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The Impact of Petroleum Industry Horizontal Divestiture on the Coal Market

Volume II

June 22, 1979

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Prepared for:
U.S. Department of Energy
Energy Information Administration
Assistant Administrator for Applied Analysis

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The Impact of Petroleum Industry Horizontal Divestiture on the Coal Market

Volume II

June 22, 1979

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APPENDIX 1

THE COAL SUPPLY CURVES

APPENDIX 1

COAL SUPPLY CURVES

METHODOLOGY

The coal supply curves generated by the National Coal Model show the relationship between levels of production for various mine types and the associated minimum acceptable selling price based on costs. The production level connected with each mine type in each region is based upon an allocation of the Bureau of Mines (BOM) demonstrated reserve base. The methodology assigns reserves to a series of mine type specifications such as overburden ratio, seam thickness, seam depth and mine size. The reserve figures are then translated into an estimate of the production level, given an assumed mine life and an assumed recovery factor.

The schematic (Figure 1) illustrates the basic methodology used in generating the coal supply curves. The steps involved in the process are described in detail below.

1. The BOM Demonstrated Reserve Base. The BOM demonstrated reserve base estimates coal tonnage and quality characteristics by seam and county.^{1/} For bituminous coals, the reserve base contains all measured and indicated reserves less than 1,000 feet in depth and at least 28 inches thick.^{2/} Strippable reserves

^{1/} BOM is relatively confident regarding the tonnage and quality characteristics of this coal included in the data base. These figures represent coal which could be mined with existing technology.

^{2/} Measured and indicated resources are comprised of the demonstrated resources category. For a coal bed to fall in this category it must be within three-quarters of a mile of a drill hole, mine or outcropping.

FIGURE 1

SCHEMATIC OF METHODOLOGY USED TO
GENERATE THE PIES COAL SUPPLY CURVES

are at least 28 inches thick. The reserve base includes only those seams of sub-bituminous coal which are at least five feet thick and less than 10,000 feet below the surface. Lignite reserves were included with a depth of up to 120 feet and a minimum seam thickness of five feet. The total BOM demonstrated reserves base is estimated to be 429 billion tons of bituminous and sub-bituminous coal and lignite.

2. Reserve Disaggregation By Supply Regions. There are two reasons for the large number of supply regions. First, the transportation costs for coal are significant, and by segmenting the reserves into geographical regions, the costs of shipping coal from specific supply regions to specific demand centers can be taken into account. Second, the rank of coal varies significantly across the United States, but remains relatively constant within wide geographic areas. Therefore, if appropriate supply region definitions are developed, all of the coal from a given supply region can be assigned an average BTU content level.

3. Product Class Disaggregation. These assigned reserves are allocated among product classes, based on the National Coal Model coal classifications. In all cases, the division of reserves was made on the basis of the quality characteristics of the coal; for example, premium quality metallurgical coal, low sulfur coal, and high sulfur coal. The highest quality metallurgical coals generally are considered low in volatile matter, sulfur, and low in ash and high in BTU content. The reserves of this coal generally are difficult to mine which forces the costs of mining above that

of steam coal. As the volatile matter, sulfur or ash content increases, the price paid for it generally declines. Thus, some coals are considered low quality metallurgical coals or high quality steam coals. Steam coal is divided into low and high sulfur coal which helps to evaluate the sulfur emission limitations on the demand side.

4. Negligible Reserve Exclusion. The BOM reserve base includes all reserves in the ground. Coal reserves were eliminated from this total figure if total regional allocations were minimal or scattered or too expensive to mine given present technology. Two major exclusions were the coal reserves of the Alaskan North Slope area and high sulfur coal reserves in Alaska. The former was excluded because of the high transportation costs of shipping coal from the North Slope. The latter was excluded since its high sulfur content would not meet the environmental standards through 1990. Reserves which lie under natural or manmade barriers such as urban areas, rivers, highways and parks were not eliminated due to a lack of data. It is assumed that the quantity of impacted reserves is small, and thus, no additional reserves were excluded for legal reasons.

5. Mine Classification. Four categories of existing mines were developed. The first category includes those surface mines which were producing from December 31, 1974. The second category includes those deep mines which were producing from December 31, 1974. The third and fourth categories include those surface and deep mines which are projected to start production in December 31, 1976.

Estimates were developed for: (a) existing production capacity for each of the four categories as of the end of 1979, 1984, and 1989; (b) reserves mined from 1974 through 1979; and (c) reserves committed to existing mines as of December 31, 1979. Estimates of reserves mined and reserves committed to existing mines were required so that these reserves could be subtracted from the total reserves reported by the Bureau of Mines for 1974 to yield reserves available for new mine development.

First, the estimates of production from mines operating as of December 31, 1974 were made. This production level was then divided into the 24 region/product class combinations. Second, the estimate of reserves mined between 1974 and 1979, was based upon the yearly estimates of existing mine production. The final step was to estimate reserves committed to existing mines as of December 31, 1979. The estimate of mine production in these cases depended on an assumed recovery factor from reserves assumed for the different product class and mining method.

6. Costs of Mining-Overburden. The next three steps describe the methodology used to determine the costs of specific types of mining operations. The overburden ratio of a coal seam is a major factor in determining the cost of strip mining coal. Therefore, all uncommitted strippable reserves were allocated to overburden ratio categories. These uncommitted strippable reserves could then be associated with specific mine types and their associated cost estimates.

7. Costs of Mining - Seam Characteristics. The second major factor that determines costs of mining coal is the depth and thickness of the coal seam. The uncommitted deep reserves were, therefore, allocated according to seam thickness and seam depth categories.

8. Costs of Mining - Mine Sizes. The third major factor that determines costs of mining coal is the size of the mines. The uncommitted reserves were, therefore, allocated to mine size categories.

9. Annual Production Potential. This step relates the disaggregated reserve categories to annual production potentials by mine type. The reserves within each overburden ratio category and within each seam thickness/depth category were distributed to mine size categories using specific allocation percentages. In those cases where the reserves assigned to a mine size were inadequate to sustain a mine of a particular size for 20 years, no mine of that size was included in the supply curve. The unused reserves assigned to each mine size were added to the next smaller mine size. From the disaggregated reserve base, 102 different mine types were developed.

The 102 mine types developed for PIES consist of 66 underground mine types and 36 surface mine types. The 66 underground mines represent various combinations of six mine sizes (annual output levels), five seam thicknesses, and four seam depth categories. The 36 surface mine varieties result from combinations

of six mine sizes with seven overburden ratio categories.

10. Minimum Acceptable Selling Price. This step determines the minimum acceptable selling price per ton of coal for each of the 102 hypothetical mine types. The minimum acceptable selling price for each of the mine types was determined by establishing two "base case" mine-cost models developed by TRW and BOM, one for strip mining and one for deep mining. A matrix of adjustment factors for costing changes in key variables was then applied. For underground operations, the base case mine was defined as a slope mine producing a million tons per year from a six foot coal seam, seven hundred feet below the surface, using continuous mining, and having unit train loading facilities, but no cleaning plant. For surface mining operations, the base case was a one million ton per year area mine with a 10:1 overburden ratio with unit train loading facilities, but no preparation plant.

The minimum acceptable selling price is the price at which a coal company would recover all of its costs plus earn an eight percent return on its investment on that mine. It is assumed that mines will be developed in order of increasing costs. The market clearing price is the minimum acceptable price for the very last mine to be developed.

The minimum acceptable prices for the model mines were estimated using the methodology below. First, the initial and deferred capital investment requirements were calculated by applying the estimated average inflation factor for capital equipment to the TRW data. Secondly, the present value of these capital outlays was estimated using the distribution of deferred capital and an eight percent discount rate. To earn a return of

eight percent on invested capital, the annual cash flow was set equal to an annuity with the same present value as the present value of invested capital. Cash flow equals the sum of depreciation, depletion and profit after tax. The income statement (Table I) for the base case models allows one to trace the various items that determine the minimum acceptable selling price of coal.

The minimum acceptable selling price equals sales divided by the assumed annual output level of the mine being costed.^{3/}

Coal from existing mines was priced at variable cost since the capital invested in these mines is sunk. The variable cost of existing mines was estimated by assuming that it was equal to the operating costs of the first new mine using the same mining method. In those cases where coal from the first new strip mine on the supply curve would have cost less than coal from an existing deep mine, the price of coal from existing deep mines was arbitrarily set \$.10 below the first new mine price.

11. Production and Price Relationship. The final step links up the minimum acceptable selling price for each mine type with the production level of that mine type in each region and product class. The mine types that comprise each supply curve are then arranged in order of increasing costs. This final result is the price/quantity relationship that determines the supply curves.

^{3/} For a more elaborate exposition of the rate of return and cost and the way the minimum selling price was determined, see Attachment 1.

APPENDIX 2

THE COAL SUPPLY MODEL MODIFICATIONS

THE COAL SUPPLY MODEL MODIFICATIONS

Introduction

This section provides the assumptions and methodology used to identify explicitly the producers and owners of coal reserves in our analysis of divestiture. Prior to this study, neither the input data of the Coal Supply Model, nor the model logic provided for the identification of coal reserve and production ownership. The reserve base and production figures in the model essentially represented geological reserves and aggregated production levels and were not determined through company ownership or individual mines.

For this analysis, however, it was necessary to identify and separate those coal reserves owned by oil coal companies and those reserves owned by non-oil companies. This was necessary to ascribe differential characteristics to those two classes of reserves. This modification represents a substantial effort and included some coding changes to the model as well as the reshaping of the input data base. These modifications involved collecting data from a number of sources, analyzing it, applying judgmental decisions, and reformulating the results into a set of data consistent with the coal supply model. These changes were required to investigate the baseline case in the absence of divestiture.

The first section of this Appendix explains the basic assumptions of the break-out of the oil companies coal reserves and production by state. The other sections discuss the in-depth methodology, conclusions, and glossary of this study.

I. Basic Assumptions

Modifications of the coal supply model were based on the following assumptions:

- * The data on current coal production owned by oil companies, by state, were extracted from the 1977 Keystone Industry Coal Manual (Keystone). The 1976 data on mine production by state are assumed to be accurate. The Keystone listing of coal companies owned by oil companies is assumed to represent the universe of oil-owned coal companies.
- * It is assumed that needed coal reserves of the oil companies are a function of three variables: (a) the average annual production of the mines; (b) the expected life of the mines, and; (c) the recovery factors, which are given in Table III of this Appendix. Further assumptions had to be made on the mines' duration of production. Mines in the East were given a life expectancy of 10 years, while those in the West were allotted 20 years.

The assumptions on the duration of mine production and the recovery factors, according to coal analysts in the Coal Analysis Division (DOE), are consistent with those that are used in the National Coal Model (NCM). It is also assumed that the 1976 production level of the individual oil company coal mines is a proxy for the future annual production of the mine.
- * It is assumed that the oil companies surveyed by the Federal Trade Commission and their reported demonstrated reserves are representative of the total demonstrated reserves of the oil companies.

- * It is assumed that the oil companies have no coal reserves nor production in states other than those states in the model. The demonstrated coal reserves of the oil companies were allocated to these states from information on the location of the mines (production) in Keystone and from information on lease ownership from the Church Report.
- * In the classification of the demonstrated coal reserves of the oil companies by sulfur/BTU categories, it is assumed that the oil-owned reserves reflect the distribution of NCM Coal Classifications that currently exist in the Coal Supply Model for each state.
- * For the classification of the state committed reserves and production by NCM coal classification, a more elaborate technique was necessary. This technique was based on the following assumptions: (a) the coal seams of the individual mines identified in Keystone give an accurate estimate of the BTU and sulfur characteristics of that particular seam and mine; (b) if a unique formation exists with no information available, the seam is assumed to have the same coal characteristics as that of the predominant geological formation of the county, and; (c) the conversion of the Keystone information for the sulfur categories from percent sulfur to lbs. sulfur/MMBTU, and the BTU categories from percent to MMBTU/Ton are within a reasonable range of confidence.
- * It is assumed that all the present production by the oil companies can be related to contract mines.

II. Methodology

The Coal Supply Model modifications were performed based on the following steps:

- (1) The major sources of information and data were obtained;
- (2) The actual coal production by mines owned by oil companies was estimated;
- (3) The committed (needed) coal reserves of the oil companies were calculated;
- (4) The demonstrated coal reserves of the oil companies were obtained;
- (5) The oil companies' regional demonstrated reserves by states were estimated;
- (6) The oil firms' demonstrated reserves were classified by the National Coal Model (NCM) sulfur/BTU categories;
- (7) Oil owned production and committed reserves were allocated by NCM Coal Classifications, and;
- (8) The oil and non-oil input data bases were constructed along with a capability to merge them.

Figure 1 traces out the steps which were necessary to separate the reserves and production on the basis of ownership. A more complete description of each step follows:

- (1) Information was required on the various types of coal and the specific state locations of the coal reserves owned by oil companies. This information must be assembled from diverse publications of the Bureau of Mines (BOM), the Federal Trade Commission (FTC), and the Keystone Coal Manual (Keystone). Information on the coal reserves owned by oil companies was

Figure 1
Schematic of the Methodology
To Break-Out the Oil Companies'
Coal Reserves

derived from the FTC coal survey data. Information on the production of oil companies was obtained from Keystone.

(2) This step requires the actual coal production of those mines owned by the oil companies in each state. This information is available in the Keystone Manual. Table I shows the coal producing companies owned by oil firms as reported by Keystone. With this information, the oil companies' mines and annual production by state were determined from the Keystone Manual. Producers of at least 100,000 tons or more of bituminous, anthracite and lignite coal were included. From these data, Table II was constructed.^{1/} Table II summarizes all the information listed in Keystone on the oil companies' mines by tonnage class, production, principal application(s), seam(s) mined, type mine, county and state. These data provided the core from which it was possible to separate the production and committed reserves by state and NCM coal classifications.

(3) The next step entails estimated the committed or needed coal reserves of the oil companies from the information in Table II. The committed reserves of all the oil companies' mines by state were determined from the following formula:^{2/}

^{1/} Due to its length, Table II is attached at the end of this Appendix.

^{2/} The needed reserves represent an estimate of the oil companies' committed reserves.

Table I

OIL COMPANY OWNERSHIP OF
COAL PRODUCING COMPANIES*

<u>Coal Operating Company</u>	<u>Parent or Controlling Company</u>
Addington Bros. Mining, Inc.	Ashland Oil Co.
Arch Mineral Corp.	Ashland Oil Co.; Hunt Petroleum Corp.; Hunt Industries
Beatrice Pocahontas Co. (Jointly owned Island Creek, Republic Steel)	Occidental Petroleum Co., and Republic Steel Corp.
Bishop Coal Co.	Continental Oil Co.
Blackwood Fuel Co., Inc.	Hawley Fuel Corp.
Braztah Corp.	McCulloch Oil Corp.
Carter Mining Co.	Exxon Corp.
Coal Resources Corp.	Flying Diamond Oil Corp.
Diamond Coal Co.	Transcontinental Oil Corp.
Island Creek Coal Co.	Occidental Petroleum Corp.
Itmann Coal Co.	Continental Oil Co.
Kitchekan Fuel Corp.	Hawley Fuel Corp.
Mathies Coal Co.	Continental Oil Co.
Monterey Coal Co.	Exxon Corp.
National Coal Mining Co.	Occidental Petroleum Co.
Old Ben Coal Co.	Sohio Petroleum Co.
Peter White Coal Mining Corp.	Hawley Fuel Corp.
Pittsburg & Midway Coal Mining Co.	Gulf Oil Co.
Southwestern Illinois Coal Corp.	Ashland Oil Co., Arch Mineral Corp.

Table I (Continued)

<u>Coal Operating Company</u>	<u>Parent or Controlling Company</u>
Tesoro Coal Co.	Tesoro Petroleum Corp.
Thunder Basin Coal Co.	Atlantic Richfield Co. (Arco)
Valley Camp Coal Co.	Quaker State Oil Refining Corp.
Valley Camp Utah	Quaker State Oil Refining Corp.
Virginia Pocahontas Co.	Occidental Petroleum Co.
Walker-Fayette Coal Co.	Ashland Oil Co., Arch Mineral Corp.
Belva Coal Co.	Reading & Bates Offshore Drilling Co.
	Getty Oil Company
	Phillips Petroleum Co.

* Table I derived from information provided in the 1977 Keystone Coal Industry Manual.

$$CR = \sum_{m=1}^n \left[\alpha_m (Y_m C_m) \right]$$

CR = committed reserves

α = "multiplier" to account for the recovery factor

Y = expected life of the mine beyond 1975

C = tonnage class of the mine

and the subscripts m and n are the type of mines in a particular state, and the total number of mines in the state, respectively.

The recovery factors used for the different types of mines as shown below in Table III:

Table III
RECOVERY FACTORS MINING METHOD

<u>Product Class</u>	<u>Surface</u>	<u>Deep</u>
Metallurgical	.7	.5
Steam	.8	.6

Source: ICF Incorporated, Coal Supply Analysis, May 1976, p. 19

The life of the mines was assumed to be 10 years for the coal mines in the Eastern states, while the coal mines in the Western states were given a life expectancy of 20 years. The production levels over the specific periods were based on 1976 production figures (Table II). Table IV contains the committed coal reserves of oil companies by surface and underground mines for each state.

(4) The information on coal reserves, by company and region, is summarized in Table V and was obtained from the FTC Coal Survey Data.^{3/} Those reserved owned by oil companies are treated as the residual from total reserves after oil-owned reserves have been subtracted. Preliminary checks were made to verify the data on oil company reserves and the coverage of major oil companies by the FTC. Their listing of oil companies and their reserve base was reasonably close to the listing and figures provided by Keystone.

(5) Since FTC data were reported on a USGS Basin basis, regional oil companies' reserves must be allocated to states. The states in each Basin are shown in Table VI. Three different criteria were used:

- (a) In the case of the Northern and Southern Rocky Mountain regions, the data on the Federal leased lands owned by oil companies were utilized (Table VII) to allocate the reserves to the states.
- (b) In the case of the other regions, the regional reserves allocation by states was based on a weighted average of the committed reserves owned by the oil companies (Table IV).

^{3/} Table V is in a separate volume of this report and is not available for general circulation. The data are proprietary and available only from the Federal Government.

Table IV

ESTIMATED OIL COMPANIES' COMMITTED COAL
RESERVES BY STATE AND MINE TYPE
(Thousands of Short Tons)

STATE	COMMITTED RESERVES		
	DEEP	SURFACE	TOTAL
Alabama		6,481	6,481
Colorado		28,504	28,504
Indiana		76,805	76,805
Eastern Kentucky	60,860	18,391	79,251
Illinois	208,211	189,534	397,745
Missouri		6,978	6,978
New Mexico		21,058	21,058
North Dakota		54,874	54,874
Ohio	33,110	70,709	103,819
Pennsylvania		113,824	113,824
Virginia	55,051	6,777	61,828
West Kentucky	103,839		103,839
West Virginia (N)	264,908		264,908
West Virginia (S)	230,474	5,550	236,024
Wyoming		<u>461,407</u>	<u>461,407</u>
TOTAL	956,453	1,060,892	2,107,345

Source: Calculated as explained in text.

STATES AND COUNTIES IN THE USGS REGIONS

Source: USGS definitions

Table VII

SUMMARY OF MAJOR COAL HOLDING IN ROCKY MOUNTAIN
AND NORTHERN GREAT PLAINS PROVINCES,
FEDERAL, STATE, AND INDIANA LEASES
AND FEE HOLDINGS*
(In Thousands of Acres)

STATE PETROLEUM COMPANY	North Dakota	Montana	Wyoming	Colorado	Utah	New Mexico	Arizona	Total
Atlantic Richfield			41					41
Belco Petroleum Corp.			8		26			34
Carter Oil Co.			179					179
Consol.	95	28	65	10	38	9		245
Discovery Oil, Ltd.			120					120
Gulf Oil Co.			3			40		43
HFC Oil Co.		60	9					69
McCulloch Oil Corp.					13			13
Mobil Oil Corp		2	25	7				34
Rio Vista Oil Co.				23	15			38
Shell Oil Co.		30						30
Texaco, Inc.			13					13
TOTAL	95	120	463	40	92	49		

* Data derived from the "Church Report" (Petroleum Industry Involvement in Alternative Sources of Energy), prepared by the Committee on Energy and Natural Resources United States Senate, Subcommittee on Energy Research and Development, September 1977, Publication No. 95-94.

- (c) The regional demonstrated coal reserves of the oil companies (Table V) were shared out to states within their geographic region and were based on the present ratio of the demonstrated reserve base in the National Coal Model. Only those states for which there was prior information of oil companies' operations were allotted reserves. For example, the information on land leases to oil companies (Table VII) and oil companies' mines production (Table II) was utilized.

Synergy worked through exercises using all three of these criteria, some separately and with combinations of the various methods before selecting a final methodology. Criteria (a) coupled with (b) produced favorable results for the Eastern states but the results in the Western states were inconsistent with the data on demonstrated reserves. For example, some results showed more reserves for the oil companies than reserves that actually existed in the State of Utah. The decision was made against the use of committed reserves of the oil companies, criteria (b). This is because the land lease information (Table V) showed states with oil-owned, demonstrated reserves having no current oil production or committed reserves.

In general, criteria (c) provided the best results and was used to estimate the relative share of regional coal reserves allocated to the states. Criteria (c) had the advantage that it utilized all the information available on the location of oil companies' reserves, and did not overestimate the reserves of any particular state. Table VIII contains the state and regional shared reserves based on criteria (c).

In order to conform with the present structure of the National Coal Model, it was necessary to allocate the oil companies' demonstrated reserves and committed reserves and production by

the National Coal Model (NCM) BTU and sulfur classifications. These classifications are defined in Table IX. Each coal class is labeled uniquely with a two-letter code. As an example, a ZB coal classification identifies a type of coal with a heat content of more than 26 million BTU's per ton and with a sulfur content of 0.4 - 0.6 pounds per million BTU. These categories were difficult to apply, as explained in steps 6 and 7 below.

(6) The Coal Model classifies demonstrated reserves which were mineable by deep thin or deep thick for underground mines, or surface mineable. All the various types of coal mined in a particular state were placed in one of those three categories. The oil companies' demonstrated reserves data base (FTC) that is used for this project specifies demonstrated reserves by surface and underground mines, by sulfur content, and type of coal (bituminous, sub-bituminous, and lignite). These classifications, however, were not usable directly for our purposes. The underground classification had to be disaggregated into deep thin and deep thick categories. Also, the wide BTU ranges of bituminous, sub-bituminous, and lignite coal did not conform with the NCM coal classifications.

Information from other sources (Keystone and BOM) could not be used to determine the coal type categories for the committed reserves and production (Step 7). Its use could not be justified since the information in Keystone pertained only to mines in current production. The bulk of oil companies' demonstrated reserves information (BOM) are in aggregate form that does not discriminate between oil and non-oil ownership. The most

Table VIII

ESTIMATED OIL COMPANIES' DEMONSTRATED
COAL RESERVES BY REGIONS, STATES AND MINE TYPES *
(millions of short tons)

REGIONS & STATES	RESERVES		
	(Deep Mines)	(Surface Mines)	(Total)
Northern Appalachian Basin	7,100	212	7,312
West Virginia	2,862	102	2,964
Pennsylvania	2,475	19	2,494
Ohio	1,763	92	1,855
Southern Appalachian Basin	400	24	424
Virginia	94	5	99
Alabama	65	1	66
Eastern Kentucky	242	18	260
Illinois Basin	11,645	630	12,275
Western Kentucky	1,458	111	1,569
Illinois	8,461	443	8,904
Indiana	1,726	76	1,802
Northern Rocky Mountains	5,358	9,692	15,050
North Dakota	0	1,606	1,606
Montana	3,828	5,096	8,924
Wyoming	1,530	2,990	4,520
Southern Rocky Mountains	1,982	520	2,502
Colorado	1,327	138	1,465
New Mexico	436	342	778
Utah	219	40	259

Source: Calculated based on FTC data and sharing methodology as described in text.

*State values may not sum exactly to Regional totals due to rounding.

Table IX
NCM COAL CLASSIFICATIONS

<u>Sulfur</u>	<u>LBS/MMBTU</u>	<u>BTU</u>	<u>MMBTU/TON</u>
A	0 - 0.4	Z	GT 26
B	0.4 - 0.6	H	23-26
C	0.6 - 0.67	M	20-23
D	0.67-0.83	S	15-20
E	0.83-0.95	L	0-15
F	0.95-1.68		
G	1.68 2.50		
H	2.50		

BTU CLASS

<u>Sulfur Class</u>	Z	H	M	S	L
A	M	I	Z	X	Y
B	M	I	Z	X	Y
C	M	I	Z		
D	M	R	S	V	U
E	R	R	S		
F	R	R	S	V	U
G	H	H	W	V	U
H		H	W	V	

Note:

1. Boxes that are blank currently do not exist in the National Coal Model.
2. LG coal is classed as U (medium sulfur) to avoid a new PIES category with very small reserve and unlikely utility.

Source: DOE Office of Coal Analysis

reasonable methodology available was to allocate the demonstrated reserves to deep thin, deep thick, and surface mines, within their respective coal type categories, based on present ratios that exist for the total demonstrated reserves in the National Coal Model.

(7) The committed reserves and production were allocated to NCM coal classifications for each state. The process was based on the following steps:

- (a) Information on seams, counties, and type coal were utilized. Each mine was identified with a coal classification. Sulfur and BTU data for most major seams were given in the Keystone Manual. Keystone also identifies the seams mined in each coal mining operation. Sulfur and BTU characteristics of each seam were determined (Keystone), and all the output from each mine was assumed to be coal from that particular seam.

The NCM Coal Classification system groups coal into sulfur categories by Lbs.Sulfur/MMBTU, and into BTU categories by MMBTU/Ton. Keystone data were converted from percent sulfur to Lbs.Sulfur/MMBTU, and to MMBTU/Ton. For the Lbs.Sulfur/MMBTU ratio, discreet points were selected from a range of values, both for sulfur and BTU content. When median values for particular seams were listed by Keystone, they were used in the ratio. If the range, and not the median, was available, an average was obtained either by an arithmetic mean of the endpoints or by estimating a weighted average. A weighted average was used when the range of data was exaggerated relative to median values of similar local geological formations.

A second type of judgment was used when a mined seam was not listed by Keystone. If a mined seam was a unique formation with no information available for it, the seam was assumed to have the same coal characteristics as that of the predominant geological formations of the county. For example, if a predominant seam in a county had geological data, the unidentified seam in the same county was given the same characteristics. Judgments of this type were usually necessary in Appalachia where several names have been given to the identical small seams in Kentucky and West Virginia.

Caution should be exercised when using these coal classifications. Primarily due to the wide range of sulfur and BTU content for any given seam, a single chosen quotient of lbs. sulfur/MMBTU may vary for different parts of the same seams.

- (b) In certain cases, the coal types for the states were determined by (a); but they were either outside of a given range or the range did not exist in the Coal Model. These coal types were either (i) passed down to the next sulfur category remaining within the BTU classification; or, (ii) shared to the sulfur categories within the BTU classification; or, (iii) shared to both the BTU and sulfur categories within the state. Table XI summarizes the methodology implemented for sharing out the committed reserves and production by NCM Coal Classifications to the states with oil-owned coal. Table XII presents the result of these methodologies for production and committed reserves by state and NCM Coal Classifications.

(8) The final step requires implementing modifications to the Coal Model data base. Current production levels are classified as contract, spot, or surge. Based on current information and recommendations of DOE personnel, all oil-owned current production was allocated to the contract category. Once this step was completed, two separate data bases were constructed -- one data base with information on the oil companies, reserves and production, and the other with the non-oil companies' reserves and production. The two output data sets which produce supply curves were then read into the FORTRAN program MERGE to produce one consistent set of supply curves.

Summary

As mentioned above, the program required major coding changes to enable the identification of those mines associated with oil-owned coal reserves and those associated with non-oil owned

Table X

METHODOLOGY USED TO ALLOCATE THE
STATES' COMMITTED RESERVES AND
PRODUCTION BY NCM COAL TYPES

States	Methodology ^{4/}			
	B(a)	b(i)	b(ii)	b(iii)
Virginia	X	X		
Illinois	X		X	
Indiana	X			
Wyoming	X		X	
Kentucky (East)	X		X	
Kentucky (West)		X		
West Virginia (South)	X	X		
West Virginia (North)				X
Ohio	X	X		
Pennsylvania	X	X		
Missouri	X			
New Mexico		X		
Colorado		X		
North Dakota		X		
Alabama		X		

Source: See text.

^{4/} Methodologies are described in the text.

Table XI

THE ESTIMATED OIL COMPANIES' COMMITTED RESERVES AND
PRODUCTION BY STATE AND NCM COAL CLASSIFICATIONS

		<u>COMMITTED RESERVES</u>	<u>PRODUCTION</u>
<u>Virginia</u>			
	ZA	59,141,777	3,069,082
	ZC	2,687,003	149,965
<u>Illinois</u>			
	HF	89,363,766	5,361,826
	MG	182,300,000	10,937,894
	MH	76,081,583	4,564,895
	MF	50,000,000	3,000,000
<u>Indiana</u>			
	HH	76,804,733	4,608,284
<u>Wyoming</u>			
	MB	67,942,125	5,435,370
	MA	33,261,625	2,660,930
	SC	360,203,750	14,408,150
<u>Kentucky</u> <u>(East)</u>			
	ZB	45,961,701	3,102,170
	ZC	22,449,149	1,518,811
	HG	10,839,400	650,364
<u>(West)</u>			
	HH	31,028,350	1,861,701
	HG	72,810,966	4,368,658
<u>West Virginia</u> <u>(South)</u>			
	ZC	31,653,253	1,775,059
	ZD	37,980,663	2,348,594
	ZA	98,823,600	4,941,180
	ZB	43,909,373	2,457,581
	ZE	23,657,266	1,419,436
<u>(North)</u>			
	HH	32,263,017	1,935,781
	ZF	232,644,620	13,958,679
<u>Ohio</u>			
	HG	16,672,143	1,331,721
	HH	86,128,907	6,795,677
	ZF	1,077,863	1,077,863

Table XI (Continued)

		<u>COMMITTED RESERVES</u>	<u>PRODUCTION</u>
<u>Pennsylvania</u>			
	HC	16,356,191	844,644
	ZD	19,739,745	1,085,686
	ZF	77,727,799	4,276,679
<u>Missouri</u>			
	MH	6,978,125	558,250
<u>New Mexico</u>			
	MB	21,058,474	842,339
<u>Colorado (North)</u>			
	HB	28,504,424	1,140,177
<u>North Dakota</u>			
	LE	54,874,125	4,048,324
<u>Alabama</u>			
	HG	6,480,788	518,463

coal reserves. Once these data and coding changes were made, a revised baseline run was made. This baseline run provided supply curves which were similar to the current baseline supply curves except that the model had the capability of separating the characteristics of oil-owned and non-oil-owned coal reserves. In addition, it was possible to identify those mines belonging to oil-owned coal companies from those which were not.

This baseline set of supply curves was then compared to a new set of supply curves which were generated after scenario changes were made to the variables. The baseline run could then be generated by separating the input data set into the oil and non-oil reserves. The data bases were then run separately through the Coal Supply Model, each generating its own output. These two outputs are merged together, and sorted to yield the total supply curves.

Once this framework was set up, the global parameters were changed on the oil-owned side or the non-oil side depending on the scenario and the economic interpretation which were ascribed to them. These changes in one or both sides could then be run through to generate new supply curves which represented shifts from the baseline case in our comparative static analyses.

GLOSSARY

Coal is defined to include bituminous, sub-bituminous, anthracite and lignite coal.

Committed Reserves (or needed reserves) are coal reserves that are required to sustain the capacity of a mine over its planned years of existence. The calculation of the committed reserves is based on: (a) planned capacity of the mines; (b) the life of the mine; and, (c) the type of mine.^{5/}

Demonstrated Reserves are the coal that the Bureau of Mines is most certain about its tonnage and quality characteristics, e.g., BTU content, sulfur content, volatile matter content, etc., and that they know could be mined with existing technology.

Federal Trade Commission Reserves includes "Measured" and "Indicated" coal reserves as defined below:

"Measured" - Reserves for which tonnage is computed from outcrops, trenches, working and drill holes and for which the grade is computed from the results of detailed sampling. The sites for inspection, sampling, and measurement are spaced so closely and the geologic character is so well-defined that size, shape, shape, and mineral content are judged to be accurate within limits which are stated, and no such limit is judged to be different from the computed tonnage in grade by more than 20 percent.

^{5/} For further information, see Step 3 in the Coal Supply Modifications.

"Indicated" - Reserves from which tonnage and grade are computed partly from specific measurement, samples, or production, and partly from projection for a reasonable distance on geologic evidence. The sites available for inspection, measurement, and sampling are too widely or otherwise inappropriately spaced to permit the mineral bodies to be outlined completely on the grade established throughout.

Surface Mineable Coal Reserves include only bituminous coal in seams 28 inches or more thick to a depth of 120 feet and only sub-bituminous coal and lignite in seams 60 inches or more thick to a depth of 120 feet which are potentially mineable by surface methods.

Underground Coal Reserves include only bituminous coal in seams 28 inches or more thick to a depth of 1,000 feet and only sub-bituminous coal and lignite in seams 60 inches or more thick to a depth of 1,000 feet which are potentially mineable by underground methods.

TABLE II

SUMMARY OF COAL PRODUCING COMPANIES BY TONNAGE CLASS, PRODUCTION, PRINCIPAL APPLICATION(S),
SEAM(S) MINED, TYPE MINE, COUNTY AND STATE. *

VIRGINIA

Coal Producing Companies	County	Type Mine	Seam(s) Mined	Principal Application(s)	1976 Production	Tonnage Class
Old Ben Coal Co. Dixiana Mines A & D	Wise	Deep	Taggart, 51 in.th.		241,446	200,000 to 499,999
Beatrice Pocahontas Co. Beatrice Mine	Buchanan	Deep	Pocahontas No. 3, 60 in. th.	Metall.	747,178	500,000 and over
Virginia Pocahontas Co. Virginia Pocahontas No. 2	Buchanan	Deep	Pocahontas No. 3, 60 in.th.	Metall.	206,413	200,000 to 499,999
Island Creek Coal Co. Virginia Pocahontas No. 1 Mine	Buchanan	Deep	Pocahontas No. 3, 56 in. th.	Metall.	617,303	500,000 and over
Island Creek Coal Co. Virginia Pocahontas No. 3 Mine	Buchanan	Deep	Pocahontas No. 3, 54 in.th.	Metall.	686,489	500,000 and over
Island Creek Coal Co. Virginia Pocahontas No. 4 Mine	Buchanan	Deep	Pocahontas No. 3, 54 in.th.	Metall.	178,277	100,000 to 199,999
Blackwood Fuel Co., Inc Pardee Mine	Wise	Deep Strip Auger	High split, 54 in.th. Morris, 50 in. th		75,469 53,952 20,344	200,000 to 499,999

* Table II derived from information provided in the 1977 Keystone Coal Industry Manual.

TABLE II

SUMMARY OF COAL PRODUCING COMPANIES BY TONNAGE CLASS, PRODUCTION, PRINCIPAL APPLICATION(S),
SEAM(S) MINED, TYPE MINE, COUNTY AND STATE.

VIRGINIA (CONTINUED)

Coal Producing Companies	County	Type Mine	Seam(s) Mined	Principal Application(s)	Production	Tonnage Class
Consolidation Coal Co. Bluefield Operation	MacDowell	Strip	Fire Creek		391,976	200,000 to 499,999

TABLE II

SUMMARY OF COAL PRODUCING COMPANIES BY TONNAGE CLASS, PRODUCTION, PRINCIPAL APPLICATION(S),
SEAM(S) MINED, TYPE MINE, COUNTY AND STATE.

ILLINOIS

Coal Producing Companies	County	Type Mine	Seam(s) Mined	Principal Application(s)	Production	Tonnage Class
<u>Old Ben Coal Co.</u> Old Ben No. 21 Mine	Franklin	Deep	No. 6, 101 in. th.		1,533,027	500,000 and over
<u>Old Ben Coal Co.</u> Old Ben No. 24 Mine	Franklin	Deep	Herrin, No. 6, 102 in th.		1,822,994	500,000 and over
<u>Old Ben Coal Co.</u> Old Ben No. 26 Mine	Franklin	Deep	No. 6, 96 in. th.		1,571,755	500,000 and over
<u>Old Ben Coal Co.</u> Old Ben No. 25 Mine	Franklin	Deep	No. 6			
<u>Southwestern Illincis Coal Co.</u> Captain Mine	Perry	Strip	Nos. 5 and 6	Steam	3,527,959	500,000 and over
<u>Southwestern Illinois Coal Co.</u> Streamline Mine	Randolph	Strip			1,450,567	500,000 and over
<u>Consolidation Coal Co.</u> Hillsboro Mine	Montgomery	Deep	No. 6, 6-7 in.th.		1,784,474	500,000 and over
<u>Consolidation Coal Co.</u> Norris Mine	Fulton	Strip	No. 5, 54 in.th.		876,365	500,000 and over

TABLE II

SUMMARY OF COAL PRODUCING COMPANIES BY TONNAGE CLASS, PRODUCTION, PRINCIPAL APPLICATION(S),
SEAM(S) MINED, TYPE MINE, COUNTY AND STATE.

ILLINOIS (CONTINUED)

Coal Producing Companies	County	Type Mine	Seam(s) Mined	Principal Application(s)	1976 Production	Tonnage Class
Consolidation Coal Co. Morning Star #2 Mine	Perry	Strip	No. 5, 60-66 in.th.		1,283,896	500,000 and over
Consolidation Coal Co. Morning Star #3 Mine	Randolph	Strip	No. 5, 54-60 in.th. No. 6, 54-60 in.th.		995,908	500,000 and over
Consolidated Coal Co. Morning Star #4 Mine	Perry	Strip	No. 5, 36 in.th., No. 6, 73 in.th.		2,803,199	500,000 and over
Consolidation Coal Co. Morning Star #5 Mine	Jackson	Strip	No. 6, 84 in.th.		434,050	200,000 to 499,999 <u>1/</u>
Monterey Coal Co. Monterey #1 Mine	Macoupin	Deep	No. 6, 87 in.th., 100% of Total	Steam	2,780,421	500,000 and over
Monterey Coal Co. Monterey #2 Mine	Clinton	Deep	No. 6, 87 in.th., 100% of Total	Steam		500,000 and over <u>2/</u>

TABLE II

SUMMARY OF COAL PRODUCING COMPANIES BY TONNAGE CLASS, PRODUCTION, PRINCIPAL APPLICATION(S),
SEAM(S) MINED, TYPE MINE, COUNTY AND STATE.

INDIANA

Coal Producing Companies	County	Type Mine	Seam(s) Mined	Principal Application(s)	1976 Production	Tonnage Class
Old Ben Coal Co. Old Ben #1 Mine	Pike	Strip	No. 5, 60 in.th.		2,527,295	500,000 and over
Old Ben Coal Co. Old Ben #2 Mine	Pike	Strip	No. 5, Lower Millersbury.		1,780,539	500,000 and over <u>3/</u>
Old Ben Coal Co. Blackfoot #5 Mine	Pike	Strip	No. 5, 60 in.th.		300,450	200,000 to 499,999

TABLE II

SUMMARY OF COAL PRODUCING COMPANIES BY TONNAGE CLASS, PRODUCTION, PRINCIPAL APPLICATION(S),
SEAM(S) MINED, TYPE MINE, COUNTY AND STATE.

WYOMING

Coal Producing Companies	County	Type Mine	Seam(s) Mined	Principal Application(s)	Production	Tonnage Class
<u>Arch Mineral Corp.</u> Medicine Bow Mine	Carbon	Strip	No. 65.		2,774,440	500,000 and over
<u>Arch Mineral Corp.</u> Seminoe Mine	Carbon	Strip			2,660,930	500,000 and over
<u>Arch Mineral Corp.</u> Seminoe No. 2 Mine	Carbon	Strip	Hanna No. 2.		2,660,930	500,000 and over
<u>Carter Mining Co.</u> Caballo Mine	Campbell <u>4/</u>					
<u>Carter Mining Co.</u> Rawhide Mine	Campbell	Strip <u>5/</u>				
<u>Thunder Basin Coal Co.</u> Black Thunder Mine	Campbell	Strip		Steam <u>6/</u>		

TABLE II

SUMMARY OF COAL PRODUCING COMPANIES BY TONNAGE CLASS, PRODUCTION, PRINCIPAL APPLICATION(S),
SEAM(S) MINED, TYPE MINE, COUNTY AND STATE

KENTUCKY

Coal Producing Companies	County	Type Mine	Seam(s) Mined	Principal Application(s)	1976 Production	Tonnage Class
<u>Addington Bros. Mining, Inc.</u> Ross Creek Mine	Johnson	Strip	Van Lear		11,617*	10,000 to 49,999
<u>Addington Bros. Mining, Inc.</u> Mine No. 10	Lawrence	Strip	Richardson		70,379*	50,000 to 99,999
<u>Addington Bros. Mining, Inc.</u> Mine No. 18	Lawrence	Strip	Van Lear		100,494	100,000 to 199,999
<u>Addington Bros. Mining, Inc.</u> Mine No. 20	Lawrence	Strip			37,508*	10,000 to 49,999
<u>Addington Bros. Mining, Inc.</u> Mine No. 15	Martin	Strip	Peach Orchard		41,955*	10,000 to 49,999
<u>Addington Bros. Mining, Inc.</u> Mine No. 21	Martin	Strip	Peach Orchard		18,075	10,000 to 49,999
<u>Addington Bros. Mining, Inc.</u> Mine No. 13	Morgan	Strip	Index		123,441*	100,000 to 199,999

* 1975 Production Level

TABLE II

SUMMARY OF COAL PRODUCING COMPANIES BY TONNAGE CLASS, PRODUCTION, PRINCIPAL APPLICATION(S),
SEAM(S) MINED, TYPE MINE, COUNTY AND STATE

KENTUCKY (CONTINUED)

Coal Producing Companies	County	Type Mine	Seam(s) Mined	Principal Application(s)	1976 Production	Tonnage Class
<u>Island Creek Coal Co.</u> Spurlock Mine	Floyd	Deep	Elkhorn No. 2, 36 in. th. Hazard No. 4, 57 in. th.	Steam, Metall.	138,813	100,000 to 199,999
<u>Island Creek Coal Co.</u> Weelwright Mine	Floyd	Deep	Elkhorn No. 3, 48 in. th. Elkhorn No. 2, 33 in. th.	Metall.	291,940	200,000 to 499,999
<u>Island Creek Coal Co.</u> Kite Mine Nos. 1 & 2	Knott	Deep	Elkhorn No. 1, 38 in. th. Elkhorn No. 2, 38 in. th. Elkhorn No. 3, 48 in. th.	Steam, Metall.	57,870	
<u>Island Creek Coal Co.</u> Pevler Mine	Martin	Deep, Strip	Stokton, 47 in. th. Clarion, 42 in. th. No.5 Block, 84 in.th.	Steam	1,532,692	500,000 and over
<u>Island Creek Coal Co.</u> Bake Creek Mine Nos. 1 and 2	Pike	Deep	Pond Creek	Steam, Metall.	109,783	
<u>Island Creek Coal Co.</u> Gund Mine	Pike	Deep, Strip	Thacker, 42 in. th. Winifrede, 52 in. th.	Steam, Metall.	335,147	200,000 to 499,999

TABLE II

SUMMARY OF COAL PRODUCING COMPANIES BY TONNAGE CLASS, PRODUCTION, PRINCIPAL APPLICATION(S),
SEAM(S) MINED, TYPE MINE, COUNTY AND STATE

KENTUCKY (CONTINUED)

Coal Producing Companies	County	Type Mine	Seam(s) Mined	Principal Application(s)	1976 Production	Tonnage Class
<u>Island Creek Coal Co.</u> Fies Mine	Hopkins	Deep	No. II, 457 in. th.	Steam	863,160	500,000 and over
<u>Island Creek Coal Co.</u> Mine No. 9	Hopkins	Deep	No. 9, 60 in. th.	Steam	921,290	500,000 and over
<u>Island Creek Coal Co.</u> Crescent Mine	Muhlenberg	Deep	No. II, 59 in. th.	Steam	412,980	500,000 and over
<u>Island Creek Coal Co.</u> Hamilton Mine No. 1	Union	Deep	No. 9, 60 in. th.	Steam	1,534,062	500,000 and over
<u>Island Creek Coal Co.</u> Hamilton Mine No. 2	Union	Deep	No. 9, 50 in. th.	Steam	720,860	500,000 and over
<u>Island Creek Coal Co.</u> Ohio Mine No. 2	Union	Deep	No. II, 56 in. th.	Steam	585,561	500,000 and over
<u>Island Creek Coal Co.</u> Providence Mine No. 1	Webster	Deep	No. 9	Steam	1,192,446	500,000 and over
<u>Coal Resources Corp.</u> Belmon Div., No. 1 Mine	Harlan	Deep	Wallins	Steam	650,364	500,000 and over
<u>Coal Resources Corp.</u> Belmon Div., No. 2 Mine	Harland	Deep	Highstlint		129,247	100,00 to 199,999

TABLE II

SUMMARY OF COAL PRODUCING COMPANIES BY TONNAGE CLASS, PRODUCTION, PRINCIPAL APPLICATION(S),
SEAM(S) MINED, TYPE MINE, COUNTY AND STATE

KENTUCKY (CONTINUED)

Coal Producing Companies	County	Type Mine	Seam(s) Mined	Principal Application(s)	1976 Production	Tonnage Class
Coal Resources Corp. Oxford Div. No.1 Mine	Harlan	Deep	Creech		316,095*	200,000 to 499,99
Coal Resources Corp. Oxford Div. No.2 Mine	Harlan	Deep	Creech		204,180*	200,000 to 499,999
Diamond Coal Co., Inc. Mines No. 5-A, 6-A, 7-A	Floyd	Strip, Auger	Broas, 42-60 in. th., 5% total; Peach Orchard, 42-72 in. th., 95% total		828,622 3,072	500,000 and over
Tesoro Coal Co. Mine No. 2	Perry	Strip	Hazard No. 9		98,504*	50,000 to 99,999
Tesoro Coal Co. Mine No. 3	Perry	Deep	Hazard No. 9		33,957*	10,000 to 49,999
Tesoro Coal Co. Mine No. 5	Perry	Strip	Hazard No. 7		120,000	100,000 to 199,999
Tesoro Coal Co. Mine No. 6	Perry	Strip			7,590*	Less than 10,000
Tesoro Coal Co. Mine No. 7	Perry	Strip	Hazard No. 10		10,000*	10,000 to 49,999

* 1975 Production Level

TABLE II

SUMMARY OF COAL PRODUCING COMPANIES BY TONNAGE CLASS, PRODUCTION, PRINCIPAL APPLICATION(S),
SEAM(S) MINED, TYPE MINE, COUNTY AND STATE

WEST VIRGINIA

Coal Producing Companies	County	Type Mine	Seam(s) Mined	Principal Application(s)	1976 Production	Tonnage Class
<u>Belva Coal Co.</u> No. 4-B Mine	Logan	Deep	Cedar Grove, 48 in. th.	Metall.	18,497*	10,000 to 49,999
<u>Belva Coal Co.</u> No. 5-A Mine	Logan	Deep	Lower Kittanning, 57 in. th.		143,441*	100,000 to 199,999
<u>Belva Coal Co.</u> Mine No. 5-C Rita	Logan	Deep	Lower Kittanning, 53 in. th.		102,723*	100,000 to 199,999
<u>Belva Coal Co.</u> Mine No. 84	Logan	Deep	Eagle, 36 in. th.		11,602*	10,000 to 49,999
<u>Belva Coal Co.</u> Mine Nos. 27-75S and 43-72S	Logan	Strip	Lower Kittanning		6,479	Less than 10,000
<u>Bishop Coal Co.</u> Bishop Mine	McDowell	Deep	Pocahontas No. 3, 45-70 in. th., Pocahontas No. 5, 43-49 in. th.	Metall.	1,249,757	500,000 and over
<u>Island Creek Coal Co.</u> Pond Fork Mine	Boone	Deep	Dorothy, 62 in. th., No. 5 Block, 44 in. th.	Steam, Metall.	178,172	100,000 to 199,999
<u>Island Creek Coal Co.</u> Elk Creek No. 10	Logan	Deep	Cedar Grove, 42 in. th.	Metall.	109,966	100,000 to 199,999

* 1975 Production Level

TABLE II

SUMMARY OF COAL PRODUCING COMPANIES BY TONNAGE CLASS, PRODUCTION, PRINCIPAL APPLICATION(S),
SEAM(S) MINED, TYPE MINE, COUNTY AND STATE

WEST VIRGINIA (CONTINUED)

Coal Producing Companies	County	Type Mine	Seam(s) Mined	Principal Application(s)	1976 Production	Tonnage Class
Island Creek Coal Co. Guyan Mine No. 1	Logan	Deep	Cedar Grove, 64 in.th. Dorothy, 48 in.th. Winifrede, 42 in.th. Stockton, 100 in.th.	Steam, Metall.	537,977	200,000 to 499,999
Island Creek Coal Co. Guyan Mine No. 4	Logan	Deep	Cedar Grove, 42 in.th.	Steam, Metall.	38,515	10,000 to 49,999
Island Creek Coal Co. Guyan Mine No. 5	Logan	Deep	Cedar Grove, 63 in.th.	Steam, Metall.	406,100	200,000 to 499,999
Island Creek Coal Co. Coal Mt. Mine #90	Wyoming	Deep	Powellton, 50 in.th. Gas, 38 in. th.	Metall.	640,372	
Island Creek Coal Co. Coal Mt. Mine #12	Wyoming	Deep	Upper Cedar Grove, 46 in. th. Eagle, 48 in. th.	Steam, Metall.	408,749	200,000 to 499,999
Island Creek Coal Co. Alpine Mine No. 1 & 2	Grant	Deep	Bakerstown	Steam, Metall.	285,445	200,000 to 499,999
Island Creek Coal Co. Beaver Mine	Nicholas	Deep	Lower Kittanning	Steam	48,778	10,000 to 49,999
Island Creek Coal Co. Birch - 2-A	Nicholas	Deep	Lower Kittanning, Upper Kittanning, Middle Kittanning	Steam	726,108	500,000 and over

TABLE II

SUMMARY OF COAL PRODUCING COMPANIES BY TONNAGE CLASS, PRODUCTION, PRINCIPAL APPLICATION(S),
SEAM(S) MINED, TYPE MINE, COUNTY AND STATE.

WEST VIRGINIA (CONTINUED)

Coal Producing Companies	County	Type Mine	Seam(s) Mined	Principal Application(s)	1976 Production	Tonnage Class
Island Creek Coal Co. Donegan No. 1 Mine	Nicholas	Deep	Betley, Sewell		148,050	100,000 to 199,999
Island Creek Coal Co. Donegan Mine 10/8	Nicholas	Deep	Sewell, 48 in. th.	Metall.	205,115	200,000 to 499,999
Island Creek Coal Co. North Branch Mine	Grant	Deep	Upper Freeport, 84 in. th.	Steam	693,328	500,000 and over
Island Creek Coal Co. Summersville Mine	Nicholas	Strip	Lower Kittanning	Steam, Metall.	269,360	200,000 to 499,999
Island Creek Coal Co. Sycamore Mine	Nicholas	Deep	Lower Kittanning	Steam, Metall.	57,027	50,000 to 999,999
Island Creek Coal Co. Tioga Mine	Nicholas	Deep	Lower Kittanning, 42 in. th.	Steam	179,455	100,000 to 199,999
Island Creek Coal Co. Upshur Mine	Upshur	Strip	Lower Kittanning; Middle Kittanning	Steam, Metall.	6,512	
Peter White Coal Mining Corp. Peter White No. 1	McDowell	Deep, Strip	Lower War Eagle, Pond Creek, Alma, Upper and Lower Cedar Grove, Williamson	Steam	347,833 80,632	200,000 to 499,999

TABLE II

SUMMARY OF COAL PRODUCING COMPANIES BY TONNAGE CLASS, PRODUCTION, PRINCIPAL APPLICATION(S),
SEAM(S) MINED, TYPE MINE, COUNTY AND STATE

WEST VIRGINIA (CONTINUED)

Coal Producing Companies	County	Type Mine	Seam(s) Mined	Principal Application(s)	1976 Production	Tonnage Class
<u>Peter White Coal Mining Corp.</u> Peter White No. 2	McDowell	Deep Strip	Alma, Pond Creek	Metall.	100,934 12,854	100,000 to 199,999
<u>Itman Coal Co.</u> Itman Mines	Wyoming	Deep	Pocahontas #3, 42-50 in. th.	Metall.	1,444,125	500,000 and over
<u>Valley Camp Coal Co.</u> Valley Camp Mine No.1	Ohio	Deep	Pittsburgh #8 58 in. th.		972,156	500,000 and over
<u>Valley Camp Coal Co.</u> Valley Camp Mine No.3	Ohio	Deep	Pittsburgh #8, 58 in. th.		529,438	500,000 and over
<u>Valley Camp Coal Co.</u> Alexander Mine	Marshall	Deep	Pittsburgh #8, 6 in. th., 100% of total		434,187	200,000 to 499,999
<u>Valley Camp Coal Co.</u> Southern Division, Valley Camp 12-A	Kanawha	Deep	Lewiston, 48 in. th.		247,015	200,000 to 499,999
<u>Valley Camp Coal Co.</u> Southern Division, Valley Camp 15	Kanawha	Deep	Coalburg, 42 in. th.		289,763	200,000 to 499,999
<u>Valley Camp Coal Co.</u> Southern Division, Valley Camp 5-A	Kanawha	Deep	Lewiston, 48 in. th.		125,317	100,000 to 199,999

TABLE II

SUMMARY OF COAL PRODUCING COMPANIES BY TONNAGE CLASS, PRODUCTION, PRINCIPAL APPLICATION(S),
SEAM(S) MINED, TYPE MINE, COUNTY AND STATE

WEST VIRGINIA (CONTINUED)

Coal Producing Companies	County	Type Mine	Seam(s) Mined	Principal Application(s)	1976 Production	Tonnage Class
<u>Valley Camp Coal Co.</u> Southern Division, Valley Camp No. 5	Kanawha	Strip	Lower Kittanning		121,800	100,000 to 199,999
<u>Valley Camp Coal Co.</u> Southern Division, Valley Camp No. 35	Kanawha	Deep	Winifrede, 38 in.th.		163,934	100,000 to 199,999
<u>Valley Camp Coal Co.</u> Southern Division, Valley Camp No. 36	Kanawha	Deep	Coalburg, 40 in.th.		322,425	200,000 to 499,999
<u>Valley Camp Coal Co.</u> Southern Division, Valley Camp No. 40	Kanawha	Deep	Winifrede, 42 in.th.		130,778	100,000 to 199,999
<u>Monterey Coal Co.</u> Wayne Mine	Wayne	Deep	Winifrede, 48 in.th.			500,000 and over <u>7</u> /
<u>Consolidation Coal Co.</u> Eckman Mine	McDowell	Deep	Pocahontas II, 38 in. th.		198,236	100,000 to 199,999
<u>Consolidation Coal Co.</u> Eckman-Page Mine	McDowell	Deep	Pocahontas II, 38½ in. th.	Metall.	184,701	100,000 to 199,999
<u>Consolidation Coal Co.</u> Jenkingones Mine	McDowell	Deep	Pocahontas III, 84 in. th. Pocahontas IV, 36-96 in. th.	Metall.	433,833	200,000 to 499,999

TABLE II

SUMMARY OF COAL PRODUCING COMPANIES BY TONNAGE CLASS, PRODUCTION, PRINCIPAL APPLICATION(S),
SEAM(S) MINED, TYPE MINE, COUNTY AND STATE

WEST VIRGINIA (CONTINUED)

Coal Producing Companies	County	Type Mine	Seam(s) Mined	Principal Application(s)	1976 Production	Tonnage Class
<u>Consolidation Coal Co.</u> Maitland Mine	McDowell	Deep	Pocahontas III, 59 in. th. Pocahontas IV, 48 in. th.	Metall.	385,245	200,000 to 499,999
<u>Consolidation Coal Co.</u> Crane Creek Mines	Mercer	Deep	Pocahontas VI, 54 in. th. Pocahontas II, 33 in. th.	Metall.	364,758	200,000 to 499,999
<u>Consolidation Coal Co.</u> Turkey Gap Mine	Mercer	Deep	Pocahontas III, 56 in. th.		414,244	500,000 and over
<u>Consolidation Coal Co.</u> Buckeye Mine	Wyoming	Deep	Pocahontas I-III, 44 in. th.	Metall.	266,281	200,000 to 499,999
<u>Consolidation Coal Co.</u> Roland Mine	Raleigh	Deep, Strip	No. 2 Gas, 49 in. th. Middle Eagle, 70 in. th. Upper Eagle, 42-60 in. th. Hernshaw Lower Eagle, 78 in. th.		835,614	500,000 and over
<u>Consolidation Coal Co.</u> Jordan No. 93 Mine	Marion	Deep	Pittsburgh, 82 in. th.		431,104	200,000 to 499,999

TABLE II

SUMMARY OF COAL PRODUCING COMPANIES BY TONNAGE CLASS, PRODUCTION, PRINCIPAL APPLICATION(S),
SEAM(S) MINED, TYPE MINE, COUNTY AND STATE

WEST VIRGINIA (CONTINUED)

Coal Producing Companies	County	Type Mine	Seam(s) Mined	Principal Application(s)	1976 Production	Tonnage Class
<u>Consolidation Coal Co.</u> <u>Arkwright Mine</u>	Monongalia	Deep	Pittsburgh, 90 in.th.		1,340,618	500,000 and over
<u>Consolidation Coal Co.</u> <u>Humphrey No. 7 Mine</u>	Monongalia	Deep	Pittsburgh, 84 in.th.		2,054,984	500,000 and over
<u>Consolidation Coal Co.</u> <u>Osage No. 3 Mine</u>	Monongalia	Deep	Pittsburgh, 90 in.th.		1,410,931	500,000 and over
<u>Consolidation Coal Co.</u> <u>Pursglove No. 15 Mine</u>	Monongalia	Deep	Pittsburgh, 84 in.th.		562,482	500,000 and over
<u>Consolidation Coal Co.</u> <u>Mine No. 1</u>	Monongalia	Deep	Pittsburgh, 78 in.th. 100% of total	Steam	1,045,986	500,000 and over
<u>Consolidation Coal Co.</u> <u>Mine No. 2</u>	Monongalia	Deep	Pittsburgh, 90 in.th.		1,636,238	500,000 and over
<u>Consolidation Coal Co.</u> <u>Mine No. 95-Robinson Run</u>	Harrison	Deep	Pittsburgh, 96 in.th. 90% of total		2,869,470	500,000 and over
<u>Consolidation Coal Co.</u> <u>Loveridge Mine No. 22</u>	Marion	Deep	Pittsburgh, 84 in.th. 100% of total	Steam	1,989,929	500,000 and over
<u>Consolidation Coal Co.</u> <u>Mine No. 9</u>	Marion	Deep	Pittsburgh, 80 in.th. 100% of total	Steam	108,070	100,000 to 199,999

TABLE II

SUMMARY OF COAL PRODUCING COMPANIES BY TONNAGE CLASS, PRODUCTION, PRINCIPAL APPLICATION(S),
SEAM(S) MINED, TYPE MINE, COUNTY AND STATE

WEST VIRGINIA (CONTINUED)

Coal Producing Companies	County	Type Mine	Seam(s) Mined	Principal Application(s)	1976 Production	Tonnage Class
Consolidation Coal Co. William Mine No. 98	Marion	Deep	Pittsburgh, 79 in.th 100% of total	Steam	508.867	500,000 and over

TABLE II

SUMMARY OF COAL PRODUCING COMPANIES BY TONNAGE CLASS, PRODUCTION, PRINCIPAL APPLICATION(S),
SEAM(S) MINED. TYPE, MINE, COUNTY AND STATE

CHIO

Coal Producing Companies	County	Type Mine	Seam(s) Mined	Principal Application(s)	1976 Production	Tonnage Class
Island Creek Coal Co. Vail Mine	Guerney	Deep	No. 7	Steam	6,151	10,000 and over
Consolidation Coal Co. Egypt Valley No. 21 Mine	Belmont	Strip Auger	Pittsburgh #8, 45 in. th. Sewickley #9, 46 in. th. No. 12, 24 in. th.		2,167,179	200,000 to 499,999
Consolidation Coal Co. Fairview No. 18 Mine	Belmont	Strip	Pittsburgh		86,229*	
Consolidation Coal Co. Bradford No. 16 Mine	Harrison		Meigs Creek #9, 50 in. th. Pittsburgh #8, 48 in. th.		442,182	200,000 to 499,999
Consolidation Coal Co. Georgetown No. 12 Mine	Harrison	Strip	Pittsburgh #8 Sewickley #9		560,065	500,000 and over
Consolidation Coal Co. Georgetown No. 24 Mine	Harrison		Pittsburgh #8, 50 in. th.		873,350	
Consolidation Coal Co. Mahoung Valley No. 33 Mine	Harrison	Strip	Meigs Creek #9		1,097,843	500,000 and over

* 1975 Production Level

TABLE II

SUMMARY OF COAL PRODUCING COMPANIES BY TONNAGE CLASS, PRODUCTION, PRINCIPAL APPLICATION(S),
SEAM(S) MINED, TYPE MINE, COUNTY AND STATE

OHIO (CONTINUED)

Coal Producing Companies	County	Type Mine	Seam(s) Mined	Principal Application(s)	1976 Production	Tonnage Class
Consolidation Coal Co. West Farms No. 22 Mine	Jefferson	Strip	Pittsburgh #8		429,872	200,000 to 499,999
Consolidation Coal Co. Rose Valley No. 6 Mine	Harrison	Deep	Lower Freeport #5-A, 56 in. th. 100% of total		766,369	500,000 and over
Consolidation Coal Co. Franklin No. 25 Mine	Harrison	Deep	Pittsburgh #8, 56 in. th. 100% of total		941,279	500,000 and over
Consolidation Coal Co. Franklin Highwall No. 65 Mine	Harrison	Deep	Pittsburgh #8, 60 in. th. 100% of total	Steam	283,907	200,000 to 499,999
Consolidation Coal Co. Oak Park No. 7 Mine	Jefferson	Deep	Lower Freeport #6-A, 60 in. th. 100% of total		559,201	500,000 and over

TABLE II

SUMMARY OF COAL PRODUCING COMPANIES BY TONNAGE CLASS, PRODUCTION, PRINCIPAL APPLICATION(S),
SEAM(S) MINED, TYPE MINE, COUNTY AND STATE

PENNSYLVANIA

Coal Producing Companies	County	Type Mine	Seam(s) Mined	Principal Application(s)	1976 Production	Tonnage Class
<u>Island Creek Coal Co.</u> Bird No. 2 and 3 Mine	Somerset	Deep	42/48 in. th.	Metall.	549,465	500,000 and over
<u>Harmer Coal Co.</u> Oakmont Mine	Allegheny	Deep	Upper Freeport, 84 in. th.		338,130*	200,000 to 499,999
<u>Mathies Coal Co.</u> Mathies Mine	Washington	Deep	Pittsburgh, 68 in. th.		2,019,281	500,000 and over
<u>Consolidation Coal Co.</u> Renton Mine	Allegheny	Deep	Upper Freeport, 96 in. th.		747,556	
<u>Consolidation Coal Co.</u> Laurel Mine	Somerset	Deep	Lower Kittanning, 84 in. th.		295,179	200,000 to 499,999
<u>Consolidation Coal Co.</u> Montour 10 Mine	Allegheny	Deep	Pittsburgh, 68 in.th.		291,605	200,000 to 499,999
<u>Consolidation Coal Co.</u> Montour 4 Mine	Washington	Deep	Pittsburgh, 68 in.th.		1,479,274*	500,000 and over
<u>Consolidation Coal Co.</u> Westland Mine	Washington	Deep	Pittsburgh, 62 in.th.		486,519	200,000 to 499,999

* 1975 Production Level

TABLE II

SUMMARY OF COAL PRODUCING COMPANIES BY TONNAGE CLASS, PRODUCTION, PRINCIPAL APPLICATION(S),
SEAM(S) MINED, TYPE MINE, COUNTY AND STATE

MISSOURI

Coal Producing Companies	County	Type Mine	Seam(s) Mined	Principal Application(s)	1976 Production	Tonnage Class
Pittsburgh and Midway Coal Mining Co. Empire Mine	Barton	Strip			558,250	500,000 and over

TABLE II

SUMMARY OF COAL PRODUCING COMPANIES BY TONNAGE CLASS, PRODUCTION, PRINCIPAL APPLICATION(S),
SEAM(S) MINED, TYPE MINE, COUNTY AND STATE

NEW MEXICO

Coal Producing Companies	County	Type Mine	Seam(s) Mined	Principal Application(s)	1976 Production	Tonnage Class
<u>Pittsburgh and Midway</u> <u>Coal Mining Co..</u> McKinley Mine	McKinley	Strip	Green		842,339	500,000 and over ^{8/}

TABLE II

SUMMARY OF COAL PRODUCING COMPANIES BY TONNAGE CLASS, PRODUCTION, PRINCIPAL APPLICATION(S),
SEAM(S) MINED, TYPE MINE, COUNTY AND STATE

COLORADO

Coal Producing Companies	County	Type Mine	Seam(s) Mined	Principal Application(s)	1976 Production	Tonnage Class
Pittsburgh and Midway Coal Mining Co. Edna Mine	Routt	Strip			1,140,177	

TABLE II

SUMMARY OF COAL PRODUCING COMPANIES BY TONNAGE CLASS, PRODUCTION, PRINCIPAL APPLICATION(S),
SEAM(S) MINED, TYPE MINE, COUNTY AND STATE

NORTH DAKOTA

Coal Producing Companies	County	Type Mine	Seam(s) Mined	Principal Application(s)	1976 Production	Tonnage Class
Consolidation Coal Co. Velva Mine	McHenry	Strip	Ccteau		341,606	200,000 to 499,999 ⁹
Consolidation Coal Co. Glen Harold Mine	Mercer	Strip			3,706,718	500,000 and over ¹⁰

TABLE II

SUMMARY OF COAL PRODUCING COMPANIES BY TONNAGE CLASS, PRODUCTION, PRINCIPAL APPLICATION(S),
SEAM(S) MINED, TYPE MINE, COUNTY AND STATE.

ALABAMA

Coal Producing Companies	County	Type Mine	Seam(s) Mined	Principal Application(s)	1976 Production	Tonnage Class
<u>Walker-Fayette Coal</u> <u>Co.</u> Corona Mine	Walker	Strip	Corona, 24 in.th.		518,463	500,000 and over

Footnotes

- 1/ Mine opened June 1976; full production by 1980.
- 2/ Scheduled opening in 1977; production of 36 million tons by 1980.
- 3/ Date opened 1975; full production by 1977.
- 4/ Scheduled opening in 1979; initial production five million tons.
- 5/ Scheduled opening mid-1977; initial production five million tons per year; full capacity of twelve million tons per year.
- 6/ Mine to be opened in 1978.
- 7/ Under construction.
- 8/ Mine expansion underway to raise capacity to 5.0 million tons in 1979.
- 9/ Life expectancy is five years.
- 10/ Life expectancy is 35 years.

Table II-A

COAL PRODUCING STATES WITH
OPERATIONS OWNED BY OIL COMPANIES

Utah
Illinois
Indiana
Virginia
Alabama
Wyoming
Kentucky
West Virginia
Ohio
Pennsylvania
Missouri
New Mexico
Colorado

APPENDIX 3

RATE OF RETURN AND FINANCIAL
VARIABLE RELATIONSHIPS
IN THE NCM

SUMMARY OF BASE CASE
UNDERGROUND MINE COSTING
(\$000)

1. Initial K = \$29,300 Deferred K = \$11,700

where, K = Capital

2. Present Discounted Value

(PDV) of total K investment = \$34,729

3. Cash Flow is treated as an annuity, such that:

$$\text{Cash Flow (CF)} = \text{PDV} \frac{.08}{1 - (1 + .08)^{-20}}$$

where,

Mine life = 20 years

Discount rate = 8 percent

Therefore, this annual Cash Flow will be the equivalent of earning 8% on invested K.

$$\text{CF} = \$34,729 \frac{.08}{1 - (1 + .08)^{-20}}$$

$$\text{CF} = \$ 3,537$$

CF = (Depreciation + Depletion + After-Tax Profit)

where, Federal Income Tax = $\frac{1}{2}$ (Taxable Income)

Depletion = 10% of Sales, up to 50% of
Gross Profit

4. Total Sales (TS) were estimated next using one of two equations:

$$TS = \frac{(.5 \text{ Operating Costs} + CF - \text{Depreciation})}{.55}$$

where, Depletion = 10% of TS, or

$$TS = \text{Operating Costs} + \frac{4 (CF - \text{Depreciation})}{3}$$

where, Depletion = 50% of Gross Profit

The choice of equations depended on which assumption represented the more binding constraint for the mine type being considered.

For the example base case, the second equation was used to estimate Total Sales:

$$TS = 11,997 + \frac{4 (3537 - 2050)}{3}$$

$$TS = \$13,980$$

5. In all cases, however, an explicit constraint was imposed that:

$$CF = (\text{Depreciation} + \text{Depletion} + \text{After-Tax Profits})$$

Plugging in our values, the constraint is met:

$$\$3,537 = 2,050 + 991 + 496$$

Minimum Acceptable Selling Price = TS/Output

For our example, Price = 13,980/1,000

Price = \$13.98

TABLE III

THE RELATIONSHIP BETWEEN
CHANGES IN ROR AND
SELECTED FINANCIAL VARIABLES

Base Case Assumptions:

Rate of Return on Invested Capital = $i = 8\%$

Mine Life = $n = 20$

Present Value = \$34,729

Cash Flow (annual) = \$3,537

The Effects of a change in i , all other base case assumptions held constant:

Variables	i				
	.06	.07	.08	.09	.10
1) Cash Flow	3028	3278	3537	3804	4079
2) Gross Profit/Sales	10%	12%	14%	16%	18%
3) Gross Profit	1,304	1,637	1,983	2,339	2,705
4) Sales	13,301	13,634	13,980	14,336	14,702
5) Price	13.30	13.63	13.98	14.34	14.70
6) Depreciation	2050	2050	2050	2050	2050
7) Operating Costs	11,997	11,997	11,997	11,997	11,997

SOLVING FOR π IN CASE WHERE
DEPLETION = 50% OF GROSS PROFIT

$$CF = DPR + DPL + (\pi - DPL - T)$$

$$CF = 2050 + .5\pi + [\pi - .5\pi - .5(\pi - (.5\pi))]$$

$$3537 = 2050 + .5\pi + [\pi - .5\pi - .5(\pi - (.5\pi))]$$

$$.5\pi + [\pi - .5\pi - .5(\pi - (.5\pi))] = 1487$$

$$.5\pi + [.5\pi - .5(.5\pi)] = 1487$$

$$.5\pi + .25\pi = 1487$$

$$.75\pi = 1487$$

$$\pi = 1983$$

$$CF = DPR + .75\pi$$

$$\pi = \frac{CF - DPR}{.75}$$

CF = Cash Flow

DPR = Depreciation

DPL = Depletion

π = Gross Profit

T = Taxes

TS = Total Sales

SOLVING FOR π IN CASE WHERE
DEPLETION = 10% OF TOTAL SALES

$$CF = DPR + DPL + (\pi - DPL - T)$$

$$CF = 2050 + .10(TS) + [\pi - .10(TS) - (.5(\pi - DPL))]$$

$$3537 = 2050 + 1361 + [\pi - 1361 - (.5(\pi - .10(TS)))]$$

$$3537 = 3411 + [\pi - 1361 - (.5(\pi - 1361))]$$

$$\pi - 1361 - (.5(\pi - 1361)) = 126$$

$$\pi - (.5(\pi - 1361)) = 1487$$

$$\pi - .5\pi + 680.50 = 1487$$

$$\pi - .5\pi = 806.50$$

$$.5\pi = 806.50$$

$$\pi = 1613$$

$$\pi = \frac{CF - DPR}{.5} - (TS)$$

APPENDIX 4

PROJECT INDEPENDENCE EVALUATION SYSTEM (PIES)

Note: The material in Appendix 4 describes the PIES Model as it existed at the beginning of this study. We understand that changes are about to be made and will be reflected in the new Administrator's Annual Report. The changes are not expected to significantly affect the conceptual material presented here. The main report (Volume I) of this study provides all current assumptions underlying PIES as of May 1, 1978.

APPENDIX 4

PROJECT INDEPENDENCE EVALUATION SYSTEM (PIES)

Introduction

The Project Independence Evaluation System (PIES) is a complex, integrated, modularized computer model developed by the Federal Energy Administration, now Department of Energy, to analyze energy policy. PIES predicts the state of the energy sector of the U.S. economy on an average day in 1985 and 1990. PIES analyzes, in a partial equilibrium context, the supply and demand for the following fuels:

electricity	steam coal
natural gas	metallurgical coal
residual oil	liquid gases
gasoline	other petroleum products
distillate oil	jet fuel

The analysis is both national and regional with each of the 10 DOE energy regions having its own equilibrium solution for each fuel. Furthermore the analysis is carried out for five sectors:

- commercial
- industrial
- residential
- transportation
- minor fuels sector

PIES also determines the sources of the ten fuels, the methods of conversion into energy amenable for end-used consumption, and the inter-regional transfers of fuels necessary for final supply-demand equilibrium. PIES also details import requirements for 19 crude types and 7 products.

The PIES model is composed of three different model systems: a collection of econometric models which predict demands for each fuel by sector, by geographic region; a set of supply representations--supply curves--for each of fuels analyzed within PIES; and an integrating mechanism which solves, with the use of a linear programming (LP) subroutine the partial equilibrium solutions.

The present study adapts and makes use of PIES to analyze the impacts on coal consumption of forced divestiture by oil companies of coal company subsidiaries and restrictions on future expansion by oil companies into the coal sector of the energy sector of the economy.

PIES is a complex system requiring considerable detail in explanation--thus this chapter is necessarily lengthy. It is important for the reader to become immersed in the PIES model, to become familiar with its strengths and mindful of its limitations. Surely, acceptance of the results of this study will hinge on the reader's confidence in the consistency and comprehensiveness of the model.

This chapter is divided into five sections. After a brief introduction section 1 describes the demand side of PIES -- the Regional Demand Forecasting Model (RDFOR). The theoretical structure of RDFOR is explained in some detail, for the consequences of any divestiture policy will be observed on the demand side--coal consumption. The second section focuses on the supply side of PIES, which is composed of a number of separate supply modules, each one a separate linear programming

which solves for the minimum acceptable price at which a certain quantity of fuel will be brought to market. A separate chapter of this report will explain in much greater detail the coal supply side of PIES.

The third section of this chapter describes the Integrating Mechanism--that part of the PIES model which brings supply and demand together and solves for an equilibrium price-quantity solution. The process of equilibration is explained in some detail.

The fourth section of the chapter explains the various (22) scenarios which can be implemented in PIES.

The fifth and final section of this chapter displays PIES output reports. The reader should familiarize himself with the structure of reporting so that the consequences of future alterations in PIES variables can be quickly and easily evaluated.

Regional Demand Forecasting Model (RDFOR)

The Regional Demand Forecasting Model (RDFOR) is a set of demand equations which provide annual estimates of the quantities demanded, prices, and price and income elasticities of demand for 30 fuel/sector pairs for each of the ten DOE energy regions from 1977 to 1990. Fuel choices are price-sensitive, price induced substitution is uninhibited, and dynamic adjustments to changing fuel prices and economic conditions are incorporated into the model. Figure 1 below depicts the structure and flow of RDFOR.

FIGURE 1 - DEMAND MODEL SCHEMATIC

The preprocessors shown near the top of the figure take regionally specific raw data for macroeconomic forecasts and initial quantities and prices and transform these data into standard format files which can be read directly by RDFOR.

In addition to macro variables, prices, and particular conservation programs' effects on the transportation sector, regional parameter values are also preprocessed as input to RDFOR; these values determine how responsive demand is to prices and economic conditions.

Within RDFOR the demands plus prices of the 30 fuel/sector pairs combine to define points on a demand surface. The slopes of the demand curve are obtained by perturbing prices and recording the new demands. The log-linearity of the equations permits a single perturbation to derive elasticities. The derived elasticities are intertemporal, not short-run, and fit well within the PIES framework where price changes are assumed rolled in over time.

The intermediate files containing regional demand points for each price path perturbation are combined with unperturbed prices in the Demand Interface Program (DFACE). Elasticities are calculated and are adjusted for specific scenario demand shifts. The adjusted demand point and elasticity arrays produced by DFACE serve as model inputs to the PIES integrating mechanism for these target years. RDFOR and DFACE also produce their own formal reports.

The Demand Interface Program (DFACE) transforms the output of RDFOR into a format usable by PIES. It is within DFACE that demand curves are approximated for each fuel.

The RDFOR model contains 14 fuels:

(1) Asphalt	(8) Metallurgical Coal
(2) Coal	(9) Natural Gas
(3) Distillate Fuel	(10) Oil
(4) Electricity	(11) Petroleum Coke
(5) Gasoline	(12) Petroleum Products
(6) Jet Fuel	(13) Residual Fuel
(7) Liquid Gases	(14) Total Fuels.

These fuels are spread over four sectors:

- (1) Commercial
- (2) Industrial
- (3) Residential
- (4) Transportation.

In addition, feedstocks and raw materials comprise two smaller sectors, which are modeled within RDFOR and PIES by DOE region. The 14 fuels spread across the sectors gives the set of 30 fuel/sector pairs, eight fuels totals, four sector totals, and a grand total for all fuels and sectors. These combinations along with their descriptive codes are listed in Tables 1, 2, and 3 below.

In addition to data on prices and quantities of fuels demanded, major inputs to RDFOR are:

- (1) The projected path of fuel prices by sector and region from 1977 to 1990;
- (2) Forecasts of population, income, and industrial activity through 1990;
- (3) Impacts of conservation programs; and
- (4) Availability of natural gas markets.

Table 1 30 Fuel/Sector Pairs

Fuel Description	Fuel Code	Price Paths Exist
Coal		
Household/Commercial Coal	CLHC	
Industrial Coal	CLIN	x
Transportation Coal	CLTR	
Commercial Asphalt	ASCM	
Distillate		
Commercial Distillate	DFCM	x
Industrial Distillate	DFIN	x
Residential Distillate	DFRS	x
Transportation Distillate	DFTR	x
Electricity		
Commercial Electricity	ELCM	x
Industrial Electricity	ELIN	x
Residential Electricity	ELRS	x
Transportation Electricity	ELTR	
Gas--Natural		
Commercial Natural Gas	NGCM	x
Industrial Natural Gas	NGIN	x
Raw Material Natural Gas	NGRM	
Residential Natural Gas	NGRG	x
Gases--Liquid		
Commercial Liquid Gases	LGCM	
Feedstock Liquid Gases	LGFS	
Industrial Liquid Gases	LGIN	x
Raw Materials Liquid Gases	LGRM	
Residential Liquid Gases	LGRS	x
Transportation Liquid Gases	LGTR	
Gasoline		
Transportation Gasoline	GSTR	x
Jet Fuel		
Transportation Jet Fuel	JFTR	x
Metallurgical Coal		
Industrial Metallurgical Coal	MCIN	

Table 1 (Continued)

Oil		
Raw Material Oil	OLRM	
Petroleum Coke		
Industrial Petroleum Coke	PCIN	
Residual		
Commercial Residual	RFCM	x
Industrial Residual	RFIN	x
Transportation Residual	RFTR	x

Table 2 - Eight Fuels Totals

Fuel Description	Fuel Code
Total Coal	CLTT
Total Distillate	DFTT
Total Electricity	ELTT
Total Liquid Gases	LGTT
Total Natural Gas	NGTT
Total Oil	CLTT
Total Other Petroleum Products	OPTT
Total Residual	RFTT

Table 3. Sector Fuel Totals

Fuel Description	Fuel Code
Commercial--All Fuels	TTCM
Industrial--All Fuels	TTIN
Residential--All Fuels	TTRS
Transportation--All Fuels	TTTR
Total--All Fuels	TTTT

As output, RDFOR provides:

- (1) Forecasts of demands for the 30 fuel/sector pairs;
- (2) The prices of the following fuels:
 - Distillate fuel
 - Gasoline
 - Household electricity
 - Household natural gas
 - Industrial bituminous coal
 - Industrial electricity
 - Industrial natural gas
 - Residual fuel
 - Other petroleum products (kerosene) and liquid gases.
- (3) The elasticities of each of the 30 fuel/sector pairs with respect to the prices of the fuels products listed in (2) above.

PIES determines supply-demand equilibrium for prices and quantities of the fuels denoted above. For each of the fuels, it is necessary to establish step function approximations to a demand curve. In order to do this, it is necessary to have estimates of price-elasticities for each of those fuels. For each of the fuels, the price-elasticity of the predominant fuel/sector pair component is selected from an electricity matrix. The elasticities used are for:

- (1) gasoline in transportation
- (2) household distillate fuel
- (3) household residual fuel
- (4) household kerosene
- (5) household electricity
- (6) industrial natural gas
- (7) industrial bituminous coal
- (8) metallurgical coal.

DFACE aggregates and transforms the demand curve estimates into a format suitable for use in PIES.

Certain fuels, e.g., metallurgical coal, are not treated in the same way as other more important fuels by RDFOR. RDFOR provides estimates of demands for these minor fuels, but the demand is then considered to be wholly elastic. Further, no interfuel substitution is permitted. These constraints are achieved within the demand model which provides estimates of zero for own and cross-price elasticities for these fuels. For example, the price of metallurgical coal is set arbitrarily at \$30/ton within the equilibrating routine and thereafter metallurgical coal is treated by the model in precisely the same way as the other price-sensitive fuels. When demand curves are calculated for these fuels, they are horizontal and quantities consumed are determined by supply.

Theoretical Structure of RDFOR

RDFOR is broken down into three submodels:

- (1) Demand relationships for the residential, commercial, and industrial sectors;
- (2) Demand for fuel in the transportation sector;
- (3) Demand equations which cover the remaining fuel consumption categories.

Residential, Commercial and Industrial Sector Fuel Demands

There are two basic demand relationships. The first relates the total use of fuel to other goods and services in the economy. The second analyzes the distribution of this total fuel demand between different types of fuels. This type of structure has implications for the extent to which different types of fuel and non-fuel goods interact as well as how changes in the rest of the economy affect various types

of fuels demanded.

Aggregate Fuel Demand. Aggregate energy consumption depends on (1) a measure of the price of energy and the level of economic activity--which represents either consumer income or value added in manufacturing--as well as (2) the number of heating degree days and cooling degree days--which reflect shifts over time and across regions in aggregate energy demand. These latter two variables serve as proxies for the quantity of one of the services produced by fuels--that of providing moderation in temperatures.

The demand function is written as

$$(1) \quad TQ = f(TP, Y, HDD, CDD,)$$

where TQ is a value weighted geometric index of individual fuel types per capita, TP is a value weighted geometric index of individual fuel prices, Y is either disposable income per capita (for the residential and commercial sector) or value added in manufacturing (VA in the industrial sector), HDD is the heating degree days, and CDD is cooling degree days.

Specific Fuel Demand. The quantity demanded of a specific fuel type relative to the aggregate fuel demand (Q/TQ) is modeled to depend on a combination of the price of the fuel in question relative to a price index for all fuels and the availability of natural gas in a region. The relative price variable (P/TP) is specified as the price of the fuel divided by the value weighted index of all the fuel prices,

$$(2) \quad Q/TQ = f(P/TP, GSC),$$

where GSC is the availability of natural gas as measured by gas service customers.

Dynamics of Fuel Demands. RDFOR extends the demand relationships given in equations 1 and 2 to include dynamic adjustment procedures. The specific adjustment mechanism is a geometric distributed lag. However, the effect of lagged variables on present period demand for fuel is allowed to be different for different variables.

To account for the differences in the income and price lag structures, the income variable is modified to represent a form of permanent income. Temporary fluctuations in the income of a region will not affect the permanent demand for fuel. Instead, permanent income or wealth affects the consumption of goods or services. Therefore, when a sector experiences a temporary reduction in income, the quantity of a fuel demanded will not change as dramatically as when the region experiences a permanent reduction in income.

The permanent income or wealth variable is specified as a function of past period disposable income variables with weights declining over time,

$$(3) \quad Y_{\text{PERM}}(t) = 4/7 Y(t) + 2/7 Y(t-1) + 1/7 Y(t-2)$$

The weights of 4/7, 2/7, and 1/7 in equation 3 have been arbitrarily imposed on the model.

The effect of lagged period prices on current period consumption is assumed to follow the geometric lag distribution. It is through this lagged adjustment process that the dynamics of demand adjustment are captured.

A similar dynamic procedure is used for the relationship specifying the demand for the share of an individual fuel in total fuel consumption. The effects of past period prices

are assumed to follow a geometric lag structure while the availability of natural gas is assumed to be effective only in the current period.

Transportation Sector Fuel Demands

For the most part, the demands for fuel in the transportation sector are modeled by end use. Interfuel substitution is assumed to be less significant in the transportation sector than in the commercial, residential, or industrial sectors.

The major components of demand for fuel in the transportation sector are auto highway gasoline use, non-auto highway gasoline fuel. A summary of the transportation fuel relationships is presented in Table 4.

The demands for auto, truck and bus fuel are specified in terms of two behavioral equations and one identity. Vehicle miles and miles per gallon are both specified as behavioral variables. Total fuel demand for each of these categories is derived by an identity where fuel demand is equal to the ratio of vehicle miles to miles per gallon.

The demand for automobile gasoline is determined by modeling vehicle and fleet average miles per gallon separately. Vehicle miles are specified as a function of per capita income, I ; the cost of vehicle operation (including both fuel and time costs), C ; and the unemployment rate, U ,

$$VM = VM(I, C, U).$$

Automobile demand for gasoline is determined by taking the ratio of automobile vehicle miles to average fleet efficiency. The fleet efficiency is specified as a weighted average of the efficiency of automobiles of various age, assuming new cars

Table 4 - Summary of Transportation Fuel Relationship

Dependent Variables	Independent Variables
1. Cost of Auto Driving	Price of Gasoline; Time-cost of Wages Foregone
Auto Vehicle Miles (VM) Capita Demanded	Cost; per capita income; unemployment rate
3. New Car Sales	VM; Unemployment rate; Per capita income; VM capacity of last period's existing stock
5. Average mpg of entire fleet	Weighted geometric mean of mpg's from current and past vintages
6. Auto gasoline demanded	Auto VM divided by average mpg of auto stock
7. Truck VM	Weighted average of prices of gasoline and diesel fuel; GNP; Industrial Production Index
8. Truck mpg	Interest rate; Unemployment Industrial Production Index
9. Truck fuel	Truck VM divided by truck mpg
10. Bus VM	Weighted average of prices of gasoline and diesel fuel; per capita income
11. Bus mpg	Unemployment rate; Average speed of buses
12. Bus Fuel	Bus VM divided by bus mpg
13. Ratio of Truck & Bus Gasoline to Truck & Bus Diesel Fuel	Ratio of gasoline to diesel fuel price; Industrial production index; ratio of single-unit to combination trucks.
14. Rail Ton Miles	Diesel fuel price (not including highway taxes);

Table 4 (Continued)

	capital expenditures in the railroad industry.
15. Rail Diesel Fuel	Rail ton miles; index of employee compensation (nonfarm)
16. Air Passenger Miles	Cost per passenger mile of aircraft operation (part of which is the price of jet fuel); per capita income.
17. Commercial Jet Fuel	Air passenger miles adjusted by CAB load factor.
18. Non-Highway Gasoline	Gross national product.
19. Military Jet Fuel	Constant at 1975 level
20. Liquid gases	Liquid gases lagged one period; PRB index for manufacturing.
21. Residual Oil	Residual oil lagged one period; contemporaneous and lagged rail diesel fuel; diesel-residual fuel price ratio.
22. Coal	Time

are driven more than older cars. Exponential scrapping of the existing fleet is also specified.

Given the desired vehicle miles, the demand for new cars depends on the capital stock of automobiles. The efficiency of new automobiles is determined by the price of gasoline in the current year.

For trucks and buses, total fuel is estimated as a function of vehicle miles and fleet efficiency without a vintaging effect. Combined automobile, truck, and bus fuel is split between gasoline and diesel fuel on the basis of the relative prices of the fuels, an industrial production index, total vehicle miles, and a measure of the size of the truck stock. Interfuel substitution is allowed in the truck and bus demand specifications.

Total rail ton miles is specified as a function of diesel fuel price and capital expenditures in the railroad industry. The demand for rail diesel fuel is then specified as a function of rail ton miles.

Commercial jet fuel is a function of air passenger miles adjusted by an airplane load factor in order to account for excess capacity of air flights. Air passenger miles are a function of operating costs, including the price of jet fuel, per capita income, and the price of military type jet fuel.

Minor Fuels Sector

Separate models for fuel categories not so far considered make up the third submodel of RDFOR. These include the demand for natural gas, liquid gas and coal in the raw materials sector; commercial demand for asphalt, and liquid gas; industrial

demand for petroleum gases and metallurgical coal; and the household/commercial demand for coal.

Except for the commercial demand for liquid gas, price variables are not included in these specifications. Instead the consumption of these fuels is a function of industrial value added, time trends, lagged consumption variables, and in the case of asphalt, gasoline consumption. The exact specifications are given in Table 5. The time trends for raw materials, liquid gases and coal are specified in terms of the logs of time and lagged time. If these variables were not in log form, there would be exact multicollinearity between these two variables. Log transformations reduce the multicollinearity; however, an interpretation of the coefficients associated with these variables is uncertain.

Table 5. Explanatory Variables in Minor Fuels Sector

Fuel Category	Explanatory Variables
Raw Materials	*VA 28
Natural Gas	
Commercial	Industrial Liquid Gas Price
Liquid Gases	Lagged Quantity
Feedstocks	VA28, Lagged VA28
Liquid Gases	Lagged Quantity
Raw Materials	Time Trends
Liquid Gases	Lagged Quantity
Raw Materials	Time Trends
Coal	Lagged Quantity
Industrial	VA 33, Lagged VA33
Petroleum Gases	Lagged Quantity
Commercial	Gasoline consumption
Asphalt	Lagged, Lagged Output
Household/Commercial	Time, Lagged Quantity
Coal	
Industrial	VA 33, Lagged VA 33
	Lagged Quantity
Metallurgical Coal	NA

*VA = Value Added in Si c

Supply

This section of the chapter describes briefly each of the eight supply modules within PIES. Less emphasis is spent on analyzing supply because: (1) the purpose of this report is to analyze demand shifts, and (2) each of specific supply modules--except for coal--is little affected by divestiture. Coal supply itself is only briefly surveyed here, for an entire chapter is devoted to describing the PIES and National Coal Model (NCM) coal supply curves.

Figure P below shows a schematic of the integrated supply model. Primary activities are represented by column in the linear programming matrix:

- (1) Production or input of a material,
- (2) Operation of a facility,
- (3) Building of a new facility,
- (4) Transportation of a material.

The rows of the matrix specify objectives and constraints:

- (1) Objective function - total cost to be minimized,
- (2) Process or material limits - restrict operating capacity of facilities,
- (3) Material balance - force input to equal output for a fuel for each region,
- (4) Demand equations which represent product delivery.

The eight supply modules analyzed are:

Coal	Utilities
Oil	Emerging Technology
Gas	Transportation
Refineries	Imports

The traditional approach to formulating supply functions would estimate output as a function of capital and labor.

Figure P
SCHEMATIC OF INTEGRATED SUPPLY MODEL (SIGN CONVENTIONS)

		Primary Production			Primary Transportation			Refining Activity	Electrical Generation		Product Transportation		Facility Expansion	Imports			Exports	Demand Approximation	Constraint				
		Oil	Gas	Coal	Oil	Gas	Coal		Fossil	Nuclear Solar Geothermal	Petroleum Products	Electricity		Oil	Petroleum Products	Gas	Coal		Type	Value			
Objective Minimization		Variable Cost of Activity											Annualized Capital Cost	Import Prices				Marginal Demand Prices					
Process Limits	Refining								+ 1*					-1						\$	Existing Capacity		
	Electrical								+ 1*				-1							\$	Existing Capacity		
Production Regions	Oil	⊕	⊕		-1*													2	○				
	Gas	⊕	⊕		-1	-1														2	○		
	Coal			⊕		-1*	-1*									-1*					2	○	
Refinery Regions	Oil				-1*				⊖					+1*							2	○	
	Petroleum Products							⊕			-1*	-1*						2	○				
Utility Regions	Gas				-1				⊖							+1*						2	○
	Coal					-1				⊖												2	○
	Petroleum Products							⊖			+1*					+1*						2	○
	Electricity							+	+			-1*										2	○
Demand Regions	Gas				-1										+1*						±	Natural Gas Demand	
	Coal					-1															±	Coal Demand	
	Petroleum Products											+1*			+1*						±	Petroleum Demand	
	Electricity											+1*								±	Electricity Demand		
Activity Bounds		+	+	+	±	±	±	±	±	±	±	±	±	±	±	F	+						

⊕ Denotes positive coefficients.
 ⊖ Denotes negative coefficients.
 * Denotes fixed value.
 L Denotes loss factor (<1).

However the major factor in determining energy output is the character and extent of the resource base. Production models using corporate finance and operation's research techniques are used to simulate actual production capabilities, given the resource base of the particular fuel being modeled.

Coal Supply Module

Coal supply curves in PIES were developed from output of the National Coal Model (NCM). A supply curve exists for each type of coal for each region of the country. The two major types of mines considered are surface and deep mines.

Within each class, Btu content, sulfur content, depth of mine and seam thickness, overburden ratios (strip mines), are all considered in determining minimum cost at which certain coal would be brought to market. PIES differentiates among 11 combinations of Btu and sulfur content. There are 12 coal regions of the country based upon combinations of Bureau of Mines' mining districts. There are 102 different mine types considered by PIES. The 102 mines consist of 36 surface mine types and 66 deep mine types. Reserve recovery fractions of 0.8 for surface mines and 0.5 for deep mines are used to determine maximum production levels for each mine type in each region over a 20 year period.

Discounted cash flow analysis is used to determine minimum acceptable selling price at which mines of each type would open. The supply curve incorporates the least to most expensive mine types and as demand changes, movements along each supply curve occur.

Reclamation costs for surface mines, severance taxes,

special adjustment for Alaskan coal, and a real rate of return of 8 percent are all considered in the price estimates.

Oil Supply Modules

Two methods are used to determine future oil supply. Estimates for traditional sources (the lower 48) and most of the Alaskan Outer Continental Shelf (OCS) are based on a DOE model which divides the areas into 12 regions. Supply curves for non-traditional sources (Alaskan North Slope, Naval Petroleum Reserve Regions, heavy hydrocarbon, shale) are based on engineering analysis and expert judgment. Primary, secondary, and tertiary production of old and new oil provide refinement to model estimates. Resource assessments, recovery factors, depletion fractions, and costs--both drilling and operating--are considered in formulating oil supply estimates. Estimates of future oil supply are undertaken given different oil and gas supply conventions--which depend upon geological conditions, percent of undiscovered resources, tertiary results, and lease schedule.

Gas Supply Module

The natural gas supply module is quite similar to the oil supply curve construction. Production comes from gas wells that produce no oil and from oil wells that produce both gaseous and liquid hydrocarbons. Non-associated gas prices are sensitive to wellhead prices while associated gas prices are tied to oil prices.

The DOE model for non-associated gas considers production rates, reserves depletion, exploration, drilling rates, and investment costing on a regional bases--given estimates of the

resource base. The model is price sensitive--important in assessing gas deregulation options.

For associated gas, the oil supply model, described above is utilized. Using historical data on the ratio of gas to oil, supply curves for gas are estimated based on the supply of oil. These estimates are also on a regional basis.

Both associated and non-associated gas are separated into inter- and intra-state categories as follows:

All Alaskan and OCS- - - - -interstate

All new on-shore - - - - -intrastate

Gas from existing well - - - - -intra or inter depending
upon historical trend.

Oil and gas regions are the National Petroleum Council (NPC) shown below in Figure L. Intrastate gas regions are equivalent to the 10 DOE energy regions. Natural gas regulation and allocation are explained in the section of this chapter which describes the integrating mechanism.

Refinery Module

The conversion of gasoline, residual oil, distillate oil, jet fuel, liquid gases, and other petroleum products from crude oil is modeled by the PLES refinery model. The model approximates the operating characteristics of existing and planned refineries in the U.S. The model represents the operation of refineries in seven regions which correspond to the Petroleum Administration for Defense Districts (PADDs) regions shown in Figure M below. Material balance equations are used to represent the transportation of domestic crudes to refinery regions.

FIGURE L OIL AND GAS REGIONS

FIGURE M REFINERY REGIONS (PADD REGIONS)

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Not every domestic crude is available in every refinery region. Table J below shows that availability. Imports occur as fixed bundles with varying proportions of each crude type. Table N below shows where each crude type is refined along with percentages of refinery bundles. Canadian crude is available to all refinery regions. After imports, crudes can be refined in almost any region.

Factors considered by the model include:

- (1) operate vectors which specify how much of each of six fuels is produced from a barrel of oil,
- (2) new refinery operate vectors which abstract from historical trends and consider post-1974 conversion of crude into the six fuels,
- (3) shift vectors which model alternative uses of the chemical process equipment in refineries,
- (4) Blend vectors which model blending activities that take place with adjacent refined products,
- (5) build vectors which allow enhancement of the capabilities of existing refineries,
- (6) process consumption vectors which model the loss in yield due to refinery consumption of fuels.

Electric Utility Supply Module

Both the building of new generating plants and the operation of new and existing plants are modeled in the Utilities Supply module. The model is regional, with regions coinciding with the 10 DOE energy regions. The distribution of demand during a year is represented by a load duration curve--see Figure X below. Base, intermediate, and peak modes are combined to provide electricity demanded. Capacity constraints for base, intermediate, and peak loads are specified for each region. Base and peak capacity factors are estimated and intermediate capacity is

TABLE J

DOMESTIC CRUDES AVAILABLE IN
EACH REFINERY REGION

Crude Type	Code	R1	R2	R3	R4	R5	R6	R7
Alaskan North Slope	AN	X	X	X	X	X	X	X
Alaskan So. Brooks Range	AS					X		
Pacific Off-Shore	WO			X		X		X
Louisiana On-Shore	LN	X	X	X	X		X	X
Louisiana Off-Shore	LO	X	X	X	X		X	X
Oklahoma Mix	OK	X	X	X	X		X	X
Synthetic Crude	SY	X	X	X	X	X	X	X
Texas Gulf	TG	X	X	X	X		X	X
East Texas Mix	ET	X	X	X	X		X	X
West Texas Mix	WT	X	X	X	X		X	X
Wyoming Mix	WM		X	X	X			X
Heavy Crude PADD 2	H2		X					X
" " " 3	H3			X	X			X
" " " 4	H4				X			
" " " 5	H5					X		
Naval Petroleum Reserve 1	NP			X		X		X
Indigenous I1	I1	X	X	X	X		X	X
Indigenous I2	I2	X	X	X	X		X	X
Shale Oil	SO	X	X	X	X		X	X
West Coast Light	W1			X		X		
West Coast Heavy	W2			X		X		

TABLE N PERCENTAGE COMPOSITION OF CRUDE IMPORT BUNDLES

Import Regions		F1 (Atlantic Coast)	F3 (Gulf Coast)	F5 (West Coast)
<u>Crude Type</u>				
North Sea	NS	5	15	
African	MF	4	2	
Mexican	MX	2	9	
Venezuelan Mix	VM	22	4	5
Libyan Es Sider Blend	LY	5	8	1
Algerian	AG	10	7	
Nigerian Blend	NI	22	26	2
Iranian Light	IL	7	3	5
Iranian Heavy	IH	1		7
Arabian Light	AL	16	18	7
Arabian Heavy	AH	1	2	4
Mid East Mix	ME	2	3	7
Indonesian Minas	IN	3	3	56
Ecuadorian	EC			6
		100	100	100

Imports from region F1 are available to refinery region R1.

" " " F3 " " " " R3.

" " " F5 " " " " R5.

Canadian oil is available to all refinery regions.

FIGURE X

ANNUAL LOAD DURATION

a residual which satisfies the overall regional load factor plus a 20 percent reserve margin. The types of generating plants include:

nuclear	sub-bituminous coal
bituminous coal	lignite
high sulfur coal	residual-fired steam turbine
low sulfur coal	gas-fired steam turbine
combined cycle turbine	distillate-fired steam turbine
gas turbine	hydro, geothermal, solar

In general base load is provided by coal and nuclear power, intermediate load by coal, residual or combined cycle plants, and peak load by oil or gas fired turbines. Base load plants have high capital and low fuel costs while peak load plants have low capital and high fuel costs.

Since utilities are regulated in their rates, the customer is charged the average cost of electricity. The method of determining average cost is described in the section of this chapter on the Integrating Mechanism.

Fuel cost for the generating plant is the marginal cost to the utility region, reflecting supply prices, transportation costs and inter fuel competition.

Synthetics, Nuclear Fuel, Shale Supply Module (Emerging Technologies)

Four modes of synthetics are modeled in PIES;

- crude oil from coal
- natural gas from coal
- electricity from low Btu fuel gas
- syngas from "others" (naphtha).

Production of electricity is modeled as a direct conversion

from coal and takes place in the utilities supply module.

Since the emerging technologies generally have higher production costs than the fuels they replace, their activity levels are fixed--unspecified subsidies are given producers to encourage production.

Coal is converted to oil and gas in coal regions and transported to refinery regions and demand regions. No existing capacity for synthetics is assumed.

Conversion of "other" petroleum to natural gas occurs in DOE energy regions from refinery regions.

One shale oil region exists and production is assumed fixed--given the particular scenario.

Nuclear fuel is modeled by formulating supply curves--a series of incremental production vectors.

Transportation Supply Module

The PIES transportation network is composed of a set of independent models:

- natural gas by pipeline
- crude oil by pipeline and barge
- gasoline and distillate by pipeline and barge
- residual oil by barge

Coal has a detailed transshipment network of 19 population centers connected by barge and rail.

Coal

There are 19 modes in the rail network and 16 modes in the water network for transshipment of coal. Maps of the rail network, water network, and links from coal supply regions to each are shown below. All demand for coal is supplied by links connecting rail to utility or demand modes. Links

MAP 1.

(Distance in Short Line Miles/Cost in 1975 Dollars per Ton)

(Link Cost in 1975 Dollars per Ton)

MAP 3. RAIL LINKS CONNECTING COAL SUPPLY REGION CENTROIDS
TO RAIL TRANSSHIPMENT NETWORK

(Distance in Short line Miles/Cost in 1975 Dollars per Ton)

connect each water node to the rail node to get coal from water nodes. To distribute coal requirements to demand centers, supply is drawn from the connecting rail nodes in fixed, pre-specified proportions based on SMSA population. Figure 2 below shows the percentage of coal supplied from transshipment networks to various DOE regions. For example coal is shipped into DOE region 9 through Los Angeles (65%) and San Francisco (35%).

The coal transshipment model is composed of seven links-- four movement and three transfer links:

Movement Links

- coal supply center to rail node
- coal supply center to water node
- rail to rail node
- water to water node

Transfer Links

- rail to water node
- water to rail node
- rail node to consumption center node.

The cost of moving coal by rail is a function of distance traveled. Transportation surcharges are also included. Handling charges and fixed charges are also included except there is no charge for links between rail nodes and utility centers. There is also a charge for moving non-unit-train coal to demand regions.

Crude Pipeline

Unit cost in dollars per barrel per 100 miles is multiplied by the distances between oil supply regions and refinery regions. Charges for gathering oil from fields are included. Tariffs are also added in. Movements of imported oil between refinery regions are considered as are charges for moving Alaskan oil

FIGURE 2

PERCENTAGE OF COAL SUPPLIED FROM TRANSSHIPMENT NETWORK
TO SATISFY REGIONAL AND UTILITY DEMAND

(Standard Federal Regions)

from North Slope - Valdez - refinery region. The costs of transporting syncrude from coal and shale supply regions are included. Table B below shows pipelines charges for crude.

Product Pipeline

The cost calculations for petroleum product transshipment are obtained in a similar manner to the crude oil model. Costs are displayed in Table C below.

Natural Gas Pipeline

Both interstate and intrastate natural gas transshipment costs are modeled in PIES. Costs are constructed in much the same manner as for crude oil. Movements of gas and syngas by pipeline from coal regions to demand and utility regions are shown in Table D below.

Crude and other oil moved by barge are also modeled in PIES. Nautical miles and cost per mile are used along with inland water rates and local distribution charges to make the necessary calculations. Cost data, capacity, speed, and turnaround are all considered in the calculation.

Electricity transmission charges are modeled in PIES and nuclear costs are also but currently considered to be zero.

Import Supply Module

Import activities assume that crude oil lands in refinery regions and products land in DOE energy regions. Transportation activities model imports as bundles. The import supply module provides the bundles and associated prices to the transportation module.

Table B.

COST OF MOVING CRUDE OIL BY PIPELINE

TABLE TROPLPRC

	R1	R2	R3	R4	R5	R6	R7	01
O2	1.89	1.26	.41	.75	.10	1.57	.63	
O3	1.99	1.36	1.13	.85	.32	1.67	1.06	
O4	1.50	.86	.72	.60	.55	1.24	.58	
O5	1.45	.43	1.03	.10	.79	1.39	.26	
O6	1.23	.46	.36	.65	.72	.90	.22	
O7	1.02	.33	.10	.91	1.08	.66	.58	
O8	.97	.60	.32	1.16	1.33	.61	.80	
O9	1.05	.41	.38	.68	1.06	.88	.19	
OA	.70	.24	.79	.92	1.45	.62	.52	
OB	.87	.77	.76	1.45	1.72	.20	1.09	
OC	.45	.74	1.05	1.43	1.90	.45	1.03	
R3		.28		.86			.53	
R1						0.00		
O1			.91				1.13	
OD								1.22
C1	.70	.24	.79	.92	1.45	.62	.52	
C2	.70	.24	.79	.92	1.45	.62	.52	
C3	1.02	.33	.10	.91	1.08	.66	.58	
C4	.70	.24	.79	.92	1.45	.62	.52	
C5	1.05	.41	.38	.68	1.06	.88	.19	
C6	1.02	.33	.10	.91	1.08	.66	.58	
C7	1.45	.43	1.03	.10	.79	1.39	.26	
C8	1.45	.43	1.03	.10	.79	1.39	.26	
C9	1.50	.86	.72	.60	.55	1.24	.58	
CA	1.50	.86	.72	.60	.55	1.24	.58	
CB	1.89	1.26	.41	.75	.10	1.57	.63	
CC			.91				1.13	
S1	1.50	.86	.72	.60	.55	1.24	.58	

TABLE C. PRICE TO MOVE PETROLEUM PRODUCTS
BY PIPELINE

TABLE TRPPLPRC

	D1	D2	D3	D4	D5	D6	D7	D8	D9
R1	.16	.05	.05	.60	.63	1.14	.93	1.35	2.21
R2	.84	.73	.64	.42	.05	.49	.19	.63	1.53
R3	1.35	.44	.40	.29	.45	.20	.38	.40	1.47
R4	1.56	1.48	1.40	1.22	.85	.81	.64	.18	.83
R5	2.27	2.15	2.03	1.59	1.55	1.02	1.24	.94	.05
R6	.67	.59	.46	.18	.69	.70	.80	1.25	2.08
R7	1.17	1.07	.98	.69	.34	.28	.05	.42	1.31

TABLE TRPPLPRC-Continued

	DA	U1	U2	U3	U4	U5	U6	U7	U8
R1	2.13	.16	.05	.05	.60	.63	1.14	.93	1.35
R2	1.54	.84	.73	.64	.42	.05	.49	.19	.63
R3	1.85	1.35	.44	.40	.29	.45	.20	.38	.40
R4	.37	1.56	1.48	1.40	1.22	.85	.81	.64	.18
R5	.05	2.27	2.15	2.03	1.59	1.55	1.02	1.24	.94
R6	2.15	.67	.59	.46	.18	.69	.70	.80	1.25
R7	1.49	1.17	1.07	.98	.69	.34	.28	.05	.42

TABLE TRPPLPRC-Continued

	U9	UA
R1	2.21	2.13
R2	1.53	1.54
R3	1.47	1.85
R4	.83	.37
R5	.05	.05
R6	2.08	2.15
R7	1.31	1.49

TABLE D. COST OF MOVING INTERSTATE NATURAL GAS
BY PIPELINE

TABLE TRNPLPRC

	D1	D2	...	D9	DA	U1	U2	...	U9	UA
G3	1.41	1.37		.16	.50	1.41	1.37		.16	.50
G4	1.54	1.48		.33	.74	1.54	1.48		.33	.74
G5	1.13	1.07		.55	.63	1.13	1.07		.55	.63
G6	1.03	.98		.53	.54	1.03	.98		.53	.54
G7	1.02	.93		.66	1.04	1.02	.93		.66	1.04
G8	.87	.76		1.03	1.26	.87	.76		1.03	1.26
G9	.73	.66		1.19	1.38	.73	.66		1.19	1.38
GA	.81	.64		.76	.99	.81	.64		.76	.99
GB	.57	.51		1.07	1.08	.57	.51		1.07	1.08
GC	.51	.37		1.27	1.34	.51	.37		1.27	1.34
GD	.59	.53		1.42	1.46	.59	.53		1.42	1.46
GE	.43	.35		1.49	1.45	.43	.35		1.49	1.45
G1	2.03	1.82		1.40	1.28	2.03	1.82		1.40	1.28
G2	2.17	2.06		1.21	1.57	2.17	2.06		1.21	1.57
FC	.02	.02		.02	.02	.02	.02		.02	.02
F1	.02	.02				.02	.02			
F5				.02					.02	
C1	.51	.37		1.27	1.34	.51	.37		1.27	1.34
C2	.51	.37		1.27	1.34	.51	.37		1.27	1.34
C3	.87	.76		1.03	1.26	.87	.76		1.03	1.26
C4	.57	.51		1.07	1.08	.57	.51		1.07	1.08
C5	.81	.64		.76	.99	.81	.64		.76	.99
C6	.87	.76		1.03	1.26	.87	.76		1.02	1.26
C7	1.03	.98		.53	.54	1.03	.98		.53	.54
C8	1.03	.98		.53	.54	1.03	.98		.53	.54
C9	1.13	1.07		.55	.63	1.13	1.07		.55	.63
CA	1.13	1.07		.55	.63	1.13	1.07		.55	.63
CB	1.41	1.37		.16	.50	1.41	1.37		.16	.50
CC	2.17	2.06		1.21	1.57	2.17	2.06		1.21	1.57

Integrating Mechanism

RDFOR provides estimates of prices, demands, and elasticities to the integrating mechanism. Initial demands for the 30 fuel/sector pairs, initial price estimates for 18 fuel/sector pairs for which price is assumed elastic (see Table X), and elasticities of the 18 fuel/sector pairs with respect to the price of each fuel type for each region are included. Demands for the 12 fuel/sector pairs for which prices are not given are considered perfectly inelastic. Except for metallurgical coal whose price is set exogenously at \$30.00/ton, the initial prices of these 12 fuel/sector pairs are set equal to one of the elastic products (see Table Y).

Demand curves are constructed by step function approximations-- which indicate a range of quantities for a specific price.

The demand model approximation relies upon 10 steps:

- Step 1 is 1 percent below initial demand price,
- Step 2 is 5 percent below initial demand price,
- Step 3 is 15 percent below initial demand price,
- Step 4 is 35 percent below initial demand price,
- Step 5 is 75 percent below initial demand price,
- Step-1 is 1 percent above initial demand price,
- Step-2 is 5 percent above initial demand price,
- Step-3 is 15 percent above initial demand price,
- Step-4 is 35 percent above initial demand price,
- Step-5 is 75 percent above initial demand price.

Figure X displays the demand curve approximation which is generated through this method. Each step is called an avoid-- units of unsatisfied demand to the left of the initial price--

TABLE X. LIST OF 30 FUEL TYPES IN PIES

<u>Code</u>	<u>Fuel Type</u>
<u>Elastic Products</u>	
ELRS	Electricity - Residential
NGRS	Natural Gas - Residential
DFRS	Distillate Fuel - Residential
LGRS	Liquid Gas - Residential
ELCM	Electricity - Commercial
NGCM	Natural Gas - Commercial
DFCM	Distillate Fuel - Commercial
RFCM	Residual Fuel - Commercial
ELIN	Electricity - Industrial
NGIN	Natural Gas - Industrial
DFIN	Distillate Fuel - Industrial
RFIN	Residual Fuel - Industrial
LGIN	Liquid Gas - Industrial
CLIN	Coal - Industrial
GSTR	Gasoline - Transportation
DFTR	Distillate Fuel - Transportation
JFTR	Jet Fuel - Transportation
RFTR	Residual Fuel - Transportation
<u>Inelastic Products</u>	
ELTR	Electricity - Transportation
NGRM	Natural Gas - Raw Material
LGCM	Liquid Gas - Commercial
LGTR	Liquid Gas - Transportation
LGFS	Liquid Gas - Feedstock
LGRM	Liquid Gas - Raw Material
OLRM	Oil - Raw Material
PCIN	Petroleum Coke - Industrial
ASCM	Asphalt - Commercial
CLHC	Coal - Residential & Commercial
CLTR	Coal - Transportation
MCIN	Metallurgical Coal - Industrial

TABLE Y. CORRESPONDENCE BETWEEN ELASTIC AND
INELASTIC PRODUCTS FOR DETERMINING INITIAL PRICES

<u>Inelastic Product</u>	<u>Elastic Product Whose Price Estimate is Used as Initial Price for Inelastic Product</u>
Electricity - Transportation	Electricity - Industrial
Natural Gas - Raw Material	Natural Gas - Industrial
Liquid Gas - Commercial	Liquid Gas - Industrial
Liquid Gas - Transportation	Liquid Gas - Industrial
Liquid Gas - Feedstock	Liquid Gas - Industrial
Liquid Gas - Raw Material	Liquid Gas - Industrial
Oil - Raw Material	Liquid Gas - Industrial
Petroleum Coke - Industrial	Residual Fuel - Industrial
Asphalt - Commercial	Gasoline - Transportation
Coal - Residential & Commercial	Coal - Industrial
Coal - Transportation	Coal - Industrial

FIGURE X. GENERATION OF AVOIDS

quantity point, and excess demand for those steps to the right.

If demand is not satisfied by supply, an avoid is activated which alters price and quantity, thus not satisfying demand. A penalty equal to the sum of the product of the price of the activated avoid times quantity of unsatisfied demand is incurred. Once avoids are activated, a new demand point is determined. The model iterates until demand can be satisfied without activating avoids.

The demand function is of the form,

$$\ln Q_{ik} = A_{ik} + \sum_{j=1}^m E_{ijk} \ln (\Pi_{jk} + M_{jk})$$

$$A_{ik} = \ln Q_{ik}^0 - \sum_{j=1}^m E_{ijk} \ln (\Pi_{jk}^0 + M_{jk})$$

where

Q_{ik}^0 = initial quantity of product i in region k

P_{jk}^0 = initial price of product j in region k

E_{ijk} = constant elasticities of product i with respect to product j in region k.

Q_{ik} = quantity of product i in region k

P_{jk} = price of product j in region k

Π_{jk} = wholesale price of product j in region k

Π_{jk}^0 = initial wholesale price of product j in region k

and

A_{ik} = the intercept.

The difference between P_{jk} and Π_{jk} is M_{jk} the markup of retail price over wholesale price. Table Q below shows the relevant markups for each of the elastic fuels in each DOE energy region.

A bound on the quantity that can be produced at each

TABLE Q. PRICE MARKUPS FOR ELASTIC PRODUCTS*

<u>Fuel-Sector</u>	<u>REGION</u>									
	1	2	3	4	5	6	7	8	9	10
Natural Gas -										
Residential	1.390	1.440	1.080	1.140	0.830	1.030	0.970	0.920	1.100	1.420
Commercial	0.800	0.910	0.670	0.690	0.590	0.560	0.610	0.720	0.640	0.900
Industrial	0.300	0.300	0.300	0.300	0.300	0.300	0.300	0.300	0.300	0.300
Distillate -										
Residential	3.280	3.780	4.710	5.180	2.860	3.780	2.640	3.310	3.780	3.780
Commercial	2.070	2.510	2.750	2.880	1.930	2.500	1.760	2.160	2.390	2.390
Industrial	2.060	2.420	3.230	3.290	1.910	2.410	1.720	2.350	2.390	2.390
Transportation	7.730	8.090	8.900	8.960	7.580	8.080	7.390	8.020	8.060	8.060
Residual -										
Commercial	0.980	1.490	3.130	1.160	1.710	1.530	1.840	1.280	1.370	0.990
Industrial	1.280	2.040	2.700	0.980	1.580	1.480	1.680	0.990	1.350	1.650
Transportation	1.280	2.040	2.700	0.980	1.580	1.480	1.680	0.990	1.350	1.650
Liquid Gas -										
Residential	2.140	2.530	3.590	3.590	1.700	2.230	1.540	2.030	2.290	2.290
Industrial	1.330	1.620	2.310	2.370	1.120	1.480	1.010	1.300	1.450	1.450
Coal-Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Gasoline -										
Transportation	10.180	11.280	10.180	9.920	10.020	9.180	9.710	10.660	10.860	10.920
Jet Fuel -										
Transportation	3.220	3.720	4.970	5.290	2.840	3.720	2.590	3.420	3.710	3.710

* Units are 1975 dollars per standard physical unit.

price is obtained by recording differences in quantities for two successive price changes. Once a specific quantity at a price has been produced, the next higher (or lower) price is activated. Thus equilibrium is obtained by moving along the demand curve until supply and demand converge.

Figure 2 below shows an example of the supply and demand curve approximations. The shaded area is equal to the sum of consumer's and producer's surplus. This area is maximized when supply equal demand. In the Figure, where points M and G converge, an equilibrium solution has been found.

The test of convergence used to determine a stable equilibrium is; when the absolute value of either the change in price (or quantity) between two successive iterations is less than or equal to 2 percent of the price (or quantity), equilibrium is achieved. When a minimum cost solution is reached which does not pass the above test, a new price is set midway between the linear programming solution and the previous price, and a new demand curve approximation is constructed. Figure S below depicts the process schematic of the various calculations performed to achieve equilibrium.

After initial demand curve approximations have been made, prices and quantities are adjusted to model natural gas regulation. The wellhead price path for new natural gas specified in FPC Decision 770 is implemented for natural gas deregulation. For each of the scenario years, the price and quantity of gas committed to the interstate market is determined. After regional and sectoral demands are computed, allocation is determined by a sectoral priority scheme. Interstate gas is used to satisfy the highest priority of needs. Imported

FIGURE 2. APPROXIMATION OF SUPPLY AND DEMAND CURVES

FIGURE S PROCESS SCHEMATIC OF THE INTEGRATING MODEL

Canadian gas and LNG are rolled in next, followed by intrastate gas or substitute fuel bundles. Each substitute fuel is converted to its natural gas equivalency according to its efficiency.

Two other calculations are performed on the first iteration of the integrating model. One is dynamics which provides inter-temporal consistency when calculating the amount of new capacity built for utilities and refineries. The idea is to ensure that new capacity built in one year has sunk capital removed when forecasting a later target year. The methodology uses the 1985 forecast as a focal point. For 1980 the build activity levels, except simple cycle turbines, must be no greater than corresponding activity levels in 1985. No new plants will be built in 1980 which are not used in 1985. For 1990, built plants from 1985 are transferred with sunk capital subtracted from its cost. This makes new plants operational in 1985 available at an existing plant marginal cost for the 1990 forecast.

The other calculation performed on the first iteration is that of determining electricity markups. Markups for electricity--different from the input of Table Y--are calculated using the price and quantity estimates obtained from the demand model. Let Q_r , Q_c , Q_i be the demands for electricity in the residential, commercial, and industrial sectors respectively. Let P_r^0 , P_c^0 , P_i^0 be initial prices for electricity in the three sectors. Markups-- M_r , M_c , M_i --are calculated to maintain the initial differences in the sectoral prices,

$$M_C - M_I = P_C^O - P_I^O$$

$$M_R - M_I = P_R^O - P_I^O$$

and to preserve the quantity-weighted average price,

$$(Q_R/T) P_R + (Q_C/T) P_C + (Q_I/T) P_I$$

where

$T = Q_R + Q_C + Q_I$ and P_R, P_C, P_I are average prices.

Markups are then,

$$M_R = (1 - (Q_R/T)) (P_R^O - P_I^O) - (Q_C/T) (P_C^O - P_I^O)$$

$$M_C = (1 - (Q_C/T)) (P_C^O - P_I^O) - (Q_R/T) (P_R^O - P_I^O)$$

$$M_I = (-Q_R/T) (P_R^O - P_I^O) - (Q_C/T) (P_C^O - P_I^O)$$

After the first iteration is performed, a solution is obtained, convergence is tested, new avoids are calculated, etc. After the solution file is read oil entitlements calculations are performed. Total dollars for imports must equal total dollars for domestic oil, where Alaska is separate from the lower 48 states. A balance is required in the entitlements plus controlled prices (including transportation). The procedure requires,

$$E_A Q_A + E_D Q_D - E_I Q_I = 0$$

$$E_A + P_A = E_D + P_D = E_I + P_I$$

where

P_I, P_D, P_A = oil prices for imports, lower-48, Alaska,

Q_I, Q_D, Q_A = quantities from imports, lower-48, Alaska,

E_I, E_D, E_A = entitlements for imports, lower-48, Alaska.

The equilibrating mechanism sees quantities changing iteratively and prices are inputs. Entitlements are then determined by the equations above. The results are used to adjust average prices of crude oil to $P(I) + E(I)$ for the next iteration. The effect is to equalize domestic and import refinery gate prices. Next, electricity prices are updated. The difference between the last price and average cost prices is added as a cost for transporting electricity from utility region to demand region. Average price (per region) is calculated as

$$AV = (C + \sum_f (\Pi_f K_f + FC_f) KWH_f) / \sum_f KWH_f$$

where

C = capital charges in rate base

Π_f = marginal price of fuel f

K_f = amount of fuel to generate 1 KWH

FC_f = fixed charges of fuel - specific plant

KWH_f = KWH generated by fuel-specific plant

After the appropriate scenario has been chosen, the President's natural gas tax program is implemented. The tax is levied on industrial and utility users and equals the difference between their cost of natural gas and a price based on distillate oil.

After new prices and demands have been calculated, convergence is again tested. If there has been no convergence, new avoids are calculated, the natural gas regulation code is executed for the chosen scenario, last prices and demands are printed, the iteration counter increases by one, and the procedure is repeated with a new linear programming solution. The model

will stop iterating after convergence or if 15 iterations have been performed.

After convergence the model checks to determine if the price of intrastate natural gas has fallen below the regulated interstate price. If so, the model parcels out the excess demand and computes a new equilibrium. The amount of intrastate gas to be shipped to the 10 DOE demand regions is determined, taking into account a 4 percent loss in transmission. Since the supply of natural gas now changes, a new equilibrium is found. PIES allows a maximum of five iterations to determine the new equilibrium.

Most of the output discussed above, the old prices, marginal price, new price, and demands for the 30 fuel/sector pairs is printed.

SCENARIOS

Twenty-two PIES scenarios--a Reference Scenario and twenty-one conceptually different variations of the Reference Scenario have been designed to provide policy-makers with projections of the state of the U.S. energy systems in 1980, 1985, and 1990.

The Reference Scenarios provide a baseline against which alternative policies can be evaluated. This scenario is not a prediction of the future since no assumptions about changes in current policies or legislation are included.

The twenty-two PIES scenarios are presented in
pages:

detail on the following

<u>Scenario</u>	<u>Page</u>
#1 Reference	B-30
#2 Low Oil Imports	B-31
#3 High Oil Imports	B-37
#4 Continued Oil Control	B-42
#5 Gas Deregulation	B-43
#6 Less OCS Leasing	B-44
#7 More OCS Leasing	B-45
#8 Low Geologic Resources	B-46
#9 High Geologic Resources	B-47
#10 Low Growth Economy	B-48
#11 Accelerated Conservation	B-49
#12 Oil and Gas Tax	B-54
#13 Oil and Gas Tax with Accelerated Conservation	B-55
#14 Gasoline Tax	B-58
#15 Depletable Resource Tax	B-59
#16 Low Gas Policies	B-60
#17 High Gas Policies	B-61
#18 Cleaner Coal	B-63
#19 Cleaner Coal and Less Nuclear	B-64
#20 Less Nuclear	B-66
#21 Industrial Resource Estimates	B-68
#22 Electric Load Management	B-69

PIES SCENARIO #1 -- REFERENCE

SCENARIO DESCRIPTION

The Reference Scenario is intended to provide a best estimate of the future U.S. energy system, assuming that policies and legislation in effect as of November, 1976, remain unchanged for the foreseeable future. As such, it provides a convenient base line against which the effects of various potential changes in policies, legislation, and assumptions regarding the state of the world can be assessed. It does not represent a prediction of how the future U.S. energy system will actually appear, since such a prediction would almost certainly incorporate some assumptions regarding changes in current policies and legislation over time. Many of these potential changes are incorporated in the other twenty-two PIES scenarios.

SCENARIO IMPLEMENTATION

The Reference Scenario in the 1977 National Energy Outlook (NEO 1977) is not directly comparable to the Reference Scenario in NEO 1976, which was designed to be comparable to the Business-As-Usual Scenario of the 1974 Project Independence Report (PIR), in order to illustrate technical changes in the PIES computer model. Maintaining the 1974 business-as-usual assumptions in NEO 1976 was not unreasonable, since that report was developed prior to the passage of major Federal energy legislation in December, 1975, and August, 1976. But significant changes in Federal energy policy and legislation since PIR and NEO 1976 have made it imperative that the basic assumptions underlying the former Reference Scenario and Business-As-Usual Scenario be reviewed and modified as appropriate. Thus, the present Reference Scenario incorporates not only the technical modeling changes described in Appendix A but also the more basic changes in the domestic energy system and perceptions of the domestic energy system described in Chapter II.

Major NEO 1977 Reference Scenario assumptions which are varied in other NEO 1977 scenarios have been previously outlined in Table B-3.

PIES SCENARIO #2 -- LOW OIL IMPORTS

SCENARIO DESCRIPTION

The Low Oil Imports Scenario is designed to show the combined impact of a set of aggressive policies and programs aimed at reducing U.S. oil imports. The set includes variations from the Reference Scenario in seven key areas which can be directly and significantly affected by government energy policy actions, as opposed to variations in basic states of the world (for example, macroeconomic forecasts or geologic estimates).

Although changes in outer continental shelf lease sales are crucially affected by government policy, no change in lease sales from the Reference Scenario is made in this scenario. The impact of relevant changes in the leasing schedule would be so significant as to obscure the interaction of other policy changes and would result in an unrealistically low level of imports when combined with the other policy changes. Changes in leasing schedules are modeled as separate scenarios.

The Low Oil Imports Scenario provides a realistic lower bound on oil imports, reflecting the reasonable strategic and economic benefits likely to accrue solely as the result of an aggressive set of policies and programs intended to reduce imports. A scenario designed to show the impact of reducing all imports (rather than just oil imports) would be essentially the same except for a reduction in the level of liquefied natural gas imports.

SCENARIO IMPLEMENTATION

This scenario is modeled by making the following changes to the Reference Scenario:

<u>Variable</u>	<u>Value in Low Oil Imports Scenario</u>	<u>Value in Reference Scenario</u>
Domestic Gas Prices	Complete and immediate deregulation of the price of all new gas. Old gas continues to be sold at nominal vintage prices.	Continued regulation of interstate sales as currently required by law at a nominal price of \$1.42 per mcf (plus a nominal increase of 4 cents per year) for new gas, and lower vintage prices for old gas. Assumes the price of new gas to be rolled in with the price of old gas.
Imported LNG	<p>1980 0.4 Tcf @ \$2.10/Mcf East Coast</p> <p>1985 0.4 Tcf @ \$2.10 - \$2.49/Mcf } East +0.4 Tcf @ \$2.50 - \$2.99/Mcf } Coast +0.5 Tcf @ \$3.00 - \$3.49/Mcf } +0.8 Tcf @ \$3.50/Mcf +0.4 Tcf @ \$3.00/Mcf West Coast = 2.5 Tcf/yr. Total</p>	<p>1980 0.4 Tcf @ \$2.10/Mcf East Coast</p> <p>1985 0.4 Tcf @ \$2.10 - \$2.49/Mcf } East +0.4 Tcf @ \$2.50 - \$2.99/Mcf } Coast +0.2 Tcf @ \$3.00/Mcf +0.2 Tcf @ \$3.00/Mcf West Coast = 1.2 Tcf/yr. Total</p>

#2 LOW OIL IMPORTS (CONT.)

<u>1990</u>	
0.4 Tcf @ \$2.10 - \$2.49/Mcf	} East Coast
+0.4 Tcf @ \$2.50 - \$2.99/Mcf	
+0.5 Tcf @ \$3.00 - \$3.49/Mcf	
+0.8 Tcf @ \$3.50/Mcf	
<hr/>	
+0.4 Tcf @ \$3.00 - \$3.49/Mcf	} West Coast
+0.8 Tcf @ \$3.50/Mcf	
<hr/>	
= Tcf/yr. Total	

<u>1990</u>	
0.4 Tcf @ \$2.10 - \$2.49/Mcf	} East Coast
+0.4 Tcf @ \$2.50 - \$2.99/Mcf	
+0.5 Tcf @ \$3.00 - \$3.49/Mcf	
+0.8 Tcf @ \$3.50/Mcf	
+0.4 Tcf @ \$3.00/Mcf West Coast	
<u>2.5 Tcf/yr. Total</u>	

Conservation Programs

The accelerated level of conservation savings results from increased savings attributable to the five programs included in the Reference Scenario, plus savings from five additional conservation programs. Each conservation program results in the following reduction in total demand for a fuel in a sector from what it otherwise would have been in the absence of the program:

Conservation savings in the Reference Scenario result from the first five of the conservation programs listed below. Each conservation program results in the following reduction in total demand for a fuel in a sector from what it otherwise would have been in the absence of the program:

o Federal Energy Management Program

Percentage reductions achieved for 1980, 1985, and 1990, in the commercial and transportation sectors:

Percentage reductions achieved for 1980, 1985, and 1990, in the commercial and transportation sectors:

<u>Fuel/Sector</u>	<u>Com.</u>	<u>Trans.</u>
Gasoline	0.0%	0.3%
Distillate	2.1	6.2
Jet Fuel	0.0	6.5
Coal	22.5	0.0
Electricity	1.0	0.0
Residual	3.5	6.2
Natural Gas ^d	2.0	0.0

<u>Fuel/Sector</u>	<u>Com.</u>	<u>Trans.</u>
Gasoline	0.0%	0.2%
Distillate	1.4	4.1
Jet Fuel	0.0	6.5
Coal	15.0	0.0
Electricity	0.7	0.0
Residual	2.3	4.1
Natural Gas	1.4	0.0

o Auto Fuel Economy Standards

The average fuel economy (in miles per gallon) of all new cars is:

1980: 20.0 mpg
1985: 27.5
1990: 27.5

The increased efficiency results in a reduction in demand for gasoline in the transportation sector.

The average fuel economy (in miles per gallon) of all new cars is:

1980: 20.0 mpg
1985: 26.0
1990: 26.0

The increased efficiency results in a reduction in demand for gasoline in the transportation sector.

o State Energy Conservation Programs

Percentage reductions in demand for all fuels in the residential, commercial, industrial, and transportation sectors:

	<u>Res.</u>	<u>Com.</u>	<u>Ind.</u>	<u>Trans.</u>
1980	0.7%	3.4%	1.4%	0.5%
1985	0.1	1.3	0.6	0.6
1990	0.1	1.2	0.7	0.0

Percentage reductions in demand for all fuels in the residential, commercial, industrial, and transportation sectors:

	<u>Res.</u>	<u>Com.</u>	<u>Ind.</u>	<u>Trans.</u>
1980	0.6%	2.6%	0.7%	0.4%
1985	1.0	3.9	0.3	0.4
1990	1.5	5.7	0.0	0.5

#2 LOW OIL IMPORTS (CONT.)

Conservation Programs (cont.)

o Weatherization Assistance Program	Percentage reductions in total demand for a fuel in the residential sector attributable to a combination of the Weatherization Assistance Program, Appliance Labeling and Efficiency Targets Program, and HUD Residential Building Standards:	Reductions (in Btu's) achieved by 1980 in the residential sector. No further savings in 1985 or 1990: <table><tr><td>Fuel/Sector</td><td>Res.</td></tr><tr><td>Distillate</td><td>13.0 MM Btu's</td></tr><tr><td>Electricity</td><td>1.5</td></tr><tr><td>Natural Gas</td><td>34.0</td></tr></table>	Fuel/Sector	Res.	Distillate	13.0 MM Btu's	Electricity	1.5	Natural Gas	34.0																		
Fuel/Sector	Res.																											
Distillate	13.0 MM Btu's																											
Electricity	1.5																											
Natural Gas	34.0																											
	<table><tr><td>1980</td><td>Res.</td></tr><tr><td>Distillate</td><td>1.6%</td></tr><tr><td>Electricity</td><td>4.7</td></tr><tr><td>Natural Gas</td><td>4.6</td></tr></table>	1980	Res.	Distillate	1.6%	Electricity	4.7	Natural Gas	4.6																			
1980	Res.																											
Distillate	1.6%																											
Electricity	4.7																											
Natural Gas	4.6																											
	<table><tr><td>1985</td><td></td></tr><tr><td>Distillate</td><td>3.8%</td></tr><tr><td>Electricity</td><td>11.0</td></tr><tr><td>Natural Gas</td><td>5.9</td></tr></table>	1985		Distillate	3.8%	Electricity	11.0	Natural Gas	5.9																			
1985																												
Distillate	3.8%																											
Electricity	11.0																											
Natural Gas	5.9																											
	<table><tr><td>1990</td><td></td></tr><tr><td>Distillate</td><td>6.1%</td></tr><tr><td>Electricity</td><td>15.1</td></tr><tr><td>Natural Gas</td><td>4.8</td></tr></table>	1990		Distillate	6.1%	Electricity	15.1	Natural Gas	4.8																			
1990																												
Distillate	6.1%																											
Electricity	15.1																											
Natural Gas	4.8																											
o Appliance Labeling and Efficiency Targets Program	See "Weatherization Assistance Program" entry for savings.	Percentage reductions achieved in the residential sector: <table><tr><td>Fuel/Sector</td><td>Res.</td></tr><tr><td>1980</td><td></td></tr><tr><td>Distillate</td><td>0.0%</td></tr><tr><td>Electricity</td><td>3.5</td></tr><tr><td>Natural Gas</td><td>1.5</td></tr></table> <table><tr><td>1985</td><td></td></tr><tr><td>Distillate</td><td>0.0%</td></tr><tr><td>Electricity</td><td>6.4</td></tr><tr><td>Natural Gas</td><td>1.4</td></tr></table> <table><tr><td>1990</td><td></td></tr><tr><td>Distillate</td><td>-0.4%</td></tr><tr><td>Electricity</td><td>8.3</td></tr><tr><td>Natural Gas</td><td>-0.3</td></tr></table>	Fuel/Sector	Res.	1980		Distillate	0.0%	Electricity	3.5	Natural Gas	1.5	1985		Distillate	0.0%	Electricity	6.4	Natural Gas	1.4	1990		Distillate	-0.4%	Electricity	8.3	Natural Gas	-0.3
Fuel/Sector	Res.																											
1980																												
Distillate	0.0%																											
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Electricity	6.4																											
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1990																												
Distillate	-0.4%																											
Electricity	8.3																											
Natural Gas	-0.3																											
o HUD Residential Building Standards	See "Weatherization Assistance Program" entry for savings.	No savings attributable to Department of Housing and Urban Development energy efficiency standards for residential buildings. (Some savings attributable to state building standards are included in the Reference Scenario under State Energy Conservation Programs.)																										
o HUD Commercial Building Standards	Percentage reductions in demand for all fuels in the commercial sector: <table><tr><td></td><td>Com.</td></tr><tr><td>1980</td><td>0.0%</td></tr><tr><td>1985</td><td>9.0</td></tr><tr><td>1990</td><td>18.0</td></tr></table>		Com.	1980	0.0%	1985	9.0	1990	18.0	No savings attributable to Department of Housing and Urban Development energy efficiency standards for commercial buildings. (Some savings attributable to state buildings are included in the Reference Scenario under State Energy Conservation Programs.)																		
	Com.																											
1980	0.0%																											
1985	9.0																											
1990	18.0																											
o Obligation Guarantees	No measurable savings from the obligation guarantee program in the residential sector. Percentage reductions in demand for all fuels in the commercial and industrial sectors: <table><tr><td></td><td>Com.</td><td>Ind.</td></tr><tr><td>1980</td><td>0.7%</td><td>1.5%</td></tr><tr><td>1985</td><td>1.9</td><td>3.9</td></tr><tr><td>1990</td><td>1.9</td><td>3.6</td></tr></table>		Com.	Ind.	1980	0.7%	1.5%	1985	1.9	3.9	1990	1.9	3.6	No savings attributable to Federal loan guarantees for energy conservation and renewable resource measures.														
	Com.	Ind.																										
1980	0.7%	1.5%																										
1985	1.9	3.9																										
1990	1.9	3.6																										

#2 LOW OIL IMPORTS (CONT.)

Conservation Programs (cont.)

o Retrofit Tax Credit

Percentage reductions achieved in the residential sector:

	<u>Res.</u>
<u>1980</u>	
Distillate	1.3%
Electricity	0.6
Natural Gas	2.8
<u>1985</u>	
Distillate	1.4%
Electricity	0.5
Natural Gas	2.8
<u>1990</u>	
Distillate	1.4%
Electricity	0.4
Natural Gas	2.8

No savings attributable to a Federal tax credit for investments in conservation measures for single family dwellings.

o CAB Load Factor

Civil Aeronautics Board average load factor for all jurisdictional commercial airlines is increased to 65 percent by 1980. Results in reduction in demand for jet fuel in the transportation sector.

Civil Aeronautics Board average load factor for all jurisdictional commercial airlines remains at 55 percent.

o Returnable Bottle Law

Percentage reductions in demand for all fuels in the industrial sector:

	<u>Ind.</u>
<u>1980</u>	0.0%
<u>1985</u>	0.4
<u>1990</u>	0.4

No savings attributable to Federal law requiring refundable deposits on all beer and soft drink containers.

Alaskan Oil Pipeline

1980
Capacity - 2.0 mmb/d
Operating Cost - \$1.22/b

1985-90
The same as the Reference Scenario

1980
Capacity - 1.2 mmb/d
Operating Cost - \$1.07/b

Alternatively, the model may build the following capacity based on the following operating cost:

Capacity - 1.6 mmb/d
Operating Cost - \$1.22/b

1985-90
Capacity - 2.0 mmb/d
Operating Cost - \$1.22/b

Alternatively, the model may build the following capacity based on the following operating cost:

Capacity - Unbounded
Operating Cost - \$2.86/b

#2 LOW OIL IMPORTS (CONT.)

Alaskan Gas Supply

One pipeline moving
 ≤ 3.3 Bcf per day by 1985.

One pipeline moving
 ≤ 3.3 Bcf per day by 1990.

Mandated Conversions from Oil and Gas

Conversion of existing oil and gas fired utility capacity is the same as in the Reference Scenario. With regard to new utility capacity, gas use is banned and oil is allowed only for peaking uses.

Pursuant to authority under the Energy Supply and Environmental Coordination Act of 1974 (ESECA), a total of 17,580 MWe of existing oil and gas fired utility capacity is forced to convert to coal. This represents all capacity ordered, but not yet converted, under ESECA as of November 1976, as well as all capacity expected to be ordered to convert before the existing legislation expires on June 30, 1977. (The approximately 2500 MWe already converted under ESECA is specified as "existing coal-fired capacity.") No constraints are imposed in PIES on fuels for new utility capacity; fuel types are determined by economic choices made within the model.

Nuclear Power Plant Build Limits

Limits on units to be built in addition to the existing 39 GWe of capacity as of 1/1/76:

1980

Upper Limit: 32 GWe (All units currently scheduled to be in commercial operation by 1/1/80.)

Lower Limit: 32 GWe (All units currently scheduled to be in commercial operation by 1/1/80.)

1985

Upper Limit: 123 GWe (All units currently scheduled to be in commercial operation by 1/1/85.)

Lower Limit: 77 GWe (All units for which construction permits were issued as of 1/1/76 and due for completion by 1985.)

1990

Upper Limit: 219 GWe (Extrapolation of baseline capacity additions forecast by 1985 Low Oil Imports Scenario run.)

Lower Limit: 77.6 GWe units forecast by the 1985 Low Oil Imports Scenario run.

Limits on units to be built in addition to the existing 39 GWe of capacity as of 1/1/76:

1980

Upper Limit: 32 GWe (All units currently scheduled to be in commercial operation by 1/1/80.)

Lower Limit: 19 GWe (All units with construction $\geq 2\%$ complete as of 1/1/76 which, if delayed by 12 months, would be in commercial operation on 1/1/80. No units not $\geq 2\%$ complete would be built.)

1985

Upper Limit: 103 GWe (All units, which if delayed by 12 months, would be in commercial operation by 1/1/85.)

Lower Limit: 56 GWe (All units with construction $\geq 2\%$ complete as of 1/1/76 which would be in commercial operation by 1/1/85. No units not $\geq 2\%$ complete by 1/1/76 would be built.)

1990

Upper Limit: 194 GWe (Extrapolation of baseline capacity additions forecast by 1985 Reference Scenario run.)

Lower Limit: 56 GWe Units forecast by 1985 Reference Scenario run to be in commercial operation on 1/1/85.

#2 LOW OIL IMPORTS (CONT.)

Synthetic Fuels

o Shale Oil	1980 - 0 Quads	1980 - 0 Quads
	1985 - .3	1985 - .1
	1990 - .6	1990 - .2
o Synthetic Crude	1980 - 0 Quads	1980 - 0 Quads
	1985 - 0	1985 - 0
	1990 - .1	1990 - 0
o High Btu Gas	1980 - 0 Quads	1980 - 0 Quads
	1985 - .2	1985 - 0
	1990 - .3	1990 - .1
o Low Btu Gas	1980 - 0 Quads	1980 - 0 Quads
	1985 - .2	1985 - .1
	1990 - .4	1990 - .2

Solar and Geothermal Electric

o Solar	1980 - 0 Quads	1980 - 0 Quads
	1985 - .86	1985 - .02
	1990 -1.80	1990 - .15
o Geothermal	1980 - .12 Quads	1980 - .12 Quads
	1985 - .47	1985 - .17
	1990 - .90	1990 - .40

Dispersed Technology Programs

o Solar	1980 - 0 Quads	1980 - 0 Quads
	1985 - .37	1985 - .11
	1990 -1.55	1990 - .60
o Geothermal	1980 - 0 Quads	1980 - 0 Quads
	1985 - .10	1985 - .10
	1990 - .40	1990 - .25

PIES SCENARIO #3 -- HIGH OIL IMPORTS

SCENARIO DESCRIPTION

The High Oil Imports Scenario is designed to show the impact of a set of policy and program actions (or failures to act) which are likely to increase oil imports. The set includes variations from the Reference Scenario in five key areas which can be significantly affected by government energy policy decisions, as opposed to variations in basic states of the world (for example, macroeconomic forecasts or geologic estimates).

Although changes in outer continental shelf lease sales are crucially affected by government policy, no change in lease sales from the Reference Scenario is made in this scenario. The impact of relevant changes in the leasing schedule would result in an unrealistically high level of imports when combined with the other policy changes. Changes in leasing schedules are modeled as separate scenarios.

The High Oil Imports Scenario provides a realistic upper bound on oil imports, reflecting the reasonable strategic and economic exposure likely to occur solely as the result of government policies and programs which may be expected to increase oil imports. A scenario designed to provide a realistic upper bound on all energy imports would be essentially the same except for an increase in the level of liquefied natural gas imports.

SCENARIO IMPLEMENTATION

This scenario is modeled by making the following changes to the Reference Scenario:

<u>Variable</u>	<u>Value in High Oil Imports Scenario</u>	<u>Value in Reference Scenario</u>
Domestic Oil Prices	Crude oil price controls continued after May 1979. Continued incentive production adjustment, plus an adjustment to account for inflation, up to a total increase of 10 percent per year in nominal terms. Composite price excludes North Slope Alaskan Oil. When the upper tier price is greater than the market price, the market price applies. This occurs for \$13 oil in 1985 and 1990.	Crude oil prices decontrolled after May 1979, as currently specified by law. In the interim, a continuation of the incentive production adjustment, plus an adjustment of account for inflation, up to a total increase of 10 percent per year in nominal terms. Composite price excludes Alaskan Oil.

#3 HIGH OIL IMPORTS (CONT.)

Imported LNG

<u>1980</u>	<u>1980</u>
0.4Tcf @ \$2.10/Mcf East Coast	0.4Tcf @ \$2.10/Mcf East Coast
<u>1985</u>	<u>1985</u>
0.4Tcf @ \$2.10/Mcf East Coast	0.4Tcf/yr @ \$2.10-\$2.49/Mcf } East Coast
0.4Tcf/yr. Total	--0.4Tcf/yr @ \$2.50-\$2.99/Mcf } East Coast
	--0.2Tcf/yr @ \$3.00
	--0.2Tcf/yr @ \$3.00/Mcf West Coast
	* 1.2Tcf/yr. Total
<u>1990</u>	<u>1990</u>
0.4Tcf/yr @ \$2.10-\$2.49 Mcf } East Coast	0.4Tcf @ \$2.10-\$2.49/Mcf } East Coast
--0.4Tcf/yr @ \$2.50-\$2.99 Mcf } East Coast	--0.4Tcf @ \$2.50-\$2.99/Mcf } East Coast
--0.2Tcf/yr @ \$3.00/Mcf } West Coast	--0.5Tcf @ \$3.00-\$3.49/Mcf } East Coast
--0.2Tcf/yr @ \$3.00/Mcf } West Coast	--0.8Tcf @ \$3.50
	--0.4Tcf @ \$3.00 West Coast
	* 2.5Tcf/yr. Total
- 1.2Tcf/yr. Total	

Conservation Programs

No savings from any conservation programs are included.

Conservation savings in the Reference Scenario result from the five conservation programs listed below. Each conservation program results in the following reduction in total demand for a fuel in a sector from what it otherwise would have been in the absence of the program.

o Federal Energy Management Program

Percentage reductions achieved for 1980, 1985, and 1990, in the commercial and transportation sectors:

<u>Fuel/Sector</u>	<u>Com.</u>	<u>Trans.</u>
Gasoline	0.0%	0.2%
Distillate	1.4	4.1
Jet Fuel	0.0	6.5
Coal	15.0	0.0
Electricity	0.7	0.0
Residual	2.3	4.1
Natural Gas	1.4	0.0

#3 HIGH OIL IMPORTS (CONT.)

- o Auto Fuel Economy Standards

The average fuel economy (in miles per gallon) of all new cars is:

1980 20.0 mpg
1985 26.0
1990 26.0

The increased efficiency results in a reduction in demand for gasoline in the transportation sector.

- o State Energy Conservation Program

Percentage reductions in demand for all fuels in the residential, commercial, industrial, and transportation sectors:

	<u>Res.</u>	<u>Com.</u>	<u>Ind.</u>	<u>Trans.</u>
<u>1980</u>	0.6%	2.6%	0.7%	0.4%
<u>1985</u>	1.0	3.9	0.3	0.4
<u>1990</u>	1.5	5.7	0.0	0.5

- o Weatherization Assistance Program

Reductions (in Btu's) achieved by 1980 in the residential sector. No further savings in 1985 or 1990:

<u>Fuel/Sector</u>	<u>Res.</u>
Distillate	13.0 MM Btu's
Electricity	1.5
Natural Gas	34.0

- o Appliance Labeling and Efficiency Targets Program

Percentage reductions achieved in the residential sector:

<u>Fuel/Sector</u>	<u>Res.</u>
<u>1980</u>	
Distillate	0.0%
Electricity	3.5
Natural Gas	1.5

<u>1985</u>	
Distillate	0.0%
Electricity	6.4
Natural Gas	1.4

<u>1990</u>	
Distillate	-0.4%
Electricity	8.3
Natural Gas	-0.3

#3 HIGH OIL IMPORTS (CONT.)

Requirements Under the Clean Air Act All regions require the use of scrubbers on all coal power plants. There is no limitation on sulphur content of coal.

FEA Regions 8 and 9 require the use of low sulphur coal and scrubbers on all new power plants. All other regions require the use of either low-sulphur coal or scrubbers with high-sulphur coal on all coal power plants.

Coal Build Limit 1980 - Capacity additions are limited to those which are currently planned for operation by 1980 (as reported on April 1, 1976, by the National Electric Reliability Council pursuant to FPC Order No. 383-3).
1985 - No limit.
1990 - No limit.

1980 - Capacity additions are limited by the same schedule as in the Reference Scenario.
1985 - Capacity additions are not allowed to exceed those that are built in the Reference Scenario.
1990 - No limit.

Nuclear Power Plant Builds Limits Limits on units to be built in addition to the existing 39 GWe of capacity as of 1/1/76:
1980
Upper Limit: 19 GWe (Units with construction $\geq 2\%$ complete as of 1/1/76 which, if delayed by 12 months, would be in commercial operation on 1/1/80. No units not $\geq 2\%$ complete would be built.)
Lower Limit: 14 GWe (Units with construction $\geq 2\%$ complete as of 1/1/76 which, if delayed by 24 months would be in commercial operation on 1/1/80. No units not $\geq 2\%$ complete would be built.)

Limits on units to be built in addition to the existing 39 GWe of capacity as of 1/1/76:

1980
Upper Limit: 32 GWe (All units currently scheduled to be in commercial operation by 1/1/80.)

Lower Limit: 19 GWe (All units with construction $\geq 2\%$ complete as of 1/1/76 which, if delayed by 12 months, would be in commercial operation on 1/1/80. No units not $\geq 2\%$ complete would be built.)

1985
Upper Limit: 56 GWe (Units with construction $\geq 2\%$ complete as of 1/1/76 which, if delayed by 24 months, would be in commercial operation on 1/1/85. No units not $\geq 2\%$ complete would be built.)
Lower Limit: 32 GWe (Units with construction $\geq 2\%$ complete as of 1/1/76 which are currently scheduled for commercial operation by 1/1/80. No units not $\geq 2\%$ complete would be built.)

1985
Upper Limit: 103 GWe (All units which if delayed by 12 months, would be in commercial operation by 1/1/85.)

Lower Limit: 54 GWe (All units with construction $\geq 2\%$ complete as of 1/1/76 which would be in commercial operation by 1/1/85. No units not $\geq 2\%$ complete by 1/1/76 would be built.)

#3 HIGH OIL IMPORTS (CONT.)

<u>1990</u>	<u>1990</u>
<u>Upper Limit:</u> 56 GWe (Units with Construction $\geq$ 2% complete as of 1/1/76 and currently scheduled to be in commercial operation on 1/1/85. No units not 2% complete would be built.)	<u>Upper Limit:</u> 168 GWe (Extrapolation of baseload capacity additions for cast by 1985 Reference Scenario run.)
<u>Lower Limit:</u> 32 GWe Units forecast by 1985 Less Nuclear Scenario run to be in commercial operation on 1/1/85.	<u>Lower Limit:</u> 56 GWe Units forecast to be built by 1985 Reference Scenario run to be in commercial operation on 1/1/85.

PIES SCENARIO #4 -- CONTINUED OIL CONTROL

SCENARIO DESCRIPTION

This scenario is designed to show the effects of continued oil price and allocation control beyond the 40-month period (ending May 1979) authorized by legislation as of November 1976. The probable effects of extending oil controls beyond the 40-month period are of such importance as to warrant analysis independent of any other changes to the Reference Scenario, which already includes continued gas regulation.

SCENARIO IMPLEMENTATION

This scenario is modeled by making the following changes to the Reference Scenario:

<u>Variable</u>	<u>Value in Continued Control Scenario</u>	<u>Value in Reference Scenario</u>
Domestic Oil Prices	Crude oil price controls continued after May 1979. Continued incentive production adjustment, plus an adjustment to account for inflation, up to a total increase of 10% per year in nominal terms. Composite price excludes North Slope Alaskan oil. When the upper tier price is greater than the market price, the market price applies. This occurs for \$13 oil in 1985 and 1990.	Crude oil prices decontrolled after May 1979. In the interim, a continuation of the incentive production adjustment, plus an adjustment to account for inflation, up to a total increase of 10% per year in nominal terms. Composite price excludes North Slope Alaskan oil.

PIES SCENARIO #5 -- GAS DEREGULATION

SCENARIO DESCRIPTION

This scenario is designed to show the effects of complete and immediate deregulation of the price of all new natural gas shipped in interstate commerce. The probable effects of gas deregulation are of such importance as to warrant analysis independent of any other changes to the Reference Scenario, which already includes complete decontrol of oil prices after May 1979.

SCENARIO IMPLEMENTATION

This scenario is modeled by making the following changes to the Reference Scenario:

<u>Variable</u>	<u>Value in Gas Deregulation Scenario</u>	<u>Value in Reference Scenario</u>
Domestic Gas Prices	Complete and immediate deregulation of all new gas. Old gas continues to be sold at nominal vintaged prices.	Continued regulation of interstate sales as currently required by law at a nominal well-head price of (\$1.33 in 1975 dollars) per mcf (plus a nominal increase of 4 cents per year) for new gas, and lower vintaged prices for old gas. Assumes the price of new gas will be rolled in with the price of old gas.

PIES SCENARIO #6 -- LESS OCS LEASING

SCENARIO DESCRIPTION

This scenario is designed to show the potential impact on domestic oil and gas production which could occur as the result of a slowdown in outer continental shelf leasing. The rate of OCS leasing depends on four separate factors: the number of sales held by the government each year; the number of acres nominated by industry for potential leasing; the number of acres which are actually offered by the government after eliminating acreage due to environmental or other concerns; and the amount of acreage actually leased by industry. All four factors have been reduced in this scenario, showing the potential losses in domestic oil and gas production resulting from assumptions somewhat unfavorable to OCS leasing activities.

SCENARIO IMPLEMENTATION

This scenario is modeled by making the following changes to the Reference Scenario:

<u>Variable</u>	<u>Value in Less OCS Leasing Scenario</u>	<u>Value in Reference Scenario</u>
OCS Lease Sales	4 sales per year; 1.5 million acres nominated per sale; .8 million acres offered per sale; Percent of offer actually leased: 1976-78 - 40% 1979-82 - 35% 1983-90 - 30%	5 lease sales per year; 1.5 million acres nominated per sale; 1.0 million acres offered per sale; Percent of offer actually leased: 1976-78 - 45% 1979-82 - 40% 1983-90 - 35%

PIES SCENARIO #7 -- MORE OCS LEASING

SCENARIO DESCRIPTION

This scenario is designed to show the potential increase in domestic oil and gas production which might occur as the result of an acceleration in the rate of outer continental shelf (OCS) leasing. The rate of OCS leasing depends on four separate factors: the number of sales held by the government each year; the number of acres nominated by industry for potential leasing; the number of acres which are actually offered by the government after eliminating acreage due to environmental or other concerns; and the amount of acreage actually leased by industry. In reality, any one, or combination, of these factors might be accelerated. However, all four are accelerated in this scenario, thus illustrating the greatest increase in oil and gas production which could reasonably be expected due to accelerated OCS leasing.

SCENARIO IMPLEMENTATION

This scenario is modeled by making the following changes to the Reference Scenario:

<u>Variable</u>	<u>Value in More OCS Leasing Scenario</u>	<u>Value in Reference Scenario</u>
OCS Lease Sales	6 sales per year; 1.5 million acres nominated per sale; 1.2 million acres offered per sale; Percent of offer actually leased: 1976-78 - 45% 1979-82 - 42% 1983-90 - 40%	5 lease sales per year 1.5 million acres nominated per sale; 1.0 million acres offered per sale; Percent of offer actually leased: 1976-78 - 45% 1979-82 - 40% 1983-90 - 35%

PIES SCENARIO #8-- LOW GEOLOGIC RESOURCES

SCENARIO DESCRIPTION

This scenario is designed to illustrate the potential U.S. energy supply situation in a state of the world in which economically recoverable domestic oil and gas resources turn out to be relatively small, in which Alaskan production start-up is delayed, and in which peak production is lower in Alaska, the Naval Petroleum Reserves and the outer continental shelf (OCS). In addition, the scenario assumes that oil recovered through tertiary processes continues to be controlled at the lower "old oil" price, thus discouraging increased enhanced recovery.

SCENARIO IMPLEMENTATION

This scenario is modeled by making the following changes to the Reference Scenario:

<u>Variable</u>	<u>Value in the Low Geologic Resources Scenario</u>	<u>Value in the Reference Scenario</u>
Oil and Gas Resources	U.S. Geological Survey (USGS) estimates of oil and gas resources (including only those resources with an 83 percent probability of recovery).	USGS estimates of oil and gas resources with a 50 percent probability of recovery.
Enhanced Oil Recovery	FEA adjustments to USGS estimates, reflecting anticipated resources economically recoverable through enhanced recovery processes. Assumes tertiary oil pricing remains at the "old oil" price control level.	FEA adjustments to USGS estimates, reflecting additional resources recoverable through enhanced recovery processes. Assumes tertiary oil pricing permitted at higher tier levels and a moderate level of Federal initiative and research and development funding, with tertiary recovery remaining a high-risk technology.
Special Oil and Gas Regions	FEA adjustments to USGS estimates, reflecting possible delays in production start-up and lower peak production rates in the special oil regions. Assumes the same investment tax credits as in the Reference Scenario, but slower drilling and development activity.	FEA adjustments to USGS estimates, reflecting a best estimate of production rates from Alaska, the NPR/s, and the OCS. Assumes a 10 percent investment tax credit through 1977, reduced to 7 percent thereafter.

PIES SCENARIO #9--HIGH GEOLOGIC RESOURCES

SCENARIO DESCRIPTION

This scenario is designed to illustrate the potential U.S. energy supply situation in a state of the world in which economically recoverable domestic oil and gas resources turn out to be relatively large, and production rates are earlier and higher in Alaska, the Naval Petroleum Reserves (NPR's), and the outer continental shelf (OCS). In addition, the scenario assumes maximum recovery from older reservoirs through tertiary processes.

SCENARIO IMPLEMENTATION

This scenario is modeled by making the following changes to the Reference Scenario:

<u>Variable</u>	<u>Value in the High Geologic Resources Scenario</u>	<u>Value in the Reference Scenario</u>
Oil and Gas Resources (excluding enhanced recovery and special regions)	U.S. Geological Survey estimates of oil and gas resources (including resources whose probability of recovery is as low as 17 percent).	U.S. Geological Survey estimates of oil and gas resources with a 50 percent probability of recovery.
Enhanced Oil Recovery	FEA adjustments to U.S. Geological Survey estimates, reflecting additional resources recoverable through enhanced recovery processes. Assumes tertiary oil pricing permitted at higher tier levels and a major Federal research and development effort, with tertiary technology becoming a proven conventional means of oil recovery.	FEA adjustments to U.S. Geological Survey estimates, reflecting additional resources recoverable through enhanced recovery processes. Assumes tertiary oil pricing permitted at higher tier levels and a moderate level of Federal research and development funding, with tertiary recovery remaining a high-risk technology.
Special Oil and Gas Regions	FEA adjustments to U.S. Geological Survey estimates, reflecting earlier and higher production levels in the special oil regions. Assumes a 10 percent investment tax credit throughout and a faster drilling and development schedule.	FEA adjustments to U.S. Geological Survey estimates, reflecting a best estimate of production rates from Alaska, the Naval Petroleum Reserves, and the outer continental shelf. Assumes a 10 percent investment tax credit through 1977, reduced to 7 percent thereafter.

PIES SCENARIO #10 -- LOW GROWTH ECONOMY

SCENARIO DESCRIPTION

This scenario is designed to show the response of the U.S. energy system to a macroeconomic growth rate considerably slower than the DRI Trend Long Forecast, which is being used in the Reference Scenario. A converse scenario, showing a higher growth economy than in the Reference Scenario, is not considered necessary or realistic, since the Reference Scenario includes assumptions of relatively high economic growth - e.g., that unemployment will be no more than 4 percent by 1985 - which are not likely to be exceeded.

SCENARIO IMPLEMENTATION

This scenario is modeled by making the following changes to the Reference Scenario:

<u>Variable</u>	<u>Value in Low Growth Economy Scenario</u>	<u>Value in Reference Scenario</u>
Macroeconomic Growth Forecast	Forecast of a lower rate of economic growth, including the following annual growth rates, compounded yearly, which are approximately 1 percent less than in the Reference Scenario:	Data Resources, Inc., Trend Long Forecast of August 1976. The forecast includes the following average annual growth rates:
	1975- 1980- 1988- 1980 1985 1990	1975- 1980- 1985- 1980 1985 1990
Gross National Product	3.83% 2.31% 2.04%	4.83% 3.29% 3.05%
Value Added in Manufacturing	5.68% 3.00% 2.92%	6.68% 4.00% 3.92%
Personal Disposable Income	2.55% 1.02% 1.22%	3.67% 1.99% 2.25%

PIES SCENARIO #11 -- ACCELERATED CONSERVATION

SCENARIO DESCRIPTION

This scenario is designed to show the response of the U.S. energy system to significantly more aggressive conservation programs than embodied in the Reference Scenario. Generally this scenario contains all conservation provisions included in both the Energy Policy and Conservation Act of 1975 and the Energy Conservation and Production Act of 1976, plus a residential tax credit, an increase in the load factor of commercial airlines and a returnable bottle program. In addition, it includes an increase in the average annual load factors of electric utilities, resulting from successful load management programs, and additional supply contributions from dispersed solar and geothermal sources. The following items are included:

- o Federal Energy Management Program -- Aimed at reducing the Federal government's energy use by 1.0 to 22.5 percent (depending on fuel type) below what it otherwise would have been.
- o Appliance Program -- Establishment of standards for appliance ranging from a 12 percent improvement from electric water heaters to a 50 percent improvement for non-electric kitchen ranges and ovens
- o Weatherization Assistance Program -- Weatherization of six million low-income homes.
- o Auto Fuel Efficiency Program -- Establishment of fuel economy standards for new cars at 20 mpg, 27.5 mpg, and 27.5 mpg for 1980, 1985, and 1990, respectively.
- o HUD Standards -- Establishment by the Department of Housing and Urban Development of standards for newly constructed residences and commercial buildings which result in energy efficiency improvements.
- o State Energy Conservation Programs -- Establishment of energy conservation programs funded by the Federal government and administered by State and local governments. Fuel savings depend on the types of programs initiated, the level of funding, and their effectiveness.
- o Obligation Guarantees -- Provision of loan guarantees amounting to \$2 billion to non-profit institutions, large and small businesses, commercial entities and residential buildings containing three or more dwelling units, and to State and local governments for purchasing energy conservation and renewable resource measures.
- o Retrofit Tax Credit -- Provision of a 30 percent tax credit for the first \$500 of investment in conservation measures in single-family residents.

#11 ACCELERATED CONSERVATION (CONT.)

- o CAB Load Factor -- Increase in the commercial airline load factor from 55 percent to 65 percent.
- o Bottle Bill -- Implementation of a national law requiring refundable deposits on all beer and soft drink containers.

SCENARIO IMPLEMENTATION

This scenario is modeled by making the following changes to the Reference Scenario:

<u>Variable</u>	<u>Value in Accelerated Conservation Scenario</u>	<u>Value in Reference Scenario</u>																																																
Conservation Programs	<p>The accelerated level of conservation savings results from increased savings attributable to the five programs included in the Reference Scenario, plus savings from five additional conservation programs. Each conservation program results in the following reduction in total demand for a fuel in a sector from what it otherwise would have been in the absence of the program:</p>	<p>Conservation savings in the Reference Scenario result from the first five of the conservation programs listed below. Each conservation program results in the following reduction in total demand for a fuel in a sector from what it otherwise would have been in the absence of the program:</p>																																																
o Federal Energy Management Program	<p>Percentage reductions achieved for 1980, 1985, and 1990, in the commercial and transportation sectors:</p> <table><thead><tr><th><u>Fuel/Sector</u></th><th><u>Com.</u></th><th><u>Trans.</u></th></tr></thead><tbody><tr><td>Gasoline</td><td>0.0%</td><td>0.3%</td></tr><tr><td>Distillate</td><td>2.1</td><td>6.2</td></tr><tr><td>Jet Fuel</td><td>0.0</td><td>6.5</td></tr><tr><td>Coal</td><td>22.5</td><td>0.0</td></tr><tr><td>Electricity</td><td>1.0</td><td>0.0</td></tr><tr><td>Residual</td><td>3.5</td><td>6.2</td></tr><tr><td>Natural Gas^c</td><td>2.0</td><td>0.0</td></tr></tbody></table>	<u>Fuel/Sector</u>	<u>Com.</u>	<u>Trans.</u>	Gasoline	0.0%	0.3%	Distillate	2.1	6.2	Jet Fuel	0.0	6.5	Coal	22.5	0.0	Electricity	1.0	0.0	Residual	3.5	6.2	Natural Gas ^c	2.0	0.0	<p>Percentage reductions achieved for 1980, 1985, and 1990, in the commercial and transportation sectors:</p> <table><thead><tr><th><u>Fuel/Sector</u></th><th><u>Com.</u></th><th><u>Trans.</u></th></tr></thead><tbody><tr><td>Gasoline</td><td>0.0%</td><td>0.2%</td></tr><tr><td>Distillate</td><td>1.4</td><td>4.1</td></tr><tr><td>Jet Fuel</td><td>0.0</td><td>6.5</td></tr><tr><td>Coal</td><td>15.0</td><td>0.0</td></tr><tr><td>Electricity</td><td>0.7</td><td>0.0</td></tr><tr><td>Residual</td><td>2.3</td><td>4.1</td></tr><tr><td>Natural Gas</td><td>1.4</td><td>0.0</td></tr></tbody></table>	<u>Fuel/Sector</u>	<u>Com.</u>	<u>Trans.</u>	Gasoline	0.0%	0.2%	Distillate	1.4	4.1	Jet Fuel	0.0	6.5	Coal	15.0	0.0	Electricity	0.7	0.0	Residual	2.3	4.1	Natural Gas	1.4	0.0
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#11 ACCELERATED CONSERVATION (CONT.)

Conservation Programs (cont.)

o Weatherization Assistance Program

Percentage reductions in total demand for a fuel in the residential sector attributable to a combination of the Weatherization Assistance Program, Appliance Labeling and Efficiency Targets Program, and HUD Residential Building Standards:

	<u>Res.</u>
<u>1980</u>	
Distillate	1.6%
Electricity	4.7
Natural Gas	4.6

<u>1985</u>	
Distillate	3.8%
Electricity	11.0
Natural Gas	5.9

<u>1990</u>	
Distillate	6.1%
Electricity	15.1
Natural Gas	4.8

Reductions (in Btu's) achieved by 1990 in the residential sector. No further savings in 1985 or 1990:

<u>Fuel/Sector</u>	<u>Res.</u>
Distillate	13.0 MM Btu's
Electricity	1.5
Natural Gas	34.0

o Appliance Labeling and Efficiency Targets Program

See "Weatherization Assistance Program" entry for savings.

Percentage reductions achieved in the residential sector:

<u>Fuel/Sector</u>	<u>Res.</u>
<u>1980</u>	
Distillate	0.0%
Electricity	3.5
Natural Gas	1.5

<u>1985</u>	
Distillate	0.0%
Electricity	6.4
Natural Gas	1.4

<u>1990</u>	
Distillate	-0.4%
Electricity	8.3
Natural Gas	-0.2

o HUD Residential Building Standards

See "Weatherization Assistance Program" entry for savings.

No savings attributable to Department of Housing and Urban Development energy efficiency standards for residential buildings. (Some savings attributable to state building standards are included in the Reference Scenario under State Energy Conservation Programs.)

o HUD Commercial Building Standards

Percentage reductions in demand for all fuels in the commercial sector:

	<u>Com.</u>
<u>1980</u>	0.0%
<u>1985</u>	9.0
<u>1990</u>	18.0

No savings attributable to Department of Housing and Urban Development energy efficiency standards for commercial buildings. (Some savings attributable to state buildings are included in the Reference Scenario under State Energy Conservation Programs.)

#11 ACCELERATED CONSERVATION (CONT.)

Conservation Programs (cont.)

o Obligation Guarantees	No measurable savings from the obligation guarantee program in the residential sector. Percentage reductions in demand for all fuels in the commercial and industrial sectors: <table><tr><td></td><td>Com.</td><td>Ind.</td></tr><tr><td><u>1930</u></td><td>0.7%</td><td>1.5%</td></tr><tr><td><u>1965</u></td><td>1.9</td><td>3.9</td></tr><tr><td><u>1990</u></td><td>1.9</td><td>3.6</td></tr></table>		Com.	Ind.	<u>1930</u>	0.7%	1.5%	<u>1965</u>	1.9	3.9	<u>1990</u>	1.9	3.6	No savings attributable to Federal loan guarantees for energy conservation and renewable resource measures.														
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o Retrofit Tax Credit	Percentage reductions achieved in the residential sector: <table><tr><td></td><td>Res.</td></tr><tr><td><u>1930</u></td><td></td></tr><tr><td>Distillate</td><td>1.3%</td></tr><tr><td>Electricity</td><td>0.6</td></tr><tr><td>Natural Gas</td><td>2.8</td></tr><tr><td><u>1985</u></td><td></td></tr><tr><td>Distillate</td><td>1.4%</td></tr><tr><td>Electricity</td><td>0.5</td></tr><tr><td>Natural Gas</td><td>2.8</td></tr><tr><td><u>1990</u></td><td></td></tr><tr><td>Distillate</td><td>1.4%</td></tr><tr><td>Electricity</td><td>0.4</td></tr><tr><td>Natural Gas</td><td>2.8</td></tr></table>		Res.	<u>1930</u>		Distillate	1.3%	Electricity	0.6	Natural Gas	2.8	<u>1985</u>		Distillate	1.4%	Electricity	0.5	Natural Gas	2.8	<u>1990</u>		Distillate	1.4%	Electricity	0.4	Natural Gas	2.8	No savings attributable to a Federal tax credit for investments in conservation measures for single family dwellings.
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o CAB Load Factor	Civil Aeronautics Board average load factor for all jurisdictional commercial airlines is increased to 65 percent by 1980. Results in reduction in demand for jet fuel in the transportation sector.	Civil Aeronautics Board average load factor for all jurisdictional commercial airlines remains at 55 percent.																										
o Returnable Bottle Law	Percentage reductions in demand for all fuels in the industrial sector: <table><tr><td></td><td>Ind.</td></tr><tr><td><u>1980</u></td><td>0.0%</td></tr><tr><td><u>1985</u></td><td>0.4</td></tr><tr><td><u>1990</u></td><td>0.4</td></tr></table>		Ind.	<u>1980</u>	0.0%	<u>1985</u>	0.4	<u>1990</u>	0.4	No savings attributable to Federal law requiring refundable deposits on all beer and soft drink containers.																		
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<u>1985</u>	0.4																											
<u>1990</u>	0.4																											
Load Management	The average of regional annual load factors achieved by electric utilities is: 1930 - 60% 1985 - 65 1990 - 63	The average of regional annual load factors achieved by electric utilities is: 1980 - 60.5% 1985 - 60 1990 - 58																										

ACCELERATED CONSERVATION (CONT.)

Dispersed Technology Programs

o Solar	1980 - 0 Quads	1980 - 0 Quads
	1985 - .37	1985 - .11
	1990 -1.55	1990 - .60
o Geothermal	1980 - 0 Quads	1980 - 0 Quads
	1985 - .10	1985 - .10
	1990 - .40	1990 - .25

PIES SCENARIO #12 -- OIL AND GAS TAX

SCENARIO DESCRIPTION

This scenario is designed to show the response of the U.S. energy system to a tariff on all imported oil and gas and a tax on all domestic oil and gas production, applied at point of supply. Both tariff and tax are applied at the same rate, based on Btu content of the assessed fuel.

SCENARIO IMPLEMENTATION

This scenario is modeled by making the following changes to the Reference Scenario:

<u>Variable</u>	<u>Value in Oil and Gas Tax Scenario</u>	<u>Value in Reference Scenario</u>
Domestic Gas Prices	Complete and immediate deregulation of the price of all new gas. Old gas continues to be sold at nominal vintaged prices.	Continued regulation of interstate sales as currently required by law at a nominal price of \$1.42 per mcf (plus a nominal increase of 4 cents per year) for new gas, and lower vintaged prices for old gas. Assumes the price of new gas will be rolled in with the price of old gas.
Btu Tax	Tax of \$1.00/MMBtu applied to all oil and gas, both domestic production and imports, at point of supply.	No special Btu tax on any fuel.

PIES SCENARIO #13—OIL AND GAS TAX WITH ACCELERATED CONSERVATION

SCENARIO DESCRIPTION

The intent of this scenario is to show the response of the U.S. energy system to the imposition of a tariff on all imported oil and gas and a tax on all domestic oil and gas production, in combination with the implementation of more aggressive energy conservation programs.

SCENARIO IMPLEMENTATION

This scenario is modeled by making the following changes to the Reference Scenario:

<u>Variable</u>	<u>Value in Oil and Gas Tax With Accelerated Conservation Scenario</u>	<u>Value in Reference Scenario</u>																																																
Domestic Gas Prices	Complete and immediate deregulation of the price of all new gas. Old gas continues to be sold at nominal vintaged prices.	Continued regulation of interstate sales as currently required by law at a nominal price of \$1.42 per mcf (plus a nominal increase of 4 cents per year) for new gas, and lower vintaged prices for old gas. Assumes the price of new gas to be rolled in with the price of old gas.																																																
Conservation Programs	The accelerated level of conservation savings results from increased savings attributable to the five programs included in the Reference Scenario, plus savings from five additional conservation programs. Each conservation program results in the following reduction in total demand for a fuel in a sector from what it otherwise would have been in the absence of the program:	Conservation savings in the Reference Scenario result from the conservation programs listed below. Each conservation program results in the following reduction in total demand for a fuel in a sector from what it otherwise would have been in the absence of the program:																																																
Federal Energy Management Program	Percentage reductions achieved for 1980, 1985, and 1990, in the commercial and transportation sectors:	Percentage reductions achieved for 1980, 1985, and 1990, in the commercial and transportation sectors:																																																
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#13 OIL AND GAS TAX WITH ACCELERATED CONSERVATION (CONT.)

Conservation Programs (cont.)

Auto Fuel Economy Standards

The average fuel economy (in miles per gallon) of all new cars is:

1980: 20.0 mpg
1985: 27.5
1990: 27.5

The increased efficiency results in a reduction in demand for gasoline in the transportation sector.

The average fuel economy (in miles per gallon) of all new cars is:

1980: 20.0 mpg
1985: 26.0
1990: 26.0

The increased efficiency results in a reduction in demand for gasoline in the transportation sector.

State Energy Conservation Programs

Percentage reductions in demand for all fuels in the residential, commercial, industrial, and transportation sectors:

	Res.	Com.	Ind.	Trans.
1980	0.7%	3.4%	1.4%	0.5%
1985	0.1	1.3	0.6	0.6
1990	0.1	1.2	0.7	0.0

Percentage reductions in demand for all fuels in the residential, commercial, industrial, and transportation sectors:

	Res.	Com.	Ind.	Trans.
1980	0.6%	2.6%	0.7%	0.4%
1985	1.0	3.9	0.3	0.4
1990	1.5	5.7	0.0	0.5

Weatherization Assistance Program

Percentage reductions in total demand for a fuel in the residential sector attributable to a combination of the Weatherization Assistance Program, Appliance Labeling and Efficiency Targets Program, and HUD Residential Building Standards:

	Res.
1980	
Distillate	1.6%
Electricity	4.7
Natural Gas	4.6
1985	
Distillate	3.8%
Electricity	11.0
Natural Gas	5.9
1990	
Distillate	6.1%
Electricity	15.1
Natural Gas	4.8

Reductions (in Btu's) achieved by 1980 in the residential sector. No further savings in 1985 or 1990:

Fuel/Sector	Res.
Distillate	13.0 MM Btu's
Electricity	1.5
Natural Gas	34.0

Appliance Labeling and Efficiency Targets Program

See "Weatherization Assistance Program" entry for savings.

Percentage reductions achieved in the residential sector:

Fuel/Sector	Res.
1980	
Distillate	0.0%
Electricity	3.5
Natural Gas	1.5
1985	
Distillate	0.0%
Electricity	6.4
Natural Gas	1.4
1990	
Distillate	-0.4%
Electricity	8.3
Natural Gas	-0.3

HUD Residential Building Standards

See "Weatherization Assistance Program" entry for savings.

No savings attributable to Department of Housing and Urban Development energy efficiency standards for residential buildings. (Some savings attributable to state building standards are included in the Reference Scenario under State Energy Conservation Programs.)

#13 OIL AND GAS TAX WITH ACCELERATED CONSERVATION (CONT.)

Conservation Programs (cont.)

HUD Commercial Building Standards	<p>Percentage reductions in demand for all fuels in the commercial sector:</p> <table><tr><td></td><td>Com.</td></tr><tr><td><u>1980</u></td><td>0.0%</td></tr><tr><td><u>1985</u></td><td>9.0</td></tr><tr><td><u>1990</u></td><td>18.0</td></tr></table>		Com.	<u>1980</u>	0.0%	<u>1985</u>	9.0	<u>1990</u>	18.0	<p>No savings attributable to Department of Housing and Urban Development energy efficiency standards for commercial buildings. (Some savings attributable to state buildings are included in the Reference Scenario under State Energy Conservation Programs.)</p>																		
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Obligation Guarantees	<p>No measurable savings from the obligation guarantee program in the residential sector. Percentage reductions in demand for all fuels in the commercial and industrial sectors:</p> <table><tr><td></td><td>Com.</td><td>Ind.</td></tr><tr><td><u>1980</u></td><td>0.7%</td><td>1.5%</td></tr><tr><td><u>1985</u></td><td>1.9</td><td>3.9</td></tr><tr><td><u>1990</u></td><td>1.9</td><td>3.6</td></tr></table>		Com.	Ind.	<u>1980</u>	0.7%	1.5%	<u>1985</u>	1.9	3.9	<u>1990</u>	1.9	3.6	<p>No savings attributable to Federal loan guarantees for energy conservation and renewable resource measures.</p>														
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Retrofit Tax Credit	<p>Percentage reductions achieved in the residential sector:</p> <table><tr><td></td><td>Res.</td></tr><tr><td><u>1980</u></td><td></td></tr><tr><td>Distillate</td><td>1.3%</td></tr><tr><td>Electricity</td><td>0.6</td></tr><tr><td>Natural Gas</td><td>2.8</td></tr><tr><td><u>1985</u></td><td></td></tr><tr><td>Distillate</td><td>1.4%</td></tr><tr><td>Electricity</td><td>0.5</td></tr><tr><td>Natural Gas</td><td>2.3</td></tr><tr><td><u>1990</u></td><td></td></tr><tr><td>Distillate</td><td>1.4%</td></tr><tr><td>Electricity</td><td>0.4</td></tr><tr><td>Natural Gas</td><td>2.9</td></tr></table>		Res.	<u>1980</u>		Distillate	1.3%	Electricity	0.6	Natural Gas	2.8	<u>1985</u>		Distillate	1.4%	Electricity	0.5	Natural Gas	2.3	<u>1990</u>		Distillate	1.4%	Electricity	0.4	Natural Gas	2.9	<p>No savings attributable to a Federal tax credit for investments in conservation measures for single family dwellings.</p>
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Electricity	0.4																											
Natural Gas	2.9																											
CAB Load Factor	<p>Civil Aeronautics Board average load factor for all jurisdictional commercial airlines is increased to 65 percent by 1980. Results in reduction in demand for jet fuel in the transportation sector.</p>	<p>Civil Aeronautics Board average load factor for all jurisdictional commercial airlines remains at 55 percent.</p>																										
Returnable Bottle Law	<p>Percentage reductions in demand for all fuels in the industrial sector:</p> <table><tr><td></td><td>Ind.</td></tr><tr><td><u>1980</u></td><td>0.0%</td></tr><tr><td><u>1985</u></td><td>0.4</td></tr><tr><td><u>1990</u></td><td>0.4</td></tr></table>		Ind.	<u>1980</u>	0.0%	<u>1985</u>	0.4	<u>1990</u>	0.4	<p>No savings attributable to Federal law requiring refundable deposits on all beer and soft drink containers.</p>																		
	Ind.																											
<u>1980</u>	0.0%																											
<u>1985</u>	0.4																											
<u>1990</u>	0.4																											
Btu Tax	<p>Tax of \$1.00/MBtu applied to all oil and gas, both domestic production and imports, at point of supply.</p>	<p>No special Btu tax applied to any fuels.</p>																										

PIES SCENARIO #14 -- GASOLINE TAX

SCENARIO DESCRIPTION

This scenario is designed to show the response of the U.S. energy system to a tax on gasoline. Thus the scenario encourages a shift away from automobile consumption of gasoline, the largest single use of any fuel in the United States.

SCENARIO IMPLEMENTATION

This scenario is modeled by making the following changes to the Reference Scenario:

<u>Variable</u>	<u>Value in Gasoline Tax Scenario</u>	<u>Value in Reference Scenario</u>
Domestic Gas Prices	Complete and immediate deregulation of the price of all new gas. Old gas continues to be sold at nominal vintaged prices.	Continued regulation of interstate sales as currently required by law at a nominal price of \$1.42 per mcf (plus a nominal increase of 4 cents per year) for new gas, and lower vintaged prices for old gas. Assumes the price of new gas will be rolled in with the old.
Btu Tax	Tax of \$1.00/MMBtu applied to gasoline at point of final sale	No special Btu tax applied to any fuel.

PIES SCENARIO #15 -- DEPLETABLE RESOURCE TAX

SCENARIO DESCRIPTION

This scenario is designed to show the response of the U.S. energy system to a tariff on all imported fuels and a tax on all domestic fuels, including oil, gas, coal and uranium, applied at point of supply. Both tariff and tax are applied at the same rate, based on the equivalent Btu content of the assessed fuels, which, in the case of uranium, is calculated in accordance with its heat rate. Thus, the scenario encourages consumption shifts away from all depletable resources, whether imported or produced domestically.

SCENARIO IMPLEMENTATION

This scenario is modeled by making the following changes to the Reference Scenario:

<u>Variable</u>	<u>Value in Depletable Resource Tax Scenario</u>	<u>Value in Reference Scenario</u>
Domestic Gas Prices	Complete and immediate deregulation of the price of all new gas. Old gas continues to be sold at nominal vintaged prices.	Continued regulation of interstate sales as currently required by law at a nominal price of \$1.42 per mcf (plus a nominal increase of 4 cents per year) for new gas, and lower vintaged prices for old gas. Assumes the price of new gas will be rolled in with the old.
Btu Tax	Tax of \$1.00/MMBtu applied to all oil, gas, coal and uranium at point of supply.	No Btu tax applied to any fuels.

PIES SCENARIO #16 -- LOW GAS POLICIES

SCENARIO DESCRIPTION

This scenario is designed to show the impact on the U.S. energy system of government energy policy actions (or failures to act) which result in a constrained level of gas supplies. The assumptions are: an Energy Resources Council decision to constrain liquefied natural gas (LNG) imports below the level in the Reference Scenario; and a slowdown in outer continental shelf (OCS) lease sales due to administrative backlog, environmental challenges, etc. Geologic estimates are the same as in the Reference Scenario, since varying them as well would have an impact of such magnitude that the impact of varying the policy variables would be obscured.

SCENARIO IMPLEMENTATION

This scenario is modeled by making the following changes to the Reference Scenario:

Variable	Value in Low Gas Policies Scenario	Value in Reference Scenario
Imported LNG	1980	1980
	0.4Tcf @ \$2.10/Mcf East Coast	0.4Tcf @ \$2.10/Mcf East Coast
	1985	1985
	0.4Tcf @ \$2.10/Mcf East Coast	0.4Tcf/yr @ \$2.10-\$2.49/Mcf East Coast
	0.4Tcf/yr. Total	+ 0.4Tcf/yr @ \$2.50-\$2.99/Mcf Coast
		+ 0.2Tcf/yr @ \$3.00/Mcf Coast
		+ 0.2Tcf/yr @ \$3.00/Mcf West Coast
		= 1.2Tcf/yr. Total
	1990	1990
	0.4Tcf/yr @ \$2.10-\$2.49/Mcf East Coast	0.4Tcf/yr @ \$2.10-\$2.49/Mcf East Coast
OCS Lease Sales	+ 0.4Tcf/yr @ \$2.50-\$2.99/Mcf Coast	+ 0.4Tcf/yr @ \$2.50-\$2.99/Mcf East Coast
	+ 0.2Tcf/yr @ \$3.00/Mcf West Coast	+ 0.5Tcf/yr @ \$3.00-\$3.49/Mcf Coast
	+ 0.2Tcf/yr @ \$3.00/Mcf West Coast	+ 0.8Tcf/yr @ \$3.50 West Coast
	= 1.2Tcf/yr. Total	+ 0.4Tcf/yr @ \$3.00 West Coast
		= 2.5Tcf/yr. Total
	4 sales per year;	5 lease sales per year;
	1.5 million acres nominated per sale;	1.5 million acres nominated per sale;
	.8 million acres offered per sale;	1.0 million acres offered per sale;
	Percent of offer actually leased:	Percent of offer actually leased:
	1976-78 - 40%	1976-78 - 45%
	1979-82 - 35%	1979-82 - 40%
	1983-90 - 30%	1983-90 - 35%

PIES SCENARIO #17 -- HIGH GAS POLICIES

SCENARIO DESCRIPTION

This scenario is designed to show the impact on the U.S. energy system of a plausible set of key government energy policy and program actions designed to encourage increased natural gas supplies.

The assumptions are: the enactment of legislation to deregulate the price of all new natural gas; an Energy Resource Council decision to allow a higher level of liquefied natural gas (LNG) imports; an acceleration of the outer continental shelf (OCS) leasing schedule; and full Federal support, including financial assistance if required, to expedite construction of an Alaskan natural gas transportation system by 1985. Geologic estimates are the same as in the Reference Scenario, since varying them as well would have an impact of such magnitude that the impact of varying the policy variables would be obscured.

SCENARIO IMPLEMENTATION

This scenario is modeled by making the following changes to the Reference Scenario:

<u>Variable</u>	<u>Value in High Gas Policies Scenario</u>	<u>Value in Reference Scenario</u>
Domestic Gas Prices	Complete and immediate deregulation of the price of all new gas. Old gas continues to be sold at nominal vintage prices.	Continued regulation of interstate sales as currently required by law at a nominal price of \$1.42 per mcf (plus a nominal increase of 4 cents per year) for new gas, and lower vintage prices for old gas. Assumes the price of new gas will be rolled in with the price of old gas.
Imported LNG	<div> <u>1980</u> 0.4Tcf @ \$2.10/Mcf East Coast </div> <div> <u>1985</u> 0.4Tcf @ \$2.10-\$2.49/Mcf + 0.4Tcf @ \$2.50-\$2.99/Mcf } East + 0.5Tcf @ \$3.00-\$3.49/Mcf } Const + 0.8Tcf @ \$3.50 + 0.4Tcf @ \$3.00 West Coast <u>2.5Tcf/yr. Total</u> </div>	<div> <u>1980</u> 0.4Tcf @ \$2.10/Mcf East Coast </div> <div> <u>1985</u> 0.4Tcf/yr @ \$2.10-\$2.49/Mcf East + 0.4Tcf/yr @ \$2.40-\$2.99/Mcf Coast + 0.2Tcf/yr @ \$3.00/Mcf + 0.2Tcf/yr @ \$3.00/Mcf West Coast <u>1.2Tcf/yr. Total</u> </div>

#17 HIGH GAS POLICIES (CONT.)

1990			1990		
0.4Tcf @ \$2.10-\$2.49/Mcf	} East Coast		0.4Tcf @ \$2.10-\$2.49/Mcf	} East Coast	
0.4Tcf @ \$2.50-\$2.99/Mcf			0.4Tcf @ \$2.50-\$2.99/Mcf		
0.5Tcf @ \$3.00-\$3.49/Mcf			0.5Tcf @ \$3.00-\$3.49/Mcf		} Coast
0.8Tcf @ \$3.50/Mcf			0.8Tcf @ \$3.50/Mcf		
0.4Tcf @ \$3.00-\$3.49/Mcf	} West Coast		0.4Tcf @ \$3.00/Mcf West Coast		
0.8Tcf @ \$3.50/Mcf		} Coast			
<hr/>				<hr/>	
0.8Tcf/yr. Total			2.5Tcf/yr. Total		

OCS Lease Sales	6 sales per year;	5 lease sales per year;
	1.5 million acres nominated per sale;	1.5 million acres nominated per sale;
	1.2 million acres offered per sale;	1.0 million acres offered per sale;
	Percent of offer actually leased:	Percent of offer actually leased:
	1976-78 - 45%	1976-78 - 45%
	1979-82 - 42%	1979-82 - 40%
	1983-90 - 40%	1983-90 - 35%

Alaskan Gas Supply	One pipeline, moving	One pipeline, moving
	≤3.3 Bcf/d by 1985.	≤3.3 Bcf/d by 1990.

PIES SCENARIO #18--CLEANER COAL

SCENARIO DESCRIPTION

This scenario is designed to show the response of the U.S. energy system to a plausible combination of circumstances which is likely to increase demand for eastern coal and thereby cause a shift in the Nation's major centers of coal production.

It is assumed that utilities are compelled to convert from oil and gas to coal to the maximum extent feasible--driving up demand for coal. In addition, scrubbers are required on all coal-burning utilities, regardless of coal sulphur content--reducing the economic advantage otherwise enjoyed by western low-sulphur coal, thereby driving demand for coal from the West to the East.

SCENARIO IMPLEMENTATION

This scenario is modeled by making the following changes to the Reference Scenario:

<u>Variable</u>	<u>Value in Cleaner Coal Scenario</u>	<u>Value in Reference Scenario</u>
Mandated Conversions from Oil and Gas	Conversion of existing oil and gas fired utility capacity is the same as in the Reference Scenario. With regard to new utility capacity, gas use is banned and oil is allowed only for peaking uses.	Pursuant to authority under the Energy Supply and Environmental Coordination Act of 1974 (ESECA), a total of 17,580 MWe of existing oil and gas fired utility capacity is forced to convert to coal. This represents all capacity ordered, but not yet converted, under ESECA as of November 1976, as well as all capacity expected to be ordered to convert before the existing legislation expires on June 30, 1977. (The approximately 2500 MWe already converted under ESECA is specified as "existing coal-fired capacity.") No constraints are imposed in PIES on fuels for new utility capacity; fuel types are determined by economic choices made within the model.
Requirements under the Clean Air Act	All regions require the use of scrubbers on all coal power plants. There is no limitation on sulphur content of coal, except in FEA Regions 8 and 9.	FEA Regions 8 and 9 require the use of low sulphur coal and scrubbers on all coal power plants. All other regions require the use of either low sulphur coal or scrubbers with high sulphur coal on all coal power plants.

PIES SCENARIO #19--CLEANER COAL AND LESS NUCLEAR

SCENARIO DESCRIPTION

This scenario is designed to show the impact of a plausible combination of circumstances that could occur, largely as a result of environmental and safety concerns, which could substantially increase demand for coal -- especially demand for eastern coal -- and thereby test the ability of coal supply to meet demand under extreme conditions.

The assumptions are that new nuclear power plant construction will be severely limited, and that utilities will be prohibited from burning oil and gas wherever possible, thus greatly increasing demand for coal. In addition, it is assumed that scrubbers will be required on all coal power plants, regardless of sulphur content, reducing the economic advantage otherwise enjoyed by low-sulphur coal, thereby driving demand for coal from the West to the East.

SCENARIO IMPLEMENTATION

This scenario is modeled by making the following changes to the Reference Scenario:

<u>Variable</u>	<u>Value in Cleaner Coal and Less Nuclear Scenario</u>	<u>Value in Reference Scenario</u>
Mandated Conversions from Oil and Gas	Conversion of existing oil and gas fired utility capacity is the same as in the Reference Scenario. With regard to new utility capacity, gas use is banned and oil is allowed only for peaking uses.	Pursuant to authority under the Energy Supply and Environmental Coordination Act of 1974 (ESECA), a total of 17,580 MWe of existing oil and gas fired utility capacity is forced to convert to coal. This represents all capacity ordered, but not yet converted, under ESECA as of November 1976, as well as all capacity expected to be ordered to convert before the existing legislation expires on June 30, 1977. (The approximately 2500 MWe already converted under ESECA is specified as "existing coal-fired capacity.") No constraints are imposed in PIES on fuels for new utility capacity; fuel types are determined by economic choices made within the model.
Requirements under the Clean Air Act	All regions require the use of scrubbers on all coal power plants. There is no limitation on sulphur content of coal, except in FEA Regions 8 and 9.	FEA Regions 8 and 9 require the use of low sulphur coal and scrubbers on all coal power plants. All other regions require the use of either low sulphur coal or scrubbers with high sulphur coal on all coal power plants.

#19 CLEANER COAL AND LESS NUCLEAR (CONT.)

Nuclear Power Plant Build Limits

Limits on units to be built in addition to the existing 39 GWe of capacity as of 1/1/76:

1980

Upper Limit: 19 GWe (Units with construction $\geq 2\%$ complete as of 1/1/76 which, if delayed by 12 months, would be in commercial operation on 1/1/80. No units not $\geq 2\%$ complete would be built.)

Lower Limit: 14 GWe (Units with construction $\geq 2\%$ complete as of 1/1/76 which, if delayed by 24 months, would be in commercial operation on 1/1/80. No units not $\geq 2\%$ complete would be built.)

1985

Upper Limit: 56 GWe (Units with construction $\geq 2\%$ complete as of 1/1/76 which, if delayed by 24 months, would be in commercial operation on 1/1/85. No units not $\geq 2\%$ complete would be built.)

Lower Limit: 32 GWe (Units with construction $\geq 2\%$ complete as of 1/1/76 which are currently scheduled for commercial operation by 1/1/80. No units not $\geq 2\%$ complete would be built.)

1990

Upper Limit: 56 GWe (Units with construction $\geq 2\%$ complete as of 1/1/76 and currently scheduled to be in commercial operation on 1/1/85. No units not $\geq 2\%$ complete would be built.)

Lower Limit: 93 GWe (Units forecast by 1985 Less Nuclear Scenario run to be in commercial operation on 1/1/85.

Limits on units to be built in addition to the existing 39 GWe of capacity as of 1/1/76:

1980

Upper Limit: 32 GWe (All units currently scheduled to be in commercial operation by 1/1/80.)

Lower Limit: 19 GWe (All units with construction $\geq 2\%$ complete as of 1/1/76 which, if delayed by 12 months, would be in commercial operation on 1/1/80. No units not $\geq 2\%$ complete would be built.)

1985

Upper Limit: 103 GWe (All units, which if delayed by 12 months, would be in commercial operation by 1/1/85.)

Lower Limit: 54 GWe (All units with construction $\geq 2\%$ complete as of 1/1/76 which would be in commercial operation by 1/1/85. No units not $\geq 2\%$ complete by 1/1/76 would be built.)

1990

Upper Limit: 165 GWe (Extrapolation of baseload capacity additions forecast by 1985 Reference Scenario run.)

Lower Limit: 56 GWe (Units forecast by 1985 Reference Scenario run to be in commercial operation on 1/1/85.

PIES SCENARIO #20 LESS NUCLEAR

SCENARIO DESCRIPTION

This scenario is designed to show the response of the U.S. energy system to a severe limitation in the number of new nuclear power plants which are allowed to be built. Prior to the November 1976 elections, 32 states were considering instituting restrictions or moratoria on new nuclear construction affecting a total of 77 GWe of planned capacity not yet under construction. In addition, the NRC was reconsidering licensing procedures immediately affecting roughly 9 GWe of planned capacity and potentially restricting nuclear development throughout the United States. Thus, severe restriction on the number of new nuclear plants which are allowed to be built is not an unreasonable possibility, significantly affecting the future development of the U.S. energy system.

SCENARIO IMPLEMENTATION

This scenario is modeled by making the following changes to the Reference Scenario:

<u>Variable</u>	<u>Value in Less Nuclear Scenario</u>	<u>Value in Reference Scenario</u>
Nuclear Power Plant Build Limits	Limits on units to be built in addition to the existing 39 GWe of capacity as of 1/1/76: <div><u>1980</u> <u>Upper Limit:</u> 19GWe (Units with construction $\geq 2\%$ complete of 1/1/76 which, if delayed by 12 months, would be in commercial operation on 1/1/80. No units not $\geq 2\%$ complete would be built.) <u>Lower Limit:</u> 14 GWe (Units with construction $\geq 2\%$ complete as of 1/1/76 which, if delayed by 24 months, would be in commercial operation on 1/1/80. No units not $\geq 2\%$ complete would be built.)</div>	Limits on units to be built in addition to the existing 39 GWe of capacity as of 1/1/76: <div><u>1980</u> <u>Upper Limit:</u> 32 GWe (All units currently scheduled to be in commercial operation by 1/1/80.) <u>Lower Limit:</u> 19 GWe (All units with construction $\geq 2\%$ complete as of 1/1/76 which, if delayed by 12 months, would be in commercial operation on 1/1/80. No units not $\geq 2\%$ complete would be built.)</div>
	<div><u>1985</u> <u>Upper Limit:</u> 56GWe (Units with construction $\geq 2\%$ complete as of 1/1/76 which, if delayed by 24 months, would be in commercial operation on 1/1/85.)</div>	<div><u>1985</u> <u>Upper Limit:</u> 103 GWe (All units, which if delayed by 12 months, would be in commercial operation by 1/1/85.)</div>

#20 LESS NUCLEAR (CONT.)

Lower Limit: 32 GWe (Units with construction recently scheduled for commercial operation by 1/1/80. No units not $\geq 2\%$ complete would be built.)

Lower Limit: 54 GWe (All units with construction $\geq 2\%$ complete as of 1/1/76 which would be in commercial operation by 1/1/85. No units not $\geq 2\%$ complete by 1/1/76 would be built.)

1990

Upper Limit: 56 GWe (Units with construction $\geq 2\%$ complete as of 1/1/76 and currently scheduled to be in commercial operation on 1/1/85. No units not $\geq 2\%$ complete would be built.)
Lower Limit: 32 GWe Units forecast by 1985 Less Nuclear Scenario run to be in commercial operation on 1/1/85.)

1990

Upper Limit: 168 GWe (Extrapolation of base-load capacity additions forecast by 1985 Reference Scenario run.)
Lower Limit: 56 GWe Units forecast by 1985 Reference Scenario run to be in commercial operation on 1/1/85.)

PIES SCENARIO #21 - INDUSTRIAL RESOURCE ESTIMATES

SCENARIO DESCRIPTION

This scenario is designed to illustrate the large uncertainty in domestic oil and gas resource estimates and the direct effect these estimates have on domestic production forecasts. The oil and gas resource estimates utilized in this scenario are the mean of three oil company estimates. These industry estimates differ substantially from the U. S. Geologic Survey (USGS) estimates used in the Reference Scenario in two key aspects: the industry estimates assume a much larger proportion of the remaining resources are located offshore; and the industry estimates assume that the oil and gas resources in Alaska are much larger. These two changes result in a much slower and more costly exploration and development process.

SCENARIO IMPLEMENTATION

This scenario is modeled by making the following changes to the Reference Scenario:

<u>Variable</u>	<u>Value in Industrial Resource Estimates Scenario</u>	<u>Value in Reference Scenario</u>
Oil and Gas Reserves	Mean of three oil company estimates of oil and gas resource located onshore and offshore.	USGS estimates of oil and gas resources with a 50% probability of recovery.

PIES SCENARIO #22—ELECTRIC LOAD MANAGEMENT

SCENARIO DESCRIPTION

This scenario is designed to show the impact on the U.S. energy system of successful programs to utilize the Nation's electric power plants on a more continuous basis, thereby increasing the productivity of capital invested in utilities.

If present trends in electric generating capacity utilization continue, utilities will be faced with the need to install a huge amount of very expensive generating capacity in the next 10-15 years to meet projected demands, particularly peak demands. The amount and kind of new capacity which must be planned for depends in part on the shape of load duration curves. There has been ample demonstration that load duration curves can be changed and that the technical equipment for utility load management is available.

In this scenario, the average annual load factors for each region are increased gradually through 1990 to show the impact of successful load management on new capacity requirements, the resulting effect on the financial position of electric utilities and the costs of electricity to the consumer, and the impact on oil and gas demand of reducing oil and gas fired peaking capacity.

SCENARIO IMPLEMENTATION

This scenario is modeled by making the following changes to the Reference Scenario:

<u>Variable</u>	<u>Value in Electric Load Management Scenario</u>	<u>Value in Reference Scenario</u>
Load Management	The average of regional annual load factors is:	The average of regional annual load factors is:
	1980: 60%	1980: 60.5%
	1985: 65%	1985: 60%
	1990: 68%	1990: 58%

APPENDIX 5

SUMMARY OF LEGISLATIVE PROPOSALS
ON HORIZONTAL DIVESTITURE

APPENDIX 5

SUMMARY OF LEGISLATIVE PROPOSALS ON HORIZONTAL DIVESTITURE

At the time this study began, there were three major Senate Legislative proposals which are summarized below: S. 489, S. 1927 and S. 977.

S. 489, The interfuel Competition Act of 1975

The bill prohibits "any person engaged in the production and refining of petroleum or not gas, or both" from acquiring any "interest in the coal business, oil shale business, uranium business, nuclear reactor business, geothermal steam business, or solar energy business." This prohibition would be effective immediately.

Effective three years after enactment, the bill would prohibit "any person" from retaining "ownership or control" over the above named businesses.

"Person" means any individual, corporation, (including affiliates), partnership, association, joint venture, or any entity organized for a common business purpose who directly or indirectly does business anywhere in the United States, its territories and possessions, or the District of Columbia. This bill would require divestiture of all gas and oil firms currently involved in the coal industry.

"Coal business" refers to "any interest in, ownership of, or control over a) reserves, b) exploration for c) mining of, d) sale of, e) production of, f) gasification or of g) liquefaction of coal."

Similar sweeping definitions apply to the oil shale, uranium, nuclear reactor, geothermal steam, and solar energy businesses. The bill would prohibit not only ownership but "control" over the businesses named. Control is defined broadly and can be direct or

indirect, "legal power" as well as "influence." Control can arise through direct or indirect "ownership of capital stock," interlocking directorates or officers," contractual relations," agency agreements," or leasing arrangements."

Each person who has an "interest in," controls," or "owns" any of the above named businesses must file reports concerning each such business with the Attorney General within 120 days of enactment. The nature of these reports is to be determined by the Attorney General.

Violations of the Act are subject to "civil action" brought by the Attorney General, and are punishable by fines up to \$100,000 or imprisonment for up to ten years. A violation by a corporation shall be considered to be a violation by "individual directors, officers, receivers, trustees, or agents" of the corporation who were responsible "in whole or in part" for the violation.

S 1927, The Energy Industry Competition and Performance Act of 1977

The bill prohibits "major petroleum producers" from acquiring any "interest in or control over" any "coal asset or uranium asset." This prohibition would be effective immediately.

Effective three years after enactment, the bill would prohibit any major petroleum company from retaining interests or ownership control over coal assets or uranium assets.

"Major petroleum producer" means a company which, with affiliates, has annual United States production, or interest in United States production, of more than 55 million barrels of crude oil, or more than 100 billion cubic feet of natural gas.

Based upon 1976 production, the following companies apparently would be affected:

Amerada Hess	Mobile
Atlantic Richfield	Panhandle Eastern
Cities Service	Pennzoil
Coastal States Gas	Phillips
Consolidated Natural Gas	Shell
Continental	Standard of California
Diamond Shamrock	Standard of Indiana
El Paso	Sun
Exxon	Superior
Getty/Skelly	Tenneco
Gulf	Texaco
Louisiana Land and Exploration	Union
Marathon	

A few other companies could also be affected, depending upon whether their production increases in the future, or whether production is measured by net or gross figures. These are Diamond Shamrock, Ashland, Kerr-McGee, and possibly Union Pacific. Standard of Ohio will be affected when its North Slope production gets under way.

The coal and uranium "assets" which may not be acquired, and must be divested, include natural deposits; assets used primarily for exploration, development, or production of coal or uranium, including interests in developed or undeveloped real property; and geological and geophysical information relating to natural deposits of coal or uranium.

The bill would prohibit not only ownership but "control" over coal and uranium assets. "Control" is defined broadly, and can be direct or indirect, legal or beneficial, "legal power" or merely "influence." "Control" can arise through direct, indirect, or interlocking ownership of stock, inter-locking directorates or officers, or "contractual relations which substantially impair the independent business behavior of another person."

To facilitate divestiture, the Federal Trade Commission may authorize exemptions from the Clayton Act, Section 8 prohibition against interlocking directorates, for up to one year.

Major petroleum producers affected are to file reports with the FTC listing their interest in assets affected within 30 days of enactment. Additional reports may be required.

Each major petroleum producer affected is to file with the Federal Trade Commission, a divestiture plan within six months of enactment. The plan is to be developed in consultation with the FTC and the SEC, pursuant to FTC guidelines promulgated after consultation with the SEC. Each plan is to be "fair and equitable to all persons affected by such plan," and provide for substantial accomplishment of divestiture within three years of enactment.

There may be an FTC hearing on the record to resolve disputes of law and fact among the FTC, SEC, and persons affected by the plan. The SEC and the Attorney General would be authorized to advise and file comments concerning each plan's conformity with general standards of fairness and equity to debt and equity holders in the corporations affected.

The FTC is to issue a final order on each plan within six months of its submission. That order may be appealed to a specially designated three-judge court in the District of Columbia within 30 days after it is issued. (When this stage is reached, any other litigation involving the divestiture plan is to be transferred to this special court.)

The FTC is to have the power to institute suits in this three-judge court, for "such relief as is appropriate to assure compliance." In administering divestiture, the FTC is to have the SEC's powers of enforcement.

Violations of the Act are to be punishable by a "civil penalty" of up to \$100,000 for individuals, and up to \$1 million for corporations. Failure to obey orders of the three-judge court are punishable as contempt. Violations of FTC orders issued pursuant to the Act are punishable by civil penalties of up to \$100,000; continuing violations would be considered to be a separate violation for each day of continuance.

The bill calls for an FTC report to Congress within one year of enactment concerning major petroleum producers' control of solar energy technology.

S. 977 An amendment to the Coal Conversion Act of 1974

The bill prohibits "major petroleum producers" from acquiring any "interest in or control over" any "coal asset or uranium asset." This would be effective immediately. This bill does not require divestiture. The affected parties would be the same as under S1927.

The only assets involved are "natural deposits....in recoverable quantities." Control is prohibited as in S. 1927.

"Each major petroleum producer" affected is to file with the Federal Trade Commission and the Attorney General a report listing and describing its interests in coal or uranium assets within thirty days after enactment or learning of the existence of such an asset. Additional reports may be required.

Violations of the Act are to be punishable by "civil penalty" of "\$100,000 for an individual" or "\$1 million in the case of a corporation." Failure to obey "a lawful order of the FTC: issued pursuant to the Act shall be punishable by a civil penalty of

\$5,000 for each violation; continuing violations would be considered to be a separate violation for each day of continuance. Provisions for other energy sources are the same as S. 1927.

"Nothing in this title" shall be considered to "convey immunity from civil or criminal liability, or to create any defenses to actions under any antitrust law."

APPENDIX 6

OVERVIEW OF OIL INVOLVEMENT IN THE COAL INDUSTRY

Introduction

Following the rapid escalation of steam coal prices in the period 1969-1974, accusations were made by certain organizations^{1/} affiliated with the electrical utilities industry that the U.S. coal industry was non-competitive, and great attention was placed on the fact that the rise in prices seemed to coincide with increasing concentration and in particular oil company entry into the coal industry. Oil companies were charged with collusion and conspiracy to restrict the supply of coal in order to raise coal prices above competitive levels. These events, together with the increasing involvement of the oil companies with other energy sources such as uranium, oil shale, geothermal, and solar energy, led to the fear that unless action was taken, the oil companies would "monopolize" the energy industry. Professor Walter Adams of Michigan State University states,

"I submit that the petroleum industry is neither competitive in structure, nor competitive in behavior, nor competitive in performance. . . that surrender of the substitute fuel industry to the petroleum giants will only solidify existing patterns of cartelization. . . (and) that our failure to assure effective competition in the energy industry will condemn that industry to private monopolization..."^{2/}

^{1/} Tennessee Valley Public Power Association, American Public Power Assoc., National Rural Electric Cooperative Assoc., Emergency Committee of the Tennessee Valley.

^{2/} Adams, Horizontal Divestiture in the Petroleum Industry: An Affirmative Case, in American Enterprise Institute for Public Policy Research, Horizontal Divestiture: Highlights of a Conference on Whether Oil Companies Should be Prohibited from Owning Nonpetroleum Energy Resources, p. 6 (W.S. Moore ed. 1977) (hereinafter cited as AEI Conference).

The Structure of the Coal Industry Prior to and After the Entrance of the Oil Companies

The coal industry had a fairly competitive market structure up until the time of the intervention of petroleum companies. Table 1 lists the 4, 8, 15, and 20 firm concentration ratios of the coal industry for selected years since 1955. Tables 2 through 7 show the individual market shares of the leading firms over this same time period. Using the Kaysen-Turner criterion of an 8 firm concentration ratio of 50 percent or more, and a market share for the largest firm of 20 percent or more, it is evident that the coal industry has never been sufficiently concentrated to qualify even as a "loose oligopoly" under the Kaysen-Turner taxonomy.^{3/} The 8-firm concentration ratio has also remained far below the 70 percent figure which most econometric studies of structure-performance relationships have found to be the dividing line between normal and above normal profit levels.^{4/}

Oil Firm Entry into the Coal Industry

Background and Modes of Entry

The diversification of oil forms into the coal industry began in 1963 when Gulf Oil Company acquired the Spencer Chemical Company

^{3/} Kaysen, Carl and Turner, Donald F. Antitrust Policy, Cambridge; Harvard University Press, 1965, p. 72.

^{4/} Mann, H. Michael, "Seller Concentration, Barriers to Entry, and Rates of Return in Thirty Industries 1950-1960," Review of Economics and Statistics, August 1966, pp. 296-307.

TABLE 1

U.S. BITUMINOUS COAL AND LIGNITE PRODUCTION
CONCENTRATION RATIOS, 1955, 1960, 1965, 1970, 1975, 1976
(PERCENT)

<u>Concentration Ratios</u>	<u>1955</u>	<u>1960</u>	<u>1965</u>	<u>1970</u>	<u>1975</u>	<u>1976</u>
4-Firm	17.8	21.4	26.6	30.7	26.4	25.1
8-Firm	25.5	30.5	36.3	41.2	36.2	34.3
15-Firm	34.7	39.7	45.6	52.2	46.2	44.9
20-Firm	39.6	44.5	50.1	56.5	51.2	50.4

TABLE 2

U.S. BITUMINOUS COAL AND LIGNITE PRODUCTION

1/
1955

<u>Company</u>	<u>Bituminous Coal and Lignite Production</u> (000 Tons)	<u>Percent of Total U.S. Production</u>
Pittsburgh Coal Co. of Pa.	28,001	6.0
U. S. Steel Corp.	25,159	5.4
Peabody Coal Co.	19,397	4.2
Island Creek Coal Co.	10,247	2.2
Bethlehem-Hines Corp.	9,886	2.1
Eastern Gas and Fuel Associates	9,307	2.0
Pocahontas Fuel Co., Inc.	8,464	1.8
The Pittston Co.	8,058	1.7
Truax Traer Coal Co.	7,662	1.6
West Kentucky Coal Corp	7,493	1.6
Freeman Coal Mining Corp. (Material Service)	6,423	1.4
Republic Steel Corp.	5,499	1.2
North American Coal Corp.	5,331	1.1
Jones & Laughlin Steel Corp.	5,313	1.1
Kirkpatrick Mining Co.	5,001	1.1
Berwind-White Coal Mining Co.	4,896	1.0
Ayrshire Collieries Corp	4,871	1.0
Rochester & Pittsburgh Coal Co.	4,602	1.0
Old Ben Coal Corp.	4,239	0.9
Omar Mining Co.	3,968	0.8
U.S. Total	464,633	100.0
Top 4	82,804	17.8
Top 8	118,519	25.5
Top 15	161,241	34.7
Top 20	183,817	39.6

1/ Includes captive production

2/ Individual percentages may not add to totals because of rounding.

Source: Keystone Coal Buyers Manual, Coal Production in the United States....1955; Bureau of Mines, Mineral Yearbook, 1970
(U.S. Total).

TABLE 3

U.S. BITUMINOUS COAL AND LIGNITE PRODUCTION

1/
1960

<u>Company</u>	<u>Bituminous Coal and Lignite Production</u> (000 Tons)	<u>Percent of Total U.S. Production</u>
Consolidation Coal Co.	29,016	7.0
Peabody Coal Co.	28,749	6.9
U.S. Steel Corp	17,971	4.3
The Pittston Co.	13,028	3.1
Island Creek Coal Co.	12,147	2.9
Eastern Gas and Fuel Associates	9,515	2.3
Bethlehem Mines Corp.	9,256	2.2
West Kentucky Coal Co.	6,927	1.7
Freeman Coal Mining Corp. (General Dynamics Corp.)	6,834	1.6
Ayrshire Collieries Corp.	6,446	1.6
North American Coal Corp.	6,325	1.5
Truax-Traer Coal Co.	5,954	1.4
Zeigler Coal & Coke Co.	4,364	1.1
Rochester & Pittsburgh Coal Co.	4,238	1.0
United Electric Coal Co.	4,229	1.0
Pittsburgh & Midway Coal Mining Co. (Spencer Chemical Co.)	4,155	1.0
Old Ben Coal Corp.	4,127	1.0
Valley Camp Coal Co.	4,010	1.0
Republic Steel Corp.	3,954	1.0
Jones & Laughlin Steel Corp.	3,764	0.9
U.S. Total	415,512	100.0
Top 4	88,764	21.4 ^{2/}
Top 8	126,609	30.5
Top 15	164,999	39.7
Top 20	185,009	44.5

1/ Includes captive production.

2/ Individual percentages may not add to totals because of rounding.

Source: Keystone Coal Buyers Manual, Coal Production in the United States.... 1960; Bureau of Mines, Minerals Yearbook, 1970 (U.S. Total)

TABLE 4

U.S. BITUMINOUS COAL AND LIGNITE PRODUCTION

1/
1965

<u>Company</u>	<u>Bituminous Coal and Lignite Production</u> (000 Tons)	<u>Percent of Total U.S. Production</u>
Peabody Coal Co.	49,050	9.6
Consolidation Coal Co.	48,643	9.5
Island Creek Coal Co.	20,584	4.0
U.S. Steel Corp.	17,991	3.5
The Pittston Co.	13,611	2.7
General Dynamics Corp.	12,668	2.5
Bethlehem Mines Corp.	11,952	2.3
Eastern Associated Coal Corp. (Eastern Gas & Fuel Assoc.)	11,603	2.3
Old Ben Coal Co.	8,474	1.7
Ayrshire Collieries Corp	8,313	1.6
Pittsburgh & Midway Coal Mining Co. (Gulf Oil Corp.)	8,186	1.6
North American Coal Corp.	5,983	1.2
Westmoreland Coal Co.	5,848	1.1
Jones & Laughlin Steel Corp.	5,345	1.0
Winding Gulf Coals, Inc.	5,280	1.0
Southwestern Illinois Coal Corp.	5,130	1.0
Republic Steel Corp.	4,840	1.0
Zeigler Coal & Coke Co.	4,468	0.9
Valley Camp Coal Co.	4,270	0.8
Rochester & Pittsburgh Coal Co.	4,252	0.8
U.S. Total	512,088	100.0
Top 4	136,268	26.6
Top 8	186,102	36.3
Top 15	233,531	45.6
Top 20	256,491	50.1

1/ Includes captive production.

2/ Individual percentages may not add to totals because of rounding.

Source: Keystone Coal Buyers Manual, Coal Production in the United States, 1965, Bureau of Mines, Mineral Yearbook, 1970 (U.S. Total).

TABLE 5

U.S. Bituminous Coal and Lignite Production
1/
1970

<u>Company</u>	<u>Bituminous Coal and Lignite Production</u> (000 Tons)	<u>Percent of Total U.S. Production</u>
Peabody Coal Co. (Kennecott Copper)	67,850	11.3
Consolidation Coal Co. (Continental Oil)	64,062	10.6
Island Creek Coal Co. (Occidental Petro.)	29,722	4.9
Pittston Co.	28,694	3.9
United States Steel Corp.	19,631	3.3
Bethlehem Mines Corp.	14,605	2.4
Eastern Associated Coal Corp. (Eastern Gas & Fuel Assoc.)	14,539	2.4
Ayrshire Coal Co. (American Metal Climax)	14,427	2.4
General Dynamics Corp.	14,092	2.3
Old Ben Coal Corp. (Standard Oil of Ohio)	11,687	1.9
Westmoreland Coal Co.	11,347	1.9
North American Coal Corp.	9,674	1.6
Pittsburg & Midway Coal Mining Co. (Gulf Oil Corp.)	7,838	1.3
Utah Construction & Mining Co.	6,021	1.0
Southwestern Illinois Coal Corp.	5,715	0.9
Valley Camp Coal Co.	5,534	0.9
Central Ohio Coal Co. (American Electric Power Co.)	5,526	0.9
Republic Steel Corp.	4,950	0.8
Ziegler Coal & Coke Co.	4,760	0.8
Rochester & Pittsburgh Coal Co.	4,707	0.8
U.S. Total	602,932	100.0
Top 4	185,328	30.7 ^{2/}
Top 8	248,530	41.2
Top 15	314,904	52.2
Top 20	340,381	56.5

1/ Includes captive production.

2/ Individual percentages may not add to totals because of rounding.

Source: Keystone Coal Industry Manual, U.S. Coal Production by
Company, 1970; Bureau of Mines, Mineral Yearbook, 1970, (U.S. Total

TABLE 6

U.S. BITUMINOUS COAL AND LIGNITE PRODUCTION

1/
1975

<u>Company</u>	<u>Bituminous Coal and Lignite Production</u> (000 Tons)	<u>Percent of Total U.S. Production</u>
Peabody Coal Co., (Kennecott Copper)	73,051	11.4
Consolidation Coal (Continental Oil) 2/	54,919	8.6
Amax Coal Co. (Amax, Inc.)	21,840	3.4
Island Creek Coal Co. (Occi- dental Petroleum	19,421	3.0
Pittston Co.	18,554	2.9
U.S. Steel Corp.	17,116	2.7
Arch Mineral Corp. (Ashland Oil)	13,468	2.1
Bethlehem Mines Corp. (Bethlehem Steel Co.)	13,355	2.1
Peter Kiewit Sons Mining Div. (Peter Kiewit & Sons Co.)	11,725	1.8
North American Coal Corp.	9,595	1.5
Old Ben Coal Co. (Std. Oil Ohio)	9,258	1.4
St. Joe Minerals	9,100	1.4
Central Ohio Coal Co. (American Electric Power Service Corp.)	8,265	1.3
Westmoreland Coal Co.	7,900	1.2
Eastern Associated Coal Co. (Eastern Gas and Fuel Assoc.)	7,840	1.2
Pittsburg & Midway Coal Mining Co. (Gulf Oil)	7,294	1.1
Freeman-United Coal Mining Co. (General Dynamics Corp.)	6,510	1.0
Western Energy Co. (Montana Power Co.)	6,407	1.0
Utah Int'l Inc.	6,073	0.9
Industrial Generating Co.	6,000	0.9
U.S. Total	640,000	100.0
Top 4	169,231	26.4
Top 8	231,724	36.2
Top 15	295,407	46.2
Top 20	327,691	51.2

1/ Includes captive production.

2/ 20.6 percent owned by Standard of California.

3/ Individual percentages may not add to totals because of rounding
r: revised August 1977, with addition of Saint Joe MineralsSource: Keystone Coal Industry Manual, U.S. Coal Production by Company,
1975, company interviews.

TABLE 7

1/

U.S. BITUMINOUS COAL & LIGNITE PRODUCTION, 1976

<u>Company</u>	<u>Production (000 Tons)</u>	<u>Percent of Total U.S. Production</u>
Kennecott Copper (Peabody)	70542	10.6
Continental (Consolidation)	55888	8.4
Amax, Inc. (Amax Coal Co.) 2/	23061	3.5
Occidental (Island Creek)	17606	2.7
Pittston	17101	2.6
U.S. Steel	15982	2.4
Bethlehem Steel	14055	2.1
Ashland-Hunt (Arch Minerals)	13600	2.1
Pacific Power & Light	12146	1.8
North American Coal	10679	1.6
American Electric Power	10504	1.6
St. Joe Minerals Corp.	10457	1.6
Sohio (Old Ben)	9515	1.4
Montana Power Co. (Western Energy)	9265	1.4
Westmoreland Coal	8100	1.2
Peter Kiewit	8038	1.2
Eastern Gas & Fuel Assoc.	7959	1.2
Gulf Oil (Pittsburgh & Midway)	7924	1.2
General Electric (Utah Int'l)	6465	1.0
General Dynamics (Freeman-United)	6126	.9
 Total U.S.	 665000	 100.0
Top 4	167097	25.1 3/
Top 8	227835	34.3
Top 15	298501	44.9
Top 20	385013	50.4

1/ Includes captive production.

2/ 20.6 percent owned by Standard of California

3/ Individual percentages may not add to totals because of rounding.

Source: 1976 Company annual reports, statistical supplements, 10-k's; Energy Resource Development, "Summary of Petroleum Company Diversification into Alternate Energy and Non-Energy Areas, Draft, June 1977; Exxon Co., U.S.A., testimony before the Senate Judiciary Subcommittee on Antitrust and Monopoly, August 4, 1977. Keystone Coal Industry Manual, U.S. Coal Production by Company, 1976.

whose subsidiary, Pittsburgh & Midway was ranked the 16th largest coal company in 1960. Although Gulf had no apparent interest in broadening its participation in the energy sector, it considered the coal operation as a desirable addition to its other operations and decided to retain ownership.^{5/} Before long, other petroleum firms either began acquiring existing coal companies or entered the coal industry de novo, through the acquisition or leasing of coal lands. This entry is documented in Table 8 (p. 287-8, Church Report).

Among those oil companies entering the coal industry by acquiring or leasing coal reserves (to be followed by development through coal producing subsidiaries) are: Exxon, Texaco, Tenneco, Sunoco, Shell, Kerr-McGee, Mobil, Atlantic Richfield, and Phillips. Of these companies, the only ones to actually begin producing coal from their reserves are Exxon (through Monterey Coal 1970) and Sunoco (through its Cordero mine in Wyoming, 1976).^{6/}

A majority of the oil firms have entered the coal industry through acquisitions or mergers with existing coal companies. Among these are Continental Oil Company which acquired the Consolidation Coal Company (1966), Sohio through the acquisition of Old Ben Coal Corporation and Enos Coal (1968), Occidental Petroleum Corporation which acquired Island Creek Coal Company

^{5/} R. Moyer, Price and Output Behavior in the Coal Industry, in T.D. Duchesneau, Competition in the U.S. Energy Industry, p. 266 (1975).

^{6/} National Coal Association, Implications of Investments in the Coal Industry by Firms From Other Energy Industries, p. 10 (1977) (hereinafter: N.C.A.).

Table 8

ENTRY ^{1/} INTO THE U.S. COAL INDUSTRY BY OIL PRODUCING COMPANIES, 1965 - 1975

Year and entrant (1)	Remarks (2)
1965:	
Atlantic Richfield Co. ²	Acquired coal lease on lands in the Powder River Basin, Wyo.; subsequently acquired leases in West Virginia, Alabama, Colorado, Illinois, and Utah, with largest gross acreage for coal mining in West Virginia and Illinois.
Kerr-McGee Corp.....	Acquired lease on 800 acres of Federal land in Wyoming on July 1, 1965. By 1970, had leased 14,402 additional acres in Montana, New Mexico, and Wyoming.
1966:	
Ashland Oil Co.....	Announcement of intention to expand activity in "chemicals field" by acquisition of a coal company. Expected expenditures in cash and stock for acquisitions was \$100,000 in fiscal year ending Sept. 31, 1966.
Continental Oil Co. ²	Acquired Consolidation Coal Co. for \$600,000,000 (approximately) in cash, stock and future production payments; production tonnage in early 1970's expected to reach 75,000,000 tons/yr with opening of new mines and expansion of old ones.
1967:	
Seneca Oil Co.....	Acquired lease on 6,336 acres of Federal coal land in New Mexico on Sept. 1, 1967.
Standard Oil Co. of Ohio.....	Acquired ownership of Mountaineer Coal Co., West Virginia.
1968:	
Ashland Oil Co.....	Arch Mineral Corp., an affiliate of Ashland, engaged in acquiring and developing coal reserves for production and sale principally to electric utilities; constructing mine in Hanna, Wyo., estimated to have annual capacity of 2,500,000 to 3,000,000 tons.
Belco Petroleum Corp.....	Purchased Hawley Fuel Corp., West Virginia, planned to expand Hawley's production to 3,000,000 tons annually; estimated reserves: 114,000,000 tons.
Exxon Corp. ² (Standard Oil Co. of New Jersey, through its subsidiaries Humble Oil Corp., Carter Oil Co., and Monterey Coal Co.)	Announced the acquisition of several hundred thousand acres of coal land in Wyoming, Colorado, Montana, North Dakota, and Illinois.
Occidental Petroleum Corp.....	Acquired Island Creek Coal Co. as a subsidiary on Jan. 29, 1968.
Standard Oil Co. of Ohio.....	Acquired Old Ben Coal Co. and its subsidiary, Enos Coal Co., in August 1968 for 1,036,664 common shares. The companies operate in Indiana and Illinois.
Sun Oil Co.....	Acquired lease on 14,680 acres of Federal coal land in Wyoming; estimated reserves: 600,000,000 tons. In 1970, acquired lease on additional 6,700 acres in Wyoming through its subsidiary, Cordero Mining Co.
1969:	
Occidental Petroleum Corp. (through its subsidiary Island Creek Coal Co.)	Acquired the Maust Coal & Coke Corp. on Aug. 8, 1969, for approximately \$20,000,000. The acquisition added 8,000,000 tons to Island Creek's previous annual production of 26,000,000 tons.
Westrans Industries, Inc.....	Acquired Canterbury Coal Co. of Pennsylvania for \$3,336,000 cash and 30,200 shares of stock; annual production: 700,000 tons. It later acquired Kristianson & Johnson Coal Co. of Lanes, Clearfield County, Pa., for \$4,500,000 in cash and stock. Coal land: More than 20,000 acres; 1971 production 450,000 tons; 1975 expected production 1,000,000 tons.
1970:	
Alco Standard Corp.....	Acquired Barnes & Hucker Co., Pennsylvania.
Belco Petroleum Corp.....	Acquired lease on 4,551 acres of Federal coal land in Wyoming on Jan. 1, 1970. Additional leases were obtained on 640 acres in Wyoming on Jan. 1, 1971.
Falcon Seaboard, Inc.....	Falcon Coal Co., a newly formed subsidiary, acquired 115,000 acres of eastern Kentucky coal mining properties with reserves estimated at 140,000,000 tons for \$10,000,000.
McCulloch Oil Corp.....	Acquired the assets of No. 7 Corp., Marietta Coal Co., Kingdom Come Dock Co., and Big 4 Coal Corp.
U.S. Natural Resources, Inc.....	Acquired Twilight Industries, Inc., Dec. 15, 1971; projected 1971 production over 1,000,000 tons.
1971:	
Ashland Oil Co. (through its affiliate Ark Land Co.)	Acquired lease on 7,595 acres of Federal coal lands in Wyoming on Feb. 1, 1971. The bid of \$1,900,000 is believed to be the highest ever made on a coal lease in the country. Sulfur content generally average(s) at about 1 percent.
California Time Petroleum, Inc.	Acquired a 20-yr mining lease on the Roslyn-Cle Elum Coal field, 20 mi southeast of Seattle, Wash.
Crestmont Oil & Gas Co.....	Acquired 10,000 acres and all outstanding stock of Black Lodge Coal Co. of Vaughan, W. Va.; estimated reserves: 24,000,000 tons of utility and metallurgical coal. Producing at annual rate of 425,000 tons in 1971.
Dal Petroleum Co.....	Agreed to acquire assets of Dusky Diamond Coal Co. of Wyoming. Coal land: 120 acres; reserves: 12,000,000 tons; planned capacity: 2,000 tons/d.
Mapco, Inc.....	Acquired Webster County Coal Corp. of Kentucky and expanded its annual capacity to 1,400,000 tons. Late in 1971 it also bought the Goldsberry Mine, Henderson, Ky., with reserves of 9,500,000 tons of steam coal and raised its annual capacity from 70,000 to 500,000 tons.
Marathon Oil Co.....	Acquired from Cameron Engineers, Inc., 50-percent interest in Mintech Corp., which has holdings in coal areas of the Rockies. Under the agreement, Marathon Oil Co. has an option to acquire the remaining 50-percent interest within 3 yr.
Mobil Corp. ²	Acquired leases on 4,000 acres of Federal coal land in Wyoming on Feb. 1, 1971.
Transcontinental Oil Corp.....	Purchased Greer-Ellison Coal Co., Inc., of Whitesburg, Ky.

TABLE 8 (Continued)

Year and entrant (1)	Remarks (2)
1972:	
Kewanee Oil Co. and Morrison Knudsen Co.	Westmoreland Resources (a partnership formed in 1970 in Montana by Kewanee Oil Co., Morrison Knudsen Co., Penn Virginia Corp., and Westmoreland Coal Co.) will operate the Sarpy Creek Coal Mine, which will begin operation February 1974. Contracts were obtained from 4 electric utilities for 76,500,000 tons over 20 yr.
Ray Resources Corp.	Acquired the coal mining operations and related interests of Sigmon Construction Co., Coalgood, Ky. Estimated reserves: 34,000,000 tons proved, 24,000,000 tons probable. Sulfur content: less than 1 percent.
1973:	
Great Basins Petroleum Co.	Acquired leases on nearly 6,000 acres of coal properties near Pennington Gap, Va., from Southwest Energy Corp. Proved reserves: 11,000,000 tons; possible reserves: 30,000,000 to 50,000,000 tons.
Mapco, Inc.	Acquired option on 18,000 acres of undeveloped coal land in Kentucky from Pechabontas Land Corp. Recoverable reserves estimated at more than 40,000,000 tons of low-sulfur, high-grade steam coal. Intended annual production: 2,000,000 tons.
1974: Crown Central Petroleum Corp.	Entered into a joint venture with a wholesale coal distributor to acquire and operate an existing mine in Kentucky.
Discovery Oil, Ltd.	Paid \$800,000 for lease rights to 41,540 acres of State coal leases within the Powder River Basin and Green River region.
Exxon Corp. ¹ (Standard Oil Co. of New Jersey, through its subsidiary Carter Oil Co.)	Formed a new subsidiary, Carter Mining Co., to conduct Western mining operations. Its first coal mining venture is being developed north of Gillette, Wyo.
International Mining & Petroleum Corp.	Acquired Belva Coal Co. of Logan, W. Va., for about \$5,000,000 in cash and stock.
Tesoro Petroleum Corp.	Signed an agreement in principle to acquire the coal-related assets of Buckhorn Hazard Coal Corp. Formed a new division, Tesoro Coal Co., for the acquisition and development of coal properties.
1975: Ashland Oil Co. ²	Formed a wholly owned subsidiary, Ashland Land & Development Co., which plans to enter the Appalachian coal business through purchase or lease of coal reserves and acquisition of existing coal companies.

¹ "Entry" consists of acquisition of coal reserves, acquisition of existing coal producers, or the development of new coal mines when this appears to represent entry into a new geographic market.

² 1 of the 10 largest oil producing companies, by assets.

Source: U.S. Congress. Senate. Committee on the Judiciary. Subcommittee on Antitrust and Monopoly. Interfuel Competition. Hearings, 94th Cong., 1st sess., June 17, 18, 19, July 14, Oct. 21, and 22, 1975. U.S. Government Printing Office, 1976, pp. 40, 41.

Source: Petroleum Industry Involvement in Alternative Sources of Energy, Publication No. 95-54, Sept. 1977, hereinafter: "Church Report", p. 287-8.

TABLE 8 (Continued)

	<u>1975</u>	<u>1976</u>
Total Oil Firm Production of Total Top 20 Production (000 Tons)	126,200	127,594
Percent Oil Firm Production of Total Top 20 Production	39.0	38.1

3

As reported by Exxon.

Source: American Petroleum Institute Discussion Paper 004R
"Concentration Levels in the Production and Reserve
Holdings of Crude Oil, Natural Gas, Coal, and Uranium
in the U.S., 1955-1976, Sept. 1977 by Amy Hersh; updated
by Pamela Murphy (hereinafter cited as API #004R).

Original Source: Keystone Coal Industry Manual, U.S. Coal Production
by Company, 1955, 1960, 1965, 1970, 1975, and 1976; U.S. Bureau
of Mines (U.S. Totals); Exxon Co., U.S.A., submission before
Senate Judiciary Subcommittee on Antitrust and Monopoly, August
4, 1977.

(1968) and Maust Properties (1969), and Belco Petroleum Corporation which acquired Hawley Fuel Corporation, (1968).

Still other firms have combined these coal-oil modes of entry, such as Ashland-H.L. Hunt which in addition to acquiring the Arch Mineral Corporation, has acquired reserves and developed its own mines.

Motives for Entry

Several reasons have been given as to why oil companies have acquired coal interests:

(1) Special Tax Provisions

One stimulus to the acquisition of coal companies may have been special provisions in the tax laws known as ABC transactions which until 1969 made coal companies more valuable to purchasers than to coal operators.^{7/}

(2) To Hedge Against Declining Oil Reserves

Since oil firms produce an exhaustible natural resource, the move to acquire coal reserves may be a means of protecting their energy interests as oil reserves decline, particularly since pre-1970 prices of coal reserves were quite low.^{8/}

(3) A Desire to Extend Skills and Expertise in the Energy Area

Oil firms have considerable technological overlap with the coal industry. The oil industry's pipeline technology has been important in bringing about the coal slurry pipeline. Catalytic processes like those used in refining petroleum are being used

^{7/} Moyer, supra note 3, p. 264-265.

^{8/} Donald Norman, The performance of Oil Firm Affiliates in the Coal Industry American Petroleum Institute Research Study #004, p. 39 (1977) (hereinafter, API #004).

to develop coal liquefaction. Once oil is produced from coal the same technology necessary for storage and transportation of oil is applicable. A process designed to remove methane gas from coal mines is based on techniques developed for drilling oil fields.^{9/} Although technologies may be transferred through market transactions, the sale of technology seldom yields a rate of return equivalent to that which can be obtained internally, since technological property rights are costly to establish and maintain.^{10/}

(4) Pressures to Invest

Pressures for internal investment, when discouraged by dwindling reserves, increased cost of development, and government regulation, provides an incentive for oil companies to invest in projects outside the oil industry. The industries which are the most likely candidates are that which are characterized by similarities in marketing, technology, distribution, management, etc., such as the coal industry.

C. Current Extent of Oil Firms' Involvement in the Coal Industry

Table 9 shows that in 1976, the United States produced 665 million tons of coal, and of this amount approximately 113 million tons or 17 percent was accounted for by oil firm affiliates. The largest twenty coal companies in 1976 produced 335 million tons, and oil affiliates among the top twenty produced 104 million tons, about 31 percent. Thus the oil companies account for a

^{9/}

See: David J. Teece, Horizontal Integration in Energy: Organizational and Technological Considerations in Moore AEI Conference supra note 2, p. 37; Norman, supra note 7, p. 41

^{10/}

Ibid.

TABLE 9

SUMMARY OF OIL FIRM ACTIVITY
IN COAL PRODUCTION^{1/}
1955, 1960, 1965, 1970, 1975, 1976

	<u>1955</u>	<u>1960</u>	<u>1965</u>	<u>1970</u>	<u>1975</u>	<u>1976</u>
Oil Firm Coal Production (000 Tons) ^{2/}	0	0	8,186	115,745	108,340	112,976 ^{3/}
Total U.S. Coal Production (000 Tons)	464,633	415,512	512,088	602,932	640,000	665,000
Oil Firm Share of Total U.S. Coal Production (Percent)	0	0	1.6	19.2	16.9	17.0
Top 20 Firm Coal Production (000 Tons)	183,817	185,009	256,491	350,381	323,912	335,013
Total Oil Firm Production of Total Top 20 Production (000 Tons)	0	0	8,186	113,309	104,360	104,533
Percent Oil Firm Production of Total Top 20 Production	0	0	3.2	33.3	32.2	31.2

^{1/} Bituminous coal and lignite production only. Excludes anthracite.

^{2/} Includes Pittsburgh and Midway Coal Mining Co. (Gulf Oil Corp.) in 1965; plus Consolidation Coal Co. (Continental Oil), Island Creek Coal Co. (Occidental Petroleum), Old Ben Coal Corp. (Standard Oil of Ohio), Hawley Fuels (Belco), Monterey Coal (Exxon) and Kingdom Come Coal (McCulloch Oil) in 1970; plus Arch Mineral Corp. (Ashland Oil) and Tesoro Coal Co. (Tesoro Petroleum) in 1975 and 1976. Excludes Amax (20.6 percent acquired by Standard of California in 1975) and Hawley Coal Mining Corp. (80% sold by Belco in Oct. 1974) in 1975. Inclusion of Amax and Hawley Coal Mining Corp. in 1975 would result in the following:

	<u>1975</u>	<u>1976</u>
Oil Firm Coal Production (000 tons)	180,978	136,800
Oil Firm Share of Total U.S. Coal Production (percent)	20.5	20.6

little less than one fifth of total coal production, and of the largest twenty coal producers, oil companies account for a little less than one third.

A similar picture is presented by examining oil companies' control of reserves, which may be regarded as an index of their potential future position in the coal industry.

Table 10 shows National Coal Association estimates of the nation's total recoverable coal reserves amounting to about 219 billion tons. Of this amount 46,858 million tons or 21.4% are controlled by oil companies. It is estimated that the largest twenty private reserve holders control ^{11/} about 91,521 million tons, and oil affiliates among these top twenty account for 51,376 million tons, or 20.6 percent of the total.

The evidence indicates that the extent of current involvement by oil companies in the coal industry is about 20 percent in both production and reserve holdings.

Impact of Oil Company Entry on Structure
and Performance of the Coal Industry

Table 1 shows a sizeable jump in all concentration ratios around 1970 coinciding with the midpoint of oil company entry activity into the coal industry. Since 1970 concentration ratios have declined to roughly their 1965 levels despite further entry of oil firms into the industry. Throughout the period concentration

11/

Amy Hersh, Concentration Levels in the Production and Reserve Holdings of Crude Oil, Natural Gas, Coal, and Uranium in the U.S., 1955-1976 (updated by Pamela Murphy) American Petroleum Institute, Discussion Paper #004R, p. 43 (1977).

Estimates of natural resource reserves are subject to wide margins of error due to differences in how such factors as depth and thickness of seams, extent of possible recovery, technological change, etc. are treated.

TABLE 10

Reserves Held by Oil & Gas Firms, 1976

<u>Company</u>	<u>Reserves^{1/}</u> <u>(million tons)</u>	<u>Percent Total</u> <u>United States</u>
Continental Oil (Consolidation)	13,700	6.3%
Exxon (Monterey Coal-Carter Mining)	8,400 ^{2/}	3.8
Occidental Petroleum (Island Creek)	3,574 ^{2/}	1.6
Gulf Oil (Pittsburg & Midway)	2,750 ^{2/}	1.3
Mobil Oil	2,500	1.1
Sun Oil	2,200	1.0
Atlantic Richfield	2,200	1.0
Phillips	2,000	0.9
Tenneco	1,700	0.8
Texaco	1,650	0.8
Kerr-McGee	1,500	0.7
Shell Oil	1,460	0.7
Sohio (Old Ben)	825	0.4
Chevron	700	0.3
Ashland Oil (Arch Mineral, Ashland Coal)	650	0.3
Belco (Hawley Fuel)	524	0.2
Quaker State (Valley Camp)	475	0.2
McCulloch	50	-
Total Oil Companies	46,858 ^{3/}	21.4
El Paso Natural Gas	5,200	2.4
Houston Natural Gas (Zeigler Coal)	1,000	0.5
Eastern Gas & Fuel (Eastern Assoc. Coal)	1,058	0.5
Panhandle Eastern (Youghiogeny & Ohio)	500	0.2
MAPCO	450	0.2
Coastal States (Southern Utah Fuel)	35 ^{2/}	-
Total Oil & Gas Companies ^{4/}	55,101	25.1
Total United States	219,169 ^{5/}	100.0%

^{1/} The data reported for each company are not differentiated between recoverable or in-place reserves.

^{2/} Data as reported by company named.

TABLE 10 (footnotes continued)

- 3/ Some studies include Amax Coal Company in this total. However, the relationship of Amax with an oil firm is not a parent-subsidary relationship, as Standard Oil of California owns only 20.6 percent of Amax stock. If Amax were included in this figure, reserves held by oil firms in 1976 would total 51,898 million tons or 23.7 percent of total.
- 4/ Excludes some reserves held by small oil and gas companies for which data are not available. It is unlikely that total oil and gas reserves are seriously understated by these exclusions.
- 5/ The 'total demonstrated coal reserve base' defined by the U.S. Geological Survey and the Bureau of Mines as that portion of the identified resources deemed suitable for mining by current methods totals 438.3 billion tons. The Bureau points out that recoverability varies in a range from 40-90 percent according to the characteristics of the coal bed, the mining method, legal restraints, and the restrictions placed upon mining a deposit because of natural and manmade features. Mining experience in the United States has indicated that, on a national basis, at least one-half of the in-place coal can be recovered. Discount the coal reserve base by 50 percent gives a total recoverable reserve of 219.2 billion tons.

Source: Implications of Investments in the Coal Industry by Firms from Other Energy Industries (N.C.A.) - p. 23.

ratios have remained substantially below those typically associated with unworkably competitive market structures. Similar conclusions follow from an examination of individual market shares (Tables 2-7). Although the leading firms' shares have not declined as much since 1970, they remain relatively low, and the industry leader is a non-oil company controlled firm. If all of the increase in concentration that occurred between 1965 and 1970 were attributed to the oil companies' entry into the industry, this sudden increase has not become a trend, and the level of concentration in 1976 does not appear to be high enough to be a cause of concern in and of itself.

Financial Positions of Coal and Oil Companies

One of the major issues surrounding oil company entry and possibly exit from the coal industry has been the potential impact on future investment in the industry. Table 11 gives various projections of the future capital requirements of the coal industry for the period 1976-1985.

The oil companies comprise a large potential source of capital for alternate fuel development. As can be seen in Table 12, oil companies involved in the coal industry all have excellent security ratings. In general they have strong balance sheets, as measured by their debt/equity ratios. The oil industry's debt/equity ratio of 0.28 is markedly lower than the average of .052 for all industries in the private sector.^{12/} Oil

^{12/}

Markham, Jesse W., Hourihan, and Sterling, Horizontal Divestiture and the Petroleum Industry, Ballinger Pub. Co., Cambridge, Mass., 1977, p. 63.

TABLE 11

PROJECTION OF AGGREGATE CAPITAL NEEDS
FOR COAL INDUSTRY, 1976-1985
(\$ billions)

AMAX Coal study cited in FEA Energy Outlook (same basis as FEA)	\$15.4-16.4
Bankers Trust Company, capital resources for energy through the year 1990 (includes \$11.1 for transportation)	\$22.6
Colsolidation Coal Company, Speech by Jarvis B. Cecil, executive vice president, April 9, 1976, Phoenix, Arizona (excludes coal conversion plants, transportation)	\$40.0-50.0
FEA Energy Outlook Reference Scenario (includes mine costs only)	\$17.7
National Coal Association, C. Bagge, Address to the Southern Governors' Conference, St. Louis, Mo., June 15, 1976	\$18.2-22.1

SOURCE: Swenson, G. L. in (Moore, ed. AEI Conference, supra
note 2).

TABLE 12

DEBT AND EQUITY RATINGS OF SELECTED
COMPANIES IN THE COAL INDUSTRY

	Moody's Debt Rating	S&P Debt Rating	S&P Stock Rating	Value Line Safety Rating (1-5, high to low)
Independent Coal Companies				
Pittston	A ^a	A ^a	A	3
North American Coal	NR	NR	B+	4
Westmoreland	NR	NR	B+	4
Eastern Gas & Fuel	A ^b	A ^b	B+	3
Rochester & Pittsburgh	NR	NR	NR	NR
Falcon Seaboard	NR	NR	B	5
Alabama By-Products	NR	NR	A-	NR
Carbon Industries	NR	NR	NR	NR
Oil Companies Involved in Coal				
Exxon	Aaa	AAA	A+	1
Gulf	Aaa	AAA	A	2
Mobil	Aaa	AAA	A+	2
Shell	Aaa	AAA	A+	2
Texaco	Aaa	AAA	A	2
Atlantic Richfield	Aa	AA	A	2
Continental	Aa	AA	A	3
*Kerr-McGee	Aa	AA	A	2
Phillips	Aa	AA	A	3
Sun	Aa	AA	A	2
*Ashland	A	A	A-	2
*Quaker State	A	A	A	2
*Standard of Ohio	A	AA-	A	3
*Occidental	Baa	BBB	B	2
MAPCO	NR	NR	A-	3

NR - securities of the company are not rated.

^aConvertible bonds.

^bEastern Associated Coal Corp.

*Non-Major Petroleum Producers.

SOURCE: G. L. Swenson in (Moore ed., AEI Conference), p. 50.

companies also have a considerable amount of funds generated internally from net profits after tax and noncash expenses (in particular depreciation and depletion allowances). Although oil firms' rate of return on investment is about the same as the national average, their asset base and net income is huge in absolute dollar terms, which provides an important source of funds to be reinvested.^{13/}

^{13/} Ibid., p. 64.

APPENDIX 7

MAJOR SOURCES OF COAL DATA AND BIBLIOGRAPHY

APPENDIX 7

MAJOR SOURCES OF COAL DATA AND BIBLIOGRAPHY

This appendix identifies major sources of coal data and provides a bibliography on the coal industry, which can be used for further reference. Not all of the data shown here were used for this study.

This appendix identifies the major sources from which the coal data are gathered and gives a concise bibliography on the coal industry, which can be used for further reference.

Essentially, there are four major sources of data:

(1) The Keystone Coal Industry Manual, where figures for such variables on the production, consumption, and revenues for coal can be obtained for a four-year period, and figures for total consumption by sector and prices for bituminous coal can be found for the period 1920-1973.

(2) From the Bureau of Statistics, coal production is broken down according to weekly and monthly series. In addition, data on the types of mines and coal employment can be obtained from this source by state to the district levels.

(3) The Mineral Yearbook from the Bureau of Mines contains some useful information on the distribution of coal according to destination and consumer use.

(4) Statistics on future coal supply and capital requirements for underground and surface mines are available up to 1985 from the National Petroleum Council.

(5) Finally, the National Coal Association provides industry statistics on the 50 biggest bituminous mines for various years. It also supplies fuel and power conversion factors.

DATA SERIES AVAILABLE FROM MAJOR SOURCES*

<u>Industry Statistics</u>	<u>Years</u>
Production (Value & Quantity)	1970-1974
Consumption	1970-1974
Number of Mines	1970-1974
Method of Mining	1970-1974
Value	1970-1974
Preparation	1970-1974
Stocks	1970-1974
Reserves	1970-1974
Capacity of New Coal Mines & Major Expansions Planned	1975-1985

Bituminous Coal Data

Production	1920-1973
Average Price per Ton	1920-1973
Man Employees	1920-1973
Number of Mines	1920-1973
Average Days Worked	1920-1973
Net Ton per Man	1920-1973
Total Consumption by Sector	1920-1973
Production of Bituminous & Lignite Coal by Months and States	1974

* 1975 Keystone Coal Industry Manual, Mining Information Services, McGraw-Hill Inc., New York, 1975.

Additional Information

Reserve Base of Bituminous Coal

in Coal Beds Greater than 28 Inches
Thick to Maximum Depth of 1,000 ft.,
by Mining Method and Sulfur Content

Estimated Remaining Coal Resources

of the United States as of
January 1, 1972 (million short tons)

Major Coal Producers by Size of the
Output

U.S. Department of Interior, Bureau of Mines, Mineral Industry
Surveys, (various years)

Salient Statistics

Reserves

Production

Weekly

Monthly

By Types of Mining

By States

By Counties

By Districts

By Size of Mine

Shipments

By Railroad and Waterways

By Unit Train

By Sulfur Content

Employment and Productivity

By State

By Districts

By Counties

Consumption and Stocks

Mine Values

Export & Imports

World Production

Salient Statistics of the Bituminous Coal and Lignite Industry
in the United States*

	<u>Years</u>
Production (value and quantity)	1970-1974
Consumption	1970-1974
Stocks at Year-end	1970-1974
Exports	1970-1974
Imports	1970-1974
Average Price	1970-1974
Number of Mines	1970-1974
Average Days Worked	1970-1974

Additional Information

Demonstrated coal reserve base on the United States on January 1, 1974 by underground and surface mining methods--millions of tons--by state and sulfur range.

Average value per ton, f.o.b. mines, of bituminous coal and lignite produced in the U.S. by state and by district.

Distribution of bituminous coal and lignite, by destination and consumer use.

The same information exists for the Pennsylvania anthracite industry.

*U.S. Department of the Interior, Bureau of Mines, Minerals Yearbook, Vol. I, Metals, Minerals, and Fuels (various years).

SALIENT STATISTICS*

Year

Total Future Coal Supply-- 1970-1985

Convention Market, Export and
Synthetic Fuels (Millions of Tons)

Capital Requirements for Underground 1963-1985

and Surface Mines (Millions of
Constant Dollars). Four Different
Supply Assumptions are Used.

Estimated Value of Coal per Ton F.O.B.

Mine at a Three Percent Growth
Rate (Constant Dollar). A DCF Rate
of Return of Ten, Fifteen and
Twenty Percent are Separately
Assumed.

* U.S. Energy Outlook, "Coal Availability.", 1970, National
Petroleum Council.

National Coal Association, Coal Fact 1974-1975, Coal Building,
Washington, D.C. 20036

Industry Statistics

50 Biggest Bituminous Mines in 1972, 1973.

Fuel and Power Conversion Factors (Btu per unit)

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