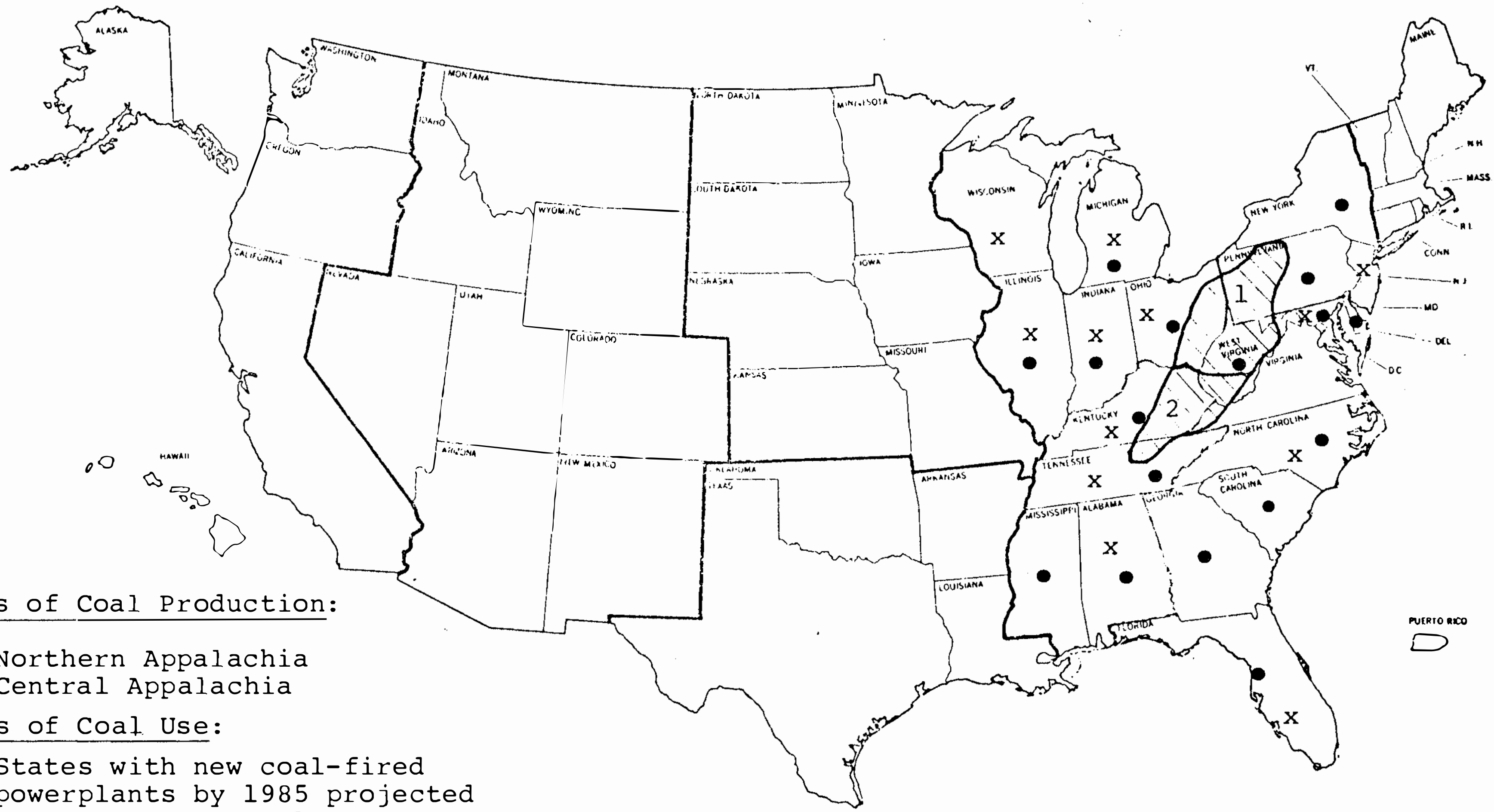
1/ Bureau of Mines, "Bituminous Coal and Lignite Distribution -- Calendar Year 1975," April 12, 1976.

FIGURE V-1

REGIONS FOR WHICH ENVIRONMENTAL IMPACTS ARE DETERMINED



Areas of Coal Production:

1 = Northern Appalachia
2 = Central Appalachia

Areas of Coal Use:

● = States with new coal-fired powerplants by 1985 projected to use program coal

x = States with existing powerplants projected to use program coal

TABLE V-1

COAL PRODUCTION AND USAGE BY REGION

	Region	BOM District	State
Production:	Northern Appalachia	1	eastern Pennsylvania Maryland
		2	western Pennsylvania
		3&6	northern West Virginia
		4	Ohio
	Central Appalachia	7	southern West Virginia Virginia
		8	southern West Virginia Virginia eastern Kentucky northeastern Tennessee
Use:	Middle Atlantic		New York New Jersey Pennsylvania
	South Atlantic		Delaware Maryland West Virginia North Carolina South Carolina Georgia Florida
	East South Central		Alabama Kentucky Tennessee Mississippi
	East North Central		Illinois Indiana Michigan Ohio Wisconsin

program will be produced in Central Appalachia. The total steam coal production affected by the Coal Loan Guarantee Program is less than 7% of the total projected 1985 coal production in Northern and Central Appalachia and approximately 3% of the total projected national coal production in 1985. Table V-2 summarizes the potential coal production impacts associated with the Coal Loan Guarantee Program in 1985.

The mining and preparation of coal will have an impact on the environment directly related to the volume of low sulfur coal produced from mines financed by the Coal Loan Guarantee Program. The environmental impacts of the program will be felt primarily in Northern and Central Appalachia. The nature of these impacts depends upon the coal mining method, the sulfur content of the coal, where the coal is mined, the land reclamation standards, and the water quality and air quality regulations which will be in effect and enforced.

The Coal Loan Guarantee Program will directly increase low sulfur coal production which will reduce the quantity of acid drainage produced and its associated impacts on water quality. The quantity and quality of acid drainage produced is a major function of the pyrite (FeS_2) content of the coal. Fine-grained, "framboidal" pyrite found in high sulfur coals has been shown to be particularly susceptible to high rates of acid production.[1/] The program will encourage underground mining which will increase the number of underground coal miners employed. Because of the dangerous nature of underground mining, an increase in fatalities and injuries is expected as a result of the Coal Loan Guarantee Program.

1/ Carruccio, F.T., and Ferm, J.C., "Paleoenvironment--Predictor of Acid Mine Drainage Problems," Fifth Symposium on Coal Mine Drainage Research, Coal and the Environment Technical Conference, Louisville, Kentucky, October 22-24, 1974.

TABLE V-2

POTENTIAL COAL PRODUCTION IMPACT OF THE COAL LOAN GUARANTEE PROGRAM IN 1985

	Annual Coal Production (10^6 tons)		
	Northern Appalachia	Central Appalachia	Total 1/
≤0.67 lbs S/MMBtu	+ 0.8	+39.0	+39.8
Surface	0	0	0
Underground	+ 0.8	+39.0	+39.8

1/ May not add to totals due to independent rounding.

SOURCE: Table IV-16.

This section presents a brief description of the major coal mining and steam coal preparation methods and the major environmental issues associated with them. The impacts of the Coal Loan Guarantee Program are discussed generally, followed by a discussion of the pollutants (residuals) produced at a typical mine and preparation plant in Northern and Central Appalachia. Quantified unit residuals also are presented in this discussion (subsection 4). These residuals are discussed with respect to their impacts on air, water, and land use. The impacts of transporting program coal are discussed generically. Specific analysis has been deferred to site-specific assessments.

2. Environmental Issues

a. Surface Mining

The major environmental issues associated with surface coal mining include preemptive use of land and water pollution resulting from erosion and sedimentation and leaching of chemical pollutants. In particularly dry areas or during a drought, particulate emissions, primarily in the form of fugitive dust from blasting and mining and heavy vehicle travel on dirt roads, may cause air quality problems locally; however, this is usually not a problem in the humid Appalchian region.

Erosion of unvegetated spoil piles by surface runoff and leaching of freshly exposed minerals - particularly pyrite, an iron disulfide - result in water pollution by sediments, acid, and metal compounds. Erosion and sedimentation are more severe in areas such as Central Appalachia where surface mining occurs on steep slopes. If uncontrolled, sediment can clog stream channels, cause flooding, and have severe impacts on aquatic ecosystems and downstream water uses. Chemical pollution by acid and metal compounds is dependent upon the chemical composition of the coal seam and overburden and is much more predominant in Northern Appalachia, which has more pyrite associated with its coal seams than does Central Appalachia. The quantity of pollutants produced by various surface mines, therefore, is a function of topography, mining method, and geochemistry. Due to the geometry of an area mine, most of the surface runoff is contained within the mine site, thereby reducing the impacts of surface runoff on surrounding areas, but increasing the potential for groundwater contamination.

During active mining, vegetation and overburden are removed from above the coal seam and are deposited elsewhere as "spoil," a mixture of soil and rock. The mine site cannot be used for other purposes during active mining and, if proper reclamation is not carried out after mining ceases, the land may not be suitable for use for many years or decades.

b. Underground Mining

The major environmental issues associated with underground mining are water pollution by acid mine drainage, land subsidence, and occupational health. Air pollution is not a problem, for fugitive dust generated by mining activities is confined within the mine. Occupational health and safety standards require that fugitive dust levels within the mine be controlled to levels below those which are harmful to the miners' health.

Acid mine drainage from underground mines is the major water pollution problem in Northern Appalachia; approximately 88 percent of acid drainage in this region is from underground mines.[1/]

1/ U.S. Environmental Protection Agency, "Mine Drainage Report to Conferees," Enforcement Conference: Monongahela River and its Tributaries, 1971.

As in the case of surface mining, the severity of acid mine drainage is highly dependent upon the pyrite content of the coal seam and associated strata and is much more prevalent in Northern Appalachia than Central Appalachia. Uncontrolled acid drainage can have severe effects on aquatic ecosystems due to high concentrations of mineral acidity and metal compounds.

Methods for controlling acid drainage from underground mines include chemical treatment of acid discharges and sealing of mine entrances to permit permanent flooding of the mine, thereby preventing acid formation. Neutralization of acidity with concurrent reduction of other pollutants to safe concentrations is usually achieved with conventional lime neutralization, followed by aeration to oxidize the iron and sedimentation to settle out insoluble iron, manganese, aluminum, zinc, and nickel hydroxides, and other suspended solids. Concentrations of fluoride, strontium, ammonia, and sulfate, although occasionally above accepted standards, are not normally high enough to have deleterious effects. In addition, the cost of technology for reduction of these constituents in the concentrations observed is not considered economically feasible.[1/]

Underground mining can also disrupt groundwater aquifers and cause groundwater contamination; however, the extent of this problem is not known.

Underground mining, by removing the support for the overlying strata, produces cave-ins and subsidence at the surface. This can have little or no effect but at the other extreme

1/ U.S. Environmental Protection Agency, "Development Document for Interim Final Effluent Limitations Guidelines and New Source Performance Standards for the Coal Mining Point Source Category," EPA 440/1-76/057-a, May, 1976, p. 1.

it can disrupt water courses, cause the collapse of buildings, and prevent use of the land for agriculture, etc.[1/] Although most mining operations leave behind pillars of unmined coal to support the roof, this is rarely a permanent solution to the subsidence problem, because coal is a poor structural material and grows weaker upon long exposure to air. Roughly 0.1 acre is subject to subsidence for every 500 tons of coal mined.[2/]

Underground coal mining is a very labor intensive as well as an extremely hazardous occupation. Fatality and injury rates are more than four times those for surface mining, and on a million-man-hours-worked basis, more than three times that for average industry.

c. Steam Coal Preparation

The major environmental issues associated with steam coal preparation plants include particulate emissions, water pollution and solid waste disposal.

Particulates, primarily coal fines, are produced during coal handling, breaking and sizing, and thermal and air drying. Baghouses and cyclone dust collectors are commonly used to control particulate emissions to within acceptable limits. Burning refuse piles may also contribute to air pollution. It is now required by law to compact, cover, grade, and revegetate refuse piles to prevent spontaneous combustion as well as water pollution.

1/ Perry, H., Environmental Aspects of Coal Mining, 136th Annual Meeting, AAAS, Boston, Massachusetts, 1969.

2/ This figure is based on an average coal seam thickness of 5 feet, producing about 8000 tons of coal per acre. Delson, J.K. and Frankel, R.J., Residuals Management in the Coal - Energy Industry. Resources for the Future, Washington, DC, 1972, p. II-2a. Cited in CEQ "Energy and the Environment: Electric Power," August, 1973, p. 42, Table A-2, F.N. 3.

Since steam coal preparation utilizes wet washing, degradation of process water will undoubtedly occur. Suspended solids are the greatest pollutant, and inclusion of a fine coal cleaning circuit intensifies this problem. Closed water circuits with either thickeners or settling ponds to remove fines will ameliorate most of the water pollution problems.[1/]

Runoff from coal storage and refuse piles is another source of water pollution and is similar to surface mine runoff. To remove suspended solids, runoff can be diverted to a settling pond. If drainage is acidic or high in iron or other metal concentrations, it may be treated at an acid mine drainage treatment facility.

Land is required for storage of raw coal, refuse piles, water treatment facilities and shipping and loading facilities. Disposal of the coal refuse and sludge from water treatment facilities can be a problem in mountainous regions where level land is scarce.

d. Coal Transportation

Except for local deliveries, which are made primarily by truck, most coal in the Appalachian region is delivered to power plants by railroad and/or barge. The environmental impacts of truck hauling include damage to public roads through excess weight, the creation of dust and mud from dirt roads, as well as noise and air pollution from exhaust. The major environmental issues associated with coal transportation are air pollution resulting from windage loss of coal fines during transport, and preemptive land use by transportation lines.

1/ U.S. Environmental Protection Agency, "Development Document..." op. cit., pp. 38-41.

3. Effects of the Coal Loan Guarantee Program

The degree of lasting environmental impact that is caused by coal production under the Coal Loan Guarantee Program is a function of geologic and climatological variables and the mining method employed, as well as the reclamation and control standards applicable and enforced. In order to evaluate the environmental impacts of the Coal Loan Guarantee Program, it is necessary to compare the environmental residuals produced by mining and preparation with and without the program. For the purposes of comparison, annual environmental residuals are presented in subsection B-4 for unit mines and a preparation plant in both Northern and Central Appalachia.

The underground mining and coal preparation technologies used will not be affected by the Coal Loan Guarantee Program. As stated above, the mining method is determined by topography, seam thickness and the depth of overburden. All program underground coal is assumed to be mined by the room-and-pillar method. The proportion of area vs. contour surface mines is based upon current production: 50 percent contour and 50 percent area mines in Northern Appalachia and 100 percent contour mines in Central Appalachia. All mines are assumed to have the same annual production, 250,000 tons per year. The average heating value of the coal is assumed to be 11,800 Btu/lb, the average for steam coal shipped from the Appalachian Region to utilities in 1975.[1/] Emissions are quantified assuming the minimum legal level of control.

1/ Federal Power Commission, "Annual Summary of Cost and Quality of Steam Electric Plant Fuels, 1975", Staff Report by the Bureau of Power, May, 1976.

Surface mine reclamation includes the following: segregation and burial of toxic materials, backfilling (to a terrace configuration for contour mines and to the approximate original contour for area mines), grading, and proper revegetation. Underground mines are assumed to have a mine drainage treatment facility to meet EPA's existing New Source Performance Standards (NSPS) for coal mine effluent, while reclamation is assumed to be adequate for surface mines to comply with existing NSPS. Surface mining equipment is assumed to be primarily diesel powered, and underground mines are assumed to employ primarily electrically powered equipment. Although standards currently control acid mine drainage from operating mines, once operations have ceased, acid mine drainage may become a serious water quality problem, particularly in Northern Appalachia. EPA has recognized this problem and is considering issuing guidelines to address acid mine drainage at abandoned underground mines.

As discussed in Chapter IV, the Coal Loan Guarantee Program is assumed to increase the number of coal preparation plants in operation by 1985 by 52 plants, each with an annual capacity of 250,000 tons. Without the program, it is assumed that these plants would not exist and that existing sulfur emission standards would be met by the use of scrubbers on coal-fired powerplants. Therefore, the program will not affect the steam coal preparation technology used; it will only affect the number of plants and quantity of coal cleaned.

It is assumed that coal preparation plants will meet existing NSPS for particulate and water effluents. Particulates are controlled by using baghouse filters which have a control efficiency of 99+ percent. Refuse piles are compacted and reclaimed to prevent combustion. Existing NSPS effluent guidelines call for no discharge of pollutants from coal preparation plants. This can be achieved by using a closed water circuit in conjunction with in-process controls and end-of-process treatment. To control runoff from coal storage, refuse storage, and the preparation plant ancillary area, a settling pond is used to settle out suspended solids, and a water treatment facility (lime neutralization) is used to neutralize acidity and reduce iron and manganese to acceptable levels.

Under uncontrolled, worst case conditions at coal preparation plants, particulates would not be controlled, the refuse pile would be burning, and process water or ancillary area runoff would not be treated. It is extremely unlikely that these worst case conditions would occur, but if an accident occurred and any of these sources were uncontrolled, the environmental impacts likely would be severe.

Coal mines and preparation plants are assumed to comply with the applicable pollution control requirements both with and without the Coal Loan Guarantee Program. The effect of the loan guarantee program on the level of pollutants produced by coal production depends not on the differences in the technologies used with and without the program, but rather on where the coal will be produced. As discussed earlier, the program will result in a net increase in underground low sulfur coal production in Central Appalachia.

By promoting more underground low sulfur coal production at the expense of surface and underground high sulfur production, a net decrease in air and water residuals is expected ✓ in the form of reduced levels of fugitive dust and sediment runoff from surface mines and reduced acid mine drainage from both underground and surface high sulfur coal mines. The shift from surface to underground mines will also affect land use patterns by increasing the area potentially affected by subsidence from underground mining and by decreasing the surface area disturbed by surface mines.

Because the Coal Loan Guarantee Program is expected to alter total coal production by approximately seven percent, some impact on transportation may occur. Depending upon the location of new or expanded mines and the capacity of nearby shipping facilities in Central Appalachia, some expansion of loading and shipping facilities may be necessary. It is expected that a greater volume of coal will be produced in and shipped from Central Appalachia as a result of the program. Coal transportation patterns may be altered, and existing transportation facilities may have to be expanded as a result of the program. Therefore, the program may affect employment or equipment demands in the transportation sector. These potential impacts will be examined in later site-specific analyses.

4. Residuals Produced

This section discusses the residuals produced by coal mining, preparation, and transportation and presents quantified emissions under controlled conditions, using unit-sized (250,000 tons per year) surface and underground mines and a steam coal preparation plant as examples. All mines and preparation plants affected by the Coal Loan Guarantee Program are assumed to comply with legal minimum control standards, existing EPA New Source Performance Standards, and State reclamation laws. The impacts of coal transportation also are discussed generally. The residuals produced during coal transportation cannot be quantified until later, site-specific environmental analyses, because uncertainties concerning the origin and destination of coal shipments preclude the possibility of meaningful analysis at this time. The issues discussed below address potential problems occurring during coal production if emissions are not controlled.

a. Air

Air emissions from mining activities can be divided into two categories: particulates and gaseous emissions. Dust created during mining is the major source of particulates, while burning coal and refuse and the operation of diesel-powered equipment are the sources of most gaseous emissions.

Fugitive dust from surface mining activities is the primary source of particulate emissions from mining operations, particularly in dry climates where high winds are more common. The two major sources of dust result from the actual mining and from hauling the coal by truck on dirt roads. In the West where rainfall is scarce, wind erosion and dust from spoil piles are a problem; however, the Appalachian region has a humid climate and abundant rainfall (over 40 inches annually), so fugitive dust emissions are usually not significant and are limited to the immediate vicinity of the mine and coal haul roads.

Particulate emissions from underground mining are not a problem, for fugitive dust generated during mining is retained within the mine. However, dust levels within the mine can be hazardous to miners' health.

Fugitive dust from coal preparation, handling, and local transportation can be a problem, but is usually confined to a small area.[1/] If not properly controlled, however, these emissions may be an occupational health problem. Particulate emissions from the preparation plant consist primarily of coal dust from handling and air drying.

1/ University of Oklahoma, op. cit.

Another source of air pollution is exhaust from machinery used to mine, process, and haul the coal. Diesel equipment used at the mine and automobiles used by the workers contribute CO, HC, and NO_x emissions. Since electrically powered equipment is generally used in underground mines, emissions from equipment are negligible.

The primary adverse impacts of underground mining on air quality are burning refuse piles and mine fires (under worst case, uncontrolled conditions only). Coal in refuse piles at mines and preparation plants may be subject to spontaneous combustion. Atmospheric pollution is the most distinctive characteristic of a burning refuse pile; gases, such as carbon monoxide, hydrogen sulfide, and ammonia may be produced in quantities that have the potential to cause injury or death. In 1969, there were 250 waste pile fires and 131 abandoned coal mine fires burning in the U.S.[1/]

Thermal drying of wet washed coal is another source of NO_x and SO_2 emissions. However, as of 1974 less than 14 percent of mechanically cleaned coal in the U.S. was thermally dried,[2/] and the large majority of thermally dried coal is metallurgical coal.[3/] Most steam coal is mechanically dried using vibrating screens, and thermal dryers are used for fine clean coal only when necessary.[4/] Therefore, steam coal preparation plants are assumed to use only mechanical dryers (vibrating screens and centrifuges).

1/ "Environmental Effects of Underground Mining and Mineral Processing," Open File Report, U.S. Department of the Interior, Washington, D.C., 1969, p. 16.

2/ U.S. Department of the Interior, Bureau of Mines, "Coal--Bituminous and Lignite in 1974," January 24, 1976, p. 49, Table 36.

3/ Charles Vannoy, mining engineer, Division of Coal, U.S. Bureau of Mines, Washington, D.C. Personal communication.

4/ U.S Environmental Protection Agency, "Development Document...," _op_. _cit_., p. 41.

Table V-3 summarizes projected controlled (legal minimum control) air emissions associated with typical surface and underground mines producing 250,000 tons per year and a preparation plant with a capacity of 250,000 tons per year. Air emissions are greater from contour mines relative to area mines, for more fuel is required for mining and reclamation on steep slopes relative to flat or gentle slopes.

Emissions from underground mines, as mentioned above, are negligible due to the increasing use of electrically powered equipment and the retention of dust generated during mining within the mine.

For purposes of analysis, all preparation plants constructed under the Coal Loan Guarantee Program are assumed to clean only the low sulfur underground coal stimulated by the program. All mines and preparation plants are assumed to comply with the existing minimum legal Federal or State standards, whichever are more stringent.

Air pollutants associated with transportation of coal either by conventional or unit train or by barge result primarily from coal dust blown from coal cars and barges and from the exhaust of train and tug engines. The majority of particulate emissions are estimated to come from wind losses of coal dust blown from open coal cars and barges.[1/] Estimates of wind losses range from 0.2 to 2%.[2/] A 2% wind loss is estimated by Hittman for conventional trains, compared to a 1% loss for unit trains and barges.[3/] These estimates assume that the coal is transported dry. If transported wet, these losses can be reduced to negligible amounts.

1/ University of Oklahoma, op. cit., pp. 1-126.

2/ Energy and Environmental Analysis, Inc., "Trip Report: Kaiser Resources, Ltd. Mining operations at Sparwood, British Columbia," May 8, 1975.

3/ Hittman Associates, Inc., "Environmental Impacts Efficiency and Cost of Energy Supply and End Use," Vol. 1, November, 1974.

TABLE V-3

ANNUAL AIR EMISSIONS FROM COAL MINING AND PREPARATION1/

Activity	Air Pollutant (tons/year) Particulates	NO_x	SO_x	HC	CO
Mining -					
Surface					
Area					
Northern Appalachia	0.3	7.5	0.5	0.7	4.6
Contour					
Northern Appalachia	0.4	11.8	0.9	1.2	7.2
Central Appalachia	0.4	11.4	0.8	1.1	7.0
Underground					
Room-and-Pillar					
Northern Appalachia	0	0	0	0	0
Central Appalachia	0	0	0	0	0
Steam Coal Preparation2/	0	0	0	0	0

1/ Basis: Annual production from mines = 250,000 tons per year.
Preparation plant capacity = 250,000 tons per year.

2/ Refuse pile is reclaimed and baghouses used to control fugitive dust emissions.

SOURCE: Hittman Associates, Inc., "Environmental Impacts Efficiency and Cost of Energy Supply and Use," Vol. 1, November, 1974.

Unit trains provide more efficient coal transportation and therefore contribute fewer air pollutants, especially particulates, than do conventional trains. The distance of transport will affect the quantity of pollutants. Table V-4 summarizes the average haul distances for coal in Northern and Central Appalachia.

b. Water

Both coal mining and coal cleaning are potential producers of mine drainage pollution which can degrade both surface and groundwater supplies. There are two types of pollutants associated with mine drainage: sediment and chemical pollutants.

Suspended sediment is the major water pollutant in areas with steep terrain, such as Central Appalachia, where contour mining is practiced. High erosion rates resulting from high precipitation and runoff, steep slopes, and unvegetated spoil piles and coal haul roads are responsible for carrying large amounts of suspended sediment into receiving surface waters. Suspended sediment concentrations in a small Appalachian stream draining surface-mined areas can be increased 100 times over that of streams draining forested areas.[1/] Exposed spoil piles at area mines and refuse piles at underground mines and coal preparation plants are also subject to erosion and pollute surface runoff with sediment. Erosion and sedimentation at area mines are usually less severe than at contour mines due to their more level terrain and geometry which tend to retain most surface runoff within the mine site.

Raw process water from coal preparation plants contains high concentrations of suspended solids, primarily coal fines. As discussed earlier, these coal fines are removed by using drag tanks and thickeners or settling ponds, and zero discharge can be achieved by using a closed water circuit.

1/ Curtis, W.R., "Strip Mining, Erosion and Sedimentation," Journal of American Society of Engineers, 14/3/434-6, 1971.

TABLE V-4

AVERAGE COAL TRANSPORTATION DISTANCES

Origin	Method	Average Haul Distance (miles)
Northern Appalachia	Unit Train	320
	Conventional Train	320
	Barge	800
Central Appalachia	Unit Train	395
	Conventional Train	275
	Barge	300

SOURCE: University of Oklahoma, "Energy Alternatives: A Comparative Analysis," May, 1975, Table 1-55.

Chemical pollutants degrade water quality of both surface and groundwater supplies. In regions such as Northern Appalachia where there is abundant pyrite (FeS_2) in the coal seam and/or overburden, acid mine drainage results when pyrite is oxidized in the presence of oxygen and water, forming sulfuric acid and iron compounds which cause severe water pollution problems. Even where acid mine drainage is not a problem in Central and Southern Appalachia and the West, chemical pollution of water supplies can still occur due to high concentrations of dissolved solids.[1/2/] During mining large quantities of unweathered material (spoil and gob piles) are exposed to the atmosphere and are weathered to produce acid drainage and possibly toxic concentrations of other dissolved solids and metallic compounds.

Acid mine drainage is characterized by low pH and high concentrations of mineral acidity, sulfate, calcium, iron, and manganese and lesser amounts of other metallic compounds such as magnesium, aluminum, nickel and zinc. It occurs at both surface and underground mines, but the large majority of the acid mine drainage in Appalachia comes from underground mines.[3/] Abandoned and inactive underground mines in Northern Appalachia are the largest contributors to stream degradation, and account for 88 percent of the acid drainage in Northern Appalachia.[4/] Due to the prevalence of high sulfur coal (which has a high pyrite content) in Northern Appalachia, acid mine drainage is particularly severe and widespread.

1/ Curtis, W.R., "Chemical Changes in Streamflow Following Surface Mining in Eastern Kentucky", _Proceedings of the 4th Symposium_, Coal Mine Drainage Research, Mellon Inst., Pittsburgh, Pa., 1972, pp. 19-31.

2/ "Effects of Coal Development in the Northern Great Plains", Northern Great Plains Resources Program, Denver, Colorado, April, 1975.

3/ "Environmental Effects of Underground Mining and Mineral Processing", _op_. _cit_., p. 16.

4/ "Summary Report: Monongahela River Mine Drainage Remedial Project", U.S. EPA, 1971.

The majority of acid drainage produced from surface mines and refuse piles at underground mines and preparation plants occurs during wet seasons when surface runoff is high; therefore acid discharges tend to be quite variable. The water in underground mines comes from seepage of surface water into mines and from groundwater aquifers. Acid discharges from underground mines tend to be steadier and more concentrated than acid drainage from surface mines. This is generally due to the longer residence time of the water in underground mines, thus permitting more leaching prior to its discharge to surface waters.

Alkaline drainage is found most frequently in the West and Midwest and is characterized by a high pH (greater than 6), low metal ion concentrations, and total dissolved solids and suspended solids concentrations in excess of acceptable levels. Alkaline drainage results from leaching of freshly exposed material and is usually only treated to reduce suspended sediment via sedimentation or sedimentation and coagulation to meet recommended standards.

Table V-5 summarizes the estimated quantity of key water pollutants produced annually by typical mines and preparation plants which produce or process 250,000 tons of coal per year. The figures in the table give an approximation of the relative differences in pollution potential of different mine types in Northern and Central Appalachia. On the average, underground mines produce much more acidity and total dissolved solids than do surface mines in both Central and Northern Appalachia. Contour mines produce almost twice as much acidity as do area mines, but still substantially less than underground mines. With respect to both surface and underground mines, acid drainage is much more severe in Northern Appalachia. This is due to the predominance of high sulfur coal production in Northern Appalachia. However, under controlled conditions no acid discharges are permitted, as Table V-5 indicates.

TABLE V-5

ANNUAL WATER POLLUTANTS FROM COAL MINING AND PREPARATION1/

Water Pollutants (tons/year)

Activity	Northern Appalachia			Central Appalachia		
	Net Acidity	TDS2/	SS3/	Net Acidity	TDS 2/	SS 3/
Mining						
Surface						
Area - Controlled 4/	0	U 6/	3	NA5/	NA5/	NA5/
Contour - Controlled4/	0	U 6/	7	0	U6/	8
Underground						
Room-and-Pillar						
Controlled7/	0	U6/	0.4	0	U6/	0.4
Steam Coal Preparation						
Controlled 8/	0	U6/	6	0	U6/	6

1/ Basis: Annual production from mines = 250,000 tons per year.
Preparation plant capacity = 250,000 tons per year.

2/ TDS = Total Dissolved Solids.

3/ SS = Suspended Solids.

4/ Based upon EPA's NSPS for acid and alkaline mine drainage effluent. Average annual runoff = 20 inches. Runoff from one acre = 1.67 ac-ft or 2264 tons of water per year per acre.

5/ NA = Not Applicable.

6/ U = Unknown. No NSPS for total dissolved solids.

7/ Based upon existing EPA's NSPS for acid and alkaline mine drainage effluent. Assumes a discharge from treatment plant and settling pond of 5 gpm., or 10,955 tons of water annually.

8/ Assumes no discharge of pollutants from preparation plant due to use of closed-circuit water system. All pollutants are from treated refuse pile runoff which meet existing EPA New Source Performance Standards. Annual runoff averages 20 inches. Approximately 0.3 acres per year are used to store refuse. Annual run-off from 0.3 acre refuse pile = 0.163×10^{o} gal/yr.

With respect to suspended solids (SS), the large majority of which is sediment, surface mines produce much greater quantities than do underground mines, for surface mining exposes significantly more material to be eroded. Large sediment loads and sedimentation of streams and reservoirs are particularly severe in Central Appalachia where virtually all surface mining is contour mining practiced on steep slopes.

Coal preparation plants generally produce less acidity and total dissolved solids than underground mines and fewer suspended solids relative to surface mines. Suspended solids should not be significantly different for preparation plant effluents in the two regions.

Transportation of coal by river barges may contribute dissolved solids to the river water. Quantities are unknown, but may be significant. Other methods of transportation do not affect water.[1/]

c. Solid Waste/Land Use

(1) Solid Waste

Solid waste from coal mining and preparation is of two types: spoil and refuse from mining and preparation, and sludge generated by water treatment. No solid waste is created by transportation of coal.

In this analysis, solid waste from surface mining is defined as the spoil and refuse material that is not returned to and backfilled on the mined area. Spoil banks generally are a homogeneous mixture of rock fragments and soil-sized particles derived from

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1/ University of Oklahoma, op. cit., pp. 1-126.

the overburden strata. Often spoil material cannot establish or support vegetation due to slope instability, high erosion rates, inadequate nutrients and soil-sized particles, and the presence of toxic materials.[1/2/] Spoil piles result from both contour and area mining, and if they are not properly regraded and revegetated, they contribute to severe erosion and sedimentation as well as esthetic degradation.

Solid waste production from underground mines is generally related to the opening of the mine (i.e., shaft sinking). Approximately 3000 tons of earth are removed to sink a 600-foot shaft.[3/]

Frequently underground mine operations have an above-ground coal preparation plant near the mine site. From 15 to 35 percent of the raw coal fed to the preparation plant is discarded as refuse.[4/] This refuse or "gob" can be either returned to the mine or dumped on surface sites.

Additional solid waste is generated when sediment basins and/or water treatment plants are built to control water discharges. Sludge from conventional lime treatment facilities consists of insoluble iron and other metal hydroxides and sulfates which precipitate out after neutralization of acid drainage. Depending on the life of the settling ponds and the period of use, solid waste in the form of sediment and sludge may have to be dredged from the settling ponds and disposed of.

1/ Grim, E.C. and R.D. Hill, "Environmental Protection in Surface Mining of Coal", EPA 680/2-74-093, U.S. Environmental Protection Agency, October, 1974.

2/ Haynes, R.J. and W.D. Klimstra, "Some Properties of Coal Spoilbank and Refuse Materials Resulting from Surface-Mining of Coal in Illinois", prepared for the State of Illinois Institute for Environmental Quality, October, 1975.

3/ Hittman Associates, Inc., op. cit., p. III-83, F.N. 1401.

4/ U.S. Environmental Protection Agency, "Development Document ...", op. cit., p. 221.

Table V-6 summarizes the estimated annual solid waste production from coal mining and a steam coal preparation plant producing 250,000 tons of coal per year. These are very general estimates which vary to within 50 percent error; however, they are useful in assessing the relative differences in solid waste production from mines and preparation plants in different regions and under controlled conditions.

As with all other residuals, under uncontrolled conditions, area mines produce significantly less solid waste per ton of coal recovered than do contour mines. For area mines only the initial box cut is considered solid waste, for all other spoil material is placed in the previous cut. The same is true for the controlled contour mining case in which the modified block cut method is assumed. This method of controlled spoil placement significantly reduces the solid waste produced relative to the uncontrolled case in which the large majority of the spoil material is dumped downslope. Due to steeper slopes in Central Appalachia more overburden must be removed, on the average, than in Northern Appalachia to recover an equivalent quantity of coal. With proper reclamation, the impacts of solid waste are negligible.

The solid waste produced primarily when opening underground mines is a relatively small quantity compared to the sludge produced in the treatment of wastewater by a lime neutralization plant in the controlled case. Sludge resulting from treatment of acid mine drainage by conventional lime neutralization consists of insoluble hydroxide and sulfate compounds, which precipitate out during the neutralization process. The quantity of sludge produced is a function of the quantity and quality of the acid drainage; the greater the concentrations of acidity, iron, magnesium, aluminum and other metal compounds are, the more sludge

TABLE V-6

ANNUAL SOLID WASTE PRODUCTION OF COAL MINING AND PREPARATION[1/]

(tons/year)

Activity	Northern Appalachia	Central Appalachia
Mining		
Surface		
Area - Controlled (spoil from initial cut)	2,575[2/]	NA
Contour - Controlled (controlled spoil placement)	740[3/]	1,040[4/]
Underground		
Room-and-Pillar - Controlled (lime neutralization)	12,265[5/6/]	2,580[5/7/]
Steam Coal Preparation		
Controlled (emission controls and water treatment)	76,090[8/9/]	76,090[8/9/]

NA = Not Applicable

1/ Basis: Annual mine production = 250,000 tons per year.
Preparation plant capacity = 250,000 tons per year.

2/ Assumes 81% recovery efficiency, solid waste produced is only from the initial cut, and 0.0103 tons of solid waste are produced per ton of coal recovered. Hittman Associates, Inc., "Environmental Impacts Efficiency and Cost of Energy Supply and End Use," Vol. 1, November, 1974, p. III-85, F.N. 1405.

3/ Assumes controlled placement of spoil material using the modified block cut method; solid waste is produced only from the initial box cut. Approximately 0.003 tons of solid waste are produced per ton of coal recovered. Ibid., p. III-100, F.N. 1469.

4/ Assumes controlled placement of spoil material using the modified block cut method; solid waste is produced only from the initial box cut. Approximately 0.004 tons of solid waste is produced per ton of coal removed. Ibid., p. III-117, F.N. 1558.

5/ Assumes 60 tons of solid waste produced per million tons of coal recovered. Ibid., p. III-105, F.N. 1501.

6/ Assumes sludge from lime treatment plant is produced at the rate of 0.049 tons per ton of coal recovered, assuming a 57% recovery efficiency. Ibid., P. III-98. F.N. 1461.

TABLE V-6

ANNUAL SOLID WASTE PRODUCTION OF COAL MINING AND PREPARATION

(cont'd)

7/ Assumes lime treatment and 0.010 tons of sludge produced per ton of coal recovered, assuming a 57% recovery efficiency. Ibid., p. III-115, F.N. 1550.

8/ Assumes 30 percent of raw coal feed is refuse. U.S. Department of the Interior, Bureau of Mines, "Coal -- Bituminous and Lignite in 1975," February 10, 1977, p. 44, Table 31.

9/ Assumes approximately 0.0002 tons of solid waste produced per ton of coal cleaned resulting from treatment of process water by sedimentation and recirculation; control of air emissions using cyclones and a wet scrubber produces approximately 0.004 tons of solid waste per ton of coal cleaned. Reclamation of waste pile eliminates sediment from runoff. Council on Environmental Quality, "Energy and the Environment: Electric Power," August, 1973, pp. 41-45.

will be produced for a given volume of water treated. Solid waste production from lime treatment of wastewater is much greater in Norther Appalachia than in Central Appalachia due to the much higher concentrations and loads of acidity and total iron in Northern Appalachian mine drainage.

Approximately 30 percent of the raw steam coal cleaned in preparation plants is assumed to be refuse.[1/] Under controlled conditions, solid waste results from refuse as well as removal of particulates by settling from process waters, removal of airborne particulates by cyclones or baghouses, and sludge from SO_2 removal by wet lime scrubbers. Although the figures in Table V-6 do not illustrate this, as in the case of water pollutants from coal preparation plants in Central Appalachia, solid waste from SO_2 control is expected to be lower in Central Appalachia than in Northern Appalachia due to the lower sulfur content of the coal being cleaned.

1/ U.S. Department of the Interior, Bureau of Mines, op. cit., p. 44, Table 31.

(2) Land Requirements

Land disturbed by mining includes the acreage required for the active mine site, spoil piles, settling ponds, water treatment facilities, haul roads, and any other supporting facilities, as well as possible offsite land and water courses affected by landslides, erosion, and sedimentation.

Surface mining drastically alters the ecological characteristics of the active mine site and in some cases has a decided effect on surrounding areas. During mining, vegetation is removed, topographic features and characteristics are altered, and the original soil and overburden profiles are destroyed. Unless the mine site is properly rehabilitated or reclaimed after mining ceases, it may remain barren and unsuitable for any use for many years or decades, particularly if the spoil material is toxic or slopes are unstable and erosion rates are high.

The primary adverse impacts of underground mining on land are subsidence and preemptive use of land for surface waste piles and possibly a water treatment facility and associated sludge disposal. Solid waste generated from underground mining consists of surface waste piles and sludge from water treatment facilities.

Subsidence, associated particularly with room-and-pillar mining, occurs when the surface settles due to the collapse of the mine roof into the void created by coal extraction. Approximately 0.2 acres are estimated to subside for every 1000 tons of underground coal produced.[1/]

Subsidence control can be handled by leaving pillars of coal to support the mine roof or by "blasting the stumps" to remove the pillars and causing a relatively uniform roof collapse. The Bureau of Mines has experimented with a technique for pumping in backfill material for roof support once mining operations cease.

1/ Delson, J.K., and R.J. Frankel, op. cit., p. II-2a.

In addition, leaving solid pillars may be required under existing surface structures to ensure their stability.

The EPA document describing Best Practices for New Source Surface and Coal Mines suggests that all pillars be removed before abandonment unless otherwise specified in the mining plan. The document recognizes that determining when subsidence will be a problem and how to control it is a function of both geologic conditions in and around the mine, and activities occurring above the mine.

The mine roof and floor characteristics and the vertical distance from the mine to the surface are key factors in determining whether subsidence will cause surface disturbance. In addition to surface environmental problems, uneven subsidence could preclude mining higher seams. If the terrain above the mine (as often happens in Central Appalachia) is mountainous and undeveloped, subsidence will probably not affect the surface environment. If however, the mining occurs under relatively level developed areas as in parts of Pennsylvania and the Midwest, the subsidence control techniques described should be applied.

Land requirements associated with the preparation plants are the preemptive use of land for the cleaning plant and necessary storage and loading areas and for solid waste (refuse or "gob") disposal. Fixed land requirements for a steam coal preparation plant with a capacity of 2 million tons per year have been estimated to be 95 acres: 5 acres for the washing plant, 40 acres for the loading facility, and 50 acres for the settling pond.[1/] Land requirements for coal preparation plants vary significantly and are not easily correlated with plant capacity.[2/] Incremental land requirements include solid waste disposal. EPA estimated that 1 million tons of refuse will occupy approximately 3 to 4 acres.[3/]

1/ Hittman Associates, Inc., op. cit., p. III-89, F.N. 1427.

2/ U.S. Environmental Protection Agency, Development Document..."

3/ Ibid.

Table V-7 presents estimates of the acreage disturbed in Northern and Central Appalachia by a typical coal preparation plant and coal mines producing 250,000 tons of coal per year. The incremental land requirement represents the acres disturbed each year by extraction of the coal and disposal of solid wastes. The fixed land requirements represent the land required for the life of the mine; this includes the loading area and the plant facility for the preparation plant, and, for the unit underground mine and preparation plants, land required for the water treatment facility and settling ponds. These figures do not include the additional acreage required by sediment ponds at surface mines or coal haul roads due to the highly variable requirements of these facilities. Surface mines, therefore, have no fixed land requirements, and the fixed land requirement of the underground mine is limited in this analysis to the land used for the water treatment facility and settling pond. The land requirements for a water treatment facility and settling pond are highly variable and depend upon the volume of wastewater to be treated and its quality; therefore, the fixed land requirement is only a very general estimate.

In the case of surface mines and preparation plants, the incremental land requirement represents land disturbed by spoil material or solid waste. Under controlled conditions, this land is reclaimed and therefore is taken out of use for only a few years until reclamation and revegetation have been satisfactorily completed. After this time the land can usually be returned to productive use (e.g., pasture, forest, recreational or wildlife areas, development). Therefore, the area disturbed is in most cases only temporarily taken out of use for a few years.

TABLE V-7

LAND REQUIREMENTS OF COAL MINING AND PREPARATION[1/]

Activity	Northern Appalachia: Fixed Land Requirement (ac)	Northern Appalachia: Annual Incremental Land Requirement (ac/yr)	Central Appalachia: Fixed Land Requirement (ac)	Central Appalachia: Annual Incremental Land Requirement (ac/yr)
Mining				
Surface[2/]				
Area - Controlled	0	43	0	NA
Contour - Controlled	0	92	0	107
Underground				
Room-and-Pillar				
Controlled	65[3/]	61[4/]	16[5/]	63[4/]
Steam Coal Preparation				
Controlled	95[6/]	0.3[7/]	95[6/]	0.3[7/]

1/ Basis: Annual mine production = 250,000 tons per year.
Preparation plant capacity = 250,000 tons per year.

2/ EEA, Inc., "Draft Final Report - Case Studies on Coal Regulations: Cost/Benefit Analyses," Vol. II. Prepared for the Office of Minerals Policy Development, U.S. Dept. of the Interior, December 8, 1976, Table IV-22.

3/ Treatment plant occupies about 3 acres. Approximately 62 acres of land are required for a 4 million gallon raw water storage pond and 400 million gallon settling pond, both with a depth of 20 feet. Ibid., p. III-98, F.N. 1464.

4/ Approximately 25 percent of the undermined area, or .24 acres/1000 tons, subsides (assumes no backfilling). Hittman Associates, Inc., "Environmental Impacts Efficiency and Cost of Energy Supply and End Use," Vol. 1, November, 1974, p. III-83, F.N. 1402.

5/ Treatment plant occupies about 3 acres. Approximately 13 acres of land are required for a 2 million gallon raw storage pond and an 80 million gallon settling pond, both with a depth of 20 feet. Ibid., p. III-15, F.N. 1553.

6/ Includes 5 acres for the washing plant, 40 acres for the loading facilities, and 50 acres for the settling pond. Ibid., p. 1-67.

7/ Assumes that 30% of the raw coal feed is refuse. U.S. Bureau of Mines, "Coal -- Bituminous and Lignite in 1974," p. 44, Table 31. Refuse pile is estimated to occupy approximately 3.5 acres per million tons of refuse. U.S. Environmental Protection Agency, "Development Document for Interim Final Effluent Limitations Guidelines and New Source Performance Standards for the Coal Mining Point Source Category," EPA 440/1-76/057-a, May, 1976, pp. 221 and 223.

The incremental land requirement of underground mining is due to subsidence of about 25 percent of the undermined area.[1/] The area affected by subsidence from underground mining, however, is much more difficult to reclaim and therefore is a long-term impact limiting the future use of the land. Impacts of subsidence are particularly severe if buildings or other structures are located on the undermined land. As stated before, these impacts may be minimized by backfilling.

As mentioned earlier, due to the mining method, area mines generally disturb less land than contour mines, for the spoil material from successive cuts can easily be placed in the preceding cut. In addition, the thicker the coal seam, the less area must be disturbed per ton of coal. The average seam thickness for area mines is estimated to be 3.9 feet, whereas contour mines average about 3 feet.[2/]

Because of the steep topography of Central Appalachia, the slope of the land on which most contour mining is practiced is greater than 20 degrees, compared to only 15 degrees in Northern Appalachia. With conventional contour mining and reclamation to a terrace backfill, the regraded spoil occupies more area the steeper the slope is.[3/] With the block cut method of mining and controlled placement of spoil material, the total area disturbed after mining can be reduced significantly.

Land utilization for the transportation of coal includes the railroads and their rights-of-way and loading facilities. The area required for railroad lines depends upon the length of the line and the width of the right-of-way. Rail rights-of-way may average about six acres per mile (approximately 55 feet wide).[4/] Specific estimates of land required to transport program coal is deferred to site-specific analyses.

1/ Hittman Associates, Inc., op. cit., p. III-83, F.N. 1402.

2/ Energy and Environmental Analysis, Inc., op. cit.

3/ Ibid.

4/ University of Oklahoma, op. cit., pp. 1-126.

C. Coal Use

1. Introduction

This section discusses the environmental impacts associated with the combustion of low sulfur coal produced under the Coal Loan Guarantee Program as compared to combustion of higher sulfur coal available without the program. For the purposes of analysis, all coal produced under the program is assumed to be used by coal-fired power plants to generate electricity. The combustion of coal by a coal-fired power plant has associated with it a number of environmental impacts which affect the air, water, land, and ecological, socioeconomic, and esthetic environments. The pollutants produced, their quantities, and their associated impacts vary according to several factors including fuel type, boiler type, operating conditions, and emissions control systems. In this analysis, the loan program is assumed to affect only the fuel type and the emissions control systems used at a power plant.

The range and type of impacts that can result from the pollutants discussed in this section were spelled out earlier in this chapter for states in which the coal mining, coal cleaning, and intensive use of Appalachian low sulfur coal are expected.

With the loan program, new and existing non-conformance coal-fired power plants are assumed to burn low sulfur coal; additional sulfur dioxide (SO_2) emission control will not be necessary to comply with existing SO_2 emission limitations. Without the program, the power plants are assumed to burn higher sulfur coal using scrubber [flue gas desulfurization (FGD)] devices to control SO_2 emissions. The two methods of controlling SO_2 emissions result in differing quantities of residuals, particularly solid waste, and associated impacts.

This section first describes the major environmental issues associated with coal combustion at a unit power plant. Principal issues associated with the Coal Loan Guarantee Program are identified. A discussion of the residuals produced follows, using the pollutants produced from a unit-sized power plant with and without the program as an example. The environmental impacts of the pollutants produced under the loan program on ambient environmental quality are analyzed, and mitigating measures that could reduce these impacts are identified and reviewed.

2. Environmental Issues

Coal combustion at power plants has a variety of environmental effects on air, water, solid waste/land use, and ecosystems. Coal combustion generates both gaseous and solid (particulate matter) pollutants that can enter the atmosphere. Water pollution results from cooling and operational blowdown water, coal pile runoff, ash sluicing discharge, and runoff from solid waste disposal areas. Solid waste is generated in the form of the residue from coal combustion and air pollution emissions control. Land is needed for coal storage, solid waste disposal, and onsite facilities for ash and coal handling and air pollution control equipment. Each of these environmental residuals can have adverse impacts on aquatic or terrestrial ecosystems or the cultural and economic life of man.

Air emissions from power plant operations are of two types: gases and particulates. Gaseous air pollutants generated by coal combustion at power plants include sulfur dioxide (SO_2), nitrogen oxides (NO_x), carbon monoxide (CO), hydrocarbons, and aldehydes. Gaseous pollutants result from the release of elements in the coal during combustion, but they are also influenced by the characteristics of the combustion process itself. Sulfur dioxide emissions, for example, are governed by the sulfur content of the coal. Nitrogen dioxide emissions, on the other hand, are independent of the chemical composition of the coal and are governed by the design of the boiler. CO, HC, and aldehydes are also governed by the operating characteristics of the boiler.

Particulate air pollutants are fly ash and small quantities of trace elements. Incombustible material in the coal is known as ash, and its characteristics depend on the type of coal. During coal combustion, the heavier and larger ash particles fall to the bottom of the boiler and remain as bottom ash solid waste. Lighter and finer ash particles are entrained in the flue gas during combustion and exit with the flue gas as fly ash. The proportion of the ash content of the coal that becomes fly ash or bottom ash solid waste during combustion depends upon the type of combustion chamber.

Trace elements are toxic substances contained in coal in trace quantities. During combustion, trace elements can vaporize to exit the boiler in a gaseous state, or they may form particulates which are then entrained in the exhaust.

Particulate matter and sulfur dioxide are the two air pollutants produced in the largest quantities at coal-burning power plants. Control equipment is used to reduce emissions of these pollutants from coal-fired power plants to comply with emission limitations. These controls, however, are an additional source of solid waste. Primarily, two control devices are used: scrubbers, which remove SO_2 and can also be designed to remove particulate matter, and ESP's (electrostatic precipitators) which remove particulate matter. In some cases, catalytic or regenerative processes can be used. ESP's operate by electrically charging particulate matter in the flue gas and collecting it on charged plates. Both processes also remove trace elements in the form of particulates from the flue gas. ESP's only remove particulates; they do not remove gaseous pollutants. Scrubbers remove some NO_x in addition

SO_2 and particulate matter. SO_2 scrubbers produce a calcium sulfite/sulfate sludge which contains fly ash. Without scrubbers, electrostatic precipitators collect fly ash.

Sources of water pollution resulting from the operation of a coal-fired steam electric plant are coal pile runoff, cooling water, process water blowdown, ash sluicing water, and runoff and/or leachate from solid waste disposal sites. Precipitation runoff from the coal pile generally is acidic and contains heavy metals and sediment. The chemical composition of the coal governs the pollutant characteristics of the coal pile runoff. Ash sluicing water also contains chemical pollutants leached from the ash and sediment. Cooling water is a major source of thermal pollution, and, due to corrosion, process water blowdown can be a source of chemical pollutants. Precipitation runoff at an ash or sludge disposal site can contribute chemical and sediment pollutants to surface water or contaminate groundwater through infiltration.

Ash and/or scrubber sludge are the solid waste products produced at coal-fired power plants. Either or both materials need land for disposal and each material presents certain disposal problems. Bottom and fly ash must be transported from the power plant and the ESP collectors for disposal. In dry ash handling, the ash does not contact the water and thus does not present a water pollution problem. Wet ash handling systems, however, do present a water quality problem. In these, ash is transported from the power plant and/or ESP in a water slurry. This conveyance water, having come in contact with ash, contains chemical water pollutants and sediments. Ash disposal techniques include landfilling and ponding. For example, ash can be sluiced to an onsite pond for disposal or to a small temporary pond, or it can be handled dry in temporary storage bins and hauled offsite by trucks to a landfill. Other ash disposal techniques include the use of ash as construction material.

Scrubber sludges ready for disposal are generally 40 to 50 percent water, the remainder being scrubber solids (calcium sulfite/sulfate and/or fly ash). Like ash sluicing water, the water in sludge is a source of chemical pollutants and sediment. Sludge disposal techniques are similar to disposal techniques for ash. Sludge can also be pumped to onsite disposal lagoons or dried and hauled by truck to an offsite disposal area. Scrubber sludge can potentially be treated to produce a variety of usable chemicals - e.g., gypsum, sulfur, or sulfuric acid; however, at present, these techniques are not economical in the U.S.

In general, the disposal of scrubber sludge requires more land than simple ash disposal. Furthermore, scrubber sludges present somewhat greater land use problems than ash. Ash compacts and is relatively stable, whereas most scrubber sludges readily retain or reabsorb water and make unstable foundation material. A variety of treatment methods is available to alleviate this problem, including chemical fixation, which, by adding chemicals to the sludge, turns it into a concrete-like mass.

3. Effects of the Coal Loan Guarantee Program

The Coal Loan Guarantee Program will affect coal-fired power plants by making available to power plants steam coal with a slightly lower ash content and a much lower sulfur content. It is assumed in this report that this coal, if availble, would be burned at existing power plants to come into compliance with air pollution control requirements or at new power plants already under construction and required to meet existing New Source Performance Standards. Without the loan program, low sulfur coal will not be available in as large quantities, and coal with a high sulfur (2 to 3% sulfur by weight) and ash content (10 to 12% by weight) will have to be used as fuel in greater quantities. The program legislation stipulates that 80% of the loan guarantees will be restricted to financing production of coal that, when burned, will meet existing NSPS for SO_2 emissions (1.2 lbs SO_2/MMBtu) without SO_2 control equipment. Coal cleaning will remove ash as well as sulfur. Approximately 1/3 of the total coal expected to be mined as a result of the program is estimated to need cleaning to meet sulfur criteria; therefore, on average, loan program coal will be slightly lower in ash content than would otherwise be available.

It is assumed that without the loan program, existing or new power plants (already under construction) will burn coal with a sulfur content that will result in sulfur dioxide emissions that exceed the SO_2 emissions limitations unless controlled. With the program, low sulfur coal would be available to permit the power plants to burn coal in compliance with air pollution control requirements without scrubbers.

a. New Powerplants

Air:

With or without the use of loan program coal, emissions from new power plants already under construction must meet the existing EPA New Source Performance Standards; for particulates, 0.1 lbs/MMBtu, and for SO_2, 1.2 lbs/MMBtu. CO, HC, and aldehyde emissions will not be affected, since these pollutants are not influenced by the characteristics of the coal burned but are governed by the operating characteristics of the power plant. Only NO_2 and trace element emissions may differ due to program coal or no-program coal cases. NO_2 emissions may be higher with the loan program because the scrubber units without the program also will remove NO_2 to a small degree. Differences in trace element emissions are largely dependent on the concentrations of the elements in the coal and the particulate and/or SO_2 air pollution control equipment used. The trace element content of coal is independent of the sulfur content, so the effect of the loan program on trace element emissions is difficult to evaluate. However, the use of scrubbers with non-loan program coal instead of ESP's alone may remove greater quantities of trace elements from the flue gas. Because the loan program will decrease the use of scrubbers, trace element emissions may be higher; however, the ultimate trace element emissions will depend upon the trace element content of the coal.

Water:

Sources of wastewater which will differ as a result of the loan program are coal pile runoff, bottom ash sluicing water, and runoff and/or leachate from solid waste disposal sites. The lower sulfur content of loan program coal creates a less acidic coal pile runoff. Similarly, with the use of low sulfur coal, bottom ash sluicing water will have lower heavy metal concentrations. In addition, since loan program coal will generally have a slightly lower ash content, the volume of water needed for sluicing will be smaller under the loan program.

The differential water quality impacts of solid waste disposal under the loan program are somewhat more complex. Under the loan program, the volume of ash produced will be smaller and require less land for disposal. Because less solid waste disposal area will be exposed to rainfall, the volume of infiltrating water or surface runoff will be lower. However, ash is more chemically reactive than scrubber sludge, and the concentration of heavy metals in ash leachate will be higher than for scrubber leachate. On the whole, without the program, the volume of water and the annual amount of heavy metals (in pounds) leached from scrubber sludges will be higher than for ash, since ash is structurally more stable and easier to keep dry. Fuel-independent sources of wastewater, cooling water, and process water blowdown will not be changed by the loan program.

In terms of actual impacts on ambient water quality from the sources outlined above, the loan program primarily will affect groundwater. Existing New Source Performance Standards allow the discharge of coal pile runoff, bottom ash sluicing water, and ash disposal site runoff to surface water bodies. Groundwater will be affected by sources outlined above. The concentrations of heavy metals in infiltrating water from coal pile runoff and bottom ash sluicing water will be less under the loan program. Without the loan program, pollutant concentrations in water infiltrating from a sludge disposal site will be less, but there will be a larger and more continuous volume of infiltrating water and the total amount of heavy metals (in pounds) entering the groundwater will be larger.

Solid Waste/Land Use:

The use of low sulfur coal instead of scrubbers to meet SO_2 standards reduces the amount of solid waste produced and the area needed for solid waste disposal. In addition, ash from low sulfur coal creates a solid waste much more conducive to environmentally sound disposal.

b. Existing Non-Conformance Powerplants

Environmental impacts of the loan program at existing powerplants may differ from impacts at new powerplants subject to existing NSPS because the emission limitations that apply to existing powerplants are in some instances much less stringent than existing NSPS limits. The relative impact of loan program vs. non-loan program coal use at existing powerplants, however, is, for the most part, the same as the relative impacts at new powerplants under construction. As can be seen from Table V-8, no major changes in the relative impact of loan vs. non-loan program coal use occur if the coals are assumed to be burned at existing plants rather than new plants under construction.

TABLE V-8

SUMMARY OF RELATIVE DIFFERENCES IN IMPACTS BETWEEN LOAN PROGRAM COAL BEING USED AT EXISTING PLANTS AS OPPOSED TO NEW PLANTS

Range of SO_2 Limitations at Existing Plants (lbs/MMBtu)	Fuel Use and Air Control Assumptions	Relative Differences in Air Impacts	Relative Differences in Land Use/Solid Waste Impacts	Relative Differen in Water Impact
0.2 - 0.7	No program coal[1/] or non-program coal suitable[2/] for use; fuel assumed to be oil or natural gas	Not applicable	Not Applicable	Not Applicable
0.7 - 1.2	"Select" program coal[3/] can be burned without scrubbers; non-program coal requires scrubbers	SO_2, particulate, HC, CO, and trace element emissions will be essentially identical whether program coal or non-program coal is burned. As is the case at new plants, 10% reduction in NO_x emissions at existing plants which burn non-program coal and use scrubbers	Depending on the particulate emissions limits,[4/] the land use/solid waste can be 4% less or 1% more than at new plants burning program coal; depending on the particulate and the SO_2 emission limits the land use/solid waste at existing plants can be 15% less or 10% more than at new plants burning non-program coal	At existing plants fly ash handling water may be discharged whereas new sources may not. Although the same amount of pollutants would be generated in both new and existing plants, the greater the amount of water retained in the system the more pollutants such as heavy metals and dissolved solids infiltrate into groundwater and are not charged into the surface water. The amount of dissolved solids generated in the program coal case is 0.3% less than the non-program coal
1.2 - 1.7	Program coal can be burned without scrubbers; non-program coal requires scrubbers	Same as above except that SO_2 emissions can be up to 42% higher burning non-program coal as compared to burning program coal	Same as above	Same as above
1.7 and greater	Both program coal and non-program coal can be burned without scrubbers	At existing plants, particulate, HC, CO, NO_x, and trace element emissions will be essentially the same whether program coal is used or not. SO_2 emissions can be up to 250% higher burning non program coal as opposed to program	Same as above, except land use/solid waste impacts can be 2% less or 1% more than ash production at new plants burning non-program coal	Same as above

Notes to Table V-8:

1/ Program coal = 11,800 Btu/lb, 9% ash, 0.7% sulfur.

2/ Non-program coal = 11,800 Btu/lb, 10.5% ash, 2.25% sulfur.

3/ "Select" program coal = 11,800 Btu/lb, 8% ash, 0.3% sulfur.

4/ SIP particulate emission limits vary from 0.02 lbs/MMBtu to 0.3 lbs/MMBtu.

Air:

Existing powerplants must meet SIP's for SO_2 emissions, which in the eastern States possibly affected by the loan program vary from as low as 0.2 lbs/MMBtu to as high as 4.2 lbs/MMBtu. This range can be divided into four parts corresponding to four different necessary operating configurations: below 0.7 lbs/MMBtu, where it is assumed that neither loan nor non-loan program coal can be burned; 0.7 to 1.2 lbs/MMBtu, where scrubbers are needed to burn non-loan program coal, while "select," that is the lowest sulfur content, loan program coal can be burned free of control; 1.2 to 1.7 lbs/MMBtu, where all loan program coal can be burned without scrubbers and non-loan program coal can be burned only in conjunction with scrubbers; and above 1.7 lbs/MMBtu, where both loan and non-loan program coal can be used without scrubbers. Since it is assumed that with the program existing powerplants burn 100% program coal (defined as meeting the 1.2 lbs/MMBtu NSPS for SO_2), SO_2 emissions from existing powerplants will be equal to SO_2 emissions from new sources.

Other air pollutant emissions also are the same or less with the use of loan program coal for all pollutants but NO_x. As at new powerplants under construction, NO_x emissions from existing powerplants burning loan program coal are approximately 10 percent more than NO_x emissions when burning non-loan program coal.

Water:

At both new and existing powerplants, bottom ash sluicing water can either be discharged directly after treatment into "navigable water" or recirculated back into the system. The higher the percentage of this water retained within the sluicing system, the greater the impact on groundwater and the less the impact on surface water. With program coal, the amount of heavy metals entering into the water bodies from bottom ash sluicing water will be less than if high sulfur coal were burned.

Fly ash handling water cannot be discharged by new sources, but can be emitted by existing sources. Fly ash, which comprises 85 percent of the ash generated during coal combustion, will have similar impacts at both new and existing plants since the same amount of contaminants will be generated. With the program, if existing sources discharge fly ash handling water, surface water quality will be affected, while handling fly ash dry at new sources would affect groundwater. Without the program, if fly ash is handled dry at existing sources and landfilled with scrubber sludge (as would be the case with new sources), the impacts will be the same from both new and existing sources. Again, however, if the existing source sluices the fly ash and discharges the sluicing water, surface water quality will be affected rather than groundwater.

Solid Waste/Land Use:

Depending on the particular SIP for particulate emissions at existing non-conformance powerplants, up to 4% less or 1% more solid waste may be produced relative to new sources meeting the existing NSPS for particulates. If higher sulfur, non-loan program coal is burned, existing plants may produce up to 15% less or 10% more solid waste than new plants burning non-loan program coal.

c. Major Impacts of the Program

The major environmental impacts of the loan program will be on land use and solid waste disposal. Without the program, more solid waste (ash as well as scrubber sludge) will require disposal, while with the program, only ash will require disposal. More sludge than ash will be produced, requiring more land for disposal.

In addition, scrubber sludges are subject to rewatering and are generally less stable than ash as a foundation material. The disposal of scrubber sludge potentially may preclude land used for disposal from future productive use. Such impacts will be avoided with the use of low sulfur coal produced under the loan program.

4. Residuals Produced

In the analysis of residuals that follows, it is assumed that coal produced under the loan program is burned at new powerplants already under construction in the following States: New York, Pennsylvania, West Virginia, Maryland, Delaware, North Carolina, South Carolina, Georgia, Florida, Kentucky, Alabama, Mississippi, Ohio, Indiana, Illinois, Michigan, and Wisconsin. It is assumed that no coal from the loan program will be burned at utilities or other facilities converting from oil and/or gas to coal.

In order to determine the environmental impacts of the loan program, pollutant residuals were calculated at the plant level for a unit-sized new powerplant already under construction. These new powerplants in the area of the eastern U.S. outlined above have a broad range in size from 280 MW to 1300 MW.[1/] The average size for a new powerplant (single unit) is approximately 570 MW. This analysis uses the 570 MW unit powerplant to calculate residuals. It is assumed that the unit operates at a 60 percent capacity with a heat rate of 10,000 Btu/kWh. For the purposes of analysis, it is assumed that, under the loan guarantee program, the powerplant will only burn coal produced as a result of the program and having the following characteristics:

1/ Kidder, Peabody & Company, Inc., "A Status Report on Electric Utility Generating Equipment, Fossil Boilers," March 18, 1976, New York, New York.

a heat rate of 11,800 Btu/lb, a sulfur content of 0.7 percent, and an ash content of 8 percent (by weight), and that powerplant particulate emissions will meet existing NSPS with the use of electrostatic precipitators (ESP's). No SO_2 control is assumed to be necessary to meet existing NSPS for SO_2 emissions.

Without the loan program, it is assumed that new powerplants will burn coal with a heat content of 11,800 Btu/lb, a sulfur content of 2.25 percent, and an ash content of 10.5 percent. The lower ash content of the loan program coal reflects the assumption that approximately 1/3 of the coal produced under the loan program will be cleaned to a sulfur content of 0.7 percent. The cleaning process on average reduces the ash content of coal by 50 percent.[1/] Powerplant emissions are assumed to meet existing NSPS for particulates and SO_2 through the use of an FGD scrubber system.

Existing non-conformance powerplants also are assumed to burn only program coal under the loan guarantee program (i.e., no blending). Again, a 570-MW unit powerplant is assumed. Existing powerplants meet the SIP of 1.2 lbs SO_2/MMBtu when burning program coal without scrubbers. Without the program, existing sources are assumed to burn high sulfur coal using scrubbers to meet SIP's ranging from 1.2 to 1.7 lbs SO_2/MMBtu. Program and non-program coal characteristics are assumed to be the same for existing sources as for new sources. Powerplant operating conditions (i.e., 60 percent capacity, heat rate of 10,000 Btu/hr) also are the same. Emissions are not quantified for existing sources, but are discussed generically in the text.

1/ U.S. Department of Interior, Bureau of Mines, "Sulfur Reduction Potential of the Coals of the United States," Bureau of Mines Report of Investigations, RI 8118, 1976.

a. Air

Air emissions from coal-fired powerplants include particulates, sulfur dioxide (SO_2), nitrogen oxides (NO_x), carbon monoxide (CO), hydrocarbons (HC), and trace elements. Because the new powerplants must meet existing NSPS, particulate and SO_2 emission rates from coal-fired powerplants affected by the loan program will not differ even though low sulfur rather than high sulfur coal will be produced and used under the loan program. However, particulate and sulfur dioxide control requirements will be greatly affected by the use of loan program coal. SO_2 emissions from coal-fired powerplants are a direct function of the sulfur content of the coal. Between 95 and 99 percent of the sulfur in coal is converted to gaseous sulfur dioxide in the process of burning coal and can be emitted to the atmosphere. The balance of the sulfur in coal remains in the fly and bottom ash residue.

Particulate emissions are a function of the ash content of the coal and boiler design. Ash largely is comprised of silica, alumina, and iron. When coal is burned, all of this inorganic matter in the coal becomes ash and either remains in the boiler as bottom ash or is exhausted through the stack as fly ash. Boiler type determines what fractions of the ash in the coal become fly and bottom ash. Normally, 65 percent of the ash in coal becomes fly ash when coal is burned in a pulverized wet bottom boiler, and 85 percent when burned in a pulverized dry bottom boiler. Cyclone boilers reinject fly ash into the boiler and result in much lower amounts of fly ash; only 20 percent of the ash in coal becomes fly ash.[1/]

1/ U.S. Environmental Protection Agency, "Compilation of Air Pollution Emission Factors," Publication No. AP-42, Second Edition.

(1) New Powerplants

Controlled ambient particulate and SO_2 levels will not be affected by the Coal Loan Guarantee Program because with or without it, particulate and SO_2 emissions from new powerplants under construction must meet existing New Source Performance Standards. Actual particulate and SO_2 emissions, therefore, will be the same regardless of whether or not the coal burned is low or high sulfur. To meet these limits, however, each coal-burning powerplant must have installed on it pollution control equipment; thus the loan program will make a significant difference in the kind and extent of air pollution control required on new powerplants under construction.

Table V-9 presents the particulate and SO_2 removal efficiencies with and without the loan program that will be needed to reduce particulate and SO_2 emission rates from new powerplants to those required under existing NSPS. Efficiencies are given in percentage removal for all types of boilers. With the loan program, the new powerplants will be able to operate with slightly lower efficiency particulate control equipment and without SO_2 control equipment. Without the loan program, new powerplants must be equipped with SO_2 removal equipment.

As discussed in Section II-D, without the program, new utilities are assumed to add only enough scrubbing capacity to comply with the maximum permissible emissions under the State's standards. This is the most economic mode of operation for a powerplant.[1/] Further, this mode of operation is the basis for the 69% required removal of sulfur shown in Table V-9 and the identical emissions projections, with and without the program, shown in Table V-12.

1/ New utilities could (and likely will) blend high sulfur with low sulfur coal to just meet the NSPS for SO_2. However, to simplify the analysis, it was assumed that no coal was blended and that new sources burn 100% program coal.

TABLE V-9

PARTICULATE AND SO_2 EMISSIONS CONTROL EFFICIENCIES NEEDED TO MEET NSPS

Powerplant Type	Required Particulate Matter Removal[1/] (% removal)		Required SO_2 Removal[2/] (% removal)	
	With Loan Program	Without Loan Program	With Loan Program	Without Loan Program
Pulverized				
Wet Bottom	98%	98.5%	0	69%
Dry Bottom	98.5%	99.0%	0	69%
Cyclone	93.0%	94.5%	0	69%

1/ The EPA NSPS is 0.10 lbs/MMBtu.

2/ The EPA NSPS is 1.2 lbs/MMBtu.

Without the program, the efficiency of the particulate control equipment used must be between 94.5 and 99 percent, depending on the type of boiler; with the loan program the required efficiencies will be slightly reduced to between 93 and 98.5 percent depending on boiler type. The three major systems for controlling particulate emissions from utility boilers are electrostatic precipitators (ESP), baghouse filters, and cyclone mechanical collectors. Of these systems, ESP's or baghouses have the removal efficiency needed to meet existing NSPS particulate matter emission rates. Baghouse filters, as their name implies, collect particulate matter in large bag filters and are 99 percent efficient. Currently, installed ESP's average removal efficiencies of more than 97 percent and can easily operate with proper maintenance at efficiencies of 99+ percent. Neither of these devices has a discernible effect on gaseous pollutant emissions, and neither results in additional air pollutants.

The loan program's most dramatic impact is on SO_2 control requirements. Without the program, the SO_2 control efficiency must be 69 percent to meet existing NSPS; with the program, no SO_2 emissions control will be required. The demonstrated effective means of SO_2 removal is the use of either a lime or limestone scrubber flue gas desulfurization (FGD) system. Such a system will be needed at new powerplants not affected by the loan program. These systems operate through introducing substances into the flue gas that chemically react with SO_2 and result in the removal of 60 to 85 percent of the SO_2 from the flue gas. If a scrubber is used, it also reduces particulate matter emissions by more than 99 percent. Thus, without the loan program, particulate and SO_2 emissions limits could be met through the use of a scrubber only.

Additional emissions associated with FGD systems depend on whether or not the scrubber medium is regenerated from the spent scrubber waste stream. The non-regenerable scrubbing systems which produce a calcium sulfite/sulfate sludge as the end product have no associated air emissions. The regenerable processes which produce elemental sulfur or sulfuric acid emit SO_2 or SO_3 during regeneration of the scrubber medium and product processing.

Table V-10 presents uncontrolled emission rates for carbon monoxide, hydrocarbons, and nitrogen oxides from the three types of powerplant boilers.[1/] Of these three pollutants, only NO_2 will be affected by the loan program.

Carbon monoxide, hydrocarbons, and aldehydes occur in relatively small quantities during coal combustion at powerplants. They result from incomplete combustion of the organic portion of the coal. Careful control of excess air rates, the use of high combustion temperatures, and provisions for intimate fuel-air contact minimize these emissions. Since emissions of these pollutants are determined by the operating characteristics of the powerplant boiler, the loan program will not affect the emission of these pollutants at new powerplants. With or without the program, these air pollutants will not be controlled and emission rates will be identical.

NO_2 emission rates are also independent of fuel type and differ only because SO_2 scrubbers also reduce NO_2 emissions.

1/ Since the emission rates shown in Table V-10 are based on complex relationships between coal type, boiler type, operating practices, and the air-to-fuel ratio, they cannot be adjusted to reflect emissions from the combustion of the low sulfur program coal and higher sulfur coal which would be used in the absence of the program. The emission rates shown in the table are only meant to give a rough estimate of actual emissions of stations affected by the program.

TABLE V-10

UNCONTROLLED POWERPLANT EMISSIONS - CO, HC, AND NO_x (lbs/MMBtu)

Powerplant Type	CO	HC	NO_x
Wet Bottom	.042	.013	1.26
Dry Bottom	.042	.013	0.76
Cyclone	.042	.013	2.31

Assuming the use of coal with the following characteristics:

Heat content:	12,000 Btu/lb
Ash content (%):	10
Sulfur content (%):	1.5

SOURCE: Compilation of Air Pollutant Emission Factors, EPA, AP-47, March, 1975.

Nitrogen oxides are produced from high-temperature reactions of nitrogen and oxygen present in the combustion atmosphere and the combustion of nitrogen-containing compounds in the fuel. The concentration of nitrogen oxides in the exhaust during coal combustion is affected by the amount of nitrogen in the coal, the air-to-fuel ratio, and the time and temperature profile of the combustion gases as they pass through the boiler. No control equipment is now in use or available for use to control NO_2 emissions (although scrubbers, as stated earlier, slightly reduce NO_2 emissions in addition to SO_2). In some cases, scrubbers can decrease NO_2 emissions from powerplants by as much as 10 percent; however, such large decreases in NO_2 emissions due to scrubbers are rare. Typically, SO_2 scrubbers reduce NO_2 emissions from powerplants by between 5 and 10 percent. Thus, with the program, NO_2 from powerplants will enter the atmosphere uncontrolled, while, on average without the program, NO_2 emissions will be reduced by scrubbers at new powerplants by approximately 10 percent.[1/]

Coal combustion also results in emission of a variety of toxic trace elements which, in sufficient quantity, can cause adverse environmental and health effects. These toxic substances are contained in coal in trace quantities. Table V-11 presents the trace element content of coal and typical trace element emission rates from a coal-fired electric powerplant. On the whole, trace element emissions from new powerplants will be slightly lower than those presented in the table because such plants will have sophisticated ESP's. Although SO_2 scrubber units also remove trace elements by entraining particles, additional removal is achieved through chemical reactions in conjunction with the

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1/ Ten percent is used in this analysis as the percent reduction in NO_2 emissions expected due to scrubber use to approximate what could be expected as the worst case impact of the loan program.

TABLE V-11

TRACE ELEMENTS AND EMISSIONS FROM COAL

Element	Concentration (ppm)	Emission Factor ($g/10^6$ Btu)a/
Antimony	5	0.20
Arsenic	32	1.3
Barium	500	20.2
Beryllium	2.44	0.099
Boron	61	2.47
Cadmium	0.03	0.001
Chlorine	160	6.48
Chromium	15.4	0.624
Cobalt	4.8	0.194
Copper	13.5	0.547
Fluorine	82	3.32
Lead	9.5	0.38
Manganese	50	2.02
Mercury	0.15	0.0061
Nickel	14.8	0.599
Selenium	2.2	0.089
Tellurium	1	0.04
Thallium	0.3	0.01
Tin	0.9	0.036
Titanium	385	15.6
Vanadium	26.4	1.07
Zinc	12	0.49

a/ Based on heating value of 11,200 Btu/lb for coal as burned.

SOURCE: Hazardous Emission Characterization of Utility Boilers, EPA-650/2-75-066, July, 1975.

removal of SO_2. Therefore, the powerplant equipped with scrubber units will have a slightly lower trace element emission rate. However, with the loan program, trace element emission rates of powerplants burning low sulfur coal rather than using scrubbers to meet SO_2 emission standards also will be slightly lower due to the use of lower ash coal made available by the program. Trace element emission rates are generally proportional to the ash content of the coal, provided all other conditions are identical.

Controlled powerplant emissions on an annual basis are summarized in Table V-12 for both the program case and the base case without the program. Annual pollutant loadings are given for a 570-MW powerplant (average size of new powerplants between 1976 and 1977), assuming a heat rate of 10,000 Btu/kWh and a 60 percent capacity use factor. Particulate and SO_2 emissions from the plant are assumed to meet existing NSPS limits. CO and hydrocarbon emissions are not affected as a result of the program. As discussed earlier, trace element emissions are slightly lowered to a similar extent both with and without the program. As can be seen from the table, only annual NO_2 loadings will be increased as a result of the program.

(2) Existing Non-Conformance Powerplants

The air quality impact of loan vs. non-loan program at existing powerplants is, for the most part, identical to the impacts at new powerplants under construction. Just as particulate and SO_2 emissions from new powerplants must meet existing NSPS limits whether or not loan or non-loan program coal is used, particulate and SO_2 emissions from existing plants will have to comply with all applicable air pollution control requirements, whether or not high or low sulfur coal is used. However, because SIP SO_2 emission rates vary from 0.2 to 4.2 lbs/MMBtu, four different sets of operating conditions must be examined for existing plants while only one, meeting existing NSPS limits, must be

TABLE V-12

IMPACT OF LOAN PROGRAM ON
CONTROLLED EMISSIONS FROM A NEW 570-MW POWERPLANT
(tons/year)

Pollutant	With Program 2/	Without Program 3/
Particulate Matter	1,498	1,498
SO_2	17, 976	17,976
HC	195	195
CO	629	629
NO_2 4/	11,384-34,602	10,246-31,142

1/ Emissions from a new 570-MW powerplant assuming particulates and SO_2 emission rates meet existing NSPS limits.

2/ Assumes ESP particulate control and no SO_2 control.

3/ Assumes SO_2 and particulate control.

4/ Depending on boiler type.

examined for new plants. The four configurations correspond to the following SIP SO_2 emissions limits: below 0.7 lbs/MMBtu, 0.7 to 1.2 lbs/MMBtu, 1.2 to 1.7 lbs/MMBtu, and above 1.7 lbs/MMBtu.

Where SIP emissions for sulfur dioxide are below 0.7 lbs/MMBtu, it is assumed that neither loan nor non-loan program coal will be used at existing powerplants. Only fuels with a very low sulfur content can be used practicably where sulfur dioxide emission rates are so stringent. Such fuels are some oils, natural gas, and metallurgical coal.

Where emission rates are from 0.7 to 1.2 lbs/MMBtu, program coal could be burned at existing plants if "select," that is, the lowest sulfur content, coal were used. SO_2 emission rates if "select" coal were used could just meet SIP limits within this range without the use of scrubbers. Non-loan program coal could also be burned but only with the use of scrubbers. Under these SIP emission limitations for SO_2, particulate, HC, CO, and trace element emissions from existing plants will not differ if loan or non-loan program coal is burned. As at new powerplants affected by the loan program, only NO_x emissions will differ. NO_x emissions from burning loan program coal would be 10 percent higher than if non-loan program coal were burned.

Where the SIP emission rate for sulfur dioxide is between 1.2 and 1.7 lbs/MMBtu, the only difference from the preceding case is that all loan program coal could be burned at existing plants without the use of scrubbers. Non-loan program coal use, again, would require the use of scrubbers. Air pollutant emissions are identical to the previous case - NO_x emissions are 10 percent less if non-loan program coal is burned and particulate, HC, CO, and trace element emissions are the same with the use of loan or non-loan program coal. However, where SO_2 emission limitations are between 1.2 and 1.7 lbs/MMBtu, SO_2 emissions using non-loan program coal will be up to 42 percent higher than SO_2 emissions using loan program coal.

The final impact case for existing powerplants concerns existing powerplants in areas where the SIP SO_2 emission rates are greater than 1.7 lbs/MMBtu. Here both loan and non-loan program coal can be used at existing plants without the use of scrubbers.[1/] Using loan or non-loan program coal at existing plants under these conditions, particulate, HC, CO, NO_x, and trace element emissions will be essentially the same and only SO_2 emissions will differ. SIP SO_2 emission limits in the eastern States possibly affected by the loan program are as high as 4.2 lbs/MMBtu, where annual SO_2 emissions from existing plants using non-loan program coal would be 250 percent more than if the plants burned loan program coal.

b. Water

Water quality impacts generated by the operation or construction of a coal-fired powerplant can be categorized into two groups: chemical and thermal. Thermal pollution of waterways occurs from the discharge of condenser cooling water, which is of significantly higher temperature than the ambient water temperature to which it is discharged. Chemical pollution occurs from discharges of chemical-containing effluents into either surface or groundwater bodies.

The amount of thermal pollution generated is dependent upon the plant's efficiency in converting heat to electricity. As shown in Table V-13, the greater this efficiency, the less heat is discharged. Generally, ambient water temperatures increase 4.5-13°C (8.6°C average). These increases are normally insignificant due to high flow rates which allow a large surface area temperature dissipation. Thermal impacts do not vary with the type of coal used and therefore will not be affected by the Coal Loan Guarantee Program.

Note

1/ Assuming non-loan program coal varies between 1 and 3.5 percent in sulfur content.

TABLE V-13

EFFICIENCIES, HEAT RATES AND HEAT REJECTED BY COOLING WATER

Plant Efficiency	Plant Heat Rate	Heat Converted to Electricity	Stack and Plant Heat Losses	Heat Rejected to Cooling Water
%	Joules per kWh x 10^{-6} (Btu/kWh)			
	Fossil-Fueled Units			
38	9.5 (9,000)	3.6 (3,400)	0.95 (900)	4.95 (4,700)
34	10.5 (10,000)	3.6 (3,400)	1.05 (1,000)	5.85 (5,600)
29	12.5 (12,000)	3.6 (3,400)	1.25 (1,200)	7.65 (7,400)
23	15.5 (15,000)	3.6 (3,400)	1.55 (1,500)	10.35 (11,100)
17	21.0 (20,000)	3.6 (3,400)	2.1 (2,000)	15.3 (14,600)
	Nuclear Units			
34	10.5 (10,000)	3.6 (3,400)	0.5 (500)	6.4 (6,100)
29	12.5 (12,000)	3.6 (3,400)	0.6 (600)	8.3 (8,000)

SOURCE: Development Document for Effluent Limitation Guidelines, Steam Electric Power Generation, EPA 440 1-74029-A, October, 1974.

Chemical pollutant effluents from powerplants may be subdivided into two categories: fuel-dependent and fuel-independent discharges. Taken together, there are over 20 different identifiable sources of chemical waste at a fossil fuel-fired plant. These sources are given in Table V-14.

Fuel-independent discharges originate from internal powerplant activities such as condenser cooling, boiler feedwater pretreatment, steam blowdown, and boiler cleaning, all of which are relatively independent of the fuel source used to fire the unit. Miscellaneous support activities such as sanitary systems, laboratory and sampling wastes, and intake screen backwashing likewise are independent of fuel types. The remaining waste streams, however, are affected according to fuel type and therefore will be affected by the loan program.

There are three significant pollutant sources which are dependent upon fuel sources: (1) coal pile runoff; (2) ash handling Note water; and (3) leachate from either ash or scrubber sludge disposal. These sources discharge sediment, heavy metals, dissolved solids, and low-pH water.

(1) Coal Pile Runoff

Because of the large space required, coal piles are generally uncovered and exposed to air and moisture. The metal sulfide compounds in the coal oxidize in the presence of air and moisture to form sulfuric acid, producing a runoff which is acidic and contains heavy metals and other dissolved pollutants. The acidity of this runoff is related to the sulfur content of the coal. Usually, the greater the sulfur content of the coal, the more sulfide compounds (particularly pyrite) there are which may oxidize to form sulfuric acid, thereby increasing the acidity of the coal pile runoff. The amount of runoff generated is dependent upon the rainfall of the area and the size of the pile. Characteristics of coal pile drainage are given in Table V-15.

TABLE V-14

SOURCES OF CHEMICAL POLLUTION

- Condenser Cooling System

  Once-through
  Recirculating

- Water Treatment

  Clarification
  Softening
  Ion Exchange
  Evaporator
  Filtration
  Other Treatment

- Boiler or Generator Blowdown

  Boiler or Generator Tubes
  Boiler Fireside
  Air Preheater
  Miscellaneous Small Equipment
  Stack
  Cooling Tower Basin

- Ash

  Bottom Ash
  Fly Ash

- Drainage

  Coal Pile
  Floor and Yard Drains

- Air Pollution (SO_2) Control Devices

- Miscellaneous

  Sanitary Wastes
  Plant Laboratory and Sampling Streams
  Intake Screen Backwash
  Closed Cooling Water Systems
  Construction Activity

SOURCE: Development Document for Effluent Limitation Guidelines, Steam Electric Power Generation, EPA 440.1-74029-A, October, 1974.

TABLE V-15

CHARACTERISTICS OF COAL PILE DRAINAGE DISTINCTIVE TO COAL-FIRED POWERPLANTS[1/]

Parameter	Coal Pile Drainage
Turbidity (JTU)	6-505
pH (units)	2.8-7.8
Total Solids	1500-45000
Total Suspended Solids	20-3300
Total Dissolved Solids	700-44000
Total Hardness (as $CaCO_3$)	130-1850
Alkalinity (as $CaCO_3$)	15-80
Acidity (as $CaCO_3$)	10-27800
Sodium	160-1260
Magnesium	--
Manganese	90-180
Copper	1.6-3.9
Nickel	--
Zinc	.006-12.5
Chromium	0-15.7
Mercury	--
Aluminum	825-1200
Iron	0.4-2.0
Chloride	20-480
Sulfate	130-20000
Phosphorus	0.2-1.2
Ammonia	0.4-1.8
Nitrate	0.3-2.3
BOD	3-10
COD	100-1000

1/ Units in milligrams/liter where not specified.

SOURCE: Based on actual plant samples, from "Development Document for Proposed Effluent Limitations Guidelines and New Source Performance Standards for the Steam Electric Powerplants," EPA 440-1-73/029, March, 1974.

The program will affect the residuals produced by coal pile runoff by making lower sulfur coal available. Due to the lower sulfur content of coal produced under the program, the acidity of coal pile runoff will be reduced. New powerplants under construction subject to existing New Source Performance Standards and existing powerplants subject to Best Available Technology (BAT) are required to control the pH of coal pile runoff to between 6.0 and 9.0. Therefore, no significant or predictable differences in treated coal pile runoff discharges are expected.

(2) Ash Handling Water

The ash resulting from the burning of coal is generally 10 to 15 percent of the weight of the coal burned. The coal ash is of two types: bottom ash which accumulates in the boiler furnace bottom and fly ash which is recovered from the exhaust and particulate control systems. The ash is often conveyed by water to a pond or ash pile. Ash transportation requires between 1200 and 40,000 gallons of water per ton of ash. This ash sluicing water can have adverse impacts on water supplies if it overflows into a surface water body or is discharged and infiltrates into the groundwater. Existing New Source Performance Standards for coal-fired powerplants assume a no-discharge fly ash system, but allow discharge of bottom ash sluicing water. However, BAT standards for existing powerplants allow for discharge of both bottom and fly ash handling water.

The amount of sluicing water required is dependent upon the size of the plant. In a 570-MW plant at 60 percent capacity, the sluicing flow is approximately 3 cfs. The concentrations of pollutants in the flow are given in Table V-16. Assuming median levels, the amount of heavy metals entering into receiving water bodies (groundwater or surface water) is given in Table V-17. The higher the amount of recycling which takes place in the powerplant, the greater the impact is on groundwater and the less the impact is on surface water.

TABLE V-16

CHARACTERISTICS OF ASH SLUICING WATER
DISTINCTIVE TO COAL-FIRED POWERPLANTS1/

Parameter	Ash Sluicing Water
Turbidity (JTU)	10-183
pH (units)	--
Total Solids	300-3500
Total Suspended Solids	25-100
Total Dissolved Solids	250-3300
Total Hardness (as $CaCO_3$)	200-750
Alkalinity (as $CaCO_3$)	30-400
Acidity (as $CaCO_3$)	--
Sodium	20-173
Magnesium	70-156
Manganese	.0002-.10
Copper	.005-.06
Nickel	.008-.015
Zinc	.001-.12
Chromium	neg .14
Mercury	.0002-.002
Aluminum	.02-513
Iron	.02-2.9
Chloride	20-2000
Sulfate	100-300
Phosphorus	.05-0.4
Ammonia	0.4-3.4
Nitrate	0.1-6.1
BOD	--
COD	--

1/ Units in milligrams/liter where not specified.

SOURCE: Based on actual plant samples, from "Development Document for Proposed Effluent Limitations Guidelines and New Source Performance Standards for the Steam Electric Powerplants," EPA 440-1-73/029, March, 1974.

TABLE V-17

LOADING OF HEAVY METALS FROM BOTTOM ASH SLUICING WATER

Parameter	Loading (pounds/year)
Magnesium	64,915
Chromium	23.6
Copper	0
Iron	266
Manganese	118
Nickel	59
Zinc	53.1
Aluminum	124

Differences in residuals loading from ash handling water will be slight. Under both cases, bottom ash can be handled by a non-recirculating system. However, minor concentration differences will be caused by the coal's ash content. Normally, the lower the ash content, the lower the concentration of heavy metals in the ash handling water. Likewise, the program's lower ash coal will produce a sluicing water with heavy metal concentrations slightly lower than those found in the high sulfur coal case. These lower levels are difficult to predict, but the decrease in heavy metal levels is not expected to be greater than 20 percent.

(3) Solid Waste Disposal Leachate

Another source of pollutants is from fly ash and scrubber sludge disposal. Fly ash is generated with the program, while scrubber sludge is generated without the program. For new sources, both are assumed to be handled either by lagooning or landfilling. In most cases, the scrubber sludge can be stabilized by the addition of chemicals. When disposing of the ash or scrubber sludge, a groundwater problem can be created. Leachate, formed by chemical reactions in the ash and sludge with moisture, is able to infiltrate the soils and contaminate the groundwater. The amount of leachate formed is dependent upon rainfall, size of disposal site, and geological conditions. Generally, increased rainfall produces increased leachate formation. Higher soil permeability tends to decrease leachate concentrations.

The differences between the program and no program cases are in the volume of ash or scrubber sludge requiring disposal and the leachate concentrations. In the unit powerplant using low sulfur coal under the loan program, 100,500 tons per year of fly ash will be generated as opposed to 505,000 tons per year of ash and scrubber sludge without the program. Since the amount of leachate produced is proportional to the quantity of solid waste, approximately 5 times more leachate will be produced without the program.

The smaller volume of leachate produced from ash alone under the program is offset by the leachate's higher concentration of heavy metals. This is because the scrubber sludge is chemically more stable with respect to heavy metals. The leachate characteristics of stabilized sludge are given in Tables V-18 and V-19 for the landfill and lagoon disposal cases, respectively. The concentrations of the fly ash leachate are similar to those shown for ash sluicing water in Table V-16.

Existing sources will have similar impacts to those described above. Similar amounts of heavy metals will be generated. The potential differences between new and existing sources are that existing sources could discharge fly ash/scrubber sludge handling water, allowing surface water contamination. The greater the amount of these solid wastes contained in the system, the greater will be the groundwater impacts, and the less the surface water impacts.

Table V-20 summarizes the water residuals produced annually by a unit-sized coal-fired steam-electric powerplant. As discussed earlier, coal pile runoff primarily affects surface water bodies, although groundwater contamination is possible if the coal pile is not located on an impermeable site. The pollutants produced by bottom ash sluicing and fly ash and scrubber sludge disposal in landfills are primarily a groundwater issue, since greater amounts of water and solid wastes are retained with the system. The program will have a minor effect on the pollutants produced from coal pile runoff and bottom ash sluicing.

As shown in the table, impacts specific to the loan, non-loan program case (associated with emissions control units) are not as severe as the impacts resulting whenever coal is used

TABLE V-18

CHARACTERISTICS OF SIMULATED LEACHATE FROM LANDFILLED SLUDGE FIXATED WITH DRAVO "CALCILOX"

Parameter	mg/l (except pH)
pH (units)	10.5-11.8
Total Alkali	42-200
Total Dissolved Solids	68-296
Total Hardness (as $CaCO_3$)	285-602
Suspended Solids	4-8
Aluminum	1.4-9.8
Arsenic	.01-.05
Cadmium	.01-.03
Calcium	102-278
Chloride	58-320
Chromium	.02
Copper	.1
Iron	.02
Magnesium	.01-1.0
Manganese	.05
Mercury	.0015-.0055
Nickel	.015
Nitrate (as N)	.05
Nitrite (as N)	.05-0.1
Phosphorus	.1-.2

TABLE V-18 (Cont'd)

Parameter	mg/l (except pH)
Silica	1.8-8.3
Sodium	18-25
Sulfate	0-344
Tin	.2
Zinc	.01-.02

SOURCE: Dravo Corporation Report, "Little Blue Run Development Area, Bruce Mansfield Power Generating Station Industrial Waste Application for a Waste Water Management Permit."

TABLE V-19

SCRUBBER SLUDGE AND POND OVERFLOW CHARACTERISTICS (OPEN-LOOP SYSTEM)

Parameter	Fixed Sludge (as discharged to pond)	Fixed Sludge Pond Overflow (open-loop discharge to water source)
pH	6.7	7.2
Acidity (as $CaCO_3$) (ppm)	5	5
Alkalinity (as $CaCO_3$) (ppm)	80	32
Hardness (as $CaCO_3$) (ppm)	696	484
Sulfate (ppm)	520	377
Sulfite (ppm)	1	1
Total dissolved solids (ppm)	1,095	750
Total suspended solids (ppm)	70,780	5

SOURCE: EPA, "Development Document for Proposed Effluent Limitations Guidelines and New Source Performance Standards--Steam-Electric Power Generation," Washington, D.C., EPA 440/1-73/029, March, 1974.

TABLE V-20

POLLUTANT LOADINGS FROM COAL-FIRED POWERPLANT OPERATIONS[1/]

(lbs/year)

	Common to Program and No Program Cases[2/]		With Program	Without Program
Heavy Metals	Coal Pile Runoff[3/]	Bottom Ash Sluicing[4/]	Fly Ash Disposal[5/]	Scrubber Sludge Disposal[6/]
Al	54,980 lbs/yr	124 lbs/yr	0.13 lbs/yr	314 lbs/yr
Cr	13.7	23.6	0.03	0.64
Cu	82.5	0	0	3.21
Fe	41.2	266	0.03	0.64
Mg	7,973	64,000	70.3	32.1
Zn	73.3	53.1	0.06	0.64
Mn	--	118	0.13	1.60
Ni	--	59.0	0.06	0.48
Total Suspended Solids	159.3	0[7/]	0[7/]	0[7/]
Total Dissolved Solids	265,800	1,936,000	2,097	9,511

1/ Quantified for a new 570-MW powerplant meeting existing NSPS.

2/ The higher the recycling rates in the powerplant become, the greater the groundwater impacts and less the surface water impacts will be.

3/ Assumes 45 inches/year of rainfall, all of which runs off as surface water, median reported concentration increases, and a coal pile 40 ft. high.

4/ Assumes median reported increases and a flow of 3 cfs to groundwater. Sluicing water is recirculated.

5/ Assumes that ash is handled dry, is disposed of in a landfill, and is sealed each month; 45 inches of rainfall of which 2% is either absorbed by the ash, evaporated or runs off; median reported concentration increases to groundwater.

6/ Same as 3 except that Table V-18, "Simulated Leachate..." concentrations were used to determine loadings on groundwater.

7/ Suspended solids assumed to be filtered out during infiltration through the soil.

(i.e., coal pile runoff and bottom ash leachate). Bottom ash is a particularly significant source of heavy metals and total dissolved solids. Whether bottom ash sluicing water is discharged or recirculated, similar impacts will occur on surface and groundwater quality, respectively. Pollutants leaching from fly ash and scrubber sludge disposal sites are negligible compared to those resulting from bottom ash sluicing. Leachate into groundwater from fly ash and scrubber sludge can be further reduced by approximately two orders of magnitude if impermeable material is used to seal the bottom of the landfill.

c. Solid Waste/Land Use

(1) Solid Waste

The Coal Loan Guarantee Program will have major impacts on the quantities of solid waste produced at coal-fired powerplants. Without the program, a new powerplant currently under construction will generate scrubber sludge in addition to fly and bottom ash, since scrubbers would be required to reduce SO_2 emissions to meet existing NSPS limitations. Burning coal produced under the loan program will allow a new powerplant to meet existing NSPS limitations without SO_2 removal; thus, such a powerplant will only generate fly and bottom ash solid waste.

The amount of ash requiring disposal is a function of the ash content of the coal and the efficiency of the air pollution control equipment that removes particulate matter from the stack. Essentially, all ash that does not escape from the stack into the atmosphere remains onsite as solid waste, either as fly ash or bottom ash. Depending on the type of furnace, bottom ash can comprise from 15 to 80 percent of the coal ash solid waste; fly ash makes up the remainder. Bottom ash is comprised of larger particles than fly ash, which is usually comprised of very fine particles. Bottom ash is usually removed from the boiler with a water sluicing system and transported in a slurry. Fly ash is removed from the flue gas stream by a particulate control device and can be transported in a water slurry or pneumatically. Wet ash is 1.25 times the weight of dry ash, assuming the use of a water ash slurry that is 80 percent solids.

Flue gas desulfurization (FGD) scrubber systems generate a sludge that is predominantly calcium sulfite/sulfate as a solid waste product. The calcium from the scrubber spray and SO_2 initially combine to form calcium sulfite in the flue gas stack. The sulfite can then oxidize to the sulfate form. The degree of oxidation increases with the amount of air contacting the sludge and the sludge acidity. If the scrubber system is also used to remove particulate matter, the solids portion of the sludge can contain from 40 to 60 percent fly ash. Scrubber sludges are produced in large quantities, depending on the amount of SO_2 removed, the sulfur and ash contents of the coal, the operating characteristics of the powerplant and the scrubber, the mole ratio of scrubbing additive, and the composition and moisture content of the sludge. Approximately 3.5 pounds of dry sludge are generated per pound of SO_2 removed by lime or limestone scrubbers.

The amount of water in sludge is a function of the ash content, the dewatering method, and the sulfite/sulfate ratio. Scrubber waste streams are usually dewatered and thickened prior to sludge disposal. Dewatering is a process in which water is removed through the use of filters, screens or absorbent media. Thickening concentrates the solids portion of the waste by simple settling. Removed water is normally recycled in the scrubber. The sludge coming out of this process usually is 50 to 60 percent solids. Regenerative processes such as sodium alkali and double alkali scrubbers generate dewatered sludges that are up to 70 percent solids.

Table V-21 presents the solid waste generation of a unit powerplant with and without the loan program. With the loan program, no scrubber sludge is produced and only ash is generated as solid waste. Without the loan program, solid waste generation will be increased by slightly more than four-fold, on a tonnage basis. Over the lifetime of the station, assuming a 20-year average operation lifespan, the solid waste impact of the program takes on even greater proportions. With the program, the plant will generate approximately 25.2 million tons of solid waste; without the loan program, approximately 106 million tons of solid waste will be generated. By increasing the amount of low sulfur coal that will be made available, the program will sharply reduce the amount of solid waste generated as a result of coal use at new powerplants under construction through 1985.

At existing powerplants affected by the loan program (assuming existing powerplants located where SIP SO_2 limits are below 0.7 lbs/MMBtu are not affected by the program), land use/solid waste impacts are dependent on SIP particulate emission limits. Variations in allowable particulate emissions from existing stations cause solid waste production to be slightly more or less, depending on the emission limits, than at new powerplants.

Where SIP SO_2 emission rates are between 0.7 and 1.7 lbs/MMBtu, non-loan program coal can be used only in conjunction with scrubbers while loan program coal can be burned at existing plants with scrubbers; thus, solid waste produced at existing plants using loan program coal is affected only by particulate emission limitation variations. Without the program, existing plants will be affected by both particulate and SO_2 emission limitation variations. Thus, depending on the particulate and SO_2 limits that apply to the station, solid waste production from burning non-loan program coal with scrubbers at existing powerplants will be between 85 and 110 percent of solid waste

TABLE V-21

SOLID WASTE GENERATION WITH AND WITHOUT THE LOAN PROGRAM AT A NEW 570-MW POWERPLANT

(tons/year)

	With Program 1/	Without Program 2/
Total ash captured (dry) 3/	100,100	130,800
Total ash captured (wet) 4/	125,200	(163,500)
Total limestone/lime Sludge (dry) 5/	------	99,200
Total limestone/lime Sludge (wet) 6/	------	198,400
Total limestone/lime Sludge with fly ash 7/	------	420,800
	------	------
Total solid waste (ash, ash & sludge)	125,200	440,400

Basis: 570-MW coal-fired steam-electric powerplant operating at a 60% capacity factor on a heat rate of 10,000 Btu/kWh.

1/ Assumes the powerplant burns coal with a heating value of 11,800 Btu/lb, a sulfur content of 0.7%, and an ash content of 8%.

2/ Assumes the powerplant burns coal with a heating value of 11,900 Btu/lb, a sulfur content of 2.25% and an ash content of 10.5%.

3/ Assumes powerplant meets existing NSPS particulate emission limit of 0.1 lbs/MMBtu.

4/ Assumes wet ash slurry of 80% solids.

5/ Assumes 3.5 pounds of dry sludge produced per pound of SO_2 removed.

6/ Assumes wet sludge of 50% solids.

7/ Assumes 85% of total ash content of coal becomes fly ash.

Scrubber sludge cannot be hauled offsite by truck to a landfill without special handling and treatment. This type of disposal requires that sludge be dewatered, dried, or incinerated to remove the moisture so that the material can be transported. Therefore, in order to use this approach, more extensive and expensive scrubber sludge handling technology is required and would need to be developed. Landfilling ash or scrubber sludge is more environmentally advantageous than ponding because onsite land is not needed and the disposal site can be chosen to minimize the adverse environmental effects of the disposal operation.

The amount of land needed for ash and sludge disposal at a steam electric powerplant is dependent on the density of the sludge and ash and the characteristics of the disposal operations. Under similar circumstances, both landfilling and ponding require approximately the same amount of land. Sludge and ash ponds or landfills are designed to hold piles that average 10 to 30 feet high. The density of scrubber sludges is approximately 7 lbs/cubic foot, while the density of ash is approximately 25 lbs/cubic foot.[1/]

Table V-22 presents the land requirements of a typical new 570-MW powerplant for solid waste disposal both with and without the loan program. Without the loan program, land will be required for the disposal of ash and SO_2 scrubber sludge. With the program, land will be required for the disposal of ash only. In general, the land required for ash and sludge disposal is 1.5 times that required for ash disposal alone. As can be seen from the table, without the program ash and sludge disposal will take approximately 11.4 acres per year or approximately 230 acres over a 20-year plant life, assuming the use of a 30-foot deep lagoon. With the

1/ Using various compacting techniques and depending upon the type of boiler, fly ash densities can range to 60 lbs/cubic foot or more. The lower density figure was used to yield the more pessimistic estimate of land impacts.

production using non-loan program coal at new powerplants under existing NSPS limitations. Likewise, using the loan program coal, total solid waste production at existing powerplants, depending on SIP particualte limits, will be between 96 and 101 percent of solid waste production using loan program coal under existing NSPS limitations. Land use requirements vary from those under existing NSPS limitations for both loan and non-loan program coal use by similar percentages.

Where SIP SO_2 limits are above 1.7 lbs/MMBtu, both loan and non-loan program coal can be used without scrubbers. Only ash will be produced as solid waste regardless of whether loan or non-loan program coal is burned, and solid waste production at existing powerplants will depend only on particulate limit variations. Under the lowest and highest SIP particulate limitations, ash production at existing plants using loan program coal will vary from 96 to 101 percent of ash production under existing NSPS limits using loan program coal. Likewise, ash production using non-loan program coal will vary from 98 to 101 percent of ash production under existing NSPS limits. The variance is not as wide using non-loan program coal because this coal has a slightly higher ash content than the loan program coal. Land use requirements will differ to the same degree.

(2) Land Use

Land use requirements associated with coal utilization at powerplants result from the coal handling equipment, the coal pile, and solid waste disposal facilities. Of these, solid waste disposal facilities are the major land use requirements that will be affected by the coal loan program.

Outside storage of coal at or near a powerplant is necessary to insure continuous plant operation. Normally, a 90-day supply of coal is maintained. Typically, 800-2400 cubic feet of storage area are required per megawatt of rated capacity. At a pile height of 25 to 50 feet, the ground area requirement can vary between 16 and 96 square feet per megawatt of capacity. The coal storage land requirements of powerplants will not be significantly affected by the loan program since the heat value and density of the coal will be essentially similar between the low sulfur and higher sulfur coals.

Two methods of ash and sludge disposal are generally employed by utilities to dispose of powerplant solid waste: ponding and landfilling. Another disposal method which could be employed, and is, in some cases, is ocean disposal. It is not clear to what extent EPA will allow it in the future. No powerplant currently practices ocean sludge disposal. The EPA action against the ocean disposal of municipal sludge from New York and Philadelphia indicates that ocean sludge disposal is not a viable disposal method; therefore, it will not be discussed further.

Onsite scrubber sludge or ash disposal operations generally involve ponding, thus enabling ash or scrubber sludge to be sluiced in a water slurry to the pond. In the pond, water in the slurry is allowed to infiltrate or evaporate, or is discharged to a surface water body, and the solids portion of the sludge or ash slurry is allowed to settle to the bottom of the lagoon. In a sludge disposal lagoon, stabilization processes are allowed to occur. This disposal method is inexpensive but requires that land at the powerplant be available for solid waste disposal.

Landfilling is a method of waste disposal used widely by U.S. electric utilities. Ash is hauled from the powerplant site to a landfill site, usually within 10 to 20 miles of the station. The ash can be hauled dry or wet directly to the site, or it can be temporarily stored at an onsite pond and later dredged and hauled to the landfill site. Scrubber sludge landfilling is not widely practiced at U.S. powerplants and is usually only practiced in the rare cases when onsite space is available for a landfill.

TABLE V-22

LAND USE IMPACT OF THE COAL LOAN PROGRAM AT A NEW 570-MW POWERPLANT1/ OVER 20 YEARS (acres)

	With Loan Program2/	Without Loan Program3/
Area need for ash disposal4/	155	---
Area needed for sludge disposal5/	---	230
Total area needed for solid waste disposal	155	230
Location of disposal site	Can be located within 10 to 20 miles of the powerplant	Technical and economic consideration strongly dictate onsite disposal
Stability of utilized land	Ash disposal site can be revegetated or used for construction of roads or buildings	Scrubber sludge disposal sites can be revegetated, but the sludge must be "fixed" to be stable enough for construction of roads and buildings

1/ 570 MW and 30-ft. deep disposal pond.

2/ Assumes the use of coal with a heat content of 11,800 Btu/lb, an ash content of 8%, a sulfur content of 0.7%, and the use of ESP's for particulate control.

3/ Assumes the use of coal with a heat content of 11,800 Btu/lb, an ash content of 10.5%, a sulfur content of 2.25%, and the use of scrubbers to remove SO_2 and fly ash.

4/ Density of fly and bottom ash assumed to be 25 lbs/cf.

5/ SO_2 and fly ash sludge plus bottom ash assumed to be 50% solids with a density of 71 lbs/cf.

program, ash disposal will take approximately 7.7 acres per year or 155 acres over the life of the plant, again assuming 30-foot deep ash piles.

Not only is the amount of land needed for solid waste disposal different, but the location of land for disposal is much more restrictive when disposing of scrubber sludge. The volume of material requiring disposal, the technical ability needed to dewater the scrubber sludge, and the extra expense strongly dictate that scrubber sludge disposal sites be adjacent or near to the powerplant. Ash, having a lower volume and being relatively easy and economical to dewater, is easier to dispose of at remote sites. Furthermore, the high moisture content of unfixed scrubber sludge renders it unsuitable for use in the construction of roads, houses, airports, or other structures unless the sludge is chemically fixed prior to disposal. Ash, however, is normally stable and therefore suitable for most future uses. Both ash and scrubber sludge disposal sites can be covered with topsoil and revegetated, and they both could support shallow rooted vegetation.

CHAPTER VI

AGGREGATE REGIONAL IMPACTS

A. Introduction

This section summarizes the quantifiable, aggregate regional impacts that could potentially result from the Coal Loan Guarantee Program. Assuming controlled conditions, a regionalized accounting of key environmental residuals resulting from program coal production and use is presented. The associated regional environmental impacts are discussed, followed by a summary of the overall benefits and negative impacts attributable to the Coal Loan Guarantee Program. Adverse impacts which can and cannot be avoided are identified, followed by a discussion of why certain impacts are unavoidable.

As discussed earlier, the major impacts of the program are expected to occur primarily in the eastern U.S.: the major impacts of coal production are based upon the production split of program coal between Northern and Central Appalachia. The environmental impacts only reflect program coal mining, i.e., they do not reflect other mining ongoing in 1985. The major impacts of coal use will occur in the states east of the Mississippi River. Minimum legal levels of control are assumed in determining all environmental residuals for coal production and use. In all cases for coal production and use, regional residuals and impacts are based upon the aggregation of residuals and associated impacts discussed in Chapter V for the unit coal mines, preparation plants, and powerplants.

B. Regional Impacts of Coal Production

1. Air

Table VI-1 summarizes the estimated annual controlled air emissions that would result in the eastern U.S. in 1985 from the Coal Loan Guarantee Program. The emissions estimates in the table represent the sum of the emissions from the unit mines and preparation plants presented and discussed in Chapter V.

TABLE VI-1

REGIONAL ANNUAL AIR RESIDUALS PRODUCED BY COAL MINING AND PREPARATION IN 1985 FROM THE COAL LOAN GUARANTEE PROGRAM[1/]

(tons/year)

	Northern Appalachia					Central Appalachia					Total				
Activity	Partic- ulates	NO_x	SO_x	HC	CO	Partic- ulates	NO_x	SO_x	HC	CO	Partic- ulates	NO_x	SO_x	HC	CO
Mining															
Underground	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Steam Coal Preparation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

1/ Assumes controlled conditions.

The Coal Loan Guarantee Program will result in little change in air pollutant emissions from coal production. However, in some individual projects, some increase in fugitive dust levels may result from associated traffic on project haulage roads. Little change in air pollutant emissions is anticipated from operation of steam coal preparation plants; however, in the event individual projects do not comply with applicable state or federal air emission requirements, some adverse air pollution impact could result from individual preparation plants.

2. Water

Annual regional water residuals resulting from coal mining and cleaning activities financed by the loan program in 1985 are summarized in Table VI-2. Compliance with New Source Performance Standards and effluent limitations would result in negligible increases in acid mine drainage in the region; however, because total compliance cannot be assured, a range of acid mine drainage impacts was estimated for Northern and Central Appalachia based on worst case conditions. Central Appalachia may experience an increase in suspended solids loads from mining due to the increased concentrations resulting from the treatment of acid mine drainage from underground mines. If the low sulfur coal emphasis of the program reduces required water treatment of mine and preparation plant effluents, however, the amount of suspended solids resulting from this water treatment may be less than estimated in Table VI-2.

3. Solid Waste/Land Use

a. Solid Waste

Solid waste production in 1985 from coal mining and preparation projects financed by the program is presented in Table VI-3. The program will result in quantities of solid waste from both mining and preparation which may be significant. The

TABLE VI-2

REGIONAL ANNUAL WATER RESIDUALS PRODUCED BY COAL MINING AND PREPARATION IN 1985 FROM THE COAL LOAN GUARANTEE PROGRAM[1/]

(tons/year)

Activity	Northern Appalachia		Central Appalachia		Total	
	Acidity	Suspended Solids	Acidity	Suspended Solids	Acidity	Suspended Solids
Mining						
Underground	0-1280 [3/]	1	0-8580[3/]	62	0-9860[3/]	64
Steam Coal Preparation[2/]	0-196 [3/]	6	0-9575[3/]	310	0-9771[3/]	316
TOTAL	0-1476	8	0-18,155	372	0-19,631	380

1/ Assumes conformance to existing EPA NSPS for coal mining effluents.

2/ Assumes 1/3 of the low sulfur coal produced under the program is cleaned (13.2 million tons/year).

3/ Higher values are for the uncontrolled case (i.e., no reclamation or water treatment). Impacts will be negligible for the controlled case (reclamation and water treatment facilities).

TABLE VI-3

REGIONAL ANNUAL SOLID WASTE RESIDUALS OF COAL MINING AND PREPARATION IN 1985 1/
(TONS/YEAR)

Activity	Northern Appalachia	Central Appalachia	Total
Mining			
Underground	39,248	402,480	441,728
Steam Coal Preparation 2/	80,304	3,915,000	3,995,309
Total	119,557	4,317,480	4,437,037

1/ Assumes controlled conditions

2/ Assumes 1/3 of all low sulfur coal produced under the program is cleaned (13.2 million tons/year) solid waste is attributable principally to coal refuse from coal preparation plant processing and to sludge produced in the treatment of acid discharges from underground mines.

b. Land Use

Table VI-4 presents the estimated land areas disturbed in 1985 by coal mining and preparation projects financed by the program. Most of the land disturbance attributable to the program is expected to be affected by potential subsidence in Central Appalachia from underground mining activities; these impacts may be significant where mining takes place in populated or relatively developed areas. Annual land requirements for solid waste disposal at coal preparation plants may also be significant in some areas, although these requirements are substantially less than the land areas disturbed by mining activities.

4. Socioeconomics

Table VI-5 summarizes the direct employment and health and safety impacts of the program. The table indicates that program-financed coal production may create 22,000 jobs in 1985, and may be responsible for 14 annual fatalities and 1,910 annual nonfatal injuries. The increases in jobs will be largely beneficial, particularly in Central Appalachia, but may also result in at least temporary housing and labor force shortages, and in certain areas, may result in at least temporary overloading of water treatment, distribution and sewerage treatment facilities. In areas where demand for underground miners increases rapidly, these socioeconomic impacts may be significant. Similarly, fatalities and injuries, especially in the case of mine catastrophies involving five or more miner fatalities, may be significant impacts of implementing the program.

TABLE VI-4

REGIONAL ANNUAL LAND REQUIREMENTS
OF COAL MINING AND PREPARATION IN 1985 1/
FROM THE COAL LOAN GUARANTEE PROGRAM

(ACRES/YEAR)

Activity	Northern Appalachia	Central Appalachia	Total
Mining			
Underground 2/	196	9,828	10,024
Steam Coal Preparation 3/	1	16	17
TOTAL	197	9,844	10,041

1/ Assumes controlled conditions.

2/ Assumes that only new mines will have to construct water treatment facilities; expansions are assumed to already have adequate water treatment facilities. New mines are assumed to account for 60 percent of the total annual production due to the program in 1985, and expansions and reopened mines are estimated to account for the remaining 40 percent.

3/ One-third of the total production stimulated by the program is assumed to be cleaned (13.2 million tons/year).

TABLE VI-5

COAL EMPLOYMENT IN 1985
FROM THE COAL LOAN GUARANTEE PROGRAM 1/
(# OF MINERS)

Activity	Northern Appalachia	Central Appalachia	Total
Mining			
Underground	378	22,464	22,842

1/ Based upon the average annual productivity in Northern and Central Appalachia in 1975 (U.S. Bureau of Mines, 1977, op. cit., Table 16, p. 19). This average productivity is 2124 tons/man/year for underground mines in Northern Appalachia and 1734 tons/man/year for underground mines in Central Appalachia.

Source: See Table IV-15

ANNUAL OCCUPATIONAL HEALTH STATISTICS FOR

THE COAL LOAN GUARANTEE PROGRAM

	Northern Appalachia		Central Appalachia	
Activity	Fatalities	Injuries	Fatalities	Injuries
Mining				
Underground	.29	34.56	14.04	1684.8

5. Transportation

As discussed in Chapter V, impacts of the Coal Loan Guarantee Program on the transportation of coal from the mines and preparation plants to the powerplants where it is used may be significant. Approximately 1/3 of the mines receiving guaranteed loans are projected to be new mines which may require the building of access roads or the extension of railroad spurs. For the most part, existing facilities can be utilized. The major effect of the program will be on transportation patterns because more coal will be shipped from Central Appalachia. ?

However, as noted in Chapter V, environmental analysis of potential transportation impacts is deferred to later site-specific environmental analyses, because uncertainties concerning the origin and destination of coal shipments from program-financed coal mines preclude the possibility of meaningful analysis at this time. Note

C. Regional Impacts of Coal Use

1. Air

Tables VI-6 and VI-7 summarize the total annual air pollutant impact that will result through the use of loan program or nonloan program coal at new and existing powerplants, respectively, in the eastern U.S. in 1985. It is assumed that existing powerplants affected by the program must meet SIP emission limits. The tables present total emissions in tons per year of each pollutant, particulate matter, SO_2, NO_x, HC, and CO by region and State. The pollutant emissions presented in the tables represent the sum of pollutant emissions from unit powerplants (outlined in Chapter V) based on the estimated State and regional demand for loan program coal by 1985 for two cases. In the first case, all loan program coal would be burned at new powerplants. In the second case, loan program coal would be burned at existing powerplants (loan program coal demand by region and State is outlined in Chapter IV.

TABLE VI-6

REGIONAL AND AGGREGATE AIR POLLUTION IMPACT OF COAL USE
NEW SOURCES - 1985

(tons/year)

Region and State	Loan Program: Particulates	Loan Program: SO_2	Loan Program: NO_2	Loan Program: HC	Loan Program: CO	Non-Loan Program: Particulates	Non-Loan Program: SO_2	Non-Loan Program: NO_2	Non-Loan Program: HC	Non-Loan Program: CO
New England	0	0	0- 0	0	0	0	0	0- 0	0	0
Middle Atlantic	9053	108635	68797- 209111	1178	3801	9053	108635	61917-188200	1178	3801
New Jersey	0	0	0- 0	0	0	0	0	0- 0	0	0
New York	2955	35461	22457- 68259	385	1241	2955	35461	20211- 61433	385	1241
Pennsylvania	6098	73174	46340- 140852	794	2560	6098	73174	41706-126767	794	2560
East North Central	15667	188000	119058- 361882	2039	6578	15667	188000	107152-325693	2039	6578
Illinois	3424	41090	26022- 79094	446	1438	3424	41090	23420- 71185	446	1438
Indiana	5863	70359	44558- 135435	763	2462	5863	70359	40102-121892	763	2462
Michigan	1313	15761	9981- 30337	171	551	1313	15761	8983- 27307	171	551
Ohio	5066	60791	38498- 117016	659	2127	5066	60791	34648-105314	659	2127
Wisconsin	0	0	0- 0	0	0	0	0	0- 0	0	0
South Atlantic	11445	137342	86977- 264369	1490	4806	11445	137342	78279-237932	1490	4806
Delaware	422	5066	3208- 9751	55	177	422	5066	2725- 8776	55	177
Florida	1923	23078	14615- 44423	250	808	1923	23078	13154- 39981	250	808
Georgia	3893	46719	29586- 89929	507	1635	3893	46719	26627- 80936	507	1635
Maryland	751	9006	5703- 17336	98	315	751	9006	5133- 15602	98	315
North Carolina	2552	27018	17110- 52007	293	945	2252	27018	15399- 46806	293	945
South Carolina	704	8443	5347- 16252	92	295	704	8443	4812- 14627	92	295
Virginia	0	0	0- 0	0	0	0	0	0- 0	0	0
West Virginia	1501	18012	11407- 34671	195	630	1501	18012	10266- 31203	195	630
East South Central	10742	128898	81630- 248116	1398	4510	10742	128898	73467-223304	1398	4510
Alabama	3190	38276	24239- 73677	415	1339	3190	38276	21815- 66309	415	1339
Kentucky	6895	82743	52400- 159271	898	2895	6895	82743	47160-143343	898	2895
Mississippi	657	7880	4990- 15169	85	276	657	7880	4991- 13652	85	276
Tennessee	0	0	0- 0	0	0	0	0	0- 0	0	0
TOTAL	46906	562875	356462-1083478	6106	19696	46906	562875	320815-975310	6106	19696

* Columns may not add due to rounding adjustments.

TABLE VI-7

REGIONAL AND AGGREGATE AIR POLLUTION IMPACT OF COAL USE
EXISTING PLANTS - 1985

(tons/year)

Region and State	Loan Program Particulates	Loan Program SO_2	Loan Program NO_2	Loan Program HC	Loan Program CO	Non-Loan Program Particulates	Non-Loan Program SO_2	Non-Loan Program NO_2	Non-Loan Program HC	Non-Loan Program CO
New England	0	0	0- 0	0	0	0	0	0- 0	0	0
Middle Atlantic	422	5066	3208- 9751	55	177	422	5066	2887- 8776	55	177
New Jersey	422	5066	3208- 9751	55	177	422	5066	2887- 8776	55	177
New York	0	0	0- 0	0	0	0	0	0- 0	0	0
Pennsylvania	0	0	0- 0	0	0	0	0	0- 0	0	0
East North Central	25236	302827	191777- 528911	3285	10596	25236	302827	172599-476020	3285	10596
Illinois	0	0	0- 0	0	0	0	0	0- 0	0	0
Indiana	13556	162671	103018- 313125	1765	5692	13556	162671	92716-281813	1765	5692
Michigan	4503	54036	34220- 104014	586	1891	4503	54036	30798- 93613	586	1891
Ohio	6520	78240	49548- 150603	849	2738	6520	78240	44593-135542	849	2738
Wisconsin	657	7880	4990- 15169	85	276	657	7880	4491- 13652	85	276
South Atlantic	4878	58539	37072- 112682	635	2048	4878	58539	33365-101414	635	2048
Delaware	0	0	0- 0	0	0	0	0	0- 0	0	0
Florida	2767	33210	21031- 63925	360	1162	2767	33210	18928- 57263	360	1162
Georgia	0	0	0- 0	0	0	0	0	0- 0	0	0
Maryland	1266	15198	9624- 29254	165	532	1266	15198	8662- 26329	165	532
North Carolina	844	10132	6416- 19503	110	355	844	10132	5774- 17553	110	355
South Carolina	0	0	0- 0	0	0	0	0	0- 0	0	0
Virginia	0	0	0- 0	0	0	0	0	0- 0	0	0
West Virginia	0	0	0- 0	0	0	0	0	0- 0	0	0
East South Central	16370	196443	124405- 378134	2131	6874	16370	196443	111965-340321	2131	6874
Alabama	985	11820	7486- 22753	128	414	985	11820	6737- 20478	128	414
Kentucky	7833	94000	59529- 180941	1020	3289	7833	94000	53576-162847	1020	3289
Mississippi	0	0	0- 0	0	0	0	0	0- 0	0	0
Tennessee	7552	90623	57390- 174440	983	3171	7552	90623	51651-156996	983	3171
TOTAL	46906	562875	356462-1083478	6106	19696	46906	562875	320816-975130	6106	19696

*Columns may not add due to rounding adjustments.

Air pollutant loadings for the most part are the same whether loan program or nonloan program coal is used. As can be seen from the tables, total annual particulate, SO_2, HC, and CO emissions from affected powerplants on a regional and State basis should be the same whether loan or nonloan program coal is used at new or existing powerplants in 1985. Only NO_x emissions from powerplants will be higher as a result of the loan program. If loan program coal is burned, total annual NO_x emissions from new or existing coal-fired powerplants in 1985 would be increased approximately 10 percent above what they would be if non-loan program coal were burned and scrubbers used.

Figure VI-1 indicates that electric powerplants are responsible for approximately 17 percent of total NO_x emissions in urbanized areas on an annual basis. This conclusion is based on an analysis of air quality in the Long Beach-Los Angeles-San Diego area by the Council on Environmental Quality, the results of which are presented in Figure VI-1.[1/] Table VI-8 presents the results of a nationwide estimate of NO_x emissions by the Health, Education, and Welfare Department and indicates that 19.4 percent of total NO_x emissions in the U.S. in 1968 were from stationary coal-fired sources, which include industrial coal burning sources such as steel mills, pulp mills, etc., in addition to electric powerplants.[2/] Although the total annual contribution of coal-fired powerplants to NO_x levels cannot be determined on the basis of this data, it can be said that coal-fired powerplants account for no more than approximately 19 percent of national NO_2 emissions. Furthermore, the data also indicate that NO_2 emissions from coal-fired powerplants in urbanized areas where ambient NO_x levels are typically a problem account for no more than approximately 19 percent of total urban NO_2 emissions. Assuming that coal-fired powerplants are responsible for 19 percent of nationwide NO_x emissions and NO_x emissions in urban areas, and that the relative contribution of coal-fired powerplants will not change

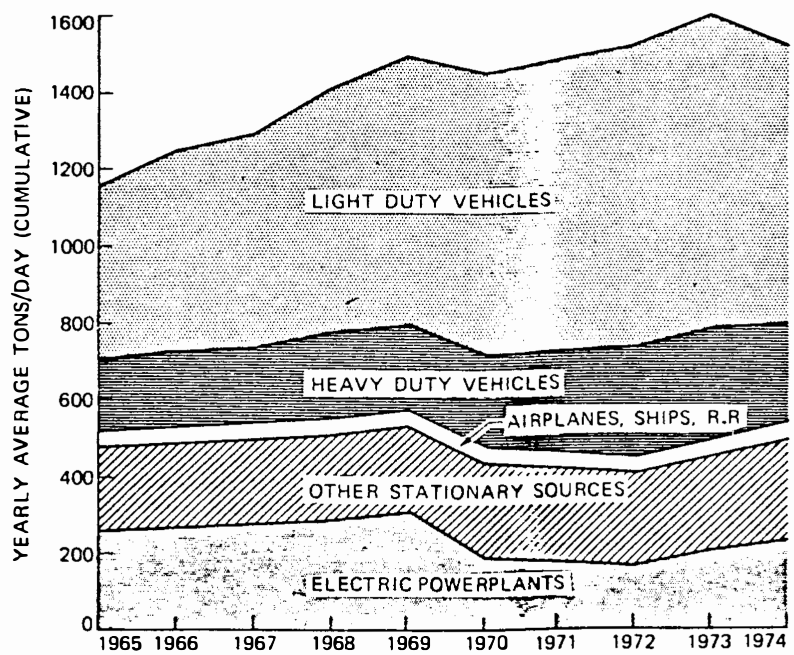
1/ Environmental Quality, 7th Annual Report of the Council on Environmental Quality, September 1976, p. 241.

2/ U.S. Department of Health, Education, and Welfare, "Nationwide Inventory of Air Pollutant Emissions," 1968, p. 15.

FIGURE VI-1

SOUTHWEST COAST AIR BASIN

NITROGEN OXIDE EMISSIONS TRENDS



SOURCE: Environmental Quality, 7th Annual Report of the Council on Environmental Quality, September, 1976.

TABLE VI-8

NATIONWIDE NITROGEN OXIDES EMISSIONS, 1968

SOURCE	EMISSIONS, 10^6 TONS/YR			PERCENTAGE OF TOTAL		
Transportation	8.1			39.3		
Motor vehicles		7.2			34.9	
Gasoline			6.6			32.0
Diesel			0.6			2.9
Aircraft		N[a]			N	
Railroads		0.4			1.9	
Vessels		0.2			1.0	
Nonhighway use of motor fuels		0.3			1.5	
Fuel combustion in stationary sources	10.0			48.5		
Coal		4.0			19.4	
Fuel oil		1.0			4.8	
Natural gas[b]		4.8			23.3	
Wood		0.2		1.0		
Industrial processes	0.2			1.0		
Solid waste disposal	0.6			2.9		
Miscellaneous	1.7			8.3		
Forest fires		1.2			5.8	
Structural fires		N			N	
Coal refuse burning		0.2			1.0	
Agricultural burning		0.3			1.5	
Total	20.6			100.0		

[a]N = Negligible.
[b]Includes LPG and kerosene.

SOURCE: Adapted from U.S. Department of Health, Education, and Welfare, "Nationwide Inventory of Air Pollutant Emissions," 1968, p. 15.

drastically between now and 1985, a 10 percent increase in NO_x emissions from powerplants burning loan program coal will result. This increase in NO_x emissions may be significant in some urbanized areas, especially where ambient NO_x levels are already a problem.

Powerplants in rural areas of the East may degrade the relatively good air quality of these areas and contribute to the current trend of air pollutant sources moving away from urban centers. If loan program coal is burned only at new powerplants, the east north central region of the U.S. will be affected more than any other region, and the state most affected will be Kentucky. If only existing powerplants are assumed affected by the loan program, the distribution of impacts changes slightly. Air pollution impacts are more concentrated in the east north central and east south central regions of the U.S. The east north central region will still be the most heavily affected; however, the state most affected will be Indiana.

2. Water

Tables VI-9 and VI-10 summarize the total annual water pollutant impact that will result from using loan program or non-loan program coal at new and existing powerplants, respectively, in the eastern U.S. in 1985. It is assumed that existing powerplants affected by the program must meet BAT treatment standards which, on average, are identical to existing NSPS water effluent limitations. The tables present total discharges in pounds per year of each pollutant, aluminum (Al), chromium (Cr), copper (Cu), iron (Fe), magnesium (Mg), zinc (Zn), manganese (Mn), nickel (Ni), total suspended solids (TSS), and total dissolved solids (TDS), by region and state. The pollutant discharge estimates presented in the tables represent the sum of pollutant discharges from unit powerplants (outlined in Chapter V) based on the estimated state and regional demand for loan program coal in 1985 for the two coal use cases.

TABLE VI-9

REGIONAL AND AGGREGATE TOTAL WATER POLLUTANT LOADINGS FROM LOAN PROGRAM COAL USE
NEW SOURCES - 1985

(lbs/year)

Region and State	Al	Cr	Cu	Fe	Mg	Zn	Mn	Ni	TSS	TDS
New England	0	0	0	0	0	0	0	0	0	0
Middle Atlantic	333012	225	498	1856	435381	764	713	356	27690	13318875
New Jersey	0	0	0	0	0	0	0	0	0	0
New York	108704	73	162	606	142119	249	233	116	9038	4347612
Pennsylvania	224309	151	335	1250	293262	514	480	240	18651	8971262
East North Central	576301	390	862	3213	753457	1322	1235	617	47920	23049244
Illinois	125958	85	188	702	164677	289	270	135	10473	5037709
Indiana	215682	146	322	1202	281982	494	462	231	17934	8626214
Michigan	48313	32	72	269	63164	110	103	51	4017	1932272
Ohio	186349	126	279	1038	243633	427	399	199	15495	7453049
Wisconsin	0	0	0	0	0	0	0	0	0	0
South Atlantic	421010	285	630	2347	550430	966	902	451	35007	1683837
Delaware	15529	10	23	86	20302	35	33	16	1291	621087
Florida	70744	47	105	394	92490	162	151	75	5882	2829398
Georgia	143213	97	214	798	187236	328	307	153	11908	5727806
Maryland	27607	18	41	153	36093	63	59	29	2295	1104155
North Carolina	82822	56	124	461	108281	190	177	88	6886	3312466
South Carolina	25882	17	38	144	33837	59	55	27	2152	1035145
Virginia	0	0	0	0	0	0	0	0	0	0
West Virginia	55214	37	82	307	72187	126	118	59	4591	2208310
East South Central	395129	267	591	2203	516592	906	847	423	32855	15803225
Alabama	117331	79	175	654	153398	269	251	125	9756	4092660
Kentucky	253642	171	379	1414	331611	582	543	271	21090	10144428
Mississippi	21456	16	36	134	31582	55	51	25	2008	966136
Tennessee	0	0	0	0	0	0	0	0	0	0
Total	1725453	1168	2583	9620	2255861	3959	3698	1849	143474	69009714

*Columns may not add due to rounding adjustments.

TABLE VI-9 (cont'd)

REGIONAL AND AGGREGATE TOTAL WATER POLLUTANT LOADINGS FROM NON-LOAN PROGRAM COAL USE
NEW SOURCES - 1985

(lbs/year)

Region and State	Al	Cr	Cu	Fe	Mg	Zn	Mn	Ni	TSS	TDS
New England	0	0	0	0	0	0	0	0	0	0
Middle Atlantic	334909	229	517	1860	435150	767	772	359	27690	13363679
New Jersey	0	0	0	0	0	0	0	0	0	0
New York	109323	74	169	607	142043	250	235	117	9038	4362237
Pennsylvania	225587	154	348	1253	293106	517	486	242	18651	9001442
East North Central	579584	396	896	3219	753056	1328	1250	622	47920	23126782
Illinois	126676	86	195	703	164590	290	273	135	10473	5054656
Indiana	216910	148	335	1204	281833	497	468	232	17934	8655233
Michigan	48588	33	75	269	63130	111	104	52	4017	1938772
Ohio	187410	128	289	1041	243503	429	404	201	15495	7478121
Wisconsin	0	0	0	0	0	0	0	0	0	0
South Atlantic	423409	289	654	2351	550138	970	913	454	35007	16895015
Delaware	15618	10	24	86	20291	35	33	16	1291	623176
Florida	71147	48	110	395	92441	163	153	76	5882	2838916
Georgia	144028	98	222	800	187137	330	310	154	11908	5747074
Maryland	27764	19	42	154	36074	63	59	29	2295	1107869
North Carolina	83293	57	128	462	108223	190	179	89	6886	3323609
South Carolina	26029	17	40	144	33819	59	56	27	2152	1038627
Virginia	0	0	0	0	0	0	0	0	0	0
West Virginia	55529	38	85	308	72149	127	119	59	4591	2215739
East South Central	397379	272	614	2207	516318	910	857	426	32885	15856386
Alabama	117999	80	182	655	153317	270	254	126	9756	4708446
Kentucky	255086	174	394	1416	331435	584	550	273	21090	10178554
Mississippi	24294	16	37	134	31565	55	52	26	2008	969386
Tennessee	0	0	0	0	0	0	0	0	0	0.00
TOTAL	1735281	1188	2683	9639	2254665	3977	3744	1862	143474	69241863

*Columns may not add due to rounding adjustments.

TABLE VI-10

REGIONAL AND AGGREGATE TOTAL WATER POLLUTANT LOADINGS FROM LOAN PROGRAM COAL USE
EXISTING PLANTS - 1985

(lbs/year)

Region and State	Al	Cr	Cu	Fe	Mg	Zn	Mn	Ni	TSS	TDS
New England	0	0	0	0	0	0	0	0	0	0
Middle Atlantic	15529	10	23	86	20302	35	33	16	1291	690097
New Jersey	15529	10	23	86	20302	35	33	16	1291	690097
New York	0	0	0	0	0	0	0	0	0	0
Pennsylvania	0	0	0	0	0	0	0	0	0	0
East North Central	928294	628	1389	5175	1213653	2130	1990	994	77189	37152399
Illinois	0	0	0	0	0	0	0	0	0	0
Indiana	498656	337	746	2780	651944	1144	1069	534	41464	19943807
Michigan	165643	112	248	923	216562	380	355	177	13773	6624932
Ohio	239838	162	359	1337	313564	550	514	257	19942	9592350
Wisconsin	24156	16	36	134	31582	55	51	25	2008	1035145
South Atlantic	179447	121	268	1000	234609	411	384	192	14921	7291592
Delaware	0	0	0	0	0	0	0	0	0	0
Florida	101802	68	152	567	133095	233	218	109	8464	4140582
Georgia	0	0	0	0	0	0	0	0	0	0
Maryland	46587	31	69	259	60908	106	99	49	3873	1932272
North Carolina	31058	21	46	173	40605	71	66	33	2582	1244174
South Carolina	0	0	0	0	0	0	0	0	0	0
Virginia	0	0	0	0	0	0	0	0	0	0
West Virginia	0	0	0	0	0	0	0	0	0	0
East South Central	602183	407	901	3357	787295	1381	1290	645	50072	23958089
Alabama	36235	24	54	202	47373	83	77	38	3012	1449204
Kentucky	288151	195	431	1606	376728	661	617	308	23960	11524622
Mississippi	0	0	0	0	0	0	0	0	0	0
Tennessee	277798	188	415	1548	363193	637	595	297	23099	11110564
TOTAL	1725453	1168	2583	9260	2255861	3959	3698	1849	143474	69009714

* Columns may not add due to rounding adjustments.

TABLE VI-10 (cont'd)

REGIONAL AND AGGREGATE TOTAL WATER POLLUTANT LOADINGS FROM NON-LOAN PROGRAM COAL USE
EXISTING PLANTS - 1985

(lbs/year)

Region and State	Al	Cr	Cu	Fe	Mg	Zn	Mn	Ni	TSS	TDS
New England	0	0	0	0	0	0	0	0	0	0
Middle Atlantic	17352	11	26	96	22546	39	37	18	1434	692418
New Jersey	17352	11	26	96	22546	39	37	18	1434	692418
New York	0	0	0	0	0	0	0	0	0	0
Pennsylvania	0	0	0	0	0	0	0	0	0	0
East North Central	933581	639	1443	5185	1213010	2140	2014	1002	77189	37277382
Illinois	0	0	0	0	0	0	0	0	0	0
Indiana	501496	343	775	2785	615198	1149	1082	538	41464	20010899
Michigan	166587	114	257	925	216447	381	359	178	13773	6647219
Ohio	241204	166	373	1339	313398	552	520	258	19942	9624619
Wisconsin	24294	16	37	134	31565	55	52	26	2008	1038628
South Atlantic	180469	123	279	1002	234485	413	389	193	14921	7316121
Delaware	0	0	0	0	0	0	0	0	0	0
Florida	102382	70	158	568	133025	234	220	109	8464	4154512
Georgia	0	0	0	0	0	0	0	0	0	0
Maryland	46853	32	72	260	60875	107	101	50	3873	1938772
North Carolina	31235	21	48	173	40583	71	67	33	2582	1246353
South Carolina	0	0	0	0	0	0	0	0	0	0
Virginia	0	0	0	0	0	0	0	0	0	0
West Virginia	0	0	0	0	0	0	0	0	0	0
East South Central	605613	414	936	3364	736878	1888	1307	650	50072	24038685
Alabama	36441	24	56	202	47347	83	78	39	3012	1384837
Kentucky	289792	198	448	1609	376529	664	625	311	23960	11563392
Mississippi	0	0	0	0	0	0	0	0	0	0
Tennessee	279380	191	432	1551	363001	640	602	299	23099	11078699
TOTAL	1735281	1188	2683	9639	2254665	3977	3744	1862	143474	69241863

*Columns may not add due to rounding adjustments.

Total state and regional pollutant discharges from new and existing powerplants should be slightly less if loan program coal is used in all states and regions for all pollutants except magnesium and total suspended solids. Copper discharges will be approximately 3.9 percent lower if loan program coal is used; chromium, 1.6 percent lower; and manganese, 1.2 percent lower. Total discharges of aluminum, iron, zinc, nickel, and total dissolved solids should differ less than 1 percent from total discharges if non-loan program coal is used. Magnesium discharges are estimated to be slightly increased if non-loan program coal is used (less than one percent for all states and regions). Total suspended solids discharges should be approximately the same throughout all states and regions.

If the loan program affects new powerplants, primarily groundwater will receive the pollutant discharges, since existing NSPS do not allow the discharge of wastewater to surface water bodies. The use of loan program coal at existing powerplants would result in approximately the same amount of water pollutants being discharged. Discharges from existing powerplants may affect surface water to a greater extent than discharges from new powerplants, since BAT treatment levels allow wastewater from powerplants to discharge to surface water bodies.

Regardless of whether program coal is used at new or existing powerplants, the east north central region of the U.S. will be the most heavily affected by the loan program. The states most affected by the program are Kentucky, if program coal is burned only at new powerplants, and Indiana, if program coal is burned at existing powerplants.

3. Land Use/Solid Waste

Tables VI-11 and VI-12 summarize the estimated total amount of solid waste and land use impacts that will result from using loan and non-loan program coal at new and existing powerplants in the

TABLE VI-11

REGIONAL AND AGGREGATE SOLID WASTE IMPACT OF THE LOAN PROGRAM

(tons/year)

Region and State	Existing Plants With Program	Existing Plants Without Program	New Sources With Program	New Sources Without Program
New England	0	0	0	0
Middle Atlantic	35508	145979	761459	3130444
New Jersey	35508	145979	0	0
New York	0	0	248559	1021855
Pennsylvania	0	0	512900	2108589
East North Central	2122618	8726316	1317759	5417453
Illinois	0	0	288013	1184054
Indiana	1140216	4687557	493173	2027490
Michigan	378757	1557112	110471	454158
Ohio	548509	2254569	426102	1751751
Wisconsin	55235	227079	0	0
South Atlantic	410320	1686872	962674	3957660
Delaware	0	0	35508	145979
Florida	232778	956975	161761	665017
Georgia	0	0	327467	1346253
Maryland	106525	437938	63126	259519
North Carolina	71017	291959	189379	778556
South Carolina	0	0	59181	243229
Virginia	0	0	0	0
West Virginia	0	0	126252	519037
East South Central	1376940	5660752	903493	3714361
Alabama	82853	340618	268286	1102954
Kentucky	658879	2708726	579972	2384328
Mississippi	0	0	55235	227079
Tennessee	635207	2611407	0	0
TOTAL	3945386	16219919	3945386	16219919

*Columns do not total due to rounding adjustments.

TABLE VI-12

REGIONAL AND AGGREGATE TOTAL LAND USE IMPACT

OF THE LOAN PROGRAM

(acres of land needed)

Region and State	Existing Plants: With Program (ash disposal)**	Existing Plants: Without Program (ash and scrubber sludge disposal)	New Sources: With Program (ash disposal)	New Sources: Without Program (ash and scrubber sludge disposal)
New England	0	0	0	0
Middle Atlantic	44	65	937	1390
New Jersey	44	65	0	0
New York	0	0	306	454
Pennsylvania	0	0	631	936
East North Central	2611	3875	1621	2405
Illinois	0	0	354	526
Indiana	1403	2081	607	900
Michigan	466	691	136	202
Ohio	675	1001	524	778
Wisconsin	68	101	0	0
South Atlantic	505	749	1184	1757
Delaware	0	0	44	65
Florida	286	425	199	295
Georgia	0	0	403	598
Maryland	131	194	78	115
North Carolina	87	130	233	346
South Carolina	0	0	73	108
Virginia	0	0	0	0
West Virginia	0	0	155	230
East South Central	1694	2413	1111	1649
Alabama	102	151	330	490
Kentucky	811	1203	713	1059
Mississippi	0	0	68	101
Tennessee	781	1160	0	0
TOTAL	4853	7202	4853	7202

*Columns do not add due to rounding adjustments.

**Assumes fly ash is handled dry.

eastern U.S. in 1985. It is assumed that existing powerplants affected by the program will have to meet SIP air pollutant emission limitations. The estimates in the tables represent the sum of unit land use and solid waste impact estimates (outlined in Chapter V) based on the estimated state and regional demand for loan program coal in 1985 for the two coal use cases. Table VI-11 shows the effect on annual solid waste production by region and state using loan program coal instead of non-loan program coal. The first column of the table presents solid waste production if loan program coal is used; the second, if non-loan program coal is used. For each region and state, Table VI-12 summarizes the amount of land that is needed for solid waste disposal using loan and non-loan program coal, if solid waste production continues for 20 years at the annual rate shown in Table VI-11 for the corresponding regions or states.

The total amount of solid waste generated and the total amount of land needed for solid waste disposal will be much less for each region and state if loan program coal is used at new and existing powerplants instead of non-loan program coal. Total solid waste production will be approximately 75 percent lower in each region and state using loan program coal. Total land use for solid waste disposal will be approximately 33 percent lower. If loan program coal is used at new powerplants, the east north central region is affected more than any other region; the state most affected is Kentucky. If only existing powerplants are assumed affected by the loan program, land use and solid waste impacts are more concentrated in the east north central and east south central regions of the U.S. As is the case with the air and water impacts associated with coal combustion at existing powerplants, the state most affected is Indiana.

D. Summary

The overall benefits of the Coal Loan Guarantee Program include the following: (1) an increase in employment--34 percent for mining--and economic activity in the poverty-stricken area of Central Appalachia; (2) an increased supply of low sulfur coal which will enable more powerplants to meet air emission standards without having to install expensive and somewhat unreliable SO_2 scrubbing systems; (3) a 33 percent reduction in the land area required for solid waste disposal and elimination of scrubber sludge disposal, which can preclude many future uses of that land after disposal operations cease; and (4) a small (1-4 percent) reduction in potential heavy metal discharges from powerplant operations.

Negative impacts of the program include: (1) a seven percent increase in land area potentially affected by underground mines in the regions; (2) preclusion of an opportunity to reduce NO_2 emissions through the use of a scrubber system, all other emissions remaining the same; and (3) an increase in the potential number of fatalities and injuries.

The negative environmental impacts of coal combustion at powerplants are primarily associated with coal combustion regardless of the sulfur content. As discussed earlier, utilities will control sulfur emissions only to the extent necessary to meet the applicable air emission standards. Because of current emission and effluent standards, the impacts resulting from combustion of low sulfur coal are identical to those associated with the use of high sulfur coal, with the exception of solid waste production and associated land use impacts and NO_2 emissions discussed above. Regardless of the sulfur content of the coal, utilities must meet the same emissions standards.

In general, EPA's Best Management Practices for surface and subsurface coal mines duplicate the requirements of the Office of Surface Mining's (OSM) Interim Regulations[1/] based on the Surface Mining Control and Reclamation Act, PL 95-87. Both sets of guidelines prescribe that mining be conducted in a manner that maximizes coal recovery with a minimum of disturbance, that mine sites be reclaimed so that the land is at least as productive as it was before mining, that runoff or pit water must be clean enough to meet Federal Effluent Standards, that blasting not harm offsite structures, and that mine facilities such as haul roads and impoundments be designed to minimize offsite disturbance. The Interim regulations generally require more detailed specifications than EPA's Best Management Practices. OSM's Interim regulations, however, do not cover managing underground mining operations to control subsidence, which EPA's guidelines do cover.

EPA's guidelines do not require the mine operator to apply specific techniques to eliminate or control subsidence. Rather, they only require the operator to plan and execute the mine in a manner which minimizes surface disturbance. To comply with these guidelines, the operator has two choices: to design the mine so that the possibility of subsidence is eliminated or to design the mine so that subsidence is predictable and controlled.

Few operators choose to design mines for eliminating subsidence. To eliminate subsidence, larger pillars of coal must be left in place and if more than one seam is being worked,

1/ Federal Register Vol. 42, No. 239 - 12/13/77
CFR 700-837.16.

the pillars in each strata must be directly superimposed. So less coal can be recovered and the operations of the mine are less flexible. Backfilling the mine with coal refuse or other loose material has been done at several sites, but the technique is experimental.

Most operators elect to control subsidence rather than eliminate it. Subsidence can be controlled by removing support pillars upon completion of mining and collapsing the roof by controlled placement of explosives. This technique has been safely executed in mines which have large buildings on the surface above them. If the operator plans to mine the seam below a mined out level, it is in his best interest to collapse the upper seam as evenly as possible, because differential subsidence causes pockets of high pressure in the lower seams. For safety reasons, the guidelines require that work on the uppermost seam in multiple seam mines progress faster than work on lower seams.

Regardless of whether the operator chooses to eliminate or control subsidence, the guidelines require that the entry of the mine be sealed and surface face-up excavations be back-filled, graded, and revegetated.

CHAPTER VII

PROBABLE ADVERSE ENVIRONMENTAL IMPACTS WHICH CANNOT BE AVOIDED AND SIGNIFICANT MITIGATING MEASURES

This chapter examines the potential impacts of the residuals produced by coal mining and preparation, coal transportation, and coal use discussed in Chapters V and VI on air, water, land use, ecosystems and the socioeconomic environment. Measures which can be taken to mitigate the adverse impacts are then discussed. Surface mining impacts are discussed for comparative purposes only; the Coal Loan Guarantee Program will affect only small underground mines.

A. Coal Production -- Mining and Preparation

1. Air

Most mines and preparation plants are located in remote, rural areas which generally have good air quality. The impacts of a mine or coal preparation plant on the ambient air quality outside the immediate area will not be significant if proper reclamation and dust and emission controls are employed.

Particulate emissions from surface mining, near-mine transport and steam coal preparation plants are by far the major air pollutant of concern, but they are generally confined to within the immediate area of activity. Although surface mining produces considerably more fugitive dust than underground mining, the adverse impacts on ambient air quality are usually not significant (i.e., air quality standards are not violated). However, during drought and stagnant weather conditions (i.e., an inversion), surface mining may cause the 24-hour secondary ambient air qualitv standards for particulates to be exceeded. If the standards are exceeded outside the area owned by the mining company, this could be considered a violation of the standards. Rapid vegetation of spoil piles and exposed areas and watering of dusty roads will mitigate the impacts of the dust formation.

Without proper control measures, fugitive dust emissions within underground mines and in handling areas of coal preparation plants may create an occupational health problem. Baghouse filters are very effective (99+ % efficient) in controlling fugitive dust to within acceptable limits for occupational health standards and protection of the environment.

The impacts of air emissions from underground mines are negligible, for the use of electrically powered machinery produces very few emissions. Impacts on ambient air quality due to diesel emissions from surface mining equipment will also be minor. Ambient air quality standards are unlikely to be exceeded in remote locations which have low background concentrations.

In the past refuse pile and mine fires have been a serious source of air pollution. Coal storage and refuse pile fires can severely degrade air quality in the vicinity of the fire. Emissions of particulates, sulfur dioxide, carbon monoxide, hydrogen sulfide, and trace elements associated with the coal can occur in quantities that have the potential to cause injury or death. However, although mine fires and burning coal and refuse piles cannot be ruled out, the incidence of these fires at new mines and preparation plants is expected to decrease sharply with the enforcement of current mining and reclamation laws. Refuse pile fires can be successfully prevented by proper segregation, burial, and compaction of combustible material, in addition to covering refuse with noncombustible overburden and revegetating the area.

2. Water

Coal production can have severe adverse impacts on water quality. Activities associated with the production and processing of bituminous coal are estimated to significantly affect 10,300 miles of stream, over 10,000 miles of which are in the

Appalachian Region.[1/] Sedimentation is the major problem associated with surface mines, particularly in Central Appalachia where contour mining on steep slopes predominates. Acid mine drainage is the predominant problem in Northern Appalachia. It is associated with both surface and underground mines, but underground mines are its major source.

The impacts of mining and coal preparation on ambient water quality depend not only on the effluent load from the mine or preparation plant but also on the flow and water quality of the receiving body of water. As mentioned earlier, many streams, particularly in Northern Appalachia, are already degraded by mine, industrial, and other pollution, so their capacity to assimilate additional pollutant discharges from a mine or preparation plant is very small. In addition, the small tributaries draining the highlands frequently have very low buffering or neutralizing capacities, for they drain primarily sandstone and shale. In regions where rivers flow through limestone, usually in the larger valleys and lowlands, the natural buffering capacity of rivers is 2 to 3 times higher provided there is no other pollution, and impacts of mine drainage effluent on ambient water quality are less severe due to some natural neutralization.

The impacts of sediment on ambient water quality depend primarily on the flow and velocity of the receiving streams. The greater the flow, the more dilution occurs; the greater the stream velocity, the less deposition and clogging of streams occurs.

Without water quality controls on the discharge of effluents from mines and preparation plants, the effluent load from a single mine or preparation plant can result in severe degradation of water quality. However, with proper reclamation and water treatment techniques, the existing NSPS effluent limitations can be met (see Table VII-1). Discharge of effluents in compliance will have a negligible impact on ambient water quality.

1/ U.S. Army Corps of Engineers, "The National Strip Mine Study," Vol. 1, July 1974, p. 13.

TABLE VII-1

NEW SOURCE PERFORMANCE STANDARDS

	Bituminous, Lignite, and Anthracite Mining Services				Bituminous, Lignite, and Anthracite Mining			
	Coal Preparation Plant		Coal Storage, Refuse Storage and Coal Preparation Plant Ancillary Area		Acid or Ferruginous Mine Drainage		Alkaline Mine Drainage	
Parameter	30-Day Average	Daily Maximum	30-Day * Average	Daily * Maximum	30-Day * Average	Daily * Maximum	30-Day * Average	Daily * Maximum
pH	No discharge of pollutants	No discharge of pollutants	6-9	6-9	6-9	6-9	6-9	6-9
Iron, Total			3.0	3.5	3.0	3.5	3.0	3.5
Dissolved Iron			0.30	0.60	0.30	0.60		
Manganese, Total			2.0	4.0	2.0	4.0		
Total Suspended Solids			35	70	35	70	35	70

*All values except pH in mg/l.

SOURCE: U.S. Environmental Protection Agency, "Development Document for Interim Final Effluent Limitations Guidelines and New Source Performance Standards for the Coal Mining Point Source Category". EPA 440/1-76/057-a, May, 1976, p. 254, Table 36.

However, some noncompliance must be anticipated which will result in degradation of water quality. It is not now possible to estimate reliably the extent of future noncompliance.

Surface mining increases erosion and sedimentation rates by exposing large amounts of unconsolidated material. For example, in a study in south-central Kentucky, the annual sediment yield from the strip-mined watershed averaged over 1900 tons per square mile during the four years following cessation of mining, compared with an annual average of only 25 tons per square mile for unmined watersheds.[1/] Ninety-six percent of the erosion in the partially stripped watershed was attributed to the disturbed area, which then covered only 10.4 percent of the area.

Sedimentation of stream channels and impoundments has adverse impacts on aquatic life and uses of water for transportation, recreation, water supply, and industrial and agricultural purposes. Effects associated with deposition of sediment include the filling up of stream channels, lakes and reservoirs, and damage to aquatic ecosystems through disruption of the food supply and breeding grounds. Flooding can result from the filling of flood control reservoirs, or a reduction in the width or depth of a river channel. Severe sedimentation can result in the closure of a river segment to navigation, or increases in the cost of dredging for maintenance of navigation.

An example of the magnitude of the problems which can result from sedimentation can be found at Fishtrap Lake, a water resource project of the U.S. Army Corps of Engineers in eastern Kentucky. Sedimentation is occurring at a rate 7½ times the normal rate for

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1/ Collier, C.R., R.J. Pickering, and J.J. Musser, "Influences of Strip-Mining on the Hydrologic Environment of Parts of Beaver Creek Basin, Kentucky, 1955-66," U.S. Geological Survey Professional Paper 427-C, 1970.

that area.[1/] Large amounts of sediment eroded from coal haul roads and refuse piles are transported by tributaries and emptied into the reservoir. As another indication of the severity of sedimentation, the National Strip Mine Study reports that the sediment yield in strip-mined areas in the Susquehanna Basin is 20 times that of unstripped areas.[2/]

If not properly reclaimed, refuse piles from underground mines and preparation plants produce the same adverse impacts as spoil piles: erosion, acid runoff, no vegetative growth, landslides, and slope instability. If reclamation techniques are used, proper drainage, stabilization, compaction, shaping, and revegetation can mitigate most of the adverse impacts of refuse piles.

Sedimentation can be controlled by minimizing surface run-off and erosion at the mine site using proper mining and reclamation methods. Controlled placement of spoil material and reclamation measures, including prompt establishment of vegetative cover, is of primary importance in controlling erosion. A study performed in eastern Kentucky indicated that the use of the above on strip-mined areas resulted in sediment yields four to six times less than the sediment yield from mined areas using no controls.[3/] Methods of controlled spoil placement currently in use and which have been proven to be effective in reducing the total area disturbed and erosion rates are box-cut, head-of-the-hollow fill, and modified block-cut techniques.[4/] Restrictions on spoil placement, particularly on steep slopes,

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1/ "Problems Caused by Coal Mining Near Federal Reservoir Projects," Report to the Conservation and Natural Resources Sub-Committee, Committee on Government Operations, House of Representatives, October 2, 1973.

2/ U.S. Army Corps of Engineers, _op_. _cit_., p. B-7.

3/ Curtis, W.R., "Sediment Yield from Strip-Mined Watersheds in Eastern Kentucky," _Second Research and Applied Technology Symposium on Mined Land Reclamation_.

4/ U.S. Army Corps of Engineers, _The National Strip Mine Study_, Vol. 1, July, 1974.

are now in general use in Kentucky, Ohio, Pennsylvania, and West Virginia. Reclamation practices commonly used to rehabilitate surface-mined areas and to control erosion include water diversion, segregation and burial of toxic material, backfilling and grading, and fertilizing, liming and seeding the mine site with grass and/or legumes. Depending on the toxicity of the spoil material and the intended use of the mined area, topsoil may be spread to enhance vegetative growth. Experience has shown that the planting of trees alone is inadequate; a quick-growing vegetative cover of herbaceous species is necessary to obtain quick stabilization and initial erosion control until trees can establish an effective cover (up to ten years).[1/2/]

A good vegetative cover is the best erosion control, but while this is being established, mulching exposed spoil material and creating sediment ponds and natural vegetation barriers between the mine site and receiving streams effectively reduce the amount of sediment reaching natural bodies of water. In order to operate efficiently, sediment ponds must be properly designed, have sufficient capacity, and be routinely maintained and cleaned. Accumulated solids can actually increase effluent suspended solids concentrations above influent concentrations, particularly in surface mining operations during periods of heavy rainfall.

Extensive studies conducted by researchers at the USDA Forest Service Experiment Stations, university personnel, and Federal and State agencies indicate that successful revegetation is feasible in most areas provided there is adequate rainfall, available

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1/ Vogel, W.G., "The Effect of Herbaceous Vegetation on Survival and Growth of Trees Planted on Coal-Mine Spoils," <u>Research and Applied Technology Symposium on Mined-Land Reclamation</u>, March 7 and 8, 1973.

2/ Grim, E.C. and Hill, R.D., *op. cit.*

plant nutrients, and a suitable seed supply, and that toxic materials are effectively buried.1/2/3/ Based upon reclamation research in the East and Midwest, a good vegetative cover usually becomes well established on properly reclaimed sites after 3 to 5 years, after which time the land can be utilized as pasture or for other agricultural uses, or for recreation or development. However, complete restoration of the soil profile to levels characteristic of productive soils will take many years under normal agricultural practices.4/ With increasingly strict regulations being established and enforced by State and Federal agencies, sediment from future coal production will be minimized.

Acid mine drainage from underground mines, surface refuse piles, and surface mines causes severe environmental impacts on water supplies. Characterized by low pH and high concentrations of mineral acidity, iron, and other metal ions, acid mine drainage is toxic to most vegetation and aquatic biota when the ambient pH is below 5.5. As a result, revegetation is hindered, therefore facilitating erosion as well as the formation of acid drainage, both of which harm aquatic habitats and make water unsuitable for industrial, agricultural, residential and recreational use. Aesthetic impacts of acid mine drainage include unvegetated spoil piles and subsequent erosion as well as the coating of stream beds by yellow or red iron particulates ("yellow boy") which are harmful to aquatic life and destroy their feeding and breeding grounds.

1/ Vogel, W.G., "Weeping Lovegrass for Vegetating Strip-Mine Spoils in Appalachia," Proceedings of the First Weeping Lovegrass Symposium, April 28-29, 1970.

2/ U.S. Environmental Protection Agency, "Processes, Procedures, and Methods to Control Pollution from Mining Activities," EPA-430/9-73-011, October, 1973.

3/ Grim, E.C. and Hill, R.D., *op. cit*.

4/ *Ibid*.

Because contour mining is practiced in steep terrain, pollution of surface waters is the primary problem. Runoff passing through the spoil piles becomes contaminated and then enters receiving streams. Area mining is practiced in relatively flat terrain; therefore, internal drainage predominates, and there is little direct runoff from the mine itself. For this reason, groundwater contamination tends to be more of a problem with area mining. Underground mining may also interrupt groundwater aquifers and cause groundwater contamination.

Methods to control the formation of mine drainage pollution from surface mines and refuse piles include burial of acid or toxic materials, drainage control, reclamation, and establishment of a good vegetative cover which retains most water to within the root zone. To prevent groundwater contamination from toxic materials in spoil and refuse piles, a layer of compacted impermeable material, such as clay, is placed beneath and on top of the segregated toxic material. It is then covered with clean overburden and revegetated. These control techniques can be augmented, if necessary, with treatment techniques including neutralization plants and sedimentation basins during mining.

Techniques to control acid mine drainage from underground mines include pre-mining planning, down-dip mining, and mine sealing to cause permanent flooding of the mine after mining operations cease. Permanent flooding greatly reduces the availability of oxygen necessary to oxidize sulfide compounds (i.e., pyrite) to form acid drainage. Infiltration control can occasionally reduce the volume of wastewater discharged from active underground mines and is achieved by implementing mine roof fracture control including design of mine pillars and barriers, sealing of boreholes and fracture zones, and backfilling of overlying surface mines. The most common method of controlling acid drainage from underground mines is conventional lime neutralization treatment followed by aeration and settling. Mine drainage neutralization treatment plants can successfully control acidity, iron, manganese, aluminum, nickel, zinc and total suspended solids. For efficient operation, routine maintenance of the plant and routine maintenance and cleaning of the settling pond are necessary.

Through a combination of efficient plant design, in-process controls and end-of-process treatment, coal preparation plants can utilize a closed water circuit and, therefore, achieve zero discharge of wastewater. This has been demonstrated at many preparation plants. Wastewater from preparation plant ancillary areas, including coal and refuse storage areas, can be controlled and treated effectively using techniques similar to those employed by surface mines.[1/]

As discussed earlier, coal mining may cause groundwater contamination and disrupt aquifers. Area and underground mining have the greatest potential for aquifer disruption. Because the underground mine operation can fracture overlying rock structures, particularly when subsidence occurs, underground mines can seriously damage aquifers. Adverse impacts include draining of usable shallow aquifers, lowering of water levels in adjacent aquifers, and interruption or shifting of groundwater flow. The impact of mining on aquifers can have serious repercussions on the surface environment by decreasing groundwater levels and stream flows. These impacts can be particularly serious in areas where shallow aquifers are important sources of water for industrial or domestic use.

1/ U.S. Environmental Protection Agency, "Development Document ...", op. cit., p. 4.

Aquifer disruption is particularly severe in the semi-arid regions of the West where groundwater supplies are of vital importance in maintaining surface flows in use for irrigation, stockwatering, and agricultural purposes. Groundwater disruption in Appalachia, particularly Central Appalachia where most of the program coal will be mined, is not expected to have major impacts on water use, due to the high rainfall and surface water flows and remote location of most mines. Mitigating measures include careful pre-mining planning of mining operations with respect to groundwater hydrology.

The adverse impacts on water use and water quality resulting from the Coal Loan Guarantee Program may be significant. They can be minimized through careful pre-mining planning and the practice of conscientious mining and pollution control techniques.

3. Land Use

The primary impact of coal mining and preparation on land use is preemptive use of land for the active mine site, spoil and refuse piles, plant facilities, and treatment plants and settling ponds. Land requirements can be divided into two categories: fixed and incremental requirements.

Fixed land requirements, as discussed in Chapter V, refer to the land required for the life of the mine or preparation plant. Fixed land requirements for surface mines are negligible. Sediment ponds used to control suspended solids during mining can be reclaimed once adequate vegetative cover is established to control erosion. Land required for water treatment and storage and loading facilities at underground mines and preparation plants may be a problem in Central Appalachia where level land is at a premium. By far the largest land requirements are for settling ponds. Although more land is generally required for water treatment facilities in Northern Appalachia due to the larger volume of mine drainage usually treated, there is also more flat land available for these facilities due to the less rugged topography.

Solid waste disposal and subsidence have the major impacts
may cause subsidence, although this can be minimized by backfilling.
from underground mines and preparation plants, and sludge from water treatment are sources of solid waste. Underground mining may cause subsidence, although this can be minimized by backfilling.

Of the surface mining methods, contour mining incurs the largest impacts on land use if no controls are practiced. This is primarily due to the steep topography in which contour mining is practiced. Uncontrolled contour mining is characterized by the dumping of overburden (containing loose rock, soil, and tree stumps) removed from above the coal seam on the slope below the coal outcrop. This can create a very steep and often unstable spoil pile which may create landslides, causing property damage and threat of personal injury below the mine site. Highwalls decrease the aesthetic value of the land and also may prevent access to useful mountain top land.[1/] If spoil piles are not regraded to reduce and stabilize slopes, vegetation is very difficult to establish.[2/] Without vegetative cover, erosion can be severe, particularly on steep slopes, and the sediment eroded from the mine site can choke stream channels and reservoirs, resulting in increased flooding and damage to bottom lands. With proper reclamation, erosion and sedimentation can be controlled, and the bench area of contour mines can provide level land which can be used for pasture or homesites in areas where flat land is scarce. In addition, the coal haul roads provide access to areas which, prior to mining, were inaccessible.

1/ Plass, W.T., "Highwalls - An Environmental Nightmare," Proceedings on Revegetation and Economic Use of Surface-Mined Land and Mine Refuse Symposium, Dec. 2-4, 1971.

2/ Grim, E.C. and Hill, R.D., op. cit.

Mountain-top removal is a mining method used when one or several coal seams lie very close to the top of the mountain. All of the overburden is removed down to the coal seam in a series of parallel cuts, just as is done in area mining. Mountain-top removal creates large, flat to rolling areas which are vitally needed in mountainous regions.[1/] When mountain-top removal is properly performed and the land reclaimed, the post-mining land use potential is enormous.[2/] Airports and townsites can be established on the reclaimed land above valley floors and away from landslide and flood hazards. Some disadvantages include high planning and operation costs. Also, creation of "table top" vistas in mountain-top mining alters the character of the land and affects its aesthetic quality.

Area mining usually results in less change to the shape or contour of the land than does conventional contour or mountain-top removal mining. Where the thickness of the coal seam is very great relative to the overburden thickness (primarily a problem in the West), the attainment of the original elevation of the land through reclamation is impossible. However, with extensive grading, the approximate original contour of the land within the perimeter of the mined site can be attained. Conventional area mining usually results in an unreclaimed "final cut" which may preempt the use of the land so affected from any future use. The final cut can, however, serve as a water impoundment with potential economic and social benefits, if the impoundment does not become acid or present safety problems.

With proper planning, mining, and reclamation most surface mines can be rehabilitated and used again after a few years as pasture, homesites, orchards, forest or recreational areas. Therefore, surface-mined land is only temporarily taken out of use and the impacts on land use are not long-term in most cases.

1/ Plass, W.T., _op. cit._

2/ Grim, E.C. and Hill, R.D., _op. cit._

Refuse piles from underground mines and preparation plants can be reclaimed in a manner similar to surface mine reclamation.

Sludge disposal is a problem in areas where suitable land is scarce. If iron compounds in the sludge are in the ferric form, sludge can be effectively disposed of in underground mines, provided the water in the mine has a pH greater than 4.0 to prevent the iron compounds in the sludge from redissolving. Solids such as calcium sulfate will also dissolve in mine water, thus raising the total dissolved solids.[1/]

Impacts due to subsidence range from facilitating the entry of air and water into uncollapsed parts of the mine, adding to acid drainage problems and fire hazards, to increasing surface erosion and stream sedimentation. Major impacts are associated with property damage. Subsidence can destroy structures and useful farmland and make new construction almost impossible where subsidence is extensive. As of 1969, nearly two million acres of land had subsided in the U.S. because of coal mining.[2/] Techniques for controlling subsidence include refilling the mined cavern with gravel or waste rock and longwall mining, a method used not to prevent subsidence but to plan and control the extent of subsidence. Proper planning and design of mine openings, limiting void widths, and timbers and roof bolts can increase roof support.

Interstate agencies with some land use control in the Appalachian Region include the Appalachian Regional Commission and the Tennessee Valley Authority. State land use controls and

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1/ U.S. Environmental Protection Agency, "Processes, Procedures, and Methods...," op. cit.

2/ "Environmental Effects of Underground Mining and Mineral Processing," op. cit., p. 17.

regulations that may pertain to mining operations are summarized as follows:1/2/

- Alabama: Strip-mine laws require backfilling and regrading of mines to a rolling topography and revegetation of land.

- Kentucky: In 1974, a state Land Use Planning Council was established. Kentucky strip-mining laws require return of land to original contour, revegetation of land, and protection of water quality. There are 16 regional planning districts that have laid out land use and water resources plans for the entire state. Most of the counties have county planning offices.

- Maryland: Long-range site selection and environmental studies of power plant siting are financed through an environmental surcharge on electric bills. Construction activity in "critical areas" may be regulated by localities under state guidelines. Maryland's tax assessment laws allow for lower taxes on agricultural or recreational land. Strip-mine reclamation laws require back-

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1/ U.S. Department of the Interior and the Energy Research and Development Administration, "Synthetic Fuels Commercialization Program - Draft Environmental Statement," Vol. III, ERDA 7547, December, 1975, p. III-27.

2/ Energy and Environmental Analysis, Inc., "Manual of Coal Production and Consumption Legislation with Summaries of Federal, State and Local Laws and Regulations Pertaining to Air and Water Pollution Control," prepared for the U.S. Department of the Interior, June 7, 1976.

filling and regrading area mines to the approximate original contour and contour mines to a terrace configuration with maximum slope restrictions. Revegetation of land is required and topsoil must be replaced. Municipalities and counties have zoning authority.

- Ohio: No statewide land use policy has been formulated; however, a power plant siting law has been recently enacted and the state is participating in the Federal Coastal Zone Management Program which includes planning along the Ohio River. Land that has been strip-mined must, by law, be returned to its original contour, the topsoil replaced, and revegetated with reclamation beginning within three months after the land is first disturbed. Municipalities and counties have zoning authority.

- Pennsylvania: Permits are required for strip mining, by law, water quality must be protected and topsoil replaced. Enforcement of the law has been strong. Land use plans and coastal zone management programs are being formulated. Counties and localities have zoning authority. All counties have planning commissions. Several regional planning bodies have also been established.

- Tennessee: Statewide land use plans are presently being formulated. After strip mining, the law requires that, within 6 months of initial disturbance, the land must be returned to its approximate original contour on slopes less than 15 degrees, and to a terrace configuration on slopes exceeding 15 degrees. Preservation of topsoil, where possible, revegetation of the mine site, and preservation of water quality are also required. Counties and municipalities have zoning authority.

- Virginia: There is no statewide land use policy. After strip mining, the law requires that the land be backfilled and regraded to a terrace configuration and revegetated. Reclamation must begin within 60 days or 700 feet of removal of the coal from contour mines and within 30 days or 350 feet if augering is done. Preferential assessment of open, agricultural, and forest land may be granted by municipalities, which also have the power to zone.
- West Virginia: There is no statewide land use plan in effect. By law, certain steep slopes are off-limits to mining. Highwalls resulting from mining operations must be reduced and level or rolling land must be returned to original contour. There are restrictions on spoil placement, bench width, and slope. Revegetation of land and protection of water quality are required. Backfilling and grading must be completed within 60 days or 3000 feet after stripping and within 30 days or 1000 feet after augering. Counties have the authority to zone.

The states in which the large majority of program coal will be mined (Kentucky and West Virginia) have strict mining and reclamation laws designed to minimize the adverse impacts on land use. Because extensive mining has occurred in these states for many years, the citizens are aware of potential problems associated with mining, and most counties have zoning authority designed to protect land resources. ✓

4. Ecosystems

a. Terrestrial Ecosystems

Both surface and underground coal mining operations disrupt terrestrial ecosystems in two ways: by altering land which would otherwise be valuable habitat, and by degrading the surrounding area with fugitive dust, pollutants from machinery, and noise from equipment and workers. Surface mining obviously causes more physical alteration of the land, but the degree of ecological damage from secondary effects (air pollution, dust, noise, floods) depends upon a particular mine's location and layout as well as the mining technique used.

Fugitive dust degrades terrestrial ecosystems primarily by blanketing the surfaces of leaves with a layer of opaque, and thus photosynthesis-inhibiting, dust. Some plants respond to this threat by growing dense mats of hair-like structures which prevent the dust from permanently settling,[1/] but the photosynthetic capacity of most plants is impaired by fugitive dust. This impairment can cause a general drop in the entire community's population and production and also alter the specific composition of the community by favoring the proliferation of the more resistant species. If the exposed land which is the source of fugitive dust is eventually reclaimed, no permanent and significant fugitive dust damage should occur.

The ecological damages caused by air pollutants from machinery and noise will vary from mine to mine and will only affect particular plants and animals. Underground mines are inherently less noisy and produce fewer air pollutants because most of the equipment is electrically powered and is operated underground, but the effects of noise and air pollution from loading and hauling machinery and coal preparation plants will vary from site to site. If a particular site has few natural or artificial noise barriers, some of the more reclusive animals such as wild turkeys may abandon the area. If air pollutants emitted by trucks and loading equipment accumulate in the valleys during temperature inversions, some of the more sensitive plants, such as white pines, American elms, and some lichens, might suffer some acute tissue loss or damage. However, neither noise nor air pollution should significantly damage local ecosystems or alter their specific composition.

1/ Elias, T. E., and Irwin, H. S., "Urban Trees" in Scientific American, November, 1976.

Underground mining is inherently less damaging to terrestrial ecosystems because, as stated in the land use section, it disturbs less land. The secondary effects of underground mining, fugitive dust, vehicular air pollution, and noise, can be minimized by selecting a site which will require a minimum of vehicular traffic to operate and by secondary measures such as wetting or paving roads, shielding stationary noise sources, and using engine air pollution control systems. By encouraging mining of underground low sulfur coal which is less disturbing ecologically than surface mining, the Coal Loan Guarantee Program will lessen the adverse impacts of mining on terrestrial ecosystems.

b. Aquatic Ecosystems

Different kinds of ecological damage risks are associated with the different coal mining techniques, but all new coal mines run one common risk: the accidental release of acidic water from abandoned and forgotten underground mines. Because abandoned mines are common to many Appalachian areas, the probability that this type of accident could happen is fairly high, and when it does, as in the case of the Black Water River, the consequences can be ecologically disastrous. Only recognition of this problem and extreme caution during exploratory drilling can prevent these disasters.

Although acidic discharges can be produced in both surface and underground mines, the problem is usually associated with underground mines because most of the existing sources are abandoned deep mines. The sulfuric acid from these mines differs from most water pollutants because it has an almost universally toxic effect; the acid often kills everything in the stream, with the occasional exception of a few Dipteran and Helgramite larvae and some algal species. The toxic action of this acid is both chronic and episodic. An acid discharge which normally affects only a small segment of a stream can affect a larger area in two ways: when the stream flow is low and when an extremely acidic low flow is pushed downstream by a sudden freshet caused by melting snow or heavy rains. A heavy rain in 1969 pushed such an "acid slug" through the North Branch of the Potomac River and killed fish in areas 90 miles downstream from the mine discharge sources.[1/]

Mine discharges carry other pollutants besides sulfuric acid, and the toxicity of these pollutants will vary with the temperature, ambient quality, and resident species of the receiving water. However, the acid in a mine discharge usually exerts a more powerful toxic effect than the associated heavy metals and sulfate.

Acidic discharges usually come from abandoned underground mines, some of which have not been operated for over a century. Most of the recent mining-related water pollution problems, however, come not from acidic discharges, but from high suspended sediment levels. As previously discussed, most of this sediment comes from surface mines.

High sediment loads decrease a stream's biological productivity in two ways: by affecting the water's opacity and temperature and by interfering with the physiology of the fauna. The increased turbidity does reduce light penetration and thereby reduces photosynthesis, but primary production is usually not that important to small streams, which are often shaded by overhanging trees and receive most of their organic nutrients from food that drops into them. Turbidity raises the water temperature and changes the flow characteristics of the stream. Turbidity also reduces the carrying capacity of a stream by inhibiting and interfering with visually-dependent behavior patterns such as feeding and mating. The West Virginia Fish and Game Commission has recently discontinued stocking several streams laden with strip-mine sediment because, even if the stream had a sub-

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1/ R. M. Davis, Maryland Fisheries Administration, Presentation given at Biological Resources of Potomac River Conference, January 26, 1977.

stantial fish population, few game fish would strike a lure or bait.[1/]

Heavy sediment accumulation on stream bottoms, particularly those which are normally rocky, can have several adverse effects on aquatic life. First, it may cause changes in the number and type of bottom-dwelling organisms. Second, covering over of rocky bottom habitats may interfere with fish breeding activities. Increased sediment loads in swift-moving streams that feed lakes or reservoirs will contribute to sediment accumulation in the lake. In addition to resulting ecosystem impacts, if such bodies of water are used for water storage, recreation, or power generation, their useful lifetimes may be reduced.

By encouraging mining of underground low sulfur coal, the program may result in some damage to aquatic ecosystems from acid mine drainage and surface mine sediment.

5. Socioeconomic Conditions

a. Economics and Employment

In 1975 the average productivity of Appalachian miners was approximately 2010 tons of coal per man per year for underground mines and 4320 tons per man per year for surface mines.[2/] Productivity is generally higher in Northern Appalachia than in Central Appalachia and productivity at surface mines is approximately twice that of underground mines. Underground mines produced 2124 and 1734 tons per man per year in 1975 in Northern and Central Appalachia, respectively, and surface miners averaged 4719 and 3390 tons per man per year.[3/] Table VII-2 summarizes the estimated number of mines required to produce 250,000 tons of coal annually.

1/ Donald Pheras, Fisheries Biologist, Jefferson National Forest, personal communication.

2/ U.S. Bureau of Mines, 1977, op. cit., Table 16, p. 19.

3/ Ibid.

TABLE VII-2

EMPLOYMENT AT A UNIT SURFACE AND UNDERGROUND MINE PRODUCING 250,000 TONS/YEAR[1/]

Mine Type	Northern Appalachia	Central Appalachia
Surface	53	74
Underground	118	144

1/ Based upon average annual productivities in 1975 for Northern and Central Appalachia.

SOURCE: U.S. Bureau of Mines, "Coal - Bituminous and Lignite in 1975," February 10, 1977, Table 16, p. 19.

The program's employment impact should be a boon to Central Appalachia's economy. Any increase in revenue will significantly benefit this area, which has the lowest per capita income ($2,363 in 1972, about 60% of the national average), the most substandard houses (about 37%), the highest infant mortality rate, and the lowest ratio of health manpower to population of the three Appalachian sub-regions. However, the program may also cause at least temporary housing and labor force shortages in Central Appalachia, as well as at least temporary overloading of local water treatment facilities and sewer systems.

b. Health and Safety

By primarily affecting underground coal production throughout Appalachia, the Coal Loan Guarantee Program could potentially increase the risk of mining fatalities and injuries. Because coal and shale are weak structural materials, mining machinery is powerful and responds quickly to control; low light levels are common despite artificial lighting. Because of this, underground coal mining will probably continue to be a dangerous occupation despite improved federal and state safety regulations. In 1974 there were 0.36 fatalities and 43.0 injuries per million tons of underground coal production.[1/] On a man-hours-worked basis, this accident rate is more than thrice the average industrial accident rate. Strip mining is safer than underground mining; in 1974 there were 0.09 fatalities and 7.9 injuries per million tons of coal produced at strip mines. The enforcement of recent safety legislation, such as the Coal Mine Health and Safety Act of 1969, has caused decreases in fatalities, but the frequency of disasters (where 5

1/ MESA Health and Safety Analysis Center, "July 1974-June 1975 Quarterly District Manager Report," Denver, Colorado, August 8, 1975, p. 359; and U.S. Department of Interior, Bureau of Mines, "Coal - Bituminous and Lignite in 1974," January 27, 1974, p. 12, Table 9.

or more workers are killed) and some kinds of injuries has remained fairly stable.[1/]

Compared to mining, fatalities and injuries at coal preparation plants are much lower. In 1974 fatalities at coal preparation plants in the U.S. averaged 0.01 death per million tons of cleaned coal. Non-fatal injuries averaged about 4.88 per million tons of cleaned coal.[2/] The lower accident rates are due to the much smaller manpower requirements of coal preparation facilities and safer working conditions. Most injuries are associated with material handling or slipping and falling.

The effect of the coal loan program on mining fatalities and injuries will depend upon the type of mine affected by the program. Table VII-3 summarizes the average number of fatalities and injuries which would occur per year at a unit-size surface and underground mine and at a unit-size coal preparation plant. A unit-size mine is assumed to be one which produces 250,000 tons of coal per year.

As can be seen from the table, fatalities and injuries are approximately 4 times higher at underground mines than at surface mines. There is essentially no difference between the statistical number of fatalities and injuries which would occur at low sulfur as opposed to high sulfur underground or surface mines. Surface mining injuries and fatalities are not related to factors associated with coal sulfur content. In underground mines, the number of injuries and fatalities is only slightly related to factors associated with coal sulfur content, but not to a point where it is possible to distinguish death and accident rates by sulfur content of underground mines. Underground mines in Appalachia with coal seams of less than 48 inches (classified as thin) currently account for approximately 20 percent of coal production in Appalachia. Approxi-

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1/ Cassidy, S. M., Elements of Practical Coal Mining, Society of Mining Engineers, 1973.

2/ MESA, *op. cit.*, p. 360; and Bureau of Mines, 1976, *op. cit.*, p. 44, Table 31.

TABLE VII-3

ANNUAL OCCUPATIONAL HEALTH STATISTICS FOR COAL MINING AND COAL PREPARATION[1/]

Activity	Fatalities	Non-Fatal Injuries
Mining		
Surface[2/]	.02	2.0
Underground	.09	10.8
Coal Preparation	<.01	1.2

1/ Basis: Annual mine production = 250,000 tons/year.
Preparation plant capacity = 250,000 tons/year.

2/ Includes strip and auger mining.

SOURCE: "July, 1974-June, 1975 Quarterly District Manager Report," MESA Health and Safety Analysis Center, Denver, Colorado, August 8, 1975, pp. 259-260.

U.S. Bureau of Mines, "Coal-Bituminous and Lignite in 1974," U.S. Department of the Interior, Washington, D.C., January 27, 1976, p. 12, Table 9.

mately 1/3 of the number of fatal haulage and rooffall accidents occur in these mines. Low sulfur underground coal seams tend to be thinner than average; thus, there may be a slightly greater risk of accidents and fatalities in underground low sulfur mines. However, both low and high sulfur coal seams occur frequently under conditions that are more conducive to accidents (thin seams) than average, and deviations from the average depth and accident rates of underground mines by sulfur content are insignificant.

The overall impact of the coal loan program on the number of deaths and accidents from coal mining will depend on the shift in mining practices brought about by the program over the entire Appalachian region. The total impact of the program on deaths and accidents will depend upon the extent to which the program results in increased regional underground mining activity. These death and accident impacts have been examined in Chapter VI.

Although accident rates are high, the leading cause of disability among coal miners is coal miner's pneumoconiosis or "black lung." In 1969, Lainhart estimated that 10 percent of working coal miners and 20 percent of non-working coal miners showed evidence of this disease.[1/] The validity of these estimates has recently been questioned, but the fact remains that "black lung" does frequently incapacitate coal miners. Heart disease is also more prevalent among coal miners. Most new mines are coming into compliance with federal respirable dust level standards which are designed to prevent new cases of "black lung" and other respiratory problems.

In the absence of particulate controls, coal dust levels within coal preparation plants and in loading areas could cause

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1/ Lainhart, W. S., et. al., Pneumoconiosis in Appalachian Bituminous Coal Miners, Public Health Service, Cincinnati, 1969.

health hazards. However, with current standards limiting particulate emissions and with the use of baghouses in coal preparation plants and loading areas, dust emissions can be reduced to acceptable levels.

The adverse impacts of coal mining on land and water use and the air environment can have a serious effect on those who live in coal mining areas. Persons living below mine sites complain of the stress of living under constant threat of landslides and falling boulders. Flooding due to the siltation of streams and poor water retention by unvegetated areas creates hazards throughout the coal stripping regions of Appalachia. The use of coal wastes in dam construction has led to floods and extensive loss of human life.[1/] A tragic example of this is the disaster of Buffalo Creek in southern West Virginia. In February, 1972, heavy rains and melting snows created pressure behind a dam constructed mainly of deteriorating coal waste from underground mines. When the water broke through the dam, it caught inhabitants of the valley below unaware, killed 124 people, and left about 4000 others homeless.[2/] With the practice of proper mining and engineering methods, future disasters of this nature can be avoided. The Coal Loan Guarantee Program will have its primary effect on the health and safety of miners, for underground mining is a more hazardous occupation than surface mining.

6. Esthetics

a. Noise

Noise impacts of both underground and surface mining operations can be significant. The coal crusher and the operation of other mining and transportation equipment can increase ambient noise levels as high as 100 dBA[3/] at 50 feet. Blasting at a strip

1/ U.S. Army Corps of Engineers, National Program of Inspection of Dams, vol. 1, May, 1975.

2/ New York Times, February 29, 1972, Section 1, p. 2.

3/ dBA (A-weighted decibels) - a unit of noise measurement which weighs high frequency noise more heavily.

mining operation creates an intermittent intense noise of over 1900 dBA. These levels decrease with distance. The more vegetation and natural barriers which exist, the greater the rate of this noise decrease. At distances of 1500-2000 feet from the coal mining equipment, noise levels have been known to decrease by 20 dBA. Even at this distance, increases in noise levels due to coal mining activities are still very noticeable. Noise receptors within ½ mile of the site would be affected.

Noise could create serious health hazards for exposed workers. However, due to safety standards,[1/] necessary source and operational control methods are employed. Such measures include mufflers, lined ducts, partial barriers, vibration isolation, imposed speed limits on vehicles, scheduled equipment operations, etc.

b. Visual Effects

Surface mining and refuse piles from underground mines and preparation plants have some of the greatest adverse effects on visual aesthetics. If surface mines and refuse piles are not properly reclaimed, they can remain an eyesore for many years, appearing as an unvegetated, easily-eroded scar on the surrounding countryside. When mining is practiced on steep slopes, refuse and spoil piles have a much greater landslide potential; landslides mar hillsides and can cause property damage and death to wildlife and anyone residing below the mine. With current mining and reclamation laws and slope restrictions in some states, landslide potential is being reduced.

Surface mining also alters the original topography of the land, as can subsidence from underground mining. Even with the proper backfilling and site reclamation, the approximate original contour of the land cannot always be restored. This is particularly

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1/ EPA has recommended a 75-dBA, 8-hour exposure level to protect from loss of hearing, and a 55-dBA background exposure level to protect from annoyance of outdoor activity.

true with contour mining on steep slopes which leaves a level bench remaining on the hillside, and mountain-top removal mining which creates a table top vista on top of the mountain.

Erosion of mine sites and sedimentation of water courses also create visual sores. Clogging of streams with sediment can cause flooding, which causes even greater damage. Streams polluted by acid drainage are also unsightly, frequently stained red or yellow from iron compounds.

Dust created by trucks hauling coal on dirt roads also is a nuisance and coats vegetation or any structures in the vicinity with dust, giving everything a shrouded appearance. As mentioned earlier, the impacts of dust can be mitigated by watering roads during dry periods.

c. Historic, Cultural, and Recreational Sites

Most of the archeological and historic sites described in the baseline section will probably not be significantly disturbed by increased underground mining because most of these sites are located on the more desirable agricultural land by the large rivers. The lifestyle of the culturally unique people who live in these backwoods areas will probably be disrupted if coal mining penetrates these regions, but the total disappearance of their culture is by no means assured. Large enclaves of other archaic societies, such as the Amish in Lancaster County, Pennsylvania, are able to maintain their cultural integrity in spite of the modernization of their neighbors.

Land-based recreational activities such as hunting and hiking will be favored by the predominance of underground mining over surface mining because underground mining disturbs less land. It also causes less stream siltation problems, which have caused the most sport fishing problems over the past few years.

If legally required control measures are not effectively enforced, fisheries and water sports could be curtailed by acidic discharges from underground mines. However, although this type of pollution is more toxic than most, it has the advantage of being easily recognized by the untrained eye. Any new cases of "red water" or "yellow boy" in fishing streams will probably be reported to local Fish and Game or Water Resources officials by fishermen, and if the stream has enough recreational value to cause a public outcry over its destruction, the mining company might be pressured into taking mitigating steps. This situation has occurred in West Virginia when strip mine sediments polluted local fishing waters.[1/]

B. Coal Production -- Transportation

Environmental impacts resulting from the transportation of coal produced under the Coal Loan Guarantee Program may be significant. Because program coal production is estimated to be about 7% of total regional coal production, the total pollutants produced due to transportation of program coal are estimated to increase in comparable proportions. The pollutants produced and their resulting impacts will be distributed along the entire length of the transportation corridor, so no one location should be severely affected.

1. Air

Adverse impacts on air quality occurring during coal shipment may occur, for particulates in the form of coal fines and diesel emissions are distributed along the entire transportation corridor. Particulate emissions may become a problem during loading or during switching operations at transfer points. Particulate emissions from wind lossage can be reduced by covering

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[1/] Gerald Lewis, Fisheries Biologist, West Virginia Department of Fish and Game, personal communication.

coal cars or by spraying the coal with oil or a chemical spray to settle dust.

2. Water

Some adverse impacts on water may occur. However, only barge transportation contributes water pollutants, and these are in relatively small quantities.

3. Land Use

Some expansion of existing transportation lines may occur as a result of the program. Increases in land use will be associated with the construction of haul roads and/or railroad spurs only a few miles in length into newly developed mining areas for the purpose of transporting the coal from the mine to the existing transportation lines. The land required for these access spurs is only a small fraction of the total area that will be disturbed by mining and preparation activities. Therefore, additional impacts on land use should be less significant.

4. Ecosystems and Socioeconomic Conditions

Because the loan program is expected to change the total quantities of coal shipped by approximately 7%, and some expansion of existing transportation facilities is expected, some adverse impacts on ecosystems and socioeconomic conditions may occur. Transportation frequencies may increase somewhat in the Central Appalachian region as a result of the program, but this should not severely affect ecosystems or people located near transportation corridors.

C. Coal Use

1. Air

The loan program will only affect ambient NO_2 levels since only emissions of these air pollutants will or may be above those occurring without the program. The coal use impacts of the loan program on ambient air quality with respect to all other pollutants - SO_2, particulate matter, CO, HC, aldehydes, and trace elements - will be no different than if there were no loan program, for emissions to the atmosphere of these pollutants from new coal-fired powerplants will be the same regardless of whether high or low sulfur coal is burned. As mentioned earlier, SO_2 and particulate emissions will be limited by the existing New Source Performance Standards and SIP's, and CO, HC, aldehyde, and trace element emissions are governed by the design and operating characteristics of the boiler. As discussed earlier, NO_2 emissions are governed by the design and operating characteristics of the boiler and SO_2 scrubbing systems which can reduce NO_2 emissions by up to 10 percent.

NO_2 emissions from new powerplants burning low sulfur coal as a result of the loan program could be reduced by using SO_2 scrubbers to a point where they would equal those of a powerplant that is not affected by the loan program. However, the use of SO_2 scrubbers to control NO_2 emissions is extremely uneconomical and not an NO_2 control measure that would be available to stations burning low sulfur coal without scrubbers which the loan program would allow. Thus, NO_2 emissions from new powerplants affected by the loan program will be approximately 10 percent greater than emissions without the loan program.

Further reduction of particulate and SO_2 emissions can be achieved with the addition of other control units in line with the primary unit, for example, two scrubber systems in line or two ESP's in line. The use of an FGD scrubber system in conjunction with low sulfur coal would result in an SO_2 emission rate of approximately 0.5 to 1.2 lbs/MMBtu, as compared to 1.2 lbs/MMBtu allowed by existing NSPS. The substitution of either oil or natural gas for coal could also further reduce particulate and SO_2 emissions. Both fuels are free of almost all ash, and natural gas does not emit SO_2.

2. Water

Water quality impacts from a coal-fired powerplant result from thermal, sediment, and chemical pollutants. Thermal impacts are independent of the fuel type used and therefore will not be affected by the Coal Loan Guarantee Program. The concern over thermal impacts results from the ecological changes caused by increased temperatures in the surface water. The types and the balance of flora and fauna in the water may be altered from the existing state.

Sediment in coal pile runoff can potentially clog small streams and affect the aesthetics of surface water. The impacts of sediments in coal pile runoff are independent of the sulfur content of the coal and therefore will not be affected by the loan program.

Chemical pollutants produced by a coal-fired utility include heavy metals, dissolved solids, and acidity. High concentrations of these pollutants can have adverse impacts on aquatic life and water use. Heavy metals can be toxic to aquatic life. Heavy metal standards have been set for both surface water and groundwater quality and are dependent upon the water bodies' beneficial uses. If they infiltrate into the groundwater, the heavy metals in the coal pile runoff, ash sluicing water, ash leachate, and scrubber sludge leachate can preclude the use of groundwater as a source of drinking, irrigation, or industrial water supply. Also, contaminated groundwater which reaches the surface water can adversely affect aquatic life. Due to the larger quantities of solid waste requiring disposal, the quantities of heavy metals reaching the groundwater are higher without the loan program than with it. Thus, the Coal Loan Guarantee Program is generally beneficial with respect to heavy metals.

Increases in dissolved solids can upset ecological balances and, if severe, render water unfit for drinking or industrial use. Dissolved solids can be contributed from ash handling water, coal pile runoff and ash disposal leachate. As in the case of heavy metals, the amount of dissolved solids generated depends upon the quantity of coal stored and burned. There is no predictable difference in levels of dissolved solids resulting from the use of high or low sulfur coal; therefore, no adverse impact is expected to result from the Coal Loan Guarantee Program.

Wastewaters generated from coal-fired operations are generally acidic. The sulfur content of the coal dictates the acidity of ash handling water and coal pile runoff. The greater the coal's sulfur content, the more acidic is its wastewater. The pH level is an important parameter, for aquatic life can live only in a limited pH range. Drinking water becomes unusable outside certain limits. Existing NSPS and BAT discharge limits require that wastewater from the coal pile be treated to meet the pH standard of 6.0 to 9.0; thus, with respect to pH, adverse impacts to surface waters are not expected. However, acidic discharge from high sulfur coal may adversely affect groundwater quality. By providing low sulfur coal the loan program will result in a smaller pH impact on groundwater subject to infiltrating water from coal piles.

Mitigating measures which a generating station could employ to minimize the environmental impacts on water quality include lining ash ponds and disposal sites with an impermeable layer such as clay. Such a layer would prohibit any infiltration of contaminants into the groundwater. However, this mitigating measure can only be implemented in areas having high evaporation rates. Another mitigating measure would be to handle the fly and bottom ash dry and sell it as a concrete aggregate. This measure is not always possible, but utilities have been known to sell or give away some of their fly ash as a construction material. By using fly ash as a construction material, one eliminates water quality impacts caused by fly ash disposal leachate. A collection system can be used to decrease the impacts of coal pile runoff. By collecting the runoff and treating it with lime, the heavy metal concentrations can be reduced. The use of drainage ditches can reduce sediment loading as a source of water pollution by up to 50 percent. These ditches have become widely used as a means of controlling erosion and sedimentation. Because the program will make more low sulfur coal available, impacts on water quality and use from coal pile runoff and sludge disposal sites will be reduced.

3. Land Use

Land use impacts are primarily of two types: first, preemptive use of land during disposal operations and second, impacts that prevent the future productive use of land after disposal operations have ceased. As was shown in Table V-29, the use of low sulfur coal reduces the amount of land required for powerplant solid waste disposal. The actual land use impact will depend upon the specific disposal practice, the material being disposed of, and the availability and existing use of the land in the vicinity of the powerplant.

When low sulfur coal associated with the loan program is used rather than high sulfur coal, the waste disposal site will be much more conducive to use after disposal operations cease. Ash is physically more stable than scrubber sludge, and therefore can be used for landfill or construction material. When the physical composition of scrubber sludge readily absorbs water, this creates a mud-like substance that cannot support structure foundations. Sludges from SO_2 scrubbers are particularly susceptible to this condition. If not stabilized, the disposal of this material can preclude the area from future use, for this often creates a landscape marred by slide scars and sink holes. Fly ash and bottom ash from most boiler types generally are not subject to rewatering problems. Therefore, because only ash will be generated by the use of low sulfur coal, the Coal Loan Guarantee Program will result in a smaller impact on land use, for land used for ash disposal is much more conducive to future use than is land used for scrubber sludge disposal.

It should be noted that in certain parts of the country it is extremely difficult to obtain disposal sites. Not only lack of available land, but local ordinances and other governmental restrictions also complicate the problem. In general, rural areas provide more available disposal sites than urban areas. The particular advantage of the loan program is that along the highly urbanized eastern seaboard, where much of the land use impact will occur, the program will reduce the area needed for powerplant solid waste disposal and prevent land use problems associated with scrubber sludge disposal.

Measures which can mitigate the impacts on land use include reducing the amount of solid waste generated, selling solid waste products, and employing handling and disposal practices that will reduce impacts on future land use. The amount of solid waste generated through coal use at a steam electric powerplant is primarily a function of the ash and sulfur content of the coal and the type of air pollution control equipment used; therefore, the amount of ash and/or scrubber sludge generated at a coal-fired powerplant usually cannot be reduced substantially. The amount of ash cannot be decreased without allowing more fly ash to escape into the atmosphere. The stoichiometry of the scrubber can decrease the amount of scrubber sludge produced by reducing the amount of unreacted $CaCO_3/CaO$ in the sludge. The amount of this reduction is dependent on the operating characteristics of the scrubber. The water content of sludge can be reduced by a variety of dewatering and chemical processes which in some cases reduce the total solid waste requiring disposal.

Solid waste requiring disposal can be reduced from powerplants if ash and scrubber sludges are handled and treated to produce a salable product. Fly ash is now being sold by coal-fired powerplants as building material for use in concrete and cement or as foundation material. Fly ash is suitable as such material because of the small and fine size of its particles. To be suitable for future use, fly ash must be handled separately and must be kept dry when transported from the flue stack. Thus, only electrostatic precipitators and baghouses lend themselves to the sale of ash. The sale of fly ash at a powerplant equipped with a scrubber would require the use of an ESP to remove fly ash before the flue gas enters the scrubber. Thus the Coal Loan Program lends itself much more to this means of reducing the volume of solid waste requiring disposal. Bottom ash is also sometimes sold or used as construction fill material. However, because it readily absorbs water, it is not suitable as foundation material.

Processes that can produce salable or usable products from sludge are very limited. They include the regeneration of lime and SO_2 through sludge sintering with conversion of the sulfur dioxide to elemental sulfur or acid, or the treatment of the sludge to make a salable gypsum product. Treatment of sludge to make gypsum involves sludge oxidation. The calcium sulfite in sludge has a large chemical oxygen demand. Oxidation of the sludge converts the sludge to a purer gypsum. Neither approach is presently used in the U.S. for lime/limestone sludge. The only alternative by-products of any of the FGD systems that appear to have a significant potential market are sulfuric acid and sulfur. In Japan, where the sludge-derived gypsum is a salable product, complete oxidation to the sulfate form is a common practice. Gypsum prices are generally too low to make sludge-derived gypsum practical in the U.S. Sludge is not suitable as construction fill material.

Selling ash or sludge-derived products will reduce the amount of land needed for ash or sludge disposal. When this alternative is not possible, impacts of solid waste disposal on future land use of the disposal site can be controlled to some extent by employing proper disposal techniques. Future land use problems associated with ash disposal can be alleviated by landfilling in a controlled manner, taking into account the particle size of the various constituents of the fill and the drainage patterns in the fill area. In some cases, landfilling can be used to reclaim quarried or other usable areas.

Prior to final disposal, sludge can be conditioned or handled in a variety of ways to render it suitable for final disposal and reuse. The basic steps available involve:

- thickening - The moisture content of the sludge is decreased, but the sludge remains a fluid;
- stabilization - Materials in the sludge are chemically altered or reduced by chemical, biological, physical, or thermal means;
- conditioning - The sludge is treated to improve its dewaterability;

- dewatering - Water is removed to the point where the sludge is a cake or a semi-solid;
- drying - Moisture is driven off to the point where solid material exceeds the moisture content; and
- incineration/recalcination - Volatile materials are burned and/or calcium carbonate is thermally converted to lime.

The resulting physical and chemical characteristics of the sludge to be disposed of are determined by the extent to which the sludge is treated and the technological option used for each step.

Simple thickening by gravity settling or air flotation is a widely used initial sludge handling processing step. The solids are concentrated, and the removed water is returned to the process.

Chemical fixation can be used to improve both the physical and chemical stability of the sludge. There are a number of chemical fixation processes now on the market which convert the sludge to a solid and stable form suitable for landfill. The reactions used to fix the sludge are similar to those employed in the preparation of cement and transform the sludge into a hard, durable mass.

The ultimate in volume reduction is drying and/or incineration. The least expensive drying techniques are sludge drying beds in which sludge moisture drains into sand and/or evaporates. However, this technology requires land, causes odor problems, and is dependent on climatic conditions. Incinerators, whether multi-hearth, fluid bed, or rotary kilns, are high in capital and operating costs and in energy demand. They also can affect the air quality adversely by increasing particulate emissions or emission of volatilized heavy metals. Rotary kilns have occasionally exploded and are somewhat dangerous. Multi-hearth furnaces are predominant, but are less efficient than the new fluid bed furnace technology. The fluid bed furnaces emit a cleaner stack gas as a result of more uniform burning, but require higher operational skill than the multi-hearth furnaces. Recalcination and reuse of lime sludge is possible with either the fluid bed or multi-hearth furnace.

In general,ash lends itself to disposal practices that alleviate future land use problems much more readily than sludge. For this reason the land use impacts of the loan program can be mitigated much more easily than those impacts that will occur with the use of high sulfur coal and scrubbers without the program.

4. Ecosystems

a. Terrestrial Ecosystems

The increased emission of NO_x compounds and heavy metals should not significantly damage terrestrial ecosystems if ambient levels of NO_x compounds are below Federal ambient air quality standards. There have been some well documented cases of acute (interveinal cell damage) and chronic (chlorotic pigment patterns and photosynthetic rate decreases) vegetation damage in response to high NO_x levels, but most of these damages occurred in the vicinity of nitric acid plants or other chemical producers.[1/] Similarly, the evidence of NO_x damage to animals was generated in experiments in which high doses were administered.[2/] Low concentrations of airborne heavy metals do not cause acute damage of terrestrial vegetation; however, the long-term effects of these metals has not been explicitly documented.

1/ EPA, Air Quality Criteria for Nitrogen Oxides, Washington, D.C.

2/ Ibid.

The elimination of the need for scrubber sludge disposal areas will benefit terrestrial ecosystems. As outlined in the land use section, within 20 years the typical powerplant will fill 230 acres 30 feet deep with scrubber sludge. This is 75 acres more than the area required for ash disposal if a powerplant uses low sulfur coal. Well-drained climax forests are often selected for disposal sites, cleared, and used with varying degrees of intensity throughout the disposal operations. Although the site will usually be re-vegetated within five years after operations cease, succession of this vegetation into a climax forest again takes many decades. Although productivity loss of this magnitude does not usually alter regional ecological dynamics, the loss of additional acreage in an urbanized area often has adverse recreational and aesthetic consequences.

b. Aquatic Ecosystems

The primary aquatic impact of powerplants, thermal discharge, will not be changed by the use of low sulfur coal. However, other less publicized but ecologically damaging consequences of coal-fired powerplant operation will be reduced.

The acidity of coal-pile runoff will be reduced considerably by the use of low sulfur coal. This reduction benefits organisms in the immediate vicinity of the discharge (few organisms can endure pH levels below 5) and those further downstream, since higher acidity levels often increase the toxicity of other ambient water pollutants. However, existing NSPS and BAT require the pH to be controlled to within 6.0 to 9.0, thus minimizing pH impacts of coal pile runoff from either low or high sulfur coal piles.

The ash pond overflow will carry lower quantities of heavy metals, thus reducing the damage due to acute toxicity and chronic toxicity through bio-accumulation if this water is discharged.

However, existing NSPS require "no discharge" from ash handling systems, so these impacts would only occur at new powerplants during operational upsets such as flooding or equipment failure.

5. Socioeconomic Conditions

a. Economics and Employment

The price of underground-mined low sulfur coal is presently marginally higher than underground and surface-mined high sulfur coal, and it will probably remain higher in the future. In Central Appalachia low sulfur coal is usually found in relatively narrow seams, so it requires substantially more effort to extract it. Also, if Federal air pollution standards are more rigidly enforced, higher demand for low sulfur coal will probably increase prices.

However, two factors will probably make the use of low sulfur coal economically attractive in spite of higher mining costs and increasing demand. The primary factor is the high cost of installing and operating a scrubber system. The cost of scrubber systems depends upon the size and capacity utilization of a particular powerplant and whether the system is retrofitted, but in general the operation of scrubbers add a cost of $9-10 per ton of coal burned.[1/] This cost offsets whatever savings are gained by purchasing cheaper high sulfur coal. Also the price of low sulfur coal should decrease if the Coal Loan Guarantee Program is successful in increasing the number of small low sulfur coal producers. Such small producers are usually more competitive and efficient than large producers.

The use of low sulfur coal instead of scrubbers should directly benefit consumers. If one assumes that the price of electricity is 4¢/kWh,[2/] that fuel accounts for 1/3 of this price, and high sulfur coal costs $20/ton, the operation of a scrubber system which costs $10/ton of coal would raise the monthly electric bill at a residence that uses 500 kWh/month from $20.00 to $23.32, or 16.6 percent.

1/ Pedco-Environmental Specialists, Inc., Flue-Gas Desulfurization, for U.S. EPA, Washington, D.C., 1975.

2/ Federal Power Commission, Typical Electric Bills, Washington, D.C., 1976.

Conversely, if low sulfur coal at \$25.00/ton were used instead of scrubbers, the monthly bill for the same amount of electricity would increase by only \$1.66, or 8.3 percent. This saving would be particularly welcomed by consumers in the Middle Atlantic region, who pay the highest electricity bills in the nation.[1/]

Retrofitting scrubber systems onto existing powerplants usually requires more capital investment and higher operating costs, so the use of low sulfur coal at such powerplants should be even more attractive than at new powerplants. Another potential benefit of low sulfur coal use at existing powerplants is that the utilities would not be forced to invest immediately in expensive scrubber systems which may soon be antiquated.

b. Health and Safety

The use of low sulfur coal instead of scrubbers will not significantly alter the operations of powerplants, so fatality and injury rates should not be affected.

Nitrogen oxide emissions, which will be slightly increased if the use of scrubbers is foregone or discontinued, could contribute to a public health hazard. High ambient levels of NO_x cause pulmonary disorders and higher frequencies of chronic respiratory ailments.[2/] However, most of the pathogenic effects of NO_x compounds have been noted only in laboratory experiments where high dosages were administered or in regions affected by abnormally high levels of NO_x emitted from nitric acid or other chemical factories.[3/] Coal-fired powerplants do not generally emit large quantities of NO_x, and the increase associated with low sulfur coal combustion is relatively insignificant, so low sulfur coal use is not expected to directly cause any public health hazards, although existing conditions may be aggravated.

1/ Federal Power Commission, 1976, Typical Electric Bills, Washington, D.C.

2/ EPA, Air Quality Criteria for Nitrogen Oxides, Washington, D.C., 1971.

3/ Ibid.

6. Esthetics

a. Noise

There will be no significant noise impacts caused by the use of low sulfur coal instead of high sulfur coal and scrubbers. Significant noise sources such as a coal car shaker operate independently of the type of coal burned. However, powerplants during both the construction and operation phases will increase noise levels over ambient levels. These increases should cause no new violations of recommended EPA levels for outside activity unless sensitive receptors (e.g., residences, schools, outdoor recreational areas) are located within ½ mile of the plant. Increases in noise levels become less noticeable the closer a plant is located to an urban area.

b. Visual Effects

Low sulfur coal combustion will not cause any increases in suspended particulate levels, the primary visual impact of powerplant operation, nor will it necessitate the construction of any large and obtrusive structures (the primary visual impact of powerplant construction). The use of low sulfur coal will alter the landscape in that it will eliminate scrubber sludge lagoons and reduce landfill areas. Although this change will only marginally alter a powerplant's visual impact, it will be beneficial.

c. Historic, Recreational, and Cultural Values

The use of low sulfur coal should enhance an area's historic, recreational, or cultural value, particularly in areas where SO_2 emission was previously uncontrolled. Lower SO_2 levels will protect the structural integrity of historic limestone buildings, art, and monuments. The program will decrease the demand for sludge landfill areas, thus protecting parklands and recreational areas. In addition, the future land use potential of disposal sites is enhanced by the program, since ash disposal is more amenable to reclamation of the land for recreational purposes. These benefits of low sulfur coal use will be proportional to an area's degree of urbanization.

CHAPTER VIII

IRREVERSIBLE AND IRRETRIEVABLE COMMITMENT OF RESOURCES

A. Background

The major resource commitment associated with implementation of the Coal Loan Guarantee Program is that of the natural resources. Since this program is national in scope and is dependent on receiving applications on behalf of individual borrowers, it is extremely difficult to predict with accuracy where the additional coal supplies will come from; therefore, this section generally describes the maximum impacts which might occur, in an attempt to bound the impacts by using a worst case approach.

B. Commitment of Mineral Resources

The maximum coal production that could be generated by this program is approximately 40 million tons of low-sulfur coal per year. Table VIII-1 represents the demonstrated eastern low-sulfur coal reserve base by State as of January 1, 1974. Fiscal Year 1975 Appalachian low-sulfur coal deliveries to utilities were 14.4 million tons, so the maximum impact of this program would result in a 1985 278 percent increase over Fiscal Year 1975 deliveries. Current demonstrated low-sulfur coal reserves for the eastern U.S. are 5.2 billion tons. The Coal Loan Guarantee Program at full implementation will utilize 0.8 percent per year of these reserves. This is not likely to pose a significant threat to depletion of current reserves.

C. Commitment of Water Resources

To the extent that coal or overlying materials are saturated, aquifers will be permanently disrupted by mining. In addition, any necessary coal processing requires commitments of volumes of water which may be significant in the local coal production area. Removal of this water has impacts which are noted under "Productivity Losses" below.

TABLE VIII-1

EASTERN BITUMINOUS DEEP MINEABLE COAL RESERVES
Range of Sulfur Content by Weight
(million short tons)

State	0-0.6%	%	0-1%	%
Alabama	123	2.3	589	2.7
Illinois	171	3.2	1,035	4.9
Indiana	144	2.7	444	2.1
Kentucky	963	18.3	5,043	23.8
Maryland	25	0.5	106	0.5
Michigan	0	0.0	5	0.0
Ohio	9	0.2	116	0.6
Pennsylvania	124	2.4	981	4.6
Tennessee	21	0.4	140	0.7
Virginia	532	10.1	1,676	7.9
West Virginia	3,152	59.9	11,087	52.2
Total	5,264	100.0	21,222	100.0

D. Productivity Losses

Where mines are located in previously undeveloped agricultural areas, certain resources can be assumed to be lost after development. In undeveloped areas, habitats for various species of wildlife may be permanently destroyed, if not through mining itself, through the presence of necessary levels of human activity.

Increased water pollutant discharges to highly productive areas such as bays, estuaries, and wetlands, may have long-term or cumulative effects on regional aquatic productivity.

Where land use was principally for cropland or grazing, these uses would be foregone at least for the period of operation of the mine. Water losses also might affect the productivity of the land. Even after reclamation, land productivity may be reduced by as much as 50 percent.

In addition to the direct impact of mine development, the mining method employed and the amount of coal mined are factors causing subsidence.

All of these impacts are site-specific in nature. Chapters V and VI of this EIS have projected these impacts for the Coal Loan Guarantee Program and quantified them where feasible.

E. Other Commitments of Resources

Other irretrievable resource commitments include any specimens of archeological or paleontological value and alterations to the natural state of a region which reduce aesthetic value. The fatal accidents (see Table VII-3) which may occur in mining also are impacts of note. Further, the manpower, machinery, and fuels needed to extract and transport the coal must be considered as irretrievably committed.

CHAPTER IX

RELATIONSHIP OF SHORT-TERM USES OF THE ENVIRONMENT AND MAINTENANCE AND ENHANCEMENT OF LONG-TERM PRODUCTIVITY

The production of low-sulfur coal underground by small coal producers and increased combustion of low-sulfur coal involves an expansion of current levels of low-sulfur coal mining, as well as an increase in emissions of nitrogen oxides. These uses of the environment are balanced by decreased utilization of land required for scrubber sludge disposal. The maximum coal production estimated to be stimulated by this program is 40 million tons of low-sulfur coal annually. By increasing production of low-sulfur coal, land utilization for scrubber sludge disposal will be reduced, the cost of achieving environmental compliance with the Clean Air Act for coal-fired utilities may be reduced, and the competitive position of small coal producers will be maintained or improved.

This increased productivity in the energy sector may cause some decline in productivity in other sectors, primarily as a result of expanded coal mining. Depending upon the land use before mining, production from land formerly used for agriculture and grazing would be diminished. In addition, wildlife habitat could be eliminated or limited.

CHAPTER X

ALTERNATIVES CONSIDERED BY DOE

A. Introduction

This chapter discusses alternative programs considered by the Federal Government to achieve the goals of increased underground low sulfur coal production by small coal producers.

Any discussion of alternatives to the proposed action must consider the objectives of the action, the extent to which each alternative achieves these objectives, and the cost to the government and the public of achieving these objectives.

The objectives of the Coal Loan Guarantee Program are threefold:

- increasing the coal production capacity of small coal producers;
- encouraging production of low sulfur coal; and
- encouraging such coal production by underground mining methods.

Given the highly directed focus of the Coal Loan Guarantee Program, there are relatively few alternatives available for consideration. These alternatives include providing financial incentives other than loan guarantees, such as direct cash subsidies or income tax reductions, to small coal producers or to coal purchasers, as well as to increase demand for low sulfur coal.

The following alternative programs and policies are discussed in this chapter:

- No Action
- Cash Subsidies

- direct cash subsidies to small coal producers who produce low sulfur coal underground;

- direct cash subsidies to coal consumers who purchase low sulfur coal produced underground by small coal producers;

- Income Tax Incentives

  - income tax incentives to small coal producers who produce low sulfur coal underground;

  - income tax incentives to coal consumers who purchase low sulfur coal produced underground by small coal producers;

- Increased Enforcement of Sulfur Emission Standards

  - expanded administrative enforcement of sulfur emission regulations for existing coal-fired utility generating stations;

  - noncompliance penalties imposed on existing coal-fired utility generating stations which are not in compliance with sulfur emission regulations.

Of these alternatives, four are concerned with providing financial incentives other than loan guarantees to coal producers or consumers: direct cash subsidies to small coal producers or consumers, and income tax incentives to small coal producers or consumers. Two alternatives involve direct Federal Government regulatory actions designed to increase demand for, and therefore production of, low sulfur coal. By increasing total demand for low sulfur coal, these latter two alternatives would have some impact on increasing the amount of low sulfur coal which is produced by underground mining methods and by small coal producers.

It should be noted that such pre-combustion coal cleaning technologies as Solvent Refined Coal have not been considered as reasonable alternatives to the Coal Loan Guarantee Program. Such approaches are not considered for several reasons. First, the Coal

Loan Guarantee Program is not a technology oriented program, but rather a program designed to increase production of low sulfur coal by small coal producers using existing underground mining technology. Second, the principal markets for coal produced under the Coal Loan Guarantee Program are believed to be existing or new coal-fired facilities already under construction, as discussed at length in Chapters II, IV, V and VI; the markets for the SRC II technology, for example, are believed to be oil-burning facilities; these different markets would make an SRC II approach non-comparable to the Coal Loan Guarantee Program. Third, SRC technologies are highly capital intensive, and generally not within the financial reach of the small coal producers; for example, one SRC II proposed project is estimated to require capital investment of $1.25 billion.

B. Relative Impacts of Alternatives

The following sections will discuss alternatives to the Coal Loan Guarantee Program in terms of their potential contributions toward increasing production of low sulfur coal underground by small coal producers. In evaluating whether these alternatives could substitute for the proposed loan guarantee program, the following factors should be considered:

1. Whether the alternative action will result in a substantial amount of low sulfur coal produced underground by small coal producers in 1985;

2. Whether the costs of the alternative action to the government and to the public are commensurate with the projected impact of increasing low sulfur coal production underground by small coal producers; and

3. Whether the environmental impacts of the alternative action are significantly different from those resulting from the proposed loan guarantee program, adjusted for differing impacts of program alternatives on increasing low sulfur coal production underground by small coal producers.

Table X-1 displays the estimated impact of alternative actions on underground low sulfur coal production by small coal producers, together with the estimated cost to the government and the public of these actions.

The preliminary estimates of the primary environmental impacts are presented in Table X-2 for mining, preparation and combustion activities associated with the alternative action. It is difficult to project, in quantitative terms, the expected environmental impacts at this point because the effects of each alternative on increasing low sulfur coal production and on the participation of small underground coal producers in these coal production increases cannot be predicted for 1985 with certainty. The estimates in the table have been derived consistently with the methodology described and employed in Chapter V for coal mining, preparation and combustion units, and are presented to indicate a range of environmental impacts which might be expected from implementation of the alternatives. These estimates should not be taken as firm projections of environmental impacts and are subject to change as alternative action parameters evolve.

Analysis of the Table X-1 estimates indicates that small underground coal producers can be anticipated to produce approximately 31 million tons per year in 1985 of low sulfur utility steam coal in the No Action alternative, based on the assumption that small coal producers maintain in 1985 their 1976 share of Northern and Central Appalachian coal production. For the Direct Cash Subsidy and Income Tax Incentives alternatives, small underground coal producers can be anticipated to increase underground low sulfur utility steam coal production by 17 million tons, or by approximately 55%, over the No Action scenario, based on the assumptions that the cash subsidy or income tax incentive is designed to offset the full amount of the mean low sulfur coal price premium projected for 1985 and that $750 million is allocated to finance one of these incentives through 1985. For these alternatives, the share of underground low sulfur utility

TABLE X-1

INCREMENTAL PRODUCTION AND COST ESTIMATES FOR PROGRAM ALTERNATIVES

Alternative	Small Underground Coal Producer Low Sulfur Utility Steam Coal Production	Annual Total Cost to the Government 1/	Total Incremental Annual Cost To Utilities
Coal Loan Guarantee Program	40 MM/tpy	$30 MM/Loan Defaults ($ 5 MM/Loan Defaults/yr)	$ 0
No Action	0 MM/typ	$ 0	$ 0
Direct Cash Subsidy			
to small coal producer	17 MM/tpy	$750 MM ($125 MM/yr)	$ 0
to coal purchaser	17 MM/tpy	$750 MM ($125 MM/yr)	$125 MM
Income Tax Incentives			
to small coal producer	17 MM/tpy	$750 MM ($125 MM/yr)	
to coal purchaser	17 MM/tpy	$750 MM ($125 MM/yr	$125 MM
Increased Enforcement			
sulfur emission limits	8 MM/tpy	$ 0	NA
Noncompliance Penalties	8 MM/tpy	$ 0	$0 - 359 MM

1/ Does not include program administrative costs

TABLE X-2

PRIMARY ENVIRONMENTAL IMPACTS
(Tons/Year)

	Proposed Program	No Action	Direct Cash Subsidies	Income Tax Incentives	Increased Enforcement
Air					
Particulates					
Combustion	46,906	36,576	20,057	20,057	9,439
NOx					
Combustion	356,462	277,600	152,250	152,250	71,647-
	1,083,478	844,600	463,169	463,169	217,962
SOx					
Combustion	562,875	439,069	240,779	240,779	113,308
Water					
Acidity					
Mining	0-9860	0-7708	0-4227	0-4227	0-1989
Preparation	0-9771	0-7623	0-4169	0-4169	0-1962
Suspended Solids					
Mining	65	50	27	27	13
Preparation	316	247	135	135	64
Combustion	143,474	111,891	61,359	61,359	28,875
Land					
Solid Waste					
Mining	441,728	345,427	189,427	189,427	88,142
Preparation	3,995,309	3,065,317	1,680,980	1,680,980	791,050
Combustion	3,945,386	3,076,603	1,687,169	1,687,169	793,962
Subsidence (acres)					
Mining	10,041	7,440	4,080	4,080	1,920

steam coal production achieved by small coal producers increases over the No Action scenario because the subsidy, or tax incentive, is restricted to coal production by small coal producers. Finally, for the Increased Enforcement of Sulfur Emission Standards scenario, low sulfur utility steam coal production by small underground coal producers increases by eight million tons, or 26%, over the No Action scenario, based on the assumption that small underground coal producers achieve their 1976 percentage share of this program alternative coal production increment. For these latter alternatives, the increase in eligible coal production is less than earlier alternatives because the small underground coal producer captures only 23.4 percent (the 1976 share) of the increased low sulfur utility steam coal production of 49.6 million tons.

It should be noted that the low sulfur utility steam coal production estimated for each of these alternatives is significantly less than the 40 million tons projected for the Coal Loan Guarantee Program in 1985, and that the costs to the government of the Direct Cash Subsidy and Income Tax Incentives alternatives are significantly higher than the estimated $30 million in loan defaults projected for the $750 million Coal Loan Guarantee Program. Lowering the amount of the cash subsidy or income tax incentive per ton would have the effect of increasing coal production more than the estimated 17 million tons for the same $750 million in total program resources or achieving the same levels of coal production at less than the projected $750 million. However, despite such possible adjustments, direct cash subsidies and income tax incentives are intrinsically more expensive than loan guarantees with relatively low rates of loan default, because loan guarantees require government expenditures only in the event of default, whereas direct cash subsidies require government expenditures for each unit of coal production stimulated and direct income tax incentives require losses in tax revenues to the government for each unit of coal production stimulated.

For the Increased Enforcement alternatives, there is little probability of increasing the small underground coal producer share of incremental low sulfur utility steam coal production above 1976 percentage share levels, because the alternatives are designed to focus on increasing environmental compliance of existing coal fired utility generating stations, not to increase coal production by small underground coal producers. In fact, the small underground coal producer share may well further continue its historic decline by 1985 in the absence of government financial incentives.

Analysis of the information presented in Table X-2 indicates that certain environmental problems can be anticipated under each alternative. The environmental impacts associated with each alternative are in all cases lower on an aggregate basis than the impacts estimated for the Coal Loan Guarantee Program because lower volumes of low sulfur utility steam coal produced by small underground coal producers are stimulated by the program alternatives. On a per ton of eligible coal production stimulated basis, however, the environmental impacts are identical for all alternatives considered.

Since the program alternatives considered do not affect the environmental impacts from each ton of coal mined, prepared and consumed, the environmental impacts are affected only by changes in the estimated coal tonnage stimulated by each program alternative. Therefore, those alternatives which result in the least underground production of low sulfur utility steam coal by small coal producers have the least aggregate environmental impact.

Each of the alternatives involve little air pollution from mining and preparation under controlled conditions, but involve particulate, sulfur dioxide and nitrogen oxide air pollutants from coal combustion, which may be significant. The increased enforcement alternatives involve least incremental aggregate air pollution because these alternatives result in the least incremental coal production.

Each of the alternatives involves risk of significant water pollution from mining and preparation activities, in the form of acidity (if uncontrolled), and suspended solids and dissolved solids. Water pollution sources associated with coal combustion activities include coal pile runoff, ash handling water, and leachate from ash disposal. The increased enforcement alternatives involve the least water pollution because these alternatives result in the least incremental coal production by small underground coal producers.

Each of the alternatives involves additional solid waste and land use which may be significant in mining, preparation, and combustion activities. The increased enforcement alternatives involve least aggregate incremental solid waste generation and land usage, because these alternatives result in the least incremental coal production.

Concerning these environmental impacts, it should be noted that primary impacts have been calculated, without explicit calculation of secondary environmental impacts relating to impacts of alternative coal or other fuel usage which in some cases would be displaced by coal produced under each program alternative. For example, while water pollution impacts which may be significant are attributable to the use of coal stimulated by program alternatives, these impacts may be substantially less than the impacts of higher sulfur coal which may have been used in the absence of the program alternative; for example, use of higher sulfur coal would typically generate substantially more acidic coal pile runoff than would use of the same quantity of low sulfur coal stimulated under the program alternative. Such secondary impacts have been omitted from the analysis because uncertainty about characteristics of displaced coal supplies precludes reliable generalizations, as would be required in a programmatic environmental analysis. Analysis of such secondary impacts must be deferred to future site-specific environmental analyses.

The following section describes impacts of each of the individual alternatives.

C. General Discussion of Alternatives

1. No Action

This alternative assumes no actions to increase low sulfur utility steam coal production underground by small coal producers. The impacts are assessed treating the coal production and consumption projections of the National Energy Act as a base case.

a. Background

Under a No Action alternative, DOE has projected total 1985 low sulfur coal production in Northern and Central Appalachia of 311 million tons per year (tpy), including 89 million tons from surface mines and 222 million tons from underground mines, as displayed in Table X-3. Of this low sulfur coal production, 133 million tpy is estimated to be utility steam coal production, with the remainder comprising production of coal for export, metallurgical, and industrial steam coal use, as displayed in Table X-4.

DOE has projected a significant price premium for low sulfur coal over the price of high sulfur coal. This projected marginal price premium ranges from $6.74 in New England to $8.18 in the Midwest, as indicated in Table X-5.

b. Economic Impact

The small underground coal producer percentage share of low sulfur utility steam coal production in 1985 has been estimated by extrapolating the 1976 percentage share for this group of total underground coal production in Northern and Central Appalachia. Historically, the small underground coal producer share of coal production nationally has been declining since 1949, as indicated in Table X-6. To assume that small underground coal producers maintain their 1976 percentage share of expanded 1985 underground Appalachian coal production in the absence

TABLE X-3

PROJECTED 1985 LOW-SULFUR COAL PRODUCTION
NORTHERN AND CENTRAL APPALACHIA
(MM TONS)

	Low-Sulfur Coal	Premium Coal	Total	Percent of Grand Total
Surface Mines				
Northern Appalachia	0.3	4.7	5.0	1.6
Central Appalachia	18.0	66.1	84.1	27.0
Subtotal	18.3	70.8	89.1	28.6
Underground Mines				
Northern Appalachia	0.4	45.8	46.2	14.8
Central Appalachia	16.7	159.5	176.2	56.6
Subtotal	17.1	205.3	222.4	71.4
Grand Total	35.4	276.1	311.5	100.0

SOURCE: Federal Energy Administration, PIES Initiatives Scenario Run #A158569C, April 15, 1977

TABLE X-4

METHODOLOGY FOR CALCULATING
EASTERN UTILITY STEAM COAL PRODUCTION

	Utility Low Sulfur Steam Coal	Utility Premium Steam Coal	Total Utility Steam Coal
Northern Appalachia			
Surface	.3	.8	1.1
Underground	.4	1.1	1.5
Central Appalachia			
Surface	18.0	49.4	67.4
Underground	16.7	46.0	62.7
TOTAL	35.4	97.3	132.7

ASSUMPTIONS:

1. 70% of low sulfur coal production is utility steam coal.
2. 100% of export coal (90 MT) is from Appalachia, and 70% of this is premium coal (63 MT).
3. 70% of eastern met coal demand (96.9 MT) is premium coal (67.8 MT).
4. Of the remaining Appalachian premium coal production, the split between industrial and utility use is proportional to their national coal use:

   $$\frac{\text{U.S. utility coal demand}}{\text{utility \& industry coal demand}} = \frac{779}{779+382.9} = \frac{779}{1162} = 67\%$$

   Therefore, total Appalachian premium coal used for utility steam coal demand is:

   276.0 (total Appalachian premium coal production)
   \- 63.0 (exports)
   \- 67.8 (met coal)

   145.2 (industrial and utility premium coal)
   \- 47.9 (industrial demand)

   97.3 (utility shipments)

5. Premium utility steam coal production is divided among regions and mine types in the same proportions as low sulfur coal.
6. All low sulfur coal is utility coal.

TABLE X-5

PIES UTILITY REGION PRICE TABLE

	New England	NY/NJ	Mid-Atlantic	South Atlantic	Midwest
Low-Sulfur Coal	$33.99	$31.98	$30.08	$33.53	$30.30
High-Sulfur Coal	27.25	24.98	22.60	26.74	22.12
Difference	6.74	7.00	7.48	6.79	8.18
Mean Difference	7.24				

Note: All prices are marginal delivered to utility region

Source: Federal Energy Administration, PIES Initiatives Scenario, Run #A158569C, April 15, 1977

TABLE X-6

COAL PRODUCTION BY VARIOUS TONNAGE GROUPS
(MM TONS)

	1949	1960	1970	1974	1975	1976
≥ 1 Million tpy	221	269	431	427	470	476
100,000 to 999,999 tpy	139	92	128	143	140	140
< 100,000 tpy	78	54	37	33	38	49
Total	438	415	596	603	648	665

Source: U.S. Coal Production by Company, 1976, Keystone Coal Industry Manual, 1977 of any governmental financial incentives to this group, may well overstate their share of 1985 coal production, particularly because of the difficulties this group has experienced in attracting debt capital financing. Nevertheless, in an effort to estimate the "worst case" environmental impact of low sulfur utility steam coal production by small underground coal producers, these producers have been assumed to maintain their 1976 percentage share of coal production in 1985.

Table X-7 displays the 1976 percentage share of Appalachian coal production achieved by large and small underground coal producers. Table X-8 indicates that small underground coal producers in Northern and Central Appalachia are estimated to produce 31 million tons of low sulfur utility steam coal in 1985 under a No Action alternative.

No incremental costs are estimated to be incurred by the government or by the public under this alternative.

c. Environmental Impacts

(1) Air Impacts

No significant air pollutant emissions are anticipated from coal mining and preparation activities, but potentially significant air pollutant emissions are anticipated from coal combustion activities. Air emissions which may be significant include particulates (36,576 tpy), sulfur dioxide (439,069 tpy) and nitrogen oxides (277,600 to 844,600 tpy) (see Table X-9).

(2) Water Impacts

Water pollutants generated under this alternative include net acidity (0 to 7,708[1/] tpy from mining and 0 to 7,623 from coal

1/ These higher numbers would occur only under worst case, uncontrolled conditions.

TABLE X-7

1976 UNDERGROUND COAL PRODUCTION BY VARIOUS TONNAGE CLASSES
NORTHERN AND CENTRAL APPALACHIA
(000 TONS)

	Large Coal Producers	Small Coal Producers		
	>1 MMTPY	999,999-100,000	<100,000	Total
Tonnage	158,604	40,861	7,683	48,544
Market Share (%)	76.6	19.7	3.7	23.4

Source: U.S. Coal Production by Company 1976, Keystone Coal Industry Manual, 1977

TABLE X-8

1985 UNDERGROUND COAL PRODUCTION
NORTHERN AND CENTRAL APPALACHIA

	1 MMTPY +		999,999-100,000		< 100,000		Subtotal < 1 MMTPY	
	MMTPY	%	MMTPY	%	MMTPY	%	MMTPY	%
Total Coal Production	320	76.6	82	19.7	15	3.7	97	23.4
Low-Sulfur Coal	238	76.6	61	19.7	12	3.7	73	23.4
Low-Sulfur Utility Steam Coal	102	76.6	26	19.7	5	3.7	31	23.4

Sources: Federal Energy Administration, PIES Initiatives Scenario, Run # A158569C, April 15, 1977, and Table IX-7

TABLE X-9

AIR POLLUTANT IMPACTS OF NO ACTION SCENARIO
TONS/YEAR

	Particulates	NOx	SOx
Underground Mining 1/	0	0	0
Coal Preparation 1/	0	0	0
Coal Combustion 1/	36,576	277,600-844,600	439,069

1/ Assumes controlled conditions

Source: See Tables V-3 and V-12.

preparation), and suspended solids (50 tpy from mining, 20,411 tpy from preparation and 111,891 tpy from coal combustion). Federal and state regulatory activities concerning water point source discharges should minimize these pollutants, but such impacts may be significant at particular coal mining and preparation sites. From coal combustion activities, water pollutant sources include coal pile runoff, ash handling water, and leachate from ash disposal. See Table X-10.

(3) Solid Waste and Land Use Impacts

Solid waste and land use impacts of coal mining and preparation activities under this alternative result principally from disposal requirements for spoil and refuse from mining and preparation, for sludge generated by water treatment, and for subsidence (7,440 acres/year) caused by underground mining. An estimated 1,857 tpy of solid waste result from mining and 3,065,317 tpy from coal preparation. For coal combustion activities, solid waste (3,076,603 tpy) and land use impacts result principally from disposal requirements for ash remaining after combustion. See Table X-11.

2. Direct Cash Subsidies

a. Background

One set of program alternatives to the Coal Loan Guarantee Program is the substitution of direct cash subsidies for loan guarantees. This financial incentive alternative could be directed either toward small underground coal producers directly or toward coal consumers purchasing coal.

By restricting the financial incentive to coal producers who produce low sulfur utility steam coal from underground mines, or to coal consumers who purchase low sulfur utility steam coal produced by small underground coal producers, these program alternatives would directly and exclusively enable small underground coal producers to

TABLE X-10

WATER POLLUTANT IMPACTS OF NO ACTION ALTERNATIVE 1/
(Tons/year)

	Acidity	Suspended Solids
Underground Mining	0 - 7708 2/	50
Coal Preparation	0 - 7623 2/	20,411
Coal Combustion	NA	111,891

1/ Weighted average for North and Central Appalachia at $\leq$ .7 percent sulfur

2/ Higher values are for the uncontrolled case. Impacts will be negligible for the controlled case.

Source: See Tables V-5 and V-20.

TABLE X-11

SOLID WASTE AND LAND IMPACTS OF THE NO ACTION ALTERNATIVE

	Solid Waste (tons)	Subsidence (acres)
Underground Mining	1,857	7440
Coal Preparation	3,065,317	0
Coal Combustion	3,076,603	0

Source: See Tables V-6, V-7, V-21 and V-22.

participate in the incremental production of eligible coal stimulated by the program alternatives.

To quantify the economic and environmental impacts of such alternatives, the analysis begins with the assumption that $750 million in subsidy funds are available from 1979 through 1985, for an average of $125 million per year. The $750 million assumed for this alternative corresponds to the $750 million guarantee ceiling authorized for the Coal Loan Guarantee Program and was chosen to provide some comparability.

Other assumptions required for quantifying the impacts of this analysis concerned the structure and amount of the subsidy. Such subsidies could be structured to provide financial incentives directly linked to development of additional underground mine low sulfur coal production capacity or to provide financial incentives linked to actual underground low sulfur coal production. Largely for the sake of computational convenience, the analysis was quantified by linking the incentive to production rather than capacity development, since economic and environmental impacts are measurable more directly in reference to actual production. Also, financial incentives linked to capacity development would require some control systems ensuring that production capacity developed was actually employed in production.

Concerning the amount of subsidy assumed in the analysis, use of the projected 1985 low sulfur coal price premium over high sulfur coal prices appeared to provide a relatively firm basis for analysis. The assumption chosen was to equate the amount of the subsidy with the full amount of the mean eastern U.S. low sulfur coal price premium. Alternative assumptions which might have been chosen include setting the subsidy at some fraction of the mean price premium (e.g. one-half) or at some multiple of the price premium (e.g. twice the premium). Had the subsidy been assumed at one-half the amount of the price premium, perhaps twice the estimated 17 million tons of low sulfur utility steam coal production by small underground coal producers could have been assumed stimulated by the program. Had the subsidy been assumed at twice the amount of the mean price premium, perhaps one-half the estimated 17 million tons of low sulfur utility steam coal production by small underground coal production could have been assumed stimulated under the program alternative.

b. Economic Impact

As displayed in Table X-12, 17 million tons of low sulfur utility steam coal production are estimated to be stimulated under this program alternative, whether the subsidy is provided to the small underground coal producer directly or whether the subsidy is provided to the coal consumer purchasing low sulfur utility steam coal from small underground coal consumers.

As described above, varying assumptions concerning the amount of subsidy funds available under the program alternative or the amount of subsidy per ton of eligible coal produced will directly increase or decrease the amount of coal estimated to be produced under the program alternative and therefore the environmental impacts of the coal which would be mined, prepared and combusted under this program alternative.

However, regardless of what level of funds are assumed available under this program alternative or of what level of subsidy per ton is chosen, the analysis is sufficient to indicate that such a direct subsidy program alternative is substantially more expensive to the government than is a loan guarantee program with guarantee authority comparable to the total program subsidy funds. Under such a subsidy program, there would be a direct, non-reimbursible cash expenditure by the government for each ton of eligible coal produced under the program alternative. Under a loan guarantee program, the government

TABLE X-12

LOW SULFUR UTILITY STEAM COAL PRODUCTION
IMPACT OF DIRECT CASH SUBSIDIES

\$750,000,000	÷	6 years	=	\$125,000,000
\$125,000,000	÷	\$7.24	=	17 MM/tpy
17 MM/tpy	÷	31 MM/tpy	=	55% increase over No Action Alternative

Source: See Tables X-5 and X-8.

makes no expenditure of funds under a loan guarantee unless and until there is a default by the borrower on the guaranteed loan. These defaults are currently estimated to average approximately 4 percent of the total loan guarantees issued under the program, or $30 million of the total $750 million issued.

c. Environmental Impacts

Tables X-13 through X-15 display environmental impacts on air and water quality, and of solid waste generation and land use resulting from coal mining, preparation and combustion activities under this Direct Cash Subsidy program alternative. Because the impacts of the program alternative on stimulating production and consumption of eligible low sulfur utility steam coal are identical in this analysis, whether the subsidy be directed to the small underground coal producer or to the coal consumer who purchases eligible coal from small underground coal producers, the environmental impacts are also identical. Therefore, environmental residuals for this program alternative are only presented once, rather than repeated in duplicate tables.

(1) Air Impacts

No significant air pollutant emissions are anticipated from coal mining and preparation activities under these alternatives, but potentially significant emissions are anticipated from coal combustion activities. Air emissions which may be significant include particulates (20,057 tpy), sulfur dioxide (240,779 tpy) and nitrogen dioxide (152,250 to 463,169 tpy). See Table X-13.

(2) Water Impacts

Water pollutants generated under these alternatives include net acidity (0 to 4,227[1/] tpy from mining and 0 to 4,169 from coal preparation) and suspended solids (27 tpy from mining, 11,162 from

1/ Higher values represent worst case, uncontrolled conditions.

TABLE X-13

AIR POLLUTANT IMPACTS OF DIRECT CASH SUBSIDY ALTERNATIVE
(Tons/year)

	Particulates	NOx	SOx
Underground Mining 1/	0	0	0
Coal Preparation 1/	0	0	0
Coal Combustion	20,057	152,250 463,169	240,779

1/ Assumes controlled conditions

Source: See Tables V-3 and V-12.

TABLE X-14

WATER POLLUTANT IMPACTS OF DIRECT CASH SUBSIDY ALTERNATIVE
(Tons/year)

	Acidity	Suspended Solids
Underground Mining	0-4227	27
Coal Preparation	0-4169	11,162
Coal Combustion	NA	61,359

Source: See Tables V-5 and V-20.

TABLE X-15

SOLID WASTE AND LAND IMPACTS OF THE
DIRECT CASH SUBSIDY ALTERNATIVE

	Solid Waste (Tons)	Subsidence (Acres)
Underground Mining	1,019	4,080
Coal Preparation	1,680,980	0
Coal Combustion	1,687,169	0

Source: See Tables V-6, V-7, V-21, and V-22.

coal preparation and 61,359 from coal combustion). Federal and state regulatory activities concerning water point source discharges should minimize these pollutants, but such impacts may be significant at particular coal mining and preparation sites. See Table X-14.

(3) Solid Waste and Land Use Impacts

Solid waste and land use impacts of coal mining and preparation activities under these alternatives result principally from disposal requirements for spoil and refuse from mining and preparation, for sludge generated by water treatment, and from subsidence (4,080 acres/ year). An estimated 1,019 tpy of solid waste result from mining activities and 1,680,980 tpy from coal preparation activities. For coal combustion activities, solid waste (1,687,169 tpy) impacts result principally from disposal requirements for ash remaining after combustion. See Table X-15.

3. Income Tax Incentives

a. Background

Another set of program alternatives to the Coal Loan Guarantee Program is the substitution of income tax incentives for loan guarantees. This financial incentive program alternative could be directed either toward small underground coal producers directly or toward coal consumers purchasing coal.

By restricting the financial incentive to coal producers who produce or purchase low sulfur utility steam coal from underground mines, or to coal consumers who purchase low sulfur utility steam coal produced by small underground coal producers, these program alternatives would directly and exclusively enable small underground coal producers to participate in the incremental production of eligible coal stimulated by these program alternatives. To reflect this additional market penetration, the full amount of eligible coal production stimulated under this alternative has been added to the estimated small underground coal producer eligible coal production.

To quantify the economic and environmental impacts of these alternatives, the analysis begins with the assumption that $750 million in tax incentives are available from 1979 through 1985, for an average of $125 million per year. The $750 million assumed for this alternative corresponds to the $750 million guarantee ceiling authorized for the Coal Loan Guarantee Program and was chosen to provide some comparability.

Other assumptions required for quantifying the impacts of this analysis concerned the structure and amount of the income tax incentive. Such incentives could be structured to provide financial incentives directly linked to development of additional underground mine low sulfur coal production capacity (as in the case of an investment tax credit) or to provide income tax incentives linked to actual underground low sulfur coal production (as in the case of a depletion allowance). Largely for the sake of computational convenience, the analysis was quantified by linking the incentive to production, rather than capacity development, since economic and environmental impacts are measurable more directly in reference to actual production. To simplify the computations, the income tax incentives are treated as tax credits per ton of eligible coal production, rather than as tax deductions; as a general rule of thumb for corporations and individuals in the 50% tax bracket, $2 of tax deductions may be assumed to be equivalent to $1 in tax credit. The $750 million in tax credits assumed available under this program alternative would therefore be approximately equivalent to $1.5 billion in tax deductions.

Concerning the amount of income tax incentive assumed in the analysis, use of the projected 1985 low sulfur coal price premium over high sulfur coal prices appeared to provide a relatively firm basis for analysis, as was the case in the Direct Cash Subsidy alternatives discussed above. The assumption chosen was to equate the amount of the income tax incentive with the full amount of the mean eastern U.S. low sulfur coal price premium. Alternative assumptions which might have been chosen include setting the income tax incentive at some fraction of the mean price premium (e.g., one-half) or at some multiple of the price premium (e.g., twice the premium). Had the income tax incentive been assumed at one-half the amount of the price premium, perhaps twice the estimated 17 million tons of low sulfur utility steam coal production by small underground coal producers could have been assumed stimulated by the program. Had the income tax incentive been assumed at twice the amount of the mean price premium, perhaps one-half the estimated 17 million tons of low sulfur utility steam coal production by small underground coal producers could have been assumed stimulated under the program alternative.

To illustrate the income tax incentive used in the analysis as an investment tax credit, the $7.24 value assumed in the analysis would be equivalent to a special purpose investment tax credit of approximately 25 percent of total eligible project capital costs. This estimate is based on the assumption that $30 of eligible project capital costs are incurred for each ton of annual coal production capacity. This special purpose investment tax credit compares with a 10 percent investment tax credit available for certain types of capital investment and with 30 and 20 percent investment tax credits authorized by H.R. 8444 for residential solar and wind energy expenditures. Similarly, illustrating the income tax incentive as a special purpose percentage depletion allowance, the incentive would be equivalent to approximately 50 percent of the sales price of eligible coal after certain adjustments at

$29 per ton. If the income tax incentive took the form of a depletion allowance, adjustments would be required to adapt certain constraints imposed on existing depletion allowance computation procedures to the needs of the program, such as the relationship between the amount of depletion allowance vs. net pre-tax income, and between the amount of depletion allowance vs. total sales revenue.

It should be acknowledged immediately that an income tax incentive alternative program will not directly respond to an important constraint inhibiting low sulfur coal production by small underground coal producers, viz. the difficulty of obtaining external financing for expanded production capacity. To the extent that the tax incentive is linked with coal production, the incentive will not directly increase capital availability, although the incentive may indirectly increase availability through participation by tax shelter investors. On the other hand, to the extent the tax incentive is linked to capital investment rather than coal production, some assurances would be required that the additional coal production capacity would be employed in increased coal production for the program alternative to achieve its goals.

b. Economic Impact

As displayed in Table X-16, 17 million tons of low sulfur utility steam coal production is estimated to be stimulated under this program alternative, whether the income tax incentive is provided to the small underground coal producer directly or whether the income tax incentive is provided to the coal consumer purchasing low sulfur utility steam coal from small underground coal producers.

As described above, varying assumptions concerning the amount of income tax incentives available under the program alternative or the amount of income tax incentive per ton of eligible coal produced

TABLE X-16

LOW SULFUR UTILITY STEAM COAL PRODUCTION
IMPACT OF INCOME TAX INCENTIVES

\$750,000,000	÷ 6 years	= \$125,000,000
\$125,000,000	÷ \$7.24	= 17 MM/tpy
17 MM/tpy	÷ 31 MM/tpy	= 55% increase over No Action Alternative

Source: See Tables X-5 and X-8.

will directly increase or decrease the amount of eligible coal estimated to be produced under the program alternative and therefore the environmental impacts of the coal which would be mined, prepared and combusted under this program alternative.

However, regardless of what level of income tax incentives are assumed available under this program alternative or of what level of income tax incentive per ton is chosen, the analysis is sufficient to indicate that such an income tax incentive program is substantially more expensive to the government than is a loan guarantee program with guarantee authority comparable to the total income tax incentives. Under such an income tax incentive program, there would be a direct, nonreimbursible loss of tax revenue to the government for each ton of eligible coal produced under the program alternative. Under a loan guarantee program, the government makes no expenditure and loses no tax revenues under a loan guarantee, unless and until an expenditure is required following a default by the borrower on the guaranteed loan. These defaults are currently estimated to average approximately four percent of the total loan guarantees issued under the program, or $30 million of the total $750 million issued.

c. Environmental Impacts

Tables X-17 through X-19 display environmental impacts on air and water quality, and of solid waste generation and land use resulting from coal mining, preparation and combustion activities under this Income Tax Incentives program alternative. It will be noted that these impacts are identical to the impacts estimated for the preceding Direct Cash Subsidy alternatives, since the total program resources of $750 million were assumed identical for both sets of alternatives and since the amount of the income tax incentive per ton of eligible coal production was assumed to equal the direct cash subsidy per ton which was assumed in the preceding program alternatives. As was also the case in the preceding alternatives, there is no difference in the production of eligible coal and therefore in the environmental impacts

TABLE X-17

AIR POLLUTION IMPACTS OF THE
INCOME TAX INCENTIVES ALTERNATIVE

	Particulates	NOx	SOx
Underground Mining 1/	0	0	0
Coal Preparation 1/	0	0	0
Coal Combustion	20,057	152,250 463,169	240,779

1/ Assumes controlled conditions

Source: See Tables V-3 and V-12.

TABLE X-18

WATER POLLUTANT IMPACTS OF THE
INCOME TAX INCENTIVES ALTERNATIVE

	Acidity	Suspended Solids
Underground Mining	0-4227 1/	27
Coal Preparation	0-4169 1/	11,162
Coal Cumbustion	NA	61,359

1/ Higher values represent worst case, uncontrolled conditions.

Source: See Tables V-5 and V-20.

TABLE X-19

SOLID WASTE AND LAND IMPACTS OF THE INCOME TAX INCENTIVES ALTERNATIVE

	Solid Waste (Tons/Year)	Subsidence (Acres)
Underground Mining	1,019	4,080
Coal Preparation	1,680,980	0
Coal Combustion	1,687,169	0

Source: See Tables V-6, V-7, V-21, and V-22.

of producing, preparing, and combusting the coal stimulated under this program alternative, whether the income tax incentives are provided directly to the small underground coal producer or to the purchaser of eligible coal from small underground coal producers. Accordingly, the quantified environmental impacts are presented only once for both versions of the Income Tax Incentive program alternatives.

(1) Air Impacts

No significant air pollutant emissions are anticipated from coal mining and preparation activities under these alternatives, but potentially significant emissions are anticipated from coal combustion activities. Air emissions which may be significant include particulates (20,057 tpy), sulfur dioxide (240,779 tpy) and nitrogen dioxide (152,250 to 463,169 tpy). See Table X-17.

(2) Water Impacts

Water pollutants generated under these alternatives include net acidity (0 to 4,227 tpy from mining and 0 to 4,169 from coal preparation) and suspended solids (27 tpy from mining, 11,162 from coal preparation and 61,359 from coal combustion). Federal and state regulatory activities concerning water point source discharges should minimize these pollutants, but such impacts may be significant at particular coal mining and preparation sites. See Table X-18.

(3) Solid Waste and Land Use Impacts

Solid waste and land use impacts of coal mining and preparation activities under these alternatives result principally from disposal requirements for spoil and refuse from mining and preparation, for sludge generated by water treatment and from subsidence (4,080 acres/

year). An estimated 1,019 tpy of solid waste result from mining activities and 1,680,980 tpy from coal preparation activities. For coal combustion activities, solid waste (1,687,169 tpy) impacts result principally from disposal requirements for ash remaining after combustion. See Table X-19.

4. Increased Enforcement Strategies

a. Background

Another set of program alternatives to the Coal Loan Guarantee Program is to substitute regulatory actions designed to increase environmental compliance by coal users for financial incentives to coal producers. These regulatory actions can be assumed to be stringent unspecified regulatory actions which result in 100% compliance with the Clean Air Act by utilities in 1985, or can be assumed to be a set of financial penalties on noncomplying coal fired utilities which are set to be equal to the economic value of noncompliance.

These program alternatives are only partially responsive to the threefold objectives of the Coal Loan Guarantee Program, i.e., low sulfur coal production would increase as a result of increased demand for low sulfur utility steam coal, but these alternatives provide no incentive for the production of this coal underground or for the production of this coal by small coal producers. Therefore, this analysis assumes that small underground coal producers obtain in 1985 only their 1976 percentage share of the incremental low sulfur coal production.

To quantify the economic and environmental impacts of these Increased Enforcement program alternatives, the analysis begins with the assumption that the program alternative achieves 100% compliance by existing cost fired utility generating stations in 1985. It is assumed that only coal fired facilities located in Air Quality Control Regions (AQCR's) with sulfur emission standards in the range of 1.2

to 1.7 pounds of sulfur dioxide per million Btu's rely on low sulfur coal as their principal compliance measure, since facilities in AQCR's with higher sulfur emission standards can purchase higher sulfur coal at lower cost than low sulfur coal, and since facilities in AQCR's with lower sulfur emission standards will in most cases require flue gas desulfurization devices to achieve compliance. Therefore, of a total 162 million tons of nonconformance coal delivered to utilities in the 12 months ended October 1976, only 49.6 million tons is considered in this analysis as potential incremental demand for low sulfur utility steam coal under an increased enforcement strategy.

Other assumptions required for quantifying the economic and environmental impacts in this analysis concerned the proportion of this incremental demand for low sulfur coal which would be produced by underground mining methods and the proportion of the underground production which would be produced by small coal producers. Seventy-one percent of the incremental low-sulfur utility steam coal was assumed to be produced underground, in accord with the PIES projected underground production of low sulfur coal. Similarly, 23.4 percent of the incremental coal produced underground was assumed to be produced by small coal producers, in accord with the 1976 share of Appalachian underground coal production achieved by small coal producers.

Concerning the amount of the noncompliance penalties to be assessed against noncomplying coal fired utilities under the noncompliance penalty version of the Increased Enforcement program alternative, section 118 of the Clean Air Act Amendments of 1977 stipulates that a noncompliance penalty equal to the economic value of noncompliance can be imposed by the Environmental Protection Agency or by the individual State government. For purposes of this analysis, therefore, the "economic value" of noncompliance was assumed to be the price premium of low sulfur coal over the cost of high sulfur coal, since utilities whose sulfur emission standards were in the range of 1.2 to 1.7 pound of sulfur dioxide per million Btu's would be able to achieve compliance without flue gas desulfurization devices. It should be noted that estimating these 1985 noncompliance penalties by multiplying 1976 nonconformance coal deliveries by the projected 1985 low sulfur coal price premium is likely to overstate the amount of the penalties assessed, because utilities are likely to have made some progress in reducing the amount of nonconformance coal consumption and because there are many exemptions and penalty reductions provided in the Clean air Act Amendments, such as reducing the amount of the penalty assessment by the amount expended to achieve compliance, exempting a noncomplying emission source to the extent progress toward compliance is in accord with a schedule of compliance, etc.

To the extent that the noncompliance penalty strategy is successful in achieving 100 percent compliance by 1985, the cost to the public utilities of noncompliance penalties will be zero.

b. Economic Impact

As displayed in Table X-20, eastern coal fired utilities are estimated to purchase an additional 49.6 million tons of low sulfur utility steam coal in 1985 under this program alternative, of which 71.4 percent is estimated to be produced underground. Only eight million tons of this incremental low sulfur coal production is estimated to be produced by small underground coal producers, assuming small producers achieve their 1976 share of total underground Appalachian coal production. It is assumed that 100 percent compliance with the Clean Air Act by eastern utilities will be achieved by 1985 under these program alternatives, whether the increased enforcement is achieved through more stringent regulatory actions or whether financial penalties are imposed on noncomplying utilities.

As displayed in Table X-21, the total annual financial penalties imposed on noncomplying utilities would total $359 million assuming

TABLE X-20

COAL PRODUCTION IMPACT ON SMALL UNDERGROUND COAL PRODUCERS
OF INCREASED ENFORCEMENT OF SULFUR EMISSION LIMITS ON COAL-FIRED UTILITIES
(000 tpy)

Amount Low Sulfur Utility Steam Coal Required for Blending	1976 Market share of Small Under ground Appalachia Coal Producers	1985 % Appalachian Low Sulfur Coal Produced Underground	1985 Appalachian Low Sulfur Utility Steam Coal Produced by Small Underground Coal Producers
49,590	23.4%	71.4%	8,282

8,285 ÷ 31 MM/tpy = 27% of No Action Alternative

Source: See Tables IV-8, X-3, and X-7.

TABLE X-21

ECONOMIC IMPACT OF NONCOMPLIANCE FINANCIAL PENALTIES
ON EXISTING NONCONFORMANCE COAL-FIRED UTILITY GENERATING STATIONS

Amount Low Sulfur Utility Steam Coal Required for Blending (000 Tons)	Mean Low Sulfur Coal Price Premium	Total 1985 Annual Financial Penalties (000's)
49,590	$7.24	$359,032

Source: Tables IV-8 and X-5.

no change in sulfur emissions by 1985. This estimated total of non-compliance penalties imposed on utilities is, of course, a maximum possible estimate, and necessarily assumes that no incremental low sulfur utility steam coal production or consumption results from the program alternative. Alternatively, the total noncompliance penalties can be estimated at zero in 1985, with 49.6 million tons incremental low sulfur utility steam coal production by 1985.

c. Environmental Impact

(1) Air Impacts

No significant air pollutant emissions are anticipated from coal mining and preparation activities under these alternatives, but potentially significant emissions are anticipated from coal combustion activities. Air emissions which may be significant include particulates (9,439 tpy), sulfur dioxide (113,308 tpy) and nitrogen dioxide (71,647 to 217,962 tpy). See Table X-22.

(2) Water Impacts

Water pollutants generated under these alternatives include net acidity (0 to 1,989 tpy from mining and 0 to 1,962 from coal preparation) and suspended solids (13 tpy from mining, 5,252 from coal preparation and 28,875 from coal combustion). Federal and state regulatory activities concerning water point source discharges should minimize these pollutants, but such impacts may be significant at particular coal mining and preparation sites. See Table X-23.

(3) Solid Waste and Land Use Impacts

Solid waste and land use impacts of coal mining and preparation activities under these alternatives result principally from disposal

TABLE X-22

AIR POLLUTANT IMPACTS OF INCREASED ENFORCEMENT ALTERNATIVE
(Tons/year)

	Particulates	NOx	SOx
Underground Mining 1/	0	0	0
Coal Preparation 1/	0	0	0
Coal Combustion 1/	9,439	71,647-217,962	113,308

1/ Assumes controlled conditions.

Source: See Tables V-3 and V-12.

TABLE X-23

WATER POLLUTANT IMPACTS OF INCREASED ENFORCEMENT ALTERNATIVE
(Tons/year)

	Acidity	Suspended Solids
Underground Mining	0-1989 1/	13
Coal Preparation	0-1962 1/	5,252
Coal Combustion	NA	28,875

1/ Higher values would occur under worst case, uncontrolled conditions.

Source: See Tables V-5 and V-20.

requirements for spoil and refuse from mining and preparation, for sludge generated by water treatment and from subsidence (1,920 acres/year). An estimated 479 tpy of solid waste result from mining activities and 791,050 tpy from coal preparation activities. For coal combustion activities, solid waste (793,962 tpy) impacts result principally from disposal requirements for ash remaining after combustion. See Table X-24.

TABLE X-24

SOLID WASTE AND LAND IMPACTS OF THE
INCREASED ENFORCEMENT ALTERNATIVE

	Solid Waste (Tons/Year)	Subsidence (Acres)
Underground Mining	479	1,920
Coal Preparation	791,050	0
Coal Combustion	793,962	0

Source: See Tables V-6, V-7, V-21, and V-22.

CHAPTER XI

COMMENTS AND RESPONSES

A. Scope of Public Review

In accordance with U.S. Council on Environmental Quality and DOE rules and guidelines, copies of the Draft EIS (DEIS) were circulated among appropriate Federal and State government agencies and made available to the public on request. A list of parties receiving copies of the DEIS for review is shown in Appendix B.

B. Summary of Comments and Responses

This section summarizes the written comments on the Draft EIS and DOE's response to them in preparing the Final EIS. Individual comments have been paraphrased and grouped into three general areas of concern:

- Scope and Adequacy of the DEIS;
- Description of the Action (including General Comments on the Program and DOE procedures); and
- Impacts of the Proposed Action.

All written comments received are reproduced in their entirety in Appendix B. Comments were received from:

- U.S. Department of the Interior;
- U.S. Environmental Protection Agency;
- State of West Virginia;

- State of Utah; and
- Burlington Northern Railroad.

The following summary provides a statement of each comment, identifies the source(s) of the comment, and notes DOE's response and the location of any changes made in the Final EIS.

1. Comments Concerning the Scope and/or Adequacy of the Draft EIS

Comments: The DEIS is inadequate in limiting its consideration of potential program impacts to the Appalachian area and to coal used for steam generation. A number of proposed underground coal developments in Utah, Colorado, and southern Wyoming may qualify for loans under the low-sulfur, small-operator criteria. Also, metallurgical coal not used for steam generation might also fall within the stated criteria. The EIS should be modified or supplemented to recognize and evaluate potential program impacts in these areas.

Commentors: U.S. Department of the Interior, State of Utah

Response: DOE's analysis indicates that the number of potential program participants outside the Appalachian region is not likely to be large enough to produce significant cumulative impacts on a program-wide level. Consequently, such impacts are not addressed in this EIS, as stated in the preface. No supplemental programmatic analysis of non-Appalachian impacts will be performed at the present time, although DOE may perform such an evaluation if significant western coal participation and potential impacts develop once program applications are accepted. DOE will, however, perform site-specific environmental reviews prior to executing a loan guarantee in the West.

Comments: The DEIS was found generally adequate and satisfies official review requirements.

Commentors: U.S. Environmental Protection Agency, State of West Virginia

Response: No change made in Final EIS as a result of this comment.

2. Comments Concerning the Description of the Action in the DEIS and General Comments on the Coal Loan Guarantee Program

Comments: The EIS is inconsistent in stating the goals of the Coal Loan Guarantee Program. Different sections identify them as providing financial aid to small operators, stimulating low-sulfur coal production and coal cleaning, and a combination of both plus additional goals. Program objectives should be clearly stated early in the EIS.

Commentor: U.S. Department of the Interior

Response: The discussion of goals has been revised and clarified in the Final EIS. Program goals are stated clearly in Chapter I and discussed further as appropriate in later sections of the EIS.

Comments: DOE's planned use of site-specific environmental analyses of specific loan candidate projects is appropriate. The scope of this analysis should characterize any potential leachate from mine waste disposal sites, treatment processes, and effluent impacts on ground and surface waters. Preliminary designation of waste disposal sites should be coordinated with appropriate State and Federal agencies before a draft environmental study is prepared.

Commentor: U.S. Environmental Protection Agency

Response: No change in Final EIS. Procedures for future site-specific environmental analyses under the Coal Loan Guarantee Program will comply with all existing regulations and review procedures.

Comments: In developing regulations and requirements for the Coal Loan Guarantee Program, DOE should coordinate on a programmatic level with appropriate offices within the Department of the Interior to ensure adequate protection of historic, archeological, and cultural resources and endangered and threatened species. Compliance with all regulations for review and protection of these resources should be made a condition of eligibility for loans under the program.

Commentor: U.S. Department of the Interior

Response: The Final EIS has been revised to state that DOE will coordinate with DOI to assure that unique esthetic and biological resources are preserved and will coordinate with other agencies whenever appropriate in developing and administering the Coal Loan Guarantee Program. However, detailed plans for future program regulations and procedures are not required for the purposes of this EIS, and will not be outlined further.

3. Comments Concerning Potential Environmental Impacts of the Proposed Action

Comments: The discussion of potential subsidence from underground mining should be expanded. The expanded discussion should include a review of currently used control methods as they affect potential impacts.

Commentor: U.S. Environmental Protection Agency

Response: Subsidence from underground mining activities is currently being controlled in a number of ways, including leaving larger pillars, and controlled pillar removal causing a relatively uniform roof collapse. Some experimental work is being done on pumping in backfill material. The Final EIS has been revised to discuss these methods of subsidence control.

Comments: The potential impact of fugitive dust from coal trains is greatly overstated. Extensive experience and studies have shown this impact to be negligible.

Commentor: Burlington Northern Railroad

Response: The range of coal loss by wind during transportation from mine to user was estimated to be between 0.2 and 2 percent. These losses are based upon worst case assumptions that the coal is dry and untreated with chemical suppressants. Coal losses associated with transportation can be significantly decreased by either wetting or adding chemicals to the coal.

Comments: The discussion of potential impacts on endangered or threatened species in both the DEIS text and the Proposed Borrower's Environmental Questionnaire is inadequate to meet DOE's statutory obligations and ensure required protection of such species and their habitats; threatened as well as endangered species should be included in any discussion, evaluation, or review. Specific listings should be obtained from the U.S. Fish and Wildlife Service.

Commentor: U.S. Department of the Interior

Response: Analyses of impacts on specific endangered or threatened species is not realistic at the programmatic EIS level; instead, such impacts will be addressed in future, site-specific analyses.

The Proposed Borrowers Environmental Impact Questionnaire has been modified to require the identification of threatened species.

Comments: The DEIS's treatment of potential socioeconomic impacts of the Coal Loan Guarantee Program is weak; however, this reflects current state-of-the art for such analysis rather than inadequacy of the DEIS.

Commentor: State of West Virginia

Response: No change was made in the Final EIS as a result of this comment.

Comments: The EIS should note the chronological range of historic, archeological, or cultural sites in the areas potentially affected by the proposed program and state that loss or damage of these resources could occur unless adequate review and protection measures are taken.

Commentor: U.S. Department of the Interior

Response: Characterization of such sites on the scale covered by this programmatic EIS would be unrealistic and would not contribute significantly to this analysis. Impacts on these resources will be more usefully addressed in future, site-specific environmental analyses under the Coal Loan Guarantee Program. The EIS recognizes the required review and mitigation procedures protecting historic/cultural/archeological sites in the Proposed Borrower's Environmental Impact Questionnaire.

Comments: The Coal Loan Guarantee Program as a whole will affect the environment favorably by providing funds for pollution control measures.

Commentor: U.S. Department of the Interior

Response: No change to the Final EIS has been made.

APPENDIX-A

PROPOSED BORROWER'S ENVIRONMENTAL IMPACT QUESTIONNAIRE

NAME & ADDRESS OF PROPOSED BORROWER (FIRM) DATE SUBMITTED

DOE CASE NO.

In order to evaluate the specific impact your proposed project will have on the environment, please complete the following items:

Is a discharge permit required under the Clean Water Act, as amended? _____ Yes _____ No

If yes, has an application been made for the permit? _____ Yes _____ No

If so, to whom has the application been made? ____________________

If so, what is the status of the application? ___ Pending ___ Disapproved

___ Approved

If the above application for permit did not cover all facilities in your project, please identify those not covered and complete the balance of the form as it pertains to those you list.

I. GENERAL (Briefly Describe)

A. Location of mining project. Provide a USGS map to show project location and areas which might be affected by the mining project.

B. Site area. A map of the site area should be included clearly showing the following: (a) property lines or lease boundary; (b) location and orientation of the major structures (principal structures should be identified as to function); (c) location of any industrial, recreational, or residential structures within the site area; (d) a scale which will permit measurement of distances with reasonable accuracy; (e) true north; and (f) highways, railways, and waterways which traverse or are proximate to the site.

C. Character of the surrounding area (include terrain, population density, etc.)

D. What is the total length of any service and/or coal haul roads and/or rail spurs in existence or expected to be developed in support of your coal mining operation (in miles or yards)?

Existing ____________________

To be Developed ____________________

E. What rate of coal production do you expect from the proposed project over the next 3 years (in tons/years)?

F. Type of project (nature of activity).

If your project must conform to approved standards established by the Federal or your State or local environmental protection agencies, please identify for each of parts II (Air), III (Water), IV (Solid), and V (Other), the appropriate regulating agencies. If you are not required to conform to such standards, please complete all questions to the best of your knowledge in each part for which standards are not set. You may wish to consult with appropriate State or local agencies in preparing your answers.

II. AIR POLLUTION (Include name and address of agencies with cognizance over your project).

Cite this project's:

A. Activities which are likely to produce air pollution, such as incinerators, exhaust systems, fossil fuel burning units, ventilation systems, crushing, storage, sorting facilities, etc.

B. Volatile solvents, types, and how used, as well as handling of discharge.

C. Kind of fuel used in combustion and heating: fossil, liquid, gaseous.

D. Control equipment to remove particulates and efficiency of such equipment.

E. Control equipment to remove gaseous pollutants and efficiency of such equipment.

F. Describe any chemicals used to control pollutants that might themselves cause another form of pollution.

G. List other major contributors, current or planned, associated with the project and which may affect the quality and quantity of emissions to the air.

III. WATER POLLUTION (Include name and address of agencies with cognizance over your project for both surface and sub-surface).

A. Describe activities that are likely to produce water pollution.

B. Describe water pollution control codes and/or regulations applicable to the project.

C. For those waters which would serve as water supplies, or as receiving bodies for routine or accidental release of fluids, describe the flow rate, temperature, pH, total dissolved solids, total suspended solids, appropriate heavy metals, volumes, ground water, elevations, and drainage patterns of the site.

D. Describe the method and sensor equipment used to determine the quantity and/or type of water pollution.

E. Will you discharge mine drainage water into a stream or river, or will the mine drainage flow in the direction of a stream or river?

____ Yes ____ No

F. If the answer is yes to the above question, give the names of all streams and rivers which will receive the mine drainage.

____

____

G. Approximately how many gallons of mine drainage water will flow or be pumped out of the mine annually?

____

H. Does your mine site overlay, or will your mining activity disturb, underground water supplies? (Contact Geological Survey)

____ Yes ____ No

I. Are aquifiers or other sources of potable water in the excavation area or close enough to be affected by it?

____ Yes ____ No

J. Pretreatment facilities; including pH neutralizers, oil separators, screens, presettling basins, etc.:

1. Does the Federal, State, or local government require your mining operation to have pretreatment facilities?

   ____ Yes ____ No

2. If yes, what type of pretreatment facilities do you plan?

   ____

   ____

K. Sanitary sewage discharge (check one and describe):

____ Municipal Treatment ____ Septic Tank

____ Local Treatment Plant ____ Other

____ Local Body of Water

____

____

L. Industrial waste discharge (check one and describe):

____ Municipal Treatment Plant

____ Industrial Treatment Plant

____ Local Body of Water ____ Other

____

____

M. Are sanitary and industrial waste waster drainage flows combined?

____ Yes ____ No

Is storm flow combined with one or with both?

____ Yes ____ No

If one, which one? ______________________________

N. Will the project create a substantial increase in the volume of sewage treated by a given facility?

____ Yes ____ No

IV. SOLID WASTE DISPOSAL (Include name and address of agencies with cognizance over your project)

A. Does your project produce amounts of solid waste which cannot be readily disposed of? For example, combustibles such as coal refuse, paper, bags, boxes; non-combustibles such as glass, sand, tars or oils, plastics, salvageable materials, sludges or filter residues, cinders or flyash, or others.

____ Yes ____ No

B. What laws, ordinances, or practices govern solid waste management?

____

____

C. How are solid wastes disposed of?

____

____

____

D. Are the equipment and techniques employed adequate for the collection, handling, and disposal of soild wastes?

____ Yes ____ No

Do they cause noise or dust?

____ Yes ____ No

E. Will they accommodate the increased load caused by the project?

____ Yes ____ No

V. OTHER

A. Have any questions or objections been raised by any governmental agency, private organization, or individual which might indicate that this mining project is, or will become, controversial?

____ Yes ____ No

B. Are there any historic sites or archaeological sites within 200 yards of your mine site? (Contact State Historic Preservation Officer and/or refer to sites listed on, or eligible for listing on, the National Register of Historic Places).

____ Yes ____ No

C. Are there any habitats of endangered species on the mine site or are there any endangered species known to inhabit the area? (Contact the National Wildlife Federation for a list of endangered and threatened species).

____ Yes ____ No

D. Is your mine site in the vicinity of (within 1/3 mile), or will point or non-point water pollution discharges from the project feed into, or possibly inadvertently reach a State or Federally designated wild and scenic river (or one authorized for study)?

____ Yes ____ No

Is it a: wild, scenic, or recreational category? (circle one)

E. Is your mining activity to take place in or adjacent to a local, State, or Federal recreation area? (Contact Bureau of Outdoor Recreation (region) and State recreation agencies).

____ Yes ____ No

F. Is your mining activity to take place in or adjacent to a flood plain or wetlands (within 1/3 mile)? (Contact Fish and Wildlife Service; National Wildlife Federation).

____ Yes ____ No

G. Is your mine site or disposed area on prime agricultural lands? (Contact Department of Agriculture and/or the State Extension Agent).

____ Yes ____ No

H. How many people permanently reside within 1/3 mile of your mine site?

____

I. Has any Federal or State agency conducted an environmental review of this project?

____ Yes ____ No

If yes, please include a copy of such review.

J. Describe noise levels associated with the project, both on and off site.

____

____

____

____

K. Will mining be conducted in a saturated zone?

____ Yes ____ No

L. Are toxic materials found in coal refuse associated with the project?

____ Yes ____ No

M. Will any mining occur on a slope of more than 25%, or in alluvial valley floors?

____ Yes ____ No

If yes, please describe: ______________________

____

____

____

N. Will the mining operation utilize best practice procedures as set forth in the EPA draft document entitled, "Best Practices for New Source Surface and Underground Coal Mines"?

____ Yes ____ No

APPENDIX B

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Washington, D.C. 20461

Dear Mr. Haney:

We have reviewed your draft environmental statement for the Coal Loan Guarantee Program. We did not receive this statement until April 19th; therefore, we were unable to comment by the requested deadline of May 6, 1978.

There are inconsistencies throughout the statement as to the purposes or goals of the program. This should be clarified as these program goals are critical to evaluation of the program and alternatives. The Executive Summary states that the program is "for the purpose of helping small coal producers finance the development of new underground coal mines, the expansion of existing underground coal mines, and the reopening of closed underground coal mines" (p. I-1, par. 2). However, Chapter III states that, "The objective of the Coal Loan Guarantee Program is to increase the production of low sulfur coal from underground mines and to encourage coal cleaning to produce 'complying' low sulfur coal" (p. III-1, par. 1). It is not until Chapter IX that the three-fold objectives of the program are clearly summarized for the first time.

The assumption implicit throughout the statement that all of the production financed under this program will take place in Appalachia may well be in error. There are a number of underground coal developments proposed in Utah, Colorado, and southern Wyoming to supply various power plants and which might qualify under the low-sulfur, small operator criteria. Also, under the specified criteria, metallurgical coal would also appear to qualify even though it was not used for steam generation. This could expand the interest in this program on the part of small western coal producers.

The discussion as to the nature of cultural resources should include some indication of the chronological range of the historic and archeological values involved. It should be clearly recognized that, unless adequate review and mitigatory procedures are undertaken, significant damages to irreplaceable cultural resources would be expected.

We urge that the Department of Energy incorporate a programmatic approach for the protection and preservation of cultural resources in conjunction with the Coal Loan Guarantee Program. A meeting should be arranged with the Office of Archeology and Historic Preservation (Carol Shull, phone: 523-5483) and the Advisory Council on Historic Preservation (Peter Smith, phone: 254-3967) to develop such an approach. Until the programmatic approach is developed, we ask that there be a commitment on the part of the Department of Energy to require that loan recipients comply with all cultural resource preservation procedures in order that impact to these values may be avoided or minimized.

The discussion and provisions in regard to Endangered and Threatened species (in both the text and in the Proposed Borrower's Environmental Questionnaire) are inadequate to meet DOE's obligations under the Endangered Species Act of 1973 and to ensure required protection to these species and their habitat. Item V C of the Questionnaire should include Threatened as well as Endangered species and the U.S. Fish and Wildlife Service (FWS) should be contacted for current listings.

Section 7 of the Endangered Species Act of 1973 provides, in part, that all Federal agencies shall utilize their authorities in furtherance of the purposes of the Act. Implementation of the Coal Loan Guarantee Program offers an excellent opportunity to control coal development activities so as to avoid or minimize adverse effects on Endangered or Threatened species or their habitats. Therefore, we request that DOE initiate consultation with FWS relative to development of procedures under this program to ensure maximum protection is provided to Endangered and Threatened species in accordance with the Act.

We believe that this program will support and assist Interior's efforts under the Surface Mining Conservation and Reclamation Act of 1977. The loans will provide these small coal producers with a more stable financial base which should enable them to fund the more sophisticated pollution, production, and abatement requirements of the Act.

We appreciate the opportunity to review this statement.

Sincerely,

SECRETARY

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
WASHINGTON, D.C. 20460

OFFICE OF THE
ADMINISTRATOR

12 MAY 1978

Mr. James L. Liverman
Acting Assistant Secretary
for Environment
Department of Energy
1200 Pennsylvania Avenue, NW
Washington, D.C. 20461

Dear Mr. Liverman:

In accordance with our responsibilities under Section 309 of the Clean Air Act, as amended, the Environmental Protection Agency has completed its review of the Department of Energy's draft environmental impact statement (EIS) prepared for the Coal Loan Guarantee Program. As a result of our review, we have the following comments to offer.

EPA concurs with DOE's proposal to utilize site-specific EIS's in analyzing individual loan guarantee actions which have the potential for significant environmental impact. Site-specific analyses should detail the nature of leachate from major mine waste disposal sites as well as the treatment processes and impact of treated effluent on surface and groundwater supplies. We also suggest that any preliminary designation of disposal sites be coordinated with the appropriate State and Federal agencies prior to circulation of the environmental assessment or EIS prepared for the site.

Our only other concern at this time involves the question of subsidence resulting from underground mining activities. We suggest that DOE expand its discussion of this issue in the final EIS. The discussion should include a review of state-of-the-art methods currently being utilized to control subsidence in underground mining activities.

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We appreciate the opportunity to review and comment on this draft EIS. In light of our review and in accordance with EPA procedures, we have categorized the Coal Loan Guarantee Program LO (Lack of Objection) and have rated the draft EIS 1 (Sufficient Information). Please provide EPA with copies of the final EIS when it is available.

Sincerely yours,

Joseph M. McCabe
Acting Director
Office of Federal Activities (A-104)

BURLINGTON NORTHERN

NORMAN M. LORENTZSEN
President

176 East Fifth Street
St. Paul, Minnesota 55101

April 27, 1978

Public Hearing Management
Box RX Room 2312
2000 M Street NW
Washington, D C 20461

Draft Programmatic CLGP-EIS-DOE/EIS-0004-D

We have reviewed the draft EIS for the Coal Loan Guarantee Program and find a misrepresentation in the "Coal Transportation" section, page IV 88-90, that coal dust blowing off cars is a major problem with coal unit train operations. As a major coal-hauling railroad, we have not found this to be the case.

Over the past several years, we have transported more than one hundred million tons of coal over very long routes in the windy Great Plains area; yet on checking, I find no complaint whatever about coal dust blowing from our trains. This is because the coal we transport from Wyoming and Montana is fairly wet and in chunk form being crushed to a size that will pass through a 2-inch screen. Also, we use high-sided coal cars.

The reference on page IV 90, to a loss of .2% to 2% is absolutely unrealistic, based on our experience. Were the losses really that great, our right-of-way would be knee-deep in coal dust; however, none is visible even on our highest-volume coal routes. On a one-hundred-car coal train, a 2% loss would mean that the equivalent of two carloads would blow away; common sense alone would indicate this to be unreal.

A recent study by the Office of Technology Assessment entitled, "A Technology Assessment of Coal Slurry Pipelines" (January 1978), found that dust emissions in coal unit train operations were confined to an area immediately adjacent to the silo exit and entrance and that dust emissions from unit train operations are likely to have "a negligible impact on air quality." The OTA study also reported that the Western Weighing and Inspection Bureau which performs weighing services for western railroads, had not received any claims of coal lost in transit. Also cited were interviews with local officials in areas in Wyoming, Colorado and Illinois which have heavy coal train traffic. None of these reported any complaints of fugitive coal dust problems. Another study, done last year for the Lincoln/Lancaster County Railroad Transportation Safety District, sampled particulates on the right-of-way of a heavy coal route near Lincoln, Nebraska, and found the presence of coal dust to be so minimal as to be almost undetectable.

It may be that some coals, particularly metallurgical coals from other parts of the country, are ground and washed, producing coal fines which could be troublesome if not covered by some sort of sealer. To make the blanket assertion that blowing coal dust is a general problem with unit coal train operations, however, is incorrect. I trust that the final draft will correct this misrepresentation.

Sincerely,

Norman M. Lorentzsen

STATE OF UTAH
OFFICE OF THE GOVERNOR
SALT LAKE CITY

SCOTT M. MATHESON
GOVERNOR

May 5, 1978

Public Hearing Management
Box RX, Room 2312
2000 "M" Street, N.W.
Washington, D. C. 20461

Dear Sirs:

Re: Draft Programmatic CLGP EIS DOE/EIS-0004-D

I have reviewed the Draft Environmental Impact Statement on the Coal Loan Guarantee Program. Quite naturally I disagree with the assumptions that limit the impacts of the program to Northern and Central Appalachia. Information from the U.S. Geological Survey indicates plans for sixteen new mines in Utah, nine of which may be able to qualify for the program. The Utah Geological and Mineral Survey has found that nearly 90% of our underground reserves meet the low-sulfur requirement of the program. Presently, about half of our coal production is being shipped out of the state in all directions; the potential market for high BTU, low sulfur coal from Utah is vast. It is our hope and intention that Utah coal operators will be a major participant in this program.

I understand that the impacts on Western coal development will be discussed in a supplement currently being prepared. This supplement should be issued as a draft, not as part of the final EIS. The final EIS should reflect comments received concerning the draft supplement on Western coal development.

I am concerned that the initial draft EIS seems to emphasize non-Western coal development for non-Western markets. This may not have been the intent of the Department of Energy, but it fits a disturbing pattern of policy - reflected in actions and debate of the Congress on the Clean Air Act Amendments of 1977, and in actions and statements by officials of the White House domestic policy staff, the Environmental Protection Agency, and the Department of Interior - designed to blunt the growing utilization of Western U.S. coal by Midwestern and Eastern utilities.

The State of Utah will withhold detailed comments until the draft supplement EIS on impacts of Western coal development under this program is issued. I anticipate this based upon conversations between a member of my staff and the Director of the Coal Loan Guarantee Program. Without such a draft supplement EIS, the State of Utah will assert the position that the EIS is inadequate and fails to meet the legal requirements of the National Environmental Policy Act.

Sincerely,

[signature]

Governor

SMM:bb

DEPARTMENT OF ENERGY

REGION VIII - SALT LAKE CITY, UTAH
[illegible] FACSIMILE TRANSMISSION HEADER

James Hanly ADDRESSEE: Room 3513 Coal Loan Guarantee Program	Charles E. Denton ORIGINATOR: D.O.E Salt Lake City

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STATE OF WEST VIRGINIA
GOVERNOR'S OFFICE
OF
ECONOMIC AND COMMUNITY DEVELOPMENT
CHARLESTON 25305

JOHN D. ROCKEFELLER IV
GOVERNOR

DONALD D. MOYER
DIRECTOR

May 3, 1978
PNRS-C-E
DEIS

Public Hearing Management
Box RX, Room 2312
2000 M Street, NW
Washington, D. C. 20461

Gentlemen:

RE: Draft Programmatic CLGP EIS DOE/EIS - 0004-D

The Draft Environmental Impact Statement for the Coal Loan Guarantee Program (P.L. 94-163) has been reviewed by the West Virginia State Clearinghouse.

This will certify that the OEIS has met requirements of the United States Office of Management & Budget Circular No. A-95 for the State of West Virginia.

Enclosed is a copy of the comments of Mr. Tom Curtis, Coordinator of our Energy Impact Program, Governor's Office of Economic and Community Development, for your consideration.

If you have any questions, please contact Mr. Tim Oxley of my staff.

Sincerely,

Daniel S. Green

Daniel S. Green, Manager
Program Support Services

DSG:skm

.. RNOR'S OFFICE OF ECONOMIC AND COMMUNITY DEVELOPMENT
PROGRAM SUPPORT SERVICES
WEST VIRGINIA STATE CLEARINGHOUSE
ROOM B-548, BUILDING #6
CHARLESTON, WEST VIRGINIA 25305

DATE: 4/19/78

FILE NO: PNRS-C-E

Comments concerning this should be received by this no later than: 5/3/78

(DRAFT) ENVIRONMENTAL IMPACT STATEMENT
(DEIS)

TO: Tom Curtis, Project Coordinator
Energy Impact Program
Program Support Services
Governor's Office of Economic and Community Development

FROM: Daniel S. Green, Program Manager
Program Support Services
Governor's Office of Economic and Community Development

DEIS DESCRIPTION: Coal Loan Guarantee Program - U. S. Dept. of Energy

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.

The socio-economic impact analysis in this DEIS is weak, reflecting the poorly developed state-of-the-art for that particular kind of analysis.

However, this DEIS does reflect the impacts expected on coal production and utilization as a result of the proposed coal loan guarentee program.

The proposed program does not conflict with any state or regional programs of which I am aware.

State Clearinghouse approval is recommended.

(Please use reverse side if additional space is needed)

Reviewer's Signature Tom Curtis Date May 2, 1978

Title Coordinator, Energy Impact Program Telephone

☆ U. S. GOVERNMENT PRINTING OFFICE : 1978 261-325/613