MASTER

An Analysis of Petroleum Company Investments in Non-Petroleum Energy Sources

Book I

October 1979

Prepared for:
U.S. Department of Energy
Energy Information Administration
Assistant Administrator For Applied Analysis
Under Contract No. CR-03-70041-00
(Mod. No. EC-77-C-01-8556)

DISCLAIMER

This report was prepared as an account of work sponsored by an agency of the United States Government. Neither the United States Government nor any agency Thereof, nor any of their employees, makes any warranty, express or implied, or assumes any legal liability or responsibility for the accuracy, completeness, or usefulness of any information, apparatus, product, or process disclosed, or represents that its use would not infringe privately owned rights. Reference herein to any specific commercial product, process, or service by trade name, trademark, manufacturer, or otherwise does not necessarily constitute or imply its endorsement, recommendation, or favoring by the United States Government or any agency thereof. The views and opinions of authors expressed herein do not necessarily state or reflect those of the United States Government or any agency thereof.

DISCLAIMER

Portions of this document may be illegible in electronic image products. Images are produced from the best available original document.

Available from:

National Technical Information Service (NTIS)
U.S. Department of Commerce
5285 Port Royal Road
Springfield, VA 22161

Price:

Printed Copy: \$9.25

Microfiche: \$3.00

For sale by the Superintendent of Documents, U.S. Government Printing Office
Washington, D.C. 20402

Stock Number 061-003-00071-1

An Analysis of Petroleum Company Investments in Non-Petroleum Energy Sources

Book I

October 1979

DISCLAIMER

This book was prepared as an account of work sponsored by an agency of the United States Government. Neither the United States Government nor any agency thereof, nor any of their employees, makes any warranty, express or implied, or assumes any legal liability or responsibility for the accuracy, completeness, or usefulness of any information, apparatus, product, or process disclosed, or represents that its use would not infringe privately owned rights. Reference herein to any specific commercial product, process, or service by trade name, trademark, manufacturer, or otherwise, does not necessarily constitute or imply its endorsement, recommendation, or favoring by the United States Government or any agency thereof. The views and opinions of authors expressed herein do not necessarily state or reflect those of the United States Government or any agency thereof.

Prepared by:
Paul Ryan, Jr., Thomas C. Ryan
Under Contract No. CR-03-70041-00
(Mod. No. EC-77-C-01-8556) ✓

✓ 951 0393

Prepared for:
U.S. Department of Energy
Energy Information Administration
Assistant Administrator For Applied Analysis
Office of Economic Analysis
Washington, D.C. 20461

DISTRIBUTION OF THIS DOCUMENT IS UNLIMITED *EB*

This report was prepared under Department of Energy (DOE) Contract Number CR-03-70041-00 and does not necessarily state or reflect the views, opinions, or policies of the DOE or the Federal Government. References to trade names or specific commercial products, commodities, or services in this report do not represent or constitute an endorsement, recommendation, or favoring by DOE of the specific commercial product, commodity, or service.

Released for printing: December 12, 1979 ✓

The purpose of this report is to analyze the investment strategies of U.S. oil companies and the depth of their present and future investments in non-petroleum energy sources. For purposes of this study, the non-petroleum energy sources to be discussed are coal, uranium/nuclear, synthetics from coal, oil shale, geothermal, and solar.

To gather necessary subjective data, the authors interviewed the managements of more than forty companies, the majority of which are directly involved in the production of various forms of energy. Others are substantial energy users. Interviews were also held with various federal and state regulatory agencies, with federal legislative groups, and with representatives of industry associations. These interviews were not intended to be a survey; their purpose was rather to explore the perceptions of petroleum company managements concerning non-petroleum energy sources and the reasons for their company's participation, or lack of participation, in the development of these resources. Quantitative data came from reports prepared by federal investigative and regulatory agencies, from testimony given before investigative and regulatory bodies, from public company reports (annual reports, quarterly reports, 10-K's, 8-K's, registration statements, press releases, etc.), from industry, research and investment organizations, from universities, and from a variety of publications.

The report is divided into two primary sections:

- a) The first section has a chapter devoted to each of the six non-petroleum energy sources. Each chapter contains:
 - 1) a summary of interviews held with the managements of oil companies, coal companies, electric utilities, and "others",
 - 2) a description of each energy source and its current and projected supply and demand characteristics, and,
 - 3) a listing, and discussion, of current developers, with particular emphasis on individual oil companies and their participation. Each chapter is designed as a self-sufficient unit.
- b) The second section contains supplementary financial and operating data for non-petroleum energy industries and for specific petroleum and non-petroleum companies.

The authors wish to thank all of those who participated in this study. The authors also retain all responsibility for any errors in judgment or fact.

Table of Contents

Chapter I - Summary	3 - 12
Chapter II - Coal	13 - 65
Chapter III - Uranium/Nuclear	66 - 126
Chapter IV - Synthetic Fuels from Coal	127 - 145
Chapter V - Oil Shale	146 - 160
Chapter VI - Geothermal	161 - 174
Chapter VII - Solar	175 - 183

Appendices

Chapter I - Summary

There are, among oil companies, varying degrees of diversification into non-petroleum energy sources. Exhibit I-1 summarizes oil company non-petroleum energy investments based on data available in December, 1977. As these indicate, only one company (Gulf Oil Corp.), is active in all of the six non-petroleum energy fields. Seven of the thirty largest oil companies, on the other hand, have no investments in non-petroleum energy sources. Between these extremes are grouped the other twenty-two largest petroleum companies. In spite of these diverse investment patterns, almost all spend more than they make; 29 of the 30 largest firms had, in 1976, "Capital Expenditures" that exceeded "Funds from Operations (Less Dividends)". The exception was Clark Oil who took in \$22 million and spent \$15 million (See Appendix A, p. 1). Comparative financial data for other companies and industries is also included in Appendix A.

Chapter II - Coal

The coal resources of the U.S. are vast, with some 437 billion tons of Demonstrated Reserves (see Exhibit II-1). An assumed 50% recovery factor would give a total recoverable reserve base of 218 billion tons, a 180 year supply of steam coal at the DOE estimated 1985 consumption rate of 1.2 billion tons per year, a rate that is almost twice the rate of 1976 production. Coal reserves, however, are not an easily definable resource; much of the government and corporate data on reserves is incompatible. Based on government, industry and company data concerning

reserves, past production, current development and pending federal leases contained in Exhibit II-2 and Appendix F-6 through F-10, it is difficult, if not impossible to make definitive conclusions on any overall effects of reserve ownership patterns on development of coal resources.

U. S. coal is currently mined by some 4000 coal mining companies, who, in 1976, produced 665 million tons of coal, some 50 million to 100 million tons below estimated production capacity. A substantial number of petroleum companies are active in the development of U.S. coal resources (See Exhibits II-2 through II-7 and Appendix F-1 through F-11). Oil and gas companies have announced plans for steam coal additions, between 1977 and 1985, of 216 million annual tons of production, an amount equal to 37% of total announced additions to capacity and 53% of non-captive (ie, coal available for sale, not used for fuel by the producing utility or steel company) steam coal additions (see Exhibit II-3). By 1985, oil and gas companies are projected to have almost 400 million tons of coal capacity, 32% of total U.S. capacity. Other industries expected to have substantial coal productive capacity in 1985 are electric utilities (18%), metals mining companies (18%) and independent coal companies (13%).

Not all companies perceive coal as an attractive investment opportunity; a number of those companies interviewed for this study cited its capital intensive nature, its historically low levels of profitability, their general discomfort with uncertain coal demand, environmental and regulatory problems, long lead

times, and distinctive contracting terms.

In spite of these negative perceptions, some companies (most of them oil companies) think that the return on investment in steam coal is sufficiently high to make significant investments. Appendix F-2a through F-2h lists, by industry, those companies expected to produce 3 million or more tons of coal in 1985.

Chapter III - Uranium/Nuclear

Like coal, the demand for nuclear power is expected to grow. At the end of 1976, there were 64 nuclear powered electric generating plants in the U.S. The National Energy Plan (NEP) calls for the construction of an additional 75 nuclear plants by 1985. Exhibit II-1 shows DOE estimates of future requirements of U₃O₈ (.15% tails) increasing from 10,000 short tons in 1977 to 27,000 short tons in 1985.

The boom/bust nature of the uranium industry (see Exhibit III-2 and III-3) has tended to inhibit the number of participants in the uranium industry. Currently, oil companies are by far the largest factor in uranium concentrate produced in 1976 (see Exhibit III-7). It appears likely, too, that oil companies will be a substantial factor in the development of additional uranium productive capacity.

Milling capacity expansion is summarized by company in Exhibit III-8 and by industry in Exhibit III-9. Capacity is currently being more than doubled; oil companies are developing 68% of this expansion. Two other industries, independent uranium and metals mining, are expected to build 13% and 16% respectively, of the projected uranium

milling expansion.

Like coal reserves, "uranium reserves" tends to be a somewhat amorphous term. "Reserves" are considered to be the amount of uranium that can be recovered with existing technology at an assumed price. Changes in technology or price will change the amount of reserves.

There is no difficulty in acquiring uranium leases, particularly federal leases. Currently, only one area, in New Mexico, is subject to competitive bidding for Federal uranium mineral rights. Federal leases are obtained by staking claims with the Bureau of Land Management. Procedures for acquiring leases on private, state or Indian lands vary, but entry is open to any interested party.

Developing the leases, however, is difficult. Capital costs for the mining and milling of uranium have risen sharply; uranium producers indicate capital costs for mines producing 1000 tons/day at a depth of 1000 feet have increased from \$50 per annual ton in the early 1970's to \$150/ton in 1977. At a depth of 2000 feet, this same mine would cost about \$300 per annual ton of mine capacity. Thus, it could cost as much as \$220 million to build the mining capacity to feed a 2000 ton per day mill.

Construction costs of new milling capacity have risen from \$4-5000 per daily ton in the early 1970's to \$12-15,000 in 1977.

Because of these high costs, uncertain demand, and long lead times (see Exhibit III-12 and III-13), the levels of corporate investment in uranium/nuclear vary considerably.

Chapter IV - Synthetic Fuels from Coal

Unlike coal and uranium, there is not yet an economically viable, proven manner to manufacture synthetic fuels from coal. Although the German military was fueled by synthetics from coal in World War II, coal gasification is only now approaching commercial feasibility in the U.S. The estimated current costs of coal liquefaction (\$20-\$25 per barrel) still substantially exceed the current price of conventional crude oil.

In spite of current cost disadvantages, synfuels from coal have the advantage of potential use in existing facilities without the need for extensive, and expensive, modifications by users/consumers. In addition, existing crude, product, and natural gas pipelines can be used to transport synfuels easily and cheaply.

As Exhibit IV-1 indicates, oil companies, chemical companies, process engineering companies, and gas utilities are well represented on the list of participants in synthetic fuels from coal, probably because these R & D efforts parallel their natural interest in the primary fuels these synthetics are designed to complement.

Capital requirements to produce synfuels are large. In 1976 dollars, high BTU synthetic gas plants were estimated, by companies interviewed, at \$1 billion for an economically sized plant of 250 M mef/day, while liquefaction plant costs were estimated at \$2 billion for a 100,000 barrel/day plant. With a current lack of

profitability, and with the knowledge that the development of syn-fuels will require considerably more capital than equivalent production of conventional oil and gas, almost all investment in syn-fuels from coal is at least partially financed by the Federal government.

Chapter V - Oil Shale

Oil shale reserves in the U.S. are huge, with recoverable reserves estimated at 610 billion barrels. Like synthetic fuels from coal, there is not at this time, however, an economically viable, proven process to extract oil from shale. (There was an apparently profitable oil shale mining operation in Scotland from 1872 until at least 1908). As a consequence, oil shale in the U.S. is currently a "non-industry" with expenses, but no revenues. All present efforts are on an R & D basis, with the expectation of profitability sometime in the future.

Also like synfuels from coal, oil shale is a direct substitute for conventional crude oil and can be used without the need for costly replacements or conversions. Because of this and because of a long history with oil shale, 21 of the 24 companies shown as participants in oil shale development (see Exhibit V-1) are oil companies.

Capital requirements are high; estimates of surface retorting costs by companies interviewed ranged from \$15,000 - \$25,000 per daily barrel, or \$15 - \$25 billion for 1 million barrels per

day of production. (For reference, a new petroleum refinery would cost about \$3,500 per daily barrel). Other processes currently being tested, (a modified in-situ process by Occidental, a multi-mineral process by Superior) may reduce costs substantially; nevertheless, cash outlays for an in-situ operating oil shale facility will, in the opinion of one participant, be in the range of \$500 million to \$1 billion.

Chapter IV - Geothermal

Although geothermal resources are thought to be very large, the hydrothermal system (hot water and steam) is the only one of five defined types of geothermal energy presently in use in the U.S. Economics of all types of geothermal energy are adversely effected by long lead times for specialized plants and by technical problems.

In general, geothermal resources are a very low grade source of heat; only a small fraction of the resource base is in the form of steam. As a consequence, kilowatt costs by utilities (the primary market for geothermal energy) are high, particularly in comparison with costs for oil, gas, coal, or nuclear. (The Geysers, a dry steam source in California, is an exception).

Exhibit VI-1 lists the geothermal energy participants and their type of participation in geothermal operations. As these data indicate, there are many holders of federal leases, most of them private individuals. Most of the companies represented are oil-

oriented, largely because of the similarities between geothermal and petroleum exploration and drilling.

Although geothermal wells cost more than oil or gas wells, capital requirements during the exploration and production phase are relatively modest. Development and capital costs for a generating facility, however, are large. This, coupled with the fact that the Geysers is currently the only commercial geothermal operation in the U.S., has inhibited the growth of geothermal-produced electrical energy.

Chapter VII - Solar Energy

Solar energy dwarfs all other known energy resources. About .15% of the energy falling on the U.S. could, if harnessed and converted at a 10% efficiency rate, supply all present U.S. electrical needs. Costs of harnessing this "free" energy source, however, have been substantially above the costs of oil, gas, coal, or nuclear. Because of this, large scale development of solar energy has not taken place. It is the goal of current solar energy R & D to reduce current high costs by solving significant technical problems encountered in the collection, concentration, and storage of solar energy.

Solar energy development has two main branches:

- 1) Solar heating and cooling and,
- 2) generation of electric power.

Solar heating and cooling is a fledgling commercial industry

with hundreds of participants, mostly smaller companies. There is virtually no oil company participation in this segment of the business. Generation of electric power, on the other hand, is a "non-industry", with expenses but no revenues. It is expected, however, that this second branch will ultimately be the larger of the two. Exhibit VII-1 lists larger companies (four of which are oil companies) active in the development of electric power from solar energy. Because of the highly technical nature of much of the current research, other large, more scientifically-oriented firms (IBM, Eastman Kodak, Texas Instruments, General Electric) are heavily involved in the conversion of sunlight to electricity.

THIS PAGE
WAS INTENTIONALLY
LEFT BLANK

Chapter II - Coal

A. Summary of Interviews	14 - 18
B. Coal Requirements	19 - 26
C. Petroleum and Other Industry Participants in Future Coal Expansion	26 - 36
D. Potential New Entrants Into Coal	36 - 39
E. Financing Coal Development	39 - 46
F. Return on Investment in Coal	46 - 48
Exhibit II-1 to II-7	49 - 63

Chapter II - Coal

A. Summary of Interviews

Numerical data contained in this report came almost totally from public sources. Corporate views and perceptions, (subjective data) of the past, the present, and the future of coal were gathered in face-to-face interviews with the managements of sixteen large oil companies, two coal companies, five electric utilities, and five "others" (a railroad, a bank active in energy loans, two large extractive mineral companies, and a conglomerate energy company). Telephone conversations were held with individuals at an additional 22 firms and/or organizations.

The individuals interviewed were in senior management positions and, as such, could intelligently discuss and influence the company's policies and current view of petroleum and non-petroleum energy. In some cases multiple interviews were conducted at a company, one person at a time. In other cases, as many as six people from the company (for example, Vice President of Finance, Comptroller, Manager of Planning, Vice President of Minerals, Vice President of Crude Oil Production, and Assistant to the President) participated in the discussion.

It should be stressed that the views expressed by corporate managements were based on economic conditions as perceived at the time of the interviews. Their views will change as economic conditions change.

These interviews were largely unstructured because:

- 1) a formal survey was beyond the scope of the study.
- 2) we wished to avoid forced responses generated by a

EXHIBIT 1-1
SUMMARY OF OPERATIONS
LARGER PETROLEUM COMPANIES - December, 1977

COMPANY	CRUDE OIL (1976)			COAL			URANIUM			OIL SHALE		SYNFUELS FROM COAL		GEO THERMAL	SOLAR
	Foreign Crude Prod. (MB/D) *	Dom. Crude Prod. (MB/D)	Dom. Ref. Capacity (MD/D)	1976 Production Mill. Tons	Reserves Billion Tons*	1977-1985 Expansion (MMT/Y)	1985 Capacity (MMT/Y)	1976 Prod. MM lbs.	1976 Mill Capacity Tons/day	Current Activity	Current Development	Reserves	Current Activity	Current Development	Current Development
Exxon	4,337	812	1,259	2.8	8.4	30	33	1.5	2,000	Mine, mill expan.	-	Pvt.	Liquefaction Pilot Plant	-	Photovoltaic
Texaco	3,249	611	1,098	-	2.0	-	-	-	-	Exploration	-	Pvt.	Liq. Plant, Germany; Gasification	-	-
3. Mobil	1,781	323	896	-	3.0	7	7	-	-	Solution Mining	-	Pvt.	H-Coal Liquefaction	Exploration	Photovoltaic
4. Socal	3,122	370	1,454	-	-	-	-	-	-	Mine, mill	-	Pvt.	-	Imperial Val.	-
" Gulf	1,392	338	885	7.9	0.8	14	22	-	-	2 mines, mill	In situ	Fed.	Liquefaction Demonstration Plant	Exploration	Thermal Elec.
Std. Indiana	389	532	1,129	-	-	-	-	-	-	-	In situ	Fed.	H-Coal Liquefaction	-	-
Shell	(C)	535	1,154	3.0	2.3	21	21	-	-	-	-	Pvt.	-	Geysers	Photovoltaic
o. Arco	148	363	772	-	1.0	30	30	4.9	2,500	Mill expan.	-	Pvt.	-	-	-
9. Conoco	275	197	373	50.6	13.8	30	90	1.1	1,750	Mill expan.	-	-	H-Coal, High BTU Gasification	-	-
10. Phillips	269	115	323	-	3.0	-	-	-	-	Mine, mill	-	Fed.	-	2 Discoveries	-
Occidental	166	7	-	17.6	3.4	12	32	-	-	Exploration	In situ	Fed.	Liquefaction	Exploration	-
1 Sun	44	203	654	6.0	2.3	13	13	-	-	Exploration	-	Fed.	Liquefaction	Exploration	-
Union of Cal.	112	205	390	-	-	-	-	-	-	Mine, mill	-	Pvt.	-	Geysers	-
14. Ashland	19	23	395	13.9	0.7	9	23	-	-	Exploration	In situ	Fed.	Operator, H-Coal Liquefaction	-	-
15. Cities Service	30	106	268	-	-	-	-	-	-	Exploration	-	Pvt.	-	-	-
Amarada Hess	71	91	798	-	-	-	-	-	-	-	-	-	-	-	-
Marathon	217	168	526	-	-	-	-	-	-	-	-	-	-	-	-
Getty	103	286	279	-	-	-	-	-	1,750 (B)	Mine, reopen mill	-	Pvt.	-	Exploration	-
19. Sohio	16	25	449	9.7	0.8	4	16	-	-	Mine, mill	-	Fed.	-	-	-
20. Kerr-McGee	11	38	181	-	2.9	33	33	4.1	7,000	5 mines, mill	-	-	-	-	-
Diamond Shamrock	-	7	50	-	-	-	-	-	-	-	-	-	-	-	-
Amer. Petrofina	(C)	20	190	-	-	-	-	-	-	-	-	-	-	-	-
Tesoro	-	5	77	.4	-	-	-	-	-	-	-	-	-	-	-
24. Pennzoil	-	25	62	-	-	-	-	-	-	Exploration	-	-	-	-	-
25. Murphy	37	9	138	-	-	-	-	-	-	-	-	-	-	-	-
26. Williams (A)	-	1	-	(A)	(A)	(A)	(A)	-	-	-	-	-	-	-	-
Tosco	-	-	220	.5	-	-	-	-	-	-	-	State	-	-	-
Clark	-	1	130	-	-	-	-	-	-	-	-	-	-	-	-
Superior	30	41	-	-	-	-	-	-	-	-	Multi-min.	Pvt.	-	-	-
30. Louisiana Land	-	75	38	-	-	-	-	-	-	-	-	-	-	-	-
Number of Companies	23	29	27	10	13	11	11	4	5	18	5	18	9	9	4

NOTES:
(A) Part owner (27.5%) of Peabody Coal. Petroleum revenues primarily from pipelines
(B) Previously shutdown; being reactivated
(C) U.S. affiliate of foreign company
*Data not comparable among companies

rigid framework of questions. The companies interviewed had diverse energy and non-energy operations.

Their operations did not and do not fit a well-defined framework (See Exhibit I-1, Summary of Operations).

Consequently, a formal survey would have required extensive management time and would have been largely irrelevant

Specific questions were asked, in the case of petroleum companies, regarding current and planned investments in petroleum and, where applicable, non-petroleum (steam coal) energy. These questions concerned the reasons for the investments, management's perceptions of relative profitability, and ease of entry.

Face-to-face interviews were also held with the managements of twelve companies outside the oil industry (those engaged in supplying or using coal, uranium, synthetics from coal, oil shale, geothermal, and/or solar energy). The selection of these companies was largely based on size and geographic dispersion of production reserves and/or use. Conversations were held with an additional twenty firms and groups active in the energy area. Those interviewed were asked to discuss, where relevant, the nature of their involvement in steam coal with particular emphasis on current and/or planned investments, or lack of them, in steam coal reserves and production. They were also asked to give their views of other participants in steam coal. Attempts, in all cases, were made to interview those companies that would have the most significant impact on energy supplies and demand.

Responses are shown below:

Twenty-one oil companies were asked to:

I. Rate their current "interest" in steam coal. "Interest" in steam coal is defined as present, or possible future, investment in coal reserve holdings and/or operation facilities. Responses were grouped into five categories:

<u>Intense Interest</u>	<u>Substantial Interest</u>	<u>Some Interest</u>	<u>Limited Interest</u>	<u>No Interest</u>
9	2	2	5	3

"Intense interest" describes those companies who have made major investments in steam coal and who can be expected to continue to invest.

"Substantial interest" describes those companies who have made substantial investments in the past and who might make future investments.

"Some interest" describes those companies with relatively minor steam coal production.

"Limited interest" describes those companies with minor steam coal leasing programs.

"No interest" describes those with no investments and no plans to make any.

As this array indicates, oil company current "interest" in coal varies widely. One company, for example, stated that the lingering pain of an unfortunate diversification experience in the 1960's had taught them to do only that which they knew best: the production and sale of liquid and gaseous hydrocarbons. Another company's management said that heavy handed regulations kept them out of the coal business. At the other end of the spectrum, was

an oil company that said, "if we had to choose one, we would keep coal and get out of oil".

The two independent coal companies interviewed had totally divergent views. One company, largely a metallurgical coal producer, had no interest in expanding its steam coal operation, citing perceptions of low profitability. The other, a current producer of steam coal with different profit perceptions, was expanding as rapidly as possible.

All of the five electric utilities interviewed showed "substantial interest" in coal. The companies stated this interest is generated not by the profit potential perceived in the resale of the coal, but rather the necessity to produce it to insure an adequate, stable fuel supply. Four are producers of steam coal; all five have reserves.

Four of the "other" companies are already active in steam coal and are arrayed as follows:

<u>Intense Interest</u>	<u>Substantial Interest</u>	<u>Some Interest</u>	<u>Limited Interest</u>	<u>No Interest</u>
2	1	1	-	-

While none of these four are primarily in petroleum, all are engaged, to varying degrees, in the petroleum business. (Three produce oil and gas, one owns a fully integrated oil company)

II. Entrance into the Coal Business

With the exception of one oil company, all of the 32 companies arrayed above felt that sufficient reserves were available to them

to enter the coal business. All that was necessary was money and desire.

III. Perceptions of Coal as an Investment Opportunity

Oil companies active in coal development state that coal is attractive investment opportunity when compared with alternative investment possibilities. The 11 oil companies showing either "substantial" or "intense" interest were asked the questions:

Is an investment in steam coal more attractive, the same, or less attractive than alternative investments?

More Attractive

The Same

Less Attractive

7

4

-

These data shown above will aid in understanding the discussion of the investments of oil companies in steam coal that follows.

Chapter II - Coal

B. COAL REQUIREMENTS

The National Energy Plan (NEP) requires doubling coal capacity by 1985, in addition to the replacement of depleting capacity. Coal is considered one of the two fuels (the other is nuclear) that can bridge the gap from the oil and gas era to the era of renewable energy sources of the future. ⁽¹⁾

735 million tons of additional annual coal productive capacity is required by 1985 (600 million for increased production, 135 million for replacement of depleting capacity) to raise production from 665 million tons in 1976 to 1265 million in 1985.

Shown below are 1977-1985 Coal Development Requirements:

	<u>Millions of Annual Tons</u>		
	<u>Total</u>	<u>East</u>	<u>West</u>
Year 1985, 1977 National Energy Plan*	1265	830	435
1976 Actual	<u>665</u>	<u>530</u>	<u>135</u>
Production Increase Needed			
1977-1985	600	300	300
Replacement of Current			
Depleting Capacity (@ 15 MMT/Y)	<u>135</u>	<u>135</u>	<u>0</u>
Capacity Additions Required			
1977-1985	735	435	300
Current Planned Capacity			
Additions 1977-1985	<u>692</u>	<u>182</u>	<u>510</u>
Planned Development Over			
(Under) Projected Requirements			
(Not adjusted for BTU differences			
of East Vs. West Coal)	(43)	(253)	210

* Includes Exports

This represents a minimal case: additional coal development of over 200 million annual tons may be required if (a) some currently planned nuclear plants are shifted to coal due to nuclear delays caused by siting and other problems or (b) coal gasification rapidly expands and requires an additional 100 million annual tons by the late 1980's.

It is important to recognize, too, that new coal-fired electric generating plants require simultaneous coal capacity development. This is due to the fact that boilers are designed to burn a particular type of coal and the range of efficient substitutes is limited. As a consequence, electric utilities, (the largest current and future market for steam coal) normally buy steam coal on 20-30 year contracts, frequently matching the life of the mine to the life of the electric generating facility.

Current production, therefore, is contracted to existing plants. New coal-fired generating plants require that new coal productive capacity be developed to supply the new facilities.

U.S. Coal Reserves and Production

The coal resources of the U.S. are vast. Using the definitions given below, the U.S. Geological Survey (USGS) has estimated total coal resources at almost 4 trillion tons, and has identified resources of nearly 1.6 trillion tons at depths of less than 3,000 feet. U.S. Bureau of Mines (BOM) estimates the demonstrated coal reserve base at 437 billion tons; this is the portion of the identified resources suitable for mining by current methods (see Exhibit II-1).

Recoverability of reserves varies from 40-90%, and nationally averages about 50%, according to characteristics of the coal bed, mining methods, legal and environmental constraints, and other factors. Strip mining will tend toward the higher recovery; under-

ground mining toward lower recoveries. Mining experience in the U. S. has indicated that nationally, at least 50% of the in-place coal can be recovered. A 50% recovery factor would give total recoverable reserves of 218 billion tons, a 180 year supply at the DOE 1985 estimated consumption rate of 1.2 billion tons per year. (2)

Establishment of accurate coal reserve data is important. In testimony given October 21, 1975 before the Senate Sub-Committee on Antitrust and Monopoly regarding the Interfuel Competition Act of 1975, Owen M. Johnson, Jr., Director, Bureau of Competition of the Federal Trade Commission, said, "Reserve data, compiled for regional and national markets, will enable us to calculate concentration ratios in various energy areas. It will also enable the staff to determine the extent to which energy conglomerates are simultaneously gaining control of reserves, in several types of fuel. At the present time, it is not possible to calculate these important reserve figures in many energy industry segments due to a lack of individual company data."

Determination of coal reserves, however, is an inexact science; reserve estimates are "best guesses" based on not always complete information. For example, on the basis of a few core holes, Oklahoma reserves were once estimated as eight feet of coal distributed evenly throughout the state; it is not known whether this remains the current basis of estimates.

There are other problems. "Reserves" are an economic concept; they are the portion of the in-place resources that are subject to recovery under today's technology and mining methods. Those

that can be economically mined under today's cost/price structures are termed "recoverable reserves". These concepts are important because there has been much analysis of reserve positions that doesn't seem to differentiate among "resources", "total reserves", and "recoverable reserves".

Government reserve figures are predominantly "total reserves" of coal in place. Company figures are sometimes "total reserves", but more often "recoverable reserves". There is no known compilation of government and company reserve data that has all figures on the same basis. The variation is usually due to the differences in the recovery factor used.

With the understanding that many of the numbers are non-comparable for the above reasons and for other reasons discussed below, Exhibit II-2 shows data by company on reserves, 1976 production, and anticipated 1985 production capacity. In addition, this Exhibit also shows data on Federal leases, including estimated reserves for the largest reserve holders, federal leased acreage, and number of federal leases.

The Federal Government holds a dominant position in the Western U.S., owning an estimated 125 billion tons (total reserves) in the six Western states of Colorado, Montana, New Mexico, N. Dakota, Utah and Wyoming. This is almost 30% of estimated total U.S. reserves, and about 60% of estimated reserves in the six state area.⁽³⁾

The Federal Government influences up to 80% of coal mine development in the six Western state area, according to the Bureau of Land Management, (BLM), due primarily to "checkerboard" acreage holdings⁽⁴⁾. DOE says that 84% of current and planned western development is involved with the Federal Government either through Federal or Indian leases.⁽⁵⁾

At a maximum, less than 15% of the estimated 125 billion tons of Federal reserves in the six state area has been leased. About 17.3 billion tons of Federal reserves are currently leased to about 110 lessees with about 470 leases. According to DOE, "less than 5% of federally owned coal resources have been leased." (6).

Appendix F-1 shows all holders of Federal leases as of the end of 1976. The top 20 lessees by acreage are shown in Appendix F-6, the top 5 and 10 lessees by acreage by state are shown in Appendix F-7. Most of the leases are held by small companies and individuals.

In addition to the 17.3 billion tons of Federal leases already awarded, an estimated 12.3 billion tons are covered by prospecting permits and preference right lease applications (PRLA). (7) Nine billion three hundred million tons of "recoverable reserves" are covered by 192 PRLA's by 45 applicants. An additional 3 billion tons of coal are covered by 28 prospecting permits. About 60% of the 12.3 billion tons covered by these applications are in Wyoming. Appendix F-8 summarizes PRLA's. Appendix F-9 summarizes prospecting permits. Appendix F-10 shows the concentration of PRLA's in order of their estimated coal reserves.

It should be noted that the Federal Coal Leasing Amendments Act of 1975 (S.391) limits the amount of federal coal leases or permits held by any entity at one time to 46,080 acres in any one state and in no case more than 100,000 acres in the United States.

Before analyzing this lease data, certain problems needed to be pointed out. As mentioned earlier, government and company

data are often inconsistent. Perhaps more importantly, the companies are inconsistent with each other. Our analysis indicates, for example, that:

- Some companies include pending preference right leases application reserves in their reserve data; others exclude them.
- Large amounts of reserves are double-counted. For example, Burlington Northern owns mineral rights to more than 12 billion tons of recoverable coal. 6.7 billion tons of these reserves have been leased to 19 large and small companies. These reserves are also reported by the companies who leased them.
- Many companies carry leases and mineral rights in real estate company or nominee names not associated with the name of the parent or coal subsidiaries. For example, Meadowlark Farms is Amax, Franklin Real Estate is American Electric Power, Ark Land is Arch Mineral (Ashland), Rosebud is Peter Kiewit. Public information does not always identify these relationships, particularly for the smaller companies.
- There are no reserves reported by McGraw-Hill (Keystone) or others for many companies who are known to have reserves, including many with current development or production (see Exhibit II-2 page 4). One example is Texas Utilities. Also, some companies appear more than once in the McGraw-Hill list.

On the basis of all the Government, industry and company data on current reserves, past production, current development, and pending Federal leases contained in Exhibit II-2 and Appendices F-6 through F-10, it is difficult, if not impossible, to make definitive conclusions on any overall effects of reserve ownership patterns on development of coal resources.

Surprisingly, the overall effects of reserve ownership on development of productive capacity appear minor. Specific conclusions, however, can only be reached on the effects of specific leases (or lack of leases) and specific mines.

The following points, however, stand out:

- There is no apparent direct correlation between current reserve holdings (or lack thereof), 1976 production, and future productive capability.
- Much of the publicly available data on reserves is non-comparable.
- Currently leased Federal reserves are only a small fraction of total Federal reserves.
- Oil companies hold about 46% of currently leased Federal reserves. The companies holding these reserves are adding about 51% of new capacity of all companies holding Federal reserves.
- Oil companies have minor holdings in preference right lease applications and preference rights on over 12 billion additional tons of coal.

Only one oil company interviewed stated that sufficient reserves were not available for them to enter the coal business. This company claimed to need 1.5-2.0 billion tons of reserves for economic development. They also claimed that the coal industry was not currently profitable and that the current price of reserves was too high for profitable development.

Other companies said that large reserves are not needed; ability to produce is the key. Ashland Oil for example, entered the coal business in 1969 primarily in the West: in 1976 they were, at 14 million tons per year, probably the largest producer of Federal coal. Ashland had less than 150 million tons of Federal coal reserves, less than 1% of Federal reserves leased to date.

One company stated that large reserve holdings are a costly liability; the price of coal, they said, must double every five years to cover the cost of reserve ownership. Since steam coal is, they say, a ubiquitous commodity, they hold relatively small reserve positions, although they are a large U.S. steam coal producer. Exhibit II-2 shows other examples of companies

developing significant amounts of productive capacity on relatively small amounts of reserves.

A U.S.G.S. study on coal resources in the U.S. states that:

"The information available on the distribution of coal and on ownership of coal rights leads convincingly to the conclusion that it would be virtually impossible for any individual, corporation, or cartel to obtain a monopoly on coal or even to significantly influence the price. The reasons for this conclusion are (1) coal is widespread and abundant in the United States; (2) ownership is broadly distributed; (3) the Federal and State Government owns substantially more than half the coal lands and coal rights in the Rocky Mountain and Northern Great Plains regions; (4) leases on Federal coal rights have practical acreage limitations for holdings in any one State; and (5) most major consumers of coal have substantial coal holdings." (8)

C. PETROLEUM AND OTHER INDUSTRY
PARTICIPANTS IN FUTURE COAL EXPANSION

Oil and Gas Companies

Oil and gas companies are the largest current developers of new steam coal productive capacity. Fifty-three percent of the projected non-captive 1977-1985 additions and 37% of total projected capacity additions are being developed by oil companies (see Exhibit II-3). This percentage rises to 70% of projected non-captive and 49% of total projected development if Amax and Union Pacific are considered as oil companies. This does not include development by firms obtaining financing from oil companies, such as the two largest independent coal companies, North American Coal and Westmoreland Coal.

Oil company coal involvement has been achieved through

- 1) Acquisition of operating coal companies, mainly in the 1960's (Gulf, Conoco, Occidental, Sohio),
- 2) Acquisition of undeveloped acreage since the mid-1960's (Exxon, Kerr-McGee, Arco, Sun, Ashland) and
- 3) Financing non-oil coal producers through joint ventures and other investments (Ashland, Socal, Getty). Many

oil firms are not involved in coal (Standard of Indiana, Union, Cities Service, Amerada Hess, Marathon etc. See Appendix A).

Of 37 non-captive 1977-1985 developers planning 3 million or more annual tons, 18 are oil companies (See Appendix F-2a). Both large and small oil companies are active coal developers. Some smaller oil firms, such as Occidental, Kerr-McGee and Mapco, are very active, particularly in relation to their company size.

Forty-eight percent of planned non-captive steam coal development (excluding gasification) is being directly financed by oil and gas companies. Oil companies are also partially financing other large coal developers, including Amax, (Standard of California), North American Coal (Getty), and Westmoreland Resources (Kewanee/Gulf).

As shown in Appendix A, oil companies have the largest financial resources of any group in American industry; \$17.9 billion was generated in cash flow after dividends in 1976 by the 30 largest U.S. oil and gas companies and \$11.7 billion in cash flow after dividends was generated by the 12 largest oil companies active in coal development. If cash generation remained level through 1985, the \$3.4 billion projected for current oil company coal development would amount to 3.5% of their total cash flows, after dividends, for that period.

Eight companies of the 25 that would be affected by recent horizontal divestiture proposals (Atlantic Richfield, Continental, El Paso, Exxon, Gulf, Mobil, Shell, and Sun) are currently active in coal development. These companies are planning to add 147

million tons of coal capacity by 1985, 36% of total projected non-captive capacity additions. Cash flow after dividends of these eight companies totaled \$9.8 billion in 1976. Estimated 1977-1985 coal expenditures of these companies are \$2.2 billion, or 31% of planned non-captive estimated coal development expenditures. (See Appendices A and D and Exhibits II-3, II-4, and II-5).

Based on reported capacity expansion plans, 18 oil and gas companies will be producing 32% of all coal and 34% of steam coal by the end of 1985 (Exhibit II-4). The largest share for a single oil company (Conoco) in coal production is expected to be about 7.4% of total coal production. This percentage would rank Conoco second in 1985 production capacity behind Peabody Coal (See Exhibit II-6). The top 4 oil companies with coal production in 1985 (Conoco, Exxon, Kerr-McGee, and Occidental) are expected to have about 15% of total coal production in 1985. The share of production of the top four coal companies in 1985 is expected to be about 26%.

Electric Utilities

Coal development by electric utilities is second only to that of oil companies. Electric utilities are projected to develop 29% of new steam coal supply capacity through 1985, comprising 24% of coal production capacity by that time (See Exhibits II-3 and II-4). Electric utility coal development is concentrated among three utilities who are projected to operate more than 66% of all electric utility coal capacity by 1985. Ninety-six percent of Eastern coal development by utilities is projected by a single firm, American Electric Power. Despite

current development, two of the three largest utility coal developers (AEP and Pacific Power) cannot meet even half their own coal needs, much less supply others, and have contracted with Exxon, Kerr-McGee and others for additional supply.

It should be noted, however, that this is not universally true; at least a few utilities, such as Montana Power, sell coal on the open market in addition to supplying their own needs.

Interviews with coal companies and utilities indicate that the utilities are not financing others in coal development as they once did. Most utilities today are apparently in a cost squeeze due to inflation and regulatory lag. Appendix B shows projected detailed capital requirements and capital availability of electric utilities. Appendix B also shows that investor-owned electric utilities are projected to generate cash of \$10 billion per year for the next 5 years, spend \$25 billion per year for generating equipment, and raise \$15 billion per year externally. In addition, 1976 estimates by the Electric Power Research Institute indicate that conversion of existing oil and gas-fired plants to coal can cost electric utilities around \$50 billion through 1985.⁽⁹⁾ Requirements of scrubbers on all coal plants will further tighten the cash squeeze. Because of these factors, utilities are less willing to, and less able to, provide financing to coal producers than in the past and, based on our interviews, few, if any, electric utilities are currently willing to guarantee financing of coal producers in which they have no ownership interest. At least some of the independent coal producers that were financed by electric utilities in the past are now getting financial assistance from oil companies.

Most electric utilities interviewed indicated a desire to avoid having any operating or financial involvement in coal production. They did it, they said, to assure a stable supply of coal. Many reasons were given for their lack of desire including lack of expertise, no intention of building coal-fired plants unless forced to do so, and capital problems.⁽¹⁰⁾

Metals Mining Companies

Metals mining companies are projected to add 14% of total steam coal expansion by 1985, and 20% of non-captive coal expansion (see Exhibit II-3). Despite the argument that metals mining companies are logical entrants to steam coal, there has been no rush of metals mining companies to enter the steam coal industry, and no significant grassroots entry.

Only two metals mining firms have significant involvement in steam coal; 92% of projected steam coal expansion is by Amax and Newmont Mining, the latter a member of the consortium that recently acquired Peabody Coal. Other metals mining companies have limited steam coal investments, and limited expansion plans; coal operations are small and are mostly concerned with metallurgical (met) coal. Kennecott Copper (a metals mining company) was the seller of Peabody Coal (the nation's largest coal producer) under court-ordered divestiture as a result of FTC anti-trust action. Newmont Mining led a 6-company group in acquiring Peabody in 1977. The acquiring group includes, in addition to Newmont, an oil company, an aerospace company, two construction companies, and an insurance company.

Both Amax and Newmont (Peabody) have needed external financing to fund their desired rates of expansion. Both have obtained some coal expansion financing from oil and gas companies. Amax, who raised \$330 million for expansion by selling equity to Standard Oil of California in 1975, is the most aggressive U.S. coal developer. Amax increased their projected 1978 coal capacity over 1973 production by 42 million annual tons, or more than 250%.

Peabody's pre-acquisition expansion plans show, on the other hand, a modest 25% capacity increase by 1985, compared to a total steam coal industry expansion of 100%.

Independent Steam Coal Companies (not owned or controlled by those in other primary industries):

Independent steam coal producers are projected to add only 12% of non-captive steam coal additions and 9% of total steam coal additions by 1985. (See Exhibit II-3, II-4). Of 30 coal producers with over 10 million tons annual capacity by 1985, only 2 are projected to be independent steam coal producers, and these are projected to rank 11th and 13th in 1985. Below the two largest, independent steam coal companies drop rapidly in size. Among 70 larger producers in 1985 of over 3 million tons annual capacity, only 7 are projected to be independent steam coal companies. (Three million tons is an approximate average annual requirement for a new electrical generating plant.)⁽¹¹⁾ Despite

significant capacity increases of individual companies, the 3rd, 4th and 5th largest independent steam coal companies are projected to rank only 31st, 38th and 42nd in total projected coal production capacity in 1985.

Steam coal development by independents is largely concentrated in a few firms. The two largest steam coal independents are developing 80.2% of all expansion of steam coal independents with 1985 projected output of 3 million or more tons. (Derived from Appendix F-2d). 79.8% of the independent steam coal capacity additions will be added by the 7 largest independent steam coal producers. 88.7% of steam coal capacity additions by the seven largest independent firms will be in the West. Most independent coal companies, however, are located in the East.

Interviews with coal producers have indicated that expansion of independent coal producers is limited by factors such as: inadequate internal funds generation; high debt/equity ratio; and, for at least Westmoreland, a lack of desire to expand rapidly.⁽¹²⁾ The two largest independent steam coal producers, (North American and Westmoreland) are family controlled (as are most independent producers) and are both financed in part by oil and gas companies through joint ventures. The production of the largest independent (North American) is coming increasingly from mines financed on the credit of others. North American has not financed a mine on its own since 1964, and, since then, almost all expansion has been financed through joint ventures. In the past, these were with

electric utilities; joint ventures have recently been initiated with oil and gas companies.

The second largest independent (Westmoreland) is financially strong. (Their 1976 balance sheet shows 100% equity, no long term debt). Fifty percent of its production (and a greater percentage of its revenues and earnings) are from met coal used in the manufacture of steel. The company does not intend to take extensive risks developing steam coal⁽¹³⁾ and is joint-venturing Western expansion with other non-coal (oil and construction) companies.

Other Industrial Companies

Some industrial companies not otherwise operating in natural resource development have acquired some coal operations, (See Exhibits II-2 and II-6) most of which have been coal producers. These companies are expected to contribute about 5% of total 1977-1985 capacity additions. (See Exhibits II-3 and II-4).

Of the anticipated projected industry capacity additions, 43% is by General Electric, now the largest "other-industrial" coal developer through its recent acquisition of Utah International, a construction and mining firm active in Western steam coal. However, Utah International's domestic steam coal operations are minor compared to their total operations that comprise met coal, metals mining, oil and gas, and uranium⁽¹⁴⁾. Although GE will double steam coal capacity by 1985, it is projected to rank only 19th in new coal capacity development.

The remainder of "other industrial" steam coal producers are not a major factor in new steam coal development because most are met coal producers. The next largest developers rank 37, 46,

and 59 in 1977-1985 development and include General Dynamics, Moore-McCormack, W. R. Grace, and ITT.

Railroads

Some railroads, involved in coal development because of large coal reserve holding, are expected to account for 3% of total 1977-1985 steam coal capacity additions. The Western railroads, Burlington Northern and Union Pacific, are the 2nd and 3rd largest coal reserve holders (See Exhibit II-2.) Combined reserves of these companies are at least 140% larger than Federal reserves leased to date and are largely "checkerboarded" with Federal holdings.

Of the railroads, Union Pacific is the largest coal developer; seventy percent of railroad projected additions are expected to be generated by Union Pacific. Most, but not all, development is through 50/50 joint ventures with lease holders of the alternate Federal acreage, including several oil companies.⁽¹⁵⁾ An officer of Union Pacific stated that the company prefers to joint venture only with proven, experienced Western coal operators.

Burlington Northern leased out about 7 billion tons to 19 companies in the late 1960's and early 1970's, but production has been modest because of the checkerboarding of reserves. BN is now beginning its own development of some of its holdings. Other railroads are minor factors in steam coal development.

Few railroad holders of coal reserves have the financial strength to add significant amounts to coal production capacity over the short to intermediate term. Even Union Pacific, with 1976 "Funds from Operations" of \$344 million, is managing and financing its coal development through joint ventures with experienced miners

who invest 50% of project financing. Burlington Northern, for example, has announced plans to raise \$2.2 billion over the next five years; \$2.0 billion is to be spent solely on the railroad.

Construction and Engineering Companies

Heavy construction and engineering firms, because of earth moving ability, are logical entrants to Western coal. However, only one, Peter Kiewit, is aggressively involved in direct development of new production capacity. Others are engaged in contract mining, or are involved in joint ventures and other arrangements. Bechtel and Fluor are part of the Newmont Mining group that acquired Peabody.

Financial commitment has been limited to date, and direct development is projected at only 2% of 1977-1985 capacity additions.

Steel Companies

Steel companies are a minor factor in 1977-1985 steam coal expansion. They are projected to develop less than 1% of new capacity and add 2% of new investment.

Virtually all production is for company use and not for sale. Steel companies have, apparently, little desire to mine significant amounts of steam coal for others. The industry is reputed to have severe financial problems and to have little capital for use outside their basic business.

Energy Intensive Industrial Companies

Some large energy users are active in steam coal production, (See Exhibits II-2) but most currently provide only part of their own needs and do not provide coal for others. Current steam coal expansion by these companies to develop coal for sale to others is minor.

Coal Gasification

40 million annual tons of coal gasification are planned by 1985. This is not included in steam coal development totals where the coal is currently being developed for steam use.

Most major gas pipelines and distributors and many oil companies have gasification reserves. Coal gasification currently is not commercially feasible, but some reserves acquired by oil and gas companies for gasification are now being developed as steam coal for sale to utilities.

D. POTENTIAL NEW ENTRANTS INTO COAL

With some 4000 U.S. coal producers presently in existence, it is likely that a great many, if not most, of the companies that are logical entrants into coal mining already hold coal reserves and/or produce coal.

Entry into coal requires:

- 1) The necessary capital or sufficient financial strength to raise it on reasonable terms.
- 2) A belief that the investment in coal will be profitable and be of long run benefit to the diversifying firm.
- 3) A subjective "comfort" with the nature of the coal industry. (As discussed earlier, investments are largely based on subjective perceptions of the future.)

Lack of involvement in steam coal development by many large American companies is not due to lack of companies with the requisite financial ability. Appendix A shows that many industries and individual companies have the financial capability to participate in coal, yet many have chosen not to participate. Financial ability to enter the industry is, apparently, not a problem. Desire to enter the industry appears to be a very real problem. There are several reasons, stated by the managements of the companies interviewed, for this lack of participation. They say that:

- 1) Steam coal development currently is not perceived as a profitable investment opportunity by much of American industry. For decades, the steam coal industry has had declining profitability due to overcapacity and declining demand caused by user shifts to cheaper and cleaner fuels. First residential and industrial heating shifted from coal, then railroads, then most electric utilities in the 1960's and early 1970's. Even now, four years after the embargo, there is excess steam coal capacity of 50-100 million annual tons.⁽⁶⁾ Despite projections of high future requirements for steam coal, uncertainties regarding the profitability of development is probably as high now as it ever has been in the past.
- 2) The nature of steam coal operations is outside the scope of operations of the vast majority of American companies. To invest and operate in the steam coal industry, a company must feel "comfortable" with large-scale, capital-intensive projects, almost constant labor problems, often dangerous working conditions, uncertain costs, unpredictable demand, major environmental and regulatory problems, and seemingly continuous delays affecting development of coal from the standpoint of both production and use. Most large-scale, non-user steam coal developers are from the oil, mining, aerospace and construction industries. Extensive past experience in their primary industries in dealing with problems and uncertainties similar to those encountered in steam coal development tends to make them more familiar and, hence, more comfortable with the kinds of problems and uncertainties currently encountered in steam coal development than managements of industries that are, for example, more strongly oriented towards branded consumer marketing, or efficient retailing and distribution, or high volume assembly lines, or high technology manufacturing. (Of course, not all oil, mining, aerospace, and construction companies have had the same experience, nor do all feel equally comfortable or perceive equal opportunity in steam coal. Many companies in these industries have no steam coal involvement whatsoever.) Probably because of this, companies dealing with consumer package goods, consumer hard good, retailing, computer and office equipment, containers, communications, cosmetics, foods and so forth (the vast bulk of American industry) have not invested in coal, and are considered unlikely entrants to steam coal development, particularly without a significant lessening of the current uncertainties surrounding steam coal development.

Most importantly, the steam coal industry operates differently from virtually all other industries of the U.S. The prime difference is the extensive use of very long term (20-30 year) production contracts. There are few, if any, other industries in which the normal practice of the industry is for a producer to build a major facility having a 6-8 year lead time and committing to deliver its output, frequently with high labor costs (in underground mining and some Eastern strip), often to a single customer and usually less than a handful of customers, at a fixed (but partially escalated price) over such a long period of time. (Natural gas production is a major industry with some similarities, but without the demand, environmental, safety and labor problems.)

There is good reason for their long term contracts: the coal-fired boilers of utilities are designed for specific coals; coals vary widely in organic properties, and are not readily mixed. The utilities state that they want to insure a continuously usable supply at a relatively stable, predictable price for the life of their generating plant. As a consequence, long-term contracts have become institutionalized in the industry and generally serve the needs of both producers and users.⁽¹⁷⁾ Long-term contracting is maintained primarily at the insistence of the steam coal buyers, mainly electric utilities, who have legal mandates to provide continuous electric service. As a result, there is normally a very small demand for steam coal by electric utilities in the spot market.

Metallurgical (met) coal production for steelmaking contrasts with this. Met coal is sold on short-term (3-12 month) "evergreen" contracts that are repriced as renewed, or, sometimes, more frequently. Many industrial companies are involved in met coal production because it is a business with which they feel more comfortable. Not all of these met coal producing companies have a desire to make significant expansions into steam coal; Pittston has, for example, diversified into armored car security services, trucking, and fuel oil rather than steam coal.

Although it is still possible to enter the coal business on a limited budget, the necessary increases in U.S. coal production for utility use will come from big deep Eastern mines and big Western mines. The size of necessary capital investments (\$40-80 million for an Eastern mine capable of producing 1-2 million tons/year; \$60-120 million for a Western mine capable of producing 5-10 million tons/year) coupled with the risks generated by uncertainty regarding environmental costs, demand factors, mine safety requirements, state severance taxes, permits and licenses, etc. limits the number of companies willing to invest in coal reserves and/or production.

Data Regarding New Sales Contracts

Although no definitive compilation is available on new coal sales contracts, a high proportion of new coal sales have been made by oil company/coal producers. These sales are made on the basis of mixtures of competitive bids and negotiations. Utilities term many of the oil companies "aggressive" and "very competitive". TVA contracts are awarded on a competitive bid basis; oil companies are reputedly the largest suppliers to TVA. Exhibit II-7 lists new sales contracts for coal produced by oil companies for the Gillette, Wyoming area.

E. FINANCING COAL DEVELOPMENT

According to representatives of the financial community involved with the financing of coal activities, financing coal

development is, not surprisingly, relatively easy as long as a company limits its attempted financing to amounts that lenders consider to be within the company's means in relation to its cash flow, profitability, and net worth. Project financing is normally available for financing equipment and some expenditures.

In today's energy climate, however, it takes more than a sales contract with a utility to finance an entire mine. Banks or other financial institutions, acting as lenders and not as investors, do not normally lend money on projects for which there is risk of non-payment without requiring additional collateral or financially strong guarantees to ensure that the contract will be fulfilled. Thus, while project financing is available, the borrower must have the financial strength to assure the lender that the financing will be repaid even if the worst acts of God, courts, or legislatures should occur.

To a lender, the most important characteristic of a financing transaction is its predictability. According to a leading coal financing bank, there are three necessary ingredients to a coal financing transaction: 1) absolute certainty that the mine will be completed, regardless of the complications or expense; 2) knowledge that the company will continuously operate the mine as a prudent operator; 3) knowledge that the output of the mine can be continuously sold at a profit.

Project financing is based on repayment, including interest, from stated percentages of future mine revenues. Such financing

is usually for a total term, including the take-down period, of 8-10 years. The lender is secured and repaid by an assignment of production revenues, which is backed up by strong commitments of the coal producer to develop and continuously operate the mine, usually pursuant to the coal sales contracts used as the basis of the financing. Although the mine operator usually has no direct responsibility for the debt in this type of financing, the operator does have the contingent financial obligation to fully develop and continuously operate the mine. More specific forms of credit support may be needed in many instances, especially where the coal producer has limited capital resources to support the development and operating covenants.

The most common problems are caused by mis-estimates of cost - either capital or operating costs - or both. Under-estimated capital costs require more investment in a project than had been anticipated when the contracts and financings were arranged. This creates two problems: one, some entity has to come up with the additional funds necessary to complete the mine to enable the sales contract to be filled in order that revenues can be generated to repay the financing; two, the cost overruns may be so large that revenues generated by the contract could be insufficient, after debt retirement payments, to pay operating expenses. Mis-estimates of operating costs create a similar situation; revenues, after financing payments, are insufficient to pay operating expenses. Because the lenders

are looking to the contract for repayment, they want specific guarantees from financially responsible parties that any such problems, regardless of their cause, will not halt the completion or operation of the mine.

In the past, inability to repay financing was usually due to physical events, such as a mine shaft failure, which could be corrected with additional investment. Events of the 1970's have added new types of uncertainties and have lessened the ability to finance new mine development on the basis of sales contracts alone. These new uncertainties arise from many sources: federal energy policy regulations, local fuel use mandates, mining safety regulations, environmental suits, strip mining requirements, possible local coal preference regulations, and high rates of inflation, among others.

According to a leading coal bank, this has resulted in so-called "take or pay" sales contracts becoming very rare, if indeed they now exist at all. Steam coal contracts almost always contain force majeure clauses, along with a provision for cancellation in the event that the buyer cannot legally use the coal within his system and if both buyer and seller agree that nothing can be done, at reasonable cost, to rectify the problem. True "take or pay" contracts, of the type which govern many natural gas contracts, are uncommon, and are unlikely to come into general use as long as substantial uncertainties exist.

Because of these risks, investors are generally unwilling

to provide financing based on the security of a single mine. They expect additional financial support through the hypothecation of additional assets or through other credit backing.

According to coal lenders, most smaller coal producers do not have the financial resources to support the completion and operating covenants of typical production payment (project financing) arrangements. Small producers borrow principally for equipment renovation and replacement and for working capital; major capital investments in mine development tend to be made only rarely.

Project financing, however, does exist. Old Ben Coal Company, a wholly owned subsidiary of Sohio, used project financing to raise \$90 million for development of an Illinois deep mine currently nearing completion. However, completion, and continuous successful operation of the mine, had to be guaranteed by the parent company (Sohio) in order to obtain the financing. Pittsburg and Midway Coal (Gulf) raised \$75 million in project financing for development of its McKinley strip mine in New Mexico. Pittsburg and Midway could not raise this money by itself; Gulf's corporate guarantee was needed to assure completion and successful operation in order to obtain the financing. Both of these coal producing subsidiaries would be high ranking independents if divested. (1976 production: Old Ben, 9.5 million tons; Pittsburg and Midway, 7.9 million tons.) Yet neither could obtain financing on their own for the rate of expansion that they are currently undertaking; the financial backing of

the parent corporations was necessary to complete the financings. Both are also developing other new capacity with the financial assistance of the parent companies.

Previously used other forms of financing coal assets have been eliminated by the Internal Revenue Service. Conoco financed its 1966 acquisition of Consolidation Coal Company through an ABC-type (three-party) production payment transaction financed by a group of banks. Acquisitions of other coal companies and several billion dollars of additional capital for expansions were raised in the 1960's through ABC-type transactions and other carved-out production payments. The tax advantages of ABC transactions were eliminated by the Tax Reform Act of 1969 which reduced their attractiveness to investors and effectively eliminated this source of funds.

In 1976, the IRS withdrew two favorable tax rulings on advance royalty payments under which a great many undeveloped coal leases had been acquired for development. This action terminated the attractiveness of this type of financing to investors and dried up this source of capital for producers.

Joint Ventures

Joint ventures in coal are common, but few involve all oil companies.

The only coal joint venture between major oil companies is the Mobil/Conoco joint development in Wyoming. This originated from Mobil's desire to geographically diversify its coal

holdings. Mobil had only Wyoming reserves. Conoco sold Mobil some Illinois reserves and received a half interest in a portion of Mobil's Wyoming reserves. The bulk of Mobil's Wyoming reserves, however, are outside this joint venture.

Getty provided financing for a joint venture with North American Coal in Texas. This is Getty's first coal investment.

Union Pacific has joint ventures with a number of qualified coal-operating companies who are holders of the contiguous alternate "checkerboard" acreage, generally Federal leases. (Both the Union Pacific and Burlington Northern railroads have large coal reserves concentrated in Wyoming, Montana and North Dakota. The Federal Government has leased 17.3 million tons of coal reserves; the two railroads own over 22 billion tons that is mostly "checkerboarded" on alternate one square mile blocks with the Federal leases).

Both Arch Minerals (Ashland) and Sun have joint mine developments with Union Pacific in Wyoming. Both Arch and Sun have Federal leases which adjoin Union Pacific holdings; in these instances economical coal production requires that the contiguous blocks be developed jointly.

Other petroleum-related joint ventures involve gasification projects, usually partnerships between a gas company (pipeline or distributor) and an independent coal producer as operator. Typical of this is the Panhandle Eastern joint venture with Newmont Mining (Peabody Coal) in Wyoming. Because gasifica-

tion is not yet economical, Panhandle and Peabody carved-out a portion of the reserves, set up Antelope Coal Company to develop them, and arranged the sale of about 3 million tons per year of steam coal to Middle South Utilities.

By far the greatest number of joint ventures are composed of 1) independent coal producers and utilities and 2) joint ventures among utilities themselves. One of the principal advantages of utilities joint venturing with other utilities is to increase the size of the project and take advantage of economies of scale. Railroads that own large reserves also joint venture with mining companies for production of the reserves.

F. RETURN ON INVESTMENT IN COAL

Despite uncertainties in demand and costs, some companies, (and they are mostly oil companies), think that return on investment in coal development and production is sufficiently high to make significant investments. Thirty-one non-captive coal producers are developing 3 million or more tons of new capacity (See Appendix F-2). An insufficient projected return, would, of course, preclude investment.

One large oil company that is very active in both Eastern and Western coal development stated that their projected returns on new coal investments are in the range of 15-25%, computed with discounted cash flow methods. (With delays that have stretched development times, actual returns will be somewhat less.) Other oil companies state that returns on coal invest-

ments exceed their minimum cut-off returns of 12-18%.

Companies use various investment evaluation techniques (See Appendix H). Return on investment, however, is not the key decision factor of one of the companies most aggressive in coal development. This company's investment decisions are based on the reasoning that if there is demand for a resource, the company will undertake all new development for which its anticipated production costs are less than the average cost of all production of that resource, regardless of whether or not the current or forecast economics give a high rate of return on investment. The result is that the company is one of the largest and most aggressive developers of Western coal.

Oil companies active in coal development state that coal is an attractive investment opportunity when compared with alternative investments. Returns can be higher in coal than in oil and gas or uranium because there is no (or very little) exploration cost for coal. Only moderate expenditures are required relative to other resource development to define reserves and determine costs before long-term sales contracts can be negotiated and signed. The bulk of development expenditures occur in the two or three years immediately prior to the start of production. This contrasts, for example, with current off-shore oil development. Even in the Gulf of Mexico, not a hostile environment compared to the Atlantic OCS or Alaska, returns on investment are declining due to increased operating costs in progressively deeper waters. Deeper waters require significantly

greater capital expenditures per barrel of daily production, and result in much longer lead times between initial expenditures and the receipt of significant revenues. To achieve the same returns in deeper waters as in shallower waters, larger, more prolific fields must be found in order to generate the higher revenues required to offset the greater expenditures of deep water operations.

Metallurgical coal producers, including both independent coal companies and steel companies, find the returns from steam coal production too small and uncertain to attract them. Although these companies produce a certain amount of steam coal as by-products of their met coal operations, the larger companies state they have no intentions of expanding steam coal production except in certain specialized circumstances, such as to supply nearby utilities.

Very few manufacturing or general industrial companies have been attracted to coal mining on a large scale despite returns that resource companies find attractive. New entrants have been limited predominately to mining, oil, construction, and aerospace companies; companies that deal with large scale, highly capital-intensive, project-type businesses with frequent delays and long lead times.

EXHIBIT II-1

Estimates of U.S. Coal Reserves and Resources
(billion tons)

	<u>TOTAL</u>	<u>East of Mississippi</u>	<u>West of Mississippi</u>
Total Resources (USGS)	3,968	- -	- -
Total Identified Resources (USGS)	1,581	487	1,094
Demonstrated Reserves (BOM):			
Surface Mining	137	34	103
Deep Mining	300	169	131
TOTAL	437	203	234

Sources: Paul Averitt, Coal Resources of the United States, January 1, 1974
United States Geological Survey, Washington D.C.,
1975

Department of the Interior, Bureau of Mines, The
Reserve Base of U.S. Coals by Sulfur Content, 1975.
Information Circulars 8680 and 8693

EXHIBIT II-2

RESERVES, PRODUCTION AND PROJECTED CAPACITY

	TOTAL RESERVES (1) (BIL. TONS)	FEDERAL (3)(4)			1976 PRODUCTION (1) (MIL. TONS)	PROJECTED 1985 CAPACITY (2) (MIL. TONS)
		RESERVES (BIL. TONS)	ACRES (THOUS.)	LEASES (NO.)		
Continental Oil (Consolidation Coal)	13.8	0.9	55	36	56	90
Burlington Northern	12.0+					16
Union Pacific	10.0+				1	6
Newmont Mining (Peabody Coal)	9.3	2.3	84	49	70	95
Exxon	8.4	2.0	15	3	3	33
North American Coal	5.1		12	12	11	31
Amox	5.0	0.6	6	2	23	80
Occidental Petroleum	3.4				18	32
Mobil Oil	3.0	0.4		1		7
U. S. Steel	3.0	0.4	19	20	16	32
Phillips Petroleum	3.0					
Kerr-McGee	2.9	0.7	13	7		33
Eastern Gas & Fuel	2.6			1	8	15
Pacific Power & Light (net)	2.5	1.0	47	22	12	48
Shell Oil	2.3			2		21
Sun Oil	2.3	0.6	25	5		13
Texaco	2.0	0.6	9	5		
Westmoreland Coal (incl. Westmoreland Resour.)	2.0				12	27
Lethlehem Steel	1.8				14	19
Tenneco	1.7					
Pittston	1.5				17	27
American Electric Power	1.5				11	57
Norfolk & Western Railway	1.4			7		
Houston Natural Gas	1.2			3	5	13
General Electric (Utah Int'l.)	1.1	0.4	24	26	6	19
Atlantic Richfield	1.0	1.0	19	6		30
Montana Power (Western Energy)	1.0		7	2	9	20
Hillman Coal and Coke	1.0					
Gulf Oil	0.8	0.3	15	14	8	22
Standard Oil of Ohio	0.8				10	16
Belco Oil	0.8	0.6	1			
Ashland (incl. Arch Mineral)	0.7	0.1	13	10	14	23

	TOTAL RESERVES (BIL. TONS)	RESERVES (BIL. TONS)	FEDERAL ACRES (THOUS.)	LEASES (NO.)	1976 PRODUCTION (MIL. TONS)	PROJECTED 1985 CAPACITY (MIL. TONS)
Cape Breton Development Co.	0.7					
Greenwood Stripping Corp.	0.7					
General Dynamics	0.6				6	11
Montana Dakota Utilities (Knife River)	0.6	0.2		7	4	6
Resources Co. (Arix. P.S., San Diego G&E)	0.6	0.6	39	20		
D. D. Stewart	0.6					
El Paso Natural Gas	0.5	0.5	27	15		4
Panhandle Eastern (Y&O)	0.5				2	3
Columbia Gas System	0.5					
Quaker State Oil	0.5				4	9
Mapco	0.5				4	10
Consolidated Natural Gas	0.5					
Kemmerer Coal	0.5	0.5	32	26	4	6
Peter Kiewit (net)	0.4	0.4	32	5	8	22
TVA	0.4					
Duke Power (Eastover)	0.4				2	5
Armco Steel	0.4				2	5
Coastal States (So. Utah)	0.4			2	1	2
Penn Pocahontas Coal	0.4					
Southern Electric	0.4					
Kentucky King Coal	0.4					
International Harvester	0.4					
Santa Fe Industries	0.4					
Reynolds Metals	0.4		9	5		
Jim Walter Corp.	0.4				1	9
Cameron Engineering (Mintech)	0.3					
St. Joe Minerals	0.3				10	
Southern Railway	0.3					
Bates Manufacturing	0.3				3	
Illinois Central Rd.	0.3					
Union Carbide	0.3				1	
Alco Standard	0.3				2	
Blue Diamond Coal	0.3				1	
A. T. Walker Estate Corp.	0.2					
Merchants Petroleum	0.2					
Gulf Resources	0.2					

	TOTAL RESERVES (BIL. TONS)	FEDERAL			1976 PRODUCTION (MIL. TONS)	PROJECTED 1985 CAPACITY (MIL. TONS)
		RESERVES (BIL. TONS)	ACRES (THOUS.)	LEASES (NO.)		
Bane Coal	0.2					
Donan Joint Venture	0.2					
Great Northern Nekoosa	0.2					
Jones & Laughlin Steel	0.2				3	5
Kentucky River Coal	0.2					
McAllester Fuel	0.2					
New Mexico & Arizona Land Co.	0.2					
Palmer Coking	0.2					
Pinson Coal	0.2					
Solar Fuel	0.2					
Zapata	0.2				2	
Black Hills Power & Light (Wyodak)	0.2			4	1	5
Lykes-Youngstown	0.2				2	
Public Service of New Mexico (Western Coal)	0.2	0.2	12	6	1	
Nevada Electric	0.2	0.2	10	8		
Garland Coal	0.2	0.2	46	27		
California Portland Cement	0.2					
New Era Resources	0.2					
Rochester & Pittsburgh Coal	0.2				6	
Kaiser Steel	0.1	0.1	15	0	2	
Neely & Gibson Coal	0.1					
B & H Elkhorn Coal	0.1					
Allied Chemical	0.1					
Drummond Co.	0.1				3	
Interstate Lumber Co.	0.1					
Slab Fork Coal Co.	0.1				1	
ITT (Carbon Fuel)	0.1				1	
Mead Corp.	0.1					
Pennsylvania Power & Light	0.1					
Allegheny Power	0.1					
Wise Development	0.1					
Southeast Coal Co.	0.1				1	
Cambica Mining & Manufacturing	0.1					
Washington Water Power (net)	0.1			2	1	
Rapoca Energy Co.	0.1					
Joseph Orlandi	0.1					
151 Additional Companies	2.7					
TOTAL	132.2	14.8		360	418	927

4
EXAMPLES OF COMPANIES WITH PRODUCTION BUT NO RESERVES

	TOTAL RESERVES (BIL. TONS)	FEDERAL RESERVES (BIL. TONS)	ACRES (THOUS.)	LEASES (NO.)	1976 PRODUCTION (MIL. TONS)	PROJECTED 1985 CAPACITY (MIL. TONS)
Raytheon	0.1				7	7
Crown Central				2	3	8
National Steel					3	4
ASARCO					3	4
Benjamin Coal					4	1
Marmon Group					3	3
Baukol-Noonan			3	1	2	5
Soverign Pocahontas					2	
Inland Steel					2	5
Sahara					2	2
Cravat Coal					2	2
Martin County					2	2
Amherst					2	2
King Knob					2	2
Barbour Coal					1	1
Duquesne Light (Util.)					2	8
Utah Power & Light (Amer. Coal)				2	2	8
Jewell Coal & Coke					4	4
Moore McCormack					2	5
United Nuclear				3	2	4
Resource Exploration & Mining (Wyo)					1	
Texas Utilities					14	52
Missouri Mining (Amer. Indus. & Resources Corp)					1	
ICI America (Tex)						
Bill's Coal Co.					1	
McCulloch Oil						
CFI Steel				1	1	2
Ideal Basic				1		1
Iowa Public Service			9	1	2	4
Richard D. Bass			21	1		
Industrial Resources			15	6		
Evans Coal			13	8		
Seneca Oil			6	1		1
Mid Continent Coal & Coke			6	9	1	
United Electric Coal			5	1		

	TOTAL RESERVES (BIL. TONS)	FEDERAL RESERVES (BIL. TONS)	ACRES (THOUS.)	LEASES (NO.)	1976 PRODUCTION (MIL. TONS)	PROJECTED 1985 CAPACITY (MIL. TONS)
Lone Star Steel			10	6		
Cameron Coal			4	3		
Jessee H. Knight			8			
Peter I Wold II						
E. L. Lockhart						
Ember Mining						
Petroleum International						

54

- Sources: (1) Keystone Coal Industry Manual, 1976.
 (2) Keystone News Eulletin, January, 1977, pp. 5-14.
 (3) Analysis of Existing Coal Leases, Bureau of Land Management, March, 1977.
 (4) Western Coal Development Monitoring System, Department of Energy,
 (Washington, D.C.) March, 1977.

Exhibit II-3

1977-1985

Announced Plans for East/West Steam Coal Additions^{1,2}

	EAST			WEST ³			TOTAL		
	Annual Tons(Mil)	% Total	% Non- Captive	Annual Tons(Mil)	% Total	% Non- Captive	Annual Tons(Mil)	% Total	% Non- Captive
Oil & Gas	29.9	25	39	186.2	40	56	216.1	37	53
Electric Utilities	38.6	32	-	133.7	29	-	172.3	29	-
Metals Mining	22.3	19	29	58.5	12	18	80.8	14	20
Independent Coal	14.3	12	18	35.7	8	11	50.0	9	12
Other Industrial	10.8	9	14	17.4	4	5	28.2	5	7
Railroads	-	-	-	21.0	4	6	21.0	3	5
Construction	-	-	-	14.0	3	4	14.0	2	3
Steel	3.8	3	-	0.9	-	-	4.7	1	-
Total	119.7	100	-	467.4	100	-	587.1	100	-
Non-Captive (Excludes Elec. Util. & Steel)	77.3	-	100	332.8	-	100	410.1	-	100

¹ Excludes Metallurgical coal and coal for Gasification.

² Includes replacement tonnage for depleted capacity. This will apply almost entirely to Eastern mines during this time period and could represent 12-15 MMT/Y. (Keystone News Bulletin, Jan 1977, p. 5)

³ Includes Alaska, Arizona, Colorado, Montana, New Mexico, North Dakota, Oklahoma, Texas, Washington, and Wyoming

Sources: Keystone News Bulletin, January 1977, pp. 5-14 (Eastern data), FEA Western Coal Development Monitoring System, (Western data) August 1977.

Exhibit II-4

PROJECTED 1985 COAL PRODUCTION CAPACITY BY INDUSTRY¹

Industry	1985 CAPACITY East (MMT/Y)			1985 CAPACITY West ² (MMT/Y)			1985 CAPACITY TOTAL							
	Steam	Met	Gasified	Steam	Met	Gasified	Steam (MMT/Y) (%)	Met (MMT/Y) (%)	Gasified (MMT/Y) (%)	Total (MMT/Y) (%)	Steam (MMT/Y) (%)	Met (MMT/Y) (%)	Gasified (MMT/Y) (%)	Total (MMT/Y) (%)
Oil & Gas	204.5	1.7	26.2	132.6	28.7	2.5	337.1	34	30.4	16	28.7	80	396.2	32
Utilities	181.7	0	0	59.5	0	0	241.2	24	0	0	0	0	241.2	18
Metals Mining	83.2	1.0	7.0	104.6	13.2	0	187.8	19	14.2	7	7.0	19	209.0	18
Independent Coal	48.7	1.3	0	67.8	46.1	0	116.5	12	47.4	25	0	0	163.9	13
Other Industrial	24.4	3.0	.2	33.3	16.5	0	57.7	6	19.5	10	.2	1	77.4	6
Railroad	23.1	0	0	0	3.5	0	23.1	2	3.5	2	0	0	26.6	2
Construction	21.8	0	0	0	0	0	21.8	2	0	0	0	0	21.8	2
Steel	.9	8.2	0	7.1	68.5	0	8	1	76.7	40	0	0	84.7	
TOTALS	588.3	15.2	33.4	404.9	176.5	2.5	993.2	100	191.7	100	35.9	100	1220.8	100

¹Includes replacement tonnage for depleted capacity. This will apply almost entirely to the East and could represent 12-15 MMT/Y. (Keystone News Bulletin, Jan 1977, p.5)

²See footnote 3, Exhibit II-3

Sources: Same as Exhibit II-3

Exhibit II-5

Coal Development by Industry TypeType of Coal Involvement

	1977-1985					
	Annual Tons Added			Steam Coal Expansion		
	Millions			Capital Costs		
	Tons	% Total	% Non-Captive	\$	% Total	% Non-Captive
<u>Vertical Integration</u>						
Electric Utilities	172.3	29%	-	\$3,148	30	-
Steel	4.7	1	-	163	2	-
	<u>177.0</u>	<u>30%</u>	<u>-</u>	<u>\$3,311</u>	<u>32%</u>	<u>-</u>
<u>Multi-Industry</u>						
Oil and Gas	216.1	37%	53%	3,430	33	48%
Metal Mining	80.8	14	20	1,594	15	20
Industrial	28.2	5	7	641	6	9
Railroads	21.0	3	5	252	2	4
Construction	14.0	2	3	168	2	2
	<u>360.1</u>	<u>61%</u>	<u>88%</u>	<u>6,085</u>	<u>58%</u>	<u>86%</u>
<u>Single Industry</u>						
Independent Coal	<u>50.0</u>	<u>9%</u>	<u>12%</u>	<u>1,001</u>	<u>10%</u>	<u>14%</u>
TOTAL	587.1	100%	-	\$10,397	100%	-
TOTALS NON-CAPTIVES	410.1	-	100%	\$ 7,086	-	100%
 Memo: Detail of Independent Coal						
North American Coal	19.1	38%		277	28%	
Westmoreland Coal (incl. 100% of Westmore- land Resources)	12.9	26%		211	21%	
All Others	18.0	36%		513	51%	
	<u>50.0</u>	<u>100%</u>		<u>1,001</u>	<u>100%</u>	

SOURCES: See Exhibit II-3 and II-6

PROJECTED 1977-1985 COAL EXPANSION AND 1985 CAPACITY BY COMPANY

OIL AND GAS COMPANIESMILLIONS OF ANNUAL TONS

<u>COMPANY</u>	<u>1977-1985 CAPACITY EXPANSION</u>		<u>RANK 1977-1985 CAPACITY EXPANSION</u>	<u>PRODUCTION CAPACITY 1985</u>	<u>RANK 1985 PRODUCTION CAPACITY</u>
	<u>E.</u>	<u>W²</u>			
CONOCO	5.4	24.5	7	90.0	2
EXXON	7.9	22.0	7	33.0	7
KERR-McGEE		32.7	5	33.0	7
OCCIDENTAL	8.9	3.0	20	32.0	9
ATLANTIC RICHFIELD		30.0	6	30.0	12
ASHLAND (INCL. ARCH)	2.1	6.5	27	22.6	15
GULF	1.5	12.1	15	21.5	17
NATURAL GAS PIPELINE OF AMERICA		21.0	9	21.0	18
SHELL		21.0	9	21.0	18
SOHIO	4.4		36	16.0	24
SUN		13.0	16	13.0	27
HOUSTON NATURAL GAS	4.0	1.9	29	13.0	27
MAPCO	4.2		40	10.0	30
QUAKER STATE	1.5	2.9	36	8.5	32
CROWN CENTRAL		4.9	35	8.0	34
MOBIL		6.5	26	6.5	37
EL PASO		3.5	44	3.5	63
GENERAL EXPLORATION		2.6	50	3.0	67
OTHER OIL & GAS COMPANIES	1.7	5.5	-	10.6	-
	<u>41.6</u>	<u>213.6</u>		<u>396.2</u>	

ELECTRIC UTILITIES

MILLIONS OF ANNUAL TONS

<u>COMPANY</u>	<u>1977-1985</u> <u>CAPACITY</u> <u>EXPANSION</u>		<u>RANK</u> <u>1977-1985</u> <u>CAPACITY</u> <u>EXPANSION</u>	<u>PRODUCTION</u> <u>CAPACITY</u> <u>1985</u>	<u>RANK</u> <u>1985</u> <u>PRODUCTION</u> <u>CAPACITY</u>
	<u>E.</u>	<u>W.²</u>			
AMERICAN ELECT. PWR.	37.1	2.5	2	56.5	4
TEXAS UTILITIES		38.5	3	52.3	5
PACIFIC POWER & LIGHT		35.2	4	47.9	6
MONTANA POWER		10.7	21	20.0	20
UTAH POWER & LIGHT		5.6	31	7.6	35
NOKOTA		6.6	25	6.6	36
MONTANA DAKOTA UTIL.		1.4	59	6.0	40
BRAZOS ELECTRIC		6.0	28	6.0	40
COMMONWEALTH EDISON		5.0	33	5.0	43
WESTERN FUELS		5.0	3	5.0	43
BLACK HILLS POWER		4.3	39	5.0	43
PUBL. SERV. OF N.M.		3.7	42	4.9	48
DUKE POWER	1.5		57	4.5	52
IWAS PUB. SVC.		3.2	45	4.4	54
TEX. MUNIC. POWER		4.0	41	4.0	59
OTHER UTILITIES		2.0	-	5.5	-
	<u>38.6</u>	<u>133.7</u>		<u>241.2</u>	

METALS MINING

MILLIONS OF ANNUAL TONS

<u>COMPANY</u>	<u>1977-1985 CAPACITY EXPANSION</u>		<u>RANK 1977-1985 CAPACITY EXPANSION</u>	<u>PRODUCTION CAPACITY 1985</u>	<u>RANK 1985 PRODUCTION CAPACITY</u>
	<u>E.</u>	<u>W. 2</u>			
NEWMONT (PEABODY)	2.8	16.6	11	95.4	1
AMAX	14.4	40.4	1	80.0	3
ST. JOE MINERAL	5.2		32	16.0	24
UNITED NUCLEAR	2.5	0.2	49	4.2	57
RANCHERS ENERGY		3.7	42	3.7	62
ASARCO	0.5		63	3.5	63
OTHER METALS MINING COMPANIES	0	5.6		6.2	
	<u>25.4</u>	<u>66.5</u>		<u>209.0</u>	

INDEPENDENT COAL

NORTH AMERICAN COAL	1.7	17.4	12	30.5	11
WESTMORELAND COAL (INCL. RESOURCES)	2.0	10.9	17	26.5	13
PITTSTON	7.5		23	26.5	14
EASTERN ASSOC GAS FUEL	2.9	3.0	29	15.0	26
ROCHESTER & PITTSBURGH	2.9		48	9.0	31
FALCON SEABOARD			-	6.5	37
KEMMERER		1.5	57	5.5	42
BAUKOL-NOONAN		2.6	50	4.7	51
BENJAMIN COAL	0.9		61	4.4	54
JEWELL COAL & COKE			-	4.2	57
OTHER INDEPENDENT COAL	8.9	1.3		31.1	
	<u>26.8</u>	<u>36.7</u>		<u>163.9</u>	

RAILROADS

MILLIONS OF ANNUAL TONS

<u>COMPANY</u>	1977-1985 CAPACITY EXPANSION		RANK 1977-1985 CAPACITY EXPANSION	PRODUCTION CAPACITY 1985	RANK 1985 PRODUCTION CAPACITY
	<u>E.</u>	<u>W.</u>			
UNION PACIFIC		14.8	13	16.2	23
BURLINGTON/NORTHERN		6.2	27	6.2	39
OTHER RAILROAD COMPANIES	1.5	2.1		4.2	
	<u>1.5</u>	<u>23.1</u>		<u>26.6</u>	

CONSTRUCTION

PETER KIEWIT	14.0	14	21.8	16
--------------	------	----	------	----

STEEL

U.S. STEEL	12.1		18	32.0	9
BETHLEHEM	2.3		53	18.5	21
LYKES	2.0		55	5.0	43
ARMCO	1.3	0.5	56	4.8	49
INLAND	2.5		52	4.8	49
NATIONAL STEEL	0.6		62	4.0	59
OTHER STEEL COMPANIES	6.8	3.7		15.6	
	<u>27.6</u>	<u>4.2</u>		<u>84.7</u>	

INDUSTRIAL

MILLIONS OF ANNUAL TONS

<u>COMPANY</u>	<u>EXPANSION E.</u>	<u>W.</u>	<u>RANK 1977-1985 CAPACITY EXPANSION</u>	<u>CAPACITY 1985</u>	<u>RANK 1985 CAPACITY</u>
GENERAL ELECTRIC		12.0	19	18.5	21
GENERAL DYNAMICS	1.9	2.5	36	11.0	29
JIM WALTER	7.3		24	8.5	32
MOORE-McCORMACK	3.1		46	5.0	43
ALCO STANDARD	2.3		53	4.5	52
ITT	0.2	1.2	59	4.0	59
BATES MFG.			-	3.5	63
MARMON GROUP			-	3.0	67
W.R. GRACE		3.0	47	3.0	67
OTHER INDUSTRIALS	5.2	1.7		16.4	
	<u>20.0</u>	<u>20.4</u>		<u>77.4</u>	

¹See footnote 1, Exhibit II-4

²See footnote 3, Exhibit II-3

Sources: See Exhibit II-3

LONG TERM COAL CONTRACTS FOR
GILLETTE, WYOMING PRODUCTION

<u>COMPANY</u>	<u>UTILITY</u>
AMAX	Colorado Public Service Kansas Power and Light Kansas City Power and Light Interstate Power Iowa Power & Light Southwestern Electric Power Co. Portland General Electric
ARCO	Nebraska Public Power District Southwestern Public Service Oklahoma Gas and Electric Lower Colorado River Authority Wisconsin Public Service
EXXON	American Electric Power Omaha Public Power
SUN	City of San Antonio Western Fuels Association Iowa Southern Power Co.
KERR-McGEE	Houston Light and Power Public Service of Oklahoma Arkansas Power and Light Central Louisiana Electric Co. Gulf States Utilities Cajun Electric Cooperative

Source: Private Communications, June - August, 1977

Footnotes

Chapter II - Coal

¹The National Energy Plan, The Executive Office of the President, Energy Policy and Planning (Washington, 1977) p. 65, 69-70.

²National Energy Outlook, Federal Energy Administration (Washington, 1976) p. 306.

³An Analysis of Existing Federal Coal Leases, Bureau of Land Management (Washington, March, 1976).

⁴A large amount of privately-owned reserves cannot be developed because these private reserves are "checkerboarded" in 640 acre blocks with Federal reserves which the Government will not lease. The bulk of the private reserves are railroad-owned, but much of the railroad-owned reserves either have been leased to coal development companies or would be leased and developed if adjacent government owned reserves could be utilized to complete economic mining units. (The "checkerboard" acreage is too small to develop completely normal-sized self-contained strip mining for supplying utilities 2-5 million tons per year for 25 years). The problem is not so much that more acreage is needed; its that specific acreage is needed so mines can be developed.

⁵Western Coal Development Monitoring System, Department of Energy (Washington, March 31, 1977) p. 2.

⁶An Analysis of Existing Coal Leases, Bureau of Land Management, (Washington, March 1977) p. 6.

⁷An Analysis of Preference Right Lease Applications for Federal Coal, Bureau of Land Management, (Washington, March 1976).

⁸Paul Averitt, Coal Resources of the United States, January 1, 1974, Bulletin 1412, United States Geological Survey, (Washington, 1975) p. 89.

⁹Richard E. Balzhiser, Electric Power Research Institute, Energy Options to the Year 2000, Chemical Engineering, January 3, 1977, p. 81.

¹⁰John J. Pyrdol, Electric Utilities Captive Coal Operations, Staff Report by the Bureau of Power, Federal Power Commission, June, 1977, p. 7.

¹¹ibid.

¹²The Waiting Game, Forbes Magazine, October 15, 1976, p. 44.

¹³ibid.

¹⁴ General Electric Company, Notice of Special Meeting of Share Owners, to be held December 15, 1976, p. 48 and F-42.

¹⁵ These include Arch Minerals, Dravo Corp., Peter Kiewit, and Energy Development Corp. (See Keystone Quarterly, January 1977 and the Annual Report, 1976, of Union Pacific Corp.)

¹⁶ Study of New Mines, Additions and Major Expansion Plans of the Coal Industry and the Potential for Future Coal Production, The National Coal Association (Washington, November 1977) p. 1.

¹⁷ John J. Pyrdol, Electric Utilities Captive Coal Operations, Staff Report by the Bureau of Power, Federal Power Commission, June, 1977, p. 17.

CHAPTER III - URANIUM/NUCLEAR

A. Summary of Interviews	67 - 70
B. Uranium/Nuclear Requirements	71 - 73
C. Historical Economics of the Uranium Industry	73 - 78
D. Petroleum and Other Industrial Participants in Uranium/Nuclear Expansions	79 - 92
E. Future Uranium/Nuclear Supplies	92 - 102
Exhibit III-1 to III-18	103 - 124

Chapter III - Uranium/Nuclear

A. Summary of Interviews

As with the previous section on coal, all numerical data, unless otherwise noted, originated with public sources. Subjective views and perceptions of the uranium nuclear industry were gathered in face-to-face interviews with sixteen large oil companies, five electric utilities, two coal companies and five "others" (a railroad, two large extractive mineral companies, a conglomerate energy company, and a large energy financing bank).

Telephone interviews were held with a number of individuals at an additional 20 firms and/or organizations active in the energy area.

As described in the Introduction of Chapter II- Coal, the individuals interviewed were in senior management positions and, as such, could intelligently discuss and influence corporate policies. It should be noted that their views were based on economic conditions as perceived at the time of the interviews. Their views will change as economic conditions change. Those interviewed were asked to discuss the nature of their involvement in uranium/nuclear energy with particular emphasis on investment strategies. They were also asked to give their views of other participants in the uranium/nuclear industry. Attempts, in all cases, were made to interview those companies that would have the most significant impact on energy supplies and demand.

Responses were as follows:

I. Current Interest in Uranium/Nuclear Energy.

"Current interest" was defined as present, or possible future investment in either the exploration for, or acquisition of, reserves, production and/or milling facilities. Oil company responses were grouped into five categories as shown below:

<u>Intense Interest</u>	<u>Substantial Interest</u>	<u>Some Interest</u>	<u>Limited Interest</u>	<u>No Interest</u>
3	6	2	3	7

"Intense interest" describes those companies who have made major uranium/nuclear investments and who can be expected to continue to invest in uranium/nuclear operations.

"Substantial Interest" describes those companies who have made major investments. They might make additional investments in the future.

"Some interest" described those companies who have made minor investments but are planning immediate future investments.

"Limited Interest" describes those companies who have relatively low-keyed leasing and exploration operations.

"No Interest" describes those companies with no present investments or plans for future investment in uranium/nuclear operations.

"Other" energy producers also had varying views.

<u>Intense Interest</u>	<u>Substantial Interest</u>	<u>Some Interest</u>	<u>Limited Interest</u>	<u>No Interest</u>
-	3	-	1	-

Three of these four companies are making substantial investments in uranium/nuclear facilities. The fourth company has sold its uranium assets and now has only a "residual" interest.

II. Entry into Uranium - Of the thirty companies interviewed, none felt constrained by competition or a perceived lack of sufficient reserves. Those not involved in uranium seemed to feel, like one, that it was "just a lousy business to be in". The uncertainties of demand and the engineering and financial risks of deep production left nineteen companies interviewed feeling lukewarm, at best, about investments in the uranium/nuclear fuel business.

III. The Comparative Attractiveness of Uranium/Nuclear as an Investment. - Oil companies active in uranium/nuclear state that it is an attractive investment alternative. Those nine companies indicating "intense" and/or "substantial" interest were asked whether uranium/nuclear was more attractive, the same, or less attractive, than alternative investments.

<u>More Attractive</u>	<u>The Same</u>	<u>Less Attractive</u>
------------------------	-----------------	------------------------

4

5

-

As these data indicate, oil company current interest in uranium/nuclear energy varies widely. One company, active in uranium/nuclear said,

"Over the years, we got continuing confirmation that we were unable to find crude oil or natural gas. Because of this, we became active in both coal and uranium,

fuels we consider to be complementary."

Another company not active in uranium/nuclear, stated,

"We are not an energy company. We are an oil company in the oil business."

A third company perceived long lead times, high capital expenditures, and uncertain demand for uranium/nuclear. Because of this, their investment efforts are being concentrated in other areas.

Electric utilities showed less interest in uranium/nuclear than the oil companies. The subjective measure of the five utilities interviewed are as follows:

<u>Intense Interest</u>	<u>Substantial Interest</u>	<u>Some Interest</u>	<u>Limited Interest</u>	<u>No Interest</u>
-	-	2	2	1

One utility with "limited interest" said, "We're in the power business, not the fuel business. We wouldn't be fooling with it today if we felt we could buy adequate supplies of uranium at reasonable prices".

Another company with "limited interest" cited supply problems, installation problems, and unfavorable cost comparisons with coal as reasons for their "go slow" attitude on uranium/nuclear.

B. Uranium/Nuclear Requirements

The role projected for nuclear power in the National Energy Plan (NEP) is considerable; it is projected to be the fastest growing major electricity source (16% per year through 1985) while coal, which has always fueled most of the electrical demand, is expected to grow at a 6.4% annual rate. During the 1977-1985 period, the absolute amount of electricity from oil and gas is expected to decline and to be replaced by nuclear power and coal. For the period 1985-2000, nuclear power is projected to grow at the slower rate of 7.3% while electricity from coal is expected to grow at over 2% annually.

Present trends toward increasing electrification are expected to continue. Electricity utilized about 29% of energy inputs in 1976. Under NEP, electricity produced by utilities will, in the year 2000, require 33% of primary energy inputs. Without NEP's estimates of energy conservation, electricity would, estimating unrestrained demand, use a slightly greater percent of resources.

At the end of 1976, there were 64 nuclear-powered electrical generating plants in the U.S. that were producing a little less than 10% of all electrical energy. To increase the supply of nuclear-powered electricity to 20% of electrical energy in 1985, NEP calls for the construction of an additional 75 nuclear-powered plants by 1985.

Nuclear's role in fueling electric generating plants is considered, by the electric industry, vital to the future adequacy of electric power supply; The National Electric Reliability Council (NERC) states that nuclear power cannot be displaced by coal, particularly in light of the many difficulties already facing

coal mining and coal burning.⁽¹⁾ NERC's forecast is based on current plans of the nation's electric utilities. In its 1977 survey, nuclear power generation, as planned by the utilities, is projected to increase its contribution to electric energy production from about 13% in 1977 to 28% in 1986, which, because of growth in electrical power, also requires a nearly fourfold increase in the absolute quantity of nuclear power generated.

NEP's nuclear projections are in terms of both nuclear electrical generation and installed nuclear capacity. Determination of uranium production needed to meet NEP's electrical projections is a complex procedure involving a large number of assumptions, mostly concerning government policies, many of which are currently subjects of heated controversy and almost all of which are in a state of flux.

Uranium needed to meet NEP requirements was projected by ERDA's (now DOE) office of Policy and Evaluation⁽²⁾. Estimates are based on complex computer models which account for shifting capacity capabilities and other variables. However, the model does not make assumptions about government uranium enrichment policies or the effect of conservation under NEP, but presents a range of forecasts which can vary by 30% for 1985 demand, depending on assumptions used.

Exhibit III-1 shows ERDA's forecasts. These assume no reprocessing of spent fuel, a procedure that would reduce demand for uranium. 1977 uranium concentrate (U_3O_8) pro-

duction is expected to exceed 14,000 tons.⁽³⁾ This production estimate exceeds ERDA's prior forecasts of 1977 uranium usage under all cases. Despite projections of increased future requirements, actual demand for uranium is created by utilities buying uranium, mainly by contracting for future requirements. From the viewpoint of the uranium developer, this actual demand is highly uncertain both in its amount, its timing, and its price. For example, uranium purchase commitments from 1975 through June, 1977 (see below) show wide variations.

Table III - a
New Uranium Commitments with Producers⁽⁴⁾

	TONS U ₃ O ₈		
	<u>First Half</u>	<u>Second Half</u>	<u>Year</u>
1975	N/A	N/A	14,500
1976	25,500	57,900	83,400
1977	2,100	N/A	-

C. Historical Economics of the Uranium Industry

An understanding of the brief history of the economics of the uranium industry and the severe boom/bust cycles of the past 20 years is vital to understanding the perceptions of current uranium industry participants, and, perhaps more importantly, the perceptions of at least some non-participants.

Although uranium was discovered in the U. S. over 100 years ago, production of uranium in the U.S. was

negligible until the decade following World War II. The only U.S. participants were prospectors and small mining companies operating principally in southeastern Utah. Prior to World War II, worldwide demand totalled about 0.4 million pounds per year, the bulk of which was used for medical purposes and was imported from Canada and the Belgian Congo, who operated under a cartel agreement. Following World War II, U.S. requirements of uranium for military use by the Atomic Energy Commission (AEC) led to substantial increases in domestic uranium demand. Uranium production capability in the U.S. grew dramatically in the late 1950's as a result of this demand. (See Exhibit III-2). Many companies, large and small, oil and non-oil, entered the uranium production business. Unexpectedly, the government stockpile began to grow so fast that in the early 1960's the AEC (now DOE) introduced a "stretchout" program and reduced its purchases. Domestic U_3O_8 production, which had averaged about 36 million pounds per year during 1959-1962, peaked in 1960 at 37.6 million pounds. Production declined during 1963-4 and dropped to an average of less than 21 million pounds per year in the 1965-1967 period.⁽⁵⁾ Production has not been close to this level since. Exhibit III-2 shows mined uranium production, unit price, and total revenues of uranium sales to the AEC for the years 1948-1976.

In the mid-1960's, a cutback in government procurement and a consequent reduction in industry revenues caused severe financial problems in the uranium industries. Many producers

merged into other firms or left the business entirely.

In the late 1960's, however, AEC projections of nuclear power generation, and consequent uranium requirements, were for sharp, sustained increases for at least the next 20 years. Again, many companies and individuals rushed into the uranium industry. The extent of uranium interest is perhaps best illustrated by the extremely large increase in acquisitions of uranium mineral rights in the late 1960's. Land held for uranium increased from 731,000 acres at the beginning of 1966 to 27.2 million acres at the end of 1969. (See Exhibit III-3).

In 1970, it became increasingly evident that ERDA (now DOE) nuclear power forecasts were much too optimistic. These projections have been revised downward each year since 1970 (See Exhibit III-4). In addition, demand for uranium to supply nuclear reactors already installed or on order was sluggish. Electric utilities were not signing many long term contracts for future uranium supplies. It was at this juncture, that the AEC announced its intention to dispose of its uranium stockpile, estimated to be about 100 million pounds. While the method chosen for this liquidation was the one least harmful to the industry, the stated intention to sell 3-4 years of current production into an already weak uranium market with existing over-capacity created an even stronger buyers market, resulting in substantial financial losses to uranium producers. Again, producers and explorers left the business.

Changes in AEC policy in late 1972, to require long-term

enrichment contracts, encouraged utility fuel buyers to enter the uranium market to secure longer-term commitments for uranium supplies. Additionally, in the fall of 1973, the Arab embargo was accompanied by higher world-wide uranium prices. Also about this time, foreign buyers entered the U.S. uranium market to secure uranium supplies. The result of all of these actions was a sharp increase in U.S. demand and a willingness for buyers to pay higher prices to obtain uranium supply commitments. (As discussed elsewhere, uranium prices are a minor factor in the costs of nuclear power generation). Upward price moves encouraged increased land holdings and exploration expenditures as shown in Exhibits III-3 and III-5.

In September 1975, Westinghouse announced that due to "commercial impracticability", it would be unable to deliver about 65 million pounds of uranium which it had contracted to sell to various buyers. (For some years, Westinghouse had been contracting fuel supplies to utilities without arranging for production of the uranium it had contracted to sell.) The reaction of the affected utility buyers was to enter the uranium market to contract for the uranium supply which they thought had been assured by Westinghouse. Many bought in the spot market. One even advertised for uranium in the Wall Street Journal. Others negotiated directly with sellers without bothering to utilize time-consuming competitive bidding processes. Under these stimuli, prices increased rapidly and, at the end of 1975 reached \$40/lb, with full payment to be

made in advance of delivery. The result of utility uranium contracting was a sharp increase in exploration and development expenditures to expand uranium production capability. (See Exhibit III-5 and III-7).

Despite higher costs for uranium and nuclear power plants, the electric power industry believes that nuclear power will continue to produce the lowest cost energy, (excluding hydro-electric in some parts of the U.S.) for the foreseeable future.⁽⁶⁾ Because of this lower cost, nuclear power is the economic choice of most electric utilities. A survey of 1975 operations published by the Atomic Industrial Forum, an industry association, showed the average cost (including capital costs, operating and maintenance costs and fuel) of a kilowatt hour produced by nuclear generators was 1.2 cents per kilowatt hour. This compared to an average total cost of 1.7 cent/kwh for electrical energy from coal and 3.3 cents/kwh from oil. Translated into total annual costs, nuclear operations in 1975 saved over \$2 billion, almost 250 million barrels of oil, or an additional 55 million tons of coal.

Despite anticipated cost increases for both nuclear and fossil-fueled generating systems, the economic advantage of nuclear is expected to increase. Internal estimates by one electric utility of electrical generating costs of new capacity installed in 1985 showed nuclear electric power to cost 25% less than oil-fired plants or coal plants with scrubbers, despite a tripling of nuclear plant operating costs and an approximate doubling of the cost of uranium

(to \$76 per pound). Their calculations indicate that the total cost of nuclear fuel could triple before electric power generated by nuclear plants and fossil-fuel plants would have equal costs.

Nuclear fuel costs have three major components: ore, enrichment, and reprocessing. Enrichment and reprocessing costs could rise dramatically without having much impact on total nuclear fuel costs. The cost of uranium ore (yellowcake) could rise to six times the current (5/78) long-term contract price of \$40 per pound (to \$240 per pound) before the total power generation costs of nuclear units would equal those of coal-fired units with scrubbers. These calculations, however, assume that nuclear fuel would be recovered and reprocessed, which is not now being done. If recovery and reprocessing were not included, it is estimated by the utility that nuclear fuel costs, with a 600% price increase in uranium ore, would increase 14% and total nuclear power generation cost would increase less than 3%. Clearly, these minor revisions would not change the conclusions of the economic comparisons above.

The Electric Power Research Institute (EPRI) reached similar conclusions.⁽⁷⁾ Their data indicate that capital costs of nuclear plants are far higher than those of fossil-fired plants, but nuclear operating, maintenance, and fuel costs are substantially lower. Once a nuclear power plant is built, it is relatively insensitive to inflation since the fuel cost, like hydroelectric, is such a small part of the total.

D. PETROLEUM AND OTHER INDUSTRY PARTICIPANTS IN
URANIUM/NUCLEAR EXPANSIONS

The number of participants in each stage of the uranium fuel cycle declines as one moves through the exploration, production and processing cycle. Shown below are the number of participants in each operation:

Larger Explorers (per ERDA)	100+
Producers (per ERDA)	38
Millers	25
Convertors	2
Enrichment (U.S. Government)	1
Fuel Fabricators	5

Although many companies participate in more than one phase, no company participates in all phases. This section will discuss only the first three stages cited above: Large Explorers, Producers, and Millers.

One hundred nineteen large uranium explorers responded to a survey made by ERDA in 1977. Exhibit II-6 shows the survey participants; it lists 17 large oil companies, 11 small oil companies, and 91 non-oil companies and individuals as active explorers for uranium. There are additional explorers and many lease holders who were not contributors to ERDA's survey.

Exhibit III-7 lists firms ERDA considers to be producers, 1976 production, and current expansion of productive capacity. As these data indicate, a substantially lesser number participate in conventional uranium mining or produce other forms of uranium from other minerals. It should be noted that most of the companies on the exploration and production lists are recent entrants to the uranium industry; as a consequence, many of these

firms are not in production.

A somewhat lesser number (25) participate in milling operations. Owners of most of the milling capacity are shown in Exhibit III-8. This list, however, does not include those companies with minority ownership of mills. (For example, Silver Bell Industries of Denver has a 35% interest in Union Oil's new mine and mill in Wyoming.) Most, but not all millers are also producers. Current exceptions are Federal Resources and American Nuclear, neither of whom are current domestic uranium producers, but whose partnership mill processes ore for others. Exhibit III-8 also shows that an increase of 43% of existing milling capacity is currently planned. Expansion of milling capacity is particularly significant as an indicator of confidence in uranium demand by industry developers. Of the 17 mills operating in 1976, only 5 have been built since 1960.

Most, but not all, producers are also explorers. Exceptions include the by-product uranium producers, such as Freeport Minerals, and companies such as U.S. Steel who acquired existing uranium reserves and production capacity.

Many explorers and lease holders are not current or potential uranium producers. A number of the explorers in ERDA's exploration survey (Exhibit III-6) have neither the desire nor the capability to become uranium miners or millers. Companies interviewed stated that to many smaller explorers, uranium is an "asset play"; it is a mineral to be explored for and, if found, the rights to the minerals sold to a producing company. Some successful explorers enter into joint ventures with producers, a move that

ties exploration rewards to the joint venture's operating profitability, a situation some explorers desire and some try to avoid.

Some smaller uranium developers interviewed stated that oil companies are the preferred companies for smaller explorers and developers to deal with when trying to explore or develop uranium holdings. Oil companies, they said, have historically been willing to enter into joint ventures with smaller partners and provide financial assistance if required. Mining companies historically have operated their mining ventures under single ownership and are less willing to participate with smaller companies.

Many holders of uranium leases and mineral rights have no stated intention of making expenditures for exploration, but are allegedly holding leases for speculation in the hope of increases in the value of their leases from general uranium price rises or, better, the discovery, by others, of commercial uranium concentrations nearby.

Recent price rises and the recent willingness of electric utilities to contract for their future requirements is causing a sharp expansion of both uranium exploration activity and of new construction and expansion of uranium production facilities. Expenditures on uranium exploration were up 40% from \$122 million in 1975 to \$171 million in 1976. (See Exhibit III-5.) According to DOE, expenditures are planned to increase 38% to \$236 million in 1977 and about 40% more in 1978. In recent years,

actual exploration expenditures have exceeded industry plans. These exploration costs are largely for land and for drilling.

Eighty-one companies reported land acquisitions of 4.75 million acres at a cost of \$13.9 million, an average of \$2.92 per acre, a 40% decline in unit acreage costs from 1975. Despite inflation, 1976 acquisition costs were 11% less than the average acreage costs from 1966-1975 (see Appendix G-7). Land acquisition costs in 1976 ranged from less than \$10 to more than \$200 per acre.

Table II-b summarizes land acquisitions by active reporting companies from 1966 through 1976.

TABLE III-b

LAND ACQUIRED FOR URANIUM EXPLORATION

<u>Acquired During</u>	<u>Millions of</u>		<u>Average Cost per Acre</u>
	<u>Acres</u>	<u>Dollars</u>	
1966-1974	26.73	\$87.68	\$3.28
1975	3.48	16.70	4.80
1976	4.75	13.89	2.92

Uranium exploration drilling expenses increased 36% in 1976 over 1975, and are expected to increase another 41% in 1977. (See Exhibit III-5.) 1976 drilling finally surpassed 1969, the previous peak year, by 15%. Ninety-seven companies reported almost 35 million feet of drilling. Drilling costs averaged \$3.13 per foot, but ranged from \$1 per foot to over \$25 per foot.

Shown below is information on the industries and companies engaged in exploration, production, and milling.

Oil Companies

Oil companies are by far the largest factor in uranium development. Oil companies mined almost half the total uranium produced in 1976, about 12 million of the 25.5 million pounds of total uranium concentrate production (see Exhibit III-7). More importantly, oil companies are currently the largest developers of new uranium capacity to meet projected energy requirements. Exhibit III-7 also shows identifiable 1976 production of all uranium producing companies (as defined by DOE) and current developers of new and expanded production capacity. Although detailed data have not yet been accumulated on total additional uranium concentrate production capacity, it is likely that oil companies are the major factor in this expansion.

Milling capacity expansion from 1977 through 1985 is summarized by company in Exhibit III-8 and by industry in Exhibit III-9. This capacity is currently being more than doubled; oil companies are developing 68% of this expansion, increasing their current milling capacity by 63%.

Exhibit III-10 shows comparative financial data for uranium developers. Financially, the oil companies have greater profits, larger shareholders equity, and more total assets than other industry groups active in uranium. Financial strength is currently important for uranium

production and will become critical as mines become deeper and more expensive. Both Gulf and Phillips, for example, have deep (3500 feet) ore deposits that have significant water problems. Gulf's mine is projected to cost more than \$150 million before a determination can be made whether it is an economically commercial venture. Because of its size (over 100 million pounds of uranium can potentially be mined) and risk, this expenditure is not financeable by independent uranium companies. Four small independent companies had been unsuccessful in developing these same deposits.

Not all oil companies, however, are capable of generating enough cash at current high rates of expansion. Kerr-McGee is currently developing 5 mines and a mill; Public Service of New Jersey has agreed to advance up to \$115 million for development of new mine and mill facilities for production of 20 million pounds of uranium over 15 years. (8)

Intercontinental Energy received \$14 million from two utilities (in separate transactions) for development of about 1.5 million pounds of solution-mined uranium. (9)

Independent Uranium and Nuclear Companies

Independent uranium companies are again becoming a factor in the uranium production industry, although well behind the oil companies in both existing production and current expansion activity. Of the seven companies included in Exhibit III-II (Independent Uranium Companies, Financial Data) four, United

Nuclear, Federal Resources, American Nuclear, and Atlas, have mined uranium in the past.⁽¹⁰⁾ Two other companies, Reserve and Bokum, have properties under development⁽¹¹⁾. Federal Resources and American Nuclear have a joint interest in some currently inactive mines, in a mill which is toll (custom) milling others' production, and in exploration operations.⁽¹²⁾ Nuclear Dynamics has only exploration operations which are financially supported by other non-uranium operations.⁽¹³⁾ None of the independent uranium companies have been consistently profitable for the last 5 years and only two are currently profitable (see Exhibit III-II). All companies except Atlas receive utility advances, principally from TVA.

United Nuclear, the largest independent, survived the lean years by having "downstream" nuclear operations, the revenues of which came principally from government contracts.⁽¹⁴⁾ Revenues and earnings from these downstream nuclear operations have substantially exceeded those from uranium exploration and production in recent years.⁽¹⁵⁾ United Nuclear's uranium operation is partially financed by TVA; in fiscal 1976, TVA supplied \$3.6 million (45%) of an \$8 million capital expenditure program.⁽¹⁶⁾

Atlas, a long time uranium miller and producer, has diversified into other minerals, profitable general manufacturing, and contract services operations.

Federal Resources, principally a Canadian uranium producer,

is an amalgamation of 11 former uranium producing companies. Federal Resources' uranium operation is principally financed by TVA and AGIP, an agency of the Italian Government. (17)

Reserve Oil and Minerals, (which has no oil operations) is a large uranium leaseholder which has not been profitable in the past 5 years. (See Exhibit III-II). Some of Reserves' uranium holdings are being developed in a joint venture with Sohio, who is the operator of the Venture, and who also provides additional financing to Reserve. (18)

American Nuclear, founded in 1959, has not yet directly produced uranium except as a minority partner with Federal Resources. American's major revenues are from a minerals exploration drilling division. American is largely financed by TVA and other utilities. (19)

From these data, it appears that there is not a strong, viable, independent uranium industry. All uranium companies receive funds from non-uranium operations or from exploration advances or funding provided by others. An elimination, or any restriction, of this funding would adversely effect the independent uranium industry.

Metals Mining Companies

Many metals mining companies are involved in uranium exploration, but have little involvement in uranium production and milling. Interest in uranium is highest among smaller mining companies. Few large-scale, substantial mining companies

have, apparently, shown interest in uranium production.

Very little planned uranium production capacity expansion is being done by metals mining firms. Only four mining firms are involved in mining capacity expansion and two in milling capacity expansion (see Exhibit III-7), accounting for 16% of total uranium milling expansion (see Exhibit III-9).

Phelps Dodge (Western Nuclear) is the largest uranium mining company, and is adding 80% of mining company milling expansion (see Exhibit III-8). Phelps Dodge had after-tax losses on uranium operations of \$16 million in 1976, \$8 million in 1975, and \$1 million in 1974.⁽²⁰⁾ The 1976 loss of \$16 million included a \$7 million provision for loss for 1977 sales of uranium concentrate at contracted prices that are substantially lower than current costs. Because of lower than anticipated production at its Wyoming properties, the company is borrowing uranium to meet near term commitments. During 1976, the company sold some of its non-producing uranium properties to others, including selling its Allied Nuclear subsidiary to Federal American Partners, a partnership which is now entirely funded by TVA.⁽²¹⁾

Homestake is the only other mining company expanding milling capacity. The largest portion of Homestake's uranium production is in partnership (30%) with United Nuclear. Much of Homestake's uranium exploration is financed by a utility.⁽²²⁾

Amax, a rapidly expanding mining company and coal developer in the U.S., has dropped all uranium activity.

Railroads/Oil

Union Pacific has extensive Western land holdings that include over 10 billion tons of coal and a high probability of significant amounts of uranium. Union Pacific is developing its first uranium producing operation in a joint venture with Southern California Edison. (23)

Other Industrial Companies

Involvement in uranium production by other industrial companies is limited. There are only four such companies active in uranium production: General Electric, Westinghouse, Union Carbide, and U.S. Steel. (See Exhibit III-7.) None of the expansion of conventional uranium production (mining and milling) is being done by these companies, although all but GE are planning to expand solution mining activities.

Two (GE and Westinghouse), are heavily involved in downstream nuclear activities, such as reactor manufacturing and fuel fabrication.

The other two companies are a chemical company (Union Carbide), who is a long-time uranium producer, and U.S. Steel, who is involved in solution mining.

Union Carbide, who at one time (1955) was the largest uranium producer, is the only chemical company with current involvement.

The nuclear operations of Olin Mathieson and Mallinckrodt Chemical companies were acquired by United Nuclear in 1961. (24)

Some other industrial companies have recently quit uranium activities. Bethlehem Steel, for example, recently transferred its interest in an exploration joint venture with Nuclear Dynamics to Pacific Power and Light.⁽²⁵⁾ Bethlehem Steel had been supplying the financing for the joint venture.

There apparently is no mass of companies rushing to enter the uranium business; R. J. Reynolds is the only large non-energy company involved in uranium, and that involvement in uranium exploration is through its acquired subsidiary, American International Oil Company (Aminoil).

Electric Utilities

Because many utilities are looking to nuclear as the preferred fuel for electric power generation, some of those interviewed are considering shifting already-planned coal-fired plants to nuclear. Substantial concern, however, has been expressed regarding environmental and political problems.

Electric utilities are a growing factor in uranium exploration and production through their financial support of uranium exploration and production companies. 25 of 68 utilities with nuclear reactors installed or on order are financing uranium exploration.⁽²⁶⁾

With few exceptions, electric utilities will need to raise substantial amounts of debt and equity in the next few years because of high capital requirements for installation of electrical generating capacity. Investor-owned electric

utilities are estimated to require capital expenditures averaging \$25 billion for the 5 years, 1977 through 1981, while generating \$10 billion internally and raising \$15 billion per year externally. (Appendix B contains the basis of this estimate). Scrubbers and other capital requirements can seriously worsen this cash problem. Exhibit III-6 and Appendix C shows utility participation in uranium exploration and production. Exhibit III-7 shows that Commonwealth Edison is the only utility expanding milling capacity. This capacity addition is equivalent to 3% of total projected milling capacity expansion. One other utility (Southern California Edison) has a joint venture with Union Pacific; they are currently developing a medium sized mining/milling operation.

TVA (federally-owned) is providing exploration funds to several uranium companies and is reputed to be the largest utility financier of uranium exploration and production. Recently, TVA agreed to supply \$130 million for uranium development to the Federal-American partnership.⁽²⁷⁾ This is 3 times the total assets of these combined companies and 30 times the total assets of the partnership.

Other utilities are also advancing substantial funds for mine and mill development. As mentioned earlier, Public Service Electric and Gas (New Jersey) has agreed to make periodic advances of up to \$115 million to Kerr-McGee (oil) to finance mining and milling facilities required for production of 20 million

pounds of uranium from 1980 to 1995.⁽²⁸⁾ Long Island Lighting advanced \$15 million to Bokum Resources (uranium).⁽²⁹⁾ Pacific Gas and Electric and Virginia Electric have advanced \$12 million and \$2 million respectively to Intercontinental Energy (oil) for solution mining development.⁽³⁰⁾ Florida Power and Light agreed to advance \$6 million to American Nuclear for delineation drilling on certain properties.⁽³¹⁾

Much of the increased utility involvement in exploration for uranium stems from abrogation of contracts for uranium delivery by Westinghouse and some independent uranium producers, including United Nuclear. By supporting exploration, the utilities are able to obtain a "call" on uranium that the exploration might discover.

Utilities are generally reluctant to invest in big, high risk, mining ventures. If the ore cannot be economically mined, utility regulation in most states does not provide for recapture of expenditures for which no benefits are obtained. The expenditures, therefore, would be charged to the shareholders. If the mine were successful, the uranium used would be charged at cost (not market price) to the utility. Gain to utility shareholders would be the allowed return on expenditures that goes into the rate base. Most utilities, therefore, do not consider high risk development expenditures an attractive investment.

Although many utilities are supporting exploration, few, it appears, want to become involved in uranium mines or mills. Most interviewed dislike advancing "front money" for exploration, but find that this is the current method of operation of the uranium industry, particularly among the less affluent independent uranium companies. Utilities indicated a preference for stronger suppliers who can assure them delivery of contracted uranium despite adverse events.

Utilities interviewed say they will not commit to construction of a nuclear plant unless they have an assured supply of fuel for at least the first 8-10 years. Larger producers of uranium have continued uranium deliveries despite operating losses on uranium production. Phelps Dodge, as mentioned, continued to deliver uranium in 1976 despite a projected \$7 million loss on deliveries.

E. FUTURE URANIUM/NUCLEAR SUPPLIES

In analyses of the adequacy of uranium resources, the importance of finding the resources and mining the ore appears to be sometimes overlooked. While the preponderance of analysis centers about the number of nuclear power plants needed between 1985 and 2000, there is less analysis given to determining how much uranium will be required to fuel these plants and keep them operating. Some of the problems concern uranium reserves. There are substantial differences between estimated "resources" and "reserves", and between "reserves" and "usable fuel". To

obtain fuel to meet future needs, uranium resources must first be located through exploration. Exploration for uranium requires, like oil, geological effort, land acquisition, exploratory drilling, and, if necessary, delineation drilling and economic evaluation.

Because of the long lead time in the exploration, development, and production cycle, decisions must be made looking forward to a uranium market 10-20 years in the future. Exhibits III-12 and III-13 shows DOE estimates of lead times required for developing uranium production. These lead times, averaging 14 years (based on predicting the expansion activities of another industry) are much different from those of an established industry which can often make decisions to expand or contract on the basis of the near term (1-3 year) economic outlook.

Exhibit III-14 compares the current plans of uranium producers with DOE's production capability estimate. (Industry plans are from a DOE survey of each uranium producers' estimated uranium production during each of the next 5 years). Producers plans are virtually identical to DOE's projected maximum capability of what could be produced for an average additional \$30 per pound in expenditures.

DOE comments that some companies provide figures that are more "targets" than plans, and that history has shown that various problems cause actual production to fall short of

plans, even if a few producers exceed production goals. These problems include equipment failures, strikes, work slowdowns, delays in equipment and material deliveries, permitting problems, litigation, and other unplanned events.

Exhibit III-15 shows this maximum production capability relative to NEP uranium requirements. "Class" numbers refer to classes of production centers.

Class 1 centers are currently producing mines and mills and other facilities.

Class 2 centers are those production facilities that are announced or underway.

Class 3 centers are production facilities which DOE thinks may be built where DOE estimates reserves to justify eventual production expenditures.

Class 4 centers are possible production facilities for which present reserves are insufficient to justify production facilities but where there is some evidence of potential resources that might justify eventual production. The lead times for Class 4 centers generally range from 6 to 22 years, and average 14 years.

Note, also in Exhibit III-15, that in 1979 NEP requirements will exceed existing production capability and in 1982 will exceed currently planned capacity, despite a planned doubling of current productive capacity.

More importantly, NEP requirements exceed development of Class 4 production centers. To reiterate, Class 4 are possible production centers where there are possible reserves which might warrant production, but for which reserves have not yet been discovered or delineated. The production centers don't exist, nor do the reserves on which to build them.

Production Costs

Funds necessary to find and develop commercial uranium deposits are increasing. Mines are getting deeper (both underground and open pit), ore grades are declining, mill recovery rates are decreasing, and labor costs are rising.

Exhibit III-16 shows ERDA's projections of increasing underground mining requirements for maximum production capability.

Exhibit III-17 shows declines in ore grades necessary to produce at maximum capability from currently "known" resources produced at \$30 per pound. The effect of declining ore grades is to increase the amounts of ore that must be mined and milled to produce constant amounts of uranium concentrate. Obviously, this raises the cost per pound of uranium concentrate.

Uranium producers indicate that capital costs for mines producing 1000 tons/day @ 1000 feet have increased from \$50 per annual ton in the early 1970's to \$150 per ton in 1977.⁽³²⁾ At a depth of 2000 feet, this same mine would cost

about \$300 per annual ton of mine capacity. Thus, it could cost as much as \$220 million to build the mining capacity to feed a 2000 ton per day mill.

A large percentage of uranium produced in 1985 and beyond will have to come from underground mines in New Mexico and Wyoming. In New Mexico, all mines are expected to be 2000 feet or deeper, with the deepest currently planned mines at 3500-4000 feet. In Wyoming, mines will be less deep at 600 to 2000 feet, but will have problems associated with unconsolidated sediments. (33).

Construction costs of new milling capacity have risen from \$4-5,000 per daily ton in the early 1970's to \$12-15,000 in 1977. New economically sized mills total \$25-30 million. (34) Recent costs for new low-cost open pit mines and mills producing about a million pounds of uranium per year are: Socal, \$45 million; Union Oil, \$45 million; Phelps Dodge, \$50 million.

Gulf's 3500 foot underground New Mexico mine is expected to cost about \$500 million without unanticipated problems. Shallower underground mine and mill complexes are estimated at \$100-200 million for about 1 million pounds of uranium concentrate per year.

Exploration and development costs necessary to meet NEP nuclear requirements vary widely because of the large number of variables that can affect both the uranium requirements and the physical development necessary to meet the requirements. Both DOE and industry estimates fall within a broad range of \$15-25 billion

over the next 12-15 years. This is an average of about \$1.5 billion per year in 1977 dollars.

Uranium Holdings

Virtually anyone can obtain uranium leases, particularly Federal leases. Federal leases are obtained by staking claims, surveying the land, and filing claims with the Bureau of Land Management (BLM). Currently only one area, in New Mexico, is subject to competitive bidding for Federal uranium mineral rights.

The Federal Mining Act requires that claims must have \$100 spent per claim (20 acres) per year in exploration or development, but expenditures on a group of contiguous claims can be averaged among the claims to achieve the \$100 per claim average. Although the \$100 expenditure requirements are difficult to police, a party desiring certain leases can file on existing claims and accede to the mineral rights if the current claimants do not meet the annual expenditure requirements.

Leasing of uranium rights on private, state and Indian lands varies from the Federal procedure, but entry is open to any interested party. According to both private mineral brokers and field offices of the U.S. Bureau of Land Management, there are no barriers to leasing, and there is no control of uranium prospects by large oil companies or others.

As noted, Exhibit III-3 shows changes in total uranium land holdings from January 1966 to January 1977. These data reflect the pessimism and the bust of the early 1960's. It also shows the bust of the early 1970's, although this is not entirely reflected because there is not sufficient time for all inactive claims to be removed from public records.

Table III-c shows detail on the increase in total uranium land holdings since January 1973.

TABLE III-c
LAND HELD FOR URANIUM EXPLORATION & MINING
 (in thousands of acres)
DISTRIBUTION BY LAND CATEGORY

	<u>1/1/73</u>	<u>1/1/74</u>	<u>1/1/75</u>	<u>1/1/76</u>	<u>1/1/77</u>
State	1,859	1,945	2,968	3,385	4,635
Claim	9,679	10,290	11,634	12,605	15,067
Acquired	206	145	275	277	293
Indian	603	646	635	627	815
Fee	<u>5,330</u>	<u>5,748</u>	<u>5,764</u>	<u>6,017</u>	<u>6,273</u>
Total	17,677	18,774	21,276	22,911	27,083

The data of Exhibit III-3 and Table III-c include acreage held by all companies and individuals as shown in public records. These data include lands which may have been relinquished, although control may still be indicated in the public records.

About half of the total acreage shown in public records is held by entities currently active in uranium exploration and develop-

ment. The remainder is held for eventual exploration or for speculation through hoped-for price appreciation and resale. Acreage is also held by hundreds of other firms and individuals whose operations, if any, are too small to be part of the ERDA exploration survey.

According to DOE (GJO-103-77), ⁽³⁵⁾ at the end of 1976, 96 companies directly involved in exploration and development drilling activities reported holdings of 14.95 million acres for uranium exploration. These holdings are up 26% from the 11.84 million acres held at the end of 1975.

In addition to companies and individuals reporting to DOE, there are hundreds of very small prospecting operations searching for uranium deposits to sell to others.

Listed below are examples of acreage holdings of some independent uranium companies:

TABLE III-d
EXAMPLES OF URANIUM HOLDINGS BY URANIUM COMPANIES

<u>Company</u>	<u>Acres</u>	<u>Reserves</u> (mm lbs.)	<u>1976</u> <u>Production</u> (mm lbs)
Reserve Oil & Minerals	1,305,000*	12	-
American Nuclear	348,000	13	-
United Nuclear	312,000	100+	2.0
Federal Resources	200,000	5 Est.	-
Nuclear Dynamics	152,000	-	-
Bokum Resources	34,000	8	-

* 1,102,000 acres acquired 1975-1976.

Sources: Company data (Annual Report, 10-K, 8-K)

There is no apparent correlation between acreage and production. Reserve, the largest acreage holder of this group, is a partner

in one mine and mill that is being developed and operated by Sohio, who is also providing financing. United Nuclear, with 312,000 acres, produced 2 million pounds in 1976 and is in the midst of a large expansion of 5 new mines and a mill. Bokum Resources has the smallest acreage, but is constructing a mine and mill on one property and has indications of uranium on others.

Exhibit II-18 shows the latest available data on reserve holdings by company. As these data indicate, oil companies are the largest reserve holders because, according to one active independent, they are making the largest expenditures for exploration and development. Much of these data are estimated, however, because mines are under development which require larger reserves to meet delivery commitments than had been reported by these companies in the past. (No reserves had been reported for some companies currently developing production). Much of the data is provided by companies in their published reports. These data are non-comparable and most are out of date. They cannot be used for detailed analysis of control of reserves. They can only be used to identify companies that are active in uranium development.

Uranium Financing

Uranium exploration companies do not consider financing uranium exploration a major problem. Electric utilities are supplying "front money" for uranium exploration to many very small companies, although at least some utilities state they

would prefer to deal with strong companies. Obviously, if utilities decide on other uses for these funds, small exploration companies would be the first to feel a restriction.

Project financing is available but is rare. The risks in uranium development do not often lend themselves to the certainties required by project financing. As with coal, the lender wants assurances from a financially strong company that the mine will be successfully completed and operated.

The Sohio/Reserve joint venture is financed largely by project financing arranged through a large New York bank. Sohio has advanced additional funds to Reserve in order to complete the mine. Although there are separate notes to the lender from Sohio and Reserve, both had to jointly and severally guarantee the successful completion of the mine. This put Sohio's credit behind the entire venture to the extent of developing an operable mine.

Uranium producers state that some current development, and probably an increasing amount of future development, is not financeable through borrowings or by electric utilities because of the large dollar amounts and high risks. As previously discussed, Gulf's Mt. Taylor development will cost over \$150 million to ascertain whether it can, in fact, be mined. (The ore deposits are at 3500 feet and are below strata with large amounts of flowing water.) If successful, full development can run to \$500 million. Phillips has similar uranium-bearing deposits. Developments of this type require companies with substantial.

financial resources who are able and willing to take these risks. Apparently because of this, oil companies are joint venturing and providing financial assistance to smaller uranium operators who are attempting to explore or develop uranium holdings.

URANIUM REQUIREMENTS

1977 Forecast

(Thousands of Short Tons of U_3O_8)

	<u>0.15% Tails*</u>		<u>0.20% Tails</u>		<u>0.25% Tails</u>		<u>0.30% Tails</u>	
	<u>Ann.</u>	<u>Cum.</u>	<u>Ann.</u>	<u>Cum.</u>	<u>Ann.</u>	<u>Cum.</u>	<u>Ann.</u>	<u>Cum.</u>
1977	10	10	11	11	12	12	13	13
1980	16	51	17	55	18	60	20	66
1985	27	166	29	179	32	194	35	213
1990	40	340	43	367	47	399	52	438
2000	68	902	74	972	80	1060	88	1160

NOTE: No allowance for existing contracts

Spent fuel not reprocessed

URANIUM REQUIREMENTS WITHOUT NEP (Conservation)

1977 Forecast

(Thousands of Short Tons of U_3O_8)

	<u>0.15% Tails</u>		<u>0.20% Tails</u>		<u>0.25% Tails</u>		<u>0.30% Tails</u>	
	<u>Ann.</u>	<u>Cum.</u>	<u>Ann.</u>	<u>Cum.</u>	<u>Ann.</u>	<u>Cum.</u>	<u>Ann.</u>	<u>Cum.</u>
1977	10	10	11	11	12	12	13	13
1980	16	51	17	55	18	60	20	66
1985	28	168	31	181	33	196	37	216
1990	45	359	48	386	52	420	58	462
2000	81	1010	88	1090	95	1180	100	1300

NOTE: 1) No allowance for existing contracts 2) Spent fuel not reprocessed

*"Tails" are the residuum at the enrichment plant. The Percentage indicates the amount of U_3O_8 left in the tails.

Source: Domestic Uranium Requirements, a paper given by R. W. Bown of DOE at the Uranium Industry Seminar, October 26, 1977.

MINED ORE RECEIPTS AT BUYING STATIONS AND MILLS

<u>Calender Year</u>	<u>Total Receipts</u>		<u>AEC Price * \$/lb</u>	<u>AEC Payments * \$ MM</u>
	<u>Ore M tons</u>	<u>U308 MM lbs</u>		
1948	38	0.2	\$ 7.14	\$ 1.7
1949	173	1.0	8.53	2.0
1950	251	1.6	9.11	5.9
1951	347	2.2	10.10	12.9
1952	435	2.6	11.28	18.6
1953	734	4.6	12.35	23.9
1954	1,106	7.0	12.27	35.2
1955	1,524	8.8	12.25	52.1
1956	3,005	16.8	11.51	96.2
1957	3,695	19.6	10.49	157.4
1958	5,178	28.0	9.45	190.5
1959	6,935	34.8	9.12	274.1
1960	7,970	37.6	8.75	287.0
1961	8,041	37.0	8.50	299.8
1962	7,053	34.2	8.15	281.0
1963	5,948	29.4	7.82	246.2
1964	5,297	27.8	8.00	201.7
1965	4,376	20.8	8.00	179.8
1966	4,329	19.8	8.00	162.8
1967	5,272	21.4	8.00	142.4
1968	6,448	25.2	8.00	127.0
1969	5,904	24.6	6.99	99.6
1970	6,324	25.6	5.74	46.0
1971	6,279	25.8	5.54	14.3
1972	6,418	27.4	-	-
1973	6,537	27.2	-	-
1974	7,027	24.8	-	-
1975	7,057	24.0	-	-
1976	8,608	27.0	-	-

*Fiscal year data

SOURCE: Statistical Data of the Uranium Industry, DOE
January, 1977

Source: Statistical Data of the Uranium Industry, DOE, January, 1977
105

Source: National Petroleum Council Committee on Future Energy Prospects Report of Analytical Group, Topic 23, Nuclear Fuel Supply, P. 12, 8/15/77

DOMESTIC EXPLORATION EXPENDITURES (Millions of Dollars)

<u>Year</u>	<u>Land Acquisition</u>	<u>Drilling and other</u>	<u>Total</u>
1966	\$ 2.24	6.15	8.39
1967	7.56	17.26	24.82
1968	18.52	34.93	53.45
1969	13.89	44.86	58.75
1970	10.74	41.47	52.21
1971	9.75	31.50	41.25
1972	4.70	27.70	32.40
1973	7.67	41.80	49.47
1974	12.61	66.47	79.08
1975	16.70	105.33	122.03
1976	13.89	156.76	170.65
1977 planned	-	-	236.20
1978 planned	-	-	330.00 estimated *

* Estimated at 40% increase based on imcomplete returns from survey.

Source: Exploration Activities, a paper given by W. L. Chenoweth of DOE at the Uranium Industry Seminar October 26, 1977.

LARGER URANIUM EXPLORERS

(Companies furnishing data for ERDA Exploration Survey)

Uranium Companies

American Nuclear
Atlas
Bokum Resources

Nuclear Exploration and Development
Power Resources
Reserve Oil and Minerals
United Nuclear

Mining Companies

Brooks Minerals
Cleveland-Cliffs Iron
Cyprus Mines
Denison Mines (Foreign)
Farris Mines
Federal Resources
Groth Minerals
Hecla Mining
Homestake Mining
Idaho Mining
Inco
International Minerals and Chemical
Kerr-Addison Mines (Foreign)
Mineral Engineering
Newmont Mining
North American Mining and Minerals
Nuclear Dynamics
Phelps Dodge
Polaris Resources
Ranchers Exploration and Development
Rio Tinto Zinc (Foreign)
Santa Maria Mining
Texasgulf
U. S. Energy Corp.
Vipont

Electric Utilities

Commonwealth Edison
Public Service Co. of Oklahoma
Tennessee Valley Authority
Utah Power and Light
Virginia Electric

Central Power and Light
Consumers Power
Detroit Edison
Florida Power & Light
Houston Lighting & Power
Long Island Lighting

Niagara Mohawk
Northern States Power
Pacific Gas & Electric
Pennsylvania Power & Light
Philadelphia Electric
Portland General Electric
San Diego Gas & Electric
Southern California Edison
Texas Utilities
Washington Public Power Supply
Wisconsin Power

Larger Oil and Gas Companies

Ashland
Arco
Cities Service
Conoco
Exxon
Getty
Gulf Oil
Kerr-McGee
Mobil
Occidental
Pennzoil
Phillips
Socal
Sohio
Sun
Texaco
Union Oil

Smaller Oil and Gas Companies

Adobe
Bennet
Buttes
Crown Central
Energy Reserves Group, Inc.
Enserch
Felmont
Intercontinental Energy
Newpark Resources
Pioneer
Sabine
Webb Resources

Large Non-Resource Companies

General Electric
Arthur D. Little, Inc.
R. J. Reynolds
Union Carbide
Union Pacific
Westinghouse

Other Uranium Explorers

AGIP (Foreign)
Walter Buchanon
W. S. Dawson
Joseph Desloge, Jr.
E. V. Reinhardt
Energy Uranium Co.
Ralph Foster and Sons
Four Corners Exploration Co.
Framco-Frominco-Urex, Inc.
Gates and Fox, Inc.
Cherokee Exploration, Inc.
Spent M. Hansen & Associates, Inc.
Minatome Corp.
Mineral Energy, Inc.
Minerals Recovery Corp.
Minex Corp.
Payne, Kibbe and Associates
Rajah Ventures Ltd.
Rampart Exploration Co.
Resource Associates of Alaska

David S. Robertson & Associates, Ltd.
Ralph Schauss & Associates
Schumacher-Lloyd Ventures
Specomp Services, Inc.
Todiito Exploration and Developing Corp.
Twentieth Century Energy, Inc.
Uranerz USA, Inc. (Foreign)
Urangesellschaft USA, Inc. (Foreign)
Urania Exploration, Inc.
Wold Nuclear Co.

Source: Uranium Exploration Expenditures in 1976 and Plans
for 1977-1978, DOE, May, 1977.

URANIUM PRODUCING COMPANIESPRIMARY
DUSTRY
AND
COMPANY1976
PRODUCTION
U₃O₈ (mm lbs.)CURRENT
PRODUCTION
DEVELOPMENTOIL

Arco (Anaconda)	4.9	Mill expansion
Kerr-McGee	4.1	5 mines, mill
Exxon	1.5	Mine, mill expansion
(a) Conoco	1.1	Mill expansion
(a) Pioneer	0.4	Mill expansion
(b) Sohio	-	Mine, mill
Getty	-	Mine, reactivate mill
Union	-	Mine, mill
Socal	-	Mine, mill
Phillips	-	Mine, mill
Gulf	-	2 mines, mill
(c) Houston Natural Gas	-	Mine
(f) Mobil	-	(f)
Inexco	-	-
(f) Intercontinental Energy	-	(f)

URANIUM/NUCLEAR

(d) United Nuclear	2.0	5 mines, mill
(c) Reserve	-	Mine
(e) American Nuclear	-	Mill expansion
(e) Federal Resources	-	Mill expansion (e)
Bokum Resources	-	Mine, mill
Atlas	N/A	-
(f) Solution Engineering	-	-

METALS MINING

Phelps Dodge	0.9	Mine, mill
(d) Homestake	0.4	Mine, mill
Newmont (Dawn)	0.3	Mine expansion
(c) Ranchers	-	Mine
Cleveland Cliffs Iron	-	-
(g) Freeport Minerals (By-product recovery)	-	-
(g) Gardiner (By-product recovery)	N/A	-
(g) Mineral Recovery Corp. (By-product recovery)	N/A	-
Rio-Tinto-Zinc (Foreign)	N/A	-
Nuclear Dynamics	-	-

MULTI-INDUSTRY

General Electric	3.8	-
(f) Westinghouse	-	(f)

ELECTRIC UTILITIES

Commonwealth Edison	N/A	-
---------------------	-----	---

RAILROADS

(h) Union Pacific	-	Mine, mill
St. Louis-San Francisco	-	-

CHEMICALS

Union Carbide	N/A	-
---------------	-----	---

STEEL

(f) U.S. Steel	N/A	-
----------------	-----	---

- (a) Joint venture between Conoco and Pioneer in one mine and mill. Conoco is operator.
- (b) Joint venture between Sohio (Oil) and Reserve (Uranium). Sohio is operator.
- (c) Joint venture between Houston Natural Gas (oil) and Ranchers (Metals Mining) on one mine. Ranchers is operator.
- (d) Joint venture between United Nuclear and Homestake in certain properties. United Nuclear is operator.
- (e) Federal Resources and American Nuclear are partners in the Federal-American Partners mill.
- (f) Solution mining.
- (g) By-product recovery of uranium produced in other mining operations.
- (h) Joint venture with Southern California Edison (not on ERDA list.) Union Pacific is operator.
- (i) 85% of revenues from metallurgical coal mining.

Notes: Dash (-) indicates NONE.
N/A indicates data not available

Sources: Company data, ERDA. Uranium producing companies according to ERDA 77-46 Attachment A, Survey of United States Marketing Activity, May, 1977.

Uranium Milling Capacity
and Expansion by Company

<u>Company</u>	<u>Primary Industry</u>	<u>Milling Capacity (Tons Ore/Day)</u>		
		<u>1977 Capacity</u>	<u>Current Expansion</u>	<u>Total Expanded Capacity</u>
Kerr-McGee	Oil	7,000	2,000 (new)	9,000
United Nuclear	Nuclear	5,450 (a)	2,000 (new)	7,450 (a)
Arco (Anaconda)	Oil	2,500	2,500 (expan)	5,000
Phelps Dodge (Western Nuclear)	Metals Mining	1,700	2,000 (new)	3,700
General Electric (Lucky McUranium)	Multi-Industry	3,000		3,000
Exxon	Oil	3,000		3,000
Union Oil	Oil		3,000 (new)	3,000
Conoco (67%)	Oil	1,750	1,150 (expan)	2,900
Pioneer (33%)	Gas			
Union Carbide	Chemicals	2,500		2,500
Socal	Oil		2,000 (new)	2,000
Getty	Oil	1,750 (b)		1,750 (b)
Sohio (50%)	Oil	1,660		1,660
Reserve (50%)	Uranium			
Homestake	Metals Mining	1,050	500 (new)	1,550
Atlas	Uranium	1,100		1,100
Commonwealth Edison	Utility	450	550 (expan)	1,000
Union Pacific (50%) (Rocky Mountain Energy)	Railroad	1,000		1,000
South California (50%) Edison	Utility			
Federal Resources (60%)	Uranium	950		950
American Nuclear (40%)	Uranium			
Rio Algom	Metals Mining	700		700
Newmont	Metals Mining	400		400
(Dawn Mining)		(b)		(b)
Tennessee Valley Authority	Utility	500		500
Totals		36,460	15,700	52,160

Source: Internal Paper Department of Energy Office of Energy Technology, Sept. 1977.

(a) Includes United Nuclear - Homestake partnership mill of 3500 daily tons divided 70 percent/30 percent, respectively.

(b) Inactive mills.

URANIUM MILLING EXPANSION BY PRIMARY INDUSTRY

Primary Industry	Milling Capacity								
	1976 Capacity			Current 1977-1985 Expansion			Total Expanded Capacity		
	tons/day	%	Firms	tons/day	%	Firms	tons/day	%	Firms
Oil and Gas	16,830	46	7	10,650	63	5	27,480	52	9
Uranium and Nuclear	8,330	23	5	2,000	13	1	10,330	20	5
Metals Mining	3,850	11	4	2,500	16	2	6,350	12	4
Electric Utilities (a)	1,450	4	3	550	3	1	2,000	4	3
Railroad	500	1	1	0	2	0	500	1	1
114 Chemicals	2,500	7	1	0	0	0	2,500	5	1
Multi-Industry	3,000	8	1	0	0	0	3,000	6	1
Totals	36,460	100	22	15,700	100	10	52,160	100	24

Note: Joint Ventures split between partners.

(a) Includes 500 ton/day capacity for Federally-owned TVA.

Source: Department of Energy

DATA ON URANIUM COMPANIES

	MILLIONS OF DOLLARS				
	URANIUM PROFIT (LOSS)	COMPANY PROFIT (LOSS)	SHARE- HOLDERS EQUITY	TOTAL ASSETS	FISCAL YEAR ENDED
OIL COMPANIES					
ARCO (ANACONDA)	N/A	575	4,091	8,853	12/31/76
KERR-McGEE	N/A	134	913	1,626	12/31/76
EXXON	N/A	2,641	18,470	36,331	12/31/76
CONOCO	N/A	878	2,635	6,041	12/31/76
PIONEER	N/A	38	136	383	12/31/76
SOHIO	N/A	137	1,549	6,260	12/31/76
GETTY	-	258	2,131	3,629	12/31/76
UNION	-	269	2,104	4,227	12/31/76
SOCAL	-	880	7,007	13,765	12/31/76
PHILLIPS	-	412	2,720	5,068	12/31/76
GULF	(11)	816	6,942	13,449	12/31/76
HOUSTON NAT'L GAS	-	95	372	903	7/31/76
MOBIL	-	943	7,652	18,767	12/31/76
INEXCO	-	10	75	170	12/31/76
INTERCONTINENTAL ENERGY	-	(.1)	4	8	9/30/76
	N/A	8,086	56,801	119,480	
URANIUM/NUCLEAR					
UNITED NUCLEAR	N/A	22	91	244	3/31/77
RESERVE OIL & MIN.	-	(1)	(1)	22	8/31/76
AMERICAN NUCLEAR	N/A	(.3)	7	11	5/31/77
FEDERAL RESOURCES	N/A	.4	15	34	4/30/77
BOKUM RESOURCES	-	(.1)	(2)	14	10/31/77
ATLAS	8*	7	38	71	6/30/77
NUCLEAR DYNAMICS	-	(1)	7	10	6/30/76
	N/A	24	155	406	
METALS MINING					
PHELPS DODGE	(16)	43	894	1,774	12/31/76
HOMESTAKE	10	22	140	166	12/31/76
NEWMONT (DAWN)	3	47	655	1,178	12/31/76
RANCHERS	2*	1	19	28	6/30/76
CLEVELAND CLIFFS IRON	-	37	243	334	12/31/76
FREEPORT MINERALS	-	4	75	171	12/31/76
GARDINIERE	N/A	N/A	N/A	N/A	
MINERAL RECOVERY CORPN	N/A	N/A	N/A	N/A	
RIO-TINTO-ZINC (Algom)	N/A	32	322	630	12/31/76
NUCLEAR DYNAMICS	-	(1)	7	10	
	N/A	N/A	N/A	N/A	

MULTI-INDUSTRY

GENERAL ELECTRIC	N/A	931	5,253	12,050	12/31/76
------------------	-----	-----	-------	--------	----------

ELECTRIC UTILITIES

COMMONWEALTH ED.	-	193	2,384	5,910	12/31/76
------------------	---	-----	-------	-------	----------

RAILROADS

UNION PACIFIC	-	195	1,968	2,597	12/31/76
---------------	---	-----	-------	-------	----------

CHEMICALS

UNION CARBIDE	-	441	3,055	6,622	12/31/76
---------------	---	-----	-------	-------	----------

STEEL

U.S. STEEL	N/A	410	5,129	9,168	12/31/76
------------	-----	-----	-------	-------	----------

*OPERATING INCOME (BEFORE INTEREST, TAXES, AND CORPORATE OVERHEAD)

Source: Annual Report for fiscal year indicated.

EXHIBIT III-11

INDEPENDENT URANIUM COMPANIES
FINANCIAL DATA (\$000)

	<u>United Nuclear(a)</u>	<u>Atlas(a)</u>	<u>Federal Resources(b)</u>	<u>Reserve O & M</u>
<u>Net Income (Loss)</u>				
Fiscal 1972	\$ 1,790	\$ 705	(\$1,582)	(\$ 169)
" 1973	(903)	(2,446)	(2,265)	(183)
" 1974	(4,667)	1,564	325	(344)
" 1975	423	3,015	(692)	(956)
" 1976	8,619	4,025	(825)	(1,615)
" 1977	21,501 (d)	7,020	390(c)(e)	
Funds from Operations *	15,405	6,378	2,764	(1,518)
Total Assets *	146,053	65,444	34,121 (c)	21,853
Shareholders Equity (Deficit) *	69,144 (d)	31,252	15,068 (c)(e)	(1,226)

	<u>Bokum Resources</u>	<u>American Nuclear</u>	<u>Nuclear Dynamics(a)</u>
<u>Net Income (Loss)</u>			
Fiscal 1972	(\$ 26)	(\$ 175)	\$ 32
" 1973	(197)	(591)	(476)
" 1974	(276)	(265)	1,922
" 1975	(389)	(77)	2,310
" 1976	(75)	(317)	(914)
" 1977		(131) (c)	(1,068) (c)
Funds from Operations *	(26,393)	60	(832)
Total Assets *	13,578	10,517 (c)	9,392 (c)
Shareholders Equity (Deficit) *	(1,983)	6,989 (c)	7,905 (c)

Notes: (a) Includes substantial non-uranium operations.

(b) Includes substantial foreign operations.

(c) Auditors' opinions on accuracy of financial statements are subject to recovery of expenditures capitalized against mining properties which do not have reserves or production.

(d) Auditors' opinion subject to resolution of lawsuits on uranium sales contracts.

(e) Auditors' opinion subject to acceptance by major customers of uranium in concentrate sales prices reported as revenues by company.

* Data from latest fiscal year for which earning have been reported.

Source: Published Company Data (Annual Report, 10-K, 8-K)

LEAD TIMES TO DEVELOP NEW \$30 PRODUCTION CENTERS

ACTIVITY*	TIME TO PREFORM		CONTRIBUTION TO TOTAL LEAD TIME
	RANGE	AVERAGE	
1. Consolidation of Property	0-10 yrs.	5 yrs.	5 yrs.
2. Feasibility and Environmental Studies	1 ½-3 yrs.	2 ¼ yrs.	2 ¼ yrs.
3. Internal Review	1 ½-3 yrs.	2 ¼ yrs.	2 ¼ yrs.
4. Property Development	3-6 yrs.	4 ½ yrs.	4 ½ yrs.
5. Mill Construction	1-2 yrs.	1 ½ yrs.	0 yrs.
	6-22 yrs.		14 yrs.

*It is assumed that some of these activities could be done concurrently.

Source: Production Capability and Supply, a paper given by J. Klemenic and D. Blanchfield of DOE at the Uranium Industry Seminar October 26, 1977.

ESTIMATED "COULD" PRODUCTION CAPABILITY
AT \$30 PER POUND AS OF 1/1/77
LEAD TIMES FOR CONVERSION OF PROBABLE POTENTIAL
TO RESERVES AND TO CONCENTRATE

Source: Production Capability and Supply, a paper given by J. Klemenic and D. Blanchfield of DOE at the Uranium Industry Seminar October 26, 1977.

COMPARISON OF INDUSTRY'S SHORT RANGE PLANS
AND DOE-GJO'S ESTIMATED \$30/LB "COULD" PRODUCTION CAPABILITY

Source: Production Capability and Supply, a paper given by J. Klemenic and D. Blanchfield of DOE at the Uranium Industry Seminar October 26, 1977.

EXHIBIT III-15

COMPARISON OF ESTIMATED "COULD" PRODUCTION CAPABILITY AS OF 1/1/77 AND ENRICHMENT PLANT FEED REQUIREMENTS U₃O₈ IN CONCENTRATE AT A COST OF \$30 PER POUND

Source: Production Capability and Supply, a paper given by J. Klemenic and D. Blanchfield of DOE at the Uranium Industry Seminar October 26, 1977.

ESTIMATED "COULD" PRODUCTION CAPABILITY AS OF 1/1/77
 U_3O_8 IN CONCENTRATE AT A COST OF \$30 PER POUND
ANNUAL BY MINING METHOD

Source: Production Capability and Supply, a paper given by J. Klemenic and D. Blanchfield of DOE at the Uranium Industry Seminar October 26, 1977.

ESTIMATED "COULD" PRODUCTION CAPABILITY AS OF 1/1/77
GRADE OF ORE MINED AND MILLED AT \$30 PER POUND
ANNUAL CONVENTIONAL ORES

Source: Production Capability and Supply, a paper given by J. Klemenic and D. Blanchfield of DOE at the Uranium Industry Seminar October 26, 1977.

EXHIBIT III-18

CURRENTLY ECONOMIC RESERVES OF LARGER PRODUCERS

	<u>U₃O₈(million lbs.)</u>
Kerr-McGee	300 est.
Gulf Oil	150 est.
United Nuclear	100 +
Arco	60 est.
Mobil	50
Phelps Dodge	45 est.
Conoco	40 est.
General Electric	35 est.
Exxon	35 est.
Getty	28
Phillips	25
Rio Tinto Zinc	20 est.
Socal	15 est.
Union Oil	15 est.
American Nuclear	13
Reserve	12
Homestake	10
Union Pacific	10 est.
Sohio	10 est.
Union Carbide	10 est.
Pioneer	8 est.
U. S. Steel	8 est.
Bokum Resources	8
Atlas	6 est.
Houston Natural Gas	5 est.
Ranchers	5 est.
Federal Resources	5 est.
Intercontinental Energy	2
St. Louis-San Francisco Railway	2 est.
Newmont (Dawn)	<u>2</u>
Total	1,034
ERDA Totals	
\$15 Forward Cost	820 Million lbs.
\$30 Forward Cost	1,360 Million lbs.
\$50 Forward Cost	1,680 Million lbs.

Source: Company data, DOE

Note: Company data is based on published (Annual Report, 10-K, 8-K) and private company communications. Data by company is not strictly comparable as companies compute reserves by varying methods with varying degrees of conservatism.

Footnotes

Chapter III - Uranium

¹National Electric Reliability Council, Fossil and Nuclear Fuel for Electric Utility Generation, Requirements and Constraints, 1979 - 1986, Princeton, J.J., August 1977, p. 6.

²R. W. Bown and R. H. W. Williamson of Policy and Evaluation, Department of Energy, "Domestic Uranium Requirements" from "Proceedings", a collection of papers given at the Uranium Industry Seminar, Grand Junction, Colorado, October, 1977.

³J. Fred Facer, Jr. of Supply Analysis Division, Department of Energy, "Uranium Production Trends" from "Proceedings," a collection of papers given at the Uranium Industry Seminar Grand Junction, Colorado, 1977, p. 171.

⁴John A. Patterson and George F. Combs, Jr., Supply Evaluation Branch, Division of Uranium Resources and Enrichment, Department of Energy, "Uranium Market Activities" from "Proceedings," a collection of papers given at the Uranium Industry Seminar, Grand Junction, Colorado, October, 1977, p. 39.

⁵Statistical Data of the Uranium Industry, Grand Junction Office, Department of Energy, January 1, 1977, p. 13.

⁶Richard E. Balzhiser (EPRI), "Energy Options to the Year 2000", Chemical Engineering, January 3, 1977, p. 78.

⁷ibid

⁸Annual Report, 1976, Kerr-McGee Corporation, p. 30.

⁹Annual Report, 1976, Intercontinental Energy Corp., p. 1 and p. 4.

¹⁰Annual Report, 1976, United Nuclear Corporation p. 9; Annual Report, 1977, Atlas Corporation, p. 1; Annual Report, 1977, Federal Resources Corporation, p. 2; and Annual Report, 1976, American Nuclear Corporation, p. 5.

¹¹Prospectus, December 15, 1976, 300,000 Shares of Common Stock of Bokum Resources Corporation, p. 3.

¹²Annual Report, 1976, American Nuclear Corporation, p. 6; and Annual Report, 1977, Federal Resources Corporation, p. 1.

¹³Annual Report, 1977, Nuclear Dynamics Incorporated, p. 5 and p. 6.

¹⁴Preliminary Prospectus, September, 1974, 1,017,539 Shares of Common Stock of United Nuclear Corporation, p. 16, 30, 31, and 32.

- ¹⁵Annual Report, 1976, United Nuclear Corporation, p. 3; and Preliminary Prospectus, September 1974, 1,017,539 Shares of Common Stock of United Nuclear Corporation, p. 16.
- ¹⁶Annual Report, 1976, United Nuclear Corporation, p. 6.
- ¹⁷Moody's Industrial Manual, Volume I 1977; and Annual Report, 1977, Federal Resources Corporation, p. 2.
- ¹⁸Annual Report, 1976, Reserve Oil and Minerals Corporation, p. 1 and p. 14; and Annual Report, 1975, Standard Oil of Ohio, p. 18.
- ¹⁹Annual Report, 1976, American Nuclear Corporation, p. 2.
- ²⁰Annual Report, 1976, Phelps Dodge Corporation, p. 12.
- ²¹Press releases, American Nuclear Corporation, July 21, 1977 and October 4, 1977.
- ²²Annual Report, 1976, Homestake Mining Company, p. 15.
- ²³Annual Report, 1976, Union Pacific Corporation, p. 15.
- ²⁴Preliminary Prospectus, September, 1974, 1,017,539 Shares of Common Stock of United Nuclear Corporation, p. 13.
- ²⁵Press release, Bethlehem Steel Corporation, August 30, 1977.
- ²⁶John A. Patterson and George F. Combs, Jr. Supply Evaluation Branch, Division of Uranium Resources and Enrichment, Department of Energy, Uranium Market Activities, P. 2, FROM "Proceedings", a collection of papers given at the Uranium Industry Seminar Grand Junction, Colorado, October, 1977.
- ²⁷Press release, Federal Resources Corporation, September 19, 1977.
- ²⁸Annual Report, 1976, Kerr-McGee Corporation, p. 30.
- ²⁹Prospectus December 15, 1976, 300,000 Shares of Bokum Resources Corporation, p. 14.
- ³⁰Annual Report, 1976, Intercontinental Energy Corporation, p.1 and 14.
- ³¹Annual Report, 1976, American Nuclear Corporation, p. 6.
- ³²Ludwig Koch (Continental Oil), Mining and Milling - Capital Requirements, A paper given at the Atomic Industry Forum, July 24 - 27, 1977, p. 9.
- ³³ibid, p. 6.
- ³⁴ibid, p. 10.
- ³⁵Uranium Exploration Expenditures in 1976 and Plans for 1977-1978, Department of Energy (Washington), May 1977, p. 2.

Chapter IV - SYNTHETIC FUELS

FROM COAL

A. Summary of Interviews	128 - 131
B. Synthetics from Coal - A Description	132 - 134
C. Current Developers	134 - 139
D. Financing Synthetic Fuels from Coal	139 - 140
Exhibit IV-1	141 - 144

Chapter IV - Synthetic Fuels from Coal

A. Summary of Interviews

There are at least eleven oil companies and forty-five other companies and organizations involved with the federal government in the search for economically attractive synthetic fuels from coal. (See Exhibit IV-1). In the course of discussions regarding investments in non-petroleum energy sources, personal interview and/or telephone conversations were held with 21 oil companies (see Summary of Interviews, Introduction, Chapter II - Coal, and Chapter III - Uranium/Nuclear), nine of which are active in research to manufacture synthetic fuels from coal. Interviews and telephone conversations were held with an additional 27 firms and/or organizations.

Those interviewed were asked, where applicable, to discuss the nature of their involvement in the manufacture of synthetic fuel from coal, with particular emphasis on current and/or planned investments. It should be noted that the views expressed were based on economic conditions as perceived at the time of the interviews; these views will change as conditions change.

Interviews

During the course of the interviews, oil companies were asked to:

I. Rate Their Current "Interest" in Synfuels from Coal.

"Interest" is defined as present, or possibly future, investments in suitable coal reserves or synthetic fuel manufacturing facilities. Appropriate categories for the responses are described below.

"Intense interest" describes those companies who have made major investments and who can be expected to continue to invest in synfuels from coal research and development.

"Substantial interest" describes those companies who have made major investments in order to watch and evaluate new technology and/or emerging energy sources. They might make additional investments in the future.

"Some interest" describes a company with investments in R&D work. The company may also be considering the possibility of larger investments in a pilot plant.

"Limited interest" describes a company with current investments in R&D work. There are no plans for expansion of their investment.

"No interest" describes those companies with no present or planned investments in synthetic fuels from coal.

Responses are grouped as follows:

<u>Intense Interest</u>	<u>Substantial Interest</u>	<u>Some Interest</u>	<u>Limited Interest</u>	<u>No Interest</u>
5	—	1	1	11

As these data indicate, oil company interest varies widely. Those companies that are involved in synfuels (both liquid and gaseous) feel that synthetics are the most logical substitutes for conventional oil and gas. Unlike both coal and, to a lesser extent, uranium, synfuels are not yet economically viable. As a consequence, only those companies with either substantial net worths or access to government funding are active in synfuel development. Those with "intense" interest tend to view synfuels

as being relatively close to economic viability; those with "no interest" perceive it as being farther away. One company, with "intense interest" in coal but "no interest" in synfuels from coal stated, "If we had our choice, we would gasify much of our coal. Legislative uncertainty, however, is giving us fits." Another company with "no interest" cited only the long lead times and the currently unprofitable nature of the business.

Of the two coal companies interviewed, one has "intense interest" and the other "no interest". The president of the former company said, "The technology is pretty good; it's the economics that are bad." The coal company is involved in synfuels through a joint venture with a natural gas utility.

Five electric utilities were interviewed; two have "substantial interest" in synfuels from coal; the other three have "no interest." The two electric utilities involved perceive synthetic fuels as being of potential value in the future; the others did not.

None of the four "other" companies interviewed (a conglomerate energy company, a railroad, and two extractive mineral companies) had any "interest" in synthetic fuels from coal, citing long lead times, current unprofitability, and regulatory problems.

II. Entrance into the Synthetic Fuels from Coal Business

None of the companies interviewed felt that there were inordinate problems that would prevent them from entering the synfuel business.

Most of those interviewed, however, saw no possibility of profitable operation, a perception that discouraged investment.

III. Synfuels from Coal as an Attractive Investment Opportunity

Companies active in the manufacture of synthetic fuels treat it as an R & D project. As a consequence, synfuels from coal do not operate under the same investment criteria as other functional areas of the oil companies. One company with investments in synfuels from coal said, "Technically, we think it is 90% feasible. We hope the economics pan out."

B. Synthetics from Coal - A Description

There are three basic types of synfuels from coal:

1. liquefaction, usually resulting in a heavy fuel oil.
2. high BTU (pipeline quality) gas, or SNG (synthetic natural gas).
3. low BTU gas, used on-site principally for electric power generation.

Synfuel's principal advantage over other forms of alternative energy is that no additional investment is normally required by users/consumers in order to utilize it. Synfuels can be used by existing equipment, including automobiles and residential and industrial furnaces.

Liquefaction

Over 75% of current energy is supplied by liquid and gaseous fuels.⁽¹⁾ High demand for liquid fuel from conventional or synthetic sources will probably always exist because of the continued dependence of the transportation sector on this fuel. The demand for liquid fuels will, therefore, continue; the question is the source of the fuels.

Gasification

Gas from coal is a far more attractive fuel than coal itself. Synthetic gas doesn't, like coal, foul the air; many consider high BTU gas to be the superior way to use coal satisfactorily in our

environment by concentrating coal use in fewer locations. Even at \$4-5 per MCF, syngas, it is estimated by some, could heat homes for as little as half the cost of electricity produced by traditional coal-fired generators. (2)

The existing gas pipeline network in the U.S. permits fast, low cost, unobtrusive movement of large amounts of energy. (In contrast, a high-coal use case by Bechtel of 2.2 billion annual tons by 1985 estimates \$86 billion for transportation equipment to haul coal. (3) This is in addition to costs for converting or replacing equipment to burn coal.)

Synfuels from coal is currently a "non-industry" in the U.S. and a limited industry throughout the world (it has expenses, but no revenue). Synthetic fuels from coal are not economic to produce at current regulated prices for oil and gas and are still in the R & D stage of development. However, gasification is approaching commercial feasibility.

Historically, the largest use of synfuels was in Germany during World War II where cost was a minor factor. Both gas and liquids were produced to supply German military and industrial requirements. Currently, South Africa is the only producer of coal-derived liquids, using a 40-year old German process. Accurate cost data on their operation is unavailable.

The U.S. has a significant need for synthetic gas. U.S. natural gas production peaked in 1973, and has declined ever since.

Although current supplies exceed demand, this situation is expected to reverse in the 1980's. Natural gas currently supplies over 25% of U.S. energy requirements. (4)

Coal liquefaction is farther in the future. Current costs are generally estimated at \$20-25 barrel for the first commercial plants. (5)

C. Current Developers

Gasification

Exhibit IV-1 lists the companies and summarizes the processes being tested. Several companies are planning syngas plants, all of which will use the Lurgi processes developed in Germany in 1936. First generation processes, such as the Lurgi, can be operational now at slightly more than twice current regulated rates for natural gas.

Second generation processes are now in pilot stages, with efforts being made to simplify them and making them more economical. However, technological breakthroughs that would sharply lower existing costs are not anticipated.

Because normally mineable coal reserves can be used for synfuels, companies currently involved in conventional coal production are evaluating synthetic fuel processes. In addition, lower quality reserves can also be used in most above ground processes, and currently unmineable coal reserves, which DOE estimates at 1.2 trillion tons, can be used for in-situ gasification. (6) Minimum reserves to support a gasification plant, however, are estimated to be 250-350 million tons. (7)

As coal prices have risen, some reserves originally acquired for possible gasification are being developed as raw coal for sale to utilities. Example of companies doing this are Panhandle Eastern and El Paso. Not all reserves, however, fall in this category; some reserves acquired for underground (in-situ) gasification cannot be economically mined and sold as conventional coal. This, reportedly, includes the coal reserves of Texaco.

Gas companies are heavily involved in proposed current development of first generation (Lurgi) commercial plants because high BTU gas is a direct replacement for natural gas.

Currently announced high BTU (pipeline quality) gasification projects include the following:

- 1) El Paso Natural Gas (New Mexico),
- 2) Texas Eastern and Pacific Lighting (Weco) (New Mexico),
- 3) American Natural Resources (North Dakota),
- 4) Panhandle Eastern and Peabody (Wyoming),
- 5) Natural Gas Pipeline of America (North Dakota),
- 6) Northern Natural Gas and Cities Service Gas (Montreal),
- 7) Panhandle Eastern (Illinois)

Although there is some minor oil company participation in the coal mining phase of these gasification projects, most oil company efforts appear to be concentrated on the development of lower cost, more reliable, second generation plants. (An example is El Paso's joint mining venture with Conoco on one of El Paso's four potential gasification projects.) Currently available less

costly gasification processes can produce lower BTU gas. (As shown in Exhibit IV-1, there are some 22 companies and groups currently active in the development of lower BTU coal gasification.) While low BTU gas cannot be used for home heating, it can be used for (1) electrical power generation or (2) as a feedstock (for example, for fertilizer). As a consequence, the most interested potential users of low BTU gas are electric utilities and energy intensive industries.

Underground gasification is attracting attention but little investment. The Soviet Union, with 50 years of experimentation, considers it promising. Gulf and Conoco have been active in past U.S. underground gasification projects and the DOE has a test site in Wyoming; Texas Utilities is experimenting in Texas with a Russian process. Significant further testing is planned.

Advantages of in-situ gasification include the elimination of mining and the utilization of low quality coal seams that would not otherwise be used. Although in-situ gas is very low quality, it could run power plant generators for as little as half the cost of coal itself with a fraction of the environmental impact.

In spite of these benefits, maximum projected contribution of in-situ gasification is about 5-10% of total U.S. energy needs in the year 2000⁽⁸⁾. In-situ gas from coal has only 10-20% of the energy value of natural gas; because of this, 5-10 times the quantity must be transported and burned to achieve the same heat

value. At long distances, therefore, transportation of low BTU gas becomes very costly.

Liquefaction

Because coal liquefaction is one of the few direct substitutes for crude oil, it will probably become more important. Liquid fuels are almost the sole source of energy for transportation, a situation that is unlikely to change quickly. Coal liquefaction has not been aggressively developed in the U.S. because its costs were, and are, substantially above the costs of crude oil.

Probably the process closest to commercialization in Gulf's Solvent Refined Coal (SRC) process. Because the process provides a sulfur-free coal product with a high BTU content, it is economical to transport over long distances. SRC, therefore, may provide a viable substitute for low sulphur conventional crude oil. Other oil companies are also active; Exxon is progressing in liquefaction technology with its Donor Solvent Process, also nearing commercial feasibility. Ashland is involved in developing the H-coal process, a procedure that converts high sulphur coal to a boiler fuel. Conoco, Standard of Indiana, and Mobil are also participating in this research. Occidental is developing a potentially competitive multi-product process that results in lower product yields, but at even lower costs.

Investment Generalizations

Company R&D investments in synfuels (See Exhibit IV-1) have paralleled companies' primary interests in natural fuels. Gas companies (pipeliners and distributors) are predominant in early

commercialization of high BTU gas through first generation processes. Although oil companies are heavily involved in liquefaction, some coal-oriented oil companies, such as Conoco, are leaders in second generation coal gasification.

Oil company perceptions of synfuels vary: Gulf, Exxon and Conoco have been among the leaders in developing synfuels from coal; Texaco is constructing a liquefaction plant in Germany and is studying a U.S. gasification project. Gulf, Ashland, and Occidental are the only companies attempting development of synthetic liquids from both shale and coal. Conoco and Exxon, on the other hand, are developing synfuels from coal, but have no shale development. Standard of Indiana, Sun, Mobil, Sohio and Phillips participate in shale but to a lesser degree than others (See Exhibit V-1). Some companies that are very aggressive in mining coal (Kerr-McGee and Arco) have no current synfuel development programs.

Engineering/construction companies, chemical catalyst and equipment manufacturers, and university research groups are also involved. Few, if any, of these can be considered manager/financiers of future commercial gasification projects, which, in most processes, include coal mining.

Gas companies who are involved in all of the currently planned high-BTU plants intend to use the German Lurgi first generation process. Oil companies are currently managing and funding (usually with DOE) the second generation demonstration plants

closest to commercial operation. Electric utilities are investing in processes to manufacture low BTU gas.

Other types of companies are also participating in synfuel development, but mainly for industrial process heating and not for the large-scale commercial replacement of natural gas.

Of those interviewed, many think the Federal government will ultimately determine the timing of coal-derived liquids commercialization through regulation of conventional crude oil prices.

D. Financing Synthetic Fuels from Coal

Capital requirements to produce synfuels are large. In 1976 dollars, high BTU gas plants were estimated at \$1 billion for an economically sized plant of 250M mcf/day.⁽⁹⁾ Liquefaction plant costs were estimated at \$2 billion for a 100,000 B/D plant.⁽¹⁰⁾

The Workshop on Alternative Energy Strategies (WAES) developed a test case for the U.S. of three million barrels per day of oil equivalent (MBDOE) synthetic oil and gas from coal and 0.5 million barrels per day (MBD) oil and shale, which was run on the Bechtel Energy Supply Planning Model. Capital investments of well over \$90 billion (in 1976 dollars) would be required over the 20 year period from 1981 to 2000.⁽¹¹⁾ The Bechtel Model estimated that initiation of such a synfuel industry would require construction of 42 nominal coal gasification facilities and 47 nominal coal liquefaction facilities.⁽¹²⁾

In addition, the Bechtel model estimated coal mining capacity of more than 600 million tons per year would need to be added (the size of the entire current coal mining industry) to support

requirements of 3.0 MBDOE, of synfuels from coal, 5% - 10% of anticipated U.S. energy requirements in the year 2000. Clearly, the development of synfuels will require considerably more capital than equivalent production of conventional oil and gas. Because of these estimated capital costs, almost all investment in synfuels from coal is at least partially financed by the federal government.

EXHIBIT IV-1

SYNFUELS FROM COAL

Coal Liquefaction and Gasification Projects

A. Liquefaction

<u>Company</u>	<u>Process</u>
1. Pittsburgh and Midway Coal (Gulf Oil)	Solvent Refined Coal (SRC). In demonstration plant stage. Probably closest to commercial production. The process was begun by Spencer Chemical under a federal research contract in 1962. (Gulf acquired Spencer Chemical in 1963.) Process converts coal to ash-free, low sulphur coal.
2. Exxon Research	Donor Solvent Process. Funding by Exxon from 1966-1975 was \$3.2 million. Detailed engineering and procurement for a plant (construction to start 1978) costing \$60.6 million, 50% funded by Exxon. Also testing fluid coke process using residues from primary coal liquefaction.
3. Ashland (operator), Standard of Indiana Conoco Coal Development Mobil Commonwealth of Kentucky Electric Power Research Institute (EPRI)	H-Coal. Pilot plant being built in Kentucky. Process developed by Hydrocarbon Research, Inc., 1964. Process converts high sulphur coal to a boiler fuel or refining syncrude. Financing 80% by ERDA. Current funding FYE 1978 - \$33.5 million.
4. Conoco Coal Development	Zinc chloride catalyst process. Converts coal into distillates (gasoline range) by severe catalytic hydrocracking. Developed by Consolidation Coal 1963-1968.
5. Occidental Research	Entrained pyrolysis process. Begun by Occidental in 1969. Testing of 3 ton/day unit.
6. Mobil	Indirect liquefaction. Testing of the Fischer-Tropsch process.
7. Sun Company	Conversion of coal to synthetic gasoline.
8. Royal Dutch Shell Group and Texaco	Constructing, to operate, a test plant (125 tons/day) in Germany. Approximate cost \$80 million. German government participation.

9.	Bethlehem Steel	Synthoil process. Converts high sulphur coal to a low sulphur, low ash synthetic fuel oil.
10.	Coalcon (Union Carbide and Chemical Construction Corp.)	Conversion of high sulphur coal to boiler fuels and gas. Sharply scaled down from prior commitments. Additional testing necessary.
11.	University of North Dakota	Solvent extraction of lignite.
12.	Lummus Company	Multistage liquefaction. Converts coal to low ash, low sulphur, low nitrogen boiler fuel and gasoline. Under private development since 1972.
13.	Englehard Minerals	Catalyst development for coal liquefaction.
14.	Dow Chemical	Research on chemicals from coal.
15.	Universal Oil Products	Research on upgrading of coal liquids.
16.	Johns Manville	Research on solids/liquids separation.
17.	Cities Service	Research on two stage liquefaction.
18.	Texaco	Research on liquefaction residue materials from gasification.
19.	Illinois Geological Survey	Research on valuable metals in residues.

B. Gasification - high BTU

Company

Process

1.	Conoco Coal Development	CO ₂ Acceptor process. Development by Consolidation since early 1960's.
2.	Exxon	Catalytic gasification process. Testing of bench scale work since 1968. Gathering information for scaleup.
3.	American Gas Assoc.	Hygas process. Coal to methane.
4.	Bituminous Coal Research	Bi-Gas process. Under development since 1963. Two-stage gasifier. Total funding \$16.5 million, AGA pays \$5.5 million (33%).

5. Battelle Memorial Inst.

Self-agglomerating burner process. Initially investigated by Battelle and Union Carbide. Currently pilot plant shakedown. Funding of \$1.5 million, all by ERDA.

6. BOM, M.W. Kellogg, Lummus

Synthane process. BOM designed the process. Kellogg designed the plant, Lummus is operating the pilot plant. Funding by ERDA. FYE 1978, \$14.5 million.

7. Dravo Corporation

Steam iron process. Used to hydrogasify coal. Funds to design, construct and operate pilot plant. Cost \$8.5 million, 33% paid by the AGA.

C. Gasification - low BTU

1. Conoco Coal Dev. Co.
(Conoco)

Demonstration plant on slagging Lurgi Fixed Bed Process.

2. Illinois Coal Gasification (Cogas)
Tenneco, Inc.
FMC

Cogas Gasifier process. Engineering phase, \$24 million in 1978.

Consolidated Natural Gas
Panhandle Eastern

3. Texaco

Texaco coal gasification process being further tested.

4. Texas Utilities

Conversion of lignite to low BTU gas. Utilization of Russian process. Active project.

5. EPRI, Commonwealth Edison,
and the state of Illinois

Combined cycle-test facility pilot plant in Illinois. Funding \$38 million, 70% by ERDA, 30% by EPRI Commonwealth Edison and the state of Illinois.

6. American Natural Gas
People's Gas
North American Coal

Gasification project in North Dakota. Awaiting federal financial aid.

7. Westinghouse

Fluidized bed gasification, two-stage pressurized process. Test program.

8. Atomics International

Molten salt pressurized process. To design, construct and operate a 1 ton/hour plant.

9.	ERDA project; contractors to be selected.	Hydrogen from coal facility.
\$36 million - in 1978.
10.	Combustion Engineering	Entrained bed gasification, atmospheric process. Test project will be defined.
11.	Memphis Light, Gas & Water Delta Refining (Earth Res.) Foster Wheeler	Negotiations with: ERDA on Institute of Gas Technology process. Intermediate BTU coal gasification.
12.	W. R. Grace Ebasco Services	Negotiations with ERDA on Texaco gasification process. Syngas to ammonia.
13.	Moore McCormick Gulf & Western	Negotiations with ERDA on low BTU Fuel Gas. Small Industrial \$10 million in 1978.
14.	Stone and Webster Burns and Roe	Direct Coal Combustion Process - Conceptual designs, \$8 million in 1978.
15.	Caterpillar Tractor	Gasifier at plant.
16.	Battelle Memorial Inst.	Research on hot gas clean up, molten sun process.
17.	Land O'Lakes (with Applied Tech.)	Research on test of low BTU gasifiers in industry.
18.	Glen-Gery Brick Co. (with Acurex-Aerotherm)	Research
19.	University of Minnesota (with Foster Wheeler)	Research
20.	Irvin Industries (with Manson and Hanger)	Research
21.	General Refractories (with Holly, Kenney, Schott, Wodall-Duckham)	Research
22.	Pike County Industrial Commission	Research

Source: Department of Energy (ERDA 77-33) Fossil Energy Research Program of the Energy Research and Development Administration
April, 1977

Footnotes

Chapter IV - Synthetic Fuels From Coal

¹National Energy Outlook, Federal Energy Administration, 1976, Washington, p. xxii.

²The Only Way to Use Coal, Newsweek Magazine, quoting Arthur J. Sedes, Jr. Chairman of the Board, American Natural Gas Co. July 4, 1977, p. 68.

³Energy: Global Prospects, Report of the Workshop on Alternative Energy Strategies, 1977, Massachusetts Institute of Technology, Nimrod Press, (Boston Mass.), p. 181 and 182.

⁴National Energy Plan, the Federal Energy Administration, 1977, (Washington), p. 16.

⁵Richard E. Balzhiser, Energy Options to the Year 2000, Chemical Engineering Magazine, January 3, 1977, p. 72.

⁶Bob Arnold, Coal Burning in Earth Looks Promising as Gas Source for Utilities and Factories, The Wall Street Journal, quoting ERDA, April 26, 1977.

⁷Derived from data in an article by Ted Wett, Coal: Future Sources of Oil and Gas, Oil and Gas Journal, Petroleum/2000, August 1977, p. 522.

⁸Bob Arnold, Coal Burning in Earth Looks Promising as Gas Source for Utilities and Factories, The Wall Street Journal, April 26, 1977.

⁹Richard E. Balzhiser, Energy Options to the Year 2000, Chemical Engineering Magazine, January 3, 1977, p. 84.

¹⁰Derived from data in the article by Richard Balzhiser, Energy Options to the Year 2000, Chemical Engineering Magazine, January 3, 1977, p. 85.

¹¹Energy: Global Prospects, Report of the Workshop on Alternative Energy Strategies, 1977, Massachusetts Institute of Technology, Nimrod Press (Boston, Mass.), p. 185.

¹²J. M. Gallagher, R. G. Zimmerman, R. Barany, P. F. Paskert, Analysis of a Synthetic Fuels Test Case Using the Bechtel Energy Supply Planning Model, prepared in support of Workshop on Alternative Energy Strategies, August 30, 1976.

Chapter V - OIL SHALE

A. Summary of Interviews	147 - 149
B. Oil Shale - A Description	150 - 153
C. Current Developers	153 - 157
Exhibit V-1	158 - 159

Chapter V - Oil Shale

A. Summary of Interviews

As in the preceding chapters, all numerical data originated with public sources. Subjective views and perceptions of oil shale came from face-to-face discussions with the managements of sixteen large oil companies, five electric utilities, two coal companies, and five "others" (a railroad, two large extractive mineral companies, a conglomerate energy company, and a large energy financing bank). Telephone interviews were held with individuals at an additional 20 firms and/or organizations active in the energy area.

Those individuals interviewed were in senior management positions and, as such, could intelligently discuss and influence corporate policy. It should be noted that their views were based on economic conditions as perceived at the time of the interviews. These views will probably change as economic conditions change.

Interviews

During the course of the interviews, companies were asked to:

I. Rate their "interest" in oil shale. "Interest" was defined as present, or possibly future, investments in oil shale reserves or extractive facilities. Categories for the responses are described below:

"Intense interest" describes those companies who have made major investments and who can be expected to continue to invest in oil shale research and development.

"Substantial interest" describes those companies who have made major investments in order to watch and evaluate new technology and/or emerging energy sources. They might make additional investments in the future.

"Some interest" describes those companies with current investment in R&D work. There are no current plans for expansion of their investment.

"Limited interest" describes those companies who have invested in the past in oil shale but are currently inactive in oil shale.

"No interest" described those companies with no present or planned investments in oil shale.

Oil company responses are grouped as follows:

<u>Intense Interest</u>	<u>Substantial Interest</u>	<u>Some Interest</u>	<u>Limited Interest</u>	<u>No Interest</u>
4	5	-	9	3

As these data indicate, oil company interest varies. Those companies with "intense" or "substantial" interest feel that the technical, environmental, and economic problems associated with oil shale are close to solution. An individual at one company with "intense interest" said, "We are going to have to get it out sometime. The question is when."

Neither of the two independent coal companies, nor any of the four "other" operating companies, expressed interest in oil shale.

II. Evaluate the attractiveness of oil shale as an investment opportunity

Those companies active in oil shale feel that the U.S. will inevitably have to develop and use oil shale. Currently, however, oil shale is treated as an R&D project with capital and operating outlays but no income. Because of this, oil shale does not operate under the same investment criteria as other functional areas. Heavy cash outlays are an inhibiting factor. One company active in oil shale said, "We'll need help. Full development will take \$500 million to \$1 billion, and we don't want to bet the company."

B. Oil Shale - A Description

Oil shale is a sedimentary rock that contains kerogen, a solid organic material that, when heated (retorted), decomposes into a form of crude oil that can be upgraded and refined. Like synthetic fuels from coal, shale oil is a direct substitute for crude oil and can use existing equipment without the need for costly replacements or conversions.

U.S. oil shale resources (concentrated in Colorado, Utah, and Wyoming), are massive, with oil in place estimated at 1.8 trillion barrels and recoverable reserves estimated at 610 million barrels.⁽¹⁾ These deposits, however, are not homogeneous; richness varies from 10 to 70 gallons of recoverable oil per ton of rock. Recovery costs vary with the richness, accessibility, and thickness of the deposits. Because of this, only 7% (130 billion barrels) are estimated to be commercially attractive. It should be noted, however, that this 7% amounts to slightly more than all U.S. crude produced since 1859.

The federal government controls an estimated 80% of U.S. oil shale resources⁽²⁾. Although these federal resources are surrounded by oil shale on private lands, the quality of the privately-held oil shale is substantially lower. Federal lands (Naval Reserves) were not available for development until 1974, when four 5,120 acre tracts were leased for commercial development.

In spite of this, there has been substantial interest in oil shale development throughout this century. In 1917, the

Oil and Gas Journal noted,

"...Statistics have recently been compiled by the Geological Department and Bureau of Mines of the United States Government and were published in the Bulletin 641-F and 581 and in Senate Documents 310 and 363 of the 64th Congress. Since that time many engineers of note and oil men from all parts of the country have taken up thousands of acres in the vicinity of the 45,000 acres situated in Garfield County, Colorado, in the Parachute Creek mining abstract which the President of the United States, on December, 1916, set aside as a fuel, lubricant and gasoline supply for the U.S. navy. Today not a foot of ground is left that has not been acquired and appropriated, there being approximately 55,000 acres in this district in addition to the Government Naval Reserve" (3).

Other early reports on oil shale were made by the Government in 1901, 1913, 1914, 1915, and 1916. Oil shale reserves of some 50 billion barrels were estimated. Accordingly, many companies and individuals have held oil shale reserves in the Colorado-Wyoming-Utah area during the past 60 years. To date, however, oil shale in the U.S. has remained a "non-industry", with cash outflows but no revenue. (There was an apparently profitable oil shale operation in Scotland from 1872 until at least 1908⁽⁴⁾). Current efforts in the U.S., however, are still unprofitable). The lack of development of

U.S. reserves is due largely to operating and capital costs for oil shale that are substantially higher than those necessary to produce conventional crude oil (see Oil Shale - Summary of Interviews), in spite of continuing efforts during this century to reduce these costs.

Oil shale production efforts have historically centered about surface retorting, a method that requires mining the oil-bearing rock, bringing it to the surface, retorting it to extract the oil, and disposing of the spent shale. While a number of different surface processes have been tested in recent years, all suffer from serious deficiencies. These include:

- 1) Materials handling problems. Production of 1 million barrels/day of oil from shale (about 2% of projected U.S. energy demand in 1985) would necessitate the mining of 500 million tons of rock per year, an amount equal in tonnage to 75% of the 1976 production of the U.S. coal mining industry. Additionally, problems occur with the disposal of the spent shale. Because retorting causes the spent shale to occupy a greater volume, (10% - 25% more after processing than before) storage of the residue will cause difficulties.
- 2) Environmental problems. Surface retorting demands large amounts of water in a geographic area of the U.S. that has historically been short of water. In addition, the spent shale has the consistency of talcum powder, a problem in an area of high winds.

Currently, all surface retorting development programs are in a "holding pattern". Other processes, however, are currently being tested by a number of companies. These include an in-situ (underground) retorting process and a multi-product process.

C. Current Developers

Union Oil has been attempting to make oil shale commercially since 1921 when they first began acquiring shale reserves in Colorado. Union today owns some 20,000 acres containing over 2 billion barrels of shale oil, an amount large enough to supply a 150,000 barrel/day shale oil retorting complex for 25-30 years. Despite the expenditure of more than \$65 million on laboratory work, pilot plants, and development plants, no Union process has yet become commercially feasible.

Union Oil has, however, been close to commercial success; in 1960, Union tried to contract with a West Coast electric utility for the sale of shale oil at about \$3/barrel delivered (\$.50/million BTU).⁽⁵⁾ With natural gas priced at \$.33/million BTU, the utility saw no reason to change suppliers. Today, the utility is paying more than \$15/barrel for low sulphur fuel oil. At current costs, however, shale oil would be priced at \$15 - \$20+/barrel.

Tosco Corporation (previously The Oil Shale Company) was formed in the 1950's, with the aid of several oil companies, to develop commercial surface shale processes. Unsuccessful, Tosco is now a large independent refiner (223,000 barrels/day

of refining capacity) and, while still a member of Colony Development (see Exhibit V-1), is substantially less active in oil shale activities.

Several other groups also experimented with surface retorting processes in the 1950's, 1960's, and early 1970's. None of these experiments resulted in commercial development.

Recently, however, some different approaches have been applied to oil shale recovery. One, considered promising by those involved in oil shale extraction, is a modified in-situ process developed by Occidental Petroleum. This process includes some mining (an estimated 20% of what would be necessary for surface retorting) to create underground caverns. These caverns provide a space in which, through explosives, a large amount of oil shale is converted to rubble. The spaces in the rubble provide sufficient permeability for a flow of hot combustion gases to decompose the kerogen, which is then pumped to the surface. Benefits of this process include a reduction in the problems associated with both materials handling and damage to the environment.

Occidental has spent about \$40 million to date on research and initial testing of the process on some less desirable private land. The company is optimistic about the commercial possibilities of modified in-situ recovery and has formed a partnership with Ashland Oil,* the remaining lessee on federal tract C-b (see Exhibit V-1) that initially also included Shell, Arco, and

*Ashland, in a letter to stockholders dated June 7, 1978, stated they have adopted "a policy of maximizing cash generation." On November 17, 1978, Ashland gave notice of its election to withdraw from the oil shale partnership. The company took a \$19 million write-off in fiscal 1978.

Tosco. The two partners (Occidental and Ashland) have begun development on what could lead to a \$440 million investment to bring the 5,000 acre tract to commercial status of 50,000 barrels of shale oil per day. The first large underground retort produced about 30,000 barrels of oil, 5,000 of which was successfully used as fuel, without further refining, by Consumers Power Company in Michigan.(6)

Gulf Oil and Standard Oil of Indiana apparently think that the Occidental process shows promise because current plans are for them to test the in-situ process on federal tract C-a, acquired in the 1974 lease sale. Testing involves a five year modular program estimated to cost some \$93 million.

Another promising process being developed by Superior Oil is a multi-product process that, if successful, would lower the cost of oil shale by simultaneously producing other products of commercial value. Superior has been developing this process on 6,500 acres of private land in Colorado. The particular land selected for testing purposes doesn't lend itself to efficient mining; Superior is negotiating to exchange its private holdings for suitable adjacent public lands.

All of these processes suffer, however, from the common ailment of high capital and operating costs. Estimates of unit costs vary substantially among those attempting oil shale development;

Tosco's President was quoted in the April, 1965 issue of Fortune magazine as saying that his company "will eventually be turning out high-quality oil for \$1.25 or \$1.30 a barrel, and will be able to pipe it to the West Coast or the Middle West for about 30 cents".⁽⁷⁾ Companies now in a "holding pattern" estimate current shale oil costs generally in the \$15-25/barrel range.

Their estimates are based on engineered capital costs for surface extraction operations of \$15,000-25,000 per daily barrel: \$1 billion for a 50,000 barrel per day plant, or \$15-\$25 billion for 1 million barrels per day. (A conventional petroleum refinery costs approximately \$3,500 per daily barrel)⁽⁸⁾. One company estimated the cost of a planned 100,000 barrels/day plant in Utah at \$1.5 billion in 1975 dollars. Because the facility would need some 2,100 employees (mostly underground miners) development of a mine and plant would necessitate the construction of a town capable of supporting about 12,000 people.

Union Oil has thought that crude from shale could be produced for something close to \$15/barrel and was seeking government support at about that level.

Occidental believes that its in-situ process can economically produce shale oil. Ashland, Gulf, and Standard of Indiana apparently concur and are making substantial investments to test it. Occidental's estimates are based on sharply lower materials handling costs and the use of underground retorts. Nevertheless, capital costs for a 50,000 barrel/day facility are estimated to approximately \$450 million.

Superior Oil believes that its multi-mineral process can produce crude oil alone for \$10-\$15/barrel⁽⁹⁾ The value of the by-products can reduce the cost of crude to less than \$10/barrel. Capital costs of the facility are estimated at \$270 million for a plant capable of producing 13,300 barrels/day, or about \$20,000 per daily barrel. In spite of these higher capital costs, unit costs are lower than shale - only surface processes due to the offsetting value of other products (nahcolite, alumina, and soda ash).

Regardless of the process, capital costs, operating costs, and technical problems are substantial.

OIL SHALECOMPANY PARTICIPATION IN DEVELOPMENT (Listed in order
of Intensity)OIL COMPANIESPARTICIPATION - May 1978

OCCIDENTAL	Developed in situ process without partners or government funding. Research cost to date is about \$40 million. Currently partner with Ashland to develop Federal tract C-b at cost of about \$450 million.
ASHLAND	Recently became partner with Occidental in developing OXY in situ process on Ashland's Federal tract C-b at estimated cost of \$450 million. (Ashland is sole remaining original partner in tract C-b.) Member Paraho, Western Oil Shale group.
GULF	Proceeding with in situ development of Federal tract C-a with Standard of Indiana at cost of about \$100 million. Member Paraho, Western Oil Shale group.
STANDARD OF INDIANA	In situ development of Federal tract C-a with Gulf using OXY process. Member Paraho, Western Oil Shale.
SUPERIOR	Developing multi-mineral process to produce shale-oil at lower net cost. Development to date on less-rich private land; attempting exchange for Federal land for further testing. Private reserves.
UNION OIL	Attempting development since 1921 on private land. No current development. About \$65 million on research to date. Private reserves.
SOHIO	One year suspension on Federal tract U-b pending environmental studies. Initiator of Paraho. Withdrew from Colony Development.
PHILLIPS	One year suspension on Federal tracts U-a and U-b pending environmental studies.
SUN	One year suspension on Federal tracts U-a and U-b pending environmental studies. Member Western Oil Shale group.
TOSCO	Some activity on state land in Utah. (Tosco was originally The Oil Shale Corp.; now principally in oil refining.) Currently in Colony Development, now inactive. Withdrew from Federal tract C-b which OXY and Ashland are developing. Member Paraho.

ARCO	Operator of Colony Development, now inactive. Withdrew from Federal tract C-b, now being developed by OXY and Ashland. Member Paraho. Private reserves.
SHELL	Withdrew from Federal tract C-b now being developed by OXY and Ashland. Withdrew from Colony Development. Member Paraho and Western Oil Shale group. Private reserves.
STANDARD OF CALIFORNIA	Member Paraho, Western Oil Shale group. Private Reserves.
TEXACO	Member Paraho. Private reserves.
EXXON	Member Paraho. Private reserves.
MOBIL	Member Paraho, Western Oil Shale group. Private reserves.
KERR-McGEE	Member Paraho.
MARATHON	Member Paraho. Private reserves.
GETTY	Member Western Oil Shale group. Private reserves.
CITIES SERVICE	Member Western Oil Shale. Private reserves.
WEBB RESOURCES	Member Paraho

OTHER COMPANIES PARTICIPATING IN DEVELOPMENT

CLEVELAND CLIFFS IRON (Metals Mining)	Member Paraho. Withdrew from Colony Development. Private reserves.
ARTHUR G. MCKEE (Engineering)	Member Paraho, Western Oil Shale group.
SOUTHERN CALIFORNIA EDISON (Electric Utility)	Member Paraho.

Source: Annual Reports, 10-K's, 8-K's, press releases and privileged conversations.

Footnotes

Chapter V - Oil Shale

¹Jim West, Obstacles To Limit U.S. Shale Production, Petroleum/
2000, Oil and Gas Journal, August 1977, p. 522.

²ibid, p. 524.

³Colorado's Oil-Shale Fields Are Vast, Oil and Gas Journal,
December 20, 1917, p. 32.

⁴ibid.

⁵Joint statement by Fred L. Hartley, Chairman and President,
Union Oil Company of California and John M. Hopkins, Acting President
of the Union Oil Synthetic Fuels Division before the Colorado
Interim Legislative Committee on Oil Shale, Coal, and Related
Minerals, Grand Junction, Colorado, July 23, 1974, p. 2.

⁶In-situ processes proposed for shale lease, Oil and Gas
Journal, June 6, 1977, p. 76.

⁷Gilbert Burck, U.S. Oil: A Giant Caught in Its Own Web
Fortune, April 1965, p. 207.

⁸Thomas C. Ryan, The Outlook for U.S. Petroleum Refining
(and Marketing), research report for Underwood Neuhaus & Co.,
Inc., August 2, 1976, p. 4.

⁹Brief by Ben Weichman, Manager of the Superior Oil Company's
Oil Shale Department, 1977, p. 5.

Chapter VI - GEOTHERMAL

A. Summary of Interview	162 - 164
B. Geothermal Energy - A description	165 - 167
C. Current Developers	168 - 168
D. Investment Perceptions of the Geothermal Industry	168 - 169
E. Oil Company Participation in Geothermal Energy Sources	169 - 169
Exhibit VI-1	170 - 173

Chapter VI - Geothermal Energy

A. Summary of Interviews

As with the other sections of this report, all numerical data came from public sources. Corporate views and perceptions came from face-to-face interviews and/or telephone conversations with the managements of twenty-one oil companies, five utilities, two coal companies, and five "others" (two large extractive mineral companies, a bank active in energy loans, a conglomerate energy company, and a railroad). Telephone conversations were held with an additional fifteen firms and/or other organizations. Those interviewed were asked, where applicable, to discuss the nature of their involvement with geothermal energy, particularly regarding current and/or planned investments. It should be noted that these views were based on economic conditions as perceived at the time of the interviews. These views will probably change as economic conditions change.

Interviews

Companies were asked to: I. Rate their "Interest" in geothermal energy. "Interest" was defined as present, or possibly future investments in geothermal energy. Responses were grouped into five categories. These categories are described below:

"Intense interest" describes those companies who have made major investments in geothermal energy and/or who can be expected to make substantial investments in the near future.

"Substantial interest" describes those companies who have made major investments in geothermal energy in the past. They might make additional investments in the future.

"Some interest" describes those companies with active R&D programs.

"Limited interest" describes those companies with low-scale R&D programs.

"No interest" describes those companies with no present investment and no plans for future investment in geothermal energy sources.

The companies were grouped as follows:

<u>Intense Interest</u>	<u>Substantial Interest</u>	<u>Some Interest</u>	<u>Limited Interest</u>	<u>No Interest</u>
3	6	-	-	12

As these data indicate, there are widely divergent views among oil companies regarding the efficacy of geothermal energy. Most companies (12 of 21 interviewed) feel that a currently limited, specialized market, coupled with long developmental lead times in geographic areas removed from "The Geysers" in California, (the only profitable, domestic geothermal energy operation in the U.S.,) make the development of geothermal energy a sub-marginal investment.

The responses of the five electric utilities interviewed are shown below:

<u>Intense Interest</u>	<u>Substantial Interest</u>	<u>Some Interest</u>	<u>Limited Interest</u>	<u>No Interest</u>
2	-	-	-	3

Not surprisingly, those utilities exhibiting interest are located on the West Coast near existing and suspected geothermal energy sources.

Of the two coal companies interviewed, neither had any interest in investing in geothermal energy.

Among the four "other" organizations that are operating companies, responses were as follows:

<u>Intense Interest</u>	<u>Substantial Interest</u>	<u>Some Interest</u>	<u>Limited Interest</u>	<u>No Interest</u>
-	1	-	1	2

Both companies indicating "substantial interest" or "limited interest" are in the exploration phase of geothermal energy development.

II. Evaluate Geothermal Energy as an Attractive Investment Opportunity

Those companies with current and/or planned investments in geothermal energy perceive it as a currently good or potentially good investment. Others feel that the long lead times, technical problems, and specialized market for geothermal energy inhibit investment.

B. Geothermal Energy - A description

There are five types of geothermal energy: 1) hydrothermal systems, 2) hot dry rocks, 3) geopressurized resources, 4) normal temperature gradients, and 5) molten magma.⁽¹⁾ All of these types of energy are generated by heat from the earth.

Although the energy contained in geothermal sources is thought to be very large, hydrothermal systems (hot water and steam) is the only one of the five types currently in use in the U.S.⁽²⁾ Economics of all types of geothermal energy are adversely affected by long lead times for specialized plants built at the energy source and by acute technical problems.

Because of these factors, the geothermal industry is not self-financing; funds are supplied by outside equity capital for both exploration and development of geothermal energy.

Although there are a handful of commercial geothermal operations throughout the world, the Geysers, in California, is the only commercial geothermal operation in the U.S. The world's largest, the Geysers is a specialized type of operation that produces dry steam.⁽³⁾ There are only two other known dry steam fields in the U.S. (both in National Parks) and one other in the world. The DOE, however, is experimenting with other types of geothermal energy, including hot dry rocks and molten magma. To date, however, no electricity has yet been generated.

Electric utilities are the primary market for geothermal energy. Although direct geothermal energy has been used for residential heating, transportation and other problems will limit

this for at least the remainder of this century.⁽⁴⁾ Geothermal energy, therefore, is a direct substitute for coal and nuclear energy, and a partial substitute for oil and natural gas. Unlike synfuels from coal or shale oil for example, geothermal energy can't be used to power automobiles or for use in fossil-fuel boilers.

Development of geothermal energy sources has been slow; economics were the principle deterrent to rapid expansion in the use of geothermal energy. In general, geothermal resources are a very low grade source of heat; only a tiny fraction of the resource base is in the form of steam. The most prevalent types of geothermal energy, therefore, are less efficient than oil, gas, coal, most synfuels, and/or nuclear. As a consequence, capital costs per kilowatt are high for generating electrical power with low efficiency turbines.⁽⁵⁾ Although fixed costs are reduced by the lack of boilers, operating cost for hydrothermal systems and others are generally high because of the need to handle large amounts of sometimes heavily mineralized water (the Geysers is an exception).

Economics of geothermal exploration and development are adversely affected (current Geysers development again excepted) because (1) there are no immediate markets for geothermal resources, (2) individually engineered power plants have to be built at the energy source, (3) in its raw form, geothermal energy can't be transported very far, and (4) development times

will be long, even if substantial "reserves" are discovered. The Geysers required 20 years of development (based on historical financial data of Magma Corp.) to become profitable.

In addition, there is also a high "engineering risk" involved in geothermal development; even when geothermal sources have been found, it is difficult to determine whether a project will be profitable because of the enormous water handling and potential corrosion problems involved. Imperial Valley sources and other more recent discoveries in Nevada and Utah are undergoing thorough engineering evaluation before utilities will commit to build electric generating plants at the sources that demand an economic life of 30 years.

Geothermal energy often has substantial environmental problems caused by the large amounts of highly mineralized waters.⁽⁶⁾ Water flow through a geothermal hot water plant would be about three times the flow through a nuclear or coal-fired plant. A geothermal hot water plant the size of a standard nuclear plant (1,300 MW) using hot water with a salt concentration only 10% that of sea water would utilize 4-8 million tons of water a day containing some 25 thousand tons of salt.⁽⁷⁾

There are other solvable environmental problems; currently unknown quantities of air pollutants would have to be controlled, including large amounts of hydrogen sulfide,⁽⁸⁾ and large land areas could be affected by subsidence caused by geothermal installations.⁽⁹⁾ Both could be particularly serious problems, especially in fault prone areas in California.

C. Current Developers

Oil and Other Industry Involvement

Exhibit VI-1 shows geothermal participants, with larger companies grouped by primary industry. As these data indicate, there are many holders of federal, state and private geothermal leases, with over 100 holders of federal leases. Although most of the lessees are individuals, many companies are active in the search for geothermal energy. Most of these are oil-oriented because of the similarities to petroleum drilling.⁽¹⁰⁾ As shown, oil industry participation is relatively broad and includes many smaller companies. Far-Western oriented U.S. companies are most active, such as Union, Shell, Standard of California, Phillips, Getty, and McCulloch.

D. Investment Perceptions of the Geothermal Industry

The leasing of potential geothermal acreage is generally not a problem. Many types and sizes of firms have leased federal acreage, as Exhibit VI-1 shows. Federal leasing has acreage limits per state per firm, and possibly as a consequence, federal government acreage is a small part of total land leased to date.

Although geothermal wells are more expensive than oil or gas wells, ⁽¹¹⁾ capital requirements are relatively modest. Financing is difficult, however, because lead times are so long and because, aside from the Geysers area, there is no current ready market (as for oil) for geothermal discoveries. With only a single commercial operation at present, and with long lead

times, the industry is not self-financing. Independent geothermal companies cannot contribute significantly to exploration and development of new geothermal sources without substantial outside funding.

Although the Geysers, for example, is apparently very profitable, more than 20 years of development was required before it reached this status. Development of the Geysers was initiated by two independent geothermal companies whose costs exceeded their ability to independently obtain capital. Union oil joined the development as a partner and operator in 1967, and the Geysers development has, since 1975, become a commercial success.

Most geothermal resources are West of the Rockies in areas with less than 20% of the U.S. population, and as previously noted, geothermal energy cannot be shipped very far without the construction of significant numbers of high-voltage power transmission lines. Because of the scarcity of readily-developable geothermal sources, little energy contribution, therefore, is expected from geothermal energy sources.

E. Oil Company Participation in Geothermal Energy Sources

Oil companies are, by far, the major contributors to exploration for additional underground geothermal energy sources. Because of limited profitability, and because no other industry drills deep wells, there has been little interest from companies in unrelated businesses.

GEO THERMALLARGER OIL AND GAS COMPANIES

UNION OIL	Operator and 50% owner of the Union-Magma-Thermal Geysers operation, the world's largest geothermal operation. Pacific Gas & Electric operates generating plants. Group drilled 13 new wells at Geysers in 1976. Union active in Imperial Valley and several Western states. Discoveries in New Mexico; further testing required.
SHELL	Four successful wells in Geysers area. Testing to determine development plan.
SOCAL	Active exploration. Imperial Valley development with utility group.
PHILLIPS	Active exploration. Discoveries in Nevada and Utah; additional testing necessary.
GULF	Exploration
GETTY	Exploration
OCCIDENTAL	Exploration
SUN	Exploration
PANHANDLE EASTERN (Anadarko)	Exploration
ARCO	Leases (Federal)
MOBIL	Exploration

SMALLER OIL AND GAS COMPANIES

NATOMAS (Thermal Power)	25% owner of Union-Magma-Thermal operation of Geysers. Leases throughout Western U.S.
MCCULLOCH OIL	Active exploration. Successful wells in Geysers area with Geothermal Kinetics and Entex.
MAPCO	Four wells at Imperial Valley; testing necessary.
SUPRON	Leases (Federal)
HUNT INTERESTS	Leases (Federal)
SUMATRA OIL	Leases (Federal)

OIL RESOURCES	Leases (Federal)
WEBB RESOURCES	Leases (Federal)
KISSENGER PETROLEUM	Leases (Federal)
CALVERT DRILLING	Leases (Federal)
HAWTHORN OIL	Leases (Federal)
<u>GEOTHERMAL COMPANIES</u>	
MAGMA POWER	25% owner of Union-Magma-Thermal operation at Geysers. Active in Imperial Valley, including ERDA-sponsored pilot plant with utility group.
GEOTHERMAL KINETICS	Partner with McCulloch Oil and in the Geysers Area.
MAGMA/GULF GEOTHERMAL	Exploration in Gulf Coast.
REPUBLIC GEOTHERMAL	Leases (Federal)
GEOTHERMAL RESOURCES	Leases (Federal)
WESTERN GEOTHERMAL	Leases (Federal)
THERMOGENICS	Leases (Federal)
EARTH POWER CORP.	Leases (Federal)
STEAM CORP. OF AMERICA	Leases (Federal)
WESTERN STEAM CO.	Leases (Federal)
THERMEX	Leases (Federal)
AMERICAN THERMAL RESOURCES	Leases (Federal)
<u>MINING COMPANIES</u>	
AMAX (Oil Division)	Exploration
<u>OTHER INDUSTRIAL COMPANIES</u>	
R. J. REYNOLDS (Aminoil)	Development in Geysers area. PG & E and to build generating plant.
HUGHES INTERESTS (Pacific Energy)	Development in Geysers area. PG & E and to build generating plant.

GENERAL ELECTRIC (Ladd Petroleum)	Exploration
ITT (Eason Oil)	Leases (Federal)
DOW CHEMICAL (Wanda Petroleum)	Leases (Federal)
<u>ELECTRIC UTILITIES</u>	
PACIFIC GAS & ELECTRIC	Power plants in Geysers field
SAN DIEGO GAS & ELECTRIC	Testing Imperial Valley development with Socal
NORTHERN CALIFORNIA POWER AUTHORITY	Joint Venture with McCulloch Oil
SOUTHERN CALIFORNIA EDISON	Researching power generation at Imperial Valley
DEPARTMENT OF WATER RESOURCES	(California) Financing Geothermal Exploration
PACIFIC POWER & LIGHT	Researching power generation at Geysers
SACRAMENTO MUNICIPAL UTILITY DISTRICT (SMUD)	Exploration
<u>INDIVIDUALS AND SMALLER COMPANIES</u>	
L. H. ARMOUS, JR.	Leases (Federal)
FRANCES B. BUNN	Leases (Federal)
RUSSELL A. POMEROY	Leases (Federal)
GERALD G. LOUKS	Leases (Federal)
JEROME P. McHUGH	Leases (Federal)
DIABLO EXPLORATION	Leases (Federal)
LELAND A. HODGES, TRUSTEE	Leases (Federal)
EDWARD H. HAGER	Leases (Federal)
PAGE T. JENKINS	Leases (Federal)
ELDON J. GILBERT	Leases (Federal)
JAMES R. ROBINSON et al	Leases (Federal)
PATRICIA F. GILBERT	Leases (Federal)
GEORGE W. WATERS	Leases (Federal)
DELTA FUNDS, INC.	Leases (Federal)
TERRY ALLEN KRAMER	Leases (Federal)
EUGENE NORTHCUTT	Leases (Federal)
ROBERT F. CORBIN	Leases (Federal)
EDWARD S. DAVIS, JR. et al	Leases (Federal)
RICHARD O. KINCAID	Leases (Federal)
RODNEY W. MARKLEY	Leases (Federal)
ROBERT L. WHEELER	Leases (Federal)
FRED H. BENNERS	Leases (Federal)

QUEST ENERGY LTD.	Leases (Federal)
YVONNE A. HAGER	Leases (Federal)
ROSE A. EARNSHAW	Leases (Federal)
WARREN E. WEST, JR.	Leases (Federal)
ENERGY PARTNERS 1974	Leases (Federal)
ROBERT L. ABBOTT	Leases (Federal)
PAUL F. SCHEIBE	Leases (Federal)
HUGO W. SCHOELLKOFF, JR.	Leases (Federal)
CAROLINE H. SCHOELLKOFF	Leases (Federal)
RICHARD C. HOEFLE	Leases (Federal)
AL-ACQUITAINE EXP. LTD. et al	Leases (Federal)
RONALD E. STONE	Leases (Federal)
SULPHUR RIVER EXPLORATION	Leases (Federal)
CHARLES L. EPPS	Leases (Federal)
KIRK GREENE	Leases (Federal)
EDWARD B. TOWNE, JR.	Leases (Federal)
RAMONA STARK SANDS	Leases (Federal)
MARCELLENE W. SANDS	Leases (Federal)
SINDEY E. GLENN	Leases (Federal)
WARREN M. WOODWARD	Leases (Federal)
NOAH SMERNOFF	Leases (Federal)
ROBERT F. GOSMAN	Leases (Federal)
W. C. DAILEY et al	Leases (Federal)
JACK F. GRIMM	Leases (Federal)
A. L. McDONALD	Leases (Federal)
JOSEPH L. WILSON	Leases (Federal)
DAVON, INC.	Leases (Federal)
MILTON FISHER	Leases (Federal)
O'BRIEN RESOURCES, INC.	Leases (Federal)
AGRI-EMPIRE	Leases (Federal)
GART W. SELTZER	Leases (Federal)
TREVAR L. WINDSOR	Leases (Federal)
CECIL L. FULMAN	Leases (Federal)
MALCOLM F. JUSTICE, JR.	Leases (Federal)
CHARLES L. GOLDING	Leases (Federal)
JAMES A. BECKER	Leases (Federal)
WILLIAM A. STEVENSON	Leases (Federal)
NOETH B. GILLETTE et al	Leases (Federal)
MILAN S. PAPULAK	Leases (Federal)

Sources: Companies; Bureau of Land Management
9/13/76

Footnotes

Chapter VI - Geothermal

¹MITRE Corporation, Nuclear Power Issues and Choices, Ballinger Publishing Company, 1977, Cambridge, Mass., p. 139.

²John E. Kilkenny. President, American Association of Petroleum Geologists, from a speech given at a meeting of the International Oil Scouts, Austin, Texas, July 9, 1977.

³John Hagel III, Alternative Energy Strategies, Praeger Publishers, Inc., 1976, New York, New York, p. 75.

⁴MITRE Corporation, op. cit. p. 142.

⁵ibid

⁶ibid, p. 141

⁷Derived from data published by MITRE Corporation, op.cit., p. 141.

⁸MITRE Corporation, op. cit., p. 141.

⁹John Hagel, III, op. cit., p. 76.

¹⁰John E. Kilkenny, op. cit.

¹¹John Hagel III, op. cit., p. 76.

Chapter VII - SOLAR

A. Summary of Interviews	176 - 178
B. Solar Energy - A Description	179 - 180
C. Current Developers	181 - 181
Exhibit VII - 1	182

Chapter VII - Solar Energy*

A. Summary of Interviews

All numerical data for this section of the report came from public sources. Subjective data came from face-to-face interviews with the managements of sixteen oil companies, five electric utilities, two coal companies, and five "others" (a railroad, two large extractive mineral companies, a conglomerate energy company, and an energy-financing bank). Extensive telephone conversations were held with an additional twenty organizations and/or firms.

Those interviewed were asked to discuss the nature of their involvement, or lack of it, in solar energy, with particular emphasis on current and/or planned investments. Their views, it should be noted, can be expected to change as conditions change.

Interviews

Oil companies were asked to:

I. Rate their current "interest" in solar energy.

"Interest" is defined as present, or possibly future, investments in solar energy. Because the nature of solar energy is such that it demands little capital, only two categories ("interest" and "no interest") are necessary to evaluate responses. Oil company responses are shown below:

Interest

4

No Interest

17

*This chapter will discuss only those areas of solar energy in which energy is derived directly from the rays of the sun, the only areas of oil company involvement. It will exclude, therefore, a review of hydroelectric power, windpower, or energy from biomass applications.

It should be noted too, that the level of interest of those responding positively could best be described as "mild".

Responses of the five utilities interviewed are shown below:

<u>Interest</u>	<u>No Interest</u>
4	1

Three of the four indicating interest are involved in operating solar facilities in residential test homes. The fourth plans to build and operate (with DOE) a ten megawatt solar plant.

Neither coal company interviewed stated any interest in solar energy.

Among "other" companies, interest in the operating companies was as follows:

<u>Interest</u>	<u>No Interest</u>
1	3

II. Entrance Into the Solar Business

None of the companies interviewed expressed difficulties in entering the solar business.

III. Solar Energy as an Attractive Investment Opportunity

Most of those companies interviewed were unenthusiastic about solar energy as an investment opportunity citing perceptions of a limited market and an alien technology. One large oil company suggested that it was "more of an IBM type of business" with the need for high technology and a large, sophisticated technically-oriented marketing and distribution system.

Most of those interviewed seemed discomforted with high technology and marketing, areas with which most petroleum company managements lack familiarity. Probably as a consequence, Exxon, Mobil, and Shell are supplying what is essentially venture capital to companies for research and development work in photovoltaic (direct conversion to electricity) technology. Mobil has committed up to \$30 million; Exxon and Shell have each spent about \$10 million.

Equity capital and "staying power" are necessary for successful R&D ventures. There is a limited number of companies capable and willing to do this on a meaningful scale.

B. Solar Energy - A Description

Solar energy dwarfs all other known energy resources. The amount of energy falling on the U.S. is enormous; if harnessed, about .15% of this energy, at 10% efficiency rate, could supply all present annual U.S. electrical needs⁽¹⁾. Because of substantially higher costs than competitive energy sources, however, large scale development of solar energy has not taken place. There are two primary reasons for these higher costs:

- 1) The sun is a very low grade, diffuse source of heat. The sun's natural energy intensity (on earth) is much lower than fossil fuels or nuclear energy.
- 2) Solar energy is least available when needed most; in winter, on cloudy days, and at night. Electrical storage costs are high, because storage efficiencies are low.⁽²⁾

It is the goal of solar research and development (R&D) to reduce these currently high costs by solving the significant technical problems encountered in the collection, concentration, and storage of solar energy.

Solar energy development has two main branches:

- 1) solar heating and cooling and,
- 2) generation of electric power

Solar heating and cooling is currently a fledgling commercial industry with hundreds of participants, mostly smaller companies. Solar Collector Manufacturing Activity,

April 1977 (3), for example, lists 185 companies, (from A-1 Prototype to Zoneworks Corporation) engaged primarily in solar heating and cooling. While solar heating and cooling shows substantial promise, some knowledgeable people feel that the near-term growth of this type of solar energy might be overstated. It is estimated that if, for example, solar captured 100% of new construction heating and cooling markets after 1985 it would represent only 6.5% of total primary energy requirements in the year 2000.(4) There is virtually no oil company involvement in this segment of the solar energy business.

Generation of electric power from solar energy is currently a "non-industry" in that it has no revenues. Although there are presently no commercial installations, it is expected that this branch will ultimately be the larger of the two. Four large oil companies and a number of other large firms (see Exhibit VII-1) are involved in various R&D projects directed towards the generation of electric power from solar energy. Because funds for R&D are generally not bank-financeable, substantial amounts of equity capital are required for successful development.

Electric power generation from solar energy is the ultimate replacement for both coal and nuclear power. (Because it cannot be used in current transportation equipment or existing boilers, it is not a direct replacement for oil or gas). To date, however, the market for solar generation of electricity has been limited to "cost-no-object" applications such as the NASA Space Program.

C. Current Developers

Oil company participation in solar energy is restricted almost entirely to conversion of sunlight to electricity. Gulf, Exxon, Mobil, and Shell are the only oil company participants with large solar R&D programs in place. Gulf is working on thermal electric methods, utilizing special mirrors to reflect and concentrate sunlight to heat fluids which drive turbines to generate electricity. Exxon, Mobil, and Shell are working on photovoltaic conversion of sunlight to electricity.

Many large high technology companies are also involved in solar energy development. These include AT&T, IBM, Eastman Kodak, Texas Instruments, and General Electric.

SOLAR

Larger Organizations Active in Solar Energy Development

OIL COMPANIES

Exxon
Gulf
Mobil
Shell (Royal Dutch)

OTHER LARGE ORGANIZATIONS

(Examples; not complete list)

Alcoa
Arthur D. Little, Inc.
AT&T
Dattelle Laboratories
Dow Chemical
Eastman Kodak
General Electric
Grumman
Honeywell
Hughes Aircraft
IBM
I.T.T.
Lennox Industries
Libby Owens Ford
Lockheed
MITRE Corp.
MMM
Monsanto
Motorola
North American Philips
Owens Illinois
PPG Industries
RCA
Revere Copper
Reynolds Aluminum
Rockwell International
Stanford Research Institute
Texas Instruments
TRW
Union Carbide
Varian Associates
Westinghouse

Source: Published company announcements and reports and ERDA
Catalog on Solar Energy Heating and Cooling Products
(Washington, October, 1975)

Footnotes

Chapter VII - Solar

¹Nuclear Energy Policy Study Group, Nuclear Power Issues and Choices, MITRE Corp., Ballinger Publishing Company, Cambridge, Mass., 1977, p. 130.

²ibid

³Solar Collector Manufacturing Activity, July through December 1976, Federal Energy Administration (Washington), April 1977.

⁴Richard E. Balzhiser (EPRI), Energy Options to the Year 2000, Chemical Engineering, January 3, 1977, p. 88.

**U.S. Department of Energy
Energy Information Administration
Office of Energy Information Services
1726 M St., N.W.
Washington, D.C. 20461.**

**OFFICIAL BUSINESS
PENALTY FOR PRIVATE USE, \$300**

FIRST CLASS MAIL