V. NATURAL GAS

NATURAL GAS

BACKGROUND (1)

- More than 84 percent of the U.S. population lives in communities served with natural gas.

Homes	Total U.S.
55%	use gas for househeating
26%	use fuel oil for househeating
8%	use electricity for househeating
6%	use LP gas for househeating
5%	use other/no heat

Census Divisions	Homes
Northeast	22% heat with gas
Middle Atlantic	42% " " "
East North Central	68% " " "
West North Central	64% " " "
South Atlantic	33% " " "
East South Central	48% " " "
West South Central	78% " " "
Mountain	73% " " "
Pacific	70% " " "

- The total investment of the U.S. homeowners in gas appliances exceeds $20 billion.

- Most of our libraries, schools, hospitals, and other public buildings are heated by gas. Many of these buildings are under "interruptible" contracts. These contracts enable the consumer to pay substantially less for gas than what other customers pay such as residential or commercial users.

- Many buildings were designed for gas use and contain no capability to use alternative fuel supplies for extended periods of time.

- Except for the transportation sector which relies on refined petroleum products, gas is the most desired fuel because it is the cleanest and most efficient in almost all of its applications.

- Natural gas is a unique and valuable raw material for the petrochemical industry and also for the liquefied petroleum gas industry.

LIQUEFIED PETROLEUM GAS (LP-GAS) (8)

- Covers such products as propane, butane, tank gas, LPG, and numerous brand names.

- Obtained from natural gas after it leaves the wells and in the refining of crude oil.

- Stored and transported as a liquid under moderate pressure.

- When released from its container the liquid becomes a clean-burning gas similar to natural gas.

- More than 13 million consumers use LP-gas.

- During the decade ending in 1973, the sales for LP-gas more than doubled.

- LP-gas annual sales are estimated at $3 billion, and represent approximately a $7.5 billion segment of the Nation's capital investment.

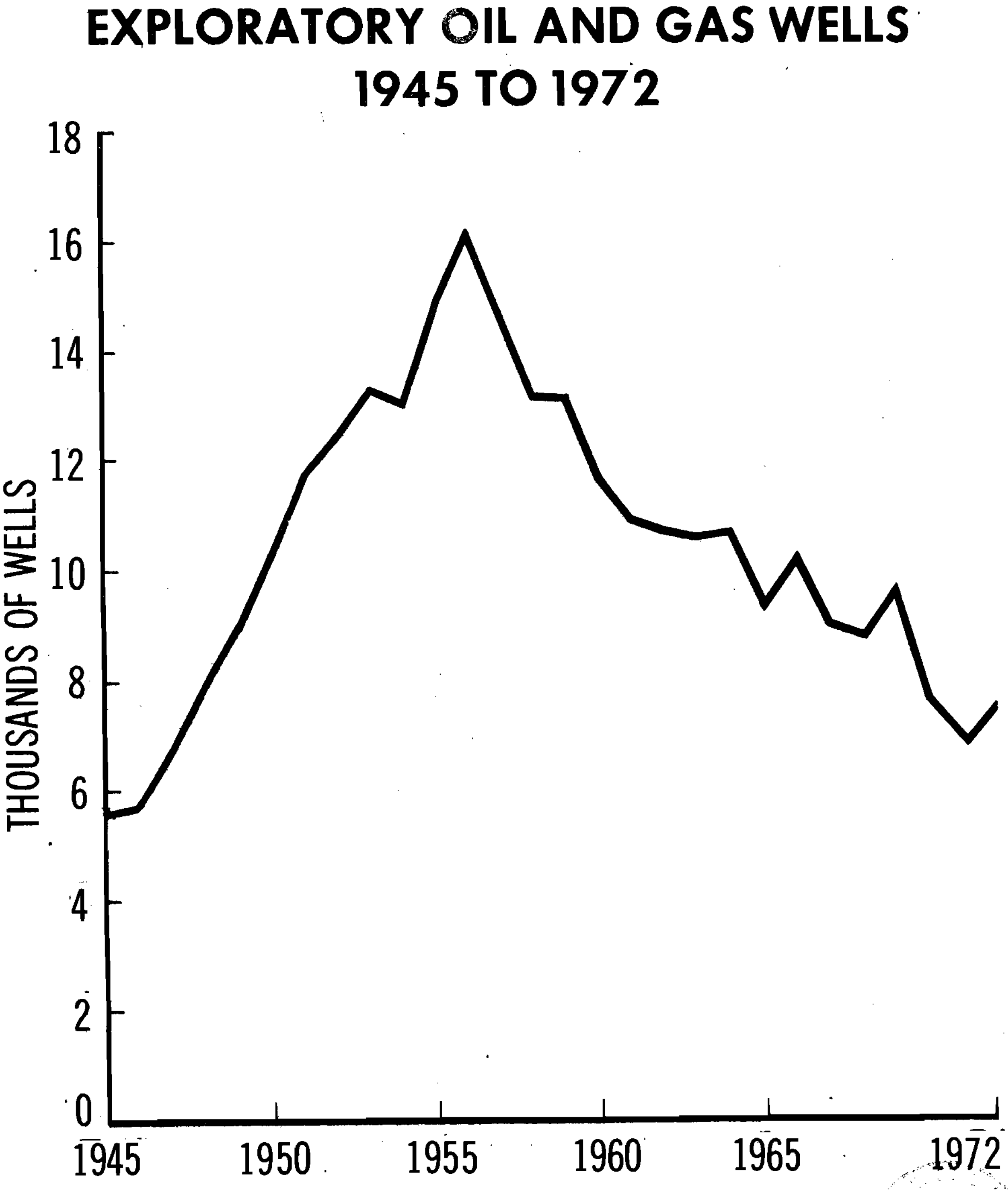
- More than 200 oil and gas companies produce LP-gas at natural gas liquid extraction plants and oil refineries.
- Physical aspects of the industry are estimated at over 22,000 railroad tank cars, 28,500 motor transport and delivery trucks, 72,000 miles of long-distance pipelines, 9,200 bulk storage plants or distribution centers, and 150 tankers and barges.
- Retail level includes over 28,000 distributors, dealers and other enterprises. The marketing portion of the LP-gas business alone employs about 86,000 people.
- The National Fire Protection Association prepares detailed standards for proper storage and handling of LP-gas.
- Containers are fabricated from high tensile steel, and usually contain safety relief valves and an excess flow valve. Bulk plants also contain quick-closing valves.
- Most deliveries to consumers are made by truck.

PRODUCTION AND SUPPLY (1)

- Over the past several years, we have witnessed a decline in the productivity of gas reservoirs due to the lack of new discoveries of reserves to offset the declining pressure in the older producing wells.
- Alternative sources of gas supplies such as liquefied natural gas and synthetic natural gas are not great enough to alter the growing gap between the demand and supply for this important source of fuel.

- To increase the production of natural gas, several steps must be taken. For example:
  - o Deeper drilling in known producing areas and drilling in new provinces.

Figure 1



Source: FPC(5)

Figure 2

NUMBER OF UNDERGROUND STORAGE POOLS AND ULTIMATE CAPACITY IN THE UNITED STATES, 1950-1973

Year	Number of Pools	Number of States	Est. Ultimate Capacity (bill. cu. ft.)[a]
1950	125	15	770
1955	178	18	2,084
1960	217	20	2,854
1965	293	24	4,086
1966	303	25	4,421
1967	308	25	4,520
1968	315	26	4,783
1969	320	26	4,927
1970	325	26	5,178
1971	333	26	5,575
1972	348	26	6,040
1973	360	26	6,279

a. At 14.73 psia and 60°F.

Figure 3

AQUIFER STORAGE POOLS IN THE UNITED STATES, 1955-1973

Note: These data are also included in Figure 5

Year	Number of Pools	Number of States
1955	5	4
1960	14	8
1965	37	9
1966	37	9
1967	37	9
1968	40	10
1969	43	10
1970	43	9
1971	44	8
1972	46	9
1973	49	10

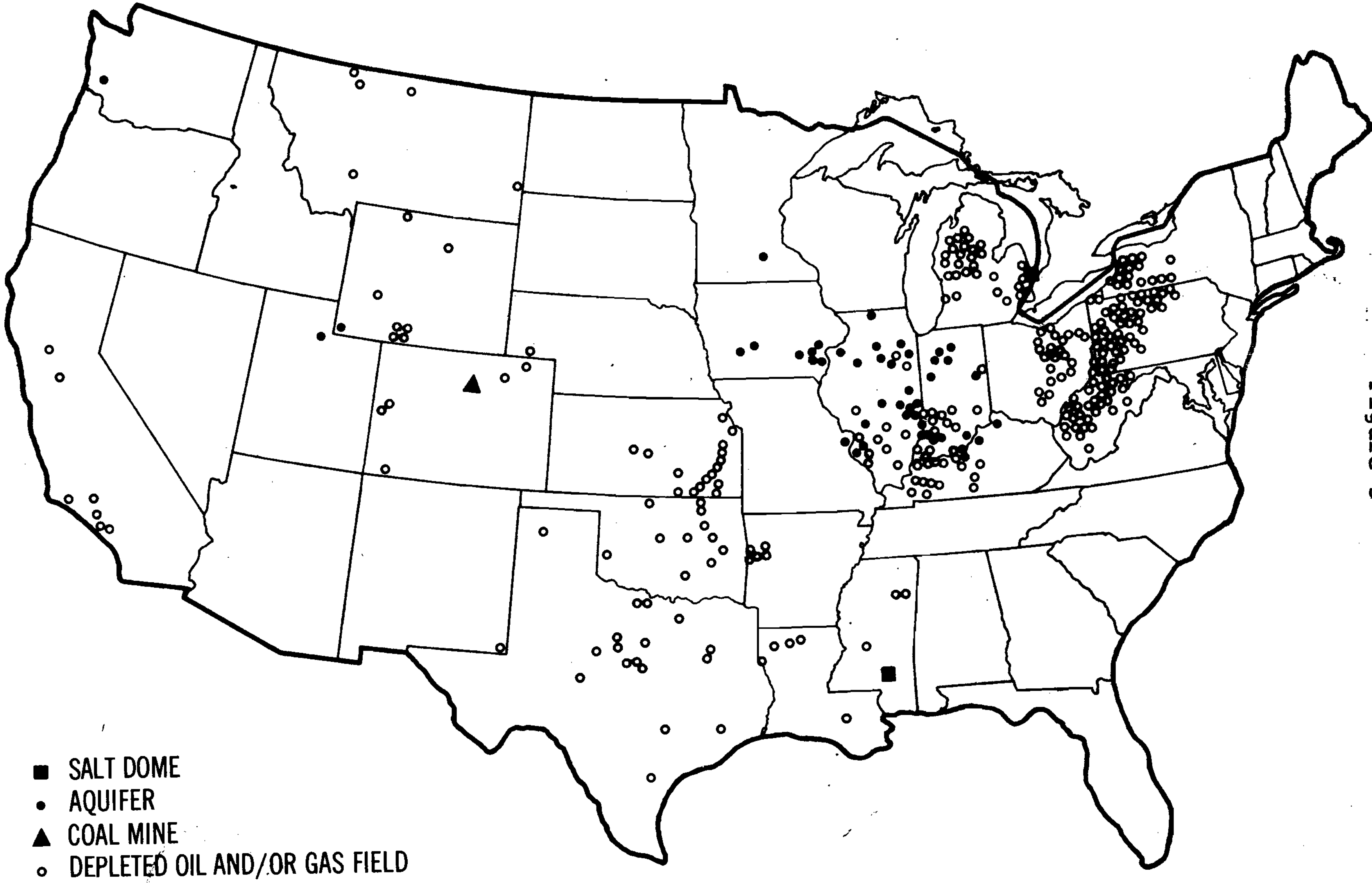
Figure 4

LIQUEFIED NATURAL GAS STORAGE OPERATIONS IN THE UNITED STATES AS OF DECEMBER 31, 1973

	Presently Operating	Proposed or Pending Operation
Complete Plants		
Storage Capacity – mmcf	35,855	18,165
Gross Liquefication Capacity – mmcf/day	204	77
Sendout Capacity – mmcf/day	4,771	1,913
Number of Facilities	36	16
Satellite Plants		
Storage Capacity – mmcf	5,284	1,040
Sendout Capacity – mmcf/day	783	86
Number of Facilities	43	5
Import Terminals		
Storage Capacity – mmcf	5,250	45,700
Sendout Capacity – mmcf/day	235	4,300
Number of Facilities	2	11

Source: AGA(6)

LOCATION OF UNDERGROUND GAS STORAGE RESERVOIRS IN THE UNITED STATES - 1973



Source: FPC(3)

Figure 5

- o Increased drilling for crude oil which may prove beneficial as natural gas reservoirs are often found in proximity to crude oil.

- o Expediting the leasing and drilling schedules on the Outer Continental Shelf.

- Total U.S. natural gas production increased at an average annual rate of 7 percent for more than 25 years to 1970. For the 3 subsequent years the growth curve flattened out, and preliminary data for 1974 shows a 3 percent decline. (9)

- Figures 2 through 5 show underground storage of natural gas.

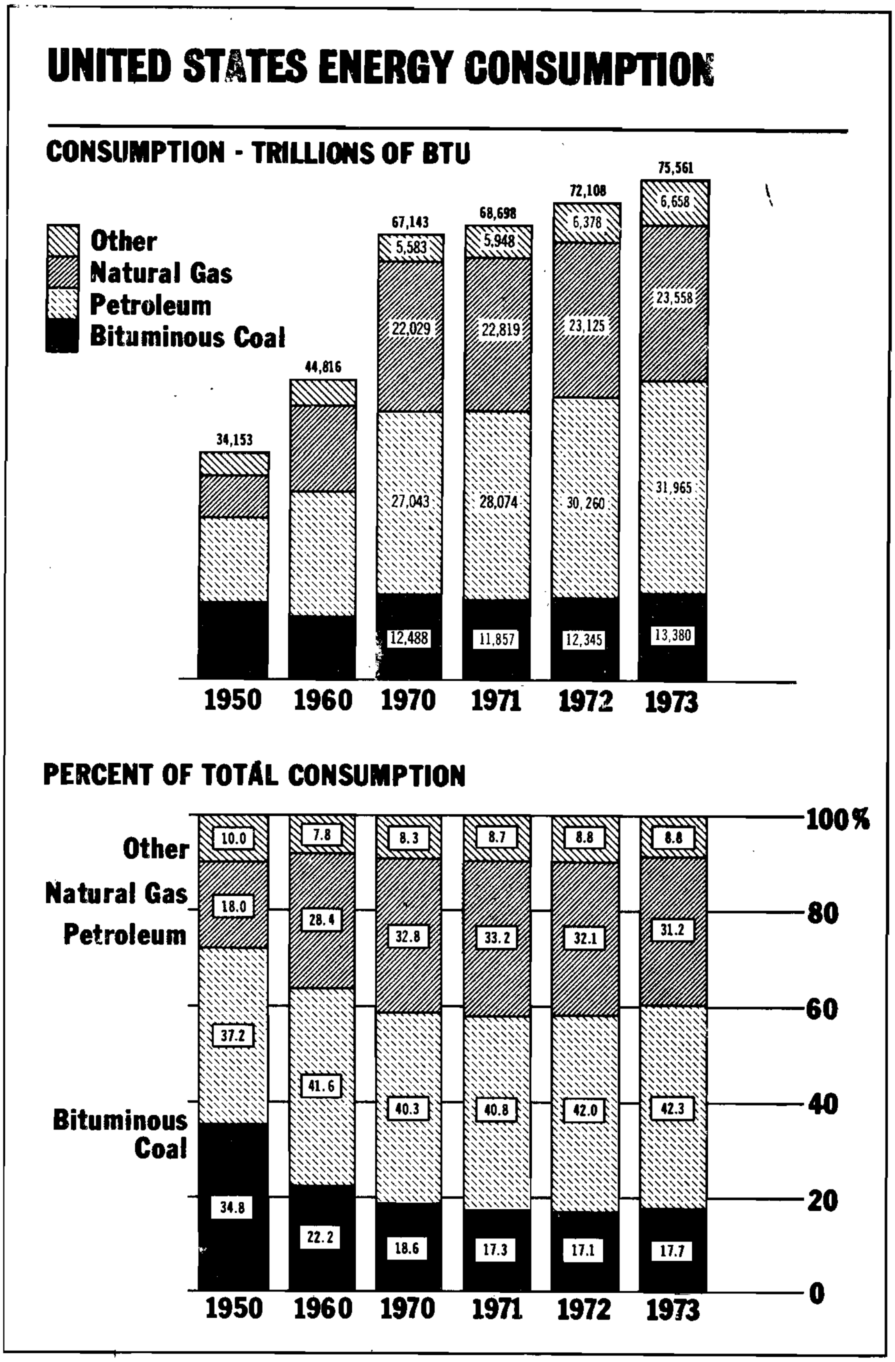
CONSUMPTION AND DEMAND (1)

- Consumption - See Figures 6 through 8.

- Inadequate gas supplies make it almost meaningless to mention the demand curve for this source of energy. However, we have noted a shift away from the demand for natural gas by industrial users who use the fuel for heating purposes. Some of these end-users are seeking sources of energy which are not in such critical supply. Therefore, the demand for natural gas appears to be shifting toward residential and commercial use, and toward those industries which use it for its unique qualities in some processes, or as a feedstock.

- Because of the gas shortage, the demand picture is dictated by regulatory agencies' allocations to gas companies, as well as the gas companies' allocations to the end-user.

Figure 6



Source: AGA(6)

Figure 7

ANNUAL INDEXES OF AVERAGE RESIDENTIAL CONSUMPTION AND GAS PRICES, 1950-1973

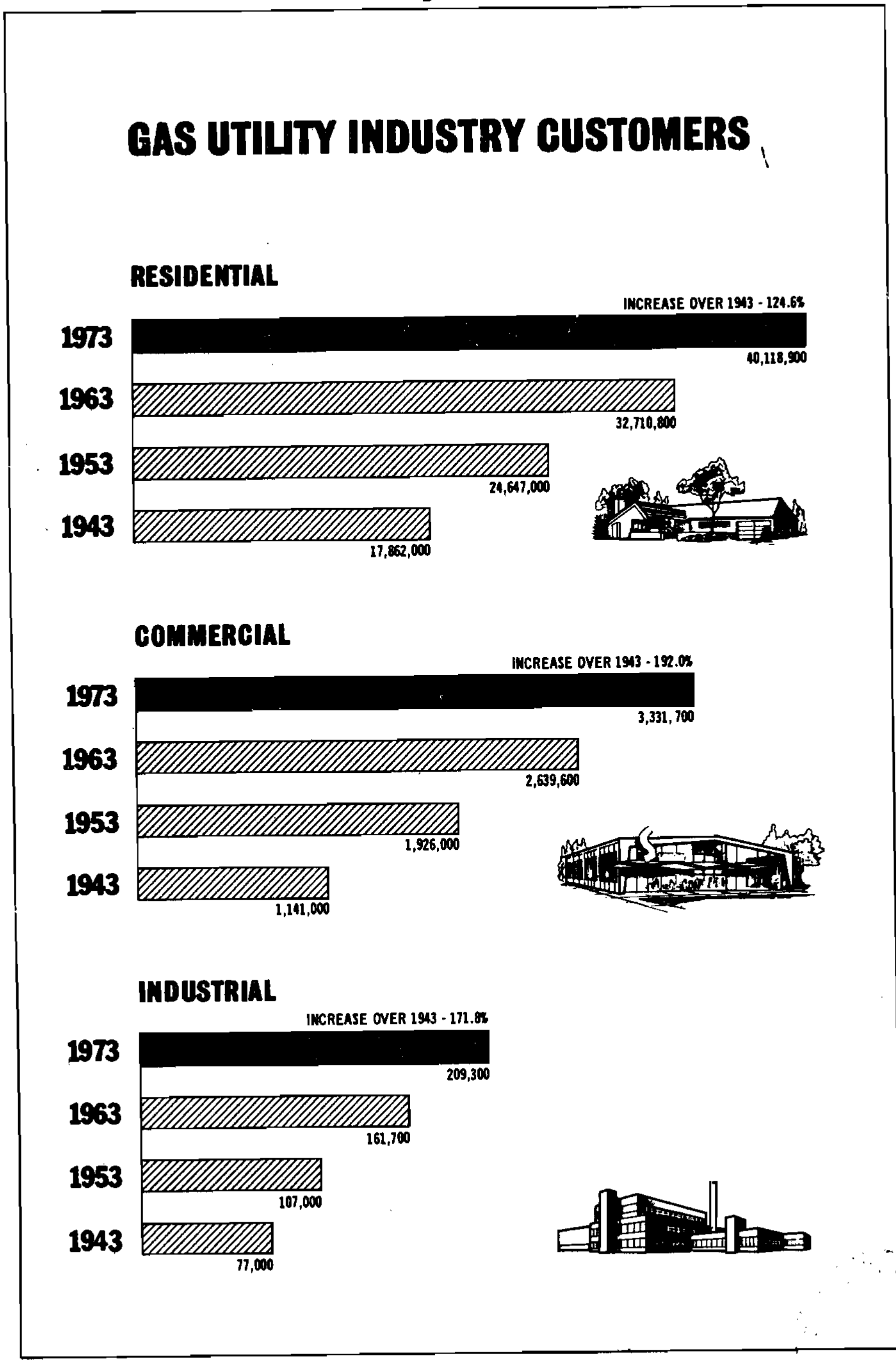
Note: Price indexes are based on average price per million Btu's paid by residential gas customers, as calculated from data appearing in Tables 64 and 79. Consumption indexes are based on average number of Btu's used per residential customer, as calculated from data appearing in Tables 58 and 64.

(1967 = 100)

Year	Average Residential Consumption	Average Gas Prices
1950	51.4	84.7
1951	57.9	82.6
1952	59.8	83.6
1953	60.3	86.9
1954	64.9	88.6
1955	70.1	89.3
1956	74.5	90.3
1957	76.1	91.2
1958	80.4	94.1
1959	82.8	96.2
1960	86.2	99.2
1961	87.8	101.2
1962	91.2	101.4
1963	92.3	101.2
1964	94.9	100.2
1965	95.9	100.4
1966	97.8	100.1
1967	100.0	100.0
1968	102.1	99.9
1969	105.6	100.9
1970	106.3	105.3
1971	106.9	111.3
1972	107.3	118.1
1973	102.4	124.6

Source: AGA(6)

Figure 8



Source: AGA(6)

Future Gas Requirements for the U.S.[1] (7)

(trillion cubic feet)[2]

	1975	1980	1985	1990
Residential	5.8	6.8	7.7	8.8
Commercial	2.6	3.2	3.9	4.8
Industrial	12.2	14.6	17.0	20.0
Electric Utility ..	5.5	6.8	7.4	9.0
Other	1.9	2.1	2.3	2.6
Total	28.0	33.4	38.4	45.3

1. Excluding Alaska and Hawaii
2. 1,000 Btu/cubic feet at 14.72 psia

NATURAL GAS REGULATIONS (1)

- Since June 7, 1954, when the United States Supreme Court interpreted that the Natural Gas Act of 1938 applied to the sale of gas in interstate commerce, natural gas producers engaged in the sale of such gas have been subject to Federal regulations administered by the Federal Power Commission. Following this decision, the FPC attempted to regulate each producer on an individual cost-of-service basis.

- In a short time, the FPC was flooded with requests by producers for rate increases resulting in a backlog of rate cases that the FPC was unable to handle. Realizing that regulating each individual producer was unworkable, the FPC in 1960 initiated the "area pricing" concept for producers. It established area ceiling prices for the major gas producing areas which a producer could then charge for gas sold in interstate commerce. For index of wholesale prices see Figure 15.

- The commission also introduced the concept of "vintaging" whereby gas sold before a certain date was defined as "old" or "flowing" gas and commanded a lower ceiling price. The idea of a higher ceiling price for "new" gas was to encourage future exploration.

- In determining area rates, the FPC used historical-type cost-of-service approach developed over the years for public utilities such as interstate gas pipelines and electric companies. The producing industry obviously has none of the characteristics of a utility since producers are engaged in other economic activities beside producing gas, none of which are regulated as in the case of natural gas.

- The impact of these regulatory standards and the uncertainty created by years of delays for rate cases to be adjudicated caused producers, who were faced with rising costs and rising prices, to seek other investment alternatives or, in the case of some small producers, to go out of business.

- In time, drilling began to decline. For example, the number of gas wells drilled in the United States declined from 5,262 in 1960 to 3,679 in 1971. Moreover, declining activitity contributed to a steady decline in annual reserve additions.

- Field prices of natural gas did not keep pace with the market clearing price, resulting in excess demand and reduced supply, and inevitably causing serious natural gas shortage.

Figure 9

INDEXES OF WHOLESALE PRICES OF GAS, YEARLY AVERAGES, 1950-1973 AND MONTHLY AVERAGES, 1973

(1967 = 100)

Year and Month		All Gas	Utility Gas	Liquefied Petroleum Gas
1950		41.8	38.2	63.1
1951		47.5	42.9	74.7
1952		49.9	45.8	73.9
1953		57.8	54.1	80.0
1954		60.6	59.4	67.4
1955		61.6	61.1	64.1
1956		65.9	63.5	80.1
1957	December[a]	72.8	71.7	78.3
1958		76.1	75.2	80.4
1959		82.9	83.2	82.6
1960		87.2	90.5	73.2
1961		88.8	94.9	58.7
1962		89.2	96.8	52.2
1963		91.8	97.5	69.6
1964		90.7	97.7	56.5
1965		92.8	97.8	69.2
1966		96.7	98.6	89.1
1967		100.0	100.0	100.0
1968		91.3	101.9	60.2
1969		93.1	103.0	63.7
1970		103.3	105.6	96.3
1971		108.0	112.2	95.7
1972		114.1	121.0	93.7
1973		126.7	131.3	113.2
1973	January	118.4	125.1	98.6
	February	118.6	125.4	98.6
	March	118.9	125.8	98.6
	April	120.1	127.4	98.6
	May	121.4	129.1	98.6
	June	128.0	130.1	121.8
	July	128.7	131.1	121.8
	August	130.4	133.3	121.8
	September	132.2	135.8	121.8
	October	133.4	135.9	126.1
	November	133.1	135.4	126.1
	December	137.6	141.5	126.1

a. 1957 yearly average not available.
Source: Bureau of Labor Statistics. *Wholesale Prices and Price Indexes*, Supplement 1973. Represents unofficial estimates of U. S. Bureau of Labor Statistics, based on Bureau of Mines wellhead prices of natural gas and average prices of L. P. G. between 1947 and 1956; and wellhead prices paid for natural gas by 20 major pipeline companies, and L. P. G. price quotations from 2 major producers subsequent to 1956.

Source: AGA (6)

IMPORTS AND EXPORTS OF NATURAL GAS

Figure 10

IMPORTS OF NATURAL GAS INTO THE UNITED STATES, 1950-1973
(Millions of cubic feet)

Year	Total	Canada	Mexico
1950	0	0	0
1955	10,888	10,881	7
1960	155,646	108,657	46,989
1965	456,394	404,686	51,708
1966	479,780	430,189	49,591
1967	564,226	513,255	50,971
1968	651,885	604,462	47,423
1969	726,951	680,106	46,845
1970	820,780[a]	778,687	41,336
1971	927,394[a]	903,772	20,689
1972	1,019,496[a]	1,009,093	8,141
1973	1,032,901[a]	1,027,214	1,632

a. Includes LNG imports of 757 MMCF into Massachusetts in 1970; 2,933 MMCF in 1971; 2,262 MMCF in 1972; and 4,055 MMCF in 1973.

Figure 11

EXPORTS OF NATURAL GAS FROM THE UNITED STATES, 1950-1973
(Millions of cubic feet)

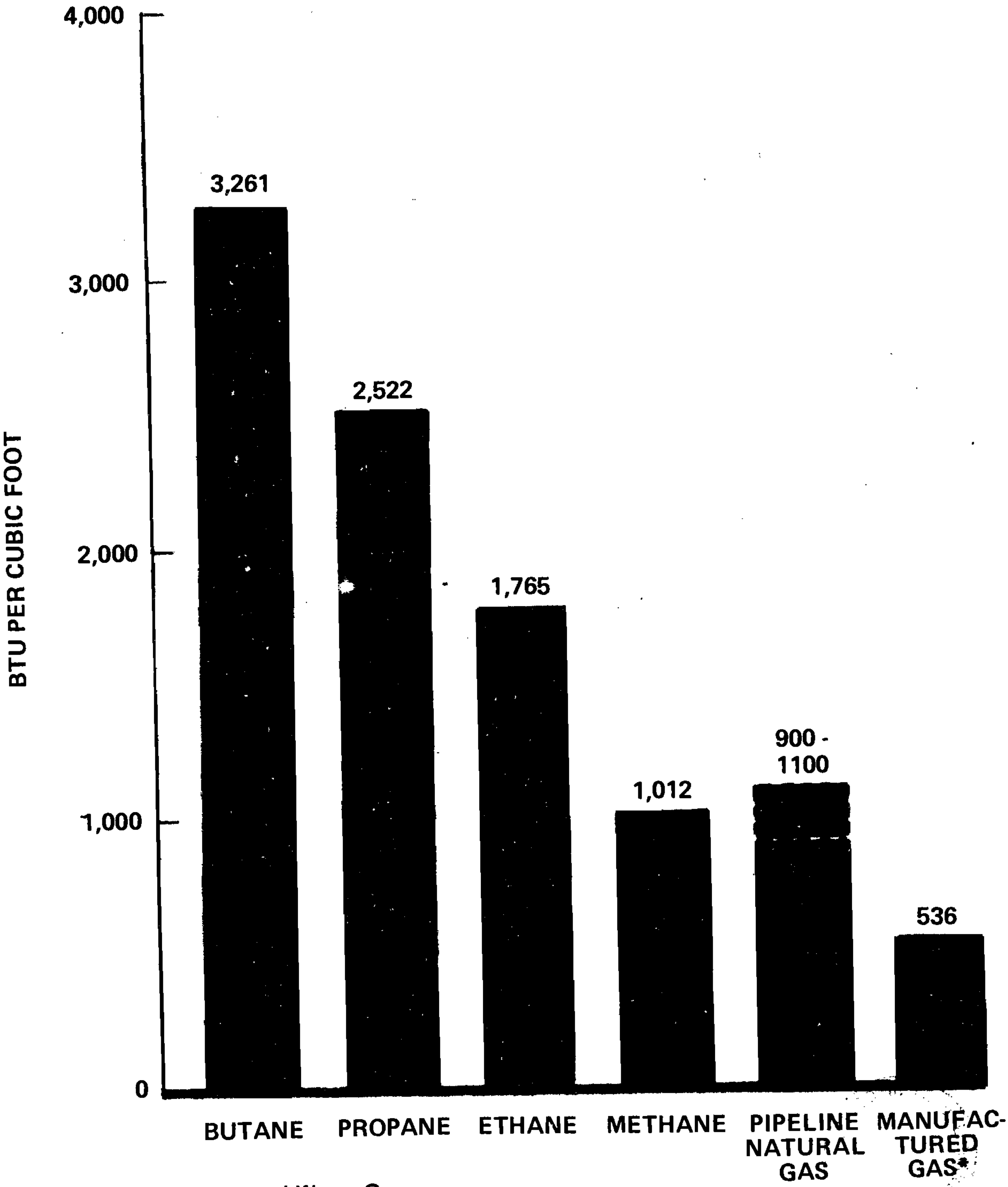
Year	Total	Canada	Mexico
1950	25,727	3,170	22,557
1955	31,029	11,467	19,562
1960	11,332	5,759	5,573
1965	26,132	17,979	8,153
1966	25,179	20,821	4,358
1967	81,614	70,456	11,158
1968	93,745	81,648	12,097
1969	51,304[a]	34,931	13,391
1970	69,813[a]	10,878	14,678
1971	80,365[a]	14,349	15,785
1972	78,013[a]	15,553	14,578
1973	77,169[a]	14,824	13,999

a. Includes 2,982 MMCF from Alaska to Japan (LNG) in 1969; 44,275 MMCF in 1970; 50,231 MMCF in 1971; 47,882 MMCF in 1972; and 48,346 MMCF in 1973.

Source: AGA(6)

Figure 12

HEAT CONTENT OF GASES



*Carbureted Water Gas

Source: FPC (3)

ANNUAL ESTIMATES OF PROVED NATURAL GAS RESERVES IN THE UNITED STATES, 1945 THROUGH 1973
TOTAL ALL TYPES

(Millions of Cubic Feet - 14.73 psia, at 60° F.)

Year	Revisions	Extensions	New Field Discoveries	New Reservoir Discoveries in Old Fields	Total of Discoveries, Revisions and Extensions	Net Change in Underground Storage	Production [d]	Proved Reserves at End of Year	Net Change From Previous Year
	Changes in Reserves During Year								
1945								146,986,723	
1946	a		a		17,632,864	a	4,915,774	159,703,813	12,717,090
1947	7,529,538		3,391,649		10,921,187	a	5,599,235	165,025,765	5,321,952
1948	9,716,426		4,106,664		13,823,090	51,202	5,975,001	172,925,056	7,899,291
1949	8,017,797		4,587,818		12,605,615	82,146	6,211,124	179,401,693	6,476,637
1950	9,123,637		2,861,724		11,985,361	52,935	6,855,244	184,584,745	5,183,052
1951	12,942,930		3,022,878		15,965,808	132,030	7,923,673	192,758,910	8,174,165
1952	8,885,950		5,381,656		14,267,606	197,766	8,592,716	198,631,566	5,872,656
1953	13,298,733		7,043,200		20,341,933	513,629 b	9,188,365	210,298,763	11,667,197
1954	4,607,155		4,939,919		9,547,074	90,408	9,375,314	210,560,931	262,168
1955	16,209,607		5,688,009		21,897,616	87,164	10,063,167	222,482,544	11,921,613
1956	19,110,251		5,605,864		24,716,115	133,241	10,848,685	236,483,215	14,000,671
1957	11,057,932		8,950,119		20,008,051	178,761	11,439,890	245,230,137	8,746,922
1958	13,316,100		5,580,624		18,896,724	57,582	11,422,651	252,761,792	7,531,655
1959	14,852,004		5,769,245		20,621,249	160,453	12,373,063	261,170,431	8,408,639
1960	7,293,015		6,600,963		13,893,978	281,273	13,019,356	262,326,326	1,155,895
1961	10,258,692		6,907,729		17,166,421	159,544	13,378,649	266,273,642	3,947,316
1962	13,184,794		6,299,164		19,483,958	159,231	13,637,973	272,278,858	6,005,216
1963	12,586,733		5,577,934		18,164,667	253,733	14,546,025	276,151,233	3,872,375
1964	13,342,838		6,909,301		20,252,139	195,110	15,347,028	281,251,454	5,100,221
1965	14,775,570 c		6,543,709 c		21,319,279	150,483	16,252,293	286,468,923	5,217,469
1966	4,937,962	9,224,745	2,947,329	3,110,396	20,220,432	134,523	17,491,073	289,332,805	2,863,882
1967	6,570,578	9,538,584	3,170,520	2,524,651	21,804,333	151,403	18,380,838	292,907,703	3,574,898
1968	3,016,146	7,758,821	1,376,429	1,545,612	13,697,008	118,569	19,373,428	287,349,852	(5,557,851)
1969	(1,238,261)	5,800,489	1,769,557	2,043,219	8,375,004	107,169	20,723,190	275,108,835	(12,241,017)
1970	(99,721)	6,158,168	27,770,223	3,367,689	37,196,359	402,018	21,960,804	290,746,408	15,637,573
1971	(1,227,400)	6,374,706	1,317,574	3,360,541	9,825,421	310,301	22,076,512	278,805,618	(11,940,790)
1972	(1,077,791)	6,153,683	1,462,539	3,096,132	9,634,563	156,563	22,511,898	266,084,846	(12,720,772)
1973	(3,474,756)	6,177,286	2,152,151	1,970,368	6,825,049	(354,282) e	22,605,406	249,950,207	(16,134,639)

a- Not estimated
b- All native gas in storage reservoirs formerly classified as proved reserves of natural gas is included in this figure.
c- Separation of revisions from extensions of new field discoveries from new reservoir discoveries in old fields not available prior to 1966.
d- Preliminary net production.
e- See footnote c, Table I.
( ) Denotes negative volume.

Source: API (4)

Figure 13

SOURCES

(1) OFFICE OF OIL AND GAS, Office of Energy Resource Development, FEA.

(2) NATIONAL ENERGY INFORMATION CENTER, Office of Policy and Analysis, FEA.

(3) FEDERAL GAS SURVEY, Vol. 1, Chapter 2, June 1974, Federal Power Commission

(4) RESERVES OF CRUDE OIL, NATURAL GAS LIQUIDS, AND NATURAL GAS IN THE UNITED STATES AND CANADA AND UNITED STATES PRODUCTIVE CAPACITY AS OF DECEMBER 31, 1973, Vol. 28, June 1974, American Gas Association, American Petroleum Institute, and Canadian Petroleum Association.

(5) FEDERAL GAS SURVEY, Vol. 1, Chapter 5, June 1974, Federal Power Commission

(6) 1973 GAS FACTS, 1974, American Gas Association

(7) FEDERAL GAS SURVEY, Vol. 1, Chapter 7, June 1974, Federal Power Commission

(8) LP-GAS ENERGY FOR AMERICA, 1974, National LP-Gas Association

(9) REALISTIC VIEW OF U.S. NATURAL GAS SUPPLY, January 2, 1975, Federal Power Commission

VI. OUTER CONTINENTAL SHELF

OUTER CONTINENTAL SHELF

BACKGROUND

- First interest in the production of petroleum from the offshore came with the discovery of sizeable fields onshore immediately adjacent to the shoreline of such places as California and Lake Maracaibo (Venezuela).

- 1896 - Drilling done from wooden piers built outward from shore at a seaward extension of the Summerland field, California.

- 1938 - Oil discovered off Louisiana in 8 meters of water a mile from shore.

- 1947 - Initial offshore discovery from mobile platform, Ship Shoal, 12 miles (3.6 kilometers) off Louisiana. This successful utilization of the mobile platform demonstrated that subsequent drilling need not be limited to the water-depth restrictions of the rigid platform that had to be built in place.

- 1947 - Also significant as the last year in which the United States was a net exporter of petroleum.

- Controversy between the maritime States and the Federal Government over jurisdiction of the seabed of the continental shelf delayed offshore development by 6 years. The Outer Continental Shelf Lands Act of 1953 provided for the immediate leasing of Federal offshore areas by the Department of the Interior and the validation of leases previously issued by the States.

- At the end of 1972, offshore petroleum exploration was in progress on the submerged continental margins of 80 countries. Some 780 oil and gas fields had been discovered.

- Estimated <u>worldwide</u> volume of oil discovered offshore as of January 1, 1973, is 172.8 billion barrels of oil, or about 26 percent of the world total, and 168.4 trillion cubic feet of natural gas.

- Present worldwide reserves of oil are 135.5 billion barrels, of which 70 percent is in the Persian Gulf.

DOMESTIC OCS RESOURCES AND RESERVES (See Figure 1)

OCS PRODUCTION

- See Figure 1.
- In 1973 OCS represented: (3)
  - o 12 percent of domestic oil production - 394 million barrels/year.
  - o 14 percent of domestic gas production - 3.2 trillion cubic feet/year.
- Cumulative OCS figures through 1973: (3)
  - o 11,899 wells drilled (6,421 wells capable of producing oil and gas at the end of 1973).
  - o Oil production (through 1973) - approximately 3 billion barrels.
  - o Gas production (through 1973) - approximately 20 trillion cubic feet.

OCS LEASING

<u>Percentages of OCS Oil and Gas Areas Leased December 1974, (4)</u>

Gulf of Mexico - more than 50 percent
Atlantic - 0 percent
Alaska - 0 percent
California - roughly 5 percent (Santa Barbara Channel)
Pacific: (Oregon and Washington) - 0 percent (past leases expired when exploration proved unproductive.

U.S. PETROLEUM AND NA[illegible] GAS RESOURCES
(onshore and offshore to water depth of 200 meters)

CRUDE OIL AND NATURAL GAS LIQUIDS
(Billions of barrels)

AREA	PRODUCTION				RESERVES				RESOURCES**	
	1972		CUMULATIVE end 1972		MEASURED***		INDICATED-INFERRED		UNDISCOVERED RECOVERABLE	
	State	Federal	State	Federal	State	Federal*	State	Federal*	State	Federal
Conterminous states onshore	3.100	0.214	104.200	5.577	29.3	1.7	16.0 - 27.0	1.0 - 1.5	100 - 200	10 - 20
Alaska onshore	0.000	0.009	0.000	0.134	9.6	0.1	5.0 - 10.0	0.0	20 - 40	5 - 10
Total onshore	3.100	0.223	104.200	5.711	38.9	1.8	21.0 - 37.0	1.0 - 1.5	120 - 240	15 - 30
Atlantic offshore	0.000	0.000	0.000	0.000	0.0	0.0	0.0	0.0	2 - 4	8 - 16
Gulf of Mexico offshore	0.100	0.390	0.700	2.770	0.5	3.5	0 - 0.5	2.0 - 3.0	2 - 4	18 - 36
Pacific offshore	0.100	0.020	1.300	0.090	0.7	2.2	0 - 0.5	1.0 - 2.0	1 - 2	4 - 8
Alaska offshore	0.100	0.000	0.500	0.000	0.7	0.0	0 - 0.5	0.0	2 - 4	28 - 56
Total offshore	0.300	0.410	2.500	2.860	1.9	5.7	0 - 1.5	3.0 - 5.0	7 - 14	58 - 116
Total on- and offshore	3.400	0.630	106.700	8.570	40.8	7.5	21.0 - 38.5	4.0 - 6.5	127 - 254	73 - 146

NATURAL GAS
(Trillions of cubic feet)

AREA	1972 State	1972 Federal	Cumulative State	Cumulative Federal	Measured State	Measured Federal*	Indicated-Inferred State	Indicated-Inferred Federal*	Undiscovered State	Undiscovered Federal
Conterminous states onshore	17.700	1.001	397.400	16.870	175.7	14.1	86.0 - 164.0	7.0 - 13.0	450 - 900	50 - 100
Alaska onshore	0.000	0.056	0.000	0.307	26.4	2.1	13.0 - 26.0	1.0 - 2.0	80 - 160	25 - 50
Total onshore	17.700	1.057	397.400	17.177	202.1	16.2	89.0 - 190.0	8.0 - 15.0	530 - 1060	75 - 150
Atlantic offshore	0.000	0.000	0.000	0.000	0.0	0.0	0.0	0.0	5 - 10	50 - 100
Gulf of Mexico offshore	0.600	3.030	3.900	17.400	6.5	36.8	3.0 - 5.0	18.0 - 36.0	10 - 20	150 - 300
Pacific offshore	0.000	0.010	1.200	0.040	0.7	2.0	0.0 - 0.5	1.0 - 2.0	5 - 10	5 - 10
Alaska offshore	0.100	0.000	0.600	0.000	1.8	0.0	1.0 - 1.5	0.0	20 - 40	150 - 300
Total offshore	0.700	3.040	5.700	17.440	9.0	38.8	4.0 - 7.0	19.0 - 38.0	40 - 80	355 - 710
Total on- and offshore	18.400	4.100	403.100	34.617	211.1	55.0	103.0 - 197.0	27.0 - 53.0	570 - 1140	430 - 860

*Distribution between State and Federal is based on assumption that reserves are in the same ratio between the two as recent production.

**As shown by the range, unit figures have little significance for individual areas, but merely show the approximate distribution of the rounded total for the United States--200-400 billion barrels of petroleum liquids and 1,000-2,000 trillion cubic feet of natural gas.

***Total U.S. measured reserves derived from American Petroleum Institute and American Gas Association.

Estimates revised: Feb. 14, 1974

Source: USGS (2)

Figure 1

Accelerated Leasing Program (5)

- The January 23, 1974, Presidential Energy Message directed the Secretary of the Interior to increase acreage leased on OCS to 10 million acres by the end of 1975, more than tripling the former leasing program.

- Leasing program goals:

    - o Provide orderly and timely resource development.
    - o Receive fair market value.
    - o Protect the environment.

- Main features of Interior's new leasing program:

    1. Two-tiered nomination procedures (regional, and tract leasing), based upon Government gathered data.
    2. Prohibition of joint bidding by majors (this provision is as yet undefined).
    3. Mandatory reporting information under leases.
    4. Prompt publication by industry of data on leased areas.
    5. Interagency environmental monitoring.

Cumulative OCS Leasing Figures (as of January 1, 1974) (3)

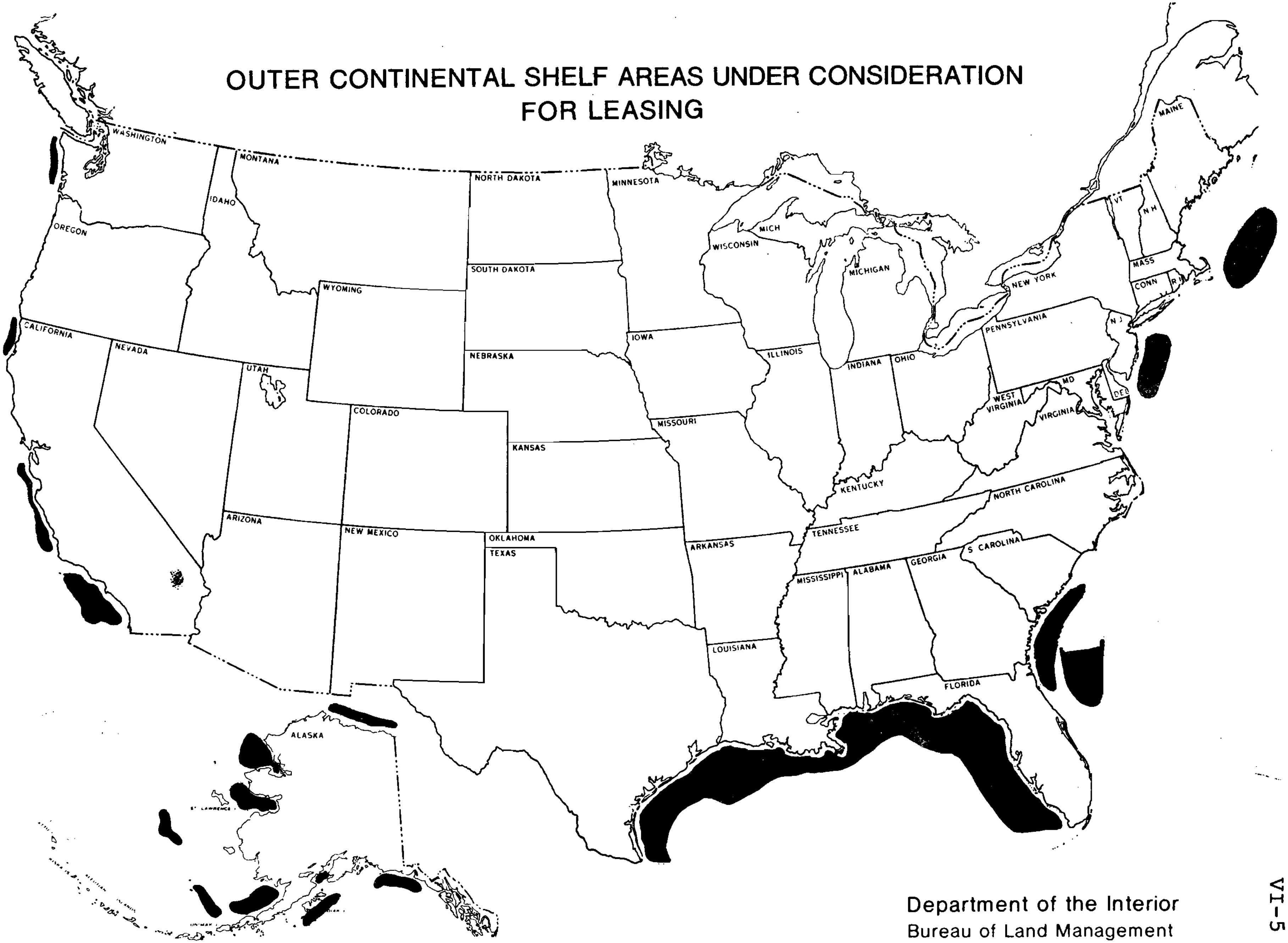
- 9.1 million acres leased on the OCS

- 7.8 million of these are located in the Gulf of Mexico.

OCS Areas Under Consideration for Leasing

- See Figures 2 through 6.

OUTER CONTINENTAL SHELF AREAS UNDER CONSIDERATION FOR LEASING

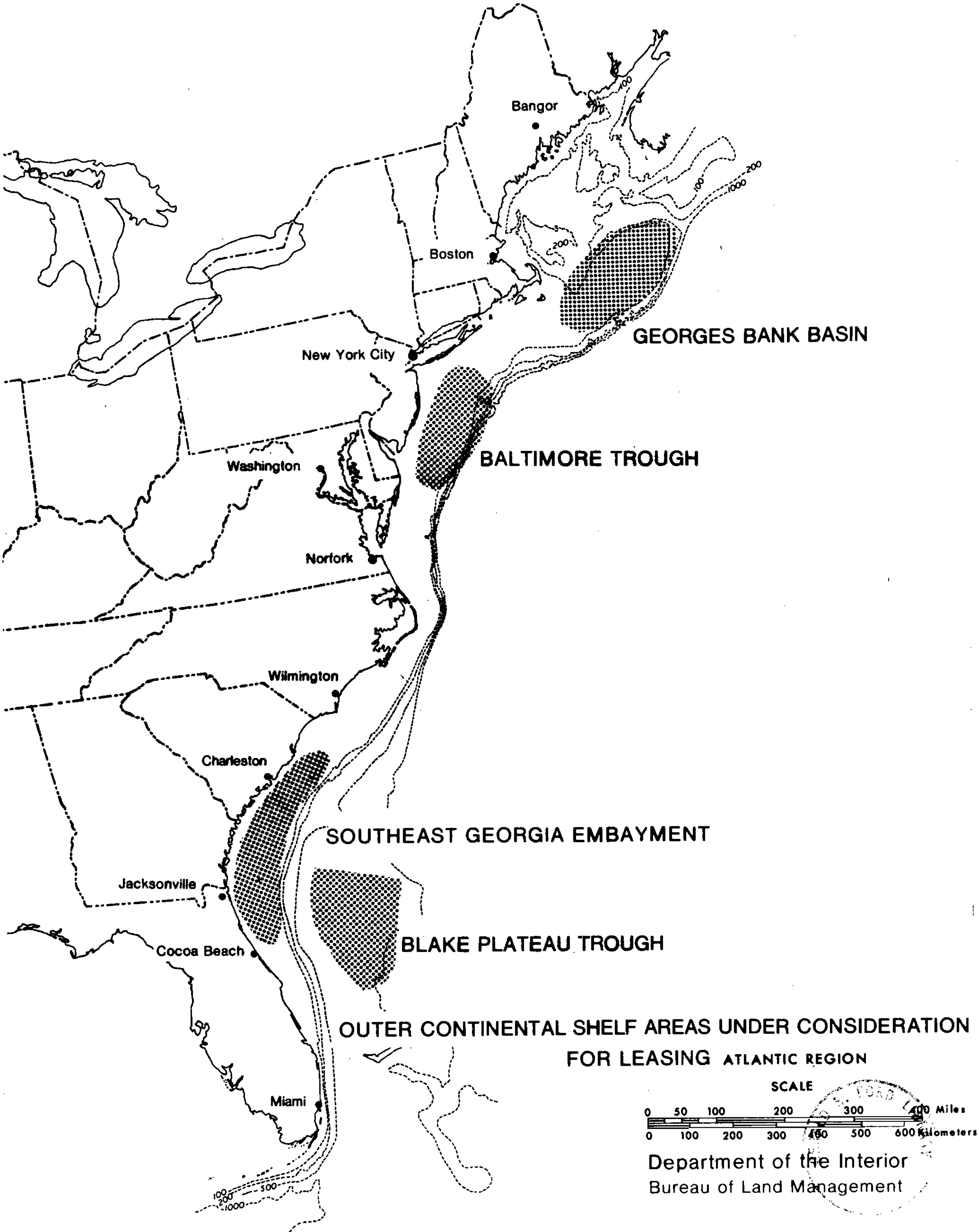


Source: BLM (5)

Figure 2

Department of the Interior
Bureau of Land Management

Figure 3

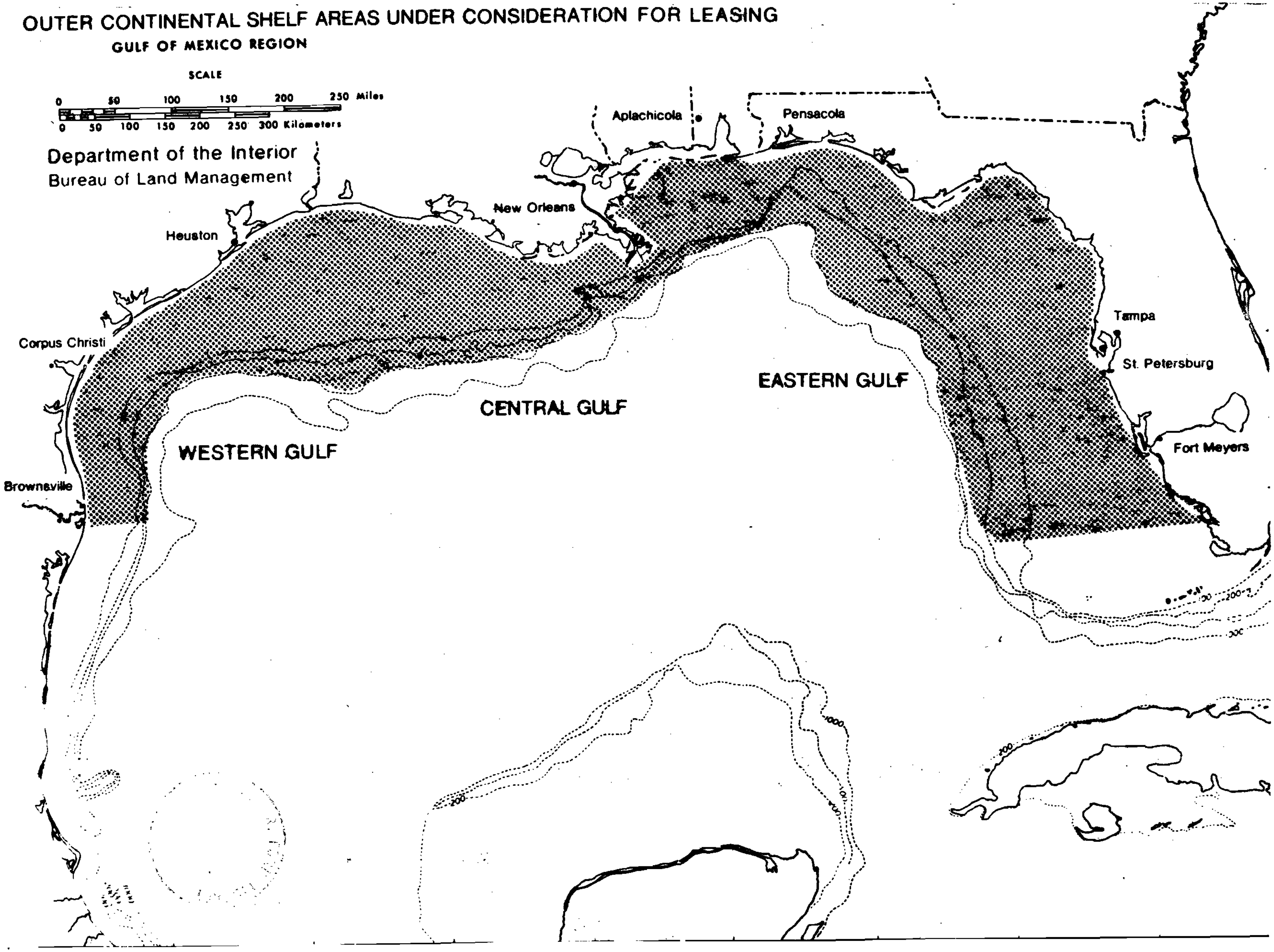


OUTER CONTINENTAL SHELF AREAS UNDER CONSIDERATION FOR LEASING ATLANTIC REGION

Source: BLM (5)

OUTER CONTINENTAL SHELF AREAS UNDER CONSIDERATION FOR LEASING

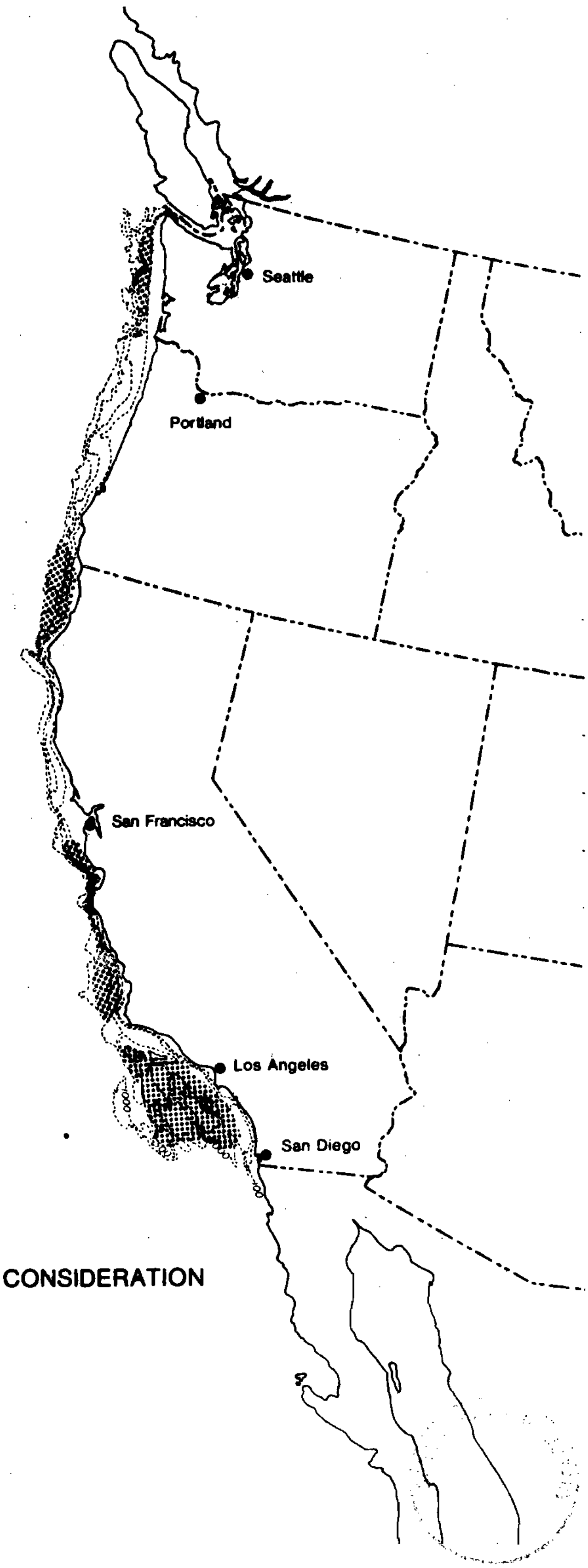
GULF OF MEXICO REGION



Source: BLM (5)

Figure 4

Figure 5



OUTER CONTINENTAL SHELF AREAS UNDER CONSIDERATION FOR LEASING

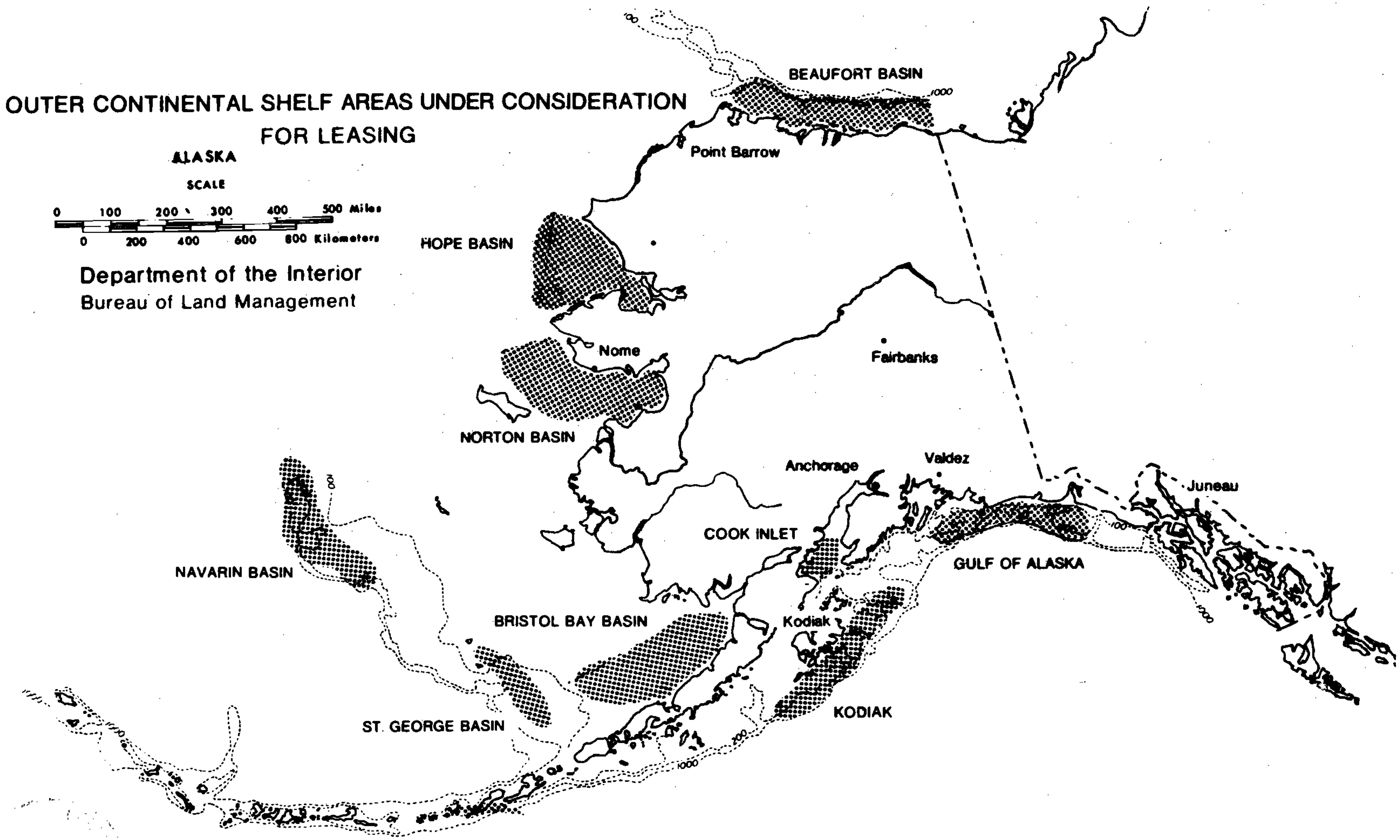
WEST COAST REGION

SCALE

0 50 100 200 300 400 Miles

0 100 200 300 400 500 600 Kilometers

Source: BLM (5)



Source: BLM (5)

Figure 6

ENVIRONMENTAL CONSTRAINTS (4)

- Two major environmental constraints to OCS development:

  1. Impact of massive and chronic oil spills. Oil spills adversely affect land, recreation areas, beaches, marine life, and wildlife. Chronic discharge may result in an accumulation of oil in one place which could have a long-term impact.

  2. Secondary effect of onshore development. Onshore industrial growth will also bring population growth which will require more services such as housing, roads, schools, and police. Communities that are very small may not be able to cope with the rapid growth.

Oil Spills

- Less than .02 percent of all oil and condensate produced in the Federal OCS was spilled between 1964 and 1973.

- Methods for cleaning spills off beaches:

  - Spreading straw. Used when water is calm and where straw can be recovered efficiently.

  - Vacuum pumping: Used when oil collects in pools. Heavy slicks tend to deposit oil near high-water mark, where it can be removed by bulldozer. If allowed to weather, oil may agglomerate in clumps, making it easier to clean up.

- Methods for containing and recovering oil:

  - Containment of ocean floor seeps: Underwater hoods to collect seep oil and carry it through flexible piping to containers -- oil/gas mixture migrates toward tent apex.

  - Sorption of oil: Commercial fish purse seiners, outfitted with properly sized nets to absorb or adsorb spill.

  - Chemical dispersants: Break up oil into tiny drops, so that natural bacteria can consume the oil. Used in rough open seas where skimming is more difficult and danger of poisoning marine life is minimal.

SOURCES

(1) THE WORLDWIDE SEARCH FOR PETROLEUM OFFSHORE--A STATUS REPORT FOR THE QUARTER CENTURY, 1947-72 (1974), by Henry L. Berryhill, Jr., U.S. Geological Survey, Circular 694, Department of the Interior.

(2) USGS RELEASES REVISED U.S. OIL AND GAS RESOURCE ESTIMATES, March 26, 1974, U.S. Geological Survey, Department of the Interior.

(3) OUTER CONTINENTAL SHELF STATISTICS, June 1974, U.S. Geological Survey, Conservation Division, Department of the Interior.

(4) LANDS AND EXPLORATION, 1975, Office of Oil and Gas, Office of Energy Resources and Development, FEA.

(5) BLM ANNOUNCES NEW TENTATIVE OCS LEASE SALE SCHEDULE THROUGH 1978, November 14, 1974, Bureau of Land Management, Department of the Interior.

VII. COAL

COAL

BACKGROUND (1)

- Coal was discovered in North America in 1679 near what is today Chicago, Illinois.

- The Nation's coal industry began in the 18th century with bituminous coal mined in Virginia and anthracite in Pennsylvania. Coal consumption and production increased steadily throughout the 19th century. Its uses included space heating, coal gas, coke for steel production, and with the development of steam-driven electric generators in the 1880's, electric power generation.

- By the turn of the 20th century, coal supplied 90 percent of U.S. energy consumption. However, during the first half of this century, coal consumption grew less rapidly than total energy consumption because more convenient and competitively priced domestic oil and natural gas became available and new uses of oil (e.g., automobiles) expanded rapidly.

- By 1950, coal dropped to 35 percent of the Nation's energy consumption. Since 1950, coal's declining role in the Nation's energy structure has been accelerated by government actions including:

  - o Fostering of nuclear research for the eventual replacement of coal-fired power generating stations with nuclear power generating stations.

  - o Lifting of restrictions in 1966 on the importing of cheaper residual fuel oil which gradually replaced coal as the main fuel for generating stations on the East Coast. (All import quotas on crude and petroleum products were lifted in 1973).

  - o Passage of the Clean Air Act which severely cut back on the development of new underground coal mines. Potential investors were hesitant to expend large sums of money if coal usage was to be largely restricted.

- By 1972, coal accounted for only 17 percent of the energy consumed by the Nation. Hence, while coal production has remained almost constant, the percentage of total energy consumption supplied by coal has declined dramatically (Figure 1).

COAL CLASSIFACATION (2)

- The most commonly used classification of coal in this country is the American Society for Testing Materials (ASTM) classification by rank found in American Standard Specification D 388-38.
    - o Figure 2 is a tabular display of ASTM classification by rank. The major classifications of anthracite, bituminous, sub-bituminous, found on the left. The sub-groups under each category are described by limits outlined in columns three and four.
- Peat, although not classified as a coal, is used in some countries as a fuel. The USSR used about 70 million tons for fuel in 1971. Because of the vast amounts of high grade coal in this country and its geographic locations, the widespread use of peat as a fuel is not competitive with coal.

COAL RESERVES

COAL REGIONS (1)

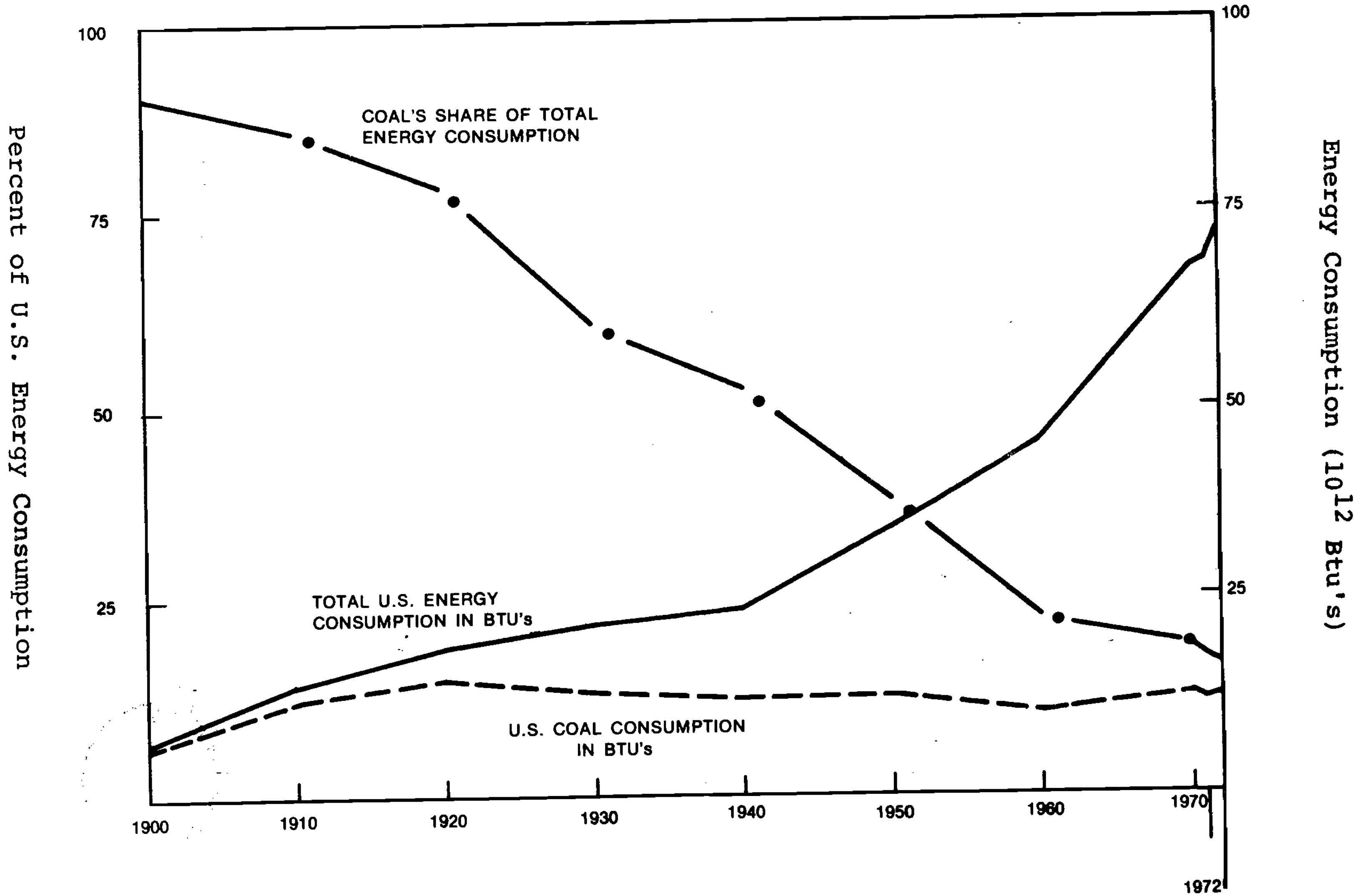
- North Appalachia - Pennsylvania, Ohio, Michigan, Northern West Virginia.
- Southern Appalachia - Southern West Virginia and Virginia, Eastern Kentucky, Tennessee, and Alabama.
- Midwestern - Western Kentucky, Illinois, Indiana, Iowa, and Arkansas.

- Gulf - Texas.
- Northern Great Plains - Wyoming, North Dakota, South Dakota, and Montana.
- Rocky Mountain - Colorado, parts of New Mexico, and Utah.
- Pacific Coast - California, Nevada, Washington, and Alaska.

Region	Billion Tons
1. Northern Appalachia	73.2
2. Southern Appalachia	39.1
3. Midwestern	104.6
4. Gulf	4.3
5. Northern Great Plains	175.4
6. Rocky Mountain	23.7
7. Pacific Coast	13.6
Total	433.9

- On a tonnage basis, about half of the reserves are located east of the Mississippi and half west. (See Figure 3) (1)
- Nearly all the coal reserves in the East are privately owned. (1)
- Most of the western reserves are owned by the Federal Government. (1)
- Approximately 60 percent of the Nation's coal reserves contain 1 percent or less sulfur by weight, and most of this is located in the West. (1)
- In 1973, the United States produced 599 million tons of coal. (4)
- About 90 percent of this production was mined in the eastern United States. (4)

COAL'S DECLINING SHARE OF TOTAL UNITED STATES ENERGY CONSUMPTION



Source: FEA (1)

Figure 1

Source: ASTM (2)

Figure 2

CLASSIFICATION OF COALS BY RANK.[a]

Class	Group	Fixed Carbon Limits, per cent (Dry, Mineral-Matter-Free Basis)		Volatile Matter Limits, per cent (Dry, Mineral-Matter-Free Basis)		Calorific Value Limits, Btu per pound (Moist,[b] Mineral-Matter-Free Basis)		Agglomerating Character
		Equal or Greater Than	Less Than	Greater Than	Equal or Less Than	Equal or Greater Than	Less Than	
I. Anthracitic	1. Meta-anthracite	98	...	...	2	...	...	...
	2. Anthracite	92	98	2	8	...	...	...
	3. Semianthracite	86	92	8	14	...	...	Nonagglomerating[c]
II. Bituminous	1. Low volatile bituminous coal	78	86	14	22	...	...	Commonly agglomerating[e]
	2. Medium volatile bituminous coal	69	78	22	31	...	...	
	3. High volatile *A* bituminous coal	...	69	31	...	14 000[d]	...	
	4. High volatile *B* bituminous coal	...	...	...	...	13 000[d]	14 000	
	5. High volatile *C* bituminous coal	...	...	...	...	11 500 10 500	13 000 11 500	 Agglomerating
III. Subbituminous	1. Subbituminous *A* coal	...	...	...	...	10 500	11 500	Nonagglomerating
	2. Subbituminous *B* coal	...	...	...	...	9 500	10 500	...
	3. Subbituminous *C* coal	...	...	...	...	8 300	9 500	...
IV. Lignitic	1. Lignite *A*	...	...	...	...	6 300	8 300	...
	2. Lignite *B*	...	...	...	...	...	6 300	...

[a] This classification does not include a few coals, principally nonbanded varieties, which have unusual physical and chemical properties and which come within the limits of fixed carbon or calorific value of the high-volatile bituminous and subbituminous ranks. All of these coals either contain less than 48 per cent dry, mineral-matter-free fixed carbon or have more than 15,500 moist, mineral-matter-free British thermal units per pound.

[b] Moist refers to coal containing its natural inherent moisture but not including visible water on the surface of the coal.

[c] If agglomerating, classify in low-volatile group of the bituminous class.

[d] Coals having 69 per cent or more fixed carbon on the dry, mineral-matter-free basis shall be classified according to fixed carbon, regardless of calorific value.

[e] It is recognized that there may be nonagglomerating varieties in these groups of the bituminous class, and there are notable exceptions in high volatile *C* bituminous group.

Figure 3

- Demonstrated Coal Reserve Base 1/ of the United States on January 1, 1974, By Area, Rank and Potential Method of Mining

(Billions of short tons)

	Anthracite	Bituminous	Subbituminous	Lignite	Total 3/
I. Underground:					
East of the Mississippi River ----	7	162	0	0	169
West of the Mississippi River ----	2/	31	98	0	129
Total ------------	7	192	98	0	297 *
II. Surface:					
East of the Mississippi River ----	2/	33	0	1	34
West of the Mississippi River ----	0	8	67	27	103
Total ------------	2/	41	67	28	137 **
III. Total 3/ ---------------	7	233	165	28	434

1/ Includes measured and indicated categories as defined by the USBM and USGS and represents 100% of the coal inplace.
2/ Less than 1/2 billion tons.
3/ Totals may not add due to rounding.

* Approximately 50% is recoverable.
** Approximately 80% is recoverable.

Source: Interior (5)

Proportion of High Sulfur to Low Sulfur Coal

- Figure 4 shows coal supply by region and estimated sulfur content.
- Figure 5 shows coal reserves by sulfur content as published by the Bureau of Mines.

SURFACE VERSUS UNDERGROUND MINING

- The underground method of coal mining is used where overburden thickness and composition make surface mining uneconomic, unsafe, or impossible.
- Surface mining is less hazardous than underground mining:
  - o There is, practically speaking, little incidence of "black lung" disease from the surface mining of coal.
  - o Deaths from surface mining fall into "industrial type" accidents, rather than the fires, explosions, and roof and rib falls that beset the underground miner.
  - o The injury rate from both underground and surface mining are similar.
- In 1973, approximately 50 percent of total coal production of 599 million tons was produced from underground mines, the remaining 50 percent from surface mines. (4)
- In 1972, bituminous and lignite coal were mined in 1,996 underground mines, 2,309 strip mines, and 574 auger mines. (See Figure 6) (3)
- Surface mining production increased 58 percent from 1965 to 1973, while underground mining decreased 11 percent in the same period. Underground costs have increased 109 percent since 1965, surface costs 46 percent. (4)

COAL SUPPLY BY REGIONS AND STATES, AND ESTIMATED SULFUR, 1975,1977, and 1980

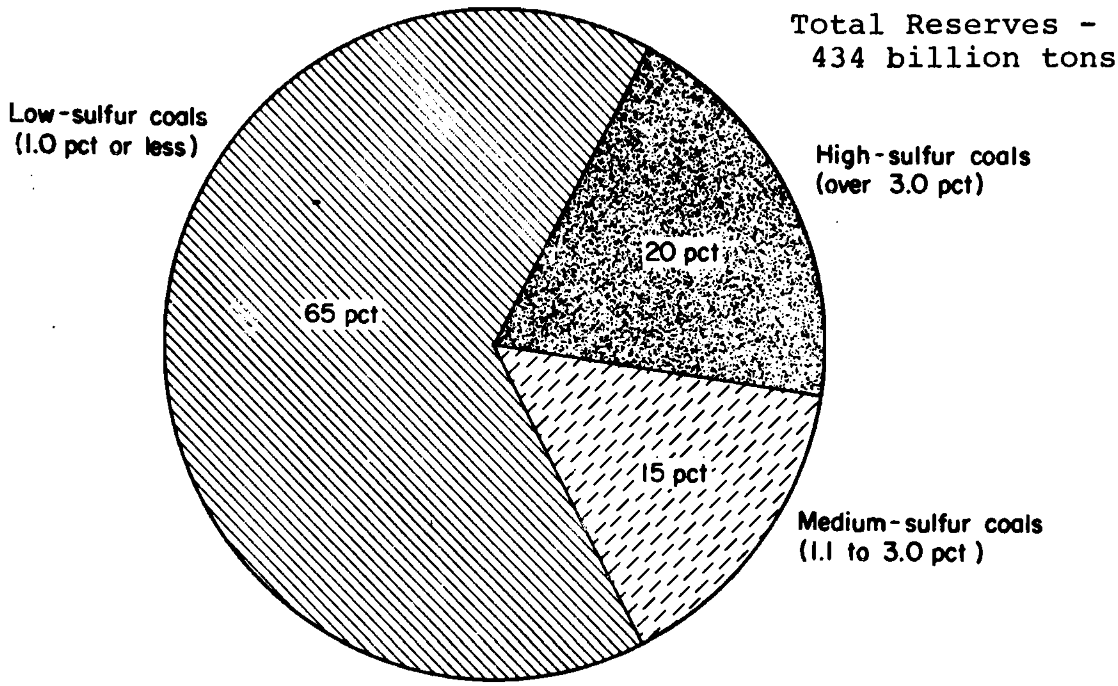
(In Thousand - Short Tons)

Regions and States	1975 Sulfur Levels of Supply (Percent) Under 1.0	1975 1.1-2.0	1975 2.1 and over	1975 Total	1977 Sulfur Levels of Supply (Percent) Under 1.0	1977 1.1-2.0	1977 2.1 and over	1977 Total	1980 Sulfur Levels of Supply (Percent) Under 1.0	1980 1.1-2.0	1980 2.1 and over	1980 Total
Appalachian												
Alabama	11,500	9,200	4,370	25,070	13,000	10,450	5,025	28,475	15,300	12,200	5,800	33,300
East Kentucky	62,000	17,000	5,810	84,810	67,600	18,500	6,400	92,500	80,000	22,000	8,000	110,000
Maryland	20	150	1,470	1,820	250	175	1,455	1,880	300	200	1,600	2,100
Ohio	-	1,200	54,000	55,200	-	1,275	56,825	58,100	-	1,400	61,500	62,900
Pennsylvania	11,900	45,000	24,000	80,900	12,500	47,250	25,250	85,000	13,750	52,000	27,650	93,400
Tennessee	4,000	1,800	3,200	9,000	4,500	2,050	3,720	10,270	5,500	2,500	4,400	12,400
Virginia	34,000	5,100	1,300	40,400	36,000	5,400	1,500	42,900	42,000	6,000	2,000	50,000
West Virginia	78,500	14,600	41,100	134,200	84,300	15,700	44,150	44,150	95,000	17,600	49,400	162,000
Total	202,100	94,050	135,250	431,400	218,150	100,800	144,325	463,275	251,350	113,900	160,350	526,100
Midwestern												
Arkansas	-	-	550	550	-	-	600	600	-	-	800	800
Illinois	4,750	6,500	57,750	69,000	5,050	6,900	61,250	73,200	5,450	7,400	66,150	79,000
Indiana	200	1,200	27,200	28,600	300	1,300	29,600	31,200	400	1,500	33,200	35,100
Iowa	-	-	1,000	1,000	-	-	1,100	1,100	-	-	1,300	1,300
Kansas	-	-	1,200	1,200	-	-	1,400	1,400	-	-	1,600	1,600
Missouri	-	-	5,000	5,000	-	-	5,300	5,300	-	-	5,800	5,800
Oklahoma	750	-	1,750	2,500	850	-	1,950	2,800	925	-	2,175	3,100
West Kentucky	-	450	57,850	58,300	-	500	61,800	62,300	-	550	68,850	69,400
Total	5,700	8,150	152,300	166,150	6,200	8,700	163,000	177,900	6,775	9,450	179,875	196,100
Gulf												
Texas	250	7,000	-	7,250	400	10,850	-	11,250	900	25,500	-	26,400
Northern Great Plains												
Montana	1,500	13,500	-	15,000	2,000	18,100	-	20,100	3,100	28,300	-	31,400
North Dakota	7,150	2,300	250	3,700	9,500	3,100	350	12,950	14,900	4,800	500	20,200
Wyoming	23,400	-	-	23,400	32,700	-	-	32,700	50,000	-	-	50,000
Total	32,050	15,800	250	43,100	44,200	21,200	350	65,750	68,000	33,100	500	101,600
Rocky Mountain												
Arizona	3,500	-	-	3,500	3,875	-	-	3,875	4,600	-	-	4,600
Colorado	6,415	-	-	6,415	6,800	-	-	6,800	7,800	-	-	7,800
New Mexico	9,485	-	-	9,485	10,850	-	-	10,850	12,000	-	-	12,000
Utah	6,000	-	-	6,000	6,500	-	-	6,500	7,000	-	-	7,000
Total	25,400	-	-	25,400	28,025	-	-	28,025	31,400	-	-	31,400
Pacific												
Alaska	700	-	-	700	800	-		800	1,000			1,000
Washington	6,000	-	-	6,000	8,000	-		8,000	12,400			12,400
Total	6,700	-	-	6,700	8,800	-		8,800	13,400	-	-	13,400
Total U.S.	272,200	125,000	287,800	685,000	305,775	141,550	307,675	755,000	372,325	181,950	340,725	895,000
Additional Available Coal Prod. Potential Per Figure #________+.				23,100				29,600				40,300
Grand Total Coal Supply				708,100				784,600				935,300
Domestic Coal Demand & Exports				660,000				712,000				824,000
Excess Coal Supply (Grand Total Less Demand)				48,100				72,600				111,300

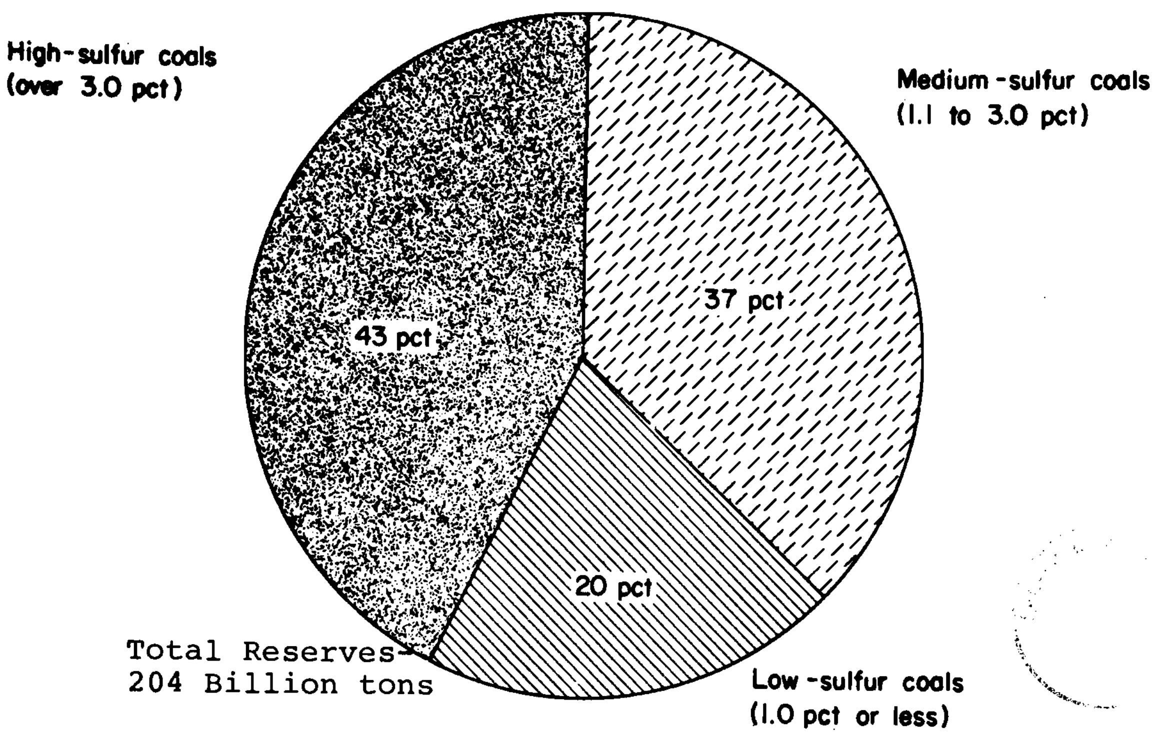
Source: Interior (6)

Figure 4

Figure 5



Estimated Remaining Coal Resources of All Ranks, by Sulfur Content, in the United States



Estimated Remaining Coal Reserves of All Ranks, by Sulfur Content, in States East of the Mississippi River.

Source: FEA (4)

SUPPLY AND DEMAND

Supply

- The United States has enormous reserves of coal; enough to last over 800 years at 1973 consumption rates. Recoverable reserves would last 500-600 years.(1)

Demand

- The largest, and at present, the only growing coal-consuming sector is the electric utility industry.(3)
- Almost two-thirds of current production is used to generate electricity, 25 percent for making coke domestically and abroad, and the balance going into the industrial and retail markets.(3)
- Figure 7 is a comparative study of domestic distribution of bituminous coal and lignite by State.
- Only about 21 percent of the coal currently mined is less than 1 percent sulfur by weight.(1)
- Nearly one-half of the low-sulfur eastern coal is used as coking coal.(1)
- Low sulfur western coals that will be in demand because of Clean Air Act requirements are located in areas far from eastern demand centers. Transportation costs will make this coal expensive in certain market areas, and its use in existing facilities is highly limited due to differences in ash, etc.(1)

Figure 6

Bituminous Coal and Lignite in 1972
Number of Active Mines, Production, Value Per Ton, Productivity, Employment, and Days Worked by Methods of Mining

Coal supply area	Underground		Surface: Strip		Surface: Auger		Surface: Total surface		Total	
	Units	Percent of total	Units	Percent of total	Units	Percent of total	Units	Percent of total	Units	Percent of total
Number of active mines										
1. Northern Appalachia	313	21.3	1,046	71.1	111	7.6	1,157	78.7	1,470	100.0
2. Southern Appalachia	1,566	51.4	1,023	33.6	458	15.0	1,481	48.6	3,047	100.0
Total Appalachia	1,879	41.6	2,069	45.8	569	12.6	2,638	58.4	4,517	100.0
3. Midwestern	59	23.2	187	74.8	5	2.0	192	76.5	251	100.0
4. Gulf	---	---	3	---	---	---	3	100.0	3	100.0
5. Northern Great Plains	8	19.5	33	80.5	---	---	33	80.5	41	100.0
6. Rocky Mountain	49	77.8	14	22.2	---	---	14	22.2	63	100.0
7. Pacific Coast	1	25.0	3	75.0	---	---	3	75.0	4	100.0
Total U.S.	1,996	40.9	2,309	47.3	574	11.8	2,883	59.1	4,879	100.0
Production (thousand short tons)										
1. Northern Appalachia	104,681	59.1	70,877	40.0	1,501	0.8	72,378	40.8	177,060	100.0
2. Southern Appalachia	137,917	65.6	58,357	27.8	13,915	6.6	72,272	34.4	210,189	100.0
Total Appalachia	242,598	62.7	129,234	33.4	15,416	3.9	144,650	37.3	387,249	100.0
3. Midwestern	52,162	34.0	101,183	65.9	137	0.1	101,320	66.0	153,483	100.0
4. Gulf	---	---	4,045	100.0	---	---	4,045	100,0	4,045	100.0
5. Northern Great Plains	459	1.8	25,323	98.2	---	---	25,323	98.2	25,781	100.0
6. Rocky Mountain	8,854	41.1	12,673	58.9	---	---	12,673	58.9	21,526	100.0
7. Pacific Coast	29	0.8	3,274	99.1	---	---	3,274	99.1	3,302	100.0
Total U.S.	304,103	51.1	275,730	46.3	15,554	2.6	291,284	48.9	595,386	100.0

Source: FEA (3)

- COMPARATIVE SUMMARY OF DISTRIBUTION OF BITUMINOUS COAL AND LIGNITE PRODUCED IN THE UNITED STATES DURING THE CALENDAR YEARS OF 1972 AND 1971 (In Thousand Net Tons)

GEOGRAPHIC DIVISION STATE OF DESTINATION METHOD OF MOVEMENT CONSUMER USE	TOTAL Calendar Year		ELECTRIC UTILITIES Calendar Year		COKE AND GAS PLANTS Calendar Year		RETAIL DEALERS Calendar Year		ALL OTHERS Calendar Year	
	1972	1971	1972	1971	1972	1971	1972	1971	1972	1971
New England, total	1,522	2,445	1,309	2,184	-	-	21	21	192	240
Massachusetts	147	227	26	122	-	-	13	14	108	91
Connecticut	109	1,271	54	1,185	-	-	-	-	55	86
Maine, New Hampshire, Vermont and Rhode Island	1,266	947	1,229	877	-	-	8	7	29	63
Middle Atlantic, total	78,998	77,552	42,529	40,508	27,309	25,948	499	696	8,661	10,400
New York	13,177	15,596	5,790	7,373	4,118	4,188	51	54	3,218	3,981
New Jersey	1,303	2,974	1,259	2,862	-	-	2	2	42	110
Pennsylvania	64,518	58,982	35,480	30,273	23,191	21,760	446	640	5,401	6,309
East North Central, total	206,504	187,969	132,931	118,164	35,637	30,407	4,931	5,926	33,005	33,472
Ohio	67,795	63,116	42,238	38,579	12,785	10,630	1,236	1,299	11,536	12,608
Indiana	46,618	38,599	26,090	21,790	13,799	11,164	847	640	5,882	5,005
Illinois	42,028	38,289	32,294	27,930	3,243	3,347	1,415	1,871	5,076	5,141
Michigan	35,085	32,625	21,424	19,416	5,378	4,861	649	817	7,634	7,531
Wisconsin	14,978	15,340	10,885	10,449	432	405	784	1,299	2,877	3,187
West North Central, total	39,587	35,407	33,115	29,519	926	807	665	870	4,881	4,211
Minnesota	8,639	8,313	6,674	6,403	608	509	303	500	1,054	901
Iowa	6,956	6,239	5,429	4,815	-	-	78	113	1,449	1,311
Missouri	15,810	13,358	13,714	11,655	318	298	96	73	1,682	1,332
North Dakota and South Dakota	5,834	5,272	5,295	4,718	-	-	132	143	407	411
Nebraska and Kansas	2,348	2,225	2,003	1,928	-	-	56	41	289	256
South Atlantic, total	96,907	90,354	75,731	68,009	8,624	8,719	1,388	1,367	11,164	12,259
Delaware and Maryland	9,744	11,599	5,408	6,408	3,580	4,369	30	41	726	781
District of Columbia	458	598	146	283	-	-	25	29	287	286
Virginia	8,027	9,258	4,894	5,821	-	27	416	407	2,717	3,003
West Virginia	32,459	26,606	22,752	17,458	5,044	4,323	271	239	4,392	4,586
North Carolina	21,489	19,779	19,696	17,687	-	-	370	355	1,423	1,737
South Carolina	6,915	6,219	5,480	4,589	-	-	214	219	1,221	1,411
Georgia and Florida	17,815	16,295	17,355	15,763	-	-	62	77	398	455
East South Central, total	78,843	72,191	61,742	56,009	9,838	9,144	894	991	6,369	6,047
Kentucky	27,389	25,590	23,460	21,611	1,631	1,660	319	341	1,979	1,978
Tennessee	21,390	18,907	18,894	16,637	174	174	450	549	1,872	1,547
Alabama and Mississippi	30,064	27,694	19,388	17,761	8,033	7,310	125	101	2,518	2,522
West South Central, total	930	887	-	-	883	840	4	4	43	43
Arkansas, Louisiana, Oklahoma and Texas	930	887	-	-	883	840	4	4	43	43

Source: Interior(6)

Figure 7

COMPARATIVE SUMMARY OF BITUMINOUS COAL AND LIGNITE PRODUCED IN THE UNITED STATES DURING THE CALENDAR YEARS OF 1972 AND 1971 (continued) (In Thousand Net Tons)

GEOGRAPHIC DIVISION STATE OF DESTINATION METHOD OF MOVEMENT CONSUMER USE	TOTAL Calendar Year		ELECTRIC UTILITIES Calendar Year		COKE AND GAS PLANTS Calendar Year		RETAIL DEALERS Calendar Year		ALL OTHERS Calendar Year	
	1972	1971	1972	1971	1972	1971	1972	1971	1972	1971
Mountain, total	26,330	21,581	21,101	16,700	2,773	2,688	652	793	1,804	1,400
Colorado	5,516	4,475	3,655	3,019	1,059	901	233	212	569	343
Utah	3,017	2,993	592	472	1,714	1,787	168	228	543	506
Montana and Idaho	1,281	1,348	753	782	-	-	210	299	318	267
Wyoming	5,152	3,728	4,903	3,542	-	-	40	26	209	160
New Mexico	6,851	6,713	6,844	6,701	-	-	-	1	7	11
Arizona and Nevada	4,513	2,324	4,354	2,184	-	-	1	27	158	113
Pacific, total	4,645	3,329	2,597	1,083	1,767	1,830	69	89	212	327
Washington and Oregon	2,865	1,482	2,597	1,083	-	-	65	86	203	313
California	1,780	1,847	-	-	1,767	1,830	4	3	9	14
Alaska	707	748	264	261	-	-	27	19	416	468
Canada 1)	17,740	17,417	8,821	8,677	7,593	6,510	293	251	1,033	1,979
Mexico	466	291	-	-	385	153	-	-	81	138
Destinations Not Revealable	1,702	2,179	122	580	513	195	87	117	980	1,287
Destinations and/or Consumer Uses Not Available										
Great Lakes movement:										
Canadian commercial docks	412	91								
Vessel fuel	595	713								
U.S. dock storage	-266	-263								
Tidewater movement:										
Overseas exports (except Canada)	2) 36,607	2) 37,810								
Bunker fuel	-	-								
U.S. dock storage	-	-								
Railroad fuel, total	367	542								
United States companies	357	528								
Canadian companies	10	14								
Coal used at mines and sales to employees	1,521	1,483								
Net change in mine inventory	1,097	397								

1) Excludes shipments to Canadian Great Lakes commercial docks and Canadian railroad companies

2) Excludes 762,000 tons from producing Districts 13, 14 & 20 in 1972, and 994,000 tons in 1971 produced in Districts 13, 14, 17 & 20

Source: Interior(6)

Figure 7 (cont.)

IMPEDIMENTS TO INCREASED COAL PRODUCTION

Declining Productivity

- Declining production of coal can be attributed to three main factors:

    1. Unwillingness of young men to follow their fathers into the mining labor force.
    2. Implementation of the Federal Coal Mine Health and Safety Act which forced small and marginally economic mining operations to close due to the cost versus profit measure.
    3. Unsettling conditions in the coal miners' union which increased the number of strikes, both in settling contract negotiations in 1971 and 1974, plus wildcat strikes in 1971, 1972, 1973, and 1974.

- The following table shows coal production levels for coal miners on a per day basis. While both strip mine and auger mine production remained relatively level, the production of underground mines declined dramatically.

	1969	1970	1971	1972	1973
Underground Mines	15.61	13.76	12.03	11.91	11.20
Strip Mines	35.71	35.96	35.69	35.95	34.60
Auger Mines	39.88	34.26	39.00	43.00	41.10
Average	19.90	18.84	18.02	17.74	16.76

Clean Air Act of 1970

- Requires State Implementation Plans (SIPs) which include emission limitations that insure attainment and maintenance of ambient air quality standards.
- Effective July 1975, States must comply with the Clean Air Act.
- In some States, standards will preclude burning of coal with sulfur content greater than 0.7 percent. (1)

- In 1975, approximately 100 million tons of current coal production will not comply; in 1977, 195 million tons; and up to 190 million tons by 1980. (1)

- SIPs will adversely affect current coal demand and will continue to do so during the early years following their implementation. The existence of a clean air deficit creates uncertainties which inhibit the development of coal resources.

    - o Reduction of clean fuels deficits will depend on the extent to which SIPs can be amended, on variances granted, and the extent to which emission control processes can be implemented.

Strip Mining Controls and Reclamation Requirements

- Surface coal mining is, at the least, a temporary disruption of the environment. The degree of disruption depends upon reclamation measures taken by the operator. Individual States have enacted legislation to control land reclamation.

- State laws vary from a registration of a mine with an annual license to an elaborate procedure for preplanning of mining operations to consider soil, water, and aesthetic values of the land when mining is completed.

- Approximately 434 billion tons of coal reserves in the United States could be recovered using current methods. Of this total, 233 million tons are bituminous, 165 million tons are sub-bituminous, 28 million tons are lignite, and 7 million tons are anthracite. (3)

- Of this amount, 128 billion tons are located in 21 States having reclamation laws. (4)

- Federal Government manages the mineral resources of all Federal lands.

- The Costs of environmental controls and requirements vary with the requirements of each individual State. These reclamation costs can range from less than $.05 per ton to $1.50 per ton; however, the average cost will be closer to the minimum. (4)

Labor Problems

- In excess of 25 million tons of coal production are lost to the Nation each year as a result of wildcat strikes and slowdowns. The contract negotiated in the Fall of 1974 between the BCOA and UMWA has several provisions expected to substantially reduce this lost production time. (4)

- Manpower is the single greatest deterent to expanded coal production. Estimates of additional manpower requirements are as high as 85,000 new workers between 1975 and 1985. (4)

  - In 1973, employment in the bituminous coal mining industry totaled 157,000 and 4,700 in the anthracite mining industry. (3)

  - An average of 225 days was worked to mine 595 million tons of coal in 1972. (3)

  - 112,252 men worked at underground mines in 1972, 37,013 worked at surface mines. (3)

  - Underground mine productivity was 11.9 tons per man-day. (3)

  - Surface operations productivity was 35.9 tons per man-day. (3)

Transportation Problems (4)

- The need to strengthen and improve current rails and roadbeds to handle heavy coal loads.

- Shortage of hopper cars will continue until track repair and turnaround time problems are resolved.

- Shortage of steel may be a constraint on the construction of new hopper cars.

- Need for new coal barges and towboats.

- Shortage of railroad cars in good repair.

- Financial condition of some railroads is a major problem. Raising capital for necessary repairs and upkeep is difficult without assurance that constraints to coal production will be removed.

Equipment Shortage

- The coal industry, as other industries, faces supply and material shortages. Lack of such items as diesel oil, lubricants, explosives, and roof bolts inhibit coal production.

  - o There is, at present, a 5-year lead time to meet increased demand on certain types of surface mining equipment. (3)

  - o There is a 2 to 3-year lead time for certain types of underground equipment. (3)

- There is an integrated system within the coal mining process. To the extent that supply, material or equipment shortages disrupt one part of the system, the entire continuum is adversely affected.

- The coal industry was discouraged from expanding production capacity because of a lack of assured demand for coal in past years. Long-term coal contracts appear to be the best incentive to accelerated production in the equipment manufacturing industry. (1)

Capital Requirements

- A coal mine represents a 20 to 25-year investment to an investor who expects to recover his capital plus and adequate return. (1) For example, a new 3 million ton-per-year slope mine will require a capital investment of $69 million over a 20 year period. (4)

- Capital investment in coal mining has varied from $300 million to $700 million from 1966 to 1973. Investment requirements are about $15 per ton for a surface mine and $20 per ton for a new deep mine. It is estimated that about $12 billion in new investments will be needed by 1985. (1)

Water

- The National Pollution Discharge Elimination System is another constraint on increased coal production. Limitations can be placed on any pollutant, including silt, chemical constituents, temperature, color or other characteristics of effluents entering waters of the State. These constraints may increase operating costs and, in some cases, eliminate mining of certain tracts for lack of a technology to handle the pollutant adequately. (4)

- Industrial water requirements for surface mining operations are small. Auxiliary water requirements for domestic and sanitation purposes for the typical surface mine will seldom exceed 5,000 gallons per day. The water requirements for surface mine rehabilitation are limited to those necessary for successful revegetation on rehabilitated mined areas. (4)

TRANSPORTATION

- Coal is moved primarily by rail. Other methods of transportation are water, truck, and slurry. (1)

- A relatively new mode of transportation is the coal slurry pipeline. In this method, finely ground coal is mixed with water and transmitted through a pipeline to its destination. (1)

    - There is currently only one slurry pipeline operating in this country, the 275 mile Black Mesa pipeline in the Southwest. (1)

    - This method may become more significant in the future for point-to-point transport of large volumes of coal. (1)

- Coal is usually mined and cleaned to remove impurities and to reduce sulfur content before being shipped. Many mines also operate breakers to reduce coal to a size suitable for particular customers. The larger mines load coal from tipples either into hopper cars or trucks, or convey it by belt to nearby river docks where it is dumped into barges. (8)

- Railroad cars transport about 66 percent of the coal produced in the United States. (1)

- The railroad hopper car can carry up to 100 tons of coal. (1)

- Unit trains, which may consist of more than 100 hopper cars carrying a nominal average of 80 tons per car, have come into extensive use. They can be efficiently loaded, transported to destination, dumped, and returned for another load in record time. This has resulted in lower rates. (8)
- Unit trains make up 25 percent of total train transport. (8)

Methods of Moving Coal (1972) (3)

Mode	Tons (millions)	%
Rail	379	66
Water	70	12
Truck	70	12
Slurry	3	--
Other	62	10
	584	100

EXPORTS (9)

- The United States is the largest coal exporting nation in the world.
- The United States exported 55 million tons or 9 percent of total coal production in 1973.

Type	Tons
Bituminous	52.8
Coke	1.3
Anthracite	.7

- Top 10 Export Destinations

Customer	Tons (million)
Japan	19.1
Canada	16.2
Italy	3.2
Spain	2.2
France	1.9
Netherlands	1.8
Brazil	1.6
W. Germany	1.6
Belgium	1.2
U.K.	.9

- Over 90 percent of the exported coal is sold under long-term contracts. Foreign customers have invested hundreds of millions of dollars in U.S. coal production facilities. Coal exports have contributed over $1 billion to U.S. efforts to achieve a favorable overall balance of trade.

IMPORTS (10)

- Although the United States has very large coal reserves, it has become an importer of solid fuels. Imports of solid fuel into the United States accelerated during the latter months of 1973. In 1973 the number of suppliers rose to seven, compared to 1972 when Canada was virtually the sole source of supply.

- In the first quarter of 1974, solid fuel imports, consisting of coal, coke, and briquets, exceeded the million short ton mark; almost 10 times higher than the level of imports for the same products during the same 1973 period.

Imports of Solid Fuels

	January-March 1974	(Short tons) 1973
Coal	320,235	7,562
Coke	695,410	91,854
Briquets	7,808	1,352
Total	1,023,453	100,768

INDUSTRY STRUCTURE AND OWNERSHIP OF MINES (8)

- The U.S. coal industry is comprised of almost 5,000 mines ranging in size from one-man operation to large mines employing nearly a thousand miners.

- Vast majority of coal is sold under long-term contracts or is produced by captive mines.

- The 50 largest bituminous coal-producing companies account for almost one-quarter of total U.S. bituminous production.

- Figure 8 lists the ownership of coal producing companies that produce 1 million tons or more annually.

- Captive mines are usually owned by companies that produce other commodities such as steel, and the coal is used in the manufacturing process; this coal is generally not sold on the open market.

- Most coal is directly marketed by producers, although a great many brokers and retail coal yards still serve as marketing agents for small consumers and in some cases for export customers.

FIGURE 8

OWNERSHIP OF COAL PRODUCING COMPANIES

Coal Operating Company	Parent or Controlling Company
Affinity Mining Co.	Eastern Gas & Fuel Associates, Inc.
Alabama By-Products Corp.	Alabama By-Products Corp.
Aloe Coal Co.	Pullman, Inc.
Alumbaugh Coal Co., Inc.	Donovan Companies, Inc.
Amax Coal Co.	American Metal Climax Inc.
American Coal Co.	Utah Power & Light Co.
Amherst Coal Co.	Amherst Coal Co.
Amigo Smokeless Coal Co.	Pittston Co.
Arch Coal Co.	Ashland Oil Co.
Arch Mineral Corp.	Ashland Oil Co.
Armco Steel Corp.	Armco Steel Corp.
Ashland Mining Corp.	Sovereign Pocahontas Coal Co.
Badger Coal Co.	Pittston Co.
Barbour Coal Co.	Barbour Coal Co.
Barnes & Tucker Co.	Alco Standard Corp.
Baukol-Noonan, Inc.	Baukol-Noonan, Inc.
Beatrice Pocahontas Co. (Jointly owned Island Creek, Republic Steel)	Occidental Petroleum Co. and Republic Steel Corp.
Belva Coal Co.	International Mining & Petroleum Corp.
Benjamin Coal Co.	Benjamin Coal Co.
Beth-Elkhorn Coal Corp.	Bethlehem Steel Co.
Bethlehem Mines Corp.	Bethlehem Steel Co.
Big Horn Coal Co.	Peter Klewit Sons Co.
Big Mountain Coal, Inc.	Armco Steel Corp.
Bishop Coal Co.	Continental Oil Co.
Black Creek Coal Sales Div.	The Drummond Co.
Blackwood Fuel Co., Inc.	Belco Petroleum Corp.
Blair Fork Coal Co.	W. R. Grace Co.
Blue Diamond Coal Co.	W. R. Grace Co.
Bradford Coal Co., Inc.	Bradford Coal Co., Inc.
Buckeye Coal Co.	Youngstown Sheet & Tube Co.
Buckeye Coal Mining Co.	Keller Steel Co.
Buckhorn Hazard Coal Corp.	General Energy Corp.
Buffalo Mining Co.	Pittston Co.
Burgess Mining & Construction Corp.	Burgess Mining & Construction Corp.
CF&I Steel Corp.	CF&I Steel Corp.
C & K Coal Co.	Gulf Resources & Chemical Co.
Cannelton Coal Co.	Cannelton Industries, Inc.
Canterbury Coal Co.	Westrans Industries
Carbon Fuel Co.	Carbon Fuel Co.
Cedar Coal Co.	American Electric Power Service Corp.

FIGURE 8
(continued)

OWNERSHIP OF COAL PRODUCING COMPANIES

Coal Operating Company	Parent or Controlling Company
Central Appalachian Coal Co.	American Electric Power Service Corp.
Central Coal Co.	American Electric Power Service Corp.
Central Ohio Coal Co.	American Electric Power Service Corp.
Charter Coal Corp.	Gulf Resources & Chemical Corp.
Cimarron Coal Corp.	Cimarron Coal Corp.
Clinchfield Coal Div.	Pittston Co.
Clintwood Mining Co.	Sovereign Pocahontas Coal Corp.
Colowyo Coal Co.	W. R. Grace Co.
Consolidation Coal Co.	Continental Oil Co.
Cravat Coal Co.	Cravat Coal Co.
Cumberland Collieries	Jewell Coal & Coke Co.
Decker Coal Co.	Peter Kiewit Sons Co.
H. E. Drummond Coal Div.	The Drummond Co.
Duquesne Light Co.	Duquesne Light Co.
ds Coal Co.	Ashland Oil Co.
Eastern Associated Coal Corp.	Eastern Gas & Fuel Associates
Eastern Coal Corp.	Pittston Co.
Eastover Mining Co.	Duke Power Co.
Elkay Mining Co.	Pittston Co.
Falcon Coal Co., Inc.	Falcon Coal Co., Inc.
Florence Mining Co.	North American Coal Corp.
Freeman Coal Mining Corp.	General Dynamics Corp.
Fresno Coal Corp.	General Exploration Co.
Gabriel Valley Enterprises	General Energy Corp.
Gateway Coal Co.	Jones & Laughlin Steel Corp.
Gibraltar Coal Corp. (Jointly owned by Peabody Coal and Amax Coal)	Kennecott Copper Corp; American Metal Climax, Inc.
Greenwich Collieries Co.	Pennsylvania Power & Light Co.
Harman Mining Corp.	Sovereign Pocahontas Coal Co.
Harmar Coal Co.	Continental Oil Co.
Hawley Coal Mining Corp.	Belco Petroleum Corp.
Helen Mining Co.	North American Coal Corp.
Helvetia Coal Co.	Rochester & Pittsburgh Coal Co.
Industrial Mining Co.	Keller Steel Co.
Inland Steel Co.	Inland Steel Co.
International Harvester Co.	International Harvester Co.

FIGURE 8
(continued)

OWNERSHIP OF COAL PRODUCING COMPANIES

Coal Operating Company	Parent or Controlling Company
Island Creek Coal Co.	Occidental Petroleum Corp.
Itmann Coal Co.	Continental Oil Co.
Jewell Coal & Coke Co.	Jewell Coal & Coke Co.
Jewell Ridge Coal Corp.	Pittston Co.
Johns Creek Elkhorn Coal Corp.	General Energy Corp.
Jones & Laughlin Steel Corp.	Jones & Laughlin Steel Corp.
Kaiser Steel Corp.	Kaiser Steel Corp.
Kellerman Mining Div.	The Drummond Co.
Kemmerer Coal Co.	Kemmerer Coal Co.
Kentland Elkhorn Coal Corp.	Pittston Co.
Kentucky Carbon Corp.	Carbon Fuel Co.
Kerr McGee Coal Corp.	Kerr-McGee Corp.
King Knob Coal Co.	King Knob Coal Co.
Knife River Coal Mining Co.	Montana Dakota Utilities Co.
Kristianson & Johnson Coal Co, Inc.	Westrans Industries
Majestic Collieries Co.	Sovereign Pocahontas Coal Co.
Maple Meadow Mining Co.	Cannelton Industries, Inc.
Marty Corporation	Marty Corporation
Mathies Coal Co.	Continental Oil Co.
Mead Corporation	Mead Corporation
Midland Coal Co.	American Smelting & Refining Co.
Midway Coal Co.	Pullman, Inc.
Monterey Coal Co.	Exxon Corp.
Mountain Drive Coal Co.	Mountain Drive Coal Co.
Nacco Mining Co.	North American Coal Corp.
National Coal Mining Co.	Occidental Petroleum Co.
National Mines Corp.	National Steel Corp.
Natural Bridge Coal Div.	The Drummond Co.
New River Coal Co.	Chessie System
North American Coal Corp.	North American Coal Corp.
Oglebay Norton Co.	Oglebay Norton Co.
Ohio Coal & Construction Co.	Ohio Coal & Construction Co.
Ohio Edison Co.	Ohio Edison Co.
Old Ben Coal Co.	Standard Oil Co. (of Ohio)
Olga Coal Co.	Youngstown Sheet & Tube Co.
Oneida Mining Co.	North American Coal Corp.
Pacific Power & Light Co.	Pacific Power & Light Co.
Peabody Coal Co.	Kennecott Copper Corp.
Peter White Coal Mining Corp.	Belco Petroleum Corp.

FIGURE 8
(continued)

OWNERSHIP OF COAL PRODUCING COMPANIES

Coal Operating Company	Parent or Controlling Company
Pikeville Coal Co.	Steel Co. of Canada
Pocahontas Red Ash Mining Corp.	Belco Petroleum Corp.
Pittsburg & Midway Coal Mining Co.	Gulf Oil Co.
Princess Susan Coal Co.	Central Penn Industries
Quarto Mining Co.	North American Coal Corp.
R & F Coal Co.	Gulf Resources & Chem. Corps.
Race Fork Coal Corp.	W. R. Grace Co.
Ranger Fuel Corp.	Pittston Co.
Republic Steel Corp.	Republic Steel Corp.
Rochester & Pittsburgh Coal Co.	Rochester & Pittsburgh Coal Co.
Rocky Mountain Energy Co.	Union Pacific Corp; Ideal Basic Industries Inc.
Rosebud Coal Sales	Peter Kiewit Sons Co.
Rushton Mining Co.	Pennsylvania Power & Light Co.
ahara Coal Co.	Sahara Coal Co.
Scotia Coal Co.	W. R. Grace Co.
Semet Solvay Div.	Allied Chemical Corp.
Sewell Coal Co.	Pittston Co.
Shamrock Coal Co.	Jewell Coal & Coke Co.
Slab Fork Coal Co.	Slab Fork Co.
Snap Creek Coal Co.	Pittston Co.
Southern Appalachian Coal Co.	American Electric Power Service Corp.
Southern Electric Generating Co.	Southern Electric Generating Co.
Southern Ohio Coal Co.	American Electric Power Service Corp.
Southern Utah Fuel Co.	Coastal States Energy Co.
Southwestern Illinois Coal Corp.	Ashland Oil Co.
Sovereign Coal Corp.	Sovereign Pocahontas Coal Co.
Tunnelton Mining Co.	Pennsylvania Power & Light Co.
Twilight Industries, Inc.	U.S. Natural Resources Co.
Union Carbide Corp., Ferroalloys Div.	Union Carbide Corp.
United Electric Coal Cos.	General Dynamics Corp.
United States Fuel Co.	U.S. Smelting & Refining Co.
United States Pipe & Foundry Co.	Jim Walter Corp.
United States Steel Corp.	United States Steel Corp.
Upshur Coals Inc.	Alco Standard, Inc.
Utah International Inc.	Utah International Inc.

FIGURE 8
(continued)

OWNERSHIP OF COAL PRODUCING COMPANIES

Coal Operating Company	Parent or Controlling Company
Valley Camp Coal Co.	Valley Camp Coal Co.
Virginia Iron Coal & Coke Co.	Virginia Iron Coal & Coke Co.
Virginia Pocahontas Co.	Occidental Petroleum Co.
Walker-Fayette Coal Co.	Ashland Oil Co.
Washington Irrig. & Devel. Co.	Pacific Pwr. & Lt.; Washington Wt. Pwr.
Webster Country Coal Corp.	Mapco Inc.
Western Energy Co.	Montana Power Co.
Westmoreland Coal Co.	Westmoreland Coal Co.
Westmoreland Resources	Westmoreland Coal Co.; Penn-Virginia Corp. Morrison-Knudsen Co; Kawanee Oil Co.
Wheeling-Pittsburgh Steel Corp.	Wheeling-Pittsburgh Steel Corp.
Windsor Power House Coal Co.	American Electric Power Service Corp.
Wyodak Resources Devel. Corp.	Black Hills Power & Light Co.
Youghiogheny & Ohio Coal Co.	Youghiogheny & Igui Coal Co.
Youngstown Mines Corp.	Youngstown Sheet & Tube Co.
Zapata Coal Corp.	Zapata Corp.
Zeigler Coal Co.	

Source: Keystone(8)

Figure 9

The 15 Largest Bituminous Mines in 1973

COMPANY	NAME OF MINE	STATE	PRODUCTION 1973	1972	1950
1. Utah International Inc.	Navajo (S)	N.M.	7,389,321	6,898,262	New 1963
2. Peabody Coal Co	River King (S)	Ill.	6,526,267	6,775,551	New 1957
3. Peabody Coal Co	Sinclair (S)	Ky.W	5,290,991	5,476,921	New 1962
4. Southwestern Illinois Coal Corp . .	Captain (S)	Ill.	4,451,313	4,481,000	New 1964
5. Consolidation Coal Co. Central Div.	Egypt Valley (S)	Ohio	4,256,821	3,822,173	New 1967
6. Western Energy Co	Colstrip (S) (C)	Mont.	4,253,681	5,500,700	New 1968
7. Peabody Coal Co	River Queen (D&S)	Ky.W.	4,172,223	4,660,542	New 1957
8. Peabody Coal Co	No. 10	Ill.	4,147,069	4,693,393	New 1952
9. Peabody Coal Co	Lynnville (S)	Ind.	4,064,910	4,173,500	New 1955
10. Clinchfield Div., Pittston Co	Moss No. 3	Va.	3,902,707	4,582,152	New 1958
11. Central Ohio Coal Co.	Muskingum (S) (C)	Ohio	3,667,844	4,309,953	New 1952
12. Peabody Coal Co	Black Mesa (S)	Ariz.	3,246,500	2,953,654	New 1970
13. Washington Irrigation Dist.	Centralia (S) (C)	Wash.	3,229,176	2,596,729	New 1970
14. Amax Coal Co.	Ayrgem (S)	Ky.W.	3,206,242	3,183,229	New 1969
15. Peabody Coal Co	Ken (D&S)	Ky.W.	3,202,350	2,771,077	672,35[illegible]

Source: Keystone(8)

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(3) TASK FORCE REPORT-COAL, 1974, FEA.

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VIII. SYNTHETIC FUELS
FROM COAL

SYNTHETIC FUELS FROM COAL

COAL GASIFICATION (1)&(2)

BACKGROUND

- Coal can be converted to three types of gas through conversion processes:

  1. High-Btu gas (SNG-Synthetic Natural Gas), which has a heating value of between 920-1020 Btu's per cubic foot.

  2. Medium-Btu gas, having a heating value of between 300-400 Btu's per cubic foot.

  3. Low-Btu gas (Industrial Gas), with a heating value of between 120-150 Btu's per cubic foot --uneconomical to transport through pipelines.

- High-Btu gas is suitable for direct distribution and use through existing pipeline systems.

- Medium and low-Btu gas have applications which include:

  1. Use as fuel for utility boilers -- eliminates need for stack gas scrubber systems on boilers using high-sulfur coal.

  2. Local use as clean fuel for industrial uses -- freeing natural gas for other purposes.

3. Blending with natural gas in the transmission system, to a limited degree, to provide gas of intermediate heating value for industrial use.

4. Potential use as valuable source for electric power generation -- if it can be used at or near the site where it is produced, it can provide adequate energy to generate electricity at a lower cost.

5. Use as a feedstock for chemical manufacture.

COMMERCIALLY AVAILABLE COAL CONVERSION PROCESSES

- Several methods of coal gasification are commercially available.
- All methods employ a basic gasification step where coal is reacted with steam and air, or oxygen.
- Gasifying with air produces low-Btu gas; with oxygen, a medium-Btu gas.
- None of the commercial processes yield a gas with the heating value of natural gas. To produce synthetic natural gas, a methanation step is required.
- Two commercial processes are:

    1. The Lurgi Process
    2. The Koppers-Totzek Process

<u>The Lurgi Process</u> (3) & (4)

- Developed in 1930's to produce synthetic gas for ammonia, liquid fuel, and petrochemical products.
- Initially limited to noncaking or mildly caking coals. With pre-treatment of coal can now use caking coals. Cannot accept coal fines.
- The gasifier operates under pressure of about 400 psi.

The Process:

- o Lump coal (up to about 1 or 2 inches but without fines) enters the coal lock at the top.
- o The coal feeds downward over a distributor and into the gasifier which is a water-jacketed vessel about 12 feet in diameter and 25 feet high.
- o Coal is held on a rotating grate with steam and oxygen coming up through the grate.
- o Ash falls through the grate and is removed from the pressure system through the ash lock at the bottom.
- o Oxygen and steam are fed up through the ash grate and create three major zones in the gasifier:

  1. Combustion zone immediately above the ash grate about 1 or 2 feet deep in which oxygen is present in excess and carbon is oxidized largely to CO_2.
  2. Reduction zone about 8 to 10 feet deep in which a series of reactions are taking place yielding CO, H_2, CH_4, CO_2.
  3. Devolatilization zone is about 4 to 6 feet deep in which the incoming coal is heated and volatile matter such as hydrogen, hydrocarbon gases, oil, and tars are driven out of the coal.

- o The product gas from the Lurgi gasifier is generally cooled by a direct water spray to condense oils and tar before it goes to purification.

<u>The Koppers-Totzek Process</u> (3)&(4)

- Developed to gasify pulverized coal at high temperatures with oxygen and steam.
- Pulverized coal, oxygen, and steam are blown in at each end of a refractory-line, water-jacketed horizontal cylinder and react to produce CO, H_2, and a small amount of CO_2.

- Some ash is removed as liquid and the rest goes out with the gas.

- Operating flame temperatures are near 3000° F and at these temperatures, almost no methane, tars, or oils are produced, but it is necessary to remove ash from the gas.

- Up to present, Koppers-Totzek gasifiers have been operated only near atmospheric pressure which results in low percentage of methane in the product gas.

- Approximately 52 commercial sized Koppers-Totzek units are in operation, but mainly for the production of hydrogen for ammonia synthesis.

COAL TO HIGH-BTU GAS - PROCESSES UNDER DEVELOPMENT (1)&(2)

- In order to improve the overall economics of coal gasification, in 1971 the Office of Coal Research (Dept. of Interior) and the American Gas Association signed an agreement for an accelerated pilot plant program which will cost an estimated $120 million over a four-year period. OCR's share totals $80 million; AGA's, $40 million.

- The processes tested under this program are:

    1. The HYGAS Process
    2. The CO_2 Acceptor Process
    3. The BI-GAS Process
    4. The Synthane Process

<u>HYGAS Process</u> (see Figure 1)

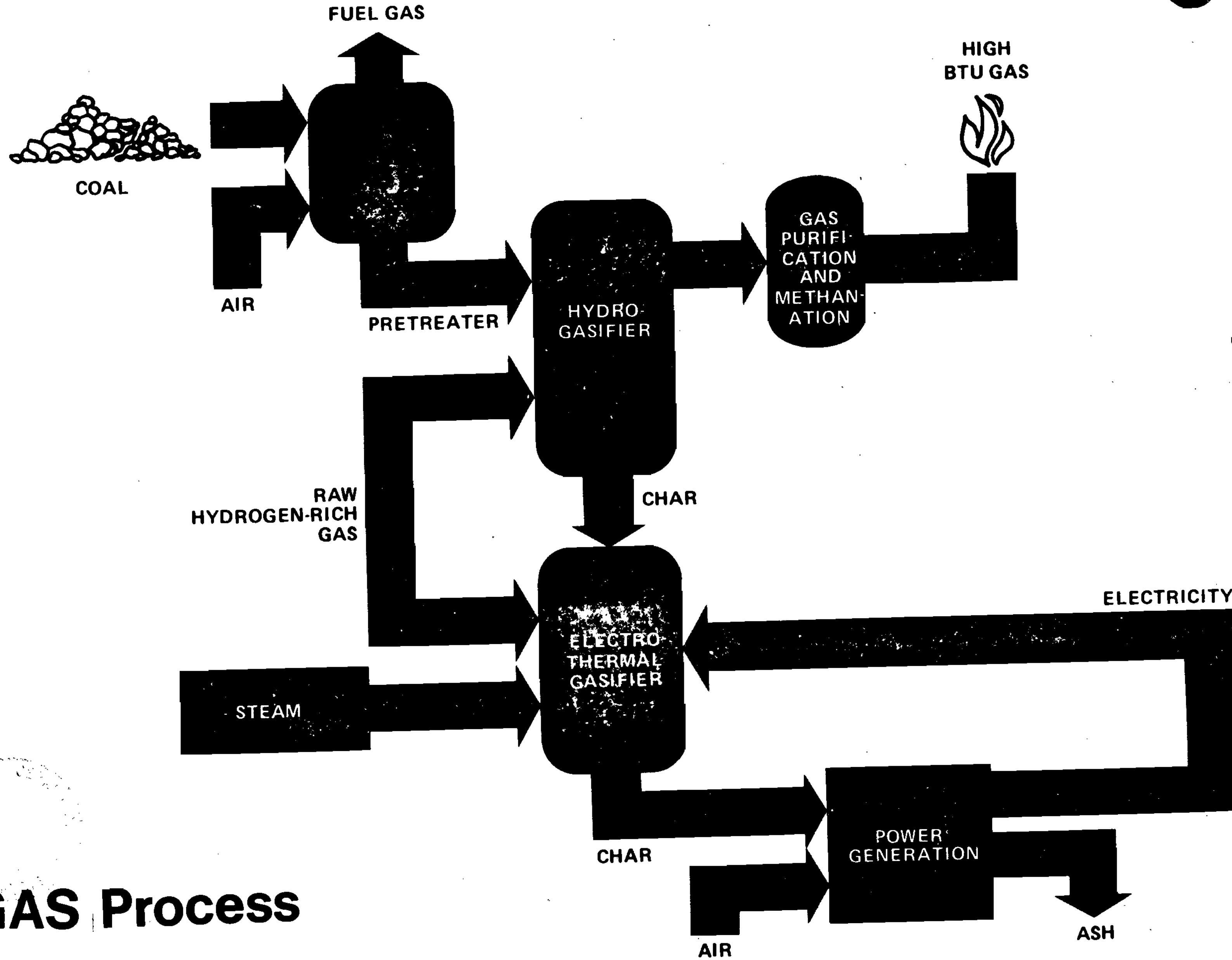
- Developed by the Institute of Gas Technology

- Co-sponsored by the Office of Coal Research and the American Gas Association

- Pilot plant located in Chicago

- Plant construction cost--$10 million

Figure 1



HYGAS Process

Source: Interior (2)

- Uses 75 tons per day of coal (can use all types of coal from low rank lignite to higher bituminous grades).
- Produces 1.5 million cubic feet per day of high-Btu gas (900-1000 Btu's)
- Most advanced of coal-to-high-Btu gas schemes under development.

The Process:

- o Coal is passed through a series of steps which put it under high pressure and intense heat.
- o Raw coal is crushed into tiny (minus 8 mesh size) particles about the size of table salt -- all moisture is removed.
- o To eliminate the tendency of some coals to become sticky at high temperatures, air heated to about 800° F is blown through the coal particles -- the particles are then combined with light oil to produce a mud-like, or slurry, mixture.
- o The coal is then fed into the gasification reactor, which puts the mixture under 1000 to 1500 pounds per square inch of pressure.
- o As slurry is injected into top of the 135-foot-high reactor, it drops downward, is subjected to heat, pressure, and exposed to hydrogen -- a chemical reaction which produces methane (the major component of natural gas) occurs.
- o Newly produced gas rises in reactor as coal falls -- when it reaches top, its temperature is about 600° F.
- o The gas is cooled and passed through a purification solution -- at this point, two-thirds of the methane in the final product gas has been produced.
- o In the methanation stage, essentially all of carbon monoxide and most of hydrogen react in contact with a catalyst to form steam and methane.

o Steam is cooled and removed, leaving product gas with heating value of 950+ Btu's.

o The gas is delivered at pipeline pressure.

CO_2 Acceptor Process (see Figure 2)

- Developed by Consolidation Coal Company
- Co-sponsored by Office of Coal Research and American Gas Association
- Pilot Plant located in Rapid City, South Dakota
- Plant construction cost -- $9.3 million
- Uses 1.5 tons of lignite per hour, 40 tons per day
- Uses 3 tons of dolomite per day
- Produces 2 million standard cubic feet of synthesis gas per day of 375 Btu's per standard cubic foot gas -- methanation step to be added to produce high-Btu gas.

The Process

o Lignite coal is ground, dried, and fed into gasifier where, under pressure of 150 to 300 psi, it is heated in presence of steam to a temperature of 1500° F.

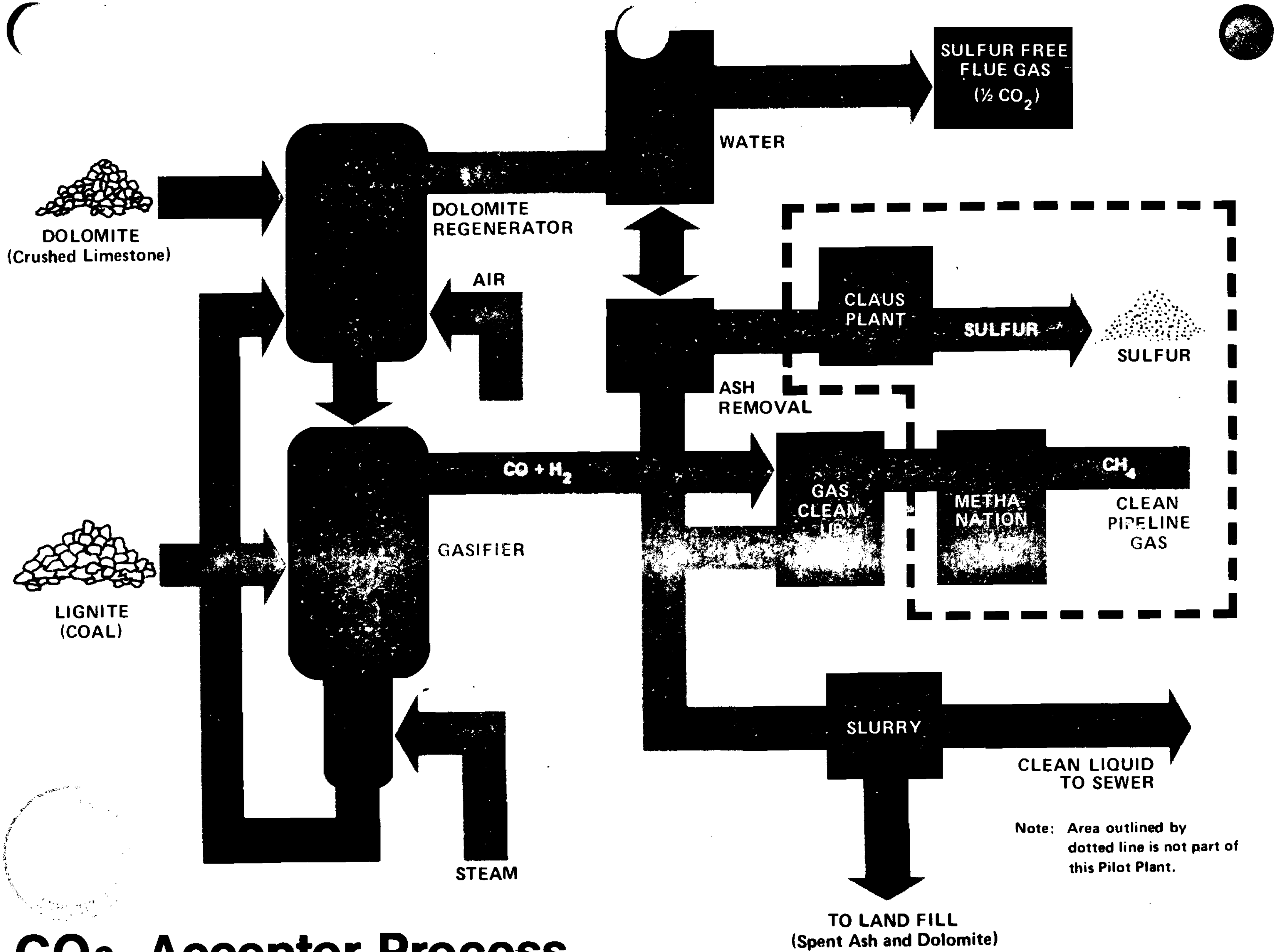
o Dolomite (crushed limestone), preheated to 1900° F in the regenerator, is fed into top of gasifier.

o Limestone particles filter down through the gasifier furnishing heat because of its high temperature and by a unique chemical reaction in which the dolomite absorbs carbon dioxide.

o Spent dolomite and carbon residue are circulated to regenerator where dolomite is regenerated using heat from burning of carbon.

o Gases released by heat and chemical reaction in gasifier contain all components necessary for pipeline gas.

o Gases are cooled and cleaned; sulfur, ash, liquids, and solids are removed to prevent air and water pollution.



CO_2 Acceptor Process

Source: Interior (2)

Figure 2

o Methanation is final step in process

BI-GAS Process (see Figure 3)

- Developed by Bituminous Coal Research, Inc.
- Co-sponsored by Office of Coal Research and American Gas Association
- Pilot Plant located in Homer City, Pennsylvania
- Plant construction cost estimated at $26 million
- Uses 5 tons of coal per hour
- Produces 2.4 million cubic feet per day of high-Btu gas

The Process

o Coal and steam are fed into upper portion (Stage 2) of gasifier and oxygen and steam are fed with char into lower portion (Stage 1).

o Volatile portion of coal is converted to methane-rich gas by reaction with hot synthesis gas coming from Stage 1.

o Gasifier operates at 1000 to 1500 psi pressure at 3000° F in Stage 1 and 1700° F in Stage 2.

o Hot Synthesis gas results from gasification of char with oxygen and steam.

o Ash from coal flows down walls of gasifier and is withdrawn at bottom as slag.

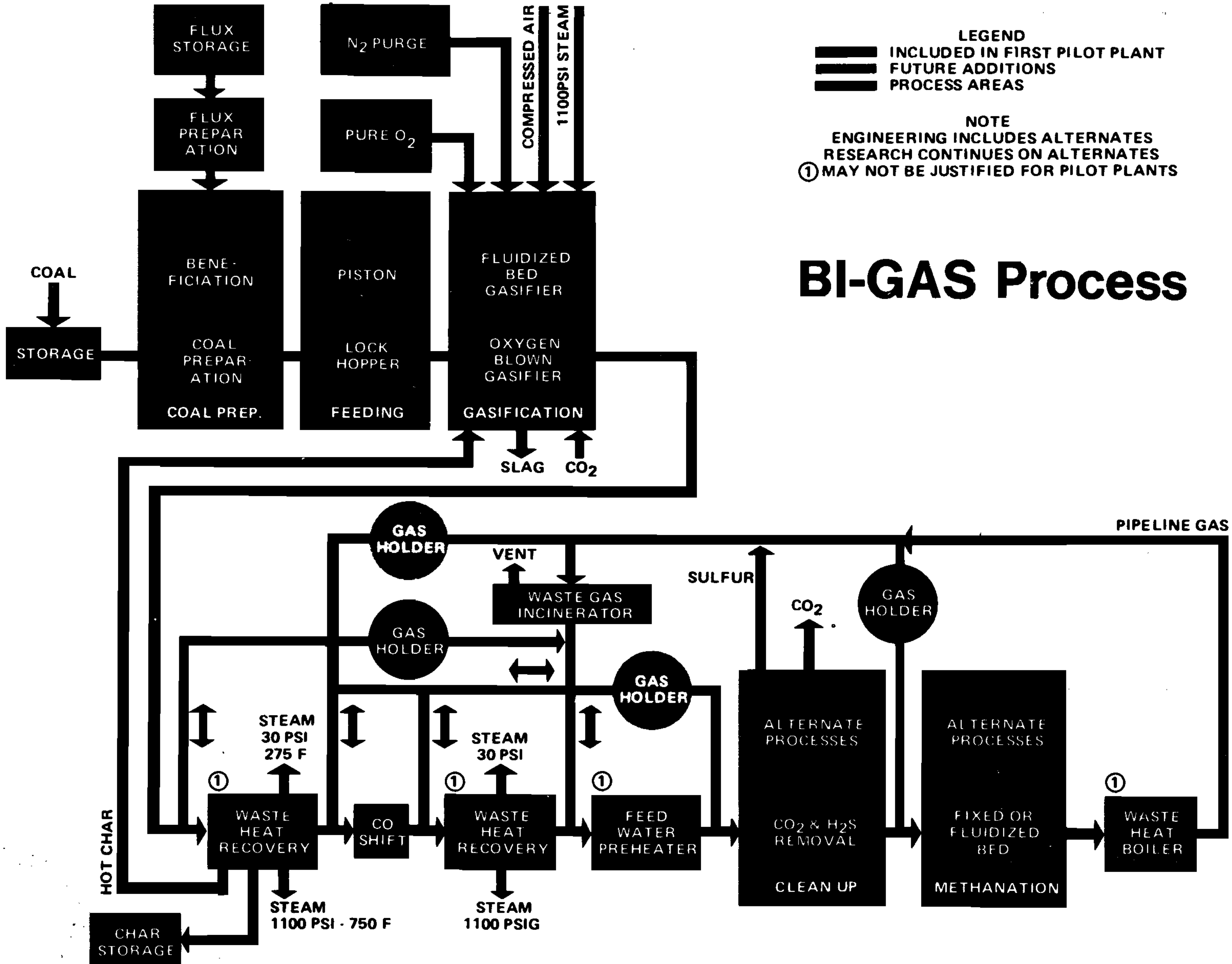
o Raw product gas withdrawn from top of gasifier passes through cyclone which separates char for return to gasifier.

o Remaining uncleaned gas moves downstream for processing.

o To produce hydrogen necessary for process, carbon monoxide shift converter releases hydrogen by reacting steam with carbon monoxide and puts gas in form suitable for use in methanation step later in process.

Figure 3

BI-GAS Process



Source: Interior (2)

- o In acid gas scrubber, materials not useful in production of pipeline gas are separated from desirable combustible gases.
- o Clean gas that emerges from gas cleaning step does not have desired heating value -- methanation step converts carbon monoxide and hydrogen in gas stream into more methane -- this methane, with that formed originally in gasifier, gives final gas stream of 900+ Btu's per cubic heating value.
- o Final product is completely interchangeable with natural gas.

Advantages of the BI-GAS Process

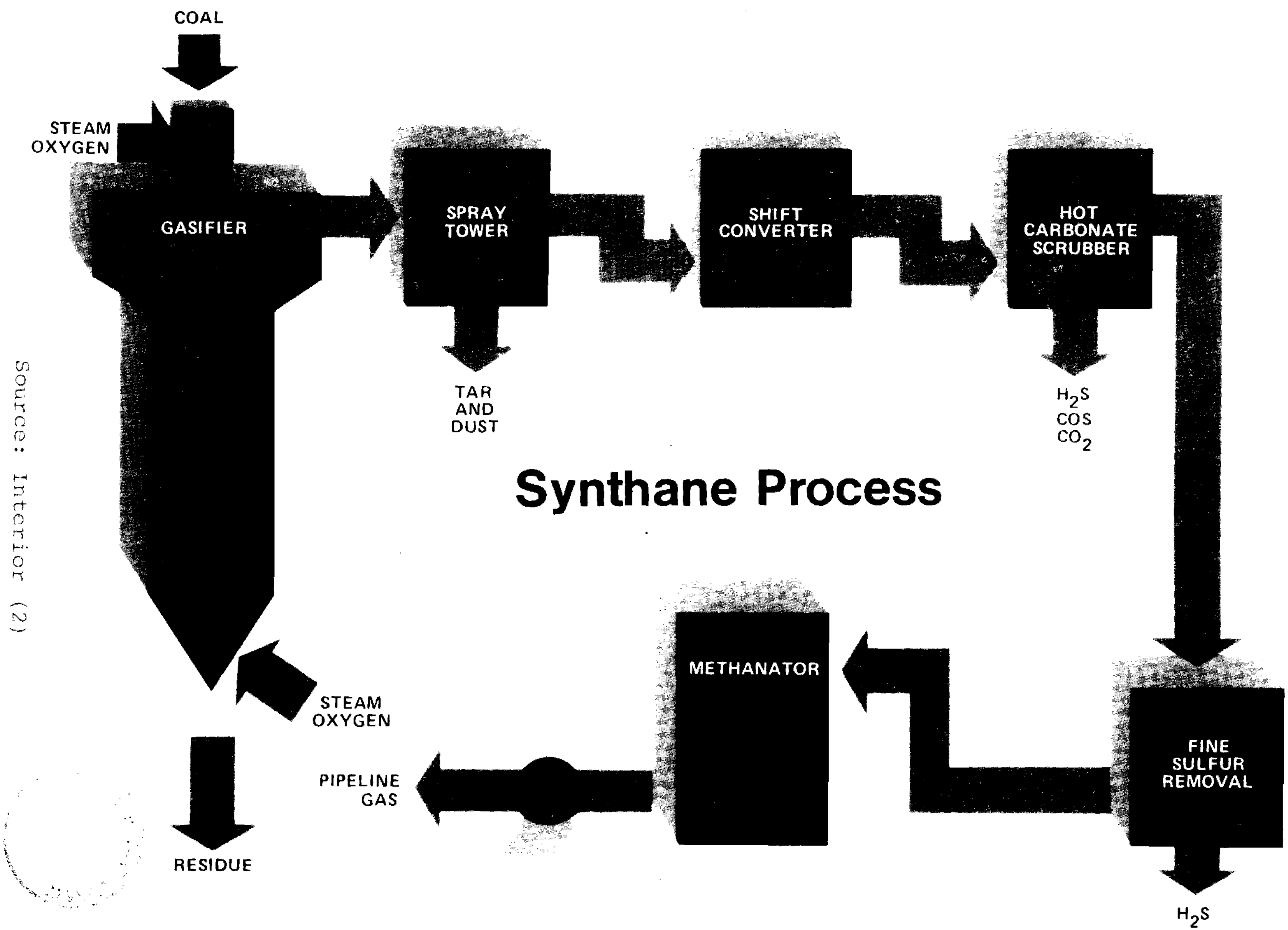
1. Two-stage gasifier is relatively simple in design and can be scaled-up readily.
2. High initial yield of methane is obtained from coal and subsequent gas processing is minimized.
3. All types of coal can be used without pretreatment.
4. All gas-making materials in the coal are used.
5. BI-GAS can be directly transported in existing gas distribution system with no compression costs because it is developed at high pressures.

<u>Synthane Process</u> (see Figure 4)

- Developed by Bureau of Mines.
- Sponsored by Bureau of Mines.
- Pilot Plant located in Bruceton, Pennsylvania.
- Cost of plant construction $12 million.
- Uses 3 tons of coal per hour, 75 tons per day.

Figure 4

Synthane Process



Source: Interior (2)

- Produces 100,000 standard cubic feet of gasifier gas per hour, 2.4 million standard cubic feet per day.

- Produces 13,000 standard cubic feet of pipeline gas per hour, 300,000 standard cubic feet per day.

The Process:

- o Converts bituminous coal, sub-bituminous coal, and lignite to natural gas substitute (SNG).

- o Involves gasifying coal in fluidized bed -- up to 1000 psi -- to raw gas containing methane, carbon monoxide, hydrogen, carbon dioxide, water vapor, and impurities such as dust, tars, and sulfur compounds.

- o Raw gas purified to mixture of methane, hydrogen, and carbon monoxide, and finally converted catalytically (methanated) to nearly 100 percent methane, or SNG.

- o Features for handling of caking coals and methanating purified gas unique to Synthane process:

  1. Coal is contacted with steam-oxygen mixture at 800°F in fluidized bed pretreater to destroy caking properties of raw coal.

  2. Decaked coal from pretreater enters gasifier at top and mixture of steam and oxygen is introduced at bottom to fluidized bed.

  3. Gasifier operates at pressures as high as 1000 psi and at fluidized bed temperatures up to 1800° F.

  4. Product gas (synthesis gas) leaves overhead, and unconverted coal, or char, is withdrawn at bottom.

  5. Char can be burned to generate all steam required in process.

  6. After removal of tars and solids, gas passes through two conventional processing steps; carbon monoxide shift and acid gas removal.

  7. Product gas goes to methanator for conversion of carbon monoxide and hydrogen to methane, increasing heating value from 500 to 900+ Btu's per cubic foot.

CONVERSION OF COAL TO LOW-BTU GAS (1)&(2)

- Basically, all processes being developed for pipeline-quality gas can be adapted to produce low-Btu gas.

- Two low-Btu pilot plants sponsored by OCR use technology developed for high-Btu gasification processes -- one uses data derived from high-Btu research on fluidized-bed gasifiers; the other will use information based on high-Btu gasification research on entrained-bed gasifiers.

- Both pilot plants will be designed to handle from 25-50 tons of coal per day under pressures ranging from 50-500 psi -- this is about 10 times the capacity of high-Btu gasification pilot plants.

- Each plant will include a low-temperature (less than 100° F) gas cleanup system to remove sulfur and particulates from gas.

- Bureau of Mines is operating a pilot plant converting 18 tons of coal per day to low-Btu gas -- it is a modified fixed-bed system -- the modification consists of a unique stirrer system which has been demonstrated to handle U.S. caking coals and run-of-mine coals.

- Pittsburgh and Midway Coal Mining Co. is working on a conceptual design of 1200-tons-per-day demonstration plant for producing low-Btu gas -- expects to utilize data from other coal gasification projects.

- Bituminous Coal Research pilot plant at Homer City, Pennsylvania, will have built-in design capabilities to produce low-Btu gas by injecting air instead of oxygen, and eliminating carbon dioxide removal and methanation steps - this not only saves on the investment, but improves thermal efficiency thereby reducing gas cost by about 20 percent compared with high-Btu processes.

COAL LIQUEFACTION (1)&(2)

- State-of-the-art in coal liquefaction in United States is not as well developed as coal gasification.

- Fully integrated pilot plant and/or large size demonstration plant must be built before technology can be applied on commercial scale.

- Technology should become available in early 1980's.

COED (Char-Oil-Energy-Development) Process (see Figure 5)

- Under development with FMC Corporation, Princeton, New Jersey since 1962 -- has been proven out in pilot plant operated at Princeton for 2 years.

- Most advanced coal-to-clean liquid fuel conversion technique at this time.

- COED involves breaking of high-volatile bituminous (caking or noncaking) coal down into various products through use of heat (pyrolysis).

- Gas that is produced can be used either as intermediate-Btu fuel or further processed to become pipeline gas.

- When coal-derived oil is hydrotreated in presence of catalyst, it becomes premium-grade synthetic crude suitable for petroleum refinery feedstock.

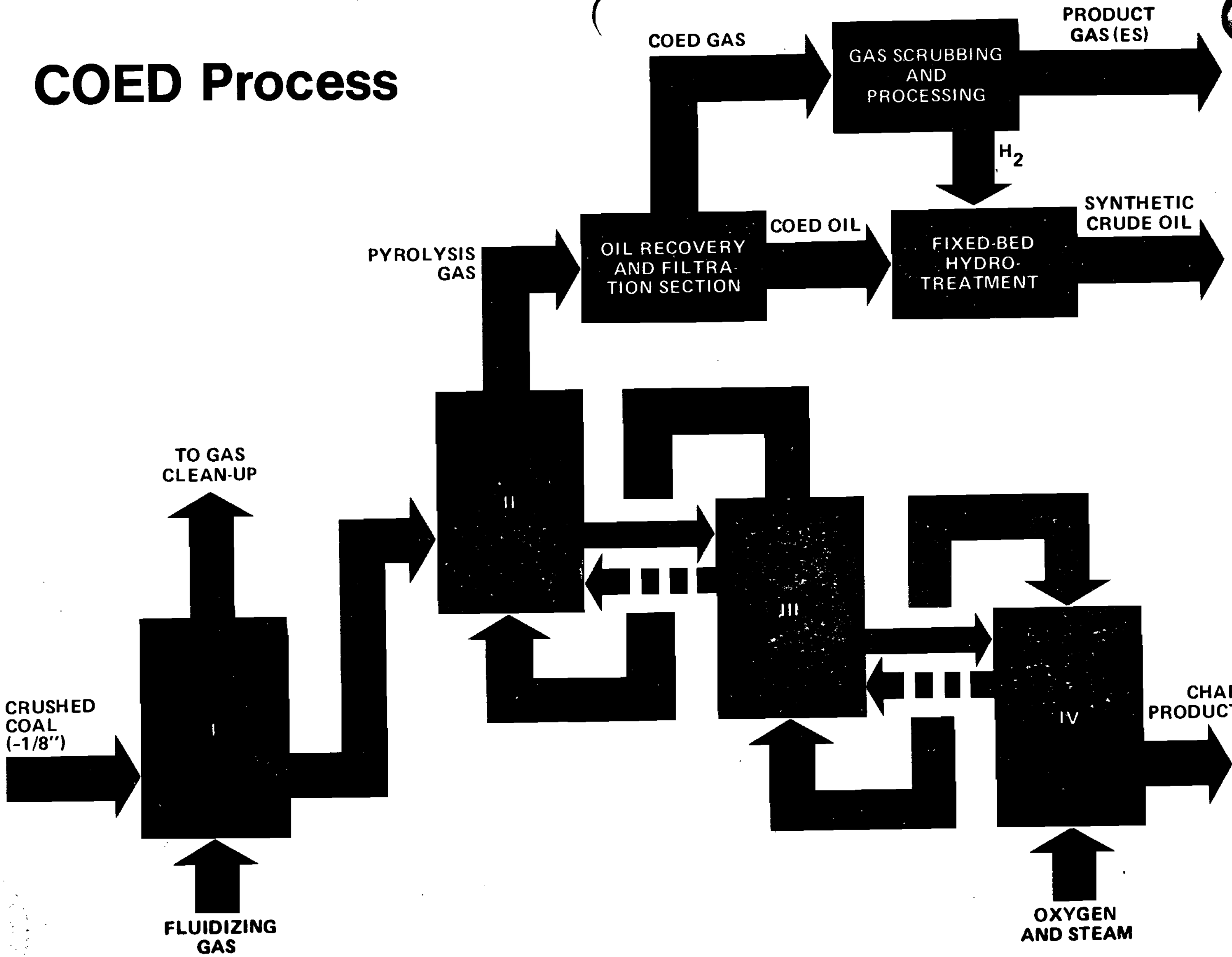
- Char can be used as direct boiler fuel for power generation, or as feedstock for further gasification and additional processing into hydrogen or pipeline gas.

The Process:

  - o Crushed coal placed in fluidized bed where particles are so small that they behave like fluid when placed in rapid, upward-moving stream of air.

  - o Process takes place in several stages, each having carefully controlled temperature (600-650° F, 1st stage; 800-850° F, 2nd stage; 100° F, 3rd stage; 1600° F, 4th stage) to prevent coal particles from softening and massing together into larger chunks of coal.

COED Process



Source: Interior (2)

Figure 5

o New Jersey COED plant is designed to process 36 tons of coal per day and treat 30 barrels of coal-derived oil per day with hydrogen.

o Produces 1.1 barrels of oil per ton of coal; 1000 pounds of char per ton.

o Produces 16,000 cubic feet of gas per ton at 400 Btu's per cubic foot.

Solvent Refined Coal - SRC (see Figure 6)

- Process for converting coal to clean liquids and gases.
- Originated by Pittsburgh and Midway Coal Mining Co.
- Designed by Ralph Parsons Co. under direction of Office of Coal Research.

The Process:

o Raw coal is pulverized and mixed with coal-based solvents to form slurry.

o Temperature of solvent-coal-slurry is raised to approximately 800° F.

o Hydrogen added prior to entering preheaters, and separated with other gases in pressure letdown.

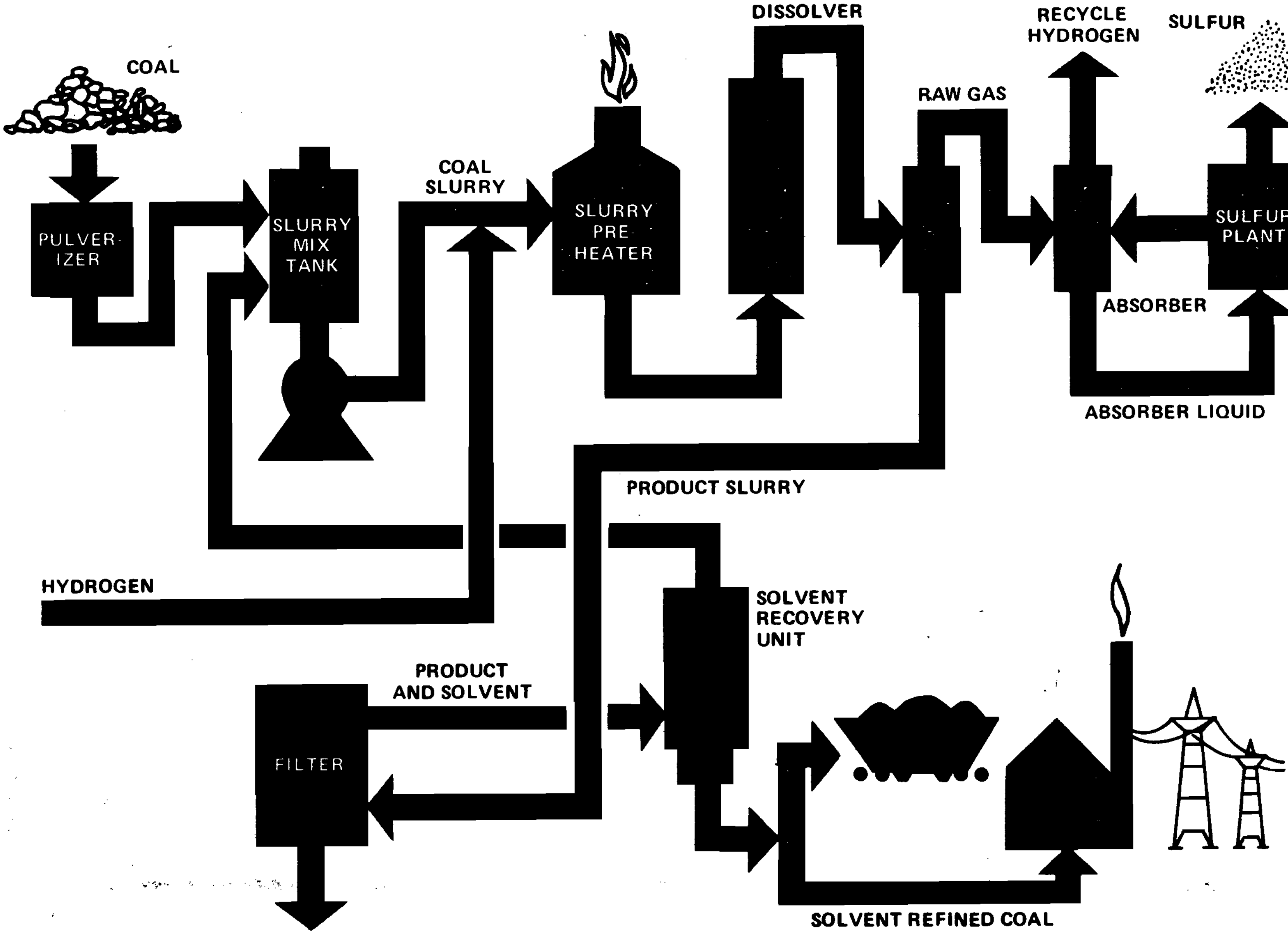
o After pressure is reduced, coal solution is passed through rotary filter -- filtrate is pumped to vacuum flash evaporator to remove solvent for recycling.

o Final product can be maintained in liquid form at an elevated temperature, or may be cooled and formed into prills (small BB-like particles) or lumps of brittle, shiney pitch-like material.

o Final product has melting point of about 350° F and contains less than 0.1 percent ash and less than 0.8 percent sulfur.

o Heating value is about 16,000 Btu per pound regardless of quality of coal feedstock.

SRC Process



Source: Interior (2)

Figure 6

Advantage of Solvent Refined Coal Process

1. Process removes all inorganic sulfur and from 60 to 70 percent of organic sulfur in original coal feedstock.

2. Process can use almost any quality of coal.

3. Solvent Refined Coal can be used in either liquid or solid form, depending on amount of solvent left in final product.

<u>The Fischer-Tropsch Process</u> (4)

- Only liquefaction process that is operating on commercial scale.
- Fischer-Tropsch process was developed in Germany in 1930's -- used to produce motor and aviation fuel in World War II.
- The Sasol plant, located in Republic of South Africa, which uses this process, was built in early 1950's, and is government owned.
- Plant produces about 9000 barrels of oil equivalent per day, 6000 of which are gasoline.

The Process:

- o Gasification is accomplished in Lurgi gasifiers.
- o Synthesis gas which is produced is put through Fischer-Tropsch reactors where liquid and wax products are formed over catalysts.
- o Products produced include:

1. Gasoline
2. Lubricating oil
3. Phenols
4. Aromatics
5. Waxes

COAL-OIL-GAS REFINERY - COG (1)&(2)

- Gasification of coal inevitably produces some "oil" or liquid fuel, liquefaction processes all produce some gas -- COG combines the Solvent Refined Coal process (liquefaction) with the BI-GAS and other processes (gasification).

- Refinery of this type would require total feed of 57,000 tons of coal and 7,740 tons of oxygen per day.

- Would produce about 1,800 tons of sulfur, 7,660 tons of high-Btu pipeline gas, 1,980 tons of liquefied petroleum gas (propane, with heating value more than twice that of methane and butane), 14,660 tons of light refinery liquid fuel (oil), 8,850 tons of Solvent Refined Coal (used to run the refinery), and 2,500 tons of Solvent Refined Coal, which can be sold as fuel to utilities and other industrial facilities now using coal.

- Process will also produce 156 tons of chemicals per day as by-products of refining process.

- About 277 million Btu's are consumed in the refining process and the net efficiency of process is 75.5 percent.

- Estimated investment in COG Refinery - $786 million.

- If COG Refinery proves economically and technically feasible, it could add one trillion cubic feet per year to synthetic gas available, and one-third billion barrels of oil per year to national oil supply, beginning in early 1980's.

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(2) CLEAN ENERGY FROM COAL TECHNOLOGY, 1974, Office of Coal Research, Department of the Interior

(3) SYNTHETIC FUELS FROM COAL TASK FORCE REPORT, Project Independence Report, November 1974, FEA

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IX. NUCLEAR

NUCLEAR

MILESTONES OF NUCLEAR FUEL DEVELOPMENT (1)

1789 Klaproth isolates uranium from pitchblend ores.

1896 Becquerel discovers uranium's radioactivity.

1898 Pierre and Marie Curie discover radium.

1905 Einstein postulates $E=MC^2$, the basis for all nuclear weapons and power plants.

1932 The neutron was discovered by James Chadwick of Great Britain.

1938 Hahn and Strassmann succeed in splitting uranium atom.

1942 First nuclear chain reaction achieved at Chicago.

1945 First succeessful test of atomic device near Alamogordo, New Mexico.

1947 Great uranium rush in U.S. began; boom came in 1951-1958

1951 First significant amount of electricity from atomic energy produced at Idaho reactor testing station.

1954 First nuclear-powered submarine, the Nautilus, commissioned.

1955 First United Nations international conference on peaceful uses of atomic energy held in Geneva, Switzerland.

1957 First full-scale U.S. commercial nuclear plant became operational in December at Shippingport, Pennsylvania.

1957 International Atomic Energy Agency formally established.

1959 First nuclear-powered merchant ship, NS Savannah, launched at Camden, New Jersey.

First nuclear-powered Polaris missile submarine, George Washington, commissioned.

1961 First use of nuclear power in space as radioisotope-operated electric generator is placed in orbit.

USAGE 1975

- Nuclear energy accounts for approximately 2 percent of our total energy sources today. It is expected to increase to 15 percent by 1985 and possibly as much as 25-30 percent by the year 2000.(3)

REACTORS

- A reactor is a device in which a nuclear chain reaction takes place. The reaction is the splitting of the nucleii of the atoms of uranium in the nuclear fuel. Protons and neutrons which make up the center of the nucleus are held together by a tremendous cohesive force. The splitting of this nucleus, otherwise known as fission, is the source of energy produced in a nuclear reactor.(2)

- The five different types of nuclear reactors:(4)

<u>Boiling-Water Reactors</u> - Water boils and is turned to steam by the heat of the nuclear reaction. Steam turns turbine and generates power. Steam then goes through a condenser, is cooled by water from a large source, and returns to reaction chamber as water to repeat process.

<u>Pressurized-Water Reactors</u> - Pressure in reactor chamber prohibits water boiling. Water leaves chamber in pressurized pipes and passes through a heat exchanger also filled with water. Hot pipes cause cold water to boil and generate steam.

<u>Gas-Cooled Reactors</u> - Operating principle is same as pressurized-water reactor, substituting gas (helium or carbon dioxide) for the water in primary heat transfer system. Heat is still transferred from the hot gas to water in the secondary system to produce high temperature steam for driving and turbines.

Heavy-Water Reactors - The hydrogen atoms in heavy water contain a neutron in addition to normal proton. These hydrogen atoms are called deuterium. Heavy water has desirable effects on nuclear reactions. It is used in the primary system to remove the heat from the reactor. Like the pressurized-water reactor, heat is transferred to a secondary system, which is filled with ordinary water; the heat generates the steam to drive the turbines. Heavy-water reactors are operated on natural uranium.

Breeder Reactors - Designed to produce more fissionable material than they consume while providing heat for the generation of electricity. Heat generated in the reactor core is transmitted by fluids or gases to a water-filled system where steam is generated to drive turbines/generators producing electric power. Breeder reactors provide more efficient means of using the energy available in uranium; they minimize the amount of uranium consumed per unit of electricity generated.

Liquid Metal Fast Breeder Reactor - A particular kind of breeder reactor which uses liquid sodium to remove the heat from the reactor and transfer it to the steam generator.

NUCLEAR POWER PLANT LICENSING (6)

- Some of the steps include:

    1. Utility submits application and environmental impact statement to AEC including design, location, safeguards, technical information, and financial qualifications.

    2. Public hearings are held near proposed site. Testimony is heard from the public and AEC representatives.

    3. Atomic Safety and Licensing Board decide for or against permit on basis of hearing findings.

    4. Permit granted or denied and public notice given. Construction subject to inspection by AEC Division of Compliance.

- The above process is facilitated by rigorous requirements for quality control during construction which were introduced by the AEC.

CONSTRUCTION (See Figure 1)

- Nuclear facilities are usually planned 10 years in advance. The lead time generally required to achieve nuclear capacity additions is 8-10 years.(3)

- Time required for construction is 5-7 years.(3)

  - Material shortages, equipment delivery delays, late design information, and financial difficulties of the utilities often contribute to extended construction time. Most of the plants built and ordered are unique designs, although efforts are underway to standardize in the future.

URANIUM RESERVES

- Deposits are scattered throughout the world. The countries with the greatest reserves are: United States, South and South West Africa, Canada, Australia, France, Niger, Gabon.

- The deposits in sandstones and conglomerates account for roughly 70 percent of the world's reserves of uranium (at \$10 per pound U_3O_8) and vein-type deposits for slightly over 20 percent.

- Estimated worldwide reserves of uranium ore at low prices (\$8-10 per lb.) are about 2.3 million tons (excluding the U.S.S.R. and China). This would probably satisfy world needs for uranium for 20 years with present type reactors, or considerably longer if breeder reactors are introduced. (8)

- Known worldwide reserves of high grade ore increased by one-third between 1970 and 1973.

- U.S. principal uranium producing areas: Rocky Mountain States, particularly Wyoming, Utah, Colorado, and New Mexico.

- Domestic Sources of Uranium (10)
(short tons of U_3O_8*)

Maximum Forward Cost/lb. of U_3O_8	Reserves[1]	Est. Add'l Resources	Total
$ 8	277,000	450,000	727,000
15	520,000	1,000,000	1,520,000
30	700,000	1,700,000	2,400,000

1-Reasonably assured Reserves

* A refined form of uranium called "yellow Cake" that is enriched for use as nuclear fuel in U.S. reactors. A large nuclear power plant typically contains from 100 to 150 tons of uranium of low enrichment.

STATUS OF NUCLEAR POWER PLANTS — JAN. 1, 1975

Number Of Units		Rated Capacity (MWe)
* 53	LICENSED TO OPERATE	36,000
** 63	CONSTRUCTION PERMIT GRANTED	63,000
25	Under Operating License Review	25,000
38	Operating License Not Yet Applied For	38,000
74	UNDER CONSTRUCTION PERMIT REVIEW	83,000
**10	Site Work Authorized, Safety Review in Process	10,000
64	Other Units Under CP Review	73,000
29	ORDERED	33,000
14	PUBLICLY ANNOUNCED	17,000
233	TOTAL	232,000

*In addition, there are two operable AEC-owned reactors with a combined capacity of 940 MWe.

**Total of units under construction (Construction Permit Granted plus Site Work Authorized): 73 units, 74,000 MWe.

Figure 1

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X. OIL SHALE

OIL SHALE

BACKGROUND

- Oil shale is a dolomitic marlstone containing a solid hydrocarbon called Kerogen which, after retorting, yields up to 60 gallons of shale oil per ton of rock.
- France was the first country to begin commercial production of liquid fuels from oil shale in 1838. Small scale oil shale industry began in Canada and in the United States in the 1860's, but was terminated after the discovery of oil in Pennsylvania.
- Nearly all the research in mining techniques has been devoted to underground mining. The Bureau of Mines first demonstrated underground mining equipment in 1947.
- Union Oil Company of California opened a mine in 1956 for a retort demonstration. Colony Development Corporation opened a mine in 1965 to demonstrate new mining techniques and equipment as well as supply shale for semi-commercial retort operations.
- Potential development: A shale oil industry, if initiated immediately, could supply 500,000 barrels per day by 1980, and one million barrels per day by 1985. However, under present economic conditions, it appears that such an industry would require a substantial subsidy.

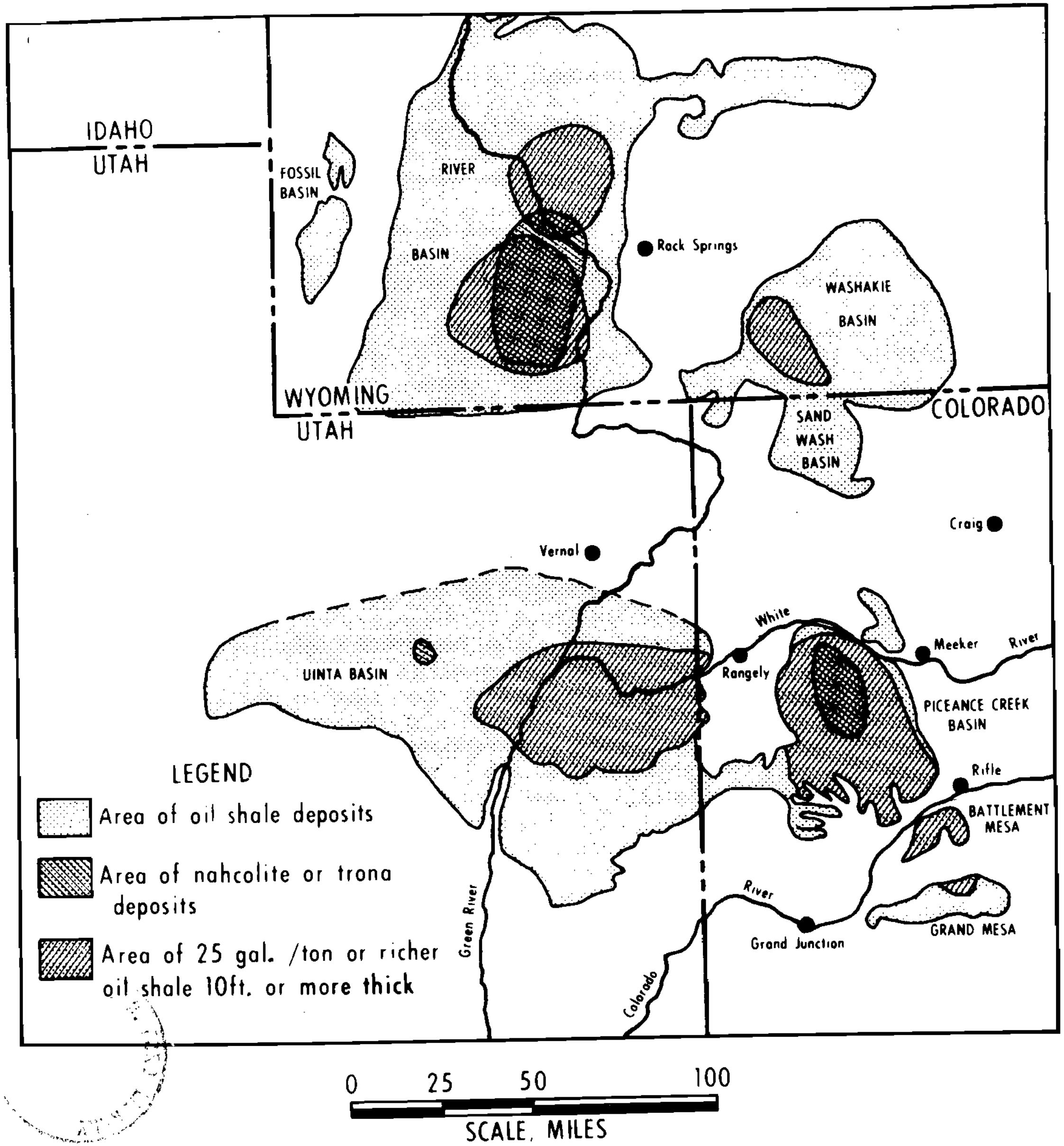
RESOURCES

- Deposits (see figure 1) are located in:

    Colorado - 84 percent of rich formations

Figure 1

Oil Shale Areas in Colorado, Utah, and Wyoming



Source: Task Force Report - Oil Shale (1)

Utah - 10 percent of rich formations
Wyoming - 6 percent of rich formations

- Resources: 1.8 trillion barrels of oil contained in 25,000 square miles.
- Colorado has the smallest geographical area of oil shale deposits, but contains the richest formations. This area is known as the Piceance Basin.
- The geological formation is called the Green River Formation. The richest part of this formation is called the Mahogany Zone, with 85 percent in Colorado.
- Recoverable resources under current technology and economics: 80 billion barrels.
- Amount of total deposits of rich shale: 600 billion barrels.
- Ownership of resources: 80 percent on public lands.
- The Federal Government is the largest owner of oil shale lands with 72 percent of the 11 million acres of possible commercial lands and nearly 80 percent of the oil shale resources.

MINING

- Both surface and underground mining can be used. Most research in techniques has been in underground mining.
- Underground mines are really underground quarries. The mined zone is very thick, and use of the room-and-pillar method of mining is probable.
- Surface mining has not yet been demonstrated, but will be utilized to recover the thick oil shale deposits near the surface. Surface mines will resemble copper pits rather than strip coal mines.

PROCESSING

- Mining followed by surface retorting:
    - o Mined shale is crushed and heated continuously in retorts similar to lime kilns or blast furnaces. The four Federal lease areas all will employ surface retorting.
    - o Commercial development requires a yield of 25-35 gallons or more per ton.
- In situ retorting:
    - o Oil shale would be heated in one place (in situ) by hot fluids injected through wells. Porosity and permeability would be created by oil field fracturing techniques including high explosives.
    - o Another in situ process involves room-and-pillar excavation, surface retorting of excavated material, collapsing the ceiling by explosives, and then in situ retorting of collapsed and fractured shale.
    - o The in situ process is still in an early stage of development.
    - o Initial plants will probably market low-sulfur fuel on long-term contracts to utilities.
    - o Commercial development requires a yield of 15-20 gallons per ton.

LEASING

- On June 29, 1971, Department of Interior announced plans for an oil shale leasing program.
- Six Federal tracts of 5,120 acres each were offered for lease in early 1974.
- Two tracts in Colorado (C-a and C-b) and two in Utah (U-a and U-b) were leased. No bids were received on the Wyoming tracts.
- C-a will be developed as a surface mine.
- C-b will be an underground mine which will require

de-watering of the mine both before and during the operation.

- Both mines in Utah will be underground mines, but will not require de-watering.
- The two tracts in Wyoming will use the in situ process.
- The Lessee is given 3 years to present a detailed development plan, and is required to get Federal approval for resource development and environmental protection methods before proceeding with development. The plan must include 30 stratigraphic tests and a 2-year inventory of the immediate environment.

STATUS OF INDUSTRY (December 1974)

- Existing Test Facilities:
  - o Parahoe - U.S. Bureau of Mines Anvil Points Experiment Station under lease to consortium organized by Development Engineering, Inc.
  - o Garrett Research Development (Occidental Petroleum) - in situ.
  - o Tosco Rocky Flats Laboratory
- Companies with plans for commercial development:
  - o Union Oil Company
  - o Colony Development Corporation: Atlantic-Richfield Corp., Ashland Shell, and Tosco (plans for a large project are in abeyance)
  - o Superior Oil Company
  - o Amoco Production Co. and Gulf Oil Corporation

ENVIRONMENTAL PROBLEMS

- Air quality standards are a constraint to oil shale development. Newly established air quality standards in Colorado limit the emissions of sulfur dioxide to 10 micrograms per cubic meter. This could limit oil shale production to 200,000 barrels per day.

- Water resources are adequate for an accelerated oil shale program but the problem lies with the right to this water.

- Estimates of requirements for process and cooling water vary over a wide range, but will, even at lowest requirement, be substantial in semi-arid region.

- Steps which may be taken to alleviate water shortage problems:

  1. Augmentation of supply

  2. Change in water use

  3. Develop less water intensive technologies

- Water quality would decline as a result of long-term industrialization. According to the Project Independence Report, one million barrels per day would create 1.7 million tons per day of solid waste which would increase the salinity of the water by one percent.

- Lower aquifer pressure and water levels will also result from oil shale production. This will have an adverse affect on wildlife, irregations, vegetation and organic materials.

- The extent of the social impact of oil shale development will depend on the planning of the community as well as state and Federal officials to handle employment, land use, population, housing, roads, schools, etc.

- Extremely rapid growth presents serious social and economic problems in the States involved.

- Recreation, wildlife, and living patterns may be affected greatly in some areas.

SOURCES

(1) OIL SHALE TASK FORCE REPORT, Project Independence Report, November 1974, FEA

(2) SYNTHETIC FUELS DIVISION, Office of Energy Resources Development, FEA